AP-42
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EMISSION FACTOR

DOCUMENTATION FOR

AP-42 SECTION 1.1

BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION

By:

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Contract No. 68-DO-00120
Work Assignment No. II-68

EPA Project Officer: Alice C. Gagnon

Office of Air Quality Planning and Standards
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1. INTRODUCTION

The document, "Compilation of Air Pollutant Emission Factors" (AP-42), has been published by the U.S. Environmental Protection Agency (EPA) since 1972. Supplements to AP-42 have been routinely published to add new emissions source categories and to update existing emission factors. An emission factor is an average value which relates the quantity (weight) of a pollutant emitted to a unit of activity of the source. In some cases, emission factors are presented in terms of an empirical formula to account for source variables. Emission factors are developed from source test data, material balance calculations, and engineering estimates. The uses for the emission factors reported in AP-42 include:

- Estimates of area-wide emissions;
- Emission estimates for a specific facility; and
- Evaluation of emissions relative to ambient air quality.

The EPA routinely updates AP-42 in order to respond to new emission factor needs of State and local air pollution control programs, industry, as well as the Agency itself. Section 1.1 in AP-42, the subject of this Emission Factor Documentation (EFD) report, pertains to bituminous and subbituminous coal combustion in stationary, external equipment.

The purpose of this EFD is to provide background information and to document the procedures used for the revision, update, and addition of emission factors for bituminous and subbituminous coal combustion. The scope of the present AP-42 Section 1.1 update is as follows:

- Update baseline, criteria emission factors with data identified since the prior updates;

- Modify equipment classifications to give separate treatment of tangentially-fired boilers and fluid bed combustors (FBCs);
- Extend emission factors to non-criteria species where data are available for volatile organic compounds (VOC) speciation, trace metals and cther air toxics, and greenhouse gases [nitrous oxide (e.g., N_2O), carbon dioxide (CO_2)]; and
- Extend documentation and emission factor development for controlled operation to reflect advances in control development and the increased importance of emission controls for combustion sources.

Data from approximately 20 test reports were used to revise and update emission factors for existing source categories; determine new emission factors for additional non-criteria pollutants; and add FBC units as a new source category.

The update of Section 1.1 of AP-42 began with a review of the existing version of Section 1.1. Spot checks were made on the quality of existing emission factors by recalculating emission factors from selected primary data references contained in the background files. These recalculated emission factors were then compared against those in the existing version of AP-42.

An extensive literature review was undertaken to improve technology descriptions, update usage trends, and collect new test reports for criteria and non-criteria emissions. The new test reports were subjected to data quality review as outlined in the draft EPA document, "Technical Procedures For Developing AP-42 Emission Factors And Preparing AP-42 Sections" (March 6, 1992). Test reports containing sufficiently high quality data ratings were combined with existing data to revise emission factors or to produce new emission factors, as appropriate. When sufficient new data were obtained that were of higher quality than existing data, old lower-quality data were removed from the existing emission factor averages. In some cases, data sources and test reports were identified during the literature review but were not received in sufficient time to incorporate into emission factor development. This information has been placed in the background files for use in future updates.

Several new emission factors for non-criteria pollutants have been added. These new emission factors pertain to total organic compounds (TOC), speciated volatile organic compounds (speciated VOC), air toxics, N_2O, CO_2, and fugitive emissions. Additionally, in this revision, the information on control technologies for particulate matter (PM), PM less than 10 microns (PM-10), sulfur oxide (SO_x), and nitrogen oxides (NO_x) emissions has been revised and updated. Add-on controls for non-criteria pollutants are not covered here because these controls have not been demonstrated on commercial scale combustors for this source category. Finally, because fluidized bed combustion of coal is finding increased commercial application in industrial and utility systems, a new source category for this combustion configuration has been added.

Including the introduction (Chapter 1), this EFD contains five chapters. Chapter 2 provides an overall characterization of bituminous and subbituminous coal combustion usage. This includes a breakdown of coal application by industry, an overview of the different source categories, a description of emissions, and a description of the technology used to control emissions resulting from coal combustion. Chapter 3 is a review of emissions data collection and analysis procedures. It describes the literature search, the screening of emissions data reports, and the quality rating system for both emission data and emission factors. Chapter 4 details pollutant emission factor development. It includes the review of specific data sets and details of emission factor compilations. Chapter 5 presents the revised AP-42 Section 1.1. Appendix A provides conversion factors and example calculations for emission factor development from test data. Appendix B contains an example of spot checking data from the fourth edition AP-42 primary references. Appendix C contains a marked-up copy of the 1988 AP-42 Section 1.1 indicating where changes have been made as a result of this update.

2. SOURCE DESCRIPTION

The amount and type of coal consumed, design of combustion equipment, and application of emission control technology have a direct bearing on emissions from coal-fired combustion equipment. This chapter characterizes bituminous and subbituminous coal combustion processes, and emission control technologies which are commercially available in the United States.

2.1 CHARACTERIZATION OF BITUMINOUS AND SUBBITUMINOUS COALS APPLICATIONS

Coal is a complex combination of organic matter and inorganic mineral matter formed over eons from successive layers of fallen vegetation. Coal types are broadly classified as anthracite, bituminous, subbituminous, and lignite. These classifications are made according to heating value as well as relative amounts of fixed carbon, volatile matter, ash, sulfur, and moisture. Formulas and tables for classifying coals based on these properties are given in Reference 1.

In general, bituminous coals have heating values of 5,800 to 7,800 kcal/kg (10,500 to 14,000 Btu/lb) while the heating values of subbituminous coals are lower at 4,600 to 6,400 kcal/kg (8,300 to 11,500 Btu/lb).[1] Subbituminous coals are typically higher in volatile matter, moisture, and oxygen contents than bituminous coals and, as a result, are lower in fixed carbon content. Because of their high heating values and high volatile contents, both bituminous and subbituminous coals burn easily when pulverized to fine powder. Because of its characteristically lower sulfur content and higher moisture content, SO_2 and NO_x emissions are generally lower for combustion of subbituminous coals relative to bituminous coals.

In 1990, a total of almost 860 million short tons of coal were consumed by the utility, industrial, commercial/institutional, and residential sectors.[2] These four sectors can be described as follows: (1) utility boilers producing steam for generation of electricity; (2) industrial boilers generating steam or hot water for process heat, generation of electricity, or space heat; (3) boilers for space-heating of commercial and institutional facilities; and (4) residential furnaces for space- heating purposes. As shown in Table 2-1, the utility sector consumed the most fuel [over 700 million metric tons (770 million short tons)]. The residential usage of coal for space heating has generally declined since 1973 as stoker- and hand-fired furnaces and boilers have been replaced by oil, gas, and electric heating systems.[2] Of the total coal produced in 1989, approximately 67 percent was bituminous, 24 percent subbituminous, 9 percent lignite, and less than 1 percent anthracite.[1]

2.2 PROCESS DESCRIPTIONS

Coal-fired boilers can be classified by type, fuel, and method of construction. Boiler types are identified by the heat transfer method (watertube, firetube, or cast iron), the arrangement of the heat transfer surfaces (horizontal or vertical, straight or bent tube), and the firing configuration (suspension, stoker, or fluidized bed). Table 2-2 summarizes boiler type usage by sector. Most of the installed capacity of firetube and cast iron units is oil- and gas-fired[3]; however, a description of these designs for coal is included here for completeness.

A watertube boiler is one in which the hot combustion gases contact the outside of the heat transfer tubes, while the boiler water and steam are contained within the tubes. Coal-fired watertube boilers consist of pulverized coal, cyclone, stoker, fluidized bed, and handfeed units. Pulverized coal and cyclone boilers are types of suspension systems because some or all of the combustion takes place while the fuel is suspended in the furnace volume. In stoker-fired systems and most handfeed units, the fuel is primarily burned on the bottom of the furnace or on a grate. Some fine particles are entrained in upwardly flowing air, however, and are burned in suspension in the upper furnace volume. In a fluidized bed combustor, the coal is introduced to a bed of either sorbent or inert material (usually sand) which is fluidized by an upward flow of air. Most of the combustion occurs within the bed, but some smaller particles burn above the bed in the "freeboard" space.

2.2.1 Suspension Firing

In pulverized coal-fired (PC-fired) boilers the fuel is pulverized to the consistency of light powder and pneumatically injected through the burners into the furnace. Combustion in PC-fired units takes place almost entirely while the coal is suspended in the furnace volume. PC-fired boilers are classified as either dry bottom or wet bottom, depending on whether the ash is removed in solid or molten state. In dry bottom furnaces, coals with high fusion temperatures are burned, resulting in dry ash. In wet bottom furnaces, coals with low fusion temperatures are used, resulting in molten ash or slag. Wet bottom furnaces are also referred to as slag tap furnaces.

Depending upon the location of the burners and the direction of coal injection into the furnace, PC-fired boilers can also be classified into three different firing types. These are:

- Single and opposed wall, also known as face firing;
- Tangential, also known as corner firing; and
- Cyclone.

Wall-fired boilers can be either single wall-fired, with burners on only one wall of the furnace firing horizontally, or opposed wall-fired, with burners mounted on two opposing walls. PC-fired suspension boilers usually are characterized by very high combustion efficiencies, and are generally receptive to low-NO_x burners and other combustion modification techniques. Tangential or corner-fired boilers have burners mounted in the corners of the furnace. The fuel and air are injected toward the center of the furnace to create a vortex that is essentially the burner. Because of the large flame volumes and relatively slow mixing, tangential boilers tend to be lower NO_x emitters for baseline uncontrolled operation. Cyclone furnaces are often categorized as a PC-fired system even though the coal burned in a cyclone is crushed to a maximum size of about 4.75 mm (4 mesh). The coal is fed tangentially, with primary air, into a horizontal cylindrical furnace. Smaller coal particles are burned in suspension while larger particles adhere to the molten layer of slag on the combustion chamber wall. Cyclone boilers are high-temperature, wet bottom-type systems. Because of their high furnace heat release rate, cyclones are high NO_x emitters and are generally more difficult to control with combustion modifications.

2.2.2 Stoker Firing

Stoker firing systems account for the vast majority of coal-fired watertube boilers for industrial, commercial, and institutional applications.[4] Most packaged stoker units designed for coal firing are less than 29 MW (100 million Btu/hr) heat input.[5] Field erected units with capacities in excess of 116 MW (400 million Btu/hr) are common. Stoker systems can be divided into three groups: underfeed stokers, overfeed stokers, and spreader stokers. These systems differ in how fuel is supplied to either a moving or stationary grate for burning. One important similarity among all stokers is that all design types use underfeed air to combust the coal char on the grate, combined with one or more levels of overfire air introduced above the grate. This helps ensure complete combustion of volatiles and low combustion emissions.

Underfeed stokers are generally of two types: the horizontal-feed, side-ash-discharge type shown in Figure 2-1; and the gravity-feed, rear-ash-discharge type shown in Figure 2-2. The horizontal-feed, side-ash-discharge type of stoker is used primarily in small boilers supplying relatively constant steam loads of less than about 14,000 kg/hr (30,000 lb/hr).[1] The gravity-feed, rear-ash-discharge underfeed stoker can be as large as 150 MW (500 million Btu/hr) heat input capacity[1], although there are a few underfeed coal stokers of up to 440 MW (1500 million Btu/hr)[3].

An overfeed stoker, shown in Figure 2-3, uses a moving grate assembly. Coal is fed from a hopper onto a continuous grate which conveys the fuel into the furnace. Caking bituminous coals can cause agglomeration and matting which can restrict the airflow through the grate causing further combustion problems.[5] The three types of grates used with overfeed coal stokers are the chain, travelling, and water-cooled vibrating grates. These overfeed stoker systems are often referred to by the type of grate employed. Overfeed coal-fired systems typically range up to 100 MW (350 million Btu/hr) heat input.

In a spreader stoker, shown in Figure 2-4, mechanical or pneumatic feeders distribute coal uniformly over the surface of a moving grate. The injection of the fuel into the furnace and onto the grate combines suspension burning with a thin, fast-burning fuel bed. The amount of fuel burned in suspension depends primarily on fuel size and composition, and air flow velocity. Generally, fuels with finer size distributions, higher volatile matter contents, and lower moisture contents result in a greater percentage of combustion and corresponding heat release rates in suspension above the bed.[6] Heat input capacities of spreader stokers typically range from 1 to 130 MW (5 to 450 million Btu/hr).[3] Unlike overfeed stokers, fuels with the potential to cake have little negative effect on spreader stokers and can be generally fired with success in these units.[5]

2.2.3 Fluidized Bed Combustion

Fluidized bed combustion boilers, while not constituting a significant percentage of the total boiler population, have nonetheless gained popularity in the last decade, and today generate steam for industries, cogenerators, independent power producers, and utilities. Fluidized bed combustion is a boiler design which can lower sulfur dioxide (SO_2) and NO_x emissions without the use of post-combustion or add-on controls. A calcium-based limestone or dolomitic sorbent is often used for the bed material to capture SO_2 evolved during combustion. The sulfur is retained as a solid sulfate and is removed from the flue gas stream by the particulate control device. Emissions of thermal NO_x are reduced because FBCs are able to operate at lower combustion temperatures compared to the more conventional designs, thus reducing the fixation of atmospheric nitrogen. Typical maximum firing temperatures for FBCs are 930°C (1700°F) compared with typical furnace-exit-gas-temperatures of 1430°C (2600°F) for dry bottom boilers and up to 1760°C (3200°F) for wet bottom boilers.[1] Conversion of fuel nitrogen to NO_x is also suppressed with FBC compared to suspension firing.

There are two major categories of FBC systems: (1) atmospheric, operating at or near ambient pressures, and (2) pressurized, operating from 4 to 30 atmospheres (60 to 450 psig). Pressurized FBC systems are being demonstrated at two utility sites in the U.S.; however, they are not yet considered fully commercialized. The remainder of this section will therefore describe only atmospheric FBCs.

Figures 2-5 and 2-6 show the two principal types of atmospheric FBC boilers, bubbling bed and circulating bed. The fundamental distinguishing feature between these types is the fluidization velocity. In the bubbling bed design, the fluidization velocity is relatively low, ranging between 1.5 and 3.6 m/s (5 and 12 ft/s), in order to minimize solids carryover or elutriation from the combustor. Circulating FBCs, however, employ fluidization velocities as high as 9 m/s (30 ft/s) to promote the carryover or circulation of the solids. High temperature cyclones are used in circulating FBCs and in some bubbling FBCs to capture the solid fuel and bed material for return to the primary combustion chamber. The circulating FBC maintains a continuous, high volume recycle rate which increases the residence time compared to the bubbling bed design. Because of this feature, circulating FBCs often achieve higher combustion efficiencies and better sorbent utilization than bubbling bed units.[7]

2.2.4 Handfeed Units

Small, coal-fired boilers and furnaces are sometimes found in small industrial, commercial, institutional, or residential applications. Small firetube boilers in these installations are sometimes capable of being hand-fired. From an emissions standpoint, handfeed units can have high carbon monoxide (CO) and VOC emissions because of generally low combustion efficiencies due, in part, to the presence of quench surfaces. Most small units may not have particulate controls while some are only equipped with simple cyclone or multiclone collectors. Small boilers and furnaces without particulate controls do not generally have emission factors as high as large uncontrolled industrial boilers because typical combustion intensities and firebox velocities are lower in the smallest units. Lower firebox velocities mean that smaller quantities of particulate matter are entrained in the combustion gases.

The most common types of firetube boilers used with coal are the horizontal return tubular (HRT), Scotch, vertical, and the firebox. Cast iron boilers are also sometimes available as coal-fired units in a handfeed configuration. The HRT boilers are generally fired with gas or oil instead of coal. A two-pass HRT boiler is shown in Figure 2-7. A Scotch or shell boiler differs from the HRT boiler in that the boiler and furnace are contained in the same shell. In a two-pass unit, combustion occurs in the lower half of the unit, with the flue gases passing beneath the bottom of the water basin occupying the upper half. Like HRT boilers, coal is not as commonly used in Scotch boilers due to slagging and scaling.[3] More common gas- and oil-fired Scotch units are shown in Figures 2-8 and 2-9.

A vertical firetube boiler is a single-pass unit in which the firetubes come straight up from the water-cooled combustion chamber located at the bottom of the unit. Figures 2-10 and 2-11 show two types of vertical firetube boilers. Vertical boilers are small, with input capacities under 0.7 MW (2.5 million Btu/hr). A firebox boiler is constructed with an internal steel encased, water-jacketed firebox. Firebox firetube boilers are also referred to as locomotive, short firebox, and compact firebox boilers. Currently available coal-fired firebox units employ mechanical stokers or are capable of being hand-fired. They are generally limited in size to below 7.3 MW (25 million Btu/hr) input capacity.[4] Cast iron boilers consist of several vertical sections of heat exchange tubes mounted above a firebox. Water enters each section at the bottom and is heated or converted to steam as it passes upward through the heat exchange tubes. Figure 2-12 shows a typical cast iron boiler.

2.3 EMISSIONS

Emissions from coal combustion depend on coal rank and composition, the design type and capacity of the boiler, the firing conditions, load, the type of control technologies, and the level of equipment maintenance. Baseline, uncontrolled sources are those without add-on air pollution control (APC) equipment, low-NO_x burners, or other modification for emission control. Baseline emission for SO_2 and particulate matter (PM) can also be obtained from measurements taken upstream of APC equipment.

Because of the inherent low NO_x emission characteristics of FBCs and the potential for in-situ SO_2 capture with calcium-based bed materials, uncontrolled emission factors for this source category were not developed in the same sense as with the other source categories. For NO_x emissions, the data collected from test reports were considered to be baseline if no additional add-on NO_x control (such as ammonia injection) was in place. For SO_2 emissions, a correlation was developed from reported data on FBCs to relate SO_2 emissions with the coal sulfur content and the calcium to sulfur ratio in the bed.

For this update of AP-42, point source emissions of NO_x, SO_2, PM, PM-10, and CO are evaluated as criteria pollutants (those emissions which have established National Primary and Secondary Ambient Air Quality Standards[8]). This update includes point source emissions of some non-criteria pollutants (e.g., N_2O, VOCs, and air toxics) as well as data on particle size distribution to support PM-10 emission inventory efforts. Emissions of CO_2 are also being considered because of its possible participation in global climatic change and the corresponding interest in including this gas in emission inventories. Most of the carbon in fossil fuels is emitted as CO_2 during combustion. Minor amounts of carbon are emitted as CO or as carbon retained in the fly ash. Finally, fugitive emissions associated with the use of coal at the combustion source are being included in this update of AP-42.

The total 1985 emissions of PM, SO_2, and NO_x emissions resulting from bituminous coal combustion in the major use sectors are summarized in Table 2-3 shown below. Table 2-4 summarizes the federal New Source Performance Standards (NSPS)[9-12] applicable to PM, SO_2, and NO_x emissions from fossil fuel-fired boilers.

A general discussion of emissions of criteria and non-criteria pollutants from coal combustion is given in the following paragraphs.

2.3.1 Particulate Matter Emissions

Uncontrolled PM emission from coal-fired boilers include the ash in the fuel as well as unburned carbon resulting from incomplete combustion. Emission factors for PM have generally been expressed as a function of fuel ash content. Coal ash may either settle out in the boiler (bottom ash) or be carried out with the flue gas (fly ash). The distribution of ash between the bottom and fly ash fractions directly affects the PM emissions rate[13] and is a function of the following:

- Boiler firing method -- The type of firing is perhaps the most important factor in determining ash distribution. For example, stoker-fired units emit less fly ash than dry bottom, PC boilers; and
- Wet or dry bottom furnace -- Wet bottom cyclone furnaces remove approximately 70 percent of ash as slag or bottom ash; with dry bottom units, the inverse is roughly the case, where 70 percent of ash exits the boiler with the combustion gases to be treated by particulate collectors.

Boiler load also affects PM emissions from coal-fired boilers. In general, decreasing load tends to reduce PM emissions; however, the magnitude of the reduction varies considerably depending on boiler type, fuel, and boiler operation.

Soot blowing is a source of intermittent PM emissions in coal-fired boilers. Steam soot blowing is used periodically to dislodge ash from heat transfer surfaces in the furnace, convective section, and economizer/preheater. On small boilers with single soot blowers, soot blowing may only take place for a few seconds once a shift. Large boilers may have numerous soot blowers installed and operated in a cycle which may approach "continuous" soot blowing.

2.3.2 Sulfur Oxide Emissions

Sulfur oxide emissions are generated during coal combustion from the oxidation of sulfur contained in the fuel. The emissions of SO_x from conventional combustion systems are predominantly in the form of SO_2. On average, more than 95 percent of the fuel sulfur is converted to SO_2, about 1 to 5 percent is further oxidized to sulfur trioxide (SO_3), and about 1 to 3 percent is converted to sulfate particulate. Sulfur trioxide readily reacts with water vapor (both in air and in flue gases) to form sulfuric acid mist.

Uncontrolled SO_x emissions are almost entirely dependent on the sulfur content of the fuel and, with the exception of fluidized bed combustors, are not affected by boiler type, size, or burner design[15]. There is some potential that stoker boilers firing high ash coal with a significant alkaline content could result in SO_2 emissions which are lower than a PC-fired boiler firing the same fuel due to sulfur retention as an alkali sulfate in the ash bed on the grate. In some cases, combustion of highly alkaline, Western subbituminous coals can result in 20 percent of the sulfur in the coal being retained in the bottom ash or fly ash.[16] However, the data reviewed did not justify the presentation of separate emission factors for stoker-fired systems. Therefore, as in the earlier versions of AP-42, a consistent SO_2 emission factor, based only on fuel sulfur content (within a coal rank), was retained for all combustion configurations, with the single exception of FBC units.

2.3.3 Nitrogen Oxide Emissions

Oxides of nitrogen formed in combustion processes are due either to thermal fixation of atmospheric nitrogen in the combustion air ("thermal NO_x") or to the conversion of chemically bound nitrogen in the fuel ("fuel NO_x"). The term NO_x customarily refers to the composite of nitric oxide (NO), and nitrogen dioxide (NO_2).

Nitrous oxide is excluded, but is an oxide of definite interest. Test data have shown that for most stationary combustion systems, over 95 percent of the emitted NO_x is in the form of NO.[15]

The qualitative global kinetics of thermal NO_x formation have shown that NO_x formation rates are exponentially dependent on temperature, and proportional to N_2 concentration in the flame, the square root of the oxygen (O_2) concentration in the flame, and the residence time.[17] Thus, the formation of thermal NO_x is affected by four factors: (1) peak temperature, (2) nitrogen concentration, (3) oxygen concentration or flame stoichiometry, and (4) time of exposure at peak temperature. The emission trends resulting from changes in these factors are fairly consistent for all types of boilers -- an increase in flame temperature, oxygen availability, and/or residence time at high temperatures leads to an increase in thermal NO_x production regardless of the boiler type.

Fuel nitrogen conversion is the more important NO_x forming mechanism in coal-fired combustion systems because of the high nitrogen content in the fuel. Fuel NO_x can account for 80 percent of the total NO_x emissions in coal firing.[18] The percent conversion of fuel nitrogen to NO_x can vary greatly. Anywhere from 5 to 60 percent of nitrogen in the coal can be converted to NO_x.[17] Furthermore, test data indicate that the percent of fuel nitrogen conversion decreases as the fuel nitrogen content increases.[19]

A number of variables influence how much NO_x is formed by these two mechanisms. One important variable is firing configuration. The NO_x emissions from tangentially (corner) fired boilers are, on the average, less than those of horizontally opposed units. Also important are the firing practices employed during boiler operation. Low excess air (LEA) firing, flue gas recirculation (FGR), staged combustion (SC), or some combination thereof may result in NO_x reductions of 5 to 60 percent. (See Section 2.4.1 for a discussion of these techniques). Load reduction can likewise decrease NO_x production. The NO_x emissions may be reduced from 0.5 to 1 percent for each percentage reduction in load from full load operation. Levels of NO_x emissions do not decrease significantly in response to load reductions in some boilers and have, in some cases, been observed to increase (due to the higher excess air levels sometimes required to maintain stable combustion). It should be noted that the discussion of these variables, with the exception of excess air, applies to the NO_x emissions only of large coal-fired boilers. Low excess air firing is possible in many small boilers, but the resulting NO_x reductions are not nearly so significant.

Test data on pulverized coal combustion utility boilers indicate that N_2O emissions were always less than 10 ppm[20] and often less than 1 ppm in the units tested.[21] Generally, N_2O emissions from FBC boilers can be higher, but are generally less than 100 ppm with U.S. coals.[22] Some of the higher N_2O emissions that have been reported are from European FBC installations and pilot plant studies.[23] Some pilot plant configurations have been suspected of producing spuriously high N_2O emissions data which are not representative.

At the third N_2O workshop held in France in June 1988,[24] data were presented suggesting the presence of an N_2O sampling artifact in sampling containers awaiting analysis. Recent N_2O emissions data indicate that direct N_2O emissions from coal combustion units are considerably below the measurements made prior to 1988. The emission ranges quoted above are based on tests employing methods to minimize or eliminate the sampling artifact. Nevertheless, the N_2O formation and reaction mechanisms are still not well understood or well characterized. Additional sampling and research is needed to fully characterize N_2O emissions and to understand the N_2O mechanism. Emissions can vary widely from unit to unit, or even at the same unit at different operating conditions. It has been shown in some cases that N_2O increases with decreasing boiler temperature.[22] For this AP-42 update, an average emission factor based on reported test data was developed for conventional coal combustion systems, and a separate emission factor was developed for fluidized bed combustors.

2.3.4 Carbon Monoxide Emissions

The rate of CO emissions from combustion sources depends on the oxidation efficiency of the fuel. By controlling the combustion process carefully, CO emissions can be minimized. Thus, if a unit is operated improperly or not maintained, the resulting concentrations of CO (as well as organic compounds) may increase by several orders of magnitude. Smaller boilers, heaters, and furnaces tend to emit more of these pollutants than larger combustors. This is because smaller units usually have less high-temperature residence time and, therefore, less time to achieve complete combustion than larger combustors.

The presence of CO in the exhaust gases of combustion systems results principally from incomplete fuel combustion. Several conditions can lead to incomplete combustion. These include:

- Insufficient oxygen availability;
- Extremely high levels of excess air leading to quenching (more common with industrial boilers);
- Poor fuel/air mixing;
- Cold wall flame quenching;
- Reduced combustion temperature;
- Decreased combustion gas residence time; and
- Load reduction (reduced combustion intensity).

Since various combustion modifications for NO_x reduction can produce one or more of the above conditions, the possibility of increased CO emissions is a concern for environmental, energy efficiency, and operational reasons.

2.3.5 Organic Compound Emissions

Total organic compounds include VOCs which remain in a gaseous state in ambient air, semi-volatile organic compounds and condensible organic compounds. According to the Federal Register, VOC has been defined as any organic compound excluding CO, CO_2, carbonic acid, metallic carbides or carbonates, and ammonium carbonate which participates in atmospheric photochemical reactions. The following additional compounds have been deemed to be of "negligible photochemical reactivity" and so are exempt from the definition of VOC: methane, ethane, methyl chloroform, methylene chloride, and most chlorinated-fluorinated compounds (commonly referred to as CFCs). Although these compounds are considered "exempt" from most ozone control programs due to their low photochemical reactivity rates, they are of concern when developing complete emission inventories which are necessary for the design of effective ozone control strategies. The term TOC will be considered to include all organic compounds, i.e. VOCs plus the "exempt" compounds including methane and ethane, toxic compounds, aldehydes, perchloroethylene, semi-volatiles, and condensibles (as measured by EPA Reference Methods).[25]

Emissions of VOCs are primarily characterized by the criteria pollutant class of unburned vapor phase hydrocarbons. Unburned hydrocarbon emissions can include essentially all vapor phase organic compounds emitted from a combustion source. These are primarily emissions of aliphatic, oxygenated, and low molecular weight aromatic compounds which exist in the vapor phase at flue gas temperatures. These emissions include all alkanes, alkenes, aldehydes, carboxylic acids, and substituted benzenes (e.g., benzene, toluene, xylene, ethyl benzene, etc.).[26,27]

The remaining organic emissions are composed largely of compounds emitted from combustion sources in a condensed phase. These compounds can almost exclusively be classed into a group known as polycyclic organic matter (POM), and a subset of compounds called polynuclear aromatic hydrocarbons (PNA or PAH). There are also PAH-nitrogen analogs. Information available in the literature on POM compounds generally pertains to these PAH groups. Because of the dominance of PAH information (as opposed to other POM categories) in the literature, many reference sources have inaccurately used the terms POM and PAH interchangeably.

Polycyclic organic matter can be especially prevalent in the emissions from coal burning, because a large fraction of the volatile matter in coal exits as POM.[4] A few comments are in order concerning an extremely toxic subclass of PNA -- the polychlorinated and polybrominated biphenyls (PCBs and PBBs). A theoretical assessment of PCB formation in combustion sources[28] concluded that, although PCB formation is thermodynamically possible for combustion of fuels containing some chlorine (e.g., some coals and residual oil), it is unlikely due to short reaction residence times at conditions favoring PCBs and to low chlorine concentrations. Also with efficient mixing, oxygen availability, and adequate residence time at temperatures in the 800-1000 °C (1470-1830 °F) range, PCBs [together with polychlorinated dibenzo-p-dioxins (PCDD) and polychlorinated dibenzofurans (PCDF)] may be efficiently destroyed.[29] Other research has shown, however, that chlorinated PNAs can be formed via catalyzed reactions on fly ash particles at low temperatures in equipment downstream of the combustion device.[61]

Formaldehyde is formed and emitted during the combustion of hydrocarbon-based fuels including coal and oil. Formaldehyde is present in the vapor phase of the flue gas. Since formaldehyde is subject to oxidation and decomposition at the high temperatures encountered during combustion, large units with efficient combustion resulting from closely regulated air-fuel ratios, uniformly high combustion chamber temperatures, and relatively long retention times should have lower formaldehyde emission rates than do small, less efficient combustion units.[30,31]

2.3.6 Trace Element Emissions

Trace elements are also emitted from the combustion of coal. For this update of AP-42, trace metals included in the list of 189 hazardous air pollutants under Title III of the 1990 Clean Air Act Amendments (CAAA-90)[32] are considered. The quantity of trace metals emitted depends on combustion temperature, fuel feed mechanism and the composition of the fuel. The temperature determines the degree of volatilization of specific compounds contained in the fuel. The fuel feed mechanism affects the partitioning of emissions into bottom ash and fly ash.

The quantity of any given metal emitted, in general, depends on:

- Its concentration in the fuel;
- The combustion conditions;
- The type of particulate control device used, and its collection efficiency as a function of particle size; and
- The physical and chemical properties of the element itself.

It has become widely recognized that some trace metals concentrate in certain waste particle streams from a combustor (bottom ash, collector ash, flue gas particulate), while others do not.[4] Various classification schemes to describe this partitioning have been developed.[33-35] The classification scheme used by Baig et al.[35] is as follows:

- Class 1: Elements which are approximately equally distributed between fly ash and bottom ash, or show little or no small particle enrichment;

- Class 2: Elements which are enriched in fly ash relative to bottom ash, or show increasing enrichment with decreasing particle size;
- Class 3: Elements which are intermediate between Class 1 and 2;
- Class 4: Volatile elements which are emitted in the gas phase.

By understanding trace metal partitioning and concentration in fine particulate, it is possible to postulate the effects of combustion controls on incremental trace metal emissions.[4] For example, several NO_x controls for boilers reduce peak flame temperatures [e.g., staged combustion, flue gas recirculation (FGR), reduced air preheat, and load reduction]. If combustion temperatures are reduced, fewer Class 2 metals will initially volatilize, and fewer will be available for subsequent condensation and enrichment on fine particulate matter. Therefore, for combustors with particulate controls, lowered volatile metal emissions should result due to improved particulate removal. Flue gas emissions of Class 1 metals (the non-segregating trace metals) should remain relatively unchanged.

Lowered local O_2 concentrations are also expected to affect segregating metal emissions from boilers with particle controls. Lowered O_2 availability decreases the possibility of volatile metal oxidation to less volatile oxides. Under these conditions, Class 2 metals should remain in the vapor phase into the cooler sections of the boiler. More redistribution to small particles should occur and emissions should increase. Again, Class 1 metals should not be significantly affected.

Other combustion NO_x controls which decrease local O_2 concentrations (staged combustion and low NOx burners) may also reduce peak flame temperatures. Under these conditions, the effect of reduced combustion temperature is expected to be stronger than that of lowered O_2 concentrations.

2.3.7 Fugitive Emissions

Fugitive emissions are pollutants which escape from an industrial process due to leakage, materials handling, inadequate operational control, transfer or storage. Depending on how the fugitive emissions are measured, under what conditions, and for what specific type of operation used, emission factors tend to vary widely in validity, absolute value, and methodology of calculation.

The fly ash handling operations in most modern utility and industrial combustion sources consist of pneumatic systems or enclosed and hooded systems which are vented through small fabric filters or other dust control devices. The fugitive PM emissions from these systems are therefore minimal. Fugitive particulate emissions can sometimes occur during transfer operations from silos to trucks or rail cars.

2.4 CONTROL TECHNOLOGIES

Only controls for criteria pollutants are discussed here because controls specifically for non-criteria emissions have not been demonstrated or commercialized for coal combustion sources.

Control techniques may be classified into three broad categories: fuel treatment/substitution, combustion modification, and post-combustion control. Fuel treatment includes coal cleaning using physical, chemical, or biological processes. Combustion modification and post-combustion control are both applicable and widely commercialized for coal combustion sources. Combustion modification is applied primarily for NO_x control purposes, although for small units, some reduction in PM emissions may be available through improved combustion practice. Post combustion control is applied to emissions of PM, SO_2, and, to some extent, NO_x for coal combustion.

Particulate emissions may be categorized as either filterable or condensible. Filterable emissions are generally considered to be the particles that are trapped by the glass fiber filter in the front half of a Reference Method 5 or Method 17 sampling train. Particles less than 0.3 microns and vapors pass through the filter. Condensible particulate matter (CPM) is material that is emitted in the vapor state which later condenses to form homogeneous and/or heterogeneous aerosol particles. The condensible particulate emitted from boilers fueled on coal or oil is primarily inorganic in nature.

2.4.1 Fuel Treatment/Substitution

Fuel treatment (or benefication) and fuel substitution are pre-combustion techniques for reducing NO_x, SO_2, and PM emissions from combustion sources. Fuel substitution involves the use of naturally occurring clean fuels, whereas benefication provides a physically or a chemically cleaned fuel.

Naturally occurring low sulfur coals may allow a source to meet SO_2 emission limits or reduce emissions with no additional controls. Low sulfur coal is sometimes defined as run-of-mine (ROM) coal which can comply with a given emission standard. Although the terms "high" and "low" are dependent on the specifics of the fuel analysis (and the area where the coal was mined), generally the break point between high and low sulfur coal is considered to be around 1100 ng/J (2.5 lbs SO_2 per million Btu of heat input).[36] This is roughly equivalent to 1.5 percent sulfur for bituminous coals, and about 1.0 percent for subbituminous coals. Nearly 85 percent of the reserve base of low sulfur coal is located in states west of the Mississippi River. The bulk of western coals are, however, of a lower rank than are the Eastern coals.

Low sulfur western coals can be burned in stoker-fired systems as long as there is sufficient undergrate air to handle any caking that may occur. Also, many low sulfur western coals have low ash fusion temperatures which may cause slagging on the grate for some stoker designs.

Pulverized coal and FBC boilers can be designed for almost any type of coal. However, once a design is set (especially for PC systems), substitutions are limited to coals with compatible combustion characteristics and ash properties. Fluidized bed boilers are generally more tolerant of alternate or "off-spec" fuels. The choice of alternate coal will depend on the type of pulverizer at the boiler site (for PC-fired systems), the spacing of watertubes in the steam generator and superheater sections, and the materials used in the furnace wall.[37] Also, the higher resistivity of the fly ash from the combustion of low sulfur coal may affect the particulate control performance of the ESP.

Physical coal benefication consists of a series of steps including size reduction, classification, cleaning, dewatering and drying, waste disposal, and pollution control. Basic physical coal cleaning techniques have been commercial for at least 50 years.[36] Currently, more than 50 percent of domestic coal is cleaned to some level before use.[36] There are in excess of 500 coal cleaning plants in the U.S., most of which are located east of the Mississippi River. Although coal cleaning was originally envisioned as an ash reduction technology, it also accomplishes reduction in SO_2 emissions. The level of reduction is dependent on the pyritic (inorganic) sulfur content and the nature and extent of cleaning operations (primarily crushing) done on the feed coal. Current, commercial physical coal cleaning plants are capable of removing 20 to 50 percent of the pyritic sulfur.[36] Assuming the high range to be achievable, and using published levels of pyritic and total sulfur for individual coals,[38] the total possible reduction in SO_2 emissions for common bituminous coals are:

- Illinois No. 6: 27%
- Upper Freeport: 47%
- Upper Kittanning: 11%

These reduction values are shown for illustration purposes only since the ratio of pyritic to organic sulfur can vary substantially alon ghe length of a seam (e.g., reductions could bary between 20 and 40 percent for Illinois No. 6 coal). It is evident that the degree of SO_2 removal available with physical coal benefication depends on the cleaning process as well as the coal type and pyritic/organic sulfur ratio. It is also clear that the removal of SO_2 is well below the 90 percent level usually required under the New Source Performance Standards (NSPS).[10-12]

Several chemical and biological benefication processes are under development, but are not yet commercialized for full-scale coal combustion applications. These advanced cleaning processes are being designed to work on the organically bound sulfur as opposed to most of the physical processes which are aimed at the pyritic sulfur. The goals of the research and development efforts which have been funded by the U.S. Department of Energy, the Electric Power Research Institute, and private industry is to produce a coal that can meet the NSPS and Clean Air Act Amendments of 1990 SO_2 emission limits without additional controls.

2.4.2 Combustion Modification

Combustion modification includes any physical or operational change in the furnace or boiler apparatus itself.[4,39-44] Maintenance of the burner system, for example, is important to assure proper mixing and subsequent minimization of any unburned combustibles. Periodic tuning is important in small units for maximum operating efficiency and emission control, particularly of smoke and CO.

2.4.2.1 Particulate Matter Control. Uncontrolled PM emissions from small stoker-fired and handfeed coal combustion sources can be minimized by employing good combustion practice. This involves operation of the combustion source within recommended load ranges, controlling the rate of load changes, and ensuring steady and uniform fuel introduction. Proper design of combustion air delivery systems can also minimize uncontrolled PM emissions. Insufficient combustion air will generate soot and condensible organic compound emissions. Conversely, the use of excessive air flow under the grate, beyond that necessary to complete char burnout and to cool the grate can give high PM emissions. Also, localized areas of high velocities near the fuel bed can entrain ash into the flue gases leaving the combustor. Excess air in these types of units should be introduced through overfire air ports where possible for volatile burnout and upper furnace temperature control.

Large industrial and utility boilers are generally well designed and maintained so that soot and condensible organic compound emissions are minimized. Particulate matter emissions are more a result of entrained fly ash in suspension-fired and FBC systems. Therefore, post combustion controls are necessary to reduce PM emissions from these sources.

2.4.2.2 Nitrogen Oxide Control. Combustion modifications, such as limited excess air firing, flue gas recirculation, staged combustion and reduced load operation, are primarily used to control NO_x emissions in large coal-fired facilities.

The formation of thermal NO_x occurs in part through the Zeldovich mechanism:

(2-1) $N_2 + O \longleftrightarrow NO + N$

(2-2) $N + O_2 \longleftrightarrow NO + O$

(2-3) $N + OH \longleftrightarrow NO + H$

Reaction (2-1) is generally the rate determining step due to its large activation energy.[4] On an overall, idealized, global basis, the thermal NO_x formation rate is related to N_2 concentration, combustion temperature, and O_2 concentration by the following equation:[4]

(2-4) $[NO] = k_1 \exp(-k_2/T) [N_2] [O_2]^{1/2} t$

where:

[ ] = mole fraction

T = temperature (°K)

t = residence time

k_1, k_2 = reaction rate coefficient constants

This idealized relationship suggests thermal NO_x formation can be controlled by four approaches: (1) reduction of peak temperature of reaction, (2) reduction of N_2 concentration, (3) reduction of oxygen level or stoichiometric ratio, and (4) reduction of the residence time of exposure at peak temperature. Typically, the N_2 mole fraction in hydrocarbon-air flames is on the order of 0.7 and is difficult to modify.[4] Therefore, combustion modification techniques to control thermal NO_x in boilers have focused on reducing oxygen level, peak temperature, and time of exposure at peak temperature in the primary flame zones of the furnaces. Equation 2-4 also shows that thermal NO_x formation depends exponentially on temperature, parabolically on oxygen concentration, and linearly on residence time. Therefore initial efforts to control NO_x emissions are often focused on methods to reduce peak flame temperatures.

In boilers fired on coal, the control of fuel NO_x is also very important in achieving the desired degree of NO_x reduction, since fuel NO_x can account for 80 percent of the total NO_x formed.[18,45,46] Fuel nitrogen conversion to NO_x is highly dependent on the fuel to air ratio in the combustion zone, and in contrast to thermal NO_x formation, is relatively insensitive to small changes in combustion zone temperature.[47] In general, increased mixing of fuel and air increases nitrogen conversion which, in turn, increases fuel NO_x. Thus, to reduce fuel NO_x formation, the most common combustion modification technique is to suppress combustion air levels below the theoretical amount required for complete combustion. The lack of oxygen creates reducing conditions that, given sufficient time at high temperatures, cause volatile fuel nitrogen to convert to N_2 rather than NO.

In the formation of both thermal and fuel NO_x, all of the above reactions and conversions do not take place at the same time, temperature, or rate. The actual mechanisms for NO_x formation in a specific situation are dependent on the quantity of fuel-bound nitrogen and the temperature and stoichiometry of the flame zone. Although the NO_x formation mechanisms are different, both thermal and fuel NO_x are promoted by rapid mixing of fuel and combustion air. This rate of mixing may itself depend on fuel characteristics such as the atomization quality of liquid fuels or the particle fineness of solid fuels.[48] Additionally, thermal NO_x is greatly increased by increased residence time at high temperatures under oxidizing conditions. Thus, primary combustion modification controls for both thermal and fuel NO_x typically rely on the following control approaches:

- Decrease residence time at high temperatures and oxidizing conditions (for oxidizing conditions):
  - Decreased adiabatic flame temperature through dilution,
  - Decreased combustion intensity,
  - Increased flame cooling,
  - Decreased primary flame zone residence time,
- Decrease primary flame zone O_2 level:
  - Decreased overall O_2 level,
  - Controlled (delayed) mixing of fuel and air, and
  - Use of fuel-rich primary flame zone.

Tables 2-5 and 2-6 summarize available NO_x control techniques currently in use of under full-scale demonstration on pulverized coal-fired boilers and stoker coal-fired boilers, respectively.

For cyclone boilers, natural gas reburning has been investigated as a combustion modification NO_x control technique. In this process, natural gas is injected into a furnace reburn zone downstream from the cyclone burners. The injection of additional fuel creates a fuel-rich zone in which NO_x from the cyclone burners is converted to molecular nitrogen and water vapor. Additional air is injected downstream of the reburn zone to complete the combustion of unburned fuel. Flue gas recirculation may be employed to facilitate mixing of natural gas with the flue gas and penetration of natural gas into the furnace.

Parametric tests for natural gas reburning aplied to a 108 MW electric output (MWe) cyclone boiler using 18 percent natural gas injection and FGR showed that NO_x emissions were reduced to approximately 300 ppm (at 3 percent O_2), corresponding to a 58 percent reduction efficiency.[62] However, the reburn system resulted in an unacceptable amount of slag build-up on the near wall of the secondary furnace. The use of a water-cooled natural gas injection system in lieu of the FGR system eliminated the excess slag build up but NO_x reduction efficiencies dropped to 46 to 48 percent, based on preliminary testing.

2.4.2.3 Fluidized Bed Combustion. Fluidized bed combustion is often considered a combustion modification for SO_2 control because FBC can sometimes be retrofit to conventional combustors and boilers. Limestone or dolomite added to the bed is calcined to lime and reacts with SO_2 to form calcium sulfate. Bed materials can also effectively capture trace metals. Bed temperatures are typically maintained between 760 and 870 °C (1400 to 1600 °F) to promote the sulfation reaction and to prevent ash fusion. Particulate matter emitted from the boiler is generally captured in a cyclone and recirculated or sent to disposal. Additional particulate control equipment, such as an ESP or baghouse, may be used after the cyclone to further reduce particulate emissions.

2.4.3 Post-Combustion Control

2.4.3.1 Particulate Matter Control. The post-combustion control of PM emissions from coal-fired combustion sources can be accomplished by using one or more of the following particulate control devices:

- Electrostatic precipitator (ESP),
- Fabric filter (or baghouse),
- Wet scrubber,
- Cyclone or muliclone collector, or
- Side stream separator.

Filterable particulate emissions can be controlled to various levels by all of these devices. Cyclones, ESPs, and fabric filters have little effect on measured condensible particulate matter (CPM) because they are generally operated at temperatures above the upper limit of the front-half of EPA Method 5 [135°C (275°F)]. Most CPM would remain vaporized and pass through the control device. Wet scrubbers, however, reduce the gas stream temperature so they could theoretically remove some of the CPM.

Electrostatic precipitation technology is applicable to a variety of coal combustion sources. Because of their modular design, ESPs can be applied to a wide range of system sizes. Application of an ESP should have no adverse effect on combustion system performance.[49] The operating parameters that influence ESP performance include:

- Fly ash mass loading,
- Particle size distribution,
- Fly ash electrical resistivity, and
- Precipitator voltage and current.

Other factors that determine ESP collection efficiency are collection plate area, gas flow velocity, and cleaning cycle. Data for ESPs applied to coal-fired sources show fractional collection efficiencies greater than 99 percent for fine (less than 0.1 micron) and coarse particles (greater than 10 microns).[50] These data show a reduction in collection efficiency for particle diameters between 0.1 and 10 microns.

Fabric filtration has been widely applied to coal combustion sources since the early 1970's. A fabric filter (baghouse) consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. Bag materials, such as fiberglass, Nomex,™ or Teflon™ are selected based on operating temperature, particle abrasiveness, and acid gas content in the flue gases. Woven, non-woven (felted), and texturized filament fabrics are chosen based on collection efficiency and cleanability requirements.

The particulate removal efficiency of fabric filters is dependent on a variety of particle and operational characteristics. Particle characteristics that affect the collection efficiency include:

- Particle size distribution,
- Particle cohesion characteristics, and
- Particle electrical resistivity.

Operational parameters that affect fabric filter collection efficiency include:

- Air-to-cloth ratio (A/C),
- Operating pressure loss,
- Cleaning sequence,

- Interval between cleaning,
- Cleaning method, and
- Cleaning intensity.

In addition, fabric properties affect the particle collection efficiency and size distribution:

- Structure of fabric
- Fiber composition
- Bag properties

In fabric filtration, both the collection efficiency and the pressure drop across the bag surface increase as the dust layer on the bag builds up. The method and frequency of bag cleaning determines the overall collection performance and pressure drop as well as the bag life. Cleaning processes include mechanical shaking, reverse-flow, and pulse-jet. Mechanical shaking and reverse-flow systems require lower air to cloth (A/C) ratios (2 to 3 rather than 6 to 12 for pulse jet) and are typically found in the electric utility industry, whereas pulse-jet types are used across most of the industrial and commercial size spectrum. There is increased interest in pulse-jet baghouses in the very large systems because of the equipment size advantage. Emission tests conducted on an industrial spreader stoker equipped with a reverse-flow fabric filter have shown fractional efficiencies as high as 99.9 percent for particles in the 0.02 to 2 micron size range.[51] Other reported test data for seven industrial boilers equipped with baghouses showed controlled PM emissions ranging from 4.1 to 15 ng/J (0.010 to 0.035 lb/million Btu) and fractional efficiencies of 99.7 to 99.9+ percent.[52]

The above tests indicate that fabric filter performance is not significantly affected by boiler design type or size. It should be noted that most bag materials will develop holes or leak paths due to flex abrasion wear, hot embers ("sparklers"), or failure of attachment points. Very small leaks can substantially diminish the collection efficiency of a baghouse system, particularly in the size range below 10 microns. Therefore, careful design and an established maintenance program are important for continued performance at the specified levels.

Wet scrubbers, including venturi and flooded disc scrubbers, tray or tower units, turbulent contact absorbers, or high pressure spray impingement scrubbers are applicable for PM as well as SO_2 control on coal-fired combustion sources. One disadvantage of using scrubbers for PM control is the disposal requirements of the resulting wet sludge as opposed to the dry product as produced by ESPs, fabric filters, or cyclone collectors. Tray tower units are best suited for SO_2 control and are effective only for particles greater than 1 micron in diameter. Venturi type scrubbers are effective down to the submicron range. Scrubber collection efficiency depends on particle size distribution, gas side pressure drop through the scrubber, and water (or scrubbing liquor) pressure. Reported fractional efficiencies for a venturi scrubber range between 95.00 and 99.89 percent for a 2 micron particle.[53] Corresponding pressure drops ranged from 2 to 10 kPa (8 to 40 inches of water).

Cyclone separators can be installed singly, in series, or grouped as in a multi-cyclone or multiclone collector. These devices are referred to as mechanical collectors because they do not rely on electrical, liquid, or barrier principles for removal of PM from a gas stream. The collection efficiency of a mechanical collector depends strongly on the effective aerodynamic particle diameter. Although these devices will reduce PM emissions from coal combustion, they are relatively ineffective for collection of PM-10. Mechanical collectors are often used as a precollector upstream of an ESP, fabric filter, or wet scrubber so that these devices can be specified for lower particle loadings to reduce capital and/or operating costs. Mechanical collectors are designed for a specified range of gas flows. Because the available collection efficiencies for a given collector depend on inlet velocity, these devices are not effective for a combustion source which typically operates over wide load ranges. The typical overall collection efficiency for mechanical collectors ranges from 90 to 95 percent.

The side-stream separator combines a multi-cyclone and a small pulse-jet baghouse to more efficiently collect small diameter particles that are difficult to capture by a mechanical collector alone. Most applications to date for side-stream separators have been on small stoker boilers.

Atmospheric fluidized bed combustion (AFBC) boilers may tax conventional particulate control systems. The particulate mass concentration exiting AFBC boilers is typically 2 to 4 times higher than pulverized coal boilers[54]. Atmospheric FBC particles are also, on average, smaller in size, irregularly shaped with higher surface area and porosity relative to pulverized coal ashes. The effect is a higher pressure drop.

The AFBC ash is more difficult to collect in ESPs than pulverized coal ash because AFBC ash has a higher electrical resistivity and the use of multiclones for recycling, inherent with the AFBC process, tends to reduce exit gas stream particulate size[54].

2.4.3.2 SO_2 Control. Commercialized post-combustion flue gas desulfurization (FGD) uses an alkaline reagent to absorb SO_2 in the flue gas and produces a sodium or a calcium sulfate compound. These solid sulfate compounds are then removed in downstream particulate control devices as described in Section 2.4.3.1. Flue gas desulfurization technologies are categorized as wet, semi-dry, or dry depending on the state of the reagent as it leaves the absorber vessel. These processes are either regenerable such that the reagent material can be treated and reused, or are non-regenerable in which all waste streams are de-watered and discarded. Table 2-7 summarizes commercially available post-combustion SO_2 control technologies.

Wet regenerable FGD processes are attractive because they have the potential for better than 95 percent sulfur removal efficiency, have minimal waste-water discharges, and produce saleable sulfur product.[36] Some of the current non-regenerable calcium based processes can, however, produce a saleable gypsum product.

To date, wet systems are the most commonly applied. Wet systems generally use alkali slurries as the SO_x absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_x. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbing are among the commercially proven wet FGD systems. The effectiveness of these devices depends not only on control device design but also on operating variables.

The lime and limestone scrubbing process uses a slurry of calcium oxide (CaO) or limestone ($CaCO_3$) to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods have been demonstrated.[53] The process produces a calcium sulfite and calcium sulfate mixture. Calcium sulfite and calcium sulfate crystals precipitate in a hold tank. The hold tank effluent is recycled to the scrubber to absorb additional SO_2. A slip stream from the hold tank is sent to a solid-liquid separator to remove precipitated solids. The waste solids, typically 35 to 70 weight percent solids, are generally disposed of by ponding or landfill.

Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide (NaOH) or sodium carbonate (Na_2CO_3) to absorb SO_2 from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs; however, these systems have been installed on industrial boilers up to 125 MW (430 million Btu/hr) thermal input.[14] SO_2 removal efficiencies of up to 96.2 percent have been demonstrated.[53] Because the SO_2 removal efficiency can vary during load swings and process upsets, a long term mean efficiency of at least 91 percent is necessary to comply with the 90 percent NSPS reduction requirement based on a 30-day rolling average. The operation of the scrubber is characterized by a low liquid-to-gas ratio [1.3 to 3.4 l/m^3 (10 to 25 gal/ft^3)] and a sodium alkali sorbent which has a high reactivity relative to lime or limestone sorbents. The scrubbing liquid is a solution rather than a slurry because of the high solubility of sodium salts.

The double or dual alkali system uses a clear sodium alkali solution for SO_2 removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. Most of the effluent from the sodium scrubber is recycled back to the scrubber, but a slipstream is withdrawn and reacts with lime or limestone in a regeneration reactor. The regeneration reactor effluent is sent to a thickener where the solids are concentrated. The overflow is sent back to the system while the underflow is further concentrated in a vacuum filter (or other device) to about 50 percent solids content. The solids are washed to recover soluble sodium compounds which are returned to the scrubber. Performance data indicate average SO_2 removal efficiencies of 90 to 96 percent.[14] However, initial reports of long-term operating histories with dual alkali scrubbing have indicated system reliability averages of only slightly higher than 90 percent.[54]

Spray drying is a dry scrubbing approach to FGD. The technology is best suited for low to medium sulfur coals with sulfur contents up to 3 percent, but may be applied to higher sulfur-content coals. A solution or slurry of alkaline material is sprayed into a reaction vessel as a fine mist and contacted with the flue gas for a relatively long period of time (5 to 10 seconds). The SO_2 reacts with the alkali solution or slurry to form liquid phase salts. The slurry is dried by the hot flue gas to about one percent free moisture. The dried material continues to react with SO_2 in the flue gas to form sulfite and sulfate salts. The spray dryer solids are entrained in the flue gas and carried out of the dryer to a particulate control device such as an ESP or baghouse. Systems using a baghouse for particulate removal report additional SO_2 capture across the baghouse.

Spray drying is a relatively new FGD technology and extensive large-scale commercial experience is limited. Vendors have offered commercial guarantees of up to 90 percent capture on low sulfur (less than 2 percent) coal.[14] Pilot data on calcium-based sorbents have also showed SO_2 reduction efficiencies of 90 percent.[14] Spray drying with sodium-based sorbents should produce greater removal efficiencies due to the greater reactivity of sodium hydroxide or sodium carbonate compared with lime.

A number of dry and wet sorbent injection technologies are under development to capture SO_2 in the furnace, the boiler sections, or ductwork downstream of the boiler. These technologies are generally designed for retrofit applications and are well suited for coal combustion sources requiring moderate SO_2. There are commercial applications of furnace sorbent injection in Europe; however, the technologies are not yet commercialized in the U.S. The objectives for SO_2 removal efficiencies are between 25 and 50 percent.[36]

2.4.3.3 $\underline{NO_x}$ Control. The injection of ammonia (NH_3)- or urea-based reagents into the furnace or flue gas path for NO_x control is considered to be post- combustion control. This process, known as Selective Non-Catalytic Reduction (SNCR), is seeing some commercial application, primarily for industrial FBC boilers in California. In bubbling bed FBCs, the reagent is injected above the bed in the freeboard space. In circulating bed FBCs, injection occurs just prior to, or sometimes within, the first stage cyclone separator.

The NO_x reduction reactions occur in a relatively narrow temperature window between 920 and 1030 °C (1700 to 1900 °F). Because of the typically limited residence times available in this temperature range, the reagent must be injected at high velocity or with steam or air assist in order to achieve good mixing. Poor quality mixing or excessive reagent use results in emissions of ammonia (slip) in the flue gas. Demonstrated efficiencies for NO_x reduction range from 30 to 50 percent for bubbling bed FBCs, and up to 80 percent for circulating bed FBCs at NO_x/NH_3 molar ratios between 2 and 4.[55] Reduction efficiencies are apparently higher for circulating FBCs because of the residence time and intense mixing available in the cyclone.

TABLE 2-1. U.S. COAL CONSUMPTION BY SECTOR in 1990[2]

Sector	Total Consumption, 10^3 metric tons (10^3 short tons)
Electric Utility	701,759 (773,549)
Industrial (Excluding Coke Plants)	69,246 (76,330)
Residential/Commercial	6,100 (6,724)
Total For All Sectors	777,105 (856,603)

TABLE 2-2. BOILER USAGE BY SECTOR

Sector	Capacity, MW	Boiler type	Application
Utility	>100	Watertube	Electricity Generation
Industrial	10-100	Watertube	Electricity Generation
		Watertube	Process Steam
		Watertube	Space Heating
		Firetube	Process Steam
		Firetube	Space Heating
Commercial	0.5-10	Watertube	Space Heating
		Firetube	Space Heating
		Cast Iron	Space Heating
Residential	<0.5	Cast Iron	Space Heating

TABLE 2-3. TOTAL 1985 EMISSIONS FROM COAL COMBUSTION BY USE SECTOR[13]

Sector	Annual emissions, 10^3 metric tons (10^3 short tons)			
	SO_2	NO_x	TSP[a]	VOC
Residential	27 (30)	1.8 (2)	10 (11)	7 (8)
Commercial/ Institutional	126 (139)	26 (29)	15 (17)	0.9 (1)
Industrial	1,478 (1,629)	513 (565)	102 (112)	5 (6)
Electric Generation	13,427 (14,801)	5,084 (5,604)	432 (476)	26 (29)
Total	20,998 (23,146)	18,635 (20,541)	7,605 (8,383)	20,024 (22,073)

[a] Total suspended particulate.

TABLE 2-4. NSPS SUMMARY FOR FOSSIL FUEL-FIRED BOILERS

Standard/ Boiler Types/ Applicability Criteria	Boiler Size MW (Million Btu/hr)	Fuel or Boiler Type	PM ng/J (lb/MMBtu) [% reduction]	SO_2 ng/J (lb/MMBtu) [% reduction]	NO_x ng/J (lb/MMBtu) [% reduction]
Subpart D Industrial-Utility Commence construction after 8/17/71	>73 (>250)	Gas	43 (0.10)	NA	86 (0.20)
		Oil	43 (0.10)	340 (0.80)	129 (0.30)
		Bit./Subbit. Coal	43 (0.10)	520 (1.20)	300 (0.70)
Subpart Da Utility Commence construction after 9/18/78	>73 (>250)	Gas	13 (0.03 [NA]	340 (0.80) [90][a]	86 (020) [25]
		Oil	13 (0.03) [70]	340 (0.80) [90][a]	130 (0.30) [30]
		Bit./Subbit. Coal	13 (0.03) [99]	520 (1.20) [90][b]	260/210[c] (0.60/0.50) [65/65]
Subpart Db Industrial-Commercial-Institutional Commence construction after 6/19/84[k]	>29 (>100)	Gas	NA[d]	NA[d]	43[f] (0.10)
		Distillate Oil	43 (0.10)	340[l] (0.80) [90]	43[f] (0.10)
		Residual Oil	(Same as for distillate oil)	(Same as for distillate oil)	130[g] (0.30)
		Pulverized Bit./Subbit. Coal	22[e] (0.05)	520[e] (1.20) [90]	300 (0.70)
		Spreader Stoker & FBC	22[e] (0.05)	520[e] (1.20) [90]	260 (0.60)
		Mass-Feed Stoker	22[e] (0.05)	520[e] (1.20) [90]	210 (0.50)
Subpart Dc Small Industrial-Commercial-Institutional Commence construction after 6/9/89	2.9 - 29 (10 - 100)	Gas	-[h]	-	-
		Oil	-[h,i]	215 (0.50)	-
		Bit. & Subbit. Coal	22[i,j] (0.05)	520[j] (1.20 [90]	-

Footnotes For Table 2-4

[a] Zero percent reduction when emissions are less than 86 ng/J (0.20 lb/MMBtu).

[b] 70 percent reduction when emissions are less than 260 ng/J (0.60 lb/MMBtu).

[c] The first number applies to bituminous coal and the second to subbituminous coal.

[d] Standard applies when gas is fired in combination with coal, see 40 CFR 60, Subpart Db.

[e] Standard is adjusted for fuel combinations and capacity factor limits, see 40 CFR 60, Subpart Db.

[f] For furnace heat release rates greater than 730,000 J/s-m^3 (70,000 Btu/hr-ft^3), the standard is 86 ng/J (0.20 lb/MMBtu).

[g] For furnace heat release rates greater than 730,000 J/s-m^3 (70,000 Btu/hr-ft^3), the standard is 170 ng/J (0.40 lb/MMBtu).

[h] Standard applies when gas or oil is fired in combination with coal, see 40 CFR 60, Subpart Dc.

[i] 20 percent capacity limit applies for heat input capacities of 8.7 Mwt (30 MMBtu/hr) or greater.

[j] Standard is adjusted for fuel combinations and capacity factor limits, see 40 CFR 60, Subpart Dc.

[k] Additional requirements apply to facilities which commenced construction, modification, or reconstruction after 6/19/84 but on or before 6/19/86 (see 40 Code of Federal Regulations Part 60, Subpart Db).

[l] 215 ng/J (0.50 lb/million Btu) limit (but no percent reduction requirement) applies if facilities combust only very low sulfur oil (< 0.5 wt. % sulfur).

TABLE 2-5. COMMERCIALLY AVAILABLE NO_x CONTROL TECHNIQUES FOR PULVERIZED COAL-FIRED BOILERS

Control technique	Description of technique	Effectiveness of control, % NO_x reduction	Range of application	Commercial availability/R&D status	Comments
Low Excess Air (LEA)	Reduction of combustion air	0-25 (avg. 9)	Excess oxygen reduced to 5.2% on the average.	Available.	Added benefits of technique include increase in boiler efficiency, limited by increase in CO. HC and smoke emissions.
Burners out of service (BOOS)	One or more burners on air only. Remainder firing fuel rich.	27-39 (avg. 33)	Applicable only for boilers with minimum of 4 burners.	Available. However, extensive engineering work necessary before implementation.	Limited by the number of burners available. Load reduction required in most cases. Possible increased slagging, corrosion.
Overfire air injection (OFA)	Secondary air from OFA ports above fuel rich firing burners.	5-30	Burner stoichiometry as low as 100%.	Commercially offered but not demonstrated for industrial size boilers.	Requires installation of OFA ports, etc. Possible increased slagging, corrosion.
Flue gas recirculation (FGR)	Recirculation of flue gas to burner windbox.	0-20	Up to 25% of the flue gas recirculated.	Not offered because relatively ineffective.	Requires installation of FGR ducts, fan, etc. Can cause combustion instability. Burner windbox may need extensive modifications.
Low NO_x burner (LNB)[a]	New burner designed utilizing controlled air-fuel mixing.	45-60	Prototype LNB limited to size ranges above 29 MW (100×10^6 Btu/h)	Still in the development stage. Prototype LNB available from major boiler mfrs.	Active R&D efforts underway.
Ammonia injection (SNCR)	Injection of NH_3 in convective section of boiler.	40-60	Limited by furnace geometry. NH_3 injection rate limited to 1.5 NH_3/NO.	Commercially offered but not demonstrated.	Elaborate NH_3 injection, monitoring, and control system required. Possible load restrictions on boiler and air preheater fouling by ammonium bisulfate.
Reduced load (RL)	Reduction of fuel and air flow to the boiler.	Varies from 45% reduction to 4% increase in NO_x	Applicable to all boilers. Load can be reduced to 25% of capacity.	Available now but not implemented because of adverse operational impacts.	Load reduction often not effective because of increase in excess O_2. Best implemented with increase in furnace size for new boilers.

[a] Low NO_x burners are the minimum control technology required for NO_x emissions from PC-fired utility boilers.

TABLE 2-6. COMMERCIALLY AVAILABLE NO_x CONTROL TECHNIQUES FOR STOKER COAL-FIRED BOILERS

Control technique	Description of technique	Effectiveness of control, % NO_x reduction	Range of application	Commercial availability/R&D status	Comments
Low Excess Air (LEA)	Reduction of air flow under stoker bed	5-25	Excess oxygen limited to 5-6% minimum.	Available now but need R&D on lower limit of excess air.	Danger of overheating grate, clinker formation, corrosion, and high CO emissions.
Staged combustion (LEA + OFA)	Reduction of undergrate air flow and increase of overfire air flow.	5-25	Excess oxygen limited to 5% minimum.	Most stokers have OFA ports as smoke control devices but may need better air flow control devices.	Need research to determine optimal location and orientation of OFA ports for NO_x emission control. Overheating grate, corrosion, and high CO emission can occur if undergrate airflow is reduced below acceptable level as in LEA.
Load reduction (LR)	Reduction of coal and air feed to the stoker.	Varies from 49% decrease to 25% increase in NO_x (average 15% decrease).	Has been used down to 25% load.	Available.	Only stokers that can reduce load without increasing excess air. Not a desirable technique because of loss in boiler efficiency.
Reduced air preheat (RAP)	Reduction of combustion air temperature.	8	Combustion air temperature reduced from 473K to 453K.	Available now if boiler has combustion air heater.	Not a desirable technique because of loss in boiler efficiency.
Ammonia injection	Injection of NH_3 in convective section of boiler.	40-60 (from gas- and oil-fired boiler experience).	Limited by furnace geometry. Feasible NH_3 injection rate limited to 1.5 NH_3/NO.	Commercially offered but not yet demonstrated.	Elaborate NH_3 injection, monitoring, and control system required. Possible load restrictions on boiler and air preheater fouling by ammonium bisulfate.

TABLE 2-7. POST COMBUSTION SO_2 CONTROLS FOR COMBUSTION SOURCES

Control technology	Process	Available control efficiencies	Remarks
Wet Scrubber	Lime/Limestone	80 - 95+%	Applicable to high sulfur fuel, Wet sludge product
	Sodium Carbonate	80 - 98%	1.5 - 125 MWt [5 - 430 million Btu/hr (MMBtu/hr) typical application range, High reagent costs
	Magnesium Oxide/ Hydroxide	80 - 95+%	Can be regenerated
	Dual Alkali	90 - 96%	Uses lime to regenerate sodium-based scrubbing liquor
Spray Drying	Calcium hydroxide slurry, vaporizes in spray vessel	70 - 90%	Applicable to low and medium sulfur fuels, Produces dry product
Furnace Injection	Dry calcium carbonate/hydrate injection in upper furnace cavity	25 - 50%	Commercialized in Europe, Several U.S. demonstration projects underway
Duct Injection	Dry sorbent injection into duct, sometimes combined with water spray	25 - 50+%	Several R&D and demonstration projects underway, Not yet commercially available in the U.S.

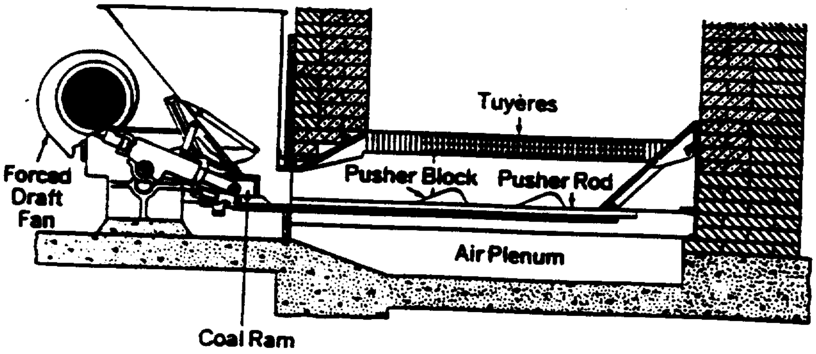

Figure 2-1. Single-retort horizontal-feed underfeed stoker.[1]

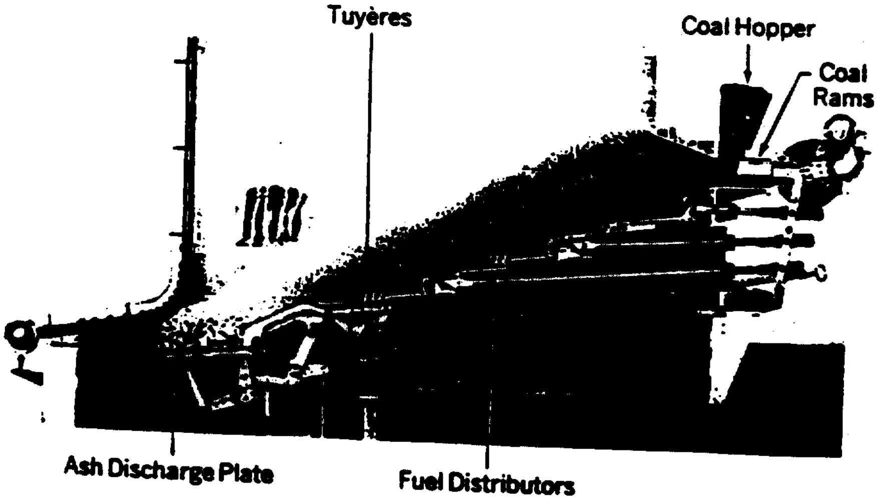

Figure 2-2. Multiple-retort gravity-feed underfeed stoker.[2]

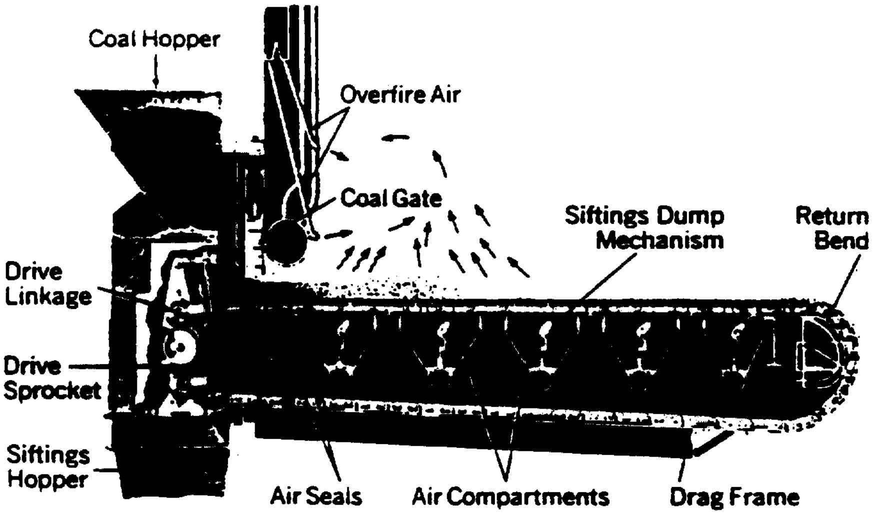

Figure 2-3. Overfeed chain-grate stoker.[1]

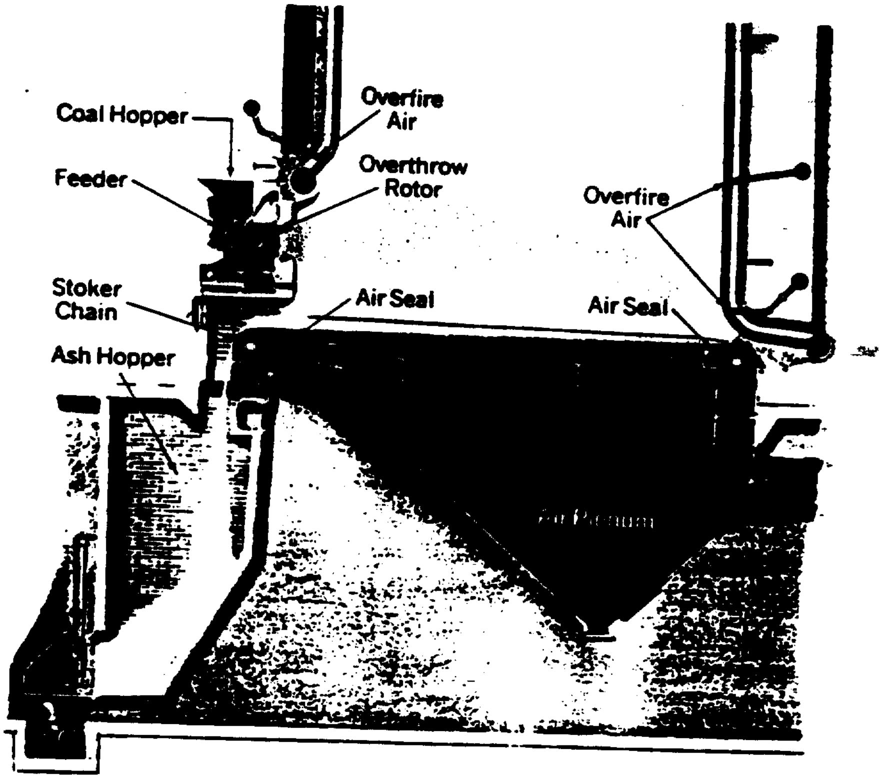

Figure 2-4. Spreader stoker.[1]

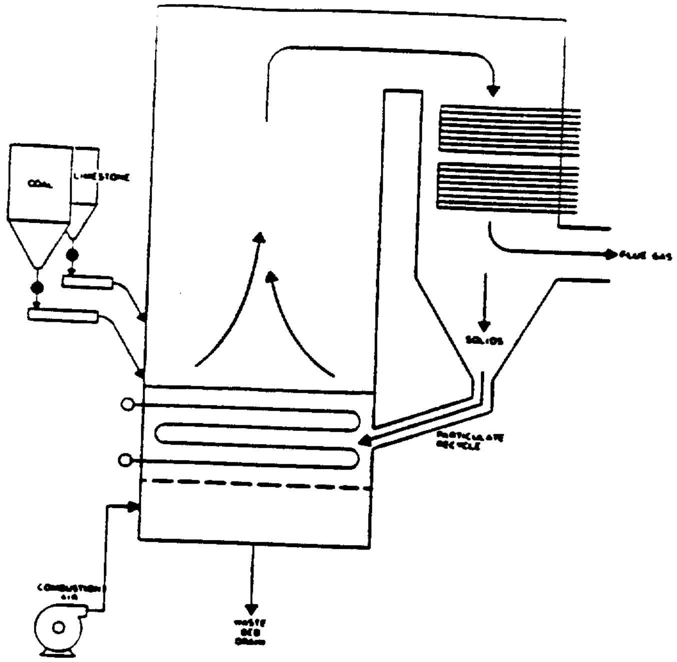

Figure 2-5. Bubbling FBC schematic.[56]

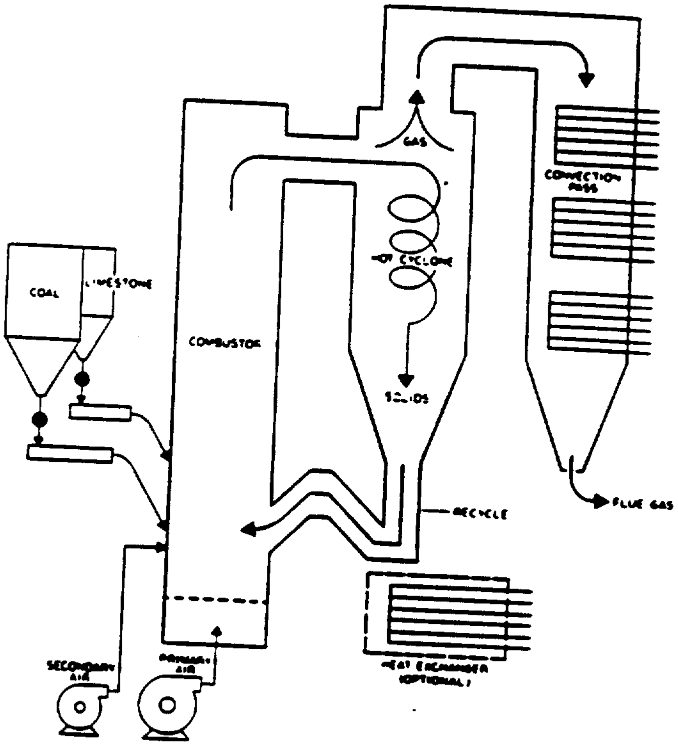

Figure 2-6. Circulating FBC schematic.[56]

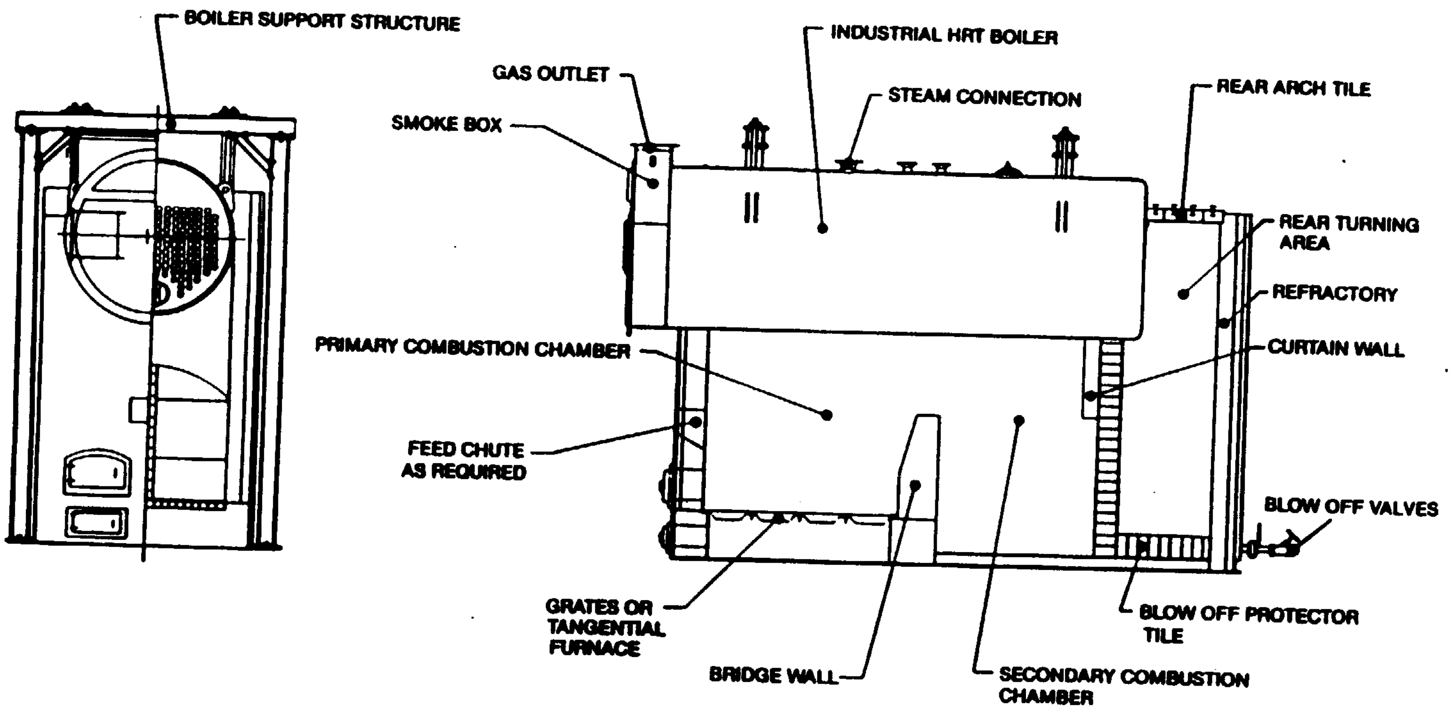

Figure 2-7. Two-pass HRT boiler.[57]

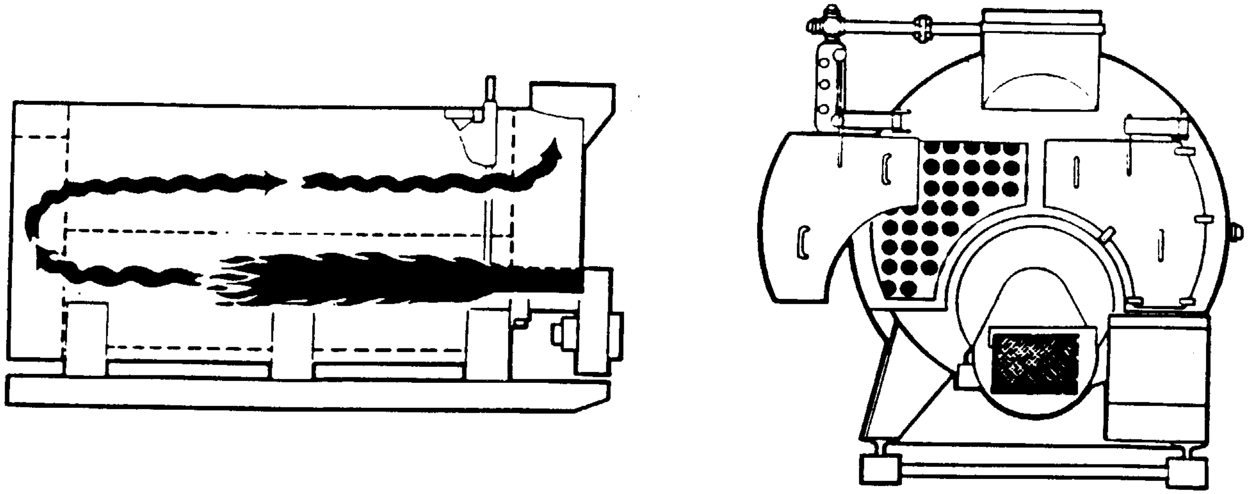

Figure 2-8. Firetube boiler.[58]

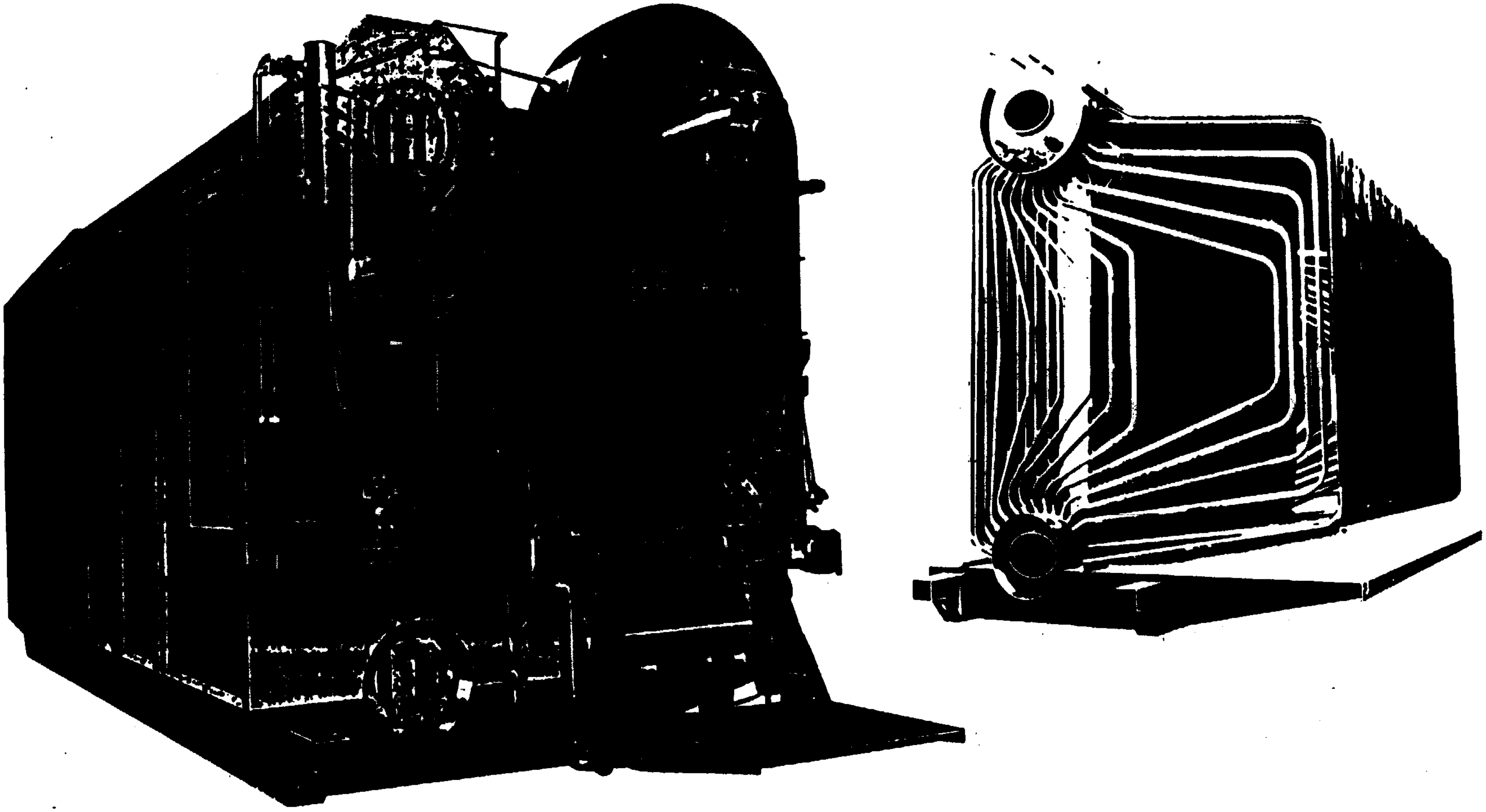

Figure 2-9. D-type packaged boiler and watertubes.[59]

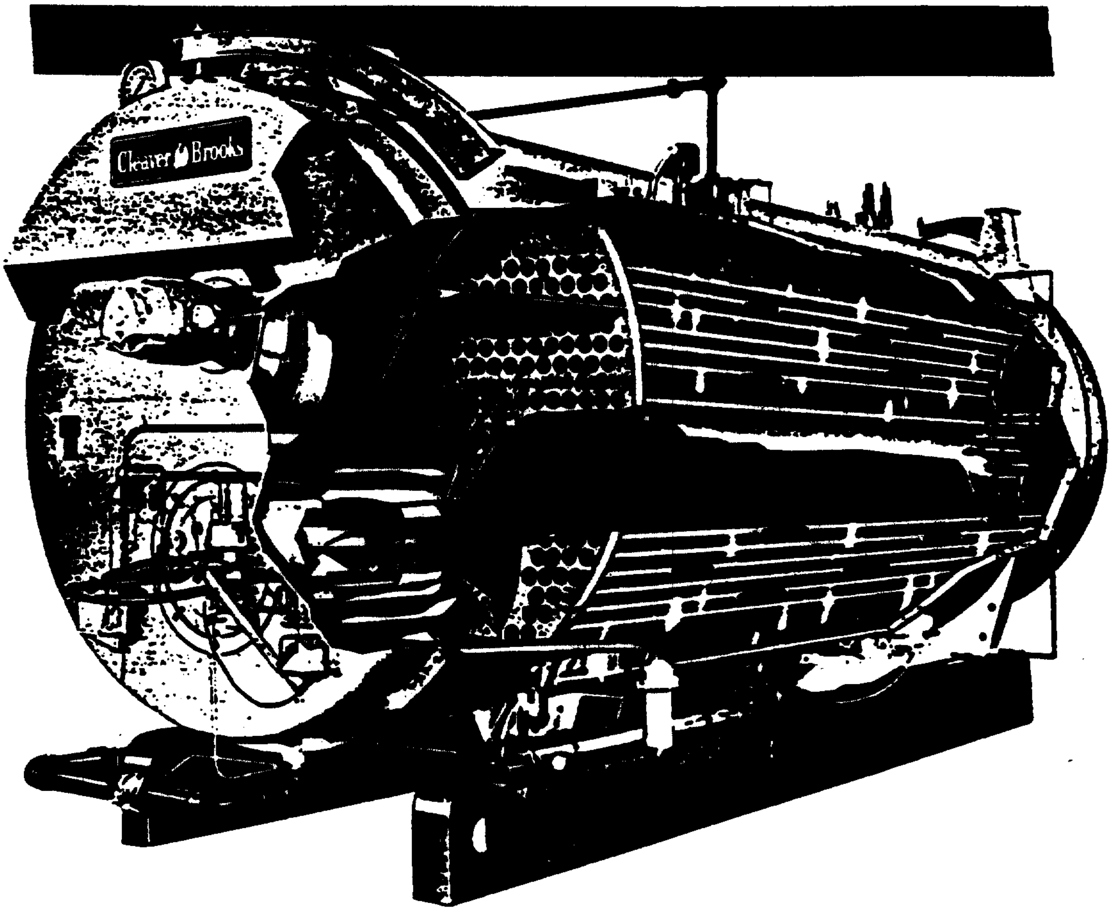

Figure 2-10. Four-pass scotch boiler.[60]

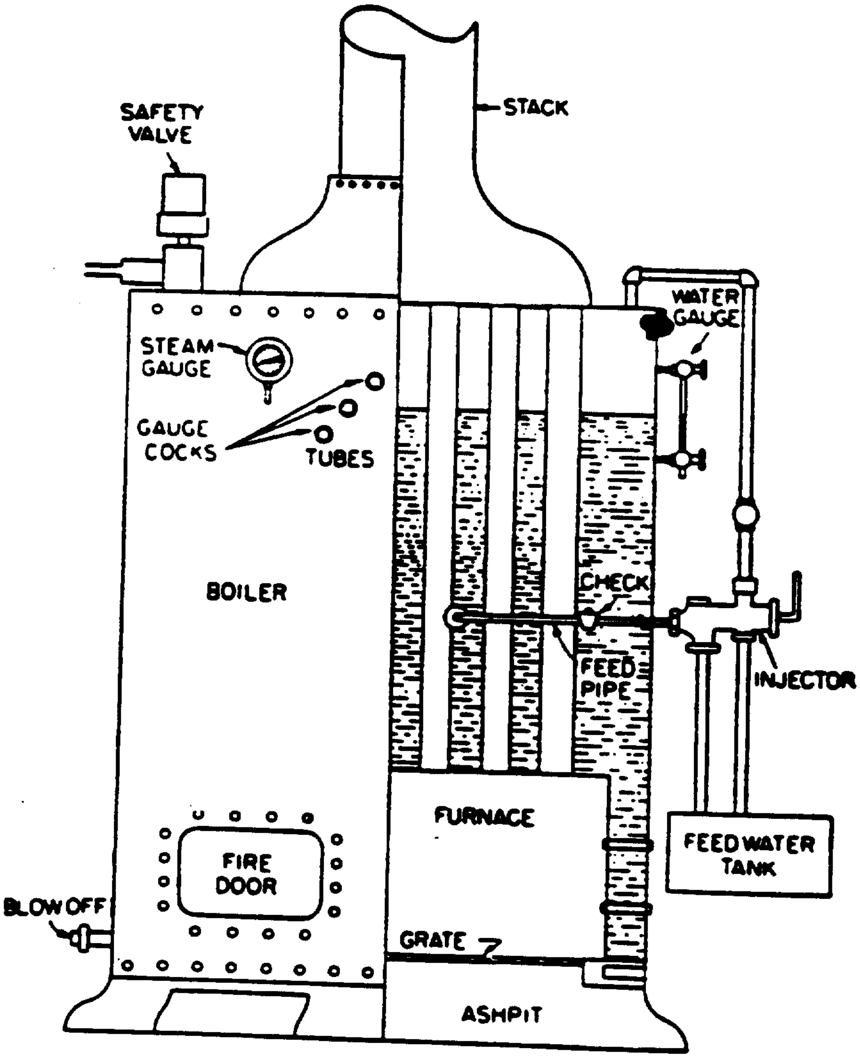

Figure 2-11. Exposed-tube vertical boiler.[3]

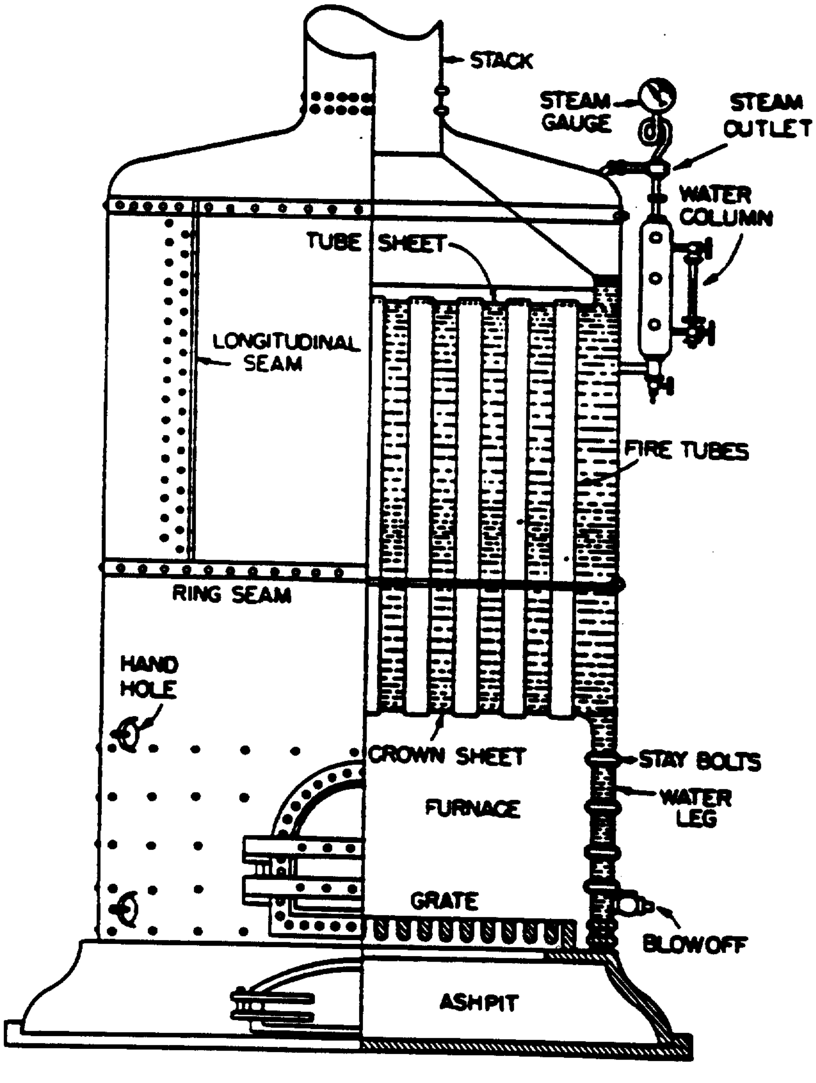

Figure 2-12. Submerged-tube vertical boiler.[3]

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3. GENERAL EMISSION DATA REVIEW AND ANALYSIS PROCEDURE

3.1 CRITERIA POLLUTANTS

3.1.1 Literature Search

The first step in this revision and update involved an extensive literature search to identify sources of criteria (non-criteria) pollutant emissions data associated with bituminous and subbituminous coal combustion. This search included:

- Existing AP-42 background files;
- Files maintained by EPA's Emission Standards Division and Emission Factor and Methodologies Section of the Office of Air Quality Planning and Standards (OAQPS);
- PM-10 documents;
- NSPS Background Information Documents;
- Various EPA emissions assessment and control technology reports;
- National Technical Information Service (NTIS) holdings;
- Reports from industry organizations including the Electric Power Research Institute (EPRI) and API;
- Various on-line computerized data bases and search services;
- EPA contractor reports; and
- Contractor in-house files.

A summary of these information sources is given in Table 3-1.

3.1.2 Literature Evaluation

To reduce the large amount of available literature to a final group of references pertinent to this task, the following general criteria were used:

1. Emissions data must be from a well documented reference;
2. The referenced study must contain results based on more than one test run; and
3. The report must contain sufficient data to evaluate the testing procedures and source operating conditions.

Employing these criteria in a thorough review of the reports, documents, and information, a final set of reference materials was compiled. The data contained in this final set of references were then subjected to a thorough quality and quantity evaluation to determine their suitability for use in emission factor calculations. Checklists were employed to facilitate and document this evaluation. The completed checklists were placed in the background files for this AP-42 update. Data with the following characteristics were excluded from further consideration:

1. Test series averages reported in units that cannot be converted to the selected reporting units;
2. Test series representing incompatible test methods (i.e., comparison of EPA Method 5 front-half with EPA Method 5 front-and back-half);
3. Test series of controlled emissions for which the control device is not specified;
4. Test series in which the source or control process is not clearly identified and described; and
5. Test series in which it is not clear whether the emissions were measured before or after the control device.

Data sets that were not excluded were assigned a quality rating. The rating system used was that specified in the draft EPA document, "Technical Procedures For Developing AP-42 Emission Factors And Preparing AP-42 Sections" (March 6, 1992). The data were rated as follows:

A: Multiple tests performed on the same source using sound methodology and reported in enough detail for adequate validation. These tests are not necessarily EPA reference method tests, although such reference methods are preferred and certainly to be used as a guide.

B: Tests that were performed by a generally sound methodology but lack enough detail for adequate validation.

C: Tests that were based on an untested or new methodology or that lacked a significant amount of background data.

D: Tests that were based on a generally unacceptable method but may provide an order-of-magnitude value for the source.

The following criteria were used to evaluate source test reports for sound methodology and adequate detail:

1. Source operation. The manner in which the source was operated is well documented in the report. The source was operating within typical parameters during the test.

2. Sampling procedures. The sampling procedures conformed to generally acceptable methodology. If actual procedures deviated from accepted methods, the deviations are well documented. When this occurred, an evaluation was made of the extent such alternative procedures could influence the test results.

3. Sampling and process data. Adequate sampling and process data are documented in the report. Many variations can occur unnoticed and without warning during testing. Such variations can induce wide deviations in sampling results. If a large spread between test results cannot be explained by information contained in the test report, the data are suspect and given a lower rating.

4. Analysis and calculations. The test reports contain original raw data sheets. The nomenclature and equations used were compared to those (if any) specified by EPA to establish equivalency. The depth of review of the calculations was dictated by the reviewer's confidence in the ability and conscientiousness of the tester, which in turn was based on factors such as consistency of results and completeness of other areas of the test report.

In most cases, emissions data were obtained from original source assessment or source test reports. In addition, there is a large body of data that have been summarized by EPA in background documents, emissions assessment reports, and control technology reports.

These reports were used to support regulatory development efforts, control technology determinations, permitting, and for setting further research priorities.

Because of their intended usage, the data contained in these reports have been produced under rigorous quality assurance/quality control procedures and, before being summarized, have undergone data quality review by EPA. Because of these procedures, emissions data were taken directly from the summary reports for input into the emission factor calculations. The data taken from these reports were assigned a "B" quality rating. This rating was given to reflect the fact that testing followed EPA reference methods or otherwise sound methodology; however, the summary reports do not contain enough raw data to verify the data reduction calculations. To supplement the summary report information, orders were placed for copies of the original test reports cited in the summary reports. These test reports, when received, were placed in the background files.

3.1.3 Emission Factor Quality Rating

In each AP-42 section, tables of emission factors are presented for each pollutant emitted from each of the emission points associated with the source. The reliability or quality of each of these emission factors is indicated in the tables by an overall Emission Factor Quality Rating ranging from A (excellent) to E (poor). These ratings incorporate the results of the above quality and quantity evaluations on the data sets used to calculate the final emission factors. The overall Emission Factor Quality Ratings are described as follows:

> A--Excellent: Developed only from A-rated test data taken from many randomly chosen facilities in the industry population. The source category is specific enough so that variability within the source category population may be minimized.
>
> B--Above average: Developed only from A-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industries. As in the A-rating, the source category is specific enough so that variability within the source category population may be minimized.
>
> C--Average: Developed only from A- and B-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. As in the A-rating, the source category is specific enough so that variability within the source category population may be minimized.

<u>D--Below average</u>: The emission factor was developed only from A- and B-rated test data from a small number of facilities, and there is reason to suspect that these facilities do not represent a random sample of the industry. There also may be evidence of variability within the source category population. Limitations on the use of the emission factor are noted in the emissions factor table.

<u>E--Poor</u>: The emission factor was developed from C- and D-rated test data, and there is reason to suspect that the facilities tested do not represent a random sample of the industry. There also may be evidence of variability within the source category population. Limitations on the use of these factors are always noted.

The use of these criteria is somewhat subjective and depends to an extent on the individual reviewer. Details of the rating of each candidate emission factor are provided in Chapter 4 of this report.

3.2 SPECIATED VOCs

3.2.1 Literature Search

An extensive literature search was conducted during this revision to identify sources of speciated VOC emissions data associated with coal fired boilers. Some specific areas of search include Tennessee Valley Authority, Electric Power Research Institute (EPRI)/PISCES, EPA/Air and Waste Mangement Association (AWMA) Air Toxics Symposia, and Toxic Air Pollutants: State and Local Regulatory Strategies 1989. The details of the literature search are summarized in Table 3-2.

3.2.2 Literature Evaluation

Until recently, little concern existed for VOC speciation on stationary external sources. Nearly all organics sampling was focused on semi-volatile compounds. Reliable methods for volatile organics sampling and analysis to low levels have only been developed since the late 1980's. Therefore, available data for VOC speciation were sparse, limiting this data evaluation essentially to the OAQPS databases, the VOC/PM Speciation Data System (SPECIATE) and the Crosswalk/Air Toxic Emission Factor data base (XATEF), and their references.

3.2.3 Data and Emission Factor Quality Rating

The ratings of emission factors in SPECIATE and XATEF should not be used without first reviewing primary sources of numerical data against the criteria presented in Chapter 3.1. The quality of the data is insufficient to satisfy the requirements for assignment of an emission factor, therefore, the data are unratable or, at best, "E" rated.

3.3 AIR TOXICS

3.3.1 Literature Search

When possible, primary references were obtained in order to calculate or verify emission factors presented. Many of the data evaluated were not of suitable quality for developing emission factors and were therefore, eliminated for use in this update.

A literature search was conducted using the Dialog Information Retrieval Service. This is a broad-base data retrieval system that has access to over 400 data bases. Specifically for the air toxics search, six data bases were queried by key words relating to the processes and chemicals of concern. The data bases accessed were: NTIS, COMPENDEX PLUS, POLLUTION ABSTRACT, CONFERENCE PAPERS, ENERGY SCIENCE & TECHNOLOGY, and EPRI. The list of literature generated from the search was evaluated for applicability and the relevant documents were obtained.

Searches of EPA's air toxics data bases were also performed. These data bases include XATEF and SPECIATE, and the Air Chief CD ROM which contains additional data in conjunction with XATEF and SPECIATE. The computer searches were performed by source category code (SCC) for all boiler sizes and types that are fired on coal. The reference numbers were recorded for each of the "hits" and these references were obtained for review.

Various air pollution control districts (APCDs) located in California were contacted to obtain air toxics data collected under California Assembly Bill 2588: Air Toxics "Hot Spots" Information and Assessment Act of 1987. This bill requires reporting of emissions of a specified list of air toxic compounds. The following APCDs were contacted by phone and with a written information request: Bay Area, South Coast, Fresno County, North Coast Unified, Sacramento Metropolitan, San Joaquin County, Ventura County, Calaveras County, Lake County, Lassen County, Santa Barbara, San Diego, Kern County, and the California Air Resources Board.

Several industry and non-agency sources were also contacted in order to obtain source test data for development of emission factors. These include the

Western States Petroleum Association (WSPA), the Canadian Electrical Association (CEA), the Ontario Ministry of the Environment and KEMA of the Netherlands.

3.3.2 Literature Evaluation for Air Toxics

The references obtained from the literature search were evaluated for their applicability for generating emission factors. Table 3-3 summarizes the data sources and indicates which sources were used in generating the emission factors and which sources were eliminated from use. The table contains a reference number which corresponds to the list of references provided at the end of this section. The references are evaluated and discussed in greater detail in Section 4.3.1. The criteria used to perform this evaluation are discussed in detail in Section 3.3.3.

3.3.3 Data and Emission Factor Quality Rating Criteria

Emissions data used to calculate emission factors are obtained from many sources such as published technical papers and reports, documented emissions test results, and regulatory agencies such as local air quality management districts. The quality of these data must be evaluated in order to determine how well the calculated emission factors represent the emissions of an entire source category. Data sources may vary from single source test runs to ranges of minimum and maximum values for a particular source. Some data must be eliminated all together due to their format or lack of documentation. Factors such as the precision and accuracy of the sampling and analytical methods and the operating and design specifications of the unit being tested are key in the evaluation of data viability.

The first step in evaluating a data report is to determine whether the source is a primary or secondary source. A primary source is that which reports the actual source test results while a secondary source is one that references a data report. Many of the sources referenced by XATEF, SPECIATE, and the CD ROM are secondary or tertiary sources. Preferably only primary sources were used in the development of emission factors. When there was not time in this work effort to obtain or evaluate the primary sources, data were taken from a secondary reference if it appeared that an adequate evaluation of the data was performed.

The primary source reports are evaluated to determine if sufficient information is included on the device of interest and on any abatement equipment associated with the device. General design parameters such as boiler size, firing configuration, atypical design parameters, fuel type, operating parameters during the test, e.g. load, are all required in order to evaluate the quality of the data. Data on the type and number of samples, sampling and analytical methods used, sampling locations, quality control samples and procedures, modifications to methods, fuel composition and feed rates, etc. are also needed. Sufficient documentation to determine how the data were reduced and how emissions estimates were made are required. This documentation should include sample calculations, assumptions, correction factors, etc. Equivalent information for the abatement device(s) must also be included.

When primary data could not be obtained in the time frame of this initial update, secondary sources were evaluated to determine the representativeness of the emission factors to a source category. A judgement of the quality of the authors' analysis of the primary data was made in this case which automatically warrants a lower quality rating for the emission factor. The secondary sources provide at least an order of magnitude estimate of emissions and possibly better, however, this cannot be evaluated without reviewing the primary data. Ideally primary data would be used for development for all emission factors.

3.4 N_2O

3.4.1 Literature Search

An extensive literature search was conducted during this revision to identify sources of N_2O emissions data associated with coal fired boilers. Some specific areas of search included European N_2O Workshop, Atmospheric Energy and Environmental Research Laboratory (AEERL), Combustion and Flame, Journal of Geophysical Research, International Conference of Fluidized Bed Combustion, and AWMA. The details of the literature search are summarized in Table 3-4.

3.4.2 Literature Evaluation

Alterations to the literature evaluation process for N_2O were made to allow the inclusion of sufficient data to calculate emission factors. Data were evaluated even if they failed one or more questions on the test report exclusion criteria checklist described in Section 3.1.2. In addition to the prescribed evaluation, the data were also evaluated for N_2O sampling method.

3.4.3 Data and Emission Factor Quality Rating

Data obtained through the literature search, except that derived from on-line N_2O analysis with gas chromotography/electron capture detection (GC/ECD), were rated C or poorer, because the data were based on untested or new methodology that lacked sufficient background data. A problem has been identified in using grab sampling techniques measuring N_2O emissions from coal combustion. Storing combustion products in grab samples containing SO_2, NO_x and water for periods as short as 1 hour can lead to the formation of several hundred parts per million (ppm) of N_2O where none originally existed. Presented below are some improved methodologies for N_2O sampling and analysis and their relative effects on data quality ratings:

- On-line N_2O analysis with GC/ECD (preferred method)
- Grab samples
  - Removing H_2O - drying the sample reduces the most important reactant, but may not entirely eliminate N_2O formation.
  - Removing SO_2 - scrubbing the sample through NaOH solution.
  - A combination of the two (second preference)

The emission factor for pulverized coal-fired boilers was calculated with B rated data. Of the data reported, eighty percent of the values used to calculate the emission factor were below the detection limit of the analytical instrument. Therefore, the emission factor was assigned a D quality rating.

The emission factor for fluidized bed combustors was developed from D rated test data. Because the data were not recorded with an on-line GC/ECD N_2O analysis and the tested facilities are not representative of the industry, the emission factor received an E rating.

3.5 FUGITIVES

A literature search was conducted on fugitive emissions as described in section 3.1.1. A literature evaluation and data rating was not conducted for coal storage and handling operations, because those fugitive emissions are covered in sub-sections of AP-42 Chapter 11. The fly ash handling operations in most modern utility and industrial combustion sources consist of pneumatic systems or enclosed and hooded systems which are vented through small fabric filters or other dust control devices. The fugitive particulate matter emissions from these systems are therefore minimal. Fugitive particulate emissions can sometimes occur during transfer operations from silos to trucks or rail cars. Particulate matter emission factors resulting from these operations can be developed using the procedures in AP-42 Chapter 11.

3.6 PARTICLE SIZE DISTRIBUTION

3.6.1 Literature Search

The literature search emphasized filling the perceived gaps in the previous updates. Updates to AP-42 are supposed to report PM-10 emissions as the sum of the in-stack filterable particulate and the organic and inorganic CPM. Upon review of the 1988 AP-42 update of particulate sizing emission data, the largest gap appeared to be the lack of CPM data.

The background files for the 1988 AP-42 update were reviewed. A Dialog data base search was conducted, focussing on reports issued since 1980. Based on the results of the Dialog search, NTIS documents, EPA reports, and conference proceedings were ordered and journal articles were collected. Conference symposia that were searched included the Eighth and Ninth Particulate Control Symposia and the Air and Waste Management Association Conferences for 1988 through 1991.

The following PM-10 "gap filling" documents were examined (with results indicated):

- "PM-10 Emission Factor Listing Developed by Technology Transfer" (EPA-450/4-89-022): The factors presented for bituminous coal came from AP-42.

- "Gap Filling PM-10 Emission Factors for Selected Open Area Dust Sources" (EPA-450/88-003): Not applicable to stationary source combustion.

- "Generalized Particle Size Distributions for Use in Preparing Size Specific Particulate Emission Inventories" (EPA-450/4-86-013): Lists the average collection efficiencies of various particulate control devices for different size fractions. This was the source of the overall collection efficiency estimates for the 1986 PM-10 update of AP-42 Chapter 1.

The following regional EPA offices and state and regional air pollution control boards were contacted:

- EPA Region 2
- EPA Region 3
- EPA Region 4
- EPA Region 5
- California Air Resources Board: Stationary Sources Division, Monitoring and Laboratory Division, and the Compliance Division
- Illinois Air Pollution Control
- New York Air Pollution Control
- New Jersey Air Pollution Control
- Bay Area Air Quality Management District (CA)
- Kern County Air Pollution Control District (CA)
- Stanislaus County Air Pollution Control District (CA)
- San Joaquin County Air Pollution Control District (CA)

The primary source of the particulate size distribution data for the previous AP-42 update was the Fine Particulate Emissions Information System (FPEIS). The FPEIS has not been updated since the previous AP-42 update.

The EPA OAQPS Emissions Monitoring Branch was contacted for test data from method development studies for EPA Method 202.

Contacts were also made with Electric Power Research Institute (EPRI), Wheelabrator Air Pollution Control, Southern Research Institute, and Entropy.

3.6.2 Literature Evaluation

The previous update was reviewed and evaluated. The size distribution data were evaluated by spot-checking the tabulated results against the original FPEIS printouts. If during the literature search, the original test report was uncovered that corresponded to a particular FPEIS printout, the data were compared. The objective of the review was to ensure that the data collected in the 1986 update were ranked and used appropriately.

The previous update was also evaluated with respect to the development of emission factors from the particle size distribution data.

The original FPEIS printouts were also examined. There were two objectives in the reevaluation of the FPEIS printouts:

(1) Ensure that only filterable PM was included in the cumulative percent mass results; and

(2) Search for impinger results to provide CPM emission data.

New literature was evaluated based on the use of appropriate sampling methods and documentation of sufficient process information.

3.6.3 Data Quality Ranking

Data were reviewed and ranked according to the criteria described previously (Ref. 31) and the data evaluation criteria presented for the previous update. Data quality was assessed based on the particle sizing and/or PM-10 measurement method used and the availability of sampling and process data.

For particulate sizing and filterable PM-10 data the following criteria were used:

A - Particle sizing tests performed by cascade impactors or PM-10 measurements performed via Method 201 or 201A. The test information must provide enough detail for adequate validation and the isokinetics must fall between 90 and 110 percent.

B - Particle sizing tests performed via SASS trains if the sampling flowrate isokinetic value was reported and sufficient operating data were used. Cascade impactor data or Method 201 or 201A data if isokinetics not reported or if isokinetics not within the 90 to 110 percent range.

C - SASS train data if the isokinetics were not reported or if the isokinetics did not fall within the 90 to 110 percent range.

D - Test results based on a generally unaccepted particulated sizing method, such as polarized light microscopy.

Although cascade impactors are generally considered the best available method for measuring particulate size distributions, errors in segregating specific sizes of combustion particles arise from the following:

- Particle bounce and re-entrainment
- Diffusive deposition of fine particles
- Deposition of condensible/adsorbable gases
- Losses to the impactor walls

The effects of such errors are described in "Cascade Impactors in the Chemical and Physical Characterization of Coal-Combustion Aerosol Particles", by John M. Ondov, Chapter 25 of Fossil Fuels Utilization: Environmental Concerns, 1986.

The ranking of data for CPM was based primarily on the methodology. Most CPM source tests have been conducted using the back-half of a Method 5, Method 17 or South Coast methods 5.2 or 5.3 trains. However, these test methods do not require a nitrogen (N_2) purge of the impingers. Without the N_2 purge, dissolved SO_2 remains in the impingers and is included in the inorganic CPM results. This type of CPM data is considered very low quality. In contrast, Method 202 includes a one-hour N_2 purge of the impingers immediately after sampling to remove dissolved SO_2. Therefore Method 202 CPM data should be ranked higher than Method 5 or Method 17 CPM data, even though Method 202 is a relatively new method. The following rankings were selected for CPM data:

A - CPM tests performed via Method 202. The test information must provide enough detail for adequate validation and the isokinetics must fall between 90 and 110 percent.

B - CPM tests performed via Method 202 but isokinetics not reported or isokinetics not within the 90 to 110 percent range. CPM tests performed via Method 5 or Method 17 or another acceptable EPA Method that does not include an impinger N_2 purge, if the isokinetics were within the 90 to 110 percent range.

C - CPM tests performed via Method 5 or Method 17 or another acceptable EPA Method that does not include an impinger N_2 purge, if the isokinetics were not reported or not within the 90 to 110 percent range.

D - Test results based on a generally unaccepted CPM method.

TABLE 3-1. LITERATURE SEARCH RESULTS

Literature Type	New baseline data	NO_x control information	Particulate control information	SO_x control information
1. AP-42 files	✓	✓	✓	✓
2. ESD Files/ NSPS Background Information Documents	None	✓	✓	✓
3. CTC publications	None	✓	None	None
4. ORD reports	✓	✓	✓	✓
5. NTIS	✓	✓	✓	✓
6. EPRI	None	✓	None	None
7. Contractor in-house documents	✓	✓	✓	✓
8. API	✓	None	None	None

ESD = Emission Standard Division (of EPA)
CTC = Control Technology Center (of EPA)
ORD = Office of Research and Development (of EPA)
NTIS = National Technical Information Service
EPRI = Electric Power Research Institute
API = American Petroleum Institute

TABLE 3-2. SPECIATED VOC LITERATURE SEARCH RESULTS

Literature Type	Remarks
EPA/AWMA Air Toxics Symposia (1988-1990)	No Data
TOXIC AIR POLLUTANTS: State and Local Regulatory Strategies (1989)	Called those states and localities listed in air toxics report. Received some data, but all was criteria data
Contractor in-house documents	No useful data.
Journals	No useful data.
COMPENDEX	No references found.
EPRI/PISCES	Available end of 1992.
Papers	No useful data.

TABLE 3-3. EVALUATION OF AIR TOXICS REFERENCES

Section 3 Reference	Used in update?	Reason	Parameter of Interest
8	No	Not a primary reference. Document references other low quality references.	
9	Yes	Not a primary reference, however, data are presented for use for rough estimates.	POM
10	No	Not a primary reference. Document references 3a.	
10a	No	Data of unacceptable quality to generate emission factors.	
11	No	Not a primary reference. Document references 4a and 4b.	
11a	No	Data not of sufficient quality to generate emission factors or enrichment ratios.	
11b	No	Emission factors units can not be converted to desired units.	
12	No	Fuel mixture is not applicable.	
13	No	Fuel mixture is not applicable.	
14	No	Fuel mixture is not applicable.	
15	No	Data from Reference 4a were sited. These data are of unacceptable quality.	
16	No	Document presents criteria data only.	
17	No	Same as Reference 2.	
18	Yes	Not a primary reference. Data are of sufficient quality for emission estimates.	Chromium
19	Yes	Not a primary reference. Data of sufficient quality for emission estimates.	Formaldehyde
20	Yes	Not a primary reference. Data of sufficient quality for emission estimates.	Metals
21	Yes	Source test data are of sufficient quality to calculate enrichment ratios and emission factors.	PAH, radionuclides, metals
22	Yes	Enrichment ratio data are of sufficient quality to present.	Metals
23	Yes	Emission factor data are of sufficient quality for emission estimates.	Manganese
24	Yes	Reference used in discussion of partitioning behavior.	

TABLE 3-4. N_2O LITERATURE SEARCH RESULTS

Literature Type	Remarks
TOXIC AIR POLLUTANTS: State and Local Regulatory Strategies (1989)	No useful data
Contractor in-house documents	One primary reference
University of North Dakota	Data apply to lignite combustion
TVA	No useful data
COMPENDEX	No references identified
EPRI/PISCES	Available end of 1992
FBC International Conferences	Did not get 11th conference proceedings; others not useful
Journals	Used one journal as a primary reference
EPA workshops	Some useful references

TVA = Tennessee Valley Authority

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4. EMISSION FACTOR DEVELOPMENT

This chapter describes the test data and methodology used to develop pollutant emission factors for bituminous and subbituminous coal combustion.

4.1 CRITERIA POLLUTANTS

4.1.1 Review of Previous AP-42 Data

The emission factor documentation files from the prior AP-42 updates of Section 1-1 were obtained and reviewed. The criteria emission factors were developed in 1981 and documented in Reference 1. The emission factors for particle sizing and particulate collection efficiencies by particle size were developed in 1984 in Reference 2. Initially, much of the documentation used in developing these prior emission factors were reviewed. The references included:

- The 61 primary references cited in the 1988 Section 1.1.;
- Secondary references from background files;
- Memoranda and emission factor worksheets from the prior updates.

The references used in developing the prior emissions factors were checked in several cases as a first-level quality check on the documentation. Table 4-1 lists several of the cases where the reference trail was spot checked. Several anomalies regarding reference documentation were revealed, but none which invalidated the quality of the results. A review of the 1988 version of Section 1.1 was accomplished by spot checking the quality of existing emission factors. This was done by selecting primary data references from the background files, reviewing data quality sampling and analytical procedures, determining completeness, and verifying that the site emission factors in the background files could be reconstructed and were accurate. Examples of spot-check data are presented in Appendix A.

Spot checks revealed that, in general, ample A-quality rated data points were available for the criteria pollutants or that most poor quality data had little affect on the published AP-42 emission factors. However, questions regarding the quality of the data used to calculate the emission factors were justified and point to a need to properly review references, assigned data quality ratings, and calculations, when developing improved emission factors for well-defined equipment categories.

4.1.2 Review of New Baseline Data

A total of 60 references were identified and reviewed during the literature search. These references are listed in the checklists added to the background files for this update to AP-42. The original group of 60 documents was reduced to a set of rated references utilizing the criteria outlined in Chapter 3. The following is a discussion of the data contained in each of the rated references.

Reference 3

This report covers the emissions of two hand-feed space heaters tested in cooperation with the Vermont Agency of Environmental Conservation. Oxygen, CO_2 and CO were measured by Orsat from a grab sample collected over the test duration. SO_2 and light hydrocarbons were analyzed from a grab sample in a gas chromatograph. Particulate measurement was made from front half catch of a Modified Method 5 (MM5) sampling train. Hazardous air pollutants (HAPs) were also reported. No original data sheets were found. Coal analysis was reported on a dry basis and higher heating value (HHV) was reported on dry ash free basis. Emissions were calculated in the report (p.15) but appear to be reported incorrectly. Particulate emissions were recalculated using the F-factor in 40 Code of Federal Regulations (CFR) Part 60 Appendix A, EPA Method 19. Data were assigned a rating of C.

Reference 4

This report covers the emissions of one 40,000 lb steam/hr (18,000 kg steam/hr) FBC for long term performance. Data were collected to support NSPS for small boilers. Oxygen, CO_2, SO_2, NO_x, and CO were analyzed by certified continuous emission monitors (CEMs). Test data for the thirty day testing period are presented in the report in molar concentration units. Data from February 28, 1986 were averaged to obtain NO_x and CO emission factors. Sulfur dioxide emissions were controlled by limestone addition to the FBC. No uncontrolled particulate data were found. Data were given a quality rating of B.

Reference 5

This is a compliance test report for PM, SO_2, and NO_x on a 100 MWe tangential-fired boiler for the Nebraska Department of Environmental Control in Lincoln, Nebraska. Particulate was sampled after an ESP and was not useful for uncontrolled emissions. Sampling was performed by EPA Methods 6 and 7. Emissions were given in lb/million Btu (MMBTU). Data were given a quality rating of A.

Reference 6

This is a compliance test report for SO_2 on a 145 MWe PC-fired unit manufactured by Riley Stoker Corporation. Sampling was performed by EPA Method 6 after an ESP. Emissions were given in lb/MMBTU. Data were given a quality rating of A.

Reference 7

This is a test report for short-term testing on seven separate boilers with different configurations over a five-day period. Emphasis of the report is on specific organic compounds; however, CEMs were used to monitor O_2, CO, and total hydrocarbons (THC) during test conditions. There was inadequate information in this report to determine reporting units and measurement method for THC. No CEM specifications or calibration procedures were found but method is fairly well established. Some sampling sites were located after ESPs but this was not expected to significantly alter CO emissions. Sulfur dioxide and NO_X data were available for one of the plants tested via plant-installed CEMs after an ESP. Data were given a quality rating of B.

Reference 8

This is a compliance test report for the Kansas Board of Public Utilities for two coal-fired cyclone boilers. Testing was done by EPA Method 6. Raw data were available but titrations were not checked. Sampling was conducted at the stack after a baghouse and ESP, respectively. A summary table listed emissions in lb/MMBTU based on Tabulated F-factor in 40 CFR Part 60 Appendix 19. Data were given a quality rating of A.

Reference 9

This is a compliance test report for the Kansas Board of Public Utilities on a PC-fired boiler. Insufficient detail for the unit was given to specify firing configuration; however, this information is not necessary for emission factor development at this time. Samples were taken both before and after an ESP to show removal efficiency. Unit was operating at nominally 90 percent of nameplate rating (145 MWe). Raw data were available. Emissions were presented in lb/MMBTU based on an F-factor derived from the fuel analysis. Data were given a quality rating of A.

Reference 10

This report is an EPA/Office of Air Quality Planning and Standards (OAQPS)/Emission Measurements Branch (EMB) document describing a test of Tennessee Eastman's Boiler 24 in Kingsport, Tennessee, in support of the industrial boiler NSPS. The tests were conducted to determine the effects of boiler load, O_2 and preheat on NO_x emissions. Continuous monitors were used to measure NO_x, CO and O_2; NO_x was also measured using EPA Method 7. Comparison of the two NO_x methods was acceptable and the average was used for emission factor calculation. Five of the nine runs were conducted at acceptable boiler loads (> 70 percent). The remaining runs at low load (approximately 55 percent) indicated a 20 percent reduction in NO_x emissions with little effect on CO levels. An A rating has been assigned to this data.

Reference 11

This report is an EPA/OAQPS/EMB document describing a test of an industrial boiler with stoker gas recirculation (SGR) at Upjohn Company's Kalamazoo, MI, facility. These tests were also in support of the industrial boiler NSPS. The effects of boiler load, O_2 and SGR on NO_x emissions were measured. Continuous monitors were used to measure NO_x, CO, and O_2. Nine of the ten runs were made at boiler loads of 75 to 100 percent with O_2 levels between 3.2 and 8.0 percent. These data were used in the emission factor calculations. The remaining run at 50-percent load showed no noted effect on NO_x or CO levels. An A rating has been assigned to this data.

Reference 12

This report is an EPA/OAQPS/EMB report describing a test of an industrial spreader stoker at the Burlington Industries facility in Clarksville, VA. These tests were conducted in support of the industrial boiler NSPS for PM. Nine runs were performed at various boiler loads using a slight variation of EPA Method 5 for the particulate measurements. The modification to the sampling method was in heating the filter box to 160°C (320°F) . In a previous report comparing results using this variation to standard Method 5 data, this method produced particulate catches of 94 to 100 percent of Method 5 results. Five of the nine runs were used in the emission factor calculations. Three of the remaining runs were at one-third boiler load and one run exceeded the acceptable percent-isokinetic standard. A B rating was assigned to this data because of the method modification and wide variation in results.

Reference 13

Contains SO_2 and NO_x summary data for the Tennessee Valley Authority's (TVA) bubbling bed FBC (with and without fly ash reinjection) and Batelle's circulating bed FBC. Original test reports are referenced in the document and should be obtained in order to upgrade quality rating. Data were assigned a quality rating of D.

4.1.3 Compilation of Baseline Emission Factors

The references described above were used in updating the uncontrolled (baseline) emission factors for criteria pollutants. Computerized spreadsheets were set up to calculate new data points from the information contained in these references. Sections of the spreadsheets, pertaining to specific pollutants are shown as Tables 4-2 through 4-8.

The new data points were combined with the 1988 AP-42 Section 1.1 data points retained from spot checking to develop new emission factors. The various formulae and conversion factors used in the spreadsheet programs and in the calculation of new emission factors are shown in Appendix B.

4.1.3.1 SO_2 Emission Factors. The new SO_2 baseline data are summarized in Table 4-2. The following new data points were added to the emission factor database:

- Cyclone furnace: 3 points
- Spreader stoker: 2 points
- Pulverized coal, tangential fired: 1 point
- Pulverized coal, dry bottom, wall fired: 1 point
- Handfeed: 1 point
- Bubbling bed FBC: 6 points
- Circulating bed FBC: 1 point

The spot checks revealed only minor anomalies in the 1988 AP-42 emission factor calculations. One test report[14] appeared to have a discrepancy in the fuel analysis procedures. For the "ALMA" site, the facility data point was developed from the fuel sulfur content measured on a dried and pulverized (as-fired) basis, but with the as-received HHV. However, making this correction only changes the data point from 33S to 33.7S, where S is the percent sulfur in the fuel. Also, for the subbituminous coal testing at the same site, the coal sample averages did not match the emissions average periods. Again, however, making these corrections did not effectively change the site data point. Therefore, all previous SO_2 emission factor background data were retained in the current update effort.

For bituminous coal firing, three new data points were added for cyclone boilers, and one data point each was added for PC wall-fired and tangential-fired boilers. Of the three cyclone boiler tests, data from two tests were rated E because the calculated emission factors were above the theoretical maximum value of 40S; the remaining cyclone boiler test produced a B-rated emission factor of 31.5S. Test data from the two PC-fired boilers were rated A and B. The average of the emission factors from these two tests was 38.1S. These data, when combined with a 1984 review[89] of the 1982 emission factor development effort and data base, justify a revision of the SO_x emission factor from 39S to 38S for PC-fired, cyclone, spreader stoker, and overfeed stoker boilers.

One new data point from Reference 1 was obtained for a small 2.9 KW (10,000 Btu/hr) hand-fired unit. However, this data point was assigned a C rating and, at a value of 52.4S, was significantly different from the existing average emission factor of 31S for underfeed and hand-fired units. Therefore, the existing AP-42 emission factor was retained.

No new data for subbituminous coal firing were identified during this update. Therefore, the existing emission factor of 35S for PC, cyclone, and spreader and overfeed stokers was retained.

New emission factors were developed for FBCs which have been included in this update of AP-42 as a new source category. As discussed in Chapter 2, a correlation was developed with the coal sulfur content and the calcium-to-sulfur ratio in the bed. The data obtained from the FBC test reports are plotted against calcium-to-sulfur ratio (Ca/S) in Figure 4-1.

Four data points were obtained from Reference 4 showing the effect of available Ca/S ratio on SO_2 emissions. Reference 4 data were given an A rating. The FBC in Reference 4 is a bubbling bed FBC incorporating reinjection of fly ash captured in the first stage cyclone. Fly ash reinjection results increase in higher calcium utilization and lower SO_2 emissions.

Reference 13 presented summary data from both bubbling and circulating bed FBCs. These data were given D ratings because the report lacked sufficient background data to fully evaluate the source operation and test methodology. However, when plotted on Figure 4-1, the data point from the bubbling bed unit with fly ash reinjection matched the data from the similar FBC in Reference 2. Because of the limited number of FBC test data reports which were obtained for this update of AP-42, all these data points were used in developing the SO_2 emission factor correlation. The data from the bubbling bed unit without fly ash reinjection do not match the reinjection data and therefore were not considered in the correlation. Also, the data point from the circulating bed FBC plotted on Figure 4-1 follows the same trend as the bubbling bed units with fly ash reinjection. This behavior is not surprising because circulating bed units are essentially an extension of bubbling bed technology but with higher fluidizing velocities and a high ratio of fly ash reinjection.

All data shown in Figure 4-1 from the bubbling bed units with fly ash reinjection and the circulating bed unit were curve-fit to develop a correlation for the emission factor. The best-fit equation reflecting the SO_2 emissions performance of FBCs was:

$$\frac{lb\ SO_2}{ton\ coal} = 39.6(S)\left(\frac{Ca}{S}\right)^{-1.9}$$

where S is the weight percent sulfur in the coal and Ca/S is the molar calcium-to-sulfur ratio in the bed. This correlation was used for the SO_2 emission factor for both bubbling bed and circulating bed FBCs. An emission factor quality rating of D was given for bubbling bed units because of the limited number of facilities used to obtain the test data. An emission factor quality rating of E was given to the circulating bed units.

When no calcium-based sorbents are used and the bed material is inert with respect to sulfur capture, the emission factor for underfeed stokers should be used to estimate FBC SO_2 emissions. In this case, the emission factor quality ratings should be E for both bubbling and circulating bed units.

4.1.3.2 NO_x Emission Factors. The new NO_x baseline data are summarized in Table 4-3. The following new data points were added to the emission factor database:

- Cyclone furnace: 1 point
- Spreader stoker: 2 points
- Pulverized coal, tangential fired: 1 point
- Handfed: 1 point

- Bubbling bed FBC: 1 point
- Circulating bed FBC: 1 point

One new data point was averaged with prior data to calculate a new emission factor for cyclone boilers. Although the data point value of 7.52 kg/Mg (15.04 lb/ton) was considerably below the previous AP-42 emission factor of 18.2 kg/Mg (36.4 lb/ton), it appears to be of at least equal quality to the previous background data. The new emission factor of 16.9 kg/Mg (33.8 lb/ton) was calculated by averaging the new data with the old data, all of which have a B quality rating. The emission factor rating of C was retained to indicate that a reasonable set of data points were used to develop the emission factor; however, it is not clear that the facilities tested represent a random sample of the population.

Data from References 10 and 11 were averaged with the prior data for spreader stokers. The resulting change in emission factor was minor. The existing value of 7 kg/Mg (14 lb/ton) was changed to 6.9 kg/Mg (13.7 lb/ton). The emission factor rating of A was retained.

One data point for a tangential-fired boiler was obtained from Reference 5. At 3.5 kg/Mg (6.9 lb/ton), this data point was somewhat below the 1988 AP-42 emission factor of 7.5 kg/Mg (15 lb/ton); however, it was rated as A quality because Reference 5 is a well-documented and complete compliance test report. A new emission factor of 7.2 kg/Mg (14.4 lb/ton) was developed by averaging the new data point with the old A-rated data. The emission factor rating of A was retained.

Two data points were obtained for bubbling bed FBCs. The FBC boiler in Reference 4 is a bubbling bed unit installed in Prince Edward Island, Canada. The data quality rating given to the Reference 4 data point was A because it is a complete and well-documented emission assessment report. Because the FBC unit in Reference 13 is the TVA 20 MWe demonstration unit, it may be more representative of NO_x emissions from new bubbling bed units designed to meet the Federal New Source Performance Standards. However, the data quality assigned to Reference 13 was D because of the lack of supporting information in the test report. Therefore, only the A-rated data from Reference 4 were used for the bubbling bed FBC emission factor. The emission factor is 7.6 kg/Mg (15.2 lb/ton) and has been given an emission factor quality rating of D because the data have been obtained from only one facility.

One data point was obtained for a circulating fluidized bed boiler from Reference 13. Because the data quality rating is D from this standard reference, an emission factor rating of E has been assigned to this source category.

One data point was obtained from a small, hand-fed domestic furnace in Reference 3. To determine if this data point should be combined with the existing data used in the 1988 AP-42 emission factor, a detailed spot check was performed. The emission factor could be reproduced from the data contained in the reference; however, with no supporting sampling discussion or data documentation, the data quality for the existing data point would warrant a C or D rating. Therefore, the new emission factor was developed by averaging the two data points [i.e., 7.6 kg/Mg (15.2 lb/ton) from Reference 1 and 1.5 kg/Mg (3 lb/ton) from the single data point in the 1988 AP-42 emission factor] to obtain a value of 4.55 kg/Mg (9.1 lb/ton). An emission factor quality rating of E was assigned for this source category.

No additional data points were obtained for overfeed and underfeed stokers nor for wet bottom wall-fired pulverized coal units. Therefore, the 1988 AP-42 emission factors were retained for these sources categories. The emission factor ratings of A were retained for the overfeed and underfeed stokers based on the quality of the original references.

Based on the existing AP-42 emission factor spot checks discussed in Section 4.1.1, two data points were removed from the emission factor calculation for wall-fired pulverized coal, dry bottom boilers. This resulted in a change in the emission factor from 10.5 kg/Mg (21 lb/ton) to 10.9 kg/Mg (21.7 lb/ton). The emission factor quality rating of A was retained based on the quality of the remaining references.

4.1.3.3 CO Emission Factors

PC Boilers. Four new data points were obtained as shown in Table 4-4. The two wall-fired data points were lower than the 1988 emission factor of 0.3 kg/Mg (0.6 lb/ton), but the individual runs were consistent at each site. The vertical V-fired data point of 0.76 kg/Mg (1.52 lb/ton) was obtained from the average of individual runs that varied from 0.16 kg/Mg (0.37 lb/ton) to 1.85 kg/Mg (2.71 lb/ton). This point was not used because of its variability and the fact that the resulting number was far outside of the previous data grouping. The tangentially-fired (T-fired) data point of 0.05 kg/Mg (0.10 lb/ton), although unusually low, appears to be high quality data. Two new cyclone boiler points were also found and added to the baseline database. Both were lower than the computed emission factor but were considered reliable data. A new average emission factor of 0.25 kg/Mg (0.52 lb/ton) was computed. This compares to the previously-computed factor of 0.29 kg/Mg (0.58 lb/ton). The current emission factor has been changed from 0.3 kg/Mg (0.6 lb/ton) to 0.25 kg/Mg (0.5 lb/ton).

The new T-fired data point was considered as a candidate for a new, separate T-fired emission factor. After it was averaged with the existing T-fired data, however, a new emission factor was not warranted.

Spreader Stoker. Two new data points were added to the existing 22 data points [i.e., 0.8 kg/Mg (1.60 lb/ton and 0.46 kg/Mg (0.92 lb/ton)]. Both were considerably below the average emission factor of 0.29 kg/Mg (0.58 lb/ton). A new average emission factor of 2.46 kg/Mg (4.92 lb/ton) was computed. It is recommended to retain the existing factor of 2.5 kg/Mg (5 lb/ton).

Overfeed and Underfeed Stoker. No new data were found. It is recommended to retain the current value.

Hand-fed Units. Two new data points were obtained. The data were assessed to be of C quality. A spot check of Reference 15 revealed that the prior data should be discarded in light of the new data. It is recommended to change the emission factor to 215 kg/Mg (430 lb/ton), which is a simple average of the two new data points.

Fluidized Bed Combustors. A new data point was obtained and is shown in Table 4-4. An emission factor of 9 kg/Mg (18 lb/ton) is recommended for both bubbling bed and circulating FBCs.

4.1.3.4 Particulate Emission Factors

PC-fired, Dry Bottom, Wall Fired. A spot check revealed one data point of low quality. This value was removed from the emission factor data base. Because of the large number of data points and the proximity of the rejected point to the average value, this process had little effect on the new average emission factor. A new data point shown in Table 4-5 was added to the data base. Although the new value was 9.16 kg/Mg (18.31 lb/ton), its addition to the data base did not cause the average emission factor to increase beyond 5.22 kg/Mg (10.44 lb/ton).

PC-fired, Dry Bottom, Tangentially Fired. Existing data were reviewed and an average emission factor was computed. The average value of four data points generated by EPA Method 5 measurements was 5.2 kg/Mg (10.3 lb/ton). An emission factor of 5 kg/Mg (10 lb/ton) is recommended. Because only four data points were used, a quality rating of B was assigned.

PC-fired, Wet Bottom. The existing data were reviewed. Because only one data point was used (the only one found using EPA Method 5), the quality rating was confirmed to be D.

Cyclone Furnace. The existing data were reviewed. Because only one data point was available and it was not obtained by an EPA-approved method, the quality rating was downgraded to E.

Spreader Stoker. Based on the findings of the spot checks, the data point based on Reference 16 was discarded from the new emission factor calculation. The remaining seven data points were averaged with the one new data point obtained from Reference 12 to give a new emission factor of 33 kg/Mg (66.0 lb/ton). The B emission factor quality rating was retained.

Spreader Stoker with Multiclones and Reinjection. Six data points were used and all were based on EPA Method 5 measurements.

Spreader Stoker with Multiclones and No Reinjection. Twelve data points were used and all were based on EPA Method 5 measurements. The A quality rating appears to be warranted since these data are from many diverse facilities. This is also an extremely specific source category and the data did not have a high degree of variability.

Overfed Stoker. Eight data points were used and all were based on EPA Method 5 measurements. Considerable data scatter indicates C quality data.

Overfed Stoker with Multiple Cyclones. All five data points were obtained using EPA Method 5 measurements. Reasonable data consistency warrants a B quality rating.

Underfed Stoker. Although nine EPA Method 5 data points were used, considerable variability exits. A quality rating of C is recommended.

Underfed Stoker with Multiple Cyclone. A quality rating of D is recommended because, although the data are consistent, only two data points are available.

Hand-fed Units. Data were reviewed from the two sources (References 17 and 15). Data from Reference 17 were discounted because the unit was from an open fireplace. Data from Reference 15 were secondary data. Two new data points were added, taken from Table 4-5. Because the two new data points have an average emission factor of approximately 7.5 kg/Mg (15 lb/ton), it is recommended that the emission factor remain unchanged.

Fluidized Bed Combustor, Bubbling Bed. No baseline particulate data, either old or new, were available. It is estimated that PM emissions would most closely match those of a spreader stoker with multiple cyclones and no flyash reinjection. The corresponding PM emission factor of 6 kg/Mg (12 lb/ton) is recommended for use. This assumption warrants the lowest quality rating of E.

Fluidized Bed Combustor, Circulating Bed. No data, either old or new, were available. It was estimated that PM emissions would most closely match those of a spreader stoker with multiple cyclones and no fly ash reinjection. Its PM emission factor of 6 kg/Mg (12 lb/ton) is recommended for use. This assumption warrants the lowest quality rating of E.

4.1.3.5 Methane Emission Factors. Reference 15 was spot checked, and it was found that methane (CH_4) emission factors could be computed for individual boiler types. The existing data were grouped into their appropriate boiler types and new individual emission factors were calculated. Although the same data were used, the emission factor data quality was downgraded to B since each boiler type had only three to five data points.

The only new data obtained were for hand-fed boilers. The spot checks of prior data showed these data to be outdated and unusable. A new emission factor was calculated based on two new data points as shown in Table 4-6.

No CH_4 data were available for FBCs. Possibilities of using data from comparable combustion devices were explored. No suitable estimation procedure was identified.

4.1.3.6 Non-CH_4 Emission Factors. As with CH_4, Reference 15 revealed individual emission data for each boiler type. The existing data were grouped into boiler categories and new individual emission factors were calculated. Although the same data were used, the emission factor data were downgraded to B since each boiler type had only three to five data points.

No new data were found for hand-fed units. Spot checks revealed previous data to be outdated and unusable. Because no other data were available, the existing emission factor was retained in this update. Its quality rating was downgraded to E.

4.1.4 Compilation of Controlled Emission Factors

A compilation of controlled emissions and control efficiencies achieved through application of some of the control technologies discussed in Section 2.4 is given in Tables 4-7 through 4-9.

4.2 SPECIATED VOCs

The VOC speciation data base was very sparse, as described in Section 3.2. The data evaluation was limited to the single report referenced in the database. The report contained only two references for VOC speciation data; only one of these references documented the protocols used for collecting and analyzing the samples. In the one case, samples were collected with Tedlar bags using a vacuum pump. Gas chromatography was the analysis technique. There were no data sheets, calibration procedures or quality control (QC) methods mentioned and no source operating conditions listed. Without these details, the data were considered "unratable," and not suitable for use in developing emission factors.

In the absence of developed emission factors for VOC speciation, the SPECIATE and XATEF databases for speciated VOCs can be consulted for qualitative guidance.

4.3 AIR TOXICS

4.3.1 Review of New Data

The data search summarized in Section 3.3 identified several key documents with primary test data or data compilations for air toxics emissions. The evaluation of several of the key references follows:

Reference 24

This article summarizes the emissions of certain trace metals and hazardous pollutants from bituminous coal combustion. The data presented are a summary of a literature review. Emission factors are presented in the units of mass emitted per heat input quantity combusted and are presented for boilers of different sizes and configurations. The article references several primary references which were evaluated but determined to be of insufficient quality.

Reference 25

This document is a compilation of the available information on sources and emission of POM and is not a primary reference. The document cautions the use of these data for development of an exact assessment of emissions from any particular facility, however, the data are useful for providing rough estimates of POM emissions from boilers firing bituminous coal. The emission factors provided are for controlled devices. Data for utility boilers are used in this update because this is the largest and most complete data set for coal combustion.

Reference 26

The data quality in this report is of unacceptable quality to generate enrichment ratios for metals or emission factors for metals, organics, and POM.

Metals:	Metals samples were not taken after the boiler and before the multicyclones so enrichment factors for the pieces of equipment could not be calculated. The multicyclones malfunctioned during the coal test rendering the metals data of questionable quality.
Organics:	It was stated in the report (on page 6-28) that the organics recovered were not combustion products but were components in the sample collection media and in the analytical lab.
POM:	POM data were below detection limit. The malfunctioning multicyclones would also impact the quality of these data.

Reference 29

The data quality and documentation in this report are of unacceptable quality to generate emission factors.

Metals: Level I sampling and analysis program which is semiquantiative (a factor of ± 3) data quality. A source assessment sampling system (SASS) train and spark source mass spectroscopy (SSMS) analyses were used. These data are not suited for calculation of enrichment factors or mass balances as stated in the source on page 269.

POM: The sampling and analytical procedures are also of lower quality [i.e., SASS and gas chromatography/mass spectrometry (GC/MS)].

The documentation for the analytical results is not clear as to why only portions of the samples were analyzed; therefore, one cannot determine if the entire sample is being accounted for.

Reference 28

The purpose of this document is to provide a preliminary emission assessment of conventional stationary combustion sources. The data presented deals with national averages or ranges based on the best available information. Emission factors in mass emitted per heat unit input are not provided.

Reference 29

The emission factors for oil combustion that were summarized in this document came from Reference 29. These data were eliminated from use in this update due to their poor quality.

Reference 30

This report summarizes testing performed on several sizes and types of boilers; however, only criteria pollutant testing was performed.

Reference 31

Measured and calculated emission factors for bituminous coal are presented in this document. The emission factors are rated as low quality because the document is not a primary source and the quality of the data cannot be verified.

Reference 32

This document presents a summary of emission factors for different types of processes which emit formaldehyde. The emission factors are presented in mass per unit heat input. A factor is provided for coal-fired sources; however, the factors are based on one or two tests. Also, the type of coal is not specified. The emission factor is therefore assigned a low rating and represents an approximate emission estimate.

Reference 33

This document provides a summary of the emissions factors for metals, POM, and formaldehyde for bituminous coal-fired boilers. Control efficiencies are reported for some control devices. No data are reported for uncontrolled emissions of POM and radionuclides. The formaldehyde data are from 1964 and are considered to be of unacceptable quality. The emission factors are based on source test data from coal-fired utility and industrial boilers. Data for different boiler configurations are presented in the units of mass emitted per unit of fuel input.

This reference is not a primary source. The document cautions that relatively limited data are available on toxic air pollutants resulting from these types of processes and that emissions data in the document should not be used to develop an exact assessment of emissions from any particular facility. Emission factors for the processes outlined in the document are summarized and provided for use in determining order-of-magnitude emissions. The emission factors are rated low quality because the data acquisition and manipulation could not be verified.

Reference 34

The data quality and documentation in this report are of high enough quality to develop enrichment ratios for metals and radionuclides on boilers and their associated abatement devices. Emission factors expressed as mass emitted per unit heat combusted are calculated for PAH compounds.

Reference 35

This report summarizes the current research effort in the Netherlands to determine the fate of trace elements at coal-fired power plants. A total of sixteen test and mass balance programs were undertaken to determine enrichment ratios for boilers and high-efficiency cold-side ESPs. Enrichment ratios for boilers are presented by classes of metals. Enrichment ratios for the ESPs are also presented. The data are of sufficient quality for use in this update.

Reference 36

This document presents emission factors for sources of chromium. A literature survey was used to compile emission estimates from bituminous coal-fired boilers. The emission data for utility boilers is used to generate the emission factor.

The data from these references were reviewed and ranked according to the quality criteria discussed in Section 3.

4.3.2 Baseline Emission Factors

Emission factors for metals, radionuclides, and other HAPs are quite often presented in units of mass emitted per heat input combusted. These units are adequate for developing emission factors for organic HAPs but are not desirable for developing factors for metals and radionuclides. Ideally, emission factors for trace elements should be developed as a function of the boiler firing configuration, boiler size, trace element content of the fuel, ash content, higher heating value, enrichment ratio (see discussion below), and the collection efficiency of the control device.

The concepts of partitioning and enrichment are needed to describe the fate of trace metals within the boiler and collection devices. The concept of partitioning is used to describe the distribution of trace elements among the boiler system outlet streams. These streams may include the bottom ash collector hoppers, boiler/economizer/preheater hoppers, and flue gas. Enrichment refers to the preferential migration of specific trace metals to a process stream or to a specific particle size range, especially the respirable range and below. The process of enrichment typically involves a control device, where collection efficiency varies by particle size range. When metals are distributed unequally across size ranges, the collection device will then yield disproportionate partitioning from the size enrichment. The physical and chemical properties of a trace metal governs how that metal will be distributed in the outlet streams. For example, mercury is a highly volatile metal and therefore, the majority of the mass of mercury in the coal tends to be emitted from the boiler in the flue gas and not in the bottom ash or in the fly ash.

A method for describing partitioning behavior is to report the fraction of the total elemental mass input that has exited the boiler in an outlet stream. Another method for quantifying the distribution of a metal is to calculate an enrichment ratio by comparing the trace element concentration of an outlet stream to the trace element concentration in the inlet coal stream. The enrichment ratio calculation that is outlined in Reference 33 is performed using the following equation:

$$ER_{ij} = (C_{ij}/C_{Rj})/(C_{ic}/C_{Rc})$$

where: ER_{ij} = enrichment ratio for element i in stream j

C_{ij} = concentration of element i in stream j

C_{Rj} = concentration of reference element R in stream j

C_{ic} = concentration of element i in coal

C_{Rc} = concentration of reference element R in coal

Enrichment ratios greater than 1 indicate that an element is enriched in a given stream, e.g. stream j, or that it partitions to a given stream. The reference element is used because its partitioning and enrichment behavior is often comparable to that for the total ash. In other words, the reference element partitions with consistent concentrations in all ash streams and normalizes the calculation. Typical reference elements are aluminum, iron, scandium, and titanium. The enrichment behavior of elements is relatively consistent in different types of boilers and can be explained by a volatilization-condensation or adsorption mechanisms. A summary of the enrichment behavior for air toxic metals and the reference metals is presented in Table 4-10. Table 4-11 presents a summary of enrichment behaviors including approximate enrichment ratios for particular classes of compounds.

The enrichment ratio can be used in conjunction with additional data from a specific facility to estimate emissions of trace elements. The equation outlined in Reference 35 is used to calculate the emission factor for a trace element as follows:

$$EF = (C/H)*F*(1-E)*ER*10^3$$

where: EF = emission factor for a specific trace element, ng/J

C = concentration of element in coal, $\mu g/g$

H = higher heating value of coal, kJ/kg

F = fraction of coal ash as fly ash

E = fractional particulate collection efficiency of control device (zero for uncontrolled emissions)

ER = enrichment factor for the trace element (ratio of concentration of element in emitted fly ash to concentration of element in coal ash, often based on aluminum).

In many cases, the source test programs did not include key parameters such as: ultimate and trace element analyses of coal used for the test, measurements of the boiler effluent for metals and ash, and measurements of metals and ash after the collection device. This made it impossible to calculate partitioning of metals within the bottom and fly ash. When supporting documentation to develop enrichment ratios were not available, emission factors in the units of mass emitted per unit thermal heat input were provided. Although this is not the optimal method of estimating emissions, it provides a means of performing approximate emission estimation.

Table 4-12 summarizes the enrichment ratios for metals and radionuclides for various uncontrolled boilers and for a high efficiency cold-side ESP. The enrichment ratios presented are the ranges for the references obtained. The quality of these enrichment ratios is low (E quality) because of the small number of boilers tested and limited control data used to perform the calculations. Enrichment ratio data are a significant data gap in the air toxic data bases.

Table 4-13 and 4-14 present summaries of emission factors in the units of mass emitted per unit thermal heat input combusted for uncontrolled boilers. Data are presented for metals, POM, and formaldehyde. The tables are presented in English units and metric units, respectively. The quality rating of these data are low because many of the sources of information are of low quality and the number of data points are too small to represent an entire source category. Limited data are available on organic air toxic compounds but could not be obtained for this update. The metals data were most abundant and the data for formaldehyde were very limited. The POM data were also fairly limited. When received, these data will be added to the AP-42 Section 1.1 Background File for consideration in the next update of this section.

4.3.3 Controlled Emission Factors

Table 4-15 and 4-16 present the summary of emission factors for various controlled emissions in the units of mass emitted per unit thermal heat input. The data obtained in the literature review were very limited. The quality rating of these data are low because many of the sources of information are of low quality and the number of data points are too small to represent an entire source category. Table 4-17 summarizes control efficiencies for various parameters of several control devices.

4.4 N_2O

A total of 43 references were documented and reviewed during the literature search. These references are listed at the end of this chapter.

The original group of 43 documents was reduced to a final set of primary references using the criteria outlined in Chapter 3. Many of the references were based on the pre-1988 protocol which resulted in unrelaible N_2O measurements because of reactions in sample containers. For the 40 references documents not used, the reason(s) for rejection are summarized below (the reference number corresponds to the reference list at the end of this chapter):

Reference	Reason for rejection
39	Data were pre-1988
40	Data were pre-1988
41	Pilot-scale boiler
42	Duplicate of test in Reference 2
43	No N_2O data
44	Only information on N_2O emissions from global sources
45	Data were pre-1988
46	Data were pre-1988
47	Test data taken from an airplane
48	Duplicate of test in Reference 12
49	Duplicate of test in Reference 2
50	Insufficient lab, process, analytical data
51	Chemical kinetics calculation
52	Insufficient lab, process, analytical data
53	No N_2O data
54	No N_2O data
55	Insufficient lab, process, analytical data
56	No N_2O data
57	Duplicate of test in Reference 2
58	Insufficient lab, process, analytical data
59	Insufficient lab, process, analytical data
60	Insufficient lab, process, analytical data
61	No N_2O data
62	Data were pre-1988
63	Data were pre-1988
64	Data were pre-1988
65	Data were pre-1988
66	Data were pre-1988

67	Solid waste co-fired in boiler
68	Data were pre-1988
69	Data were pre-1988
70	Data were pre-1988
71	Data were pre-1988
72	Not citable as a primary reference
73	Not citable as a primary reference
74	Pilot-scale boiler
75	Pilot-scale boiler
76	Pilot-scale boiler
77	Pilot-scale boiler

This screening resulted in the selection of three references which could be used to develop N_2O emission factors. The following paragraphs discuss the data contained in each of the primary references used to develop emission factors. Emission factor calculations were made in terms of mass of pollutant per unit mass of coal feed. It should be noted that the terms "controlled" and "uncontrolled" in this discussion are indicative only of the location at which the measurements were made [i.e., after or before control device(s), respectively].

Reference 78

This reference contained N_2O emissions data from eight full-scale tests. All test reports were rejected except for the test report from the Italian power plant. The Italian power plant had two sources. One source combusted fuel oil while the other source combusted bituminous coal. The data from both the boilers were acceptable; only the coal data were used for the update of AP-42 Section 1.1.

In the Italian test report, a B quality rating was assigned to the data from both sources. The report provided adequate detail for validation and the sampling and analysis methodology appeared sound.

Reference 79

This reference contained data from N_2O emissions tests conducted at six boilers. Data were used from four of the sources, because the other two boilers were operated below 70 percent of full load (although the data were comparable). The acceptable N_2O emissions data correspond to coal boiler test conducted with on-line GC. The tests were conducted after the economizer and flue gas cleaning.

An A quality rating would have been applied to the data except that the calibration data showed excessively high values; therefore a B quality rating was assigned.

Reference 80

This reference contained data for N_2O emissions from FBCs. The data are in graphical form and presented in units of milligrams per megajoule. The conversion from milligram per megajoule to ppm is one milligram per megajoule equals 1.7 ppm. The test was performed on a circulating fluidized bed boiler controlled by recirculation of flue gases. The reference case is defined by a bed temperature of 850 °C (1,560 °F), a primary air stoichiometry of 0.75 and excess air ratio of 1.2. The actual emission values can only be estimated from the graphs and, therefore, the data were assigned a rating of D.

The new N_2O emissions data are presented in Table 4-18 and a summary of the emission factor results are shown in Table 4-19.

4.5 PARTICLE SIZE DISTRIBUTION

For the current revision, the scope of AP-42 was extended to include segregation of filterable and condensible PM-10 emission factors along with the particle size distribution data. The prior AP-42 updates include detailed analysis of particulate size distribution data.

4.5.1 Review of 1986 AP-42 Data

The 1986 database[2] was evaluated with respect to sources of data, data analyses, and calculations. Data retrieved and analyzed for that update were all filterable particulate.

Table 4-20 lists the sets of A and B rated data that the 1986 AP-42 emission factors update used. This table shows where high-quality data are lacking. The Fine Particulate Emission Inventory System (FPEIS) data base was the primary source of emissions data for the 1986 update. In some instances, the data were given a low rating because of insufficient data in the FPEIS printouts. During the literature search, original documents with primary test data were uncovered that corresponded to the FPEIS documents.

The original test document for the FPEIS Test Series Number 35 in the 1986 background document is EPA-600/2-75-013-a (Reference 81). The tests were conducted on a bituminous-coal-fired spreader stoker to determine the fractional efficiency of the boiler baghouse. Inlet and outlet data are provided for 22 tests. All 22 data sets were used for the particle size distribution for baghouse controlled spreader stokers and 21 of the 22 data sets were used in the preparation of the size distribution data for uncontrolled spreader stoker boilers. The data were B-rated in the 1986 update because the system operating conditions and sampling flowrate isokinetic results were unknown. Review of the report did not uncover isokinetic results; however, there was considerable discussion of the baghouse operating conditions. Eleven of the 22 tests were conducted under normal baghouse operating conditions while the remaining tests were conducted under experimental conditions. The range of conditions may explain the large variation in the controlled emissions results. For instance, the cumulative mass less than 10 microns ranged from 16 percent to 96 percent. However, little difference was found overall by comparing the average distribution of the "normal" runs with the average distribution of all 22 runs. Because of this finding, it was concluded that the data need not be changed and are indeed representative of baghouse emission distributions. The values in the 1986 background document were also spot-checked against the numbers in the plots of the original test report. The numbers compared favorably.

4.5.2 Review of New Data

A search for additional data was conducted. Of primary interest was CPM data collected via EPA Method 202 because this particulate fraction has not been addressed in previous AP-42 updates. Unfortunately, only methods development source test data were found because this is still a relatively new protocol.

Although a variety of sources were contacted regarding particulate sizing and PM-10 data, very little additional data were located. State and district offices that were contacted either had no PM-10 data available or were unable to process such a request due to other staff commitments. Several groups within the California Air Resources Board were contacted because California considers condensible particulate as a portion of total particulate; however, no data were received.

The New Jersey Air Pollution Control Office likely has particulate sizing data for coal emissions. Their policy is to conduct data searches only when a written request is submitted which includes lists of specific facilities.[82] Because specific facility lists were unavailable, this avenue was not pursued.

One test report[83] was obtained that contained CPM emission data for coal-fired boilers. The tests were conducted by EPA/OAQPS/EMB. The test objectives were to determine the adequacy of and produce documentation to support Draft Method 202; revise the candidate method based on results of laboratory experiments; validate the method in field tests; and revise the method, if necessary.

It was not possible to prepare emission factors from the results. The data wer presented as mg emitted/m^3 and no data were presented regarding the volumetric flue gas flow rate or the size of the boiler. F-factors are provided in 40 CFR Part 60.45 to convert emissions into mass emitted per unit heat input. However, to use an F-factor, one must first be able to correct the flue gas volume to zero percent O_2. No data were available regarding the percent O_2 in the flue gas flow; therefore the calculation was not conducted.

Emission factors from these tests would not be reliable because the sampling was single-point sampling rather than a duct traverse (since the objective was to examine the test method rather than to obtain representative data). Therefore, any emission factors derived from this data would be of D-rating. However, inferences may be drawn regarding the relative size of the organic and inorganic fractions of the CPM. These results are presented in Table 4-21. The results indicate that CPM originating from coal-fired boilers are at least 90 percent inorganic matter.

An EPRI report[84] describes tests of a 22 MW Babcock and Wilcox front wall fired boiler fueled on low-sulfur bituminous coal. The particulate sizing data were collected with a cascade impactor upstream of the fabric filter control system. The results are presented in Table 4-22. Total particulate was measured both upstream and downstream of the fabric filter via EPA Method 5. The overall baghouse efficiency was 99.8 percent. Because sufficient raw data were not provided in the report, the data were rated B quality. Because sufficient A quality data exist for pulverized coal-fired boilers in the 1988 version of AP-42, it was not necessary to incorporate these new data.

For atmospheric fluidized bed boilers, two sets of data are available for the filterable particulate emissions.[87] A pilot AFBC unit was tested while firing both subbituminous coal and lignite. The purpose of these tests was to investigate the corrosive and/or erosive properties of low-rank coal ash on heat transfer surfaces.

As part of the test, the PM exiting a multicyclone system was measured for particule size distribution. A flow sensor multicyclone and laser aerodynamic particle sizer (APS) provided particle size distribution data at the inlet to the scrubber (after the multiclone controls). The APS is a real-time particle sizer that measures sizes in the range of 0.5 to 15 microns.

The data are rated as D quality due to the pilot-scale size, the particulate collection methods, and lack of sufficient background data on protocols and unit operation. For these tests, the cumulative percent mass collection values were inferred via interpolation of log-log graphs of the results. The particulate size distribution data are shown on Table 4-23.

A paper presented at the 51st American Power Conference describes particulate size distribution data from a coal-fired pressurized fluidized bed combustion (PFBC) unit, before and after high-pressure, high-temperature emission control devices.[86] As PFBC is not a common coal-combustion device at this time, these data were not evaluated.

4.6.3 Compilation of Uncontrolled Emission Factors

The 1988 update was reviewed with respect to the procedure used to develop emission factors from the particle size distribution data. The uncontrolled emission factors were calculated for each size fraction by multiplying the total particulate emission factor by the cumulative percent mass for the given size interval. Therefore all uncontrolled emission factors will change as a result of updating the total PM emission factors.

It is apparent that the level of uncertainty increases as one moves from the cumulative percent mass to the uncontrolled emission factors. The uncontrolled emission factors are functions of two numbers estimated generally from different sets of data: the cumulative percent mass, and the total PM emission factor.

The filterable PM-10 emission factors are included in the particulate size distribution tables. There is currently no need to prepare tables devoted only to PM-10. As CPM data become available, a new table should be added to each AP-42 section. The table should include columns for filterable PM-10, inorganic CPM, and organic CPM.

4.6.4 Control Technology Emission Factors

There were two calculation steps used in the development of controlled emission factors in the 1986 particulate sizing update.[2] First, a controlled emission factor was developed for total particulate by multiplying the uncontrolled total particulate emission factor from the criteria pollutant table by one of the following estimated control efficiency factors:

- Multiple cyclone - 80 percent,
- Baghouse - 99.8 percent,
- ESP - 99.2 percent, and
- Scrubber - 94 percent.

Next, a controlled emission factor was developed for each of the cumulative size ranges by multiplying the controlled emission factor for total particulate by the cumulative percent mass for the size range. Thus the quality of the right-hand side of each size distribution table in Section 1.1 of AP-42 is directly related to the quality of three other numbers: (1) the control efficiency factors, (2) the total particulate emission factor (from the criteria pollutant table), and (3) the cumulative percent mass data. This, in part, explains the low data rating generally listed in AP-42 for the controlled particle-specific emission factors.

The disadvantage of this procedure is the loss of emission factor quality. The advantage of the procedure is that it allows the determination of control device-specific controlled emission factors rather than using generalized control efficiency results. Control device-specific controlled emission factors are better than generalized control efficiencies results because control efficiency is dependent on particulate parameters, such as the resistivity, and not just the particle size distribution.

It is useful to note that the procedure does not assume a single control efficiency for each particle size. Rather, it assumes a single overall efficiency and applies this to the total particulate emission factor. The size-based emission factors depend on the total controlled emission factor and the percent of the total controlled mass within a particular size range. For example, collected data indicated that 71 percent of controlled PM from a wet scrubber is less than or equal to 10 microns. Based on this value; on an uncontrolled emission factor of 5A kg/Mg; and on an estimated scrubber control efficiency of 94 percent, the controlled PM-10 emission factor is calculated as 0.21 kg/Mg:

$$0.71 \times 5A \times (1.0-0.94) = 0.21 \text{ kg/Mg.}$$

Although different methods could be used to develop controlled emission estimates, the procedure used in the 1986 document[2] is a logical way to compensate for sparse data. The process appears to create conservatively high values for the controlled emission factors, as there are occasionally controlled emission factors in the tables that are larger than the uncontrolled factors.

The particulate control efficiencies for the four technologies used throughout the previous update are all reasonable and were retained in the current update.

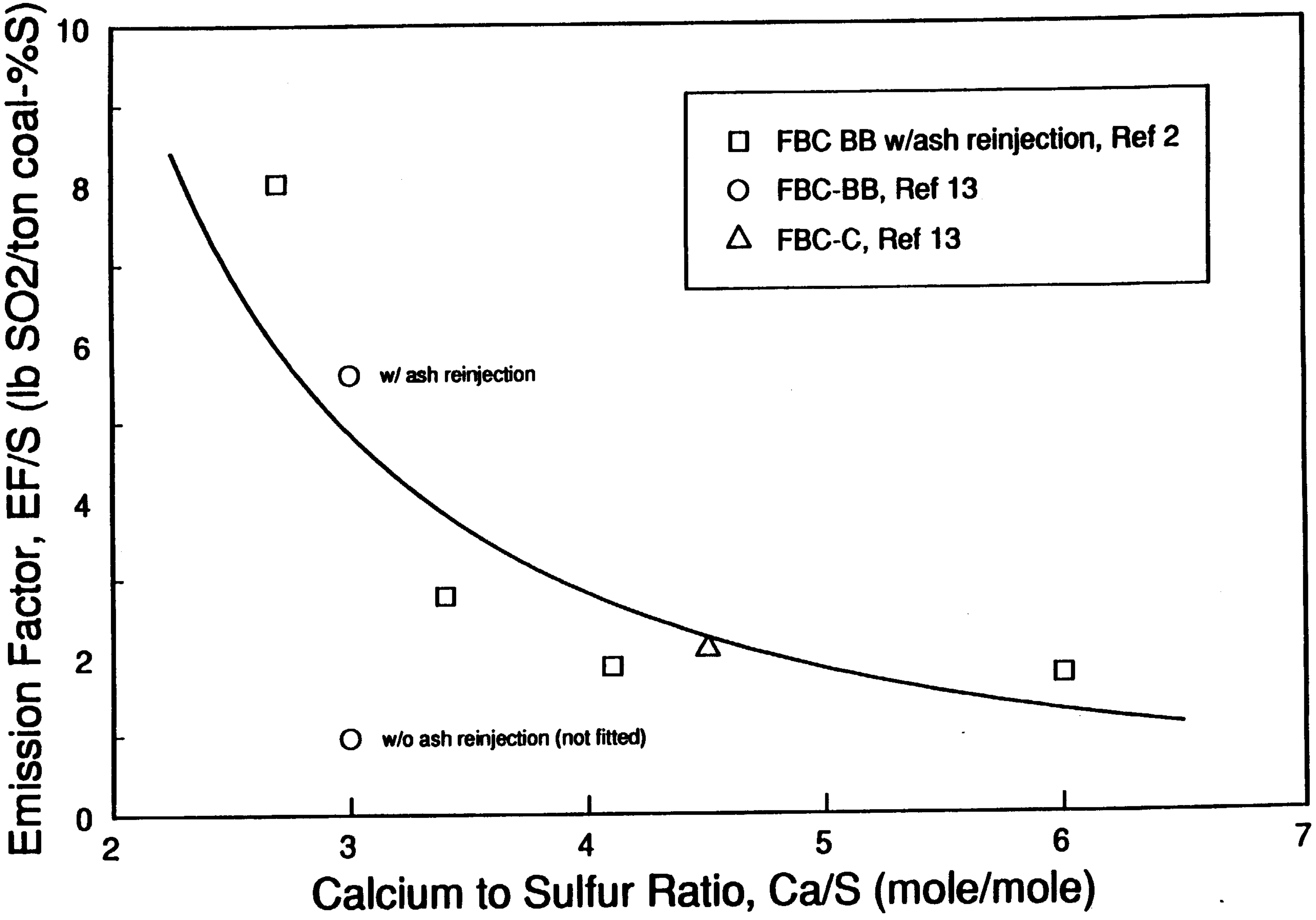

Figure 4-1. FBC SO_2 emissions versus calcium-to-sulfur ratio.

TABLE 4-1. BACKGROUND DOCUMENT CHECK

Pollutant	Configuration	References cited in 1988 AP-42 Section 1.1	Site No.	Emission factor	References spot checked
PM	PC dry bottom	15, 16, 17, 19, 21 EPA-650/7-80-171 (20)	17	10A	15, 17
PM	Handfired units				49, 50
SO_2	Bituminous emission-based	9, 16, 17, 18, 19, 21, 31, 37, 39, 41, 42, 43, 46, 51, 52, 55	49	39S	17, 18
SO_2	Bituminous retention-based	17, 18, 32, 33, 34, 35, 41, 42, 44, 45	11	39S	18
SO_2	Subbituminous	9, 17, 31, 53, 54	15	35S	17
NO_x	PC dry bottom	11, 14, 16, 17, 21, 56	28	21	17
NO_x	Handfired units				50
CO	Handfired units				50
VOC	PC dry bottom	58	17	.07	58
VOC	PC wet bottom				58
VOC	Cyclone, spreader stoker, overfeed stoker				58
VOC	Underfeed stoker				58
VOC	Handfired units				58, 50
CH_4	PC, Cyclone, Spreader Stoker, Overfeed Stoker	58	16	.03	58
CH_4	Underfeed Stoker				58
CH_4	Handfired Units				58, 50

A = weight percent ash in fuel
S = weight percent sulfur in fuel

TABLE 4-2. NEW SO_2 BASELINE DATA FOR BITUMINOUS COAL

Ref.	Data qality	Boiler type	Site	Run	Fuel		Operation			SO_2 Emissions,			FBC control efficiency	
					HHV, Btu/lb	S, wt%	Capacity	Units	Load Factor	ppm	lb/MMBtu	(lb/ton)/S	Ca/S, mole/mole	SO2, %
8	E	Cyclone	KAW Unit 1	3B	11496	2.68	400000	lb/hr	0.96		5.0700	43.50		
8	E	Cyclone	KAW Unit 1	1B	11629	2.63	400000	lb/hr	0.96		4.9700	43.95		
8	E	Cyclone	KAW Unit 1	3A	11496	2.68	400000	lb/hr	0.96		5.0700	43.50		
8	E	Cyclone	KAW Unit 1	2B	11584	2.58	400000	lb/hr	0.96		5.0600	45.44		
8	E	Cyclone	KAW Unit 1	1A	11629	2.63	400000	lb/hr	0.96		5.2100	46.07		
8	E	Cyclone	KAW Unit 1	2A	11584	2.58	400000	lb/hr	0.96		5.0600	45.44		
												44.65		
7	B	Cyclone	Plant 5	3	12121	1.81	584	MW	1.01	980.0	2.4880	33.32		
7	B	Cyclone	Plant 5	1	12121	1.81	584	MW	1.01	840.0	2.2153	29.67		
7	B	Cyclone	Plant 5	2	12121	1.81	584	MW	1.00	950.0	2.5054	33.56		
7	B	Cyclone	Plant 5	4	12121	1.81	584	MW	0.79	900.0	2.1263	28.48		
7	B	Cyclone	Plant 5	5	12121	1.81	584	MW	0.63	950.0	2.4119	32.30		
												31.47		
8	E	Cyclone	Quindaro #1	2A	11375	2.81	625000	lb/hr	0.74		5.7000	46.15		
8	E	Cyclone	Quindaro #1	2B	11375	2.81	625000	lb/hr	0.74		5.6800	45.99		
8	E	Cyclone	Quindaro #1	3A	11387	1.93	625000	lb/hr	0.75		5.6500	66.67		
8	E	Cyclone	Quindaro #1	1B	11309	2.76	625000	lb/hr	0.74		5.7200	46.87		
8	E	Cyclone	Quindaro #1	3B	11387	1.93	625000	lb/hr	0.75		5.7400	67.73		
8	E	Cyclone	Quindaro #1	1A	11309	2.76	625000	lb/hr	0.74		5.5400	45.40		
												53.14		
4	A	FBC-BB	Summerside	AVE	11770	5.96	50	MMBTU/hr	0.72		2.0300	8.02*	2.70	0.73
4	A	FBC-BB	Summerside	AVE	11510	5.92	50	MMBTU/hr	0.73		0.4800	1.87*	4.10	0.95
4	A	FBC-BB	Summerside	AVE	11750	5.90	50	MMBTU/hr	0.73	212.3	0.6981	2.78*	3.40	0.93

TABLE 4-2. NEW SO_2 BASELINE DATA FOR BITUMINOUS COAL

					Fuel		Operation			SO_2 Emissions,			FBC control efficiency	
Ref.	Data qality	Boiler type	Site	Run	HHV, Btu/lb	S, wt%	Capacity	Units	Load Factor	ppm	lb/MMBtu	(lb/ton)/S	Ca/S, mole/mole	SO2, %
4	A	FBC-BB	Summerside	AVE	11430	5.20	50	MMBTU/hr	0.65		0.4000	1.76[a]	6.00	0.96
13	D	FBC-BB	TVA 20MWe	2	13000	3.84	228	MMBTU/hr	0.68		0.1400	0.95[a]	3.00	0.98
13	D	FBC-BB	TVA 20MWe	1	13000	4.46	228	MMBTU/hr	0.68		0.9600	5.61[a]	3.00	0.87
13	D	FBC-C	BATTELLE	1	13000	1.50	50	MMBTU/hr			0.1200	2.08	4.50	0.95
3	C	Hand-Fed		Coal Stove	14119	0.77	0.01	MMBTU/hr		208.0	0.8957	32.69		
3	E	Hand-Fed		Modified Wood Stove	13421	0.79	0.01	MMBTU/hr		430.0	2.1201	72.07		
6	A	PC-fired	Quindaro #2	2B	11201	1.70	145	MW	0.83		2.9700	39.14		
6	A	PC-fired	Quindaro #2	2A	11201	1.70	145	MW	0.83		2.8600	37.69		
6	A	PC-fired	Quindaro #2	4A	11304	1.72	145	MW	0.83		2.8500	37.46		
6	A	PC-fired	Quindaro #2	4B	11304	1.72	145	MW	0.83		2.8900	37.99		
6	A	PC-fired	Quindaro #2	3A	11185	1.77	145	MW	0.83		2.9700	37.54		
6	A	PC-fired	Quindaro #2	1A	11230	1.80	145	MW	0.83		2.8100	35.06		
6	A	PC-fired	Quindaro #2	3B	11185	1.77	145	MW	0.83		2.9400	37.16		
												37.43		
5	A	PC-TFired		3	8104	0.44	100	MW	1.02		1.1000	40.52		
5	A	PC-TFired		2	8104	0.44	100	MW	1.02		1.0390	38.27		
5	A	PC-TFired		1	8104	0.44	100	MW	1.02		1.0200	37.57		
												38.79		

[a] SO_2 emissions controlled by the addition of sorbents (e.g., limestone) to the FBC.
S = weight percent sulfur in fuel

TABLE 4-3. NEW NO_x BASELINE DATA FOR BITUMINOUS COAL

Ref.	Data qality	Boiler type	Site	Run	Fuel				Operation			NO_x emissions,	
					HHV, Btu/lb	S, wt%	N, wt%	Ash, wt%	Capacity	Units	Load factor	lb/MMBtu	lb/ton
7	B	Cyclone	Plant 5	4	12121	1.81		13.81	584	MW	0.79	0.5773	14.00
7	B	Cyclone	Plant 5	1	12121	1.81		13.81	584	MW	1.01	0.5307	12.87
7	B	Cyclone	Plant 5	3	12121	1.81		13.81	584	MW	1.01	0.7117	17.25
7	B	Cyclone	Plant 5	2	12121	1.81		13.81	584	MW	1.00	0.6445	15.62
7	B	Cyclone	Plant 5	5	12121	1.81		13.81	584	MW	0.63	0.6387	15.48
													15.04
4	A	FBC-BB	Summerside	Avg.	11430	5.20	1.05	11.20	50	MMBtu/hr	0.65	0.6800	15.54
4	A	FBC-BB	Summerside	Avg.	11760	5.90	1.06	9.58	50	MMBtu/hr	0.73	0.6195	14.56
4	A	FBC-BB	Summerside	Avg.	11510	5.92	1.08	11.40	50	MMBtu/hr	0.73	0.6500	14.96
4	A	FBC-BB	Summerside	Avg.	11770	5.96	1.03	9.73	50	MMBtu/hr	0.72	0.6700	15.77
													15.21
13	D	FBC-BB	TVA 20MWe	1	13000	4.45			228	MMBtu/hr	0.68	0.3400	8.84
13	D	FBC-BB	TVA 20MWe	2	13000	3.84			228	MMBtu/hr	0.68	0.2300	5.98
													7.41
13	D	FBC-C	BATTELLE	1	13000	1.50			50	MMBtu/hr		0.1500	3.90

TABLE 4-3. NEW NO_x BASELINE DATA FOR BITUMINOUS COAL

					Fuel				Operation			NO_x emissions,	
Ref.	Data qality	Boiler type	Site	Run	HHV, Btu/lb	S, wt%	N, wt%	Ash, wt%	Capacity	Units	Load factor	lb/MMBtu	lb/ton
3	C	Hand-Fed		Mod-ified wood stove	13421	0.79		5.43	0.01	MMBtu/hr		0.5670	15.22
5	A	PC:T-Fired		1	8104	0.44		5.42	100	MW	1.02	0.4310	6.99
5	A	PC:T-Fired		3	8104	0.44		5.42	100	MW	1.02	0.4140	6.71
5	A	PC:T-Fired		2	8104	0.44		5.42	100	MW	1.02	0.4390	7.12
													6.94
10	A	Stoker-spreader	Boiler 24	2	12906				320000	lb/hr	0.82	0.7500	19.36
10	A	Stoker-spreader	Boiler 24	6	13581				320000	lb/hr	0.82	0.5750	15.62
10	A	Stoker-spreader	Boiler 24	7	13761				320000	lb/hr	0.81	0.6900	18.99
10	A	Stoker-spreader	Boiler 24	5	13674				320000	lb/hr	1.00	0.6550	17.91
10	A	Stoker-spreader	Boiler 24	1	13203				320000	lb/hr	0.81	0.6000	15.84
													17.54
11	A	Stoker-spreader	Kalamazoo	2	13645				90000	lb/hr	1.00	0.4347	11.86
11	A	Stoker-spreader	Kalamazoo	6	13592				90000	lb/hr	0.75	0.3567	9.70

TABLE 4-3. NEW NO_x BASELINE DATA FOR BITUMINOUS COAL

					Fuel				Operation			NO_x emissions,	
Ref.	Data qality	Boiler type	Site	Run	HHV, Btu/lb	S, wt%	N, wt%	Ash, wt%	Capacity	Units	Load factor	lb/MMBtu	lb/ton
11	A	Stoker-spreader	Kalamazoo	3	13617				90000	lb/hr	0.75	0.4626	12.60
11	A	Stoker-spreader	Kalamazoo	8	13827				90000	lb/hr	0.75	0.5066	14.01
11	A	Stoker-spreader	Kalamazoo	5	13059				90000	lb/hr	0.75	0.5345	13.96
11	A	Stoker-spreader	Kalamazoo	4	13576				90000	lb/hr	1.00	0.3702	10.05
11	A	Stoker-spreader	Kalamazoo	1	13727				90000	lb/hr	1.00	0.4032	11.07
11	A	Stoker-spreader	Kalamazoo	9	13559				90000	lb/hr	0.75	0.3840	10.41
11	A	Stoker-spreader	Kalamazoo	10	13628				90000	lb/hr	0.75	0.3546	9.67
													11.48

TABLE 4-4. NEW CO BASELINE DATA

						Fuel			Operation			CO Emissions,		
Ref.	Data quality	Boiler type	Fuel	Site	Run	HHV, Btu/lb	N, wt%	Ash, wt%	Capacity	Units	Load factor	ppm	lb/MMBtu	lb/ton
7	B	Cyclone	Bituminous	Plant 5	3	12121		13.81	584	MW	1.01	7.3	0.0068	0.16
7	B	Cyclone	Bituminous	Plant 5	1	12121		13.81	584	MW	1.01	12.9	0.0129	0.31
7	B	Cyclone	Bituminous	Plant 5	4	12121		13.81	584	MW	0.79	9.4	0.0090	0.22
7	B	Cyclone	Bituminous	Plant 5	2	12121		13.81	584	MW	1.00	8.0	0.0076	0.18
														0.22
7	B	Cyclone	Bituminous	Plant 6	4	8895		11.06	180	MW	0.94	36.4	0.0354	0.63
7	B	Cyclone	Bituminous	Plant 6	3	8895		11.06	180	MW	1.03	17.9	0.0168	0.30
7	B	Cyclone	Bituminous	Plant 6	5	8895		11.06	180	MW	0.98	15.1	0.0146	0.26
7	B	Cyclone	Bituminous	Plant 6	1	8895		11.06	180	MW	1.00	28.3	0.0277	0.49
7	B	Cyclone	Bituminous	Plant 6	2	8895		11.06	180	MW	1.02	12.1	0.0120	0.21
														0.38
4	A	FBC-BB	Bituminous	Summerside	Avg.	11750	1.06	9.58	50	MMBtu/hr	0.73	419.2	0.6032	14.17
4	A	FBC-BB	Bituminous	Summerside	Avg.	11510	1.08	11.40	50	MMBtu/hr	0.73	452.8	0.6418	14.78
4	A	FBC-BB	Bituminous	Summerside	Avg.	11430	1.05	11.20	50	MMBtu/hr	0.65	800.7	1.1788	26.96
4	A	FBC-BB	Bituminous	Summerside	Avg.	11770	1.03	9.73	50	MMBtu/hr	0.72	432.4	0.6560	15.44
														17.83
3	C	Hand-Fed	Bituminous		Modified wood stove	13421		5.43	0.01	MBtu/hr		4000.0	8.6283	231.60
3	C	Hand-Fed	Bituminous		Coal stove	14119		3.09	0.01	MBtu/hr		6000.0	11.3042	319.20
														275.40
7	B	PC-TFired	Subbituminous	Plant 1	4B	7842		13.91	660	MW	0.84	6.5	0.0063	0.10
7	B	PC-TFired	Subbituminous	Plant 1	4A	7842		13.91	660	MW	0.84	6.5	0.0063	0.10

TABLE 4-4. NEW CO BASELINE DATA

Ref.	Data quality	Boiler type	Fuel	Site	Run	Fuel			Operation			CO Emissions,		
						HHV, Btu/lb	N, wt%	Ash, wt%	Capacity	Units	Load factor	ppm	lb/MMBtu	lb/ton
7	B	PC-TFired	Subbituminous	Plant 1	3B	7842		13.91	660	MW	0.93	6.9	0.0066	0.10
7	B	PC-TFired	Subbituminous	Plant 1	3A	7842		13.91	660	MW	0.93	6.9	0.0066	0.10
7	B	PC-TFired	Subbituminous	Plant 1	5B	7842		13.91	660	MW	0.92	7.4	0.0072	0.11
														0.10
7	B	PC:V-Fired	Bituminous	Plant 2	4B	11576		13.55	250	MW	1.06	31.7	0.0270	0.62
7	B	PC:V-Fired	Bituminous	Plant 2	5A	11576		13.55	250	MW	1.04	71.7	0.0596	1.38
7	B	PC:V-Fired	Bituminous	Plant 2	1A	11576		13.55	250	MW	1.07	119.9	0.1088	2.52
7	B	PC:V-Fired	Bituminous	Plant 2	2A	11576		13.55	250	MW	1.07	143.8	0.1170	2.71
7	B	PC:V-Fired	Bituminous	Plant 2	3B	11576		13.55	250	MW	1.04	19.4	0.0168	0.39
7	B	PC:V-Fired	Bituminous	Plant 2	4A	11576		13.55	250	MW	1.06	31.7	0.0270	0.62
7	B	PC:V-Fired	Bituminous	Plant 2	2B	11576		13.55	250	MW	1.07	143.8	0.1170	2.71
7	B	PC:V-Fired	Bituminous	Plant 2	3A	11576		13.55	250	MW	1.04	19.4	0.0168	0.39
7	B	PC:V-Fired	Bituminous	Plant 2	5B	11576		13.55	250	MW	1.04	71.7	0.0596	1.38
7	B	PC:V-Fired	Bituminous	Plant 2	1B	11576		13.55	250	MW	1.07	119.9	0.1088	2.52
														1.52
7	B	PC:W-Fired	Bituminous	Plant 3	2	11660		13.40	125	MW	0.98	14.6	0.0138	0.32
7	B	PC:W-Fired	Bituminous	Plant 3	5	11660		13.40	125	MW	0.97	10.3	0.0096	0.22
7	B	PC:W-Fired	Bituminous	Plant 3	1	11660		13.40	125	MW	0.97	17.7	0.0165	0.38
7	B	PC:W-Fired	Bituminous	Plant 3	3	11660		13.40	125	MW	0.97	11.7	0.0110	0.26
7	B	PC:W-Fired	Bituminous	Plant 3	4	11660		13.40	125	MW	0.97	8.8	0.0082	0.19
														0.28
7	B	PC:W-Fired	Bituminous	Plant 4	1	11920		11.78	217	MW	0.96	9.2	0.0096	0.23
7	B	PC:W-Fired	Bituminous	Plant 4	2	11920		11.78	217	MW	0.98	17.0	0.0176	0.42

TABLE 4-4. NEW CO BASELINE DATA

Ref.	Data quality	Boiler type	Fuel	Site	Run	Fuel			Operation			CO Emissions,		
						HHV, Btu/lb	N, wt%	Ash, wt%	Capacity	Units	Load factor	ppm	lb/MMBtu	lb/ton
7	B	PC:W-Fired	Bituminous	Plant 4	3	11920		11.78	217	MW	0.99	20.1	0.0208	0.50
7	B	PC:W-Fired	Bituminous	Plant 4	4	11920		11.78	217	MW	0.98	24.4	0.0250	0.60
														0.43
10	A	Sprdr Stkr	Bituminous	Boiler 24	1	13203			320000	lb/hr	0.81	29.0	0.0271	0.72
10	A	Sprdr Stkr	Bituminous	Boiler 24	6	13581			320000	lb/hr	0.82	60.0	0.0572	1.55
10	A	Sprdr Stkr	Bituminous	Boiler 24	7	13761			320000	lb/hr	0.81	40.0	0.0431	1.19
10	A	Sprdr Stkr	Bituminous	Boiler 24	5	13674			320000	lb/hr	1.00	96.0	0.0928	2.54
10	A	Sprdr Stkr	Bituminous	Boiler 24	2	12906			320000	lb/hr	0.82	72.0	0.0782	2.02
														1.60
11	A	Sprdr Stkr	Bituminous	Kalamazoo	2	13645			90000	lb/hr	1.00	42.0	0.0434	1.18
11	A	Sprdr Stkr	Bituminous	Kalamazoo	6	13592			90000	lb/hr	0.75	36.0	0.0315	0.86
11	A	Sprdr Stkr	Bituminous	Kalamazoo	3	13617			90000	lb/hr	0.75	24.0	0.0241	0.66
11	A	Sprdr Stkr	Bituminous	Kalamazoo	8	13827			90000	lb/hr	0.75	22.0	0.0236	0.65
11	A	Sprdr Stkr	Bituminous	Kalamazoo	5	13059			90000	lb/hr	0.75	26.0	0.0300	0.78
11	A	Sprdr Stkr	Bituminous	Kalamazoo	4	13576			90000	lb/hr	1.00	42.0	0.0353	0.96
11	A	Sprdr Stkr	Bituminous	Kalamazoo	1	13727			90000	lb/hr	1.00	63.0	0.0548	1.51
11	A	Sprdr Stkr	Bituminous	Kalamazoo	9	13559			90000	lb/hr	0.75	28.0	0.0256	0.69
11	A	Sprdr Stkr	Bituminous	Kalamazoo	10	13628			90000	lb/hr	0.75	43.0	0.0374	1.02
														0.92

TABLE 4-5. NEW PM BASELINE DATA FOR BITUMINOUS COAL

Ref.	Data qality	Boiler type	Site	Run	Fuel			Operation			PM Emissions,	
					HHV, Btu/lb	S, wt%	Ash, wt%	Capacity	Units	Load factor	lb/MMBtu	lb/ton
3	C	Hand-Fed		Coal Stove	14119	0.77	3.09	0.01	MMBtu/hr			20.94
3	C	Hand-Fed		Modified Wood Stove	13421	0.79	5.43	0.01	MMBtu/hr			10.14
												15.54
9	A	PC-	Quindaro #2	1	11460	2.69	12.43	145	MW	0.91	9.9130	227.21
9	A	PC-	Quindaro #2	2	11460	2.69	12.43	145	MW	0.92	10.4090	238.57
9	A	PC-	Quindaro #2	3	11061	2.71	14.06	145	MW	0.89	12.3170	272.48
9	A	PC-	Quindaro #2	5	11161	2.63	13.23	145	MW	0.89	9.7040	216.61
												238.72
12	B	Stoker-Spreader	Clarksville	2	13885	0.69	6.10	150000	lb/hr	1.00	6.7000	186.06
12	B	Stoker-Spreader	Clarksville	3	13771	0.68	6.50	150000	lb/hr	1.00	5.2200	143.77
12	B	Stoker-Spreader	Clarksville	4	13728	0.62	7.50	150000	lb/hr	0.66	4.7900	131.51
12	B	Stoker-Spreader	Clarksville	5	13846	0.68	6.00	150000	lb/hr	0.66	5.1600	142.89
12	B	Stoker-Spreader	Clarksville	6	13808	0.85	5.40	150000	lb/hr	0.66	9.8200	271.19
												175.08

TABLE 4-6. NEW CH_4 BASELINE DATA FOR BITUMINOUS COAL

					Fuel			Operation		CH_4 Emissions,		
Ref.	Data quality	Boiler type	Fuel	Run	HHV, Btu/lb	S, wt%	Ash, wt%	Capacity	Units	ppm	lb/MMbtu	lb/ton
3	C	Hand-Fed	Bituminous	Coal Stove	14119	0.77	3.09	0.01	MMBtu/hr	210.0	0.2261	6.38
3	C	Hand-Fed	Bituminous	Modified Wood Stove	13421	0.79	5.43	0.01	MMBtu/hr	95.0	0.1171	3.14
												4.76

Table 4-7. CONTROLLED PM EMISSIONS

Boiler capacity, actual/design	Boiler type	Fuel			Control technology	Emissions (uncontrolled/ controlled), lb/MMBtu	Removal efficiency (%)	Ref.
		S, wt %	Ash, wt %	HHV, Btu/lb				
36 MW	Coal/industrial				Wet scrubber	(311 kg/hr/2.0 kg/hr)	99.4	20
10.2/15 MW 34/50 MMBtu/hr	Coal fired/ spreader stoker	0.8	9.7	12,900	Side stream separator	(23.3^{a}/0.12)	99.5^{a}	21
12.6-14/15 MW 39-47/50 MMBtu/hr	Coal fired/ spreader stoker	1.8	9.0	12,400	Side stream separator	(24.2^{a}/0.12)	99.5^{a}	21
15.6-16/20 MW 55-56/70 MMBtu/hr	Coal fired/ spreader stoker	0.9	4.3	13,700	Side stream separator	(21.9^{a}/0.12)	99.4^{a}	21
16.3-18.4/23 MW 56.8-64/80 MMBtu/hr	Coal fired/ spreader stoker	0.8	10.1	11,400	Side stream separator	(26.3^{a}/0.13)	99.6	21
17.8-18.9/18 MW 59.4-63/60 MMBtu/hr	Coal fired/ spreader stoker	2.1	8.8	12,400	Side stream separator	(24.2^{a}/0.14)	99.4^{a}	21
17.5-19.4/18 MW 53.8-65/60 MMBtu/hr	Coal fired/ spreader stoker	0.8	7.8	13,100	Side stream separator	(22.9^{a}/0.17)	99.3^{a}	21
24.7-28.1/29 MW 85-91/100 MMBtu/hr	Coal fired/ spreader stoker	1.7	6.1	13,100	Side stream separator	(22.9^{a}/0.16)	99.3^{a}	21
9/9 MW31/31 MMBtu/hr	Coal fired/ spreader stoker	1.3	7.8	13,200	Side stream separator	(22.7^{a}/0.12)	99.6^{a}	21
50.4/69 MW 172.3/236 MMBtu/hr	Coal fired	2.6	11.4	NR	Wet scrubber/ venturi	(NR/0.10)	N/A	21
58.7-62.8/69 MW 200-215/236 MMBtu/hr	Coal fired	2.5	10.4	NR	Wet scrubber/ venturi	(NR/0.07)	N/A	21
34/37 MW 115/125 MMBtu/hr	Coal fired	1.3	4.4	NR	Wet scrubber/ venturi	(NR/0.08)	N/A	21
18.6-19/19 MW 62.7-64/64 MMBtu/hr	Coal fired spreader stoker	2.8	6.9	13,600	Fabric filter	(^{a}22.1 /0.015)	99.7^{a}	21
16-18.2/19 MW 58.3-61.4/64 MMBtu/hr	Coal fired spreader stoker	0.8	6.9	NR	Fabric filter	(NR/0.033)	N/A	21
28.5/37 MW 96/125 MMBtu/hr	Coal fired spreader stoker	2.6	7.0	13,500	Fabric filter	(^{a}22.2/0.01)	100.0^{a}	21
43.2/46 MW 173.8/18 MMBtu/hr	Coal fired spreader stoker	2.9	6.5	13,800	Fabric filter	(^{a}21.7/0.028)	99.9^{a}	21
23.4/33 MW 81.7/115 MMBtu/hr	Coal fired/FBC	3.6	12.3	11,900	Fabric filter	(NR/0.019 lb/MMBtu)	N/A	21

Table 4-7. CONTROLLED PM EMISSIONS

Boiler capacity, actual/design	Boiler type	Fuel			Control technology	Emissions (uncontrolled/ controlled), lb/MMBtu	Removal efficiency (%)	Ref.
		S, wt %	Ash, wt %	HHV, Btu/lb				
9.6/13 MW 35.5/48 MMBtu/hr	Coal fired/ spreader stoker	0.6	8.3	13,700	Fabric filter	([a]21.9 lb/MMBtu/ 0.016 lb/MMBtu)	99.9[a]	21
58.4/59 MW 206/208 MMBtu/hr	Circulating FBC	0.4	8.8	12,200	Fabric filter	([a]24.6 lb/MMBtu/ 0.036 lb/MMBtu)	99.8[a]	21
27.8-28.6/27 MW 95-98/92 MMBtu/hr	Coal fired/ spreader stoker	NR	12.0	12,600	ESP	([a]24.0 lb/MMBtu/ 0.007 lb/MMBtu)	99.9[a]	21
32.6-34.3/35 MW 112-118/120 MMBtu/hr	Coal fired/ spreader stoker	1.0	11.2	12,600	ESP	([a]24.0 lb/MMBtu/ 0.006 lb/MMBtu)	99.9[a]	21
45.5-46.9/46 MW 154-159/156 MMBtu/hr	Coal fired/ spreader stoker	0.57	11.4	11,400	ESP	([a]26.3 lb/MMBtu/ 0.012 lb/MMBtu)	100.0[a]	21
63.5-65/73 MW 218-223/250 MMBtu/hr	Coal fired/ spreader stoker	0.73	6.6	13,100	ESP	([a]22.9 lb/MMBtu/ 0.021 lb/MMBtu)	99.9[a]	21
83.6/110 MW 285/375 MMBtu/hr	Coal fired/ spreader stoker	0.54	8.3	10,200	ESP	([a]29.4 lb/MMBtu/ 0.044 lb/MMBtu)	99.9[a]	21
57.2-64.9/110 MW 195/221 MMBtu/hr	Coal fired/ spreader stoker	0.63	5.4	10,600	ESP	([a]28.3 lb/MMBtu/ 0.018 lb/MMBtu)	99.9[a]	21

[a] Calculated

NR = not reported

TABLE 4-8. CONTROLLED SO_x EMISSIONS

Boiler capacity, actual/design	Boiler type	Fuel S[a], %	Control technology	Emissions (uncontrolled/ controlled), lb/MMBtu[a]	Removal efficiency, %	Ref.
NR/36 MW	Coal/industrial		Wet scrubber	(115 kg/h/3.7 kg/h)	96.8	20
NR/400 MW NR/1360 MMBtu/hr	Coal	2.5-2.8	Dual alkali/wet scrubber	(5.4/0.65 lb/MMBTU)	88.0	22
NR/163 MW NR/570 MMBtu/hr	Coal	2.5	Dual alkali/wet scrubber	(3.85/0.31 lb/MMBTU)	92.2	22
NR/40 MW NR/140 MMBtu/hr	Coal	3-3.5	Dual alkali/wet scrubber	(5.6/0.47 lb/MMBTU)	91.2	22
82/82 MW 280/280 MMBtu/hr	Pulverized coal	13.33 lb SO_2/MMBtu	Dual alkali/wet scrubber	N/A	74.5	22
26/34 MW 86.3/115 MMBtu/hr	Pulverized coal	.96 lb SO_2/MMBtu	Lime spray dry FGD	N/A	92.4	22
24/69 MW 82.1/235 MMBtu/hr	Coal spreader stoker	5.09 lb SO_2/MMBtu	Lime spray dry FGD	N/A	79.7	22
48/69 MW 1645/235 MMBtu/hr	Spreader stoker	5.09 lb SO_2/MMBtu	Lime spray dry FGD	N/A	89.9	22
57/69 MW 193/235 MMBtu/hr	Spreader stoker	5.09 lb SO_2/MMBtu	Lime spray dry FGD	N/A	95.6	22
35-52/69 MW 118-174/235 MMBtu/hr	Spreader stoker	6.6 lb SO_2/ MMBtu	Lime spray dry FGD	N/A	64-96	22
69/69 MW 235/235 MMBtu/hr	Pulverized coal	.96 lb SO_2/ MMBtu	Lime spray dry FGD	N/A	96.6	22
305,000 SCFM	Industrial coal	3.0	Double Alkali System	(18,000 ppm/ 1,800 ppm)	90	23
210,000 SCFM	Industrial coal	3.2	Double Alkali System	(20,000 ppm/ 2,000 ppm)	90	23
67,000 SCFM	Industrial coal	3.2	Double Alkali System	(20,000 ppm/ 2,000 ppm)	90	23
236,000 SCFM	Industrial coal	3.2	Double Alkali System	(20,000 ppm/ 2,000 ppm)	90	23
38,000 SCFM	Industrial coal	3.2	Double Alkali System	(20,000 ppm/ 2,000 ppm)	90	23
140,000 SCFM	Industrial coal	3.2	Double Alkali System	(20,000 ppm/ 2,000 ppm)	90	23
8,070 SCFM	Industrial coal	2.5-3.0	Double Alkali System	(10,000 ppm/ 1,000 ppm)	90.5	23
128,400 SCFM	Industrial coal	2.5	Double Alkali System	(8,000 ppm/ 800 ppm)	90	23

[a] Unless otherwise noted

N/A = Not available

TABLE 4-9. CONTROLLED NO_X EMISSIONS

Boiler load level	Boiler type	Fuel N, wt %	Control technology	Emissions (uncontrolled/ controlled), lb/MMBtu	Removal efficiency, %	Ref.
14.6/18 MW 51/63 MMBtu/hr	Coal/spreader stoker	1.5	LEA	(0.635/0.452)	29	24
23.5/28 MW 79/94 MMBtu/hr	Coal/spreader stoker	1.4	LEA	(0.634/0.491)	23	24
28.7/29 MW 98/99 MMBtu/hr	Coal/spreader stoker	1.0	LEA	(0.540/0.412)	24	24
28.7/29 MW 98/99 MMBtu/hr	Coal/spreader stoker	1.0	LEA	(0.572/0.401)	30	24
21.8/29 MW 73.5/98 MMBtu/hr	Coal/spreader stoker	1.2	LEA	(0.468/0.443)	5	24
21.8/29 MW 73.5/98 MMBtu/hr	Coal/spreader stoker	1.1	LEA	(0.454/0.312)	31	24
21.8/29 MW 75/h/100 MMBtu/hr	Coal/spreader stoker	1.1	LEA	(0.506/0.405)	20	24
22/29 MW 76/100 MMBtu/hr	Coal/spreader stoker	0.5	LEA	(0.483/0.418)	13	24
16.9/22 MW 57.8/75 MMBtu/hr	Coal/underfed stoker	1.4	LEA	(0.364/0.263)	28	24
16.9/22 MW 57.8/75 MMBtu/hr	Coal/underfed stoker	1.4	LEA	(0.433/0.361)	17	24
29.1/28 MW 98.8/95 MMBtu/hr	Coal/overfed stoker	1.8	LEA	(0.400/0.283)	29	24
28.6/28 MW 96.9/95 MMBtu/hr	Coal/overfed stoker	1.4	LEA	(0.229/0.211)	8	24
23/23 MW 77/77 MMBtu/hr	Coal/overfed stoker	1.7	LEA	(0.353/0.316)	10	24
18.2/18 MW 63.6/63 MMBtu/hr	Coal/overfed stoker	1.6	LEA	(0.324/0.310)	4	24
9.1/6 MW 31.9/56 MMBtu/hr	Coal/vibrating grate stoker	0.9	LEA	(0.277/0.209)	25	24
40-82%-150 MWe	PC: tangentially fired	N/A	OFA	(0.59/0.48)	19	25
40-82%-150 MWe	PC: wall fired	N/A	OFA	(0.77/0.06)	22	25

TABLE 4-9. CONTROLLED NO_x EMISSIONS

Boiler load level	Boiler type	Fuel N, wt %	Control technology	Emissions (uncontrolled/ controlled), lb/MMBtu	Removal efficiency, %	Ref.
40-82%-150 MWe	PC: wall fired	N/A	LNB + OFA	(0.77/0.33)	57	25
40-82%-150 MWe	PC: wall fired	N/A	LNB	(0.77/0.45)	42	25
40-82%-150 MWe	PC: tangentially fired	N/A	LBN + OFA + FGR	(0.58/0.28)	52	25
40-82%-150 MWe	PC: tangentially fired	N/A	SNCR	(0.70/0.35)	50	25
40-82%-150 MWe	PC: wall fired	N/A	SNCR	(0.28/0.18)	36	25
40-82%-150 MWe	PC: wall fired	N/A	SCR	(0.28/0.08)	71	25
40-82%-150 MWe	PC: tangentially fired	N/A	SCR	(0.70/0.15)	79	25
40-82%-190 MWe	Cyclone	N/A	NGR	(1.28/0.56)	56	25
60-123 MWe/150 MWe	Coal/wall fired	N/A	OFA	(0.77/0.60)	22	25
60-123 MWe/150 MWe	Coal/wall fired	N/A	LNB	(0.77/0.45)	41	25
60-123 MWe/150 MWe	Coal/wall fired	N/A	LNB + OFA	(0.77/0.33)	57	25
60-123 MWe/150 MWe	Coal/tangential	N/A	LNB + OFA +FGR	(0.58/0.28)	52	25
60-123 MWe/150 MWe	Coal/cyclone	N/A	reburn	(1.28/0.55)	57	25
60-123 MWe/150 MWe	Coal/wall + tangential	N/A	SCR	(0.28/0.08)	71	25
60-123 MWe/150 MWe	Coal/wall + tangential	N/A	SCR	(0.70/0.15)	78	25
60-123 MWe/150 MWe	Coal/wall + tangential	N/A	SNCR	(0.28/0.18)	35	25
60-123 MWe/150 MWe	Coal/wall + tangential	N/A	SNCR	(0.70/0.35)	50	25
60-123 MWe/150 MWe	PC: tangentially fired	N/A	OFA	(0.59/0.48)	19	25

LEA = Low excess air
OFA = Overfired air ports
LNB = Low NO_x burner
FGR = Flue gas recirculation
NGR = Natural gas reburn
N/A = Not available

TABLE 4-10 METAL ENRICHMENT BEHAVIORS

Class	Description	Reference 35	Reference 28	Reference 39
I	Equal distribution between fly ash and bottom ash		Aluminum (Al), Cobalt (Co), Iron (Fe), Manganese (Mn), Scandium (Sc), Titanium (Ti)	Al, Co, Chromium (Cr), Fe Mn, Sc, Ti
II	Enriched in fly ash relative to bottom ash	Arsenic (As), Cadmium (Cd)	As, Cd, Lead (Pb), Antimony (Sb)	As, Cd, Pb, Sb
III	Somewhere in between Class I and II, multiple behavior	Beryllium (Be), Cr, Nickel (Ni), Mn	Cr, Ni	Ni
IV	Emitted in gas phase	Mercury (Hg)	Hg	Hg

TABLE 4-11. ENRICHMENT RATIOS FOR CLASSES OF ELEMENTS

Class	Description	Metals	Fly ash enrichment ratio
I	Nonvolatile	Cr, Sc, Ti, Fe	$ER \approx 1$
IIa	Volatile with varying condensation on ash particles	As, Cd, Pb, Sb	$ER > 4$
IIb		Be, Co, Ni	$2 < ER < 4$
IIC		Mn	$1.3 < ER \leq 2$
III	Very volatile, almost no condensation	Hg, Se	

ER = Enrichment ratio

TABLE 4-12. ENRICHMENT RATIOS FOR BOILERS AND ESP

Boiler type (SCC)	Sb	As	Be	Cd	Cr	Co	Pb	Mn	Hg	Ni	Se	Th 232	Th 228	U 238	Th 230	Ra 226	Pb 210
Pulverized Coal Dry Bottom (10100202)	1.07	1.25	0.65	0.66	0.98	1.02	1.48	1.07	0.72	0.97	1.01	1.43	0.96	1.19		0.98	1.33
Pulverized Coal Dry Bottom Tangential (10100212)	0.97 to 1.33	1.08 to 1.27	0.78 to 1.12	0.49 to 0.88	0.42 to 0.97	0.90 to 0.97	1.28 to 1.42	0.86 to 1.02	0.71	0.94 to 1.54	0.75 to 0.82	1.04 to 1.16	0.92 to 1.16	1.06 to 1.24	1.19	0.95 to 1.19	1.36
High efficiency Cold-side ESP	5.4 to 26	5 to 29.6	2.1	9	1 to 21.7	1.1 to 9.9	3.0 to 18.3	1.4 to 13.8	1.0 to 19.3	1.8 to 10.1	7 to 86.2	0.04 to 0.88	1.19	1.15 to 1.35		1.68	0.94

TABLE 4-13. HAP EMISSION FACTORS (ENGLISH UNITS) FOR UNCONTROLLED BITUMINOUS COAL-FIRED BOILERS[a]

Firing configuration (SCC)	As	Be	Cd	Cr	Pb	Mn	Hg	Ni	POM	HCOH
Pulverized Coal Configuration Unknown (No SCC)	N/A	N/A	N/A	1922	N/A	N/A	N/A	N/A	N/A	112[b]
Pulverized Coal Wet Bottom (10100201)	538	81	44-70	1020-1570	507[c]	808-2980	16	840-1290	N/A	N/A
Pulverized Coal Dry Bottom (10100202)	684	81	44.4	1250-1570	507[c]	228-2980	16	1030-1290	2.08	N/A
Pulverized coal Dry Bottom, Tangential (10100212)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.4	N/A
Cyclone Furnace (10100203)	115	<81	28	212-1502	507[c]	228-1300	16	174-1290	N/A	N/A
Stoker Configuration Unknown (No SCC)	N/A	73	N/A	19-300	N/A	2170	16	775-1290	N/A	N/A
Spreader Stoker (10100204)	264-542	N/A	21-43	942-1570	507[c]	N/A	N/A	N/A	N/A	221[d]
Traveling Grate, Overfed Stoker (10100205)	542-1030	N/A	43-82	N/A	507[c]	N/A	N/A	N/A	N/A	140[e]

[a] All emission factors in lb/10^{16} Btu; all emission factors rated E.

[b] Based on 2 units; 456 MWe and 133 MMBtu/hr.

[c] Lead emission factors were taken directly from an EPA background document for support of the NAAQS.

[d] Based on 1 unit; 59 MMBtu/hr.

[e] Based on 1 unit; 52 MMBtu/hr.

TABLE 4-14. HAP EMISSION FACTORS (METRIC UNITS) FOR UNCONTROLLED BITUMINOUS COAL-FIRED BOILERS[a]

Firing configuration (SCC)	As	Be	Cd	Cr	Pb	Mn	Hg	Ni	POM	HCOH
Pulverized Coal Configuration Unknown (No SCC)	N/A	N/A	N/A	825	N/A	N/A	N/A	N/A	N/A	48[b]
Pulverized Coal Wet Bottom (10100201)	231	35	18-30	439-676	218[c]	348-1282	7	361-555	N/A	N/A
Pulverized Coal Dry Bottom (10100202)	294	35	19	538-676	218[c]	98-1282	7	443-555	0.894	N/A
Pulverized coal Dry Bottom, Tangential (10100212)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.03	N/A
Cyclone Furnace (10100203)	49.5-133	<34.9	12	91.2-676	218[c]	98-559	6.9	74.9-555	N/A	N/A
Stoker Configuration Unknown (No SCC)	N/A	31.4	N/A	8.1-675	N/A	934	6.9	334-555	N/A	N/A
Spreader Stoker (10100204)	114-233	N/A	9.0-18.5	N/A	218[c]	N/A	N/A	N/A	N/A	95[d]
Traveling Grate, Overfed Stoker (10100205)	233-443	N/A	19-35	N/A	218[c]	N/A	N/A	N/A	N/A	60[e]

[a] All emission factors in pg/J; all emission factors rated E.
[b] Based on 2 units; 456 MWe and 39 MW.
[c] Lead emission factors were taken directly from an EPA background document for support of the NAAQS.
[d] Based on 1 unit; 17 MW.
[e] Based on 1 unit; 15 MW.

TABLE 4-15. HAP EMISSION FACTORS (ENGLISH UNITS) FOR CONTROLLED BITUMINOUS COAL-FIRED BOILERS[a]

Boiler configuration (SCC)	Control device	Cr	Mn	POM
Pulverized coal Configuration unknown (no SCC)	Multicyclones	12		
	ESP	5.8-7990		
	Wet scrubber	0.61-12		
	Multicyclones/wet scrubber	18		
Pulverized coal Wet bottom (10100201)	ESP		78	18.6
	Wet scrubber			565
Cyclone Furnace (10100203)	ESP	19-22	60.8	0.46
	Wet scrubber	107	126	57.2
Stoker Configuration unknown	Multicyclones	62-2423	110	16.2
(no SCC)	ESP	135		
Pulverized coal Dry bottom (10100202)	ESP		96.2	8.55
	Wet scrubber		112	0.033-18.6
	Multicyclones/ ESP			

[a] All emission factors in lb/MMBtu; all emission factors rated E.

TABLE 4-16. HAP EMISSION FACTORS (METRIC UNITS) FOR CONTROLLED BITUMINOUS COAL-FIRED BOILERS[a]

Boiler configuration (SCC)	Control device	Cr	Mn	POM
Pulverized coal Configuration unknown (No SCC)	Multicyclones	5.3		
	ESP	2.5-3430		
	Wet scrubber	0.26-5.3		
	Multicyclones/wet scrubber	7.8		
Pulverized coal Wet bottom (10100201)	ESP		33.5	8.0
	Wet scrubber			2.43
Cyclone furnace (10100203)	ESP	8.4-9.7	27	0.20
	Wet scrubber	47.3	55.8	25.3
Stoker Configuration unknown (No SCC)	Multicyclones	27.4-1072	48.7	7.2
	ESP	59.7		
Pulverized coal Dry bottom (10100202)	ESP		41.3	3.68
	Wet scrubber		48.2	0.014-8
	Multicyclones/ESP			

[a] All emission factors in pg/J; all emission factors rated E.

TABLE 4-17. AVERAGE TRACE ELEMENT REMOVAL EFFICIENCY FOR CONTROL DEVICES[a]

Compound	Mechanical precipitation	ESP	FGD scrubber	Two ESPs in series	ESP/ scrubber	Two multicyclones
Arsenic	51	87.5		99.6	98.9	
Beryllium	37	91.9	94.3	99.94		
Cadmium	28.9	74.6	94.4[b]	90.5		
Chromium[d]	42.3	71.5	91.8[b]	93.7	92.9	50[c]
Manganese	54.3	78.1	89.1[b]	96.4	97.7	
Nickel	49.4	79.1	96.4[b]	96.6	97.2	

[a] These average control efficiencies represent measured control levels reported in the literature. They may or may not be indicative of the long-term performance of these types of controls on emissions from coal combustion sources. The average values should not be construed to represent an EPA-recommended efficiency level for these devices. Only limited data are available for lead and mercury removal efficiencies. Each emission test was weighted equally.

[b] The type of scrubber was not specified.

[c] These control efficiencies are for hexavalent chromium; the remaining values are for total chromium.

[d] The chromium control efficiencies may be biased low due to contamination from sampling equipment. Emission factors calculated using these efficiencies probably represent, in most cases, upper bound estimates.

TABLE 4-18. N_2O EMISSIONS DATA

Ref.	Data quality	Boiler type	Fuel type	Boiler capacity	Boiler load	Uncontrolled N_2O emissions, ppm	N_2O emission factor, lb/ton
78	B	DRUM-BOILER NAT. CIRC.	BIT.	171 MW	0.96	2.1	7.56E-02
78	B	DRUM-BOILER NAT. CIRC.	BIT.	171 MW	0.82	2.5	9.00E-02
78	B	DRUM-BOILER NAT. CIRC.	BIT.	171 MW	0.76	5.1	1.84E-01
78	B	DRUM-BOILER NAT. CIRC.	BIT.	171 MW	0.96	3.3	1.19E-01
							1.17E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3.6	1.28E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	0.92	2	7.28E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3.6	1.28E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	0.92	1.8	6.55E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	4.6	1.64E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	0.92	0.7	2.55E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3.6	1.28E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	0.92	1.1	4.01E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	0.92	0.9	3.28E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	0.92	0.8	2.91E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	0.92	0.9	3.28E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3.6	1.28E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3	1.07E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3.6	1.28E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3.6	1.28E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3.6	1.28E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	0.92	2.1	7.66E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3.6	1.28E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	3.6	1.28E-01
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	0.7	2.49E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	0.92	1.4	5.10E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.1	7.47E-02
79	B	P.C. CIRCULAR WALL-FIRED	BIT.	250 MW	1.08	2.4	8.53E-02
							8.74E-02
79	B	P.C. TRIPLE CELL WALL-FIRED	BIT.	250 MW	1.09	2.4	8.64E-02
79	B	P.C. TRIPLE CELL WALL-FIRED	BIT.	250 MW	1.09	2.4	8.64E-02
79	B	P.C. TRIPLE CELL WALL-FIRED	BIT.	250 MW	1.09	2.4	8.64E-02
79	B	P.C. TRIPLE CELL WALL-FIRED	BIT.	250 MW	1.09	3.6	1.30E-01
79	B	P.C. TRIPLE CELL WALL-FIRED	BIT.	250 MW	1.09	2.4	8.64E-02
79	B	P.C. TRIPLE CELL WALL-FIRED	BIT.	250 MW	1.09	2.4	8.64E-02
79	B	P.C. TRIPLE CELL WALL-FIRED	BIT.	250 MW	1.09	3.6	1.30E-01
79	B	P.C. TRIPLE CELL WALL-FIRED	BIT.	250 MW	1.09	3.6	1.30E-01
79	B	P.C. TRIPLE CELL WALL-FIRED	BIT.	250 MW	1.09	3.6	1.30E-01
							1.06E-01
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.4	1.42E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.9	3.20E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.7	2.49E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.8	2.84E-02

TABLE 4-18. N_2O EMISSIONS DATA

Ref.	Data quality	Boiler type	Fuel type	Boiler capacity	Boiler load	Uncontrolled N_2O emissions, ppm	N_2O emission factor, lb/ton
79	B	TANGENTIAL	BIT.	700 MW	0.8	2.3	8.19E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	1.2	4.27E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	1.2	4.27E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.5	1.78E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.4	1.42E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.4	1.42E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	1.2	4.27E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.5	1.78E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.7	2.49E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.8	2.84E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.4	1.42E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.4	1.42E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	1.2	4.27E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.7	2.49E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	1.2	4.27E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.5	1.78E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.9	3.20E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	1.2	4.27E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.5	1.78E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.7	2.49E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.8	2.84E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.9	3.20E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	0.7	2.49E-02
79	B	TANGENTIAL	BIT.	700 MW	0.8	1.2	4.27E-02
							2.96E-02
80	C	FLUIDIZED BED COMBUSTION CIRC	BIT.	8 MW		136	5.55E+00

TABLE 4-19.SUMMARY OF N_2O EMISSION FACTORS FOR BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION

Firing configuration	Rating	N_2O emission factor, lb/ton	N_2O emission factor, kg/Mg
Pulverized coal fired			
Dry bottom - wall fired	D	0.09	0.045
Dry bottom - tangential	D	0.03	0.015
Wet bottom	E	0.09[a]	0.045[a]
Cyclone furnace	E	0.09[a]	0.045[a]
Spreader stoker	E	0.09[a]	0.045[a]
Overfeed stoker	E	0.09[a]	0.045[a]
Underfeed stoker	E	0.09[a]	0.045[a]
Handfired units	E	0.09[a]	0.045[a]
Fluidized beds			
Bubbling	E	5.5[b]	2.7[b]
Circulating	E	5.5	2.7

[a] No data; value for pulverized coal dry bottom - wall fired was assigned.
[b] No data; value for circulating fluidized bed was assigned.

TABLE 4-20. PARTICULATE SIZING DATA FOR THE 1986 AP-42 DATABASE: NUMBER OF A & B RANKED DATA SETS[a]

Source category	Emission control device				
	None	Multiple cyclones	Scrubber	ESP	Baghouse
Bituminous/subbituminous coal combustion					
- Dry bottom, pulv. coal	>30	3	>30	>30	2
- Wet bottom, pulv. coal	3	0	0	0	0
- Cyclone furnace	0	0	1	2	0
- Spreader stoker	>30	11[b]	0	0	>30
- Overfeed stoker	3	2	0	0	0
- Underfeed stoker	6		0	0	0

[a] Data from Reference 2

[b] All data correspond to no fly ash reinjection

TABLE 4-21. COMPARISON OF ORGANIC AND INORGANIC CPM EMISSIONS FROM A COAL-FIRED BOILER[a]

Run Number[b]	Organic CPM emissions,		Inorganic CPM emissions[c],	
	mg/m^3	% of total	mg/m^3	% of total
1	0.5	1.2	40.1	98.8
2	0.5	1.3	37.4	98.7
3	1.6	4.5	33.9	95.5
4	1.6	3.7	42.0	96.3
5	0.6	1.5	38.9	98.5

[a] Based on Reference 83.

[b] Run 1 results consist of one train with an N_2 purge. Run 2 is an average of two simultaneous trains purged with N_2. Runs 3 and 5 are averages of three simultaneous trains purged with N_2. Run 4 is an average of four simultaneous trains purged with N_2.

[c] Corrected for chlorides.

TABLE 4-22. FILTERABLE PARTICULATE FOR A FRONT WALL FIRED BOILER FUELED ON A LOW SULFUR WESTERN BITUMINOUS COAL

	Filterable particulate, Cumulative mass percent less than stated size (in microns)								
Side of duct	0.625	1.00	1.25	2.50	6.00	10	15	Data quality rating	Ref.
West side	< 4	< 4	4	5	8	13	18	B	86
East side	< 2	< 2	2	4	9	15	24	B	86

TABLE 4-23. FILTERABLE PARTICULATE FOR SUBBITUMINOUS COAL FIRED FLUIDIZED BED COMBUSTORS WITH MULTICLONE CONTROLS

	Filterable particulate, Cumulative mass percent less than stated size (in microns)								
Fuel	0.625	1.00	1.25	2.50	6.00	10	15	Data quality rating	Ref.
Navajo subbituminous	< 2	12	22	56	82	88	90	D	85
Sarpy Creek subbituminous	< 2	9	17	55	74	85	90	D	85

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5. AP-42 SECTION 1.1: BITUMINOUS/SUBBITUMINOUS COAL COMBUSTION

The revision to Section 1.1 of AP-42 is presented in the following pages as it would appear in the document. A marked-up copy of the 1988 version of this section is included in Appendix C.

1.1 BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION

1.1.1 General

Coal is a complex combination of organic matter and inorganic ash formed over eons from successive layers of fallen vegetation. Coal types are broadly classified as anthracite, bituminous, subbituminous, or lignite. These classifications are based on coal heating value together with relative amounts of fixed carbon, volatile matter, ash, sulfur, and moisture. Formulae and tables for classifying coals are given in Reference 1. See AP-42 Sections 1.2 and 1.7 for discussions of anthracite and lignite combustion, respectively.

There are three major coal combustion techniques: suspension firing, grate firing, and fluidized bed combustion. Suspension firing is the primary combustion mechanism in pulverized coal and cyclone systems. Grate firing is the primary mechanism in underfeed and overfeed stokers. Both mechanisms are employed in spreader stokers. Fluidized bed combustion, while not constituting a significant percentage of the total boiler population, has nonetheless gained popularity in the last decade and today generates steam for industries, cogenerators, independent power producers, and utilities.

Pulverized coal furnaces are used primarily in utility and large industrial boilers. In these systems, the coal is pulverized in a mill to the consistency of talcum powder (i.e., at least 70 percent of the particles will pass through a 200 mesh sieve). The pulverized coal is generally entrained in primary air before being fed through burners to the furnace, where it is fired in suspension. Pulverized coal furnaces are classified as either dry or wet bottom, depending on the ash removal technique. Dry bottom furnaces fire coals with high ash fusion temperatures and use dry ash removal techniques. In wet bottom (or slag tap) furnaces, coals with low ash fusion temperatures are combusted and molten ash is drained from the bottom of the furnace. Pulverized coal furnaces are further classified by the firing position of the burners, [i.e., single (front or rear) wall, horizontally opposed, vertical, tangential (or corner-fired)]. Wall-fired boilers can be either single wall-fired (with burners on only one wall of the furnace firing horizontally) or opposed wall-fired (with burners mounted on two opposing walls). Tangentially-fired boilers have burners mounted in the corners of the furnace. The fuel and air are injected toward the center of the furnace to create a vortex that enhances air and fuel mixing.

Cyclone furnaces burn low ash fusion temperature coal which has been crushed to below 4 mesh particle size. The coal is fed tangentially in a stream of primary air to a horizontal cylindrical furnace. Within the furnace, small coal particles are burned in suspension while larger particles are forced against the outer wall. Because of the high temperatures developed in the relatively small furnace volume, and because of the low fusion temperature of the coal ash, much of the ash forms a liquid slag on the furnace walls. The slag drains from the walls to the bottom of the furnace where it is removed through a slag tap opening. Cyclone furnaces are used mostly in utility and large industrial applications.

In spreader stokers, a flipping mechanism throws the coal into the furnace and onto a moving fuel bed. Combustion occurs partly in suspension and partly on the grate. Because of significant carbon content in the particulate, fly ash reinjection from mechanical collectors is commonly employed to improve boiler efficiency. Ash residue from the fuel bed is deposited in a receiving pit at the end of the grate.

In overfeed stokers, coal is fed onto a traveling or vibrating grate and burns on the fuel bed as it progresses through the furnace. Ash particles fall into an ash pit at the rear of the stoker. The term "overfeed" applies because the coal is fed onto the moving grate under an adjustable gate. Conversely, in "underfeed" stokers, coal is fed into the firing zone from below by mechanical rams or screw conveyors. The coal moves in a channel, known as a retort, from which it is forced upward, spilling over the top of each side to form and to feed the fuel bed. Combustion is completed by the time the bed reaches the side dump grates, from which the ash is discharged into shallow pits. Underfeed stokers include single retort units and multiple retort units, the latter having several retorts side by side.

Small hand-fired boilers and furnaces are sometimes found in small industrial, commercial, institutional, or residential applications. In most hand-fired units, the fuel is primarily burned in layers on the bottom of the furnace or on a grate. From an emissions standpoint, hand-fired units generally have higher carbon monoxide (CO) and volatile organic compounds (VOC) emissions than larger boilers because of their lower combustion efficiencies.

In a fluidized bed combustor (FBC), the coal is introduced to a bed of either sorbent (limestone or dolomite) or inert material (usually sand) which is fluidized by an upward flow of air. Most of the combustion occurs within the bed, but some smaller particles burn above the bed in the "freeboard" space. The two principal types of atmospheric FBC boilers are bubbling bed and circulating bed. The fundamental distinguishing feature between these types is the fluidization velocity. In the bubbling bed design, the fluidization velocity is relatively low, ranging between 1.5 and 4 m/sec (5 and 12 ft/sec), in order to minimize solids carryover or elutriation from the combustor. Circulating FBCs, however, employ fluidization velocities as high as 9 m/sec (30 ft/sec) to promote the carryover or circulation of solids. High temperature cyclones are used in circulating FBCs and in some bubbling FBCs to capture the solid fuel and bed material for return to the primary combustion chamber. The circulating FBC maintains a continuous, high-volume recycle rate which increases the fuel residence time compared to the bubbling bed design. Because of this feature, circulating FBCs often achieve higher combustion efficiency and better sorbent utilization than bubbling bed units.[3]

1.1.2 Emissions and Controls

The major pollutants of concern from bituminous and subbituminous coal combustion are particulate matter (PM), sulfur oxides (SO_x), and nitrogen oxides (NO_x). Emissions from coal combustion depend on the rank and composition of the fuel, the type and size of the boiler, firing conditions, load, type of control technologies, and the level of equipment maintenance. Some unburnt combustibles, including numerous organic compounds and CO, are generally emitted even under proper boiler operating conditions. Emission factors for major and minor pollutants are given in Tables 1.1-1 through 1.1-14.

Particulate Matter - Particulate matter composition and emission levels are a complex function of firing configuration, boiler operation, and coal properties.[2-5] In pulverized coal systems, combustion is almost complete, and thus emitted particulate is largely comprised of inorganic ash residues. In wet bottom pulverized coal units and cyclones, the quantity of ash leaving the boiler is lower than in dry bottom units, because some of the ash liquifies, collects on the furnace walls, and drains from the furnace bottom as molten slag. Particulate emission limits specified in applicable New Source Performance Standards (NSPS) are summarized in Table 1.1-15.

Because a mixture of fine and coarse coal particles is fired in spreader stokers, significant unburnt carbon can be present in the particulate. To improve boiler efficiency, fly ash from collection devices (typically multiple cyclones) is sometimes reinjected into spreader stoker furnaces. This practice can dramatically increase the particulate loading at the boiler outlet and, to a lesser extent, at the mechanical collector outlet. Fly ash can also be reinjected from the boiler, air heater, and economizer dust hoppers. Fly ash reinjection from these hoppers increases particulate loadings less than from multiple cyclones.

Uncontrolled overfeed and underfeed stokers emit considerably less particulate than do pulverized coal units and spreader stokers, since combustion takes place in a relatively quiescent fuel bed. Fly ash reinjection is not practiced in these kinds of stokers.

Variables other than firing configuration and fly ash reinjection can affect PM emissions from stokers. Particulate loadings will often increase as load increases (especially as full load is approached) and with sudden load changes. Similarly, particulate can increase as the coal ash and "fines" contents increase. Fines, in this context, are coal particles smaller than about 1.6 millimeters (1/16 inch) in diameter. Conversely, particulate can be reduced significantly when overfire air pressures are increased.

FBCs may tax conventional particulate control systems. The particulate mass concentration exiting FBCs is typically 2 to 4 times higher than that from pulverized coal boilers.[13] Fluidized bed combustor particles are also, on average, smaller in size, irregularly shaped, and have higher surface area and porosity relative to pulverized coal ashes. Fluidized bed combustion ash is more difficult to collect in electrostatic precipitators (ESPs) than pulverized coal ash because FBC ash has a higher electrical resistivity. In addition, the use of multiclones for fly ash recycling, inherent with FBC processes, tends to reduce flue gas stream particulate size.[13]

The primary kinds of PM control devices used for coal combustion include multiple cyclones, ESPs, fabric filters (or baghouses), and scrubbers. Some measure of control will even result from fly ash settling in boiler/air heater/economizer dust hoppers, large breeching, and chimney bases. The effects of such settling are reflected in current emission factors.

ESPs are the most common high-efficiency PM control device used on pulverized coal and cyclone units; they are also being used increasingly on stokers. Generally, ESP collection efficiencies are a function of collection plate area per unit volumetric flow rate of flue gas through the device. Particulate control efficiencies of 99.9 percent or above are obtainable with ESPs. Electrostatic precipitators located downstream of air preheaters (i.e., cold side precipitators) operate at significantly reduced efficiencies when low sulfur coal is fired. Fabric filters have recently seen increased use in both utility and industrial applications, generally achieving at least 99.8 percent efficiency. An advantage of fabric filters is that they are unaffected by the high fly ash resistivities associated with low sulfur coals. Scrubbers are also used to control particulate, although their primary use is to control sulfur oxides. One drawback of scrubbers is the high energy usage required to achieve control efficiencies comparable to those for ESPs and baghouses.[2]

Mechanical collectors, generally multiple cyclones, are the primary means of PM control on many stokers. They are sometimes installed upstream of high-efficiency control devices in order to reduce the ash collection burden on these devices. Cyclones are also an integral part of most FBC designs. Depending on application and design, multiple cyclone efficiencies can vary widely. Where cyclone design flow rates are not attained (which is common with underfeed and overfeed stokers), these devices may be only marginally effective and may prove little better in reducing particulate than a large breeching. Conversely, well-designed multiple cyclones, operating at the required flow rates, can achieve collection efficiencies on spreader stokers and overfeed stokers of 90 to 95 percent. Even higher collection efficiencies are obtainable on spreader stokers with reinjected fly ash because of the larger particle sizes and increased particulate loading reaching the controls.[5-6]

Sulfur Oxides - Gaseous SO_x from coal combustion are primarily sulfur dioxide (SO_2), with a much lower quantity of sulfur trioxide (SO_3) and gaseous sulfates.[7-9] These compounds form as the organic and pyritic sulfur in the coal is oxidized during the combustion process. On average, about 95 percent of the sulfur present in bituminous coal will be emitted as gaseous SO_x, whereas somewhat less will be emitted when subbituminous coal is fired. The more alkaline nature of the ash in some subbituminous coals causes some of the sulfur to react in the furnace to form various sulfate salts that are retained in the boiler or in the flyash. In general, boiler size, firing configuration and boiler operations have little effect on the percent conversion of fuel sulfur to SO_x. Sulfur dioxide emission limits specified in applicable NSPS are summarized in Table 1.1-15.

Several techniques are used to reduce SO_x emissions from coal combustion. One way is to switch to lower sulfur coals, since SO_x emissions are proportional to the sulfur content of the coal. This alternative may not be possible where lower sulfur coal is not readily available or where a different grade of coal cannot be satisfactorily fired. In some cases, various coal cleaning processes may be employed to reduce the fuel sulfur content. Physical coal cleaning removes mineral sulfur such as pyrite but is not effective in removing organic sulfur. Chemical cleaning and solvent refining processes are being developed to remove organic sulfur.

Many flue gas desulfurization (FGD) techniques can remove SO_2 formed during combustion. Flue gases can be treated using wet, dry, or semi-dry desulfurization processes of either the throwaway type (in which all waste streams are discarded) or the recovery/regenerable type (in which the SO_2 absorbent is regenerated and reused). To date, wet systems are the most commonly applied. Wet systems generally use alkali slurries as the SO_2 absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_2. Particulate reduction of up to 99 percent is also possible with wet scrubbers, but fly ash is often collected by upstream ESPs or baghouses, to avoid erosion of the desulfurization equipment and possible interference with FGD process reactions.[7] Also, the volume of scrubber sludge is reduced with separate fly ash removal and contamination of the reagents and byproducts is prevented. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbing are among the commercially proven wet FGD systems. The effectiveness of these devices depends not only on control device design but also operating variables. A summary table of commercial post-combustion SO_2 controls is provided in Table 1.1-16.

A number of dry and wet sorbent injection technologies are under development to capture SO_2 in the furnace, the heat transfer sections, or ductwork downstream of the boiler. These technologies are generally designed for retrofit applications and are well-suited for coal combustion sources requiring moderate SO_2 reduction and which have a short remaining life.

Nitrogen Oxides - Nitrogen Oxide emissions from coal combustion are primarily NO_x, with only a few volume percent as nitrogen dioxide (NO_2).[10-11] Nitrous oxide (N_2O) is also emitted at ppm levels. Nitrogen oxides formation results from thermal fixation of atmospheric nitrogen in the combustion flame and from oxidation of nitrogen bound in the coal. Experimental measurements of thermal NO_x formation have shown that the NO_x concentration is exponentially dependent on temperature and is proportional to N_2 concentration in the flame, the square root of oxygen (O_2) concentration in the flame, and the gas residence time.[22] Typically, only 20 to 60 percent of the fuel nitrogen is converted to NO_x. Bituminous and subbituminous coals usually contain from 0.5 to 2 weight percent nitrogen, mainly present in aromatic ring structures. Fuel nitrogen can account for up to 80 percent of total NO_x from coal combustion. Nitrogen oxide emission limits in applicable NSPS are summarized in Table 1.1-15.

A number of combustion modifications have been used to reduce NO_x emissions from boilers. A summary of currently utilized NO_x control technology for stokers is given in Table 1.1-17. Low excess air (LEA) firing is the most widespread combustion modification, because it can be practiced in both old and new units and in all sizes of boilers. Low excess air firing is easy to implement and has the added advantage of increasing fuel use efficiency. Low excess air firing is generally effective only above 20 percent excess air for pulverized coal units and above 30 percent excess air for stokers. Below these levels, the NO_x reduction from decreased O_2 availability is offset by increased NO_x production due to higher flame temperatures. Another NO_x reduction technique is simply to switch to a coal having a lower nitrogen content, although many boilers may not properly fire coals with different properties.

Off-stoichiometric (or staged) combustion is also an effective means of controlling NO_x emissions from coal-fired equipment. This can be achieved by using overfire air or low-NO_x burners designed to stage combustion in the flame zone. Other NO_x reduction techniques include flue gas recirculation, load reduction, and steam or water injection. However, these techniques are not very effective for use on coal-fired equipment because of the fuel nitrogen effect. Ammonia injection is a post-combustion technique which can also be used, but it is costly relative to other methods. For cyclone boilers, the use of natural gas reburning for NO_x emission control is under investigation on a full-scale utility boiler.[33] The net reduction of NO_x from any of these techniques or combinations thereof varies considerably with boiler type, coal properties, and boiler operating practices. Typical reductions will range from 10 to 60 percent. References 10 and 27 may be consulted for detailed discussion of each of these NO_x reduction techniques. To date, flue gas treatment has not been used commercially to reduce NO_x emissions from coal-fired boilers because of its higher relative cost.

Carbon Monoxide - The rate of CO emissions from combustion sources depends on the fuel oxidation efficiency of the source. By controlling the combustion process carefully, CO emissions can be minimized. Thus, if a unit is operated improperly or not well maintained, the resulting concentrations of CO (as well as organic compounds) may increase by several orders of magnitude. Smaller boilers, heaters, and furnaces ten to emit more CO and organics than larger combustors. This is because smaller units usually have less high-temperature residence time and, therefore, less time to achieve complete combustion than larger combustors. Various combustion modification techniques used to reduce NO_x can produce increased CO emissions.

Organic Compounds - Small amounts of organic compounds are emitted from coal combustion. As with CO emissions, the rate at which organic compounds are emitted depends on the combustion efficiency of the boiler. Therefore, any combustion modification which reduces the combustion efficiency will most likely increase the concentrations of organic compounds in the flue gases.

Total organic compounds (TOC) include volatile organic compounds (VOCs), semi-volatile organic compounds, and condensible organic compounds. Emissions of VOCs are primarily characterized by the criteria pollutant class of unburned vapor-phase hydrocarbons. Unburned hydrocarbon emissions can include essentially all vapor phase organic compounds emitted from a combustion source. These are primarily emissions of aliphatic, oxygenated, and low molecular weight aromatic compounds which exist in the vapor phase at flue gas temperatures. These emissions include alkanes, alkenes, aldehydes, carboxylic acids, and substituted benzenes (e.g., benzene, toluene, xylene, and ethyl benzene).[17,18]

The remaining organic emissions are composed largely of compounds emitted from combustion sources in a condensed phase. These compounds can almost exclusively be classed into a group known as polycyclic organic matter (POM), and a subset of compounds called polynuclear aromatic hydrocarbons (PNA or PAH). There are also PAH-nitrogen analogs. Polycyclic organic matter can be especially prevalent in the emissions from coal combustion, because a large fraction of the volatile matter in coal exits as POM.[19]

Formaldehyde is formed and emitted during combustion of hydrocarbon-based fuels such as coal. Formaldehyde is present in the vapor phase of the flue gas. Formaldehyde is subject to oxidation and decomposition at the high temperatures encountered during combustion Thus, larger units with efficient combustion (resulting from closely regulated air-fuel ratios, uniformly high combustion chamber temperatures, and relatively long gas residence times) have lower formaldehyde emission rates than do smaller, less efficient combustion units.[20,21]

Trace elements - Trace elements are also emitted from the combustion of coal. For this update of AP-41, trace metals included in the list of 189 hazardous air pollutants under Title III of the 1990 Clean Air Act Amendments were considered.[23] The quantity of trace metals depends on combustion temperature, fuel feed mechanism, and the composition of the fuel. The temperature determines the degree of volatilization of specific trace elements contained in the fuel. The fuel feed mechanism affects the partitioning of elements between bottom ash and fly ash. The quantity of any given metal emitted, in general, depends on:

- the physical and chemical properties of the element itself;
- its concentration in the fuel;
- the combustion conditions; and
- the type of particulate control device used, and its collection efficiency as a function of particle size.

It has become widely recognized that some trace metals become concentrated in certain waste particle streams from a combustor (e.g., bottom ash, collector ash, and flue gas particulate) while others do not.[19] Various classification schemes have been developed to describe this partitioning behavior.[24-26] The classification scheme used by Baig, et al., is as follows:[26]

- Class 1: Elements which are approximately equally distributed between fly ash and bottom ash, or show little or no small particle enrichment.

- Class 2: Elements which are enriched in fly ash relative to bottom ash, or show increasing enrichment with decreasing particle size.

- Class 3: Elements which are intermediate between Class 1 and 2.

- Class 4: Elements which are emitted in the gas phase.

Fugitive Emissions - Fugitive emissions are defined as pollutants which escape from an industrial process due to leakage, materials handling, inadequate operational control, transfer or storage. The fly ash handling operations in most modern utility and industrial combustion sources consist of pneumatic systems or enclosed and hooded systems which are vented through small fabric filters or other dust control devices. The fugitive PM emissions from these systems are therefore minimal. Fugitive particulate emissions can sometimes occur during fly ash transfer operations from silos to trucks or rail cars.

Emission factors for SO_x, NO_x, and CO are presented in Tables 1.1-1 and 1.1-2, along with emission factor ratings. Particulate matter and PM-10 emission factors and ratings are given in Tables 1.1-3 and 1.1-4. Cumulative particle size distribution and particulate size specific emission factors are given in Figures 1.1-1 through 1.1-6 and Tables 1.1-5 through 1.1-10, respectively. Emission factors and ratings for speciated organics and N_2O are given in Tables 1.1-11 and 1.1-12. Emission factors and ratings for other non-criteria pollutants and lead are listed in Tables 1.1-13 and 1.1-14.

In general, the baseline emissions of criteria and non- criteria pollutants are those from uncontrolled combustion sources. Uncontrolled sources are those without add-on pollution control (APC) equipment, low-NO_x burners, or other modifications designed for emission control. Baseline emission for SO_2 and PM can also be obtained from measurements taken upstream of APC equipment.

Because of the inherently low NO_x emission characteristics of FBCs and the potential for in-bed SO_2 capture by calcium-based sorbents, uncontrolled emission factors for this source category were not developed in the same sense as with the other source categories. For NO_x emissions, the data collected from test reports were considered to be baseline if no additional add-on NO_x control system (such as ammonia injection) was operated. For SO_2 emissions, a correlation was developed from reported data on FBCs to relate SO_2 emissions to the coal sulfur content and the calcium-to-sulfur ratio in the bed.

TABLE 1.1-1. (ENGLISH UNITS) EMISSION FACTORS FOR SULFUR OXIDES (SO_x), NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	Source Classification Codes (SCC)	SO_x[b]		NO_x[c]		CO[d,e]	
		Emission Factor lb/ton	Rating	Emission Factor lb/ton	Rating	Emission Factor lb/ton	Rating
Pulverized coal fired, dry bottom, wall fired	101002-02/22 102002-02/22 103002-06/22	38S (35S)	A	21.7	A	0.5	A
Pulverized coal fired, dry bottom, tangentially fired	101002-12/26 102002-12/26 103002-16/26	38S (35S)	A	14.4	A	0.5	A
Pulverized coal fired, wet bottom	101002-01/21 102002-01/21 103002-05/21	38S (35S)	D	34.0	C	0.5	A
Cyclone furnace	101002-03/23 102002-03/23 103002-23	38S (35S)	D	33.8	C	0.5	A
Spreader stoker	101002-04/24 102002-04/24 103002-09/24	38S (35S)	B	13.7	A	5	A
Spreader stoker, with multiple cyclones, and reinjection	101002-04/24 102002-04/24 103002-09/24	38S (35S)	B	13.7	A	5	A
Spreader stoker, with multiple cyclones, no reinjection	101002-04/24 102002-04/24 103002-09/24	38S (35S)	A	13.7	A	5	A

TABLE 1.1-1. (ENGLISH UNITS) EMISSION FACTORS FOR SULFUR OXIDES (SO_x),NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a] (Continued)

Firing Configuration	Source Classification Codes (SCC)	SO_x[b]		NO_x[c]		CO[d,e]	
		Emission Factor lb/ton	Rating	Emission Factor lb/ton	Rating	Emission Factor lb/ton	Rating
Overfeed stoker[f]	101002-05/25 102002-05/10/25 103002-07/25	38S (35S)	B	7.5	A	6	B
Overfeed stoker, with multiple cyclones[f]	101002-05/25 102002-05/10/25 103002-07/25	38S (35S)	B	7.5	A	6	B
Underfeed stoker	102002-06 103002-08	31S	B	9.5	A	11	B
Underfeed stoker, with multiple cyclone	102002-06 103002-08	31S	B	9.5	A	11	B
Hand-fed units	103002-14	31S	D	9.1	E	275	E
Fluidized bed combustor, circulating bed	101002-17 102002-17 103002-17	g	E	3.9	E	18	E
Fluidized bed combustor, bubbling bed	101002-17 102002-17 103002-17	g	E	15.2	D	18	D

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[a] Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired.

[b] Expressed as SO_2, including SO_2, SO_3, and gaseous sulfates. Factors in parentheses should be used to estimate gaseous SO_x emissions for subbituminous coal. In all cases, S is weight % sulfur content of coal as fired. Emission factor would be calculated by multiplying the weight percent sulfur in the coal by the numerical value preceding S. On average for bituminous coal, 95% of fuel sulfur is emitted as SO_2, and only about 0.7% of fuel sulfur is emitted as SO_3 and gaseous sulfate. An equally small percent of fuel sulfur is emitted as particulate sulfate (References 9, 13). Small quantities of sulfur are also retained in bottom ash. With subbituminous coal, about 10% more fuel sulfur is

TABLE 1.1-1. (ENGLISH UNITS) EMISSION FACTORS FOR SULFUR OXIDES (SO_x), NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a] (Continued)

retained in the bottom ash and particulate because of the more alkaline nature of the coal ash. Conversion to gaseous sulfate appears about the same as for bituminous coal.

[c] Expressed as NO_2. Generally, 95+ volume % of nitrogen oxides present in combustion exhaust will be in the form of NO, the rest NO_2 (Reference 11). To express factors as NO, multiply factors by 0.66. All factors represent emission at baseline operation (i.e., 60 to 110% load and no NO_x control measures).

[d] Nominal values achievable under normal operating conditions. Values are one or two orders of magnitude higher can occur when combustion is not complete.

[e] Emission factors for CO_2 emissions from coal combustion should be calculated using CO_2/ton coal = 73.3C, where C is the weight percent carbon content of the coal.

[f] Includes traveling grate, vibrating grate and chain grate stokers.

[g] Sulfur dioxide emission factors for fluidized bed combustion are a function of fuel sulfur content and calcium-to-sulfur ratio. For both bubbling bed and circulating bed design, use: lb SO_2/ton coal = $39.6(S)(Ca/S)^{-1.9}$. In this equation, S is the weight percent sulfur in the fuel and Ca/S is the molar calcium-to-sulfur ratio in the bed. This equation may be used when the Ca/S is between 1.5 and 7. When no calcium-based sorbents are used and the bed material is inert with respect to sulfur capture, the emission factor for underfeed stokers should be used to estimate the FBC SO_2 emissions. In this case, the emission factor ratings are E for both bubbling and circulating units.

TABLE 1.1-2. (METRIC UNITS) EMISSION FACTORS FOR SULFUR OXIDES (SO_x),NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	Source Classification Codes (SCC)	SO_x[b]		NO_x[c]		CO[d,e]	
		Emission Factor kg/Mg	Rating	Emission Factor kg/Mg	Rating	Emission Factor kg/Mg	Rating
Pulverized coal fired, dry bottom, wall fired	101002-02/22 102002-02/22 103002-06/22	19S (17.5S)	A	10.85	A	.25	A
Pulverized coal fired, dry bottom, tangentially fired	101002-12/26 102002-12/26 103002-16/26	19S (17.5S)	A	7.2	A	.25	A
Pulverized coal fired, wet bottom	101002-01/21 102002-01/21 103002-05/21	19S (17.5S)	D	17	C	.25	A
Cyclone furnace	101002-03/23 102002-03/23 103002-23	19S (17.5S)	D	16.9	C	.25	A
Spreader stoker	101002-04/24 102002-04/24 103002-09/24	19S (17.5S)	B	6.85	A	2.5	A
Spreader stoker, with multiple cyclones, and reinjection	101002-04/24 102002-04/24 103002-09/24	19S (17.5S)	B	6.85	A	2.5	A
Spreader stoker, with multiple cyclones, no reinjection	101002-04/24 102002-04/24 103002-09/24	19S (17.5S)	A	6.85	A	2.5	A
Overfeed stoker[f]	101002-05/25 102002-05/10/25 103002-07/25	19S (17.5S)	B	3.75	A	3	B

TABLE 1.1-2. (METRIC UNITS) EMISSION FACTORS FOR SULFUR OXIDES (SO_x), NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a] (Continued)

Firing Configuration	Source Classification Codes (SCC)	SO_x[b]		NO_x[c]		CO[d,e]	
		Emission Factor kg/Mg	Rating	Emission Factor kg/Mg	Rating	Emission Factor kg/Mg	Rating
Overfeed stoker, with multiple cyclones[f]	101002-05/25 102002-05/10/25 103002-07/25	19S (17.5S)	B	3.75	A	3	B
Underfeed stoker	102002-06 103002-08	15.5S	B	4.75	A	5.5	B
Underfeed stoker, with multiple cyclone	102002-06 103002-08	15.5S	B	4.75	A	5.5	B
Hand-fed units	103002-14	15.5S	D	4.55	E	137.5	E
Fluidized bed combustor, circulating bed	101002-17 102002-17 103002-17	g	E	1.95	E	9	E
Fluidized bed combustor, bubbling bed	101002-17 102002-17 103002-17	g	E	7.6	D	9	D

[a] Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired.

[b] Expressed as SO_2, including SO_2, SO_3, and gaseous sulfates. Factors in parentheses should be used to estimate gaseous SO_x emissions for subbituminous coal. In all cases, S is weight % sulfur content of coal as fired. Emission factor would be calculated by multiplying the weight percent sulfur in the coal by the numerical value preceding S. On average for bituminous coal, 95% of fuel sulfur is emitted as SO_2, and only about 0.7% of fuel sulfur is emitted as SO_3 and gaseous sulfate. An equally small percent of fuel sulfur is emitted as particulate sulfate (References 9, 13). Small quantities of sulfur are also retained in bottom ash. With subbituminous coal, about 10% more fuel sulfur is retained in the bottom ash and particulate because of the more alkaline nature of the coal ash. Conversion to gaseous sulfate appears about the same as for bituminous coal.

TABLE 1.1-2. (METRIC UNITS) EMISSION FACTORS FOR SULFUR OXIDES (SO_x),NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a] (Continued)

[c] Expressed as NO_2. Generally, 95+ volume % of nitrogen oxides present in combustion exhaust will be in the form of NO, the rest NO_2 (Reference 11). To express factors as NO, multiply factors by 0.66. All factors represent emission at baseline operation (i.e., 60 to 110% load and no NO_x control measures).

[d] Nominal values achievable under normal operating conditions. Values are one or two orders of magnitude higher can occur when combustion is not complete.[e] Emission factors for CO_2 emissions from coal combustion should be calculated using CO_2/Mg coal = 36.7C, where C is the weight percent carbon content of the coal.

[f] Includes traveling grate, vibrating grate and chain grate stokers.

[g] Sulfur dioxide emission factors for fluidized bed combustion are a function of fuel sulfur content and calcium-to-sulfur ratio. For both bubbling bed and circulating bed design, use: kg SO_2/Mg coal = $19.8(S)(Ca/S)^{-1.9}$. In this equation, S is the weight percent sulfur in the fuel and Ca/S is the molar calcium-to-sulfur ratio in the bed. This equation may be used when the Ca/S is between 1.5 and 7. When no calcium-based sorbents are used and the bed material is inert with respect to sulfur capture, the emission factor for underfeed stokers should be used to estimate the FBC SO_2 emissions. In this case, the emission factor ratings are E for both bubbling and circulating units.

TABLE 1.1-3. (ENGLISH UNITS) EMISSION FACTORS FOR PARTICULATE MATTER (PM) AND PM LESS THAN 10 MICRONS (PM-10) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	Source Classification Codes (SCC)	Filterable PM[b]		PM-10	
		Emission Factor lb/ton	Rating	Emission Factor lb/ton	Rating
Pulverized coal fired, dry bottom, wall fired	101002-02/22 102002-02/22 103002-06/22	10A	A	2.3A	E
Pulverized coal fired, dry bottom, tangentially fired	101002-12/26 102002-12/26 103002-16/26	10A	B	2.3A[c]	E
Pulverized coal fired, wet bottom	101002-01/21 102002-01/21 103002-05/21	7A[d]	D	2.6A	E
Cyclone furnace	101002-03/23 102002-03/23 103002-23	2A[d]	E	0.26A	E
Spreader stoker	101002-04/24 102002-04/24 103002-09/24	66[e]	B	13.2	E
Spreader stoker, with multiple cyclones, and reinjection	101002-04/24 102002-04/24 103002-09/24	17	B	12.4	E
Spreader stoker, with multiple cyclones, no reinjection	101002-04/24 102002-04/24 103002-09/24	12	A	7.8	E
Overfeed stoker[f]	101002-05/25 102002-05/10/25 103002-07/25	16[g]	C	6.0	E

TABLE 1.1-3. (ENGLISH UNITS) EMISSION FACTORS FOR PARTICULATE MATTER (PM) AND PM LESS THAN 10 MICRONS (PM-10) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a] (Continued)

Firing Configuration	Source Classification Codes (SCC)	Filterable PM[b]		PM-10	
		Emission Factor lb/ton	Rating	Emission Factor lb/ton	Rating
Overfeed stoker, with multiple cyclones[f]	101002-05/25 102002-05/10/25 103002-07/25	16[h]	C	5.0	E
Underfeed stoker	102002-06 103002-08	15[j]	D	6.2	E
Underfeed stoker, with multiple cyclone	102002-06 103002-08	11[h]	D	6.2[j]	E
Hand-fed units	103002-14	15	E	6.2[k]	E
Fluidized bed combustor, bubbling bed	101002-17 102002-17 103002-17	12	E	13.2[m]	E
Fluidized bed combustor, circulating bed	101002-17 102002-17 103002-17	17	E	13.2	E

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[a] Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired.

[b] Based on EPA Method 5 (front half catch) as described in Reference 28. Where particulate is expressed in terms of coal ash content, A,
factor is determined by multiplying weight % ash content of coal (as fired) by the numerical value preceding the A. For example, if coal with
8% ash is fired in a pulverized coal fired, dry bottom unit, the PM emission factor would be 10 x 8, or 80 lb/ton. The "condensible" matter
collected in back half catch of EPA Method 5 averages <5% of front half, or "filterable," catch for pulverized coal and cyclone furnaces; 10%
for spreader stokers; 15% for other stokers; and 50% for handfired units (References 6, 29, 30).

[c] No data found; use assume emission factor for pulverized coal-fired dry bottom boilers.

[d] Uncontrolled particulate emissions, when no fly ash reinjection is employed. When control device is installed, and collected fly ash is reinjected to boiler, particulate from boiler reaching control equipment can increase up to a factor of two.

TABLE 1.1-3. (ENGLISH UNITS) EMISSION FACTORS FOR PARTICULATE MATTER (PM) AND PM LESS THAN 10 MICRONS (PM-10) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a] (Continued)

[e] Accounts for fly ash settling in an economizer, air heater or breaching upstream of control device or stack. (Particulate directly at boiler outlet typically will be twice this level.) Factor should be applied even when fly ash is reinjected to boiler from air heater or economizer dust hoppers.

[f] Includes traveling grate, vibrating grate and chain grate stokers.

[g] Accounts for fly ash settling in breaching or stack base. Particulate loadings directly at boiler outlet typically can be 50% higher.

[h] See Reference 34 for discussion of apparently low multiple cyclone control efficiencies, regarding uncontrolled emissions.

[j] Accounts for fly ash settling in breaching downstream of boiler outlet.

[k] No data found; use emission factor for underfeed stoker.

[m] No data found; use emission factor for spreader stoker.

TABLE 1.1-4. (METRIC UNITS) EMISSION FACTORS FOR PARTICULATE MATTER (PM) AND PM LESS THAN 10 MICRONS (PM-10) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	Source Classification Codes (SCC)	Fitlerable PM[b]		PM-10	
		Emission Factor kg/Mg	Rating	Emission Factor kg/Mg	Rating
Pulverized coal fired, dry bottom, wall fired	101002-02/22 102002-02/22 103002-06/22	5A	A	1.15A	E
Pulverized coal fired, dry bottom, tangentially fired	101002-12/26 102002-12/26 103002-16/26	5A	B	1.15A[c]	E
Pulverized coal fired, wet bottom	101002-01/21 102002-01/21 103002-05/21	3.5A[d]	D	1.3A	E
Cyclone furnace	101002-03/23 102002-03/23 103002-23	1A[d]	E	0.13A	E
Spreader stoker	101002-04/24 102002-04/24 103002-09/24	33[e]	B	6.6	E
Spreader stoker, with multiple cyclones, and reinjection	101002-04/24 102002-04/24 103002-09/24	8.5	B	6.6	E
Spreader stoker, with multiple cyclones, no reinjection	101002-04/24 102002-04/24 103002-09/24	6	A	3.9	E
Overfeed stoker[f]	101002-05/25 102002-05/10/25 103002-07/25	8[g]	C	3.0	E

TABLE 1.1-4. (METRIC UNITS) EMISSION FACTORS FOR PARTICULATE MATTER (PM) AND PM LESS THAN 10 MICRONS (PM-10) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a] (Continued)

Firing Configuration	Source Classification Codes (SCC)	Filterable PM[b]		PM-10	
		Emission Factor kg/Mg	Rating	Emission Factor kg/Mg	Rating
Overfeed stoker, with multiple cyclones[f]	101002-05/25 102002-05/10/25 103002-07/25	4.5^h	C	2.5	E
Underfeed stoker	102002-06 103002-08	7.5^j	D	3.1	E
Underfeed stoker, with multiple cyclone	102002-06 103002-08	5.5^h	D	3.1^j	E
Hand-fed units	103002-14	7.5	E	3.1^k	E
Fluidized bed combustor, bubbling bed	101002-17 102002-17 103002-17	6	E	6.6^m	E
Fluidized bed combustor, circulating bed	101002-17 102002-17 103002-17	8.5	E	6.6	E

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[a] Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired.

[b] Based on EPA Method 5 (front half catch) as described in Reference 28. Where particulate is expressed in terms of coal ash content, A, factor is determined by multiplying weight % ash content of coal (as fired) by the numerical value preceding the A. For example, if coal with 8% ash is fired in a pulverized coal fired, dry bottom unit, the PM emission factor would be 5 x 8, or 40 kg/Mg. The "condensible" matter collected in back half catch of EPA Method 5 averages <5% of front half, or "filterable," catch for pulverized coal and cyclone furnaces; 10% for spreader stokers; 15% for other stokers; and 50% for handfired units (References 6, 29, 30).

[c] No data found; use assume emission factor for pulverized coal-fired dry bottom boilers.

[d] Uncontrolled particulate emissions, when no fly ash reinjection is employed. When control device is installed, and collected fly ash is reinjected to boiler, particulate from boiler reaching control equipment can increase up to a factor of two.

TABLE 1.1-4. (METRIC UNITS) EMISSION FACTORS FOR PARTICULATE MATTER (PM) AND PM LESS THAN 10 MICRONS (PM-10) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a] (Continued)

[e] Accounts for fly ash settling in an economizer, air heater or breaching upstream of control device or stack. (Particulate directly at boiler outlet typically will be twice this level.) Factor should be applied even when fly ash is reinjected to boiler from air heater or economizer dust hoppers.

[f] Includes traveling grate, vibrating grate and chain grate stokers.

[g] Accounts for fly ash settling in breaching or stack base. Particulate loadings directly at boiler outlet typically can be 50% higher.

[h] See Reference 34 for discussion of apparently low multiple cyclone control efficiencies, regarding uncontrolled emissions.

[j] Accounts for fly ash settling in breaching downstream of boiler outlet.

[k] No data found; use emission factor for underfeed stoker.

[m] No data found; use emission factor for spreader stoker.

TABLE 1.1-5. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR DRY BOTTOM BOILERS BURNING PULVERIZED BITUMINOUS COAL[a]

(Source Classification Codes: 101002-02, 102002-02, 103002-06, 101002-12, 102002-12, 103002-16)

Particle Size[b] (µm)	Cumulative Mass % ≤ stated size					Cumulative Emission Factor[c] [kg/Mg (lb/ton) coal, as fired]				
	Uncontrolled	Controlled				Uncontrolled[d]	Controlled[e]			
		Multiple cyclones	Scrubber	ESP	Baghouse		Multiple cyclones[f]	Scrubber[g]	ESP[g]	Baghouse[f]
15	32	54	81	79	97	1.6A (3.2A)	0.54A (1.08A)	0.24A (0.48A)	0.032A (0.06A)	0.010A (0.02A)
10	23	29	71	67	92	1.15A (2.3A)	0.29A (0.58A)	0.21A (0.42A)	0.027A (0.05A)	0.009A (0.02A)
6	17	14	62	50	77	0.85A (1.7A)	0.14A (0.28A)	0.19A (0.38A)	0.020A (0.04A)	0.008A (0.02A)
2.5	6	3	51	29	53	0.3A (0.6A)	0.03A (0.06A)	0.15A (0.3A)	0.012A (0.02A)	0.005A (0.01A)
1.25	2	1	35	17	31	0.10A (0.2A)	0.01A (0.02A)	0.11A (0.22A)	0.007A (0.01A)	0.003A (0.006A)
1.00	2	1	31	14	25	0.10A (0.2A)	0.01A (0.02A)	0.09A (0.18A)	0.006A (0.01A)	0.003A (0.006A)
0.625	1	1	20	12	14	0.05A (0.10A)	0.01A (0.02A)	0.06A (0.12A)	0.005A (0.01A)	0.001A (0.002A)
TOTAL	100	100	100	100	100	5A (10A)	1A (2A)	0.3A (0.6A)	0.04A (0.08A)	0.01A (0.02A)

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[a] Reference 32.

[b] Expressed as aerodynamic equivalent diameter.

[c] A = coal ash weight %, as fired.

TABLE 1.1-5. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR DRY BOTTOM BOILERS BURNING PULVERIZED BITUMINOUS COAL[a] (Continued)

(Source Classification Codes: 101002-02, 102002-02, 103002-06, 101002-12, 102002-12, 103002-16)

[d] Emission factor rating = C.

[e] Estimated control efficiency for multiple cyclones is 80%; for scrubber, 94%; for ESP, 99.2%; and for baghouse, 99.8%.

[f] Emission factor rating = E.

[g] Emission factor rating = D.

ESP = Electrostatic precipitator.

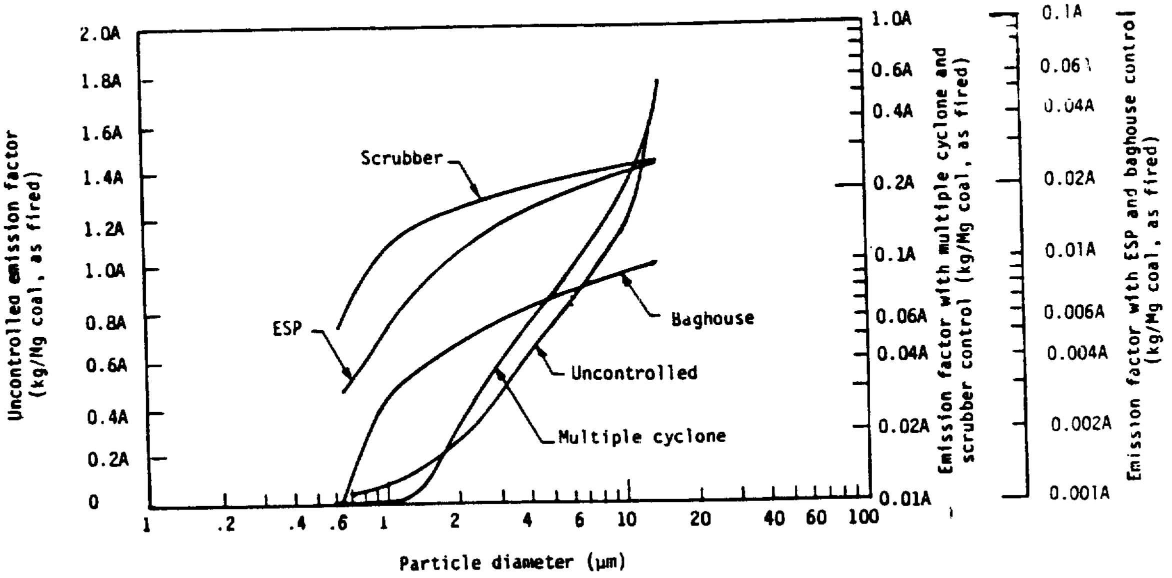

Figure 1.1-1. Cumulative size specific emission factors for dry bottom boilers burning pulverized bituminous coal.

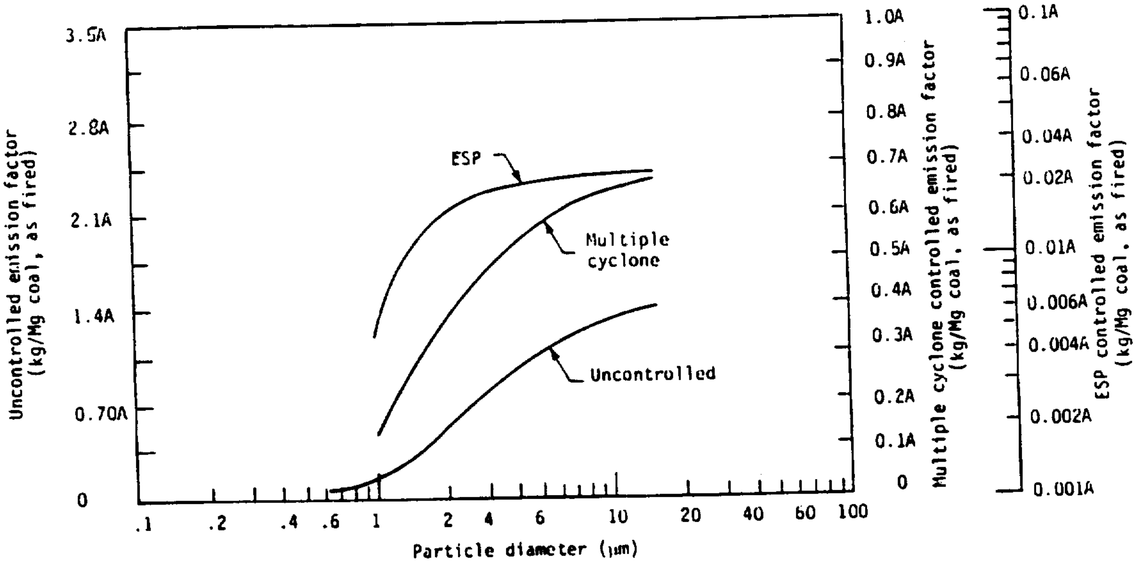

Figure 1.1-2. Cumulative specific emission factors for wet bottom boilers burning pulverized bituminous coal.

TABLE 1.1-7. CUMULATIVE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR CYCLONE FURNACES BURNING BITUMINOUS COAL[a]

(Source Classification Codes: 101002-03, 102002-03)

(EMISSION FACTOR RATING: E)

Particle Size[b] (µm)	Cumulative Mass % ≤ stated size			Cumulative Emission Factor[c] [kg/Mg (lb/ton) coal, as fired]		
		Controlled			Controlled[e]	
	Uncontrolled	Multiple cyclones	ESP	Uncontrolled	Multiple cyclones	ESP
15	33	95	90	0.33A (0.66A)	0.057A (0.114A)	0.0064A (0.013A)
10	13	94	68	0.13A (0.26A)	0.056A (0.112A)	00054A (0.011A)
6	8	93	56	0.08A (0.16A)	0.056A (0.112A)	0.0045A (0.009A)
2.5	0	92	36	0	0.055A (0.11A)	0.0029A (0.006A)
1.25	0	85	22	0	0.051A (0.10A)	0.0018A (0.004A)
1.00	0	82	17	0	0.049A (0.10A)	0.0014A (0.003A)
0.625	0	d	d	0	d	d
TOTAL	100	100	100	1A (2A)	0.06A (0.12A)	0.008A (0.016A)

[a] Reference 32.

[b] Expressed as aerodynamic equivalent diameter.

[c] A = coal ash weight %, as fired.

[d] Insufficient data.

[e] Estimated control efficiency for multiple cyclones is 94%; and for ESP, 99.2%.

ESP = Electrostatic precipitator.

TABLE 1.1-6. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR WET BOTTOM BOILERS BURNING PULVERIZED BITUMINOUS COAL[a]

(Source Classification Codes: 101002-01, 102002-01, 103002-05)

(EMISSION FACTOR RATING: E)

Particle Size[b] (µm)	Cumulative Mass % ≤ stated size			Cumulative Emission Factor[c] [kg/Mg (lb/ton) coal, as fired]		
		Controlled			Controlled[d]	
	Uncontrolled	Multiple cyclones	ESP	Uncontrolled	Multiple cyclones	ESP
15	40	99	83	1.4A (2.8A)	0.69A (1.38A)	0.023A (0.46A)
10	37	93	75	1.30A (2.6A)	0.65A (1.3A)	0.021A (0.42A)
6	33	84	63	1.16A (2.32A)	0.59A (1.18A)	0.018A (0.36A)
2.5	21	61	40	0.74A (1.48A)	0.43A (0.86A)	0.011A (0.022A)
1.25	6	31	17	0.21A (0.42A)	0.22A (0.44A)	0.005A (0.01A)
1.00	4	19	8	0.14A (0.28A)	0.13A (0.26A)	0.002A (0.004A)
0.625	2	e	e	0.07A (0.14A)	e	e
TOTAL	100	100	100	3.5A (7.0A)	0.7A (1.4A)	0.028A (0.056A)

[a] Reference 32.

[b] Expressed as aerodynamic equivalent diameter.

[c] A = coal ash weight %, as fired.

[d] Estimated control efficiency for multiple cyclones is 94%; and for ESP, 99.2%.

[e] Insufficient data.

ESP = Electrostatic precipitator.

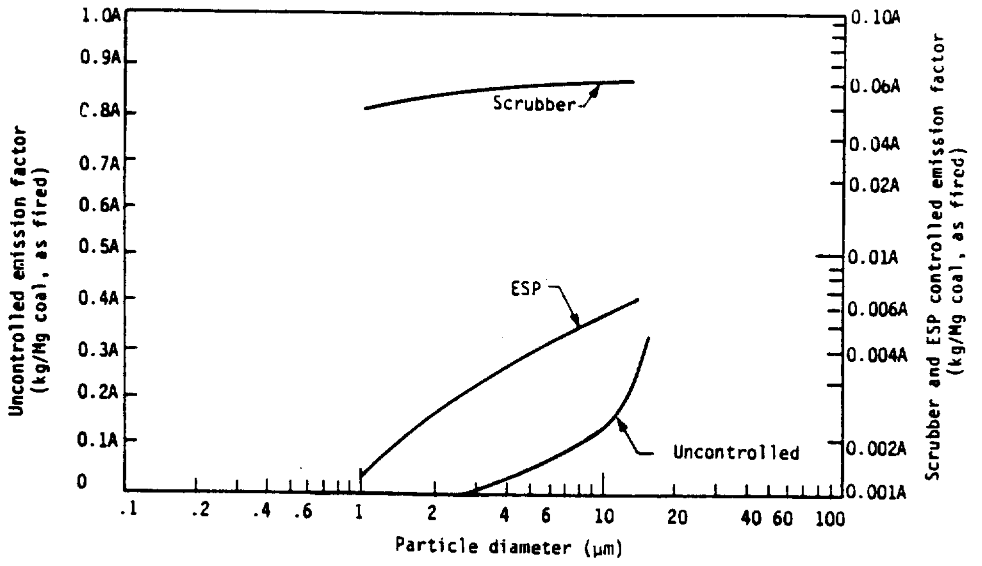

Figure 1.1-3. Cumulative size specific emission factors for cyclone furnaces burning bituminous coal.

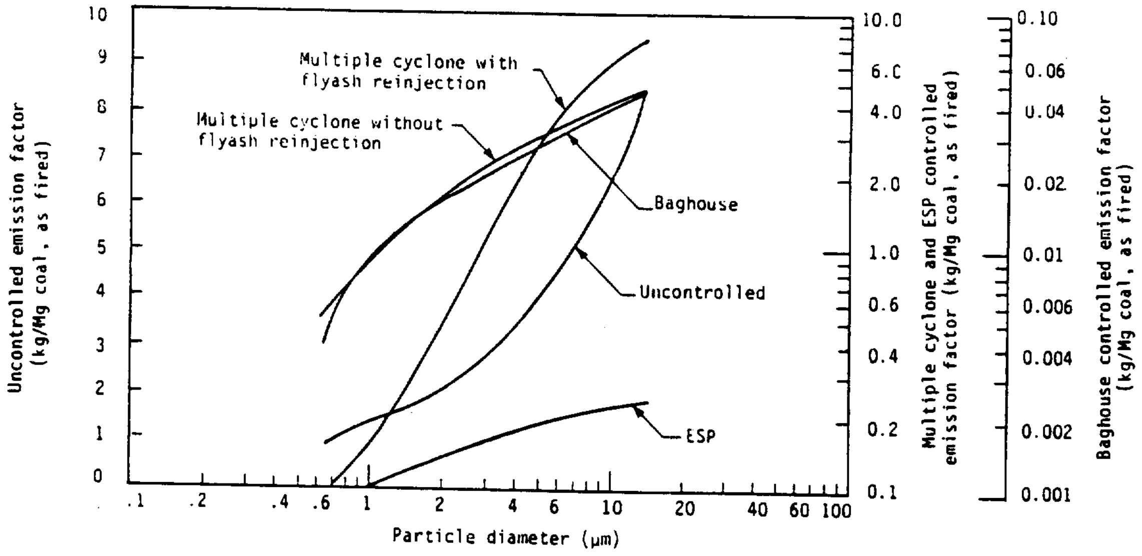

Figure 1.1-4. Cumulative size specific emission factors for spreader stokers burning bituminous coal.

TABLE 1.1-8. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR SPREADER STOKERS BURNING BITUMINOUS COAL[a]

(Source Classification Codes: 101002-04, 102002-04, 103002-09)

Particle Size[b] (µm)	Cumulative Mass % ≤ stated size (SCC)					Cumulative Emission Factor[c] [kg/Mg (lb/ton) coal, as fired]				
	Un-controlled	Controlled				Un-controlled[e]	Controlled[d]			
		Multiple cyclones[c]	Multiple cyclones[d]	ESP	Baghouse		Multiple cyclones[c,f]	Multiple cyclones[d,e]	ESP[f,g]	Bag-house[e,g]
15	28	56	74	97	72	8.4 (16.8)	4.4 (8.8)	0.23 (0.46)	0.043 (0.086)	0.010A (0.02A)
10	20	73	65	90	60	6.2 (12.4)	3.9 (7.8)	0.22 (0.44)	0.036 (0.072)	0.009A (0.02A)
6	14	51	52	82	46	4.3 (8.6)	3.1 (6.2)	0.20 (0.60)	0.028 (0.056)	0.008A (0.02A)
2.5	7	8	27	61	26	0.7 (1.4)	1.6 (3.2)	0.15 (0.30)	0.016 (0.032)	0.005A (0.01A)
1.25	5	2	16	46	18	0.2 (0.4)	1.0 (2.0)	0.11 (0.22)	0.011 (0.022)	0.003A (0.006A)
1.00	5	2	14	41	15	0.2 (0.4)	0.8 (1.6)	0.10 (0.20)	0.009 (0.018)	0.003A (0.006A)
0.625	4	1	9	h	7	0.1 (0.2)	0.5 (1.0)	h	0.004 (0.006)	0.001A (0.002A)
TOTAL	100	100	100	100	100	8.5 (17.0)	6.0 (12.0)	0.24 (0.48)	0.06 (0.12)	0.01A (0.02A)

TABLE 1.1-8. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR SPREADER STOKERS BURNING BITUMINOUS COAL[a] (Continued)

(Source Classification Codes: 101002-04, 102002-04, 103002-09)

[a] Reference 32.
[b] Expressed as aerodynamic equivalent diameter.
[c] With flyash reinjection.
[d] Without flyash reinjection.
[e] Emission factor rating = C.
[f] Emission Factor rating = E.
[g] Estimated control efficiency for electrostatic precipitator (ESP) is 99.22%; and for baghouse, 99.8%.
[h] Insufficient data.

TABLE 1.1-9. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR OVERFEED STOKERS BURNING BITUMINOUS COAL[a]

(Source Classification Codes: 1001002-05, 102002-05/10, 103002-07)

Particle Size[b] (µm)	Cumulative Mass % ≤ stated size		Cumulative Emission Factor[c] [kg/Mg (lb/ton) coal, as fired]			
	Uncontrolled	Multiple Cyclones Controlled	Uncontrolled		Multiple Cyclones Controlled[d]	
			Factor	Rating	Factor	Rating
15	49	60	3.9 (7.8)	C	2.7 (5.4)	E
10	37	55	3.0 (6.0)	C	2.5 (5.0)	E
6	24	49	1.9 (3.8)	C	2.2 (4.4)	E
2.5	14	43	1.1 (2.2)	C	1.9 (3.8)	E
1.25	13	39	1.0 (2.0)	C	1.8 (3.6)	E
1.00	12	39	1.0 (2.0)	C	1.8 (3.6)	E
0.625	c	16	c	C	0.7 (1.4)	E
TOTAL	100	100	8.0 (16.0)	C	4.5 (9.0)	E

[a] Reference 32.
[b] Expressed as aerodynamic equivalent diameter.
[c] Insufficient data.
[d] Estimated control efficiency for multiple cyclones is 80%.

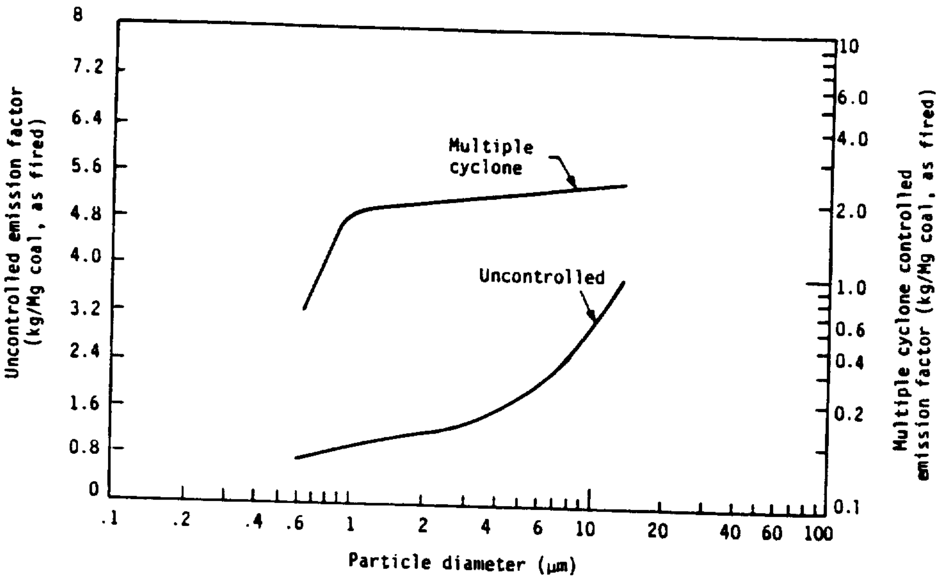

Figure 1.1-5. Cumulative size specific emission factors for overfeed stokers burning bituminous coal.

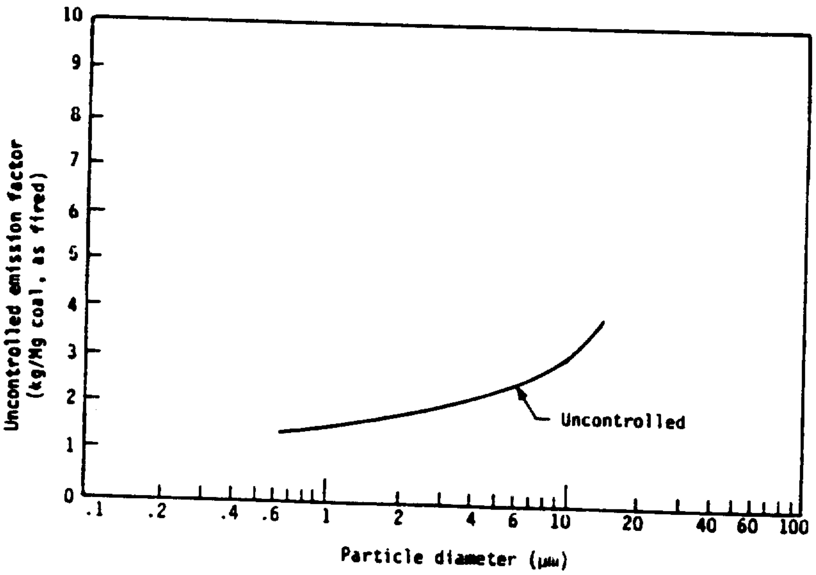

Figure 1.1-6. Cumulative specific emission factors for underfeed stokers burning bituminous coal.

TABLE 1.1-10. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR UNDERFEED STOKERS BURNING BITUMINOUS COAL[a]
(Source Classification Codes: 102002-06, 103002-08)

Particle Size[b] (μm)	Cumulative Mass %, ≤ stated size	Uncontrolled Cumulative Emission Factor[c] [kg/Mg (lb/ton) coal, as fired]	
		Factor	Rating
15	50	3.8 (7.6)	C
10	41	3.1 (6.2)	C
6	32	2.4 (4.8)	C
2.5	25	1.9 (3.8)	C
1.25	22	1.7 (3.4)	C
1.00	21	1.6 (3.2)	C
0.625	18	1.4 (2.7)	C
TOTAL	100	7.5 (15.0)	C

[a] Reference 32.
[b] Expressed as aerodynamic equivalent diameter.
[c] May also be used for uncontrolled hand-fired units.

TABLE 1.1-11. (ENGLISH UNITS) EMISSION FACTORS FOR METHANE (CH_4), NON-METHANE TOTAL ORGANIC COMPOUNDS (NMTOC), AND NITROUS OXIDE (N_2O) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	Source Classification Codes (SCC)	CH_4[b]		NMTOC[b,c]		N_2O[d]	
		Emission Factor lb/ton	Rating	Emission Factor lb/ton	Rating	Emission Factor lb/ton	Rating
Pulverized coal fired, dry bottom, wall fired	101002-02/22 102002-02/22 103002-06/22	0.04	B	0.06	B	.09	D
Pulverized coal fired, dry bottom, tangentially fired	101002-12/26 102002-12/26 103002-16/26	0.04	B	0.06	B	.03	D
Pulverized coal fired, wet bottom	101002-01/21 102002-01/21 103002-05/21	0.05	B	0.04	B	.09[e]	E
Cyclone furnace	101002-03/23 102002-03/23 103002-23	0.01	B	0.11	B	.09[e]	E
Spreader stoker	101002-04/24 102002-04/24 103002-09/24	0.06	B	0.05	B	.09[e]	E
Spreader stoker, with multiple cyclones, and reinjection	101002-04/24 102002-04/24 103002-09/24	0.06	B	0.05	B	.09[e]	E
Spreader stoker, with multiple cyclones, no reinjection	101002-04/24 102002-04/24 103002-09/24	0.06	B	0.05	B	.09[e]	E

TABLE 1.1-11. (ENGLISH UNITS) EMISSION FACTORS FOR METHANE (CH_4), NON-METHANE TOTAL ORGANIC COMPOUNDS (NMTOC), AND NITROUS OXIDE (N_2O) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a] (Continued)

Firing Configuration	Source Classification Codes (SCC)	CH_4[b]		NMTOC[b,c]		N_2O[d]	
		Emission Factor lb/ton	Rating	Emission Factor lb/ton	Rating	Emission Factor lb/ton	Rating
Overfeed stoker[f]	101002-05/25 102002-05/10/25 103002-07/25	0.06	B	0.05	B	.09[e]	E
Overfeed stoker, with multiple cyclones[f]	101002-05/25 102002-05/10/25 103002-07/25	0.06	B	0.05	B	.09[e]	E
Underfeed stoker	102002-06 103002-08	0.8	B	1.3	B	.09[e]	E
Underfeed stoker, with multiple cyclone	102002-06 103002-08	0.8	B	1.3	B	.09[e]	E
Hand-fed units	103002-14	5	E	10	E	.09[e]	E
Fluidized bed combustor, bubbling bed	101002-17 102002-17 103002-17	0.06	E	0.05	E	5.9[g]	E
Fluidized bed combustor, circulating bed	101002-17 102002-17 103002-17	0.06	E	0.05	E	5.5	E

[a] Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired.

[b] Reference 35. Nominal values achievable under normal operating conditions; values one or two orders of magnitude higher can occur when combustion is not complete.

TABLE 1.1-11. (ENGLISH UNITS) EMISSION FACTORS FOR METHANE (CH_4), NON-METHANE TOTAL ORGANIC COMPOUNDS (NMTOC), AND NITROUS OXIDE (N_2O) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a] (Continued)

[c] Nonmethane total organic compounds are expressed as C2 to C16 alkane equivalents (Reference 31). Because of limited data, the effects of firing configuration on NMTOC emission factors could not be distinguished. As a result, all data were averaged collectively to develop a single average emission factor for pulverized coal units, cyclones, spreaders and overfeed stokers.

[d] References 36 - 38.

[e] No data found; use emission factor for pulverized coal-fired dry bottom boilers.

[f] Includes traveling grate, vibrating grate and chain grate stokers.

[g] No data found; use emission factor for circulating fluidized bed.

TABLE 1.1-12. (METRIC UNITS) EMISSION FACTORS FOR METHANE (CH_4), NON-METHANE TOTAL ORGANIC COMPOUNDS (NMTOC), AND NITROUS OXIDE (N_2O) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	Source Classification Codes (SCC)	CH_4[b]		NMTOC[b,c]		N_2O[d]	
		Emission Factor kg/Mg	Rating	Emission Factor kg/Mg	Rating	Emission Factor kg/Mg	Rating
Pulverized coal fired, dry bottom, wall fired	101002-02/22 102002-02/22 103002-06/22	0.02	B	0.04	B	.045	D
Pulverized coal fired, dry bottom, tangentially fired	101002-12/26 102002-12/26 103002-16/26	0.02	B	0.04	B	.015	D
Pulverized coal fired, wet bottom	101002-01/21 102002-01/21 103002-05/21	0.025	B	0.02	B	.045[e]	E
Cyclone furnace	101002-03/23 102002-03/23 103002-23	0.005	B	0.055	B	.045[e]	E
Spreader stoker	101002-04/24 102002-04/24 103002-09/24	0.03	B	0.025	B	.045[e]	E
Spreader stoker, with multiple cyclones, and reinjection	101002-04/24 102002-04/24 103002-09/24	0.03	B	0.025	B	.045[e]	E
Spreader stoker, with multiple cyclones, no reinjection	101002-04/24 102002-04/24 103002-09/24	0.03	B	0.025	B	.045[e]	E

TABLE 1.1-12. (METRIC UNITS) EMISSION FACTORS FOR METHANE (CH_4), NON-METHANE TOTAL ORGANIC COMPOUNDS (NMTOC), AND NITROUS OXIDE (N_2O) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a] (Continued)

Firing Configuration	Source Classification Codes (SCC)	CH_4[b]		NMTOC[b,c]		N_2O[d]	
		Emission Factor kg/Mg	Rating	Emission Factor kg/Mg	Rating	Emission Factor kg/Mg	Rating
Overfeed stoker[f]	101002-05/25 102002-05/10/25 103002-07/25	0.03	B	0.025	B	.045[e]	E
Overfeed stoker, with multiple cyclones[f]	101002-05/25 102002-05/10/25 103002-07/25	0.03	B	0.025	B	.045[e]	E
Underfeed stoker	102002-06 103002-08	0.4	B	.65	B	.045[e]	E
Underfeed stoker, with multiple cyclone	102002-06 103002-08	0.4	B	.65	B	.045[e]	E
Hand-fed units	103002-14	2.5	E	5	E	.045[e]	E
Fluidized bed combustor, bubbling bed	101002-17 102002-17 103002-17	0.03	E	0.025	E	2.75[g]	E
Fluidized bed combustor, circulating bed	101002-17 102002-17 103002-17	0.03	E	0.025	E	2.75	E

[a] Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired.

[b] Reference 35. Nominal values achievable under normal operating conditions; values one or two orders of magnitude higher can occur when combustion is not complete.

TABLE 1.1-12. (METRIC UNITS) EMISSION FACTORS FOR METHANE (CH_4), NON-METHANE TOTAL ORGANIC COMPOUNDS (NMTOC), AND NITROUS OXIDE (N_2O) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a] (Continued)

[c] Nonmethane total organic compounds are expressed as C2 to C16 alkane equivalents (Reference 31). Because of limited data, the effects of firing configuration on NMTOC emission factors could not be distinguished. As a result, all data were averaged collectively to develop a single average emission factor for pulverized coal units, cyclones, spreaders and overfeed stokers.

[d] References 36 - 38.

[e] No data found; use emission factor for pulverized coal-fired dry bottom boilers.

[f] Includes traveling grate, vibrating grate and chain grate stokers.

[g] No data found; use emission factor for circulating fluidized bed.

TABLE 1.1-13. (ENGLISH UNITS) EMISSION FACTORS FOR TRACE ELEMENTS, POLYCYCLIC ORGANIC MATTER (POM), AND FORMALDEHYDE (HCOH) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

(EMISSION FACTOR RATING: E)

Firing Configuration (Source Classification Codes)	Emission Factor, lb/10^{12} Btu									
	As	Be	Cd	Cr	Pb	Mn	Hg	Ni	POM	HCOH
Pulverized coal, configuration unknown (no SCC)	NA	NA	NA	1922	NA	NA	NA	NA	NA	112[b]
Pulverized coal, wet bottom (101002-01/21 102002-01/21 103002-05/21)	538	81	44-70	1020-	507	808-2980	16	840-1290	NA	NA
Pulverized coal, dry bottom (101002-02/22 102002-02/22 103002-06/22)	684	81	44.4	1250-2570	507	228-2980	16	1030-1290	2.08	NA
Pulverized coal, dry bottom, tangential (101002-12/26 102002-12/26 103002-16/26)	NA	NA	NA	NA	NA	NA	NA	NA	2.4	NA
Cyclone furnace (101002-03/23 102002-03/23 103002-23)	115	<81	28	212-1502	507	228-1300	16	174-1290	NA	NA

TABLE 1.1-13. (ENGLISH UNITS) EMISSION FACTORS FOR TRACE ELEMENTS, POLYCYCLIC ORGANIC MATTER (POM), AND FORMALDEHYDE (HCOH) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a] (Continued)

(EMISSION FACTOR RATING: E)

Firing Configuration (Source Classification Codes)	Emission Factor, lb/10^{12} Btu									
	As	Be	Cd	Cr	Pb	Mn	Hg	Ni	POM	HCOH
Stoker, configuration unknown (no SCC)	NA	73	NA	19-300	NA	2170	16	775-1290	NA	NA
Spreader stoker (101002-04/24 102002-04/24 103002-09/24)	264-542	NA	21-43	942-1570	507	NA	NA	NA	NA	221[c]
Overfeed stoker, traveling grate (101002-05/25 102002-05/10/25 103002-07/25)	542-1030	NA	43-82	NA	507	NA	NA	NA	NA	140[d]

[a] References 39 - 44. The emission factors in this table represent the ranges of factors reported in the literature. If only one data point was found, it is still reported in this table.

[b] Based on 2 units; 456 MWe and 133 million Btu/hr.

[c] Based on 1 unit; 59 million Btu/hr.

[d] Based on 1 unit; 52 million Btu/hr.

NA = Not available.

TABLE 1.1-14. (METRIC UNITS) EMISSION FACTORS FOR TRACE ELEMENTS, POLYCYCLIC ORGANIC MATTER (POM), AND FORMALDEHYDE (HCOH) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

(EMISSION FACTOR RATING: E)

Firing Configuration (Source Classification Codes)	Emission Factor, pg/J									
	As	Be	Cd	Cr	Pb	Mn	Hg	Ni	POM	HCOH
Pulverized coal, configuration unknown (no SCC)	NA	NA	NA	825	NA	NA	NA	NA	NA	48[b]
Pulverized coal, wet bottom (101002-01/21 102002-01/21 103002-05/21)	231	35	18-30	439-676	218[c]	348-1282	7	361-555	NA	NA
Pulverized coal, dry bottom (101002-02/22 102002-02/22 103002-06/22)	294	35	19	538-676	218[c]	98-1282	7	443-555	0.894	NA
Pulverized coal, dry bottom, tangential (101002-12/26 102002-12/26 103002-16/26)	NA	NA	NA	NA	NA	NA	NA	NA	1.03	NA
Cyclone furnace (101002-03/23 102002-03/23 103002-23)	49.5-133	<34.9	12	91.2-676	218[c]	98-5590	6.9	74.9-555	NA	NA

TABLE 1.1-14. (METRIC UNITS) EMISSION FACTORS FOR TRACE ELEMENTS, POLYCYCLIC ORGANIC MATTER (POM), AND FORMALDEHYDE (HCOH) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a] (Continued)

(EMISSION FACTOR RATING: E)

Firing Configuration (Source Classification Codes)	Emission Factor, pg/J									
	As	Be	Cd	Cr	Pb	Mn	Hg	Ni	POM	HCOH
Stoker, configuration unknown (no SCC)	NA	31.4	NA	8.1-675	NA	934	6.9	334-555	NA	NA
Spreader stoker (101002-04/24 102002-04/24 103002-09/24)	114-233	NA	9.0-18.5	404-674	218[c]	NA	NA	NA	NA	95[d]
Overfeed stoker, traveling grate (101002-05/25 102002-05/10/25 103002-07/25)	233-443	NA	19-35	NA	218[c]	NA	NA	NA	NA	60[e]

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[a] References 39 - 44. The emission factors in this table represent the ranges of factors reported in the literature. If only one data point was found, it is still reported in this table.

[b] Based on 2 units; 456 MWe and 39 MW.

[c] Based on 1 unit; 17 MW.

[d] Based on 1 unit; 15 MW.

NA = Not available.

TABLE 1.1-15. NEW SOURCE PERFORMANCE STANDARDS FOR FOSSIL FUEL-FIRED BOILERS

Standard/ Boiler Types/ Applicability Criteria	Boiler Size MW (Million Btu/hr)	Fuel or Boiler Type	PM ng/J (lb/MMBtu) [% reduction]	SO_2 ng/J (lb/MMBtu) [% reduction]	NO_x ng/J (lb/MMBtu) [% reduction]
Subpart D Industrial-Utility Commence construction after 8/17/71	>73 (>250)	Gas	43 (0.10)	NA	86 (0.20)
		Oil	43 (0.10)	340 (0.80)	129 (0.30)
		Bit./Subbit. Coal	43 (0.10)	520 (1.20)	300 (0.70)
Subpart Da Utility Commence construction after 9/18/78	>73 (>250)	Gas	13 (0.03 [NA]	340 (0.80) [90][a]	86 (020) [25]
		Oil	13 (0.03) [70]	340 (0.80) [90][a]	130 (0.30) [30]
		Bit./Subbit. Coal	13 (0.03) [99]	520 (1.20) [90][b]	260/210[c] (0.60/0.50) [65/65]
Subpart Db Industrial-Commercial-Institutional Commence construction after 6/19/84[m]	>29 (>100)	Gas	NA[d]	NA[d]	43[f] (0.10)
		Distillate Oil	43 (0.10)	340[n] (0.80) [90]	43[f] (0.10)
		Residual Oil	(Same as for distillate oil)	(Same as for distillate oil)	130[g] (0.30)
		Pulverized Bit./Subbit. Coal	22[e] (0.05)	520[e] (1.20) [90]	300 (0.70)
		Spreader Stoker & FBC	22[e] (0.05)	520[e] (1.20) [90]	260 (0.60)
		Mass-Feed Stoker	22[e] (0.05)	520[e] (1.20) [90]	210 (0.50)

TABLE 1.1-15. NEW SOURCE PERFORMANCE STANDARDS FOR FOSSIL FUEL-FIRED BOILERS (Continued)

Standard/ Boiler Types/ Applicability Criteria	Boiler Size MW (Million Btu/hr)	Fuel or Boiler Type	PM ng/J (lb/MMBtu) [% reduction]	SO_2 ng/J (lb/MMBtu) [% reduction]	NO_x ng/J (lb/MMBtu) [% reduction]
Subpart Dc	2.9 - 29 (10 - 100)	Gas	-[h]	-	-
Small Industrial-Commercial-Institutional		Oil	-[h,j]	215 (0.50)	-
Commence construction after 6/9/89		Bit. & Subbit. Coal	22[j,k] (0.05)	520[k] (1.20 [90]	-

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[a] Zero percent reduction when emissions are less than 86 ng/J (0.20 lb/MMBtu).

[b] 70 percent reduction when emissions are less than 260 ng/J (0.60 lb/MMBtu).

[c] The first number applies to bituminous coal and the second to subbituminous coal.

[d] Standard applies when gas is fired in combination with coal, see 40 CFR 60, Subpart Db.

[e] Standard is adjusted for fuel combinations and capacity factor limits, see 40 CFR 60, Subpart Db.

[f] For furnace heat release rates greater than 730,000 J/s-m^3 (70,000 Btu/hr-ft^3), the standard is 86 ng/J (0.20 lb/MMBtu).

[g] For furnace heat release rates greater than 730,000 J/s-m^3 (70,000 Btu/hr-ft^3), the standard is 170 ng/J (0.40 lb/MMBtu).

[h] Standard applies when gas or oil is fired in combination with coal, see 40 CFR 60, Subpart Dc.

[j] 20 percent capacity limit applies for heat input capacities of 8.7 Mwt (30 MMBtu/hr) or greater.

[k] Standard is adjusted for fuel combinations and capacity factor limits, see 40 CFR 60, Subpart Dc.

[m] Additional requirements apply to facilities which commenced construction, modification, or reconstruction after 6/19/84 but on or before 6/19/86 (see 40 Code of Federal Regulations Part 60, Subpart Db).

[n] 215 ng/J (0.50 lb/million Btu) limit (but no percent reduction requirement) applies if facilities combust only very low sulfur oil (< 0.5 wt. % sulfur).

FBC = Fluidized bed combustion.

TABLE 1-16. POST-COMBUSTION SO_2 CONTROLS FOR COAL COMBUSTION SOURCES

Control Technology	Process	Typical Control Efficiencies	Remarks
Wet scrubber	Lime/limestone	80-95+%	Applicable to high sulfur fuels, Wet sludge product
	Sodium carbonate	80-98%	1-125 MW (5-430 million Btu/hr) typical application range, High reagent costs
	Magnesium oxide/hydroxide	80-95+%	Can be regenerated
	Dual alkali	90-96%	Uses lime to regenerate sodium-based scrubbing liquor
Spray drying	Calcium hydroxide slurry, vaporizes in spray vessel	70-90%	Applicable to low and medium sulfur fuels, Produces dry product
Furnace injection	Dry calcium carbonate/hydrate injection in upper furnace cavity	25-50%	Commercialized in Europe, Several U.S. demonstration projects underway
Duct injection	Dry sorbent injection into duct, sometimes combined with water spray	25-50+%	Several R&D and demonstration projects underway, Not yet commercially available in the U.S.

TABLE 1-17. COMBUSTION MODIFICATION NO_x CONTROLS FOR STOKER COAL-FIRED INDUSTRIAL BOILERS

Control Technique	Description of Technique	Effectiveness of Control (% NO_x reduction)	Range of Application	Commercial Availability/R&D Status	Comments
Low Excess Air (LEA)	Reduction of air flow under stoker bed	5-25	Excess oxygen limited to 5-6% minimum	Available now but need R&D on lower limit of excess air	Danger of overheating grate, clinker formation, corrosion, and high CO emissions
Staged combustion (LEA + OFA)	Reduction of undergrate air flow and increase of overfire air flow	5-25	Excess oxygen limited to 5% minimum	Most stokers have OFA ports as smoke control devices but may need better sir flow control devices	Need research to determined optimum location and orientation of OFA ports for NO_x emission control. Overheating grate, corrosion, and high CO emission can occur if undergrate airflow is reduced below acceptable level as in LEA
Load Reduction (LR)	Reduction of coal and air feed to the stoker	Varies from 49% decrease to 25% increase in NO_x (average 15% decrease)	Has been used down to 25% load	Available	Only stokers that can reduce load without increasing excess air. Not a desirable technique because of loss in boiler efficiency
Reduced air preheat (RAP)	Reduction of combustion air temperature	8	Combustion air temperature reduced from 473K to 453K	Available now if boiler has combustion air heater	Not a desirable technique because of loss in boiler efficiency
Ammonia injection	Injection of NH_3 in convective section of boiler	40-40 (from gas- and oil-fired boiler experience)	Limited by furnace geometry. Feasible NH_3 injection rate limited to 1.5 NH_3/NO	Commercially offered but not yet demonstrated	Elaborate NH_3 injection, monitoring, and control system required. Possible load restrictions on boiler and air preheater fouling by ammonium bisulfate

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APPENDIX A

BACKGROUND FILE DATA SPOT CHECK SUMMARY

A review of the 1988 AP-42 version of Section 1.1 was accomplished by spot checking the quality of existing emission factors. This was sone by selecting primary data references from the background file, reviewing data quality sampling and analytical procedures, determining completeness, and verifyuing that the site emission factors in the background files could be reconstructed and were accurate. The results of these spot checks are summarized below; the reference numbers correspond to the 1988 AP-42 Section 1.1 reference list. Example spot check data are presented in Table A-1.

Reference 15

Contains six data p;oints. States in the paper that a sampling was only for comparative purposes and emission shouldn't be taken as absolute. Couldn't get all representative sampling locations due to obstruction or bends. Able to recreate "background" data values in histogram.

Reference 17

Checked "ALMA" site. Particulate tests done with bituminous and subbituminous coal. Appears two values were averaged and entered in histogram twice.

Sulfur dioxide data are questionable because sulfur analysis was taken from samples after the blower but HHV is baseed on "as received" coal. Need to eliminate some anomalous data points. Requires minor adjustment to SO_2 histograms. Chedked "ALMA" site. Appears that emission factor was calculated from parametric test midifying combustion air. Normal operation should be used for emission factor indicating a revision of the histogram and emission factor.

Reference 18

Sample train was an unproven Method 5 midified to collect HAPs from utility boilers. Sulfur dioxide based on sulfur retention in bottom ash was acceptable. Carbon monoxide data were not of good quality but hadd not been used in the previous AP-42 update. Particulate data (uncontrolled) were colleced in an improper sampling location with poor flow distribution and significant swirl because it was only two diameters from the inlet breaching. Data should be rated as poor quality but calculated emission factor (96A) is very close to the AP-42 published average. therefore, inclusion or exclusion is not significant.

Reference 23

Particulate measurements were nade using currently unapproved APCO and ASME methods. Correlation between tow methods was not good; test conditions, methodologies, and data collected were not well-documented (no raw data sheets). Data quality should be reated no better than C. Calculations were correct.

Reference 34

Appeared to be a well-codumented test report with good quality measurement methodology. the source operation, however, appeared to be somewhat variable with paramenter swings and intermittent periods of fly ash reinjection.

Reference 49

All dat for fireplaces. Several points burning coal in fireplaces. Discard data. New data available for hand-fed particulate.

Reference 50

No CH_4 data. Emission factor given as "estimate", but references 1966 data not representative of current protocols. Recommend not using current published emission factor.

Reference 58

No CH_4 data for handfed units. All data in this report are for larger utility boilers. Volatile organic compound data were acceptable.

TABLE A-1. SO_x EMISSIONS FROM PULVERIZED COAL, DRY BOTOM BOILERS

Boiler[a] Type	Fuel[b]	Ref.[c]	Site	Data Date	Run No.	Fuel				Operation	Controls	Sampling		Emission	Remarks
						HHV Btu/lb, Btu/g	S%	N%	Ash%	Load/Capacity	Description	Method	O_2	UC, C #/10^6 Btu	
FW	B	17	ALMA	75	6	10776	3.66	1.00	13.47	196/230 10^3 lb st/hr	Cold side ESP	Shell-Emery Vile	3. 5	5.957 34.9 (S) N/A	Uses S analysis from blower catch in report. This sample has been ground and dried substantially. HHV is taken from 1 as received ultimate analysis. Recalculate EF data point with ulimate analysis Nos. Previous average appears to be 335. New average would be 33.7(S) but 12.2% O_2 is very high and at low load, probably should drop. No sampling data sheets in this reference; they are contained in EPA60017-78-1-55b.
FW	B	17	ALMA	75	9	10776	3.66	1.00	13.47	57/230 10^3 lb st/hr	Cold side ESP	Shell-Emery Vile	4. 0	6.396 37.5 (S) N/A	
FW	B	17	ALMA	75	16	10776	3.66	1.00	13.47	60/230 10^3 lb st/hr	Cold side ESP	Shell-Emery Vile	12 .2	4.905 28.7 (S) N/A	
FW	S	17	ALMA	75	63	9336	0.81	0.73	17.26	131/230 10^3 lb st/hr	Cold side ESP	Shell-Emery Vile	2. 8	2.888 66.6 (S)	
FW	S	17	ALMA	75	64	9336	0.81	0.73	17.26	170/230 10^3 lb st/hr	Cold side ESP	Shell-Emery Vile	2. 9	1.440 33.2 (S)	
FW	S	17	ALMA	75	72	9336	0.81	0.73	17.26	101/230 10^3 lb st/hr	Cold side ESP	Shell-Emery Vile	6. 7	2.387 55 (S)	
FW	S	17	ALMA	75	73	9336	0.81	0.73	17.26	94/230 10^3 lb st/hr	Cold side ESP	Shell-Emery Vile	5. 0	1.799 41.5 (S)	
FW	S	17	ALMA	75	74	9336	0.81	0.73	17.26	90/230 10^3 lb st/hr	Cold side ESP	Shell-Emery Vile	6. 8	1.407 32.4 (S)	
FW	S	17	ALMA	75	75	9336	0.81	0.73	17.26	160/230 10^3 lb st/hr	Cold side ESP	Shell-Emery Vile	5. 8	1.367 31.5	

[a] FW-Front wall-fired pulverized coal boiler.

[b] B-Bituminous coal, S-Subbituminous coal.

[c] Reference numbers as cited in 1988 AP-42 Section 1.1.

TABLE A-2. NO_x EMISSIONS FROM PULVERIZED COAL, DRY BOTTOM BOILERS

Boiler Type	Fuel	Reference	Site	Data Date	Run No.	Fuel				Operation	Sampling		Emission	Remarks
						HHV Btu/lb, Btu/g	S%	N%	Ash%	Load/ Capacity	Method	O_2 %	UC, C # NO_2 / 10^3 Btu	
FW	B	17	ALMA	75	50	10776	3.66	1.09	13.47	200/230 10^3 lb st/hr	Teco 10	5.2	0.935	Presented in summary table = 20.15 + 15.5. Burner diffuser varied from normal, high O_2.
FW	B	17	ALMA	75	25	10776	3.66	1.09	13.47	200/230 10^3 lb st/hr		3.8	0.834	EF-17.97 Air Reg. as found.
FW	B	17	ALMA	75	42	10776	3.66	1.09	13.47	200/230 10^3 lb st/hr		2.9	0.785	EF-16.9 as found.
FW	B	17	ALMA	75	47	10776	3.66	1.09	13.47	200/230 10^3 lb st/hr		3.7	0.860	EF-18.64 Air Reg. as found.
FW	B	17	ALMA	75	49	10776	3.66	1.09	13.47	200/230 10^3 lb st/hr		1.8	0.481	EF-10.36 Burners varied, Low O^2 appears EF based on parametric O_2 tests No. 47, 49, 50-yielding 15.2 normal operation would be better described by "as found" No. 25, 42, 47-yielding EF-17.8.
FW	S	17	ALMA	75	57A	9336	0.81	0.73	17.26	170/230 10^3 lb st/hr		5.7	0.958	Chosen for summary table EF-17.89 old EFD value - 12 only high load test w/o modifying air.
FW	S	17	ALMA	75	57A	9336	0.81	0.73	17.26	170/230 10^3 lb st/hr	avgs in table 6.1-10		25.1% of fuel N	EF-12.04 but includes averages from all parametric tests including 25% and 50% loads.
FW	S	17	ALMA	75	68	9336	0.81	0.73	17.26	170/230 10^3 lb st/hr		2.7	0.469	CO high, 750 ppm, ignore EF-8.76.

[a] FW-front wall-fired pulverized coal boiler.
[b] B-Bituminous coal, S-Subbituminous coal.
[c] Reference numbers as cited in 1988 AP-42 Section 1.1.

TABLE A-3. PM EMISSIONS FROM PULVERIZED COAL, DRY BOTTOM BOILERS

Boiler Type	Fuel	Reference	Site	Data Date	Run No.	Fuel	Operation	Sampling		Emission	
						HHV Btu/lb, Btu/g	Load/ Capacity	Method	O_2 %	UC, C $\frac{\# NO_2}{10^3 Btu}$	Emission Factor
HO	B	15	Hartlee #3	72	1	12310	490/480	5	3.0	3.03	12.05A
HO	B	15	Hartlee #3	72	2	12589	488/480	5	3.7	3.20	9.72A
HO	B	15	Hartlee #3	72	3	12121	483/480	5	3.0	3.84	8.58A
HO	S	15	Four Corners #4	72	1	8821	755/800	5	3.4	7.65	21.92A
HO	S	15	Four Corners #4	72	2	8811	755/800	5	3.1	8.91	21.96A
FW	B	15	Widows Creek #6	72	1	11452	125/125	5	3.3	4.65	15.87A
FW	B	15	Widows Creek #6	72	2	11477	128/125	5	3.6	7.89	18.39A
T	B	15	Barry #3	73	1	12706	293/360	5	5.0	2.0	4.89A
T	B	15	Barry #3	73	2	12641	283/360	5	4.5	5.14	4.86A

FW = Front Wall.
HO = Horizontally opposed pulverized coal boiler.
T = tangentially fired pulverized coal boiler.
B = Bituminous coal, S- Subbituminous coal.
Reference numbers as cited in 1988 AP-42 Section 1.1.

APPENDIX B

CONVERSION FACTORS

TABLE B-1. CONVERSION FACTORS

Given	To Obtain	Multiply By
ppm	lb/MBtu	2.59×10^{-9} (MW)Fd $(20.9/20.9-O_2)$ Where Fd from 40 CFR Part 60 Appendix A M19 - usually 9820
lb/MBtu	lb/ton	HHV (as rec'd) = $2{,}000/10^6$
lb/ton	kg/Mg	0.5
HHV dry, mineral matter free	HHV (as rec'd)	(100-M-A)/100

MW = Molecular weight of pollutant.
O_2 = Oxygen concentration at sampling point in percent.
M = Moisture in as received coal sample in percent.
A = Ash in as received coal sample in percent.

APPENDIX C

MARKED-UP 1988 AP-42 SECTION 1.1

Significant changes to this section are marked as shown below.

1.1 BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION

1.1.1 General[1]

Coal is a complex combination of organic matter and inorganic ash formed over eons from successive layers of fallen vegetation. Coal types are broadly classified as anthracite, bituminous, subbituminous or lignite, and classification is made by heating values and amounts of fixed carbon, volatile matter, ash, sulfur and moisture. Formulas for differentiating coals based on these properties are given in Reference 1. See Sections 1.2 and 1.7 for discussions of anthracite and lignite, respectively.

and FBC

There are ~~two~~ three major coal combustion techniques, suspension firing and grate firing. Suspension firing is the primary combustion mechanism in pulverized coal and cyclone systems. Grate firing is the primary mechanism in underfeed and overfeed stokers. Both mechanisms are employed in spreader stokers.

Add FBC discussion

Add discussion of burner firing positions

Pulverized coal furnaces are used primarily in utility and large industrial boilers. In these systems, the coal is pulverized in a mill to the consistency of talcum powder (i. e., at least 70 percent of the particles will pass through a 200 mesh sieve). The pulverized coal is generally entrained in primary air before being fed through the burners to the combustion chamber, where it is fired in suspension. Pulverized coal furnaces are classified as either dry or wet bottom, depending on the ash removal technique. Dry bottom furnaces fire ~~coals~~ with high ash fusion temperatures, and dry ash removal techniques are used. In wet bottom (slag tap) furnaces, coals with low ash fusion temperatures are used, and molten ash is drained from the bottom of the furnace. Pulverized coal furnaces are further classified by the firing position of the burners, i. e., single (front or rear) wall, horizontally opposed, vertical, tangential (corner fired), turbo or arch fired.

Cyclone furnaces burn low ash fusion temperature coal crushed to a 4 mesh size. The coal is fed tangentially, with primary air, to a horizontal cylindrical combustion chamber. In this chamber, small coal particles are burned in suspension, while the larger particles are forced against the outer wall. Because of the high temperatures developed in the relatively small furnace volume, and because of the low fusion temperature of the coal ash, much of the ash forms a liquid slag which is drained from the bottom of the furnace through a slag tap opening. Cyclone furnaces are used mostly in utility and large industrial applications.

In spreader stokers, a flipping mechanism throws the coal into the furnace and onto a moving fuel bed. Combustion occurs partly in suspension and partly on the grate. Because of significant carbon in the particulate, flyash reinjection from mechanical collectors is commonly employed to improve boiler efficiency. Ash residue in the fuel bed is deposited in a receiving pit at the end of the grate.

D

Break out into separate tables

TABLE 1.1-1. EMISSION FACTORS FOR EXTERNAL BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	Particulate[b]		Sulfur Oxides[c]		Nitrogen Oxides[d]		Carbon Monoxide[e]		Nonmethane VOC[e,f]		Methane[e]	
	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton
Pulverized coal fired Dry bottom	5A	10A	19 ~~19.5~~S(17.5S)	38 ~~39~~S(35S)	10.5(7.5)[g]	21(15)[g]	0.3	0.6	0.04	0.07	0.015	0.03
Wet bottom	3.5A[h]	7A[h]	19 ~~19.5~~S(17.5S)	38 ~~39~~S(35S)	17	34	0.3	0.6	0.04	0.07	0.015	0.03
Cyclone furnace	1A[h]	2A[h]	19 ~~19.5~~S(17.5S)	38 ~~39~~S(35S)	18.5	37	0.3	0.6	0.04	0.07	0.015	0.03
Spreader stoker Uncontrolled	30[j]	60[j]	19 ~~19.5~~S(17.5S)	38 ~~39~~S(35S)	7	14	2.5	5	0.04	0.07	0.015	0.03
After multiple cyclone With fly ash reinjection from multiple cyclone	8.5	17	19 ~~19.5~~S(17.5S)	38 ~~39~~S(35S)	7	14	2.5	5	0.04	0.07	0.015	0.03
No fly ash reinjection from multiple cyclone	6	12	19 ~~19.5~~S(17.5S)	38 ~~39~~S(35S)	7	14	2.5	5	0.04	0.07	0.015	0.03
Overfeed stoker[k] Uncontrolled	8[m]	16[m]	19 ~~19.5~~S(17.5S)	38 ~~39~~S(35S)	3.25	7.5	3	6	0.04	0.07	0.015	0.03
After multiple cyclone	4.5[n]	9[n]	19 ~~19.5~~S(17.5S)	38 ~~39~~S(35S)	3.25	7.5	3	6	0.04	0.07	0.015	0.03
Underfeed stoker Uncontrolled	7.5[p]	15[p]	15.5S	31S	4.75	9.5	5.5	11	0.65	1.3	0.4	0.8
After multiple cyclone	5.5[n]	11[n]	15.5S	31S	4.75	9.5	5.5	11	0.65	1.3	0.4	0.8
Handfired units	7.5	15	15.5S	31S	1.5	3	45	90	5	10	4	8

Add SCCs ~~above~~ to all EF tables

Add:
- FBC/bubbling
- FBC/circulating

Add:
- PM-10
- CO_2
- CH_4, NMTOC, N_2O
- Trace elements
- POM
- Formaldehyde

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[a] Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal consumption as fired.

[b] Based on EPA Method 5 (front half catch) as described in Reference 12. Where particulate is expressed in terms of coal ash content, A, factor is determined by multiplying weight % ash content of coal (as fired) by the numerical value preceding the "A". For example, if coal having 8% ash is fired in a dry bottom unit, the particulate emission factor would be 5 x 8, or 40 kg/Mg (80 lb/ton). The "condensible" matter collected in back half catch of EPA Method 5 averages <5% of front half, or "filterable", catch for pulverized coal and cyclone furnaces; 10% for spreader stokers; 15% for other stokers; and 50% for handfired units (References 6, 19, 49).

[c] Expressed as SO_2, including SO_2, SO_3 and gaseous sulfates. Factors in parentheses should be used to estimate gaseous SO_x emissions for subbituminous coal. In all cases, "S" is weight % sulfur content of coal as fired. See Footnote b for example calculation. On average for bituminous coal, 97% of fuel sulfur is emitted as SO_2, and only about 0.7% of fuel sulfur is emitted as SO_3 and gaseous sulfate. An equally small percent of fuel sulfur is emitted as particulate sulfate (References 9, 13). Small quantities of sulfur are also retained in bottom ash. With subbituminous coal generally about 10% more fuel sulfur is retained in the bottom ash and particulate because of the more alkaline nature of the coal ash. Conversion to gaseous sulfate appears about the same as for bituminous coal.

[d] Expressed as NO_2. Generally, 95 - 99 volume % of nitrogen oxides present in combustion exhaust will be in the form of NO, the rest NO_2 (Reference 11). To express factors as NO, multiply by factor of 0.66. All factors represent emission at baseline operation (i.e., 60 - 110% load and no NO_x control measures, as discussed in text).

[e] Nominal values achieveable under normal operating conditions. Values one or two orders of magnitude higher can occur when combustion is not complete.

[f] Nonmethane volatile organic compounds (VOC), expressed as C_2 to C_{16} n-alkane equivalents (Reference 58). Because of limited data on NMVOC available to distinguish the effects of firing configuration, all data were averaged collectively to develop a single average for pulverized coal units, cyclones, spreaders and overfeed stokers.

[g] Parenthetic value is for tangentially fired boilers.

[h] Uncontrolled particulate emissions, when no fly ash reinjection is employed. When control device is installed, and collected fly ash is reinjected to boiler, particulate from boiler reaching control equipment can increase by up to a factor of two.

[j] Accounts for fly ash settling in an economizer, air heater or breeching upstream of control device or stack. (Particulate directly at boiler outlet typically will be twice this level.) Factor should be applied even when fly ash is reinjected to boiler from boiler, air heater or economizer dust hoppers.

[k] Includes traveling grate, vibrating grate and chain grate stokers.

[m] Accounts for fly ash settling in breeching or stack base. Particulate loadings directly at boiler outlet typically can be 50% higher.

[n] See text for discussion of apparently low multiple cyclone control efficiencies, regarding uncontrolled emissions.

[p] Accounts for fly ash settling in breeching downstream of boiler outlet.

- Add tables for SO_2 and NO_x control techniques

12

Break into separate tables

Add references and factor ratings to each table

TABLE 1.1-2. EMISSION FACTOR RATINGS* AND REFERENCES FOR BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION

Firing Configuration	Particulate		Sulfur Oxides		Nitrogen Oxides		Carbon Monoxide		Nonmethane VOC		Methane	
	Rating	Ref.	Rating	Ref.	Rating	Ref.	Rating	Ref.	Rating	Ref.	Rating	Ref.
Pulverized coal fired												
Dry bottom	A	14-25	A	9,16-19,21, 31-37,39, 41-46,51-55	A	11,14,16-17, 21,46,56	A	16,18-19,21 47,57	A	55,58	A	58
Wet bottom	D	14,16,26	A	"	C	14,16	A	"	A	58	A	"
Cyclone furnace	D	14,19,22, 27-29	A	"	B	11	A	"	A	"	A	"
Spreader stoker Uncontrolled	B	17,30-35	A	"	A	11,17,31-37 39-40,46	A	17,19,31-34, 36,47,51	A	"	A	"
After multiple cyclone With flyash reinjection from cyclone	B	14,32,36-38	A	"	A	"	A	"	A	"	A	"
No flyash reinjection from cyclone	A	17,31-35, 39,40,59	A	"	A	"	A	"	A	"	A	"
Overfeed stoker Uncontrolled	B	6,17,41-43, 45-47	A	"	A	11,17,19, 41-45	B	17,41-42,45, 47,51	A	"	A	"
After multiple cyclone	B	6,41,44-45	A	"	A	"	B	"	A	"	A	"
Underfeed stoker Uncontrolled	B	6,19,47-48	B	19,48	B	19,47-48	B	19,47-48	A	47,58	A	47,58
After multiple cyclone	C	6	B	"	B	"	B	"	A	"	A	"
Handfired units	D	49-50	D	"	D	50	D	50	D	50,58	D	50,58

Add FBC (bubbling bed and FBC (circulating bed

---

*These ratings, in the context of this Section, refer to the number of test data on which each emission factor is based. An "A" rating means the factor is based on tests at ten or more boilers, a "B" rating on six to nine test data, and a "C" rating on test data for two to five boilers. A "D" rating indicates the factor is based on only a single datum or extrapolated from a secondary reference. These ratings are not a measure of the scatter in the underlying test data. However, a higher rating will generally increase confidence that a given factor will better approximate the average emissions for a particular boiler category.

Add FBC discussion

In overfeed stokers, coal is fed onto a traveling or vibrating grate, and it burns on the fuel bed as it progresses through the furnace. Ash particles fall into an ash pit at the rear of the stoker. The term "overfeed" applies because the coal is fed onto the moving grate under an adjustable gate. Conversely, in "underfeed" stokers, coal is fed into the firing zone from underneath by mechanical rams or screw conveyers. The coal moves in a channel, known as a retort, from which it is forced upward, spilling over the top of each side to form and to feed the fuel bed. Combustion is completed by the time the bed reaches the side dump grates from which the ash is discharged to shallow pits. Underfeed stokers include single retort units and multiple retort units, the latter having several retorts side by side.

1.1.2 Emissions And Controls

Add discussion of small hand-fired boilers

The major pollutants of concern from external coal combustion are particulate, sulfur oxides and nitrogen oxides. Some unburnt combustibles, including numerous organic compounds and carbon monoxide, are generally emitted even under proper boiler operating conditions.

Particulate[2-4] - Particulate composition and emission levels are a complex function of firing configuration, boiler operation and coal properties. In pulverized coal systems, combustion is almost complete, and thus particulate largely comprises inorganic ash residue. In wet bottom pulverized coal units and cyclones, the quantity of ash leaving the boiler is less than in dry bottom units, since some of the ash liquifies, collects on the furnace walls, and drains from the furnace bottom as molten slag. To increase the fraction of ash drawn off as wet slag, and thus to reduce the flyash disposal problem, flyash may be reinjected from collection equipment into slag tap systems. Dry bottom unit ash may also be reinjected into wet bottom boilers for the same purpose.

Refer to NSPS summary

Because a mixture of fine and coarse coal particles is fired in spreader stokers, significant unburnt carbon can be present in the particulate. To improve boiler efficiency, flyash from collection devices (typically multiple cyclones) is sometimes reinjected into spreader stoker furnaces. This practice can dramatically increase the particulate loading at the boiler outlet and, to a lesser extent, at the mechanical collector outlet. Flyash can also be reinjected from the boiler, air heater and economizer dust hoppers. Flyash reinjection from these hoppers does not increase particulate loadings nearly so much as from multiple cyclones.[5]

Uncontrolled overfeed and underfeed stokers emit considerably less particulate than do pulverized coal units and spreader stokers, since combustion takes place in a relatively quiescent fuel bed. Flyash reinjection is not practiced in these kinds of stokers.

Other variables than firing configuration and flyash reinjection can affect emissions from stokers. Particulate loadings will often increase as load increases (especially as full load is approached) and with sudden load changes. Similarly, particulate can increase as the ash and fines contents increase. ("Fines", in this context, are coal particles smaller than about 1.6 millimeters, or one sixteenth inch, in diameter.) Conversely, particulate can be reduced significantly when overfire air pressures are increased.[5]

Add discussion of FBC impacts

The primary kinds of particulate control devices used for coal combustion include multiple cyclones, electrostatic precipitators, fabric filters (baghouses) and scrubbers. Some measure of control will even result from ash settling in boiler/air heater/economizer dust hoppers, large breeches and chimney bases. To the extent possible from the existing data base, the effects of such settling are reflected in the emission factors in Table 1.1-1.

Electrostatic precipitators (ESP) are the most common high efficiency control device used on pulverized coal and cyclone units, and they are being used increasingly on stokers. Generally, ESP collection efficiencies are a function of collection plate area per volumetric flow rate of flue gas through the device. Particulate control efficiencies of 99.9 weight percent are obtainable with ESPs. Fabric filters have recently seen increased use in both utility and industrial applications, generally effecting about 99.8 percent efficiency. An advantage of fabric filters is that they are unaffected by high flyash resistivities associated with low sulfur coals. ESPs located after air preheaters (i. e., cold side precipitators) may operate at significantly reduced efficiencies when low sulfur coal is fired. Scrubbers are also used to control particulate, although their primary use is to control sulfur oxides. One drawback of scrubbers is the high energy requirement to achieve control efficiencies comparable to those of ESPs and baghouses.[2]

Mechanical collectors, generally multiple cyclones, are the primary means of control on many stokers and are sometimes installed upsteam of high efficiency control devices in order to reduce the ash collection burden. Depending on application and design, multiple cyclone efficiencies can vary tremendously. Where cyclone design flow rates are not attained (which is common with underfeed and overfeed stokers), these devices may be only marginally effective and may prove little better in reducing particulate than large breeching. Conversely, well designed multiple cyclones, operating at the required flow rates, can achieve collection efficiencies on spreader stokers and overfeed stokers of 90 to 95 percent. Even higher collection efficiencies are obtainable on spreader stokers with reinjected flyash, because of the larger particle sizes and increased particulate loading reaching the controls.[5-6]

Sulfur Oxides[7-9] - Gaseous sulfur oxides from external coal combustion are largely sulfur dioxide (SO_2) and much less quantity of sulfur trioxide (SO_3) and gaseous sulfates. These compounds form as the organic and pyritic sulfur in the coal is oxidized during the combustion process. On average, 98 percent of the sulfur present in bituminous coal will be emitted as gaseous sulfur oxides, whereas somewhat less will be emitted when subbituminous coal is fired. The more alkaline nature of the ash in some subbituminous coal causes some of the sulfur to react to form various sulfate salts that are retained in the boiler or in the flyash. Generally, boiler size, firing configuration and boiler operations have little effect on the percent conversion of fuel sulfur to sulfur oxides.

Several techniques are used to reduce sulfur oxides from coal combustion. One way is to switch to lower sulfur coals, since sulfur oxide emissions are proportional to the sulfur content of the coal. This alternative may not be possible where lower sulfur coal is not readily available or where a different grade of coal can not be satisfactorily fired. In some cases, various cleaning processes may be employed to reduce the fuel sulfur content. Physical coal cleaning removes mineral sulfur such as pyrite but is not effective in removing

Add discussion of dry and wet sorbent injection technologies.

organic sulfur. Chemical cleaning and solvent refining processes are being developed to remove organic sulfur.

Many flue gas desulfurization techniques can remove sulfur oxides formed during combustion. Flue gases can be treated through wet, semidry or dry desulfurization processes of either the throwaway type, in which all waste streams are discarded, or the recovery (regenerable) type, in which the SO_x absorbent is regenerated and reused. To date, wet systems are the most commonly applied. Wet systems generally use alkali slurries as the SO_x absorbent medium and can be designed to remove well in excess of 90 percent of the incoming SO_x. Particulate reduction of up to 99 percent is also possible with wet scrubbers, but flyash is often collected by upsteam ESPs or baghouses, to avoid erosion of the desulfurization equipment and possible interference with the process reactions.[7] Also, the volume of scrubber sludge is reduced with separate flyash removal, and contamination of the reagents and byproducts is prevented. References 7 and 8 give more details on scrubbing and other SO_x removal techniques.

Refer to NSPS summary

Add discussion of variables influencing NO_x formation.

Nitrogen Oxides[10-11] - Nitrogen oxides (NO_x) emissions from coal combustion are primarily nitrogen oxide (NO). Only a few volume percent are nitrogen dioxide (NO_2). NO results from thermal fixation of atmospheric nitrogen in the combustion flame and from oxidation of nitrogen bound in the coal. Typically, only 20 to 60 percent of the fuel nitrogen is converted to nitrogen oxides. Bituminous and subbituminous coals usually contain from 0.5 to 2 weight percent nitrogen, present mainly in aromatic ring structures. Fuel nitrogen can account for up to 80 percent of total NO_x from coal combustion.

A number of combustion modifications can be made to reduce NO_x emissions from boilers. Low excess air (LEA) firing is the most widespread control modification, because it can be practiced in both old and new units and in all sizes of boilers. LEA firing is easy to implement and has the added advantage of increasing fuel use efficiency. LEA firing is generally effective only above 20 percent excess air for pulverized coal units and above 30 percent excess air for stokers. Below these levels, the NO_x reduction from decreased O_2 availability is offset by increased NO_x because of increased flame temperature. Another NO_x reduction technique is simply to switch to a coal having a lower nitrogen content, although many boilers may not properly fire coals of different properties.

Off-stoichiometric (staged) combustion is also an effective means of controlling NO_x from coal fired equipment. This can be achieved by using overfire air or low NO_x burners designed to stage combustion in the flame zone. Other NO_x reduction techniques include flue gas recirculation, load reduction, and steam or water injection. However, these techniques are not very effective for use on coal fired equipment because of the fuel nitrogen effect. Ammonia injection is another technique which can be used, but it is costly. The net reduction of NO_x from any of these techniques or combinations thereof varies considerably with boiler type, coal properties and existing operating practices. Typical reductions will range from 10 to 60 percent. References 10 and 60 should be consulted for a detailed discussion of each of these NO_x reduction techniques. To date, flue gas treatment is not used to reduce nitrogen oxide emissions because of its higher cost.

Refer to NSPS summary

Add reference to gas reburning in cyclone boilers

Split out CO and VOC discussions into separate subsections

Volatile Organic Compounds And Carbon Monoxide - Volatile organic compounds (VOC) and carbon monoxide (CO) are unburnt gaseous combustibles which generally are emitted in quite small amounts. However, during startups, temporary upsets or other conditions preventing complete combustion, unburnt combustible emissions may increase dramatically. VOC and CO emissions per unit of fuel fired are normally lower from pulverized coal or cyclone furnaces than from smaller stokers and handfired units where operating conditions are not so well controlled. Measures used for NO_x control can increase CO emissions, so to reduce the risk of explosion, such measures are applied only to the point at which CO in the flue gas reaches a maximum of about 200 parts per million. Other than maintaining proper combustion conditions, control measures are not applied to control VOC and CO.

Emission Factors And References - Emission factors for several pollutants are presented in Table 1.1-1, and factor ratings and references are presented in Table 1.1-2. The factors for uncontrolled underfeed stokers and hand fired units also may be applied to hot air furnaces. Tables 1.1-3 through 1.1-8 present cumulative size distribution data and size specific emission factors for particulate emissions from the combustion sources discussed above. Uncontrolled and controlled size specific emission factors are presented in Figures 1.1-1 through 1.1-6.

Add discussion of
- Baseline vs. controlled emissions
- PBC emissions

Add discussion of:
- TOC
- POM/PAH/PNA
- Formaldehyde
- Trace elements
- Fugitive emissions

Add columns for ratings

TABLE 1.1-3. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR DRY BOTTOM BOILERS BURNING PULVERIZED BITUMINOUS COAL[a]

EMISSION FACTOR RATING: C (uncontrolled)
D (scrubber and ESP controlled
E (multiple cyclone and baghouse)

Particle size[b] (um)	Cumulative mass % ≤ stated size					Cumulative emission factor[c] [kg/Mg (lb/ton) coal, as fired]				
	Uncontrolled	Controlled				Uncontrolled	Controlled[d]			
		Multiple cyclone	Scrubber	ESP	Baghouse		Multiple cyclone	Scrubber	ESP	Baghouse
15	32	54	81	79	97	1.6A (3.2A)	0.54A (1.08A)	0.24A (0.48A)	0.032A (0.06A)	0.010A (0.02A)
10	23	29	71	67	92	1.15A (2.3A)	0.29A (0.58A)	0.21A (0.42A)	0.027A (0.05A)	0.009A (0.02A)
6	17	14	62	50	77	0.85A (1.7A)	0.14A (0.28A)	0.19A (0.38A)	0.020A (0.04A)	0.008A (0.02A)
2.5	6	3	51	29	53	0.30A (0.6A)	0.03A (0.06A)	0.15A (0.3A)	0.012A (0.02A)	0.005A (0.01A)
1.25	2	1	35	17	31	0.10A (0.2A)	0.01A (0.02A)	0.11A (0.22A)	0.007A (0.01A)	0.003A (0.006A)
1.00	2	1	31	14	25	0.10A (0.2A)	0.01A (0.02A)	0.09A (0.18A)	0.006A (0.01A)	0.003A (0.006A)
0.625	1	1	20	12	14	0.05A (0.10)	0.01A (0.02A)	0.06A (0.12A)	0.005A (0.01A)	0.001A (0.002A)
TOTAL	100	100	100	100	100	5A (10A)	1A (2A)	0.3A (0.6A)	0.04A (0.08A)	0.01A (0.02A)

[a] Reference 61. ESP = electrostatic precipitator.
[b] Expressed as aerodynamic equivalent diameter.
[c] A = coal ash weight %, as fired.
[d] Estimated control efficiency for multiple cyclone, 80%; scrubber, 94%; ESP, 99.2%; baghouse, 99.8%.

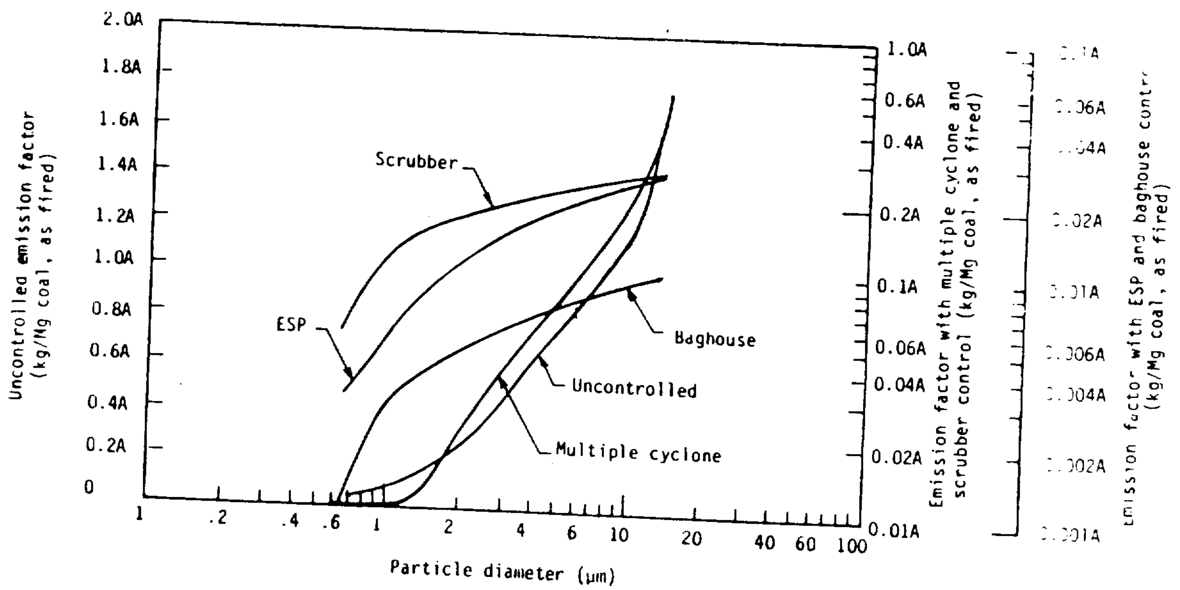

Figure 1.1-1. Cumulative size specific emission factors for dry bottom boilers burning pulverized bituminous coal.

TABLE 1.1-4. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR WET BOTTOM BOILERS BURNING PULVERIZED BITUMINOUS COAL[a]

EMISSION FACTOR RATING: E

Particle size[b] (μm)	Cumulative mass % ≤ stated size			Cumulative emission factor[c] [kg/Mg (lb/ton) coal, as fired]		
	Uncontrolled	Controlled		Uncontrolled	Controlled[d]	
		Multiple cyclone	ESP		Multiple cyclone	ESP
15	40	99	83	1.4A (2.8A)	0.69A (1.38A)	0.023A (0.046A)
10	37	93	75	1.30A (2.6A)	0.65A (1.3A)	0.021A (0.042A)
6	33	84	63	1.16A (2.32A)	0.59A (1.18A)	0.018A (0.036A)
2.5	21	61	40	0.74A (1.48A)	0.43A (0.86A)	0.011A (0.022A)
1.25	6	31	17	0.21A (0.42A)	0.22A (0.44A)	0.005A (0.01A)
1.00	4	19	8	0.14A (0.28A)	0.13A (0.26A)	0.002A (0.004A)
0.625	2	e	e	0.07A (0.14A)	e	e
TOTAL	100	100	100	3.5A (7.0A)	0.7A (1.4A)	0.028A (0.056A)

[a] Reference 61. ESP = electrostatic precipitator.
[b] Expressed as aerodynamic equivalent diameter.
[c] A = coal ash weight %, as fired.
[d] Estimated control efficiency for multiple cyclone, 80%; ESP, 99.2%.
[e] Insufficient data.

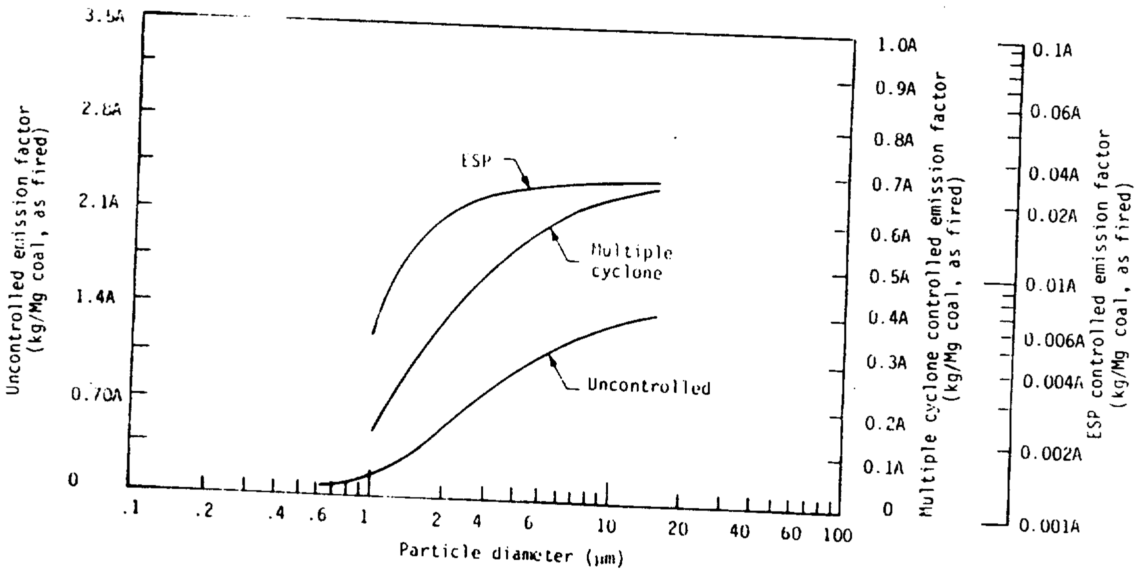

Figure 1.1-2. Cumulative size specific emission factors for wet bottom boilers burning pulverized bituminous coal

TABLE 1.1-5. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR CYCLONE FURNACES BURNING BITUMINOUS COAL[a]

EMISSION FACTOR RATING: E

Particle size[b] (µm)	Cumulative mass % ≤ stated size			Cumulative emission factor[c] [kg/Mg (lb/ton) coal, as fired]		
	Uncontrolled	Controlled		Uncontrolled	Controlled[e]	
		Scrubber	ESP		Scrubber	ESP
15	33	95	90	0.33A (0.66A)	0.057A (0.114A)	0.0064A (0.013A)
10	13	94	68	0.13A (0.26A)	0.056A (0.112A)	0.0054A (0.011A)
6	8	93	56	0.08A (0.16A)	0.056A (0.112A)	0.0045A (0.009A)
2.5	0	92	36	0 (0)	0.055A (0.11A)	0.0029A (0.006A)
1.25	0	85	22	0 (0)	0.051A (0.10A)	0.0016A (0.004A)
1.00	0	82	17	0 (0)	0.049A (0.10A)	0.0014A (0.003A)
0.625	0	d	d	0 (0)	d	d
TOTAL	100	100	100	1A (2A)	0.06A (0.12A)	0.008A (0.016A)

[a] Reference 61. ESP = electrostatic precipitator.
[b] Expressed as aerodynamic equivalent diameter.
[c] A = coal ash weight %, as fired.
[d] Insufficient data.
[e] Estimated control efficiency for scrubber, 94%; ESP, 99.2%.

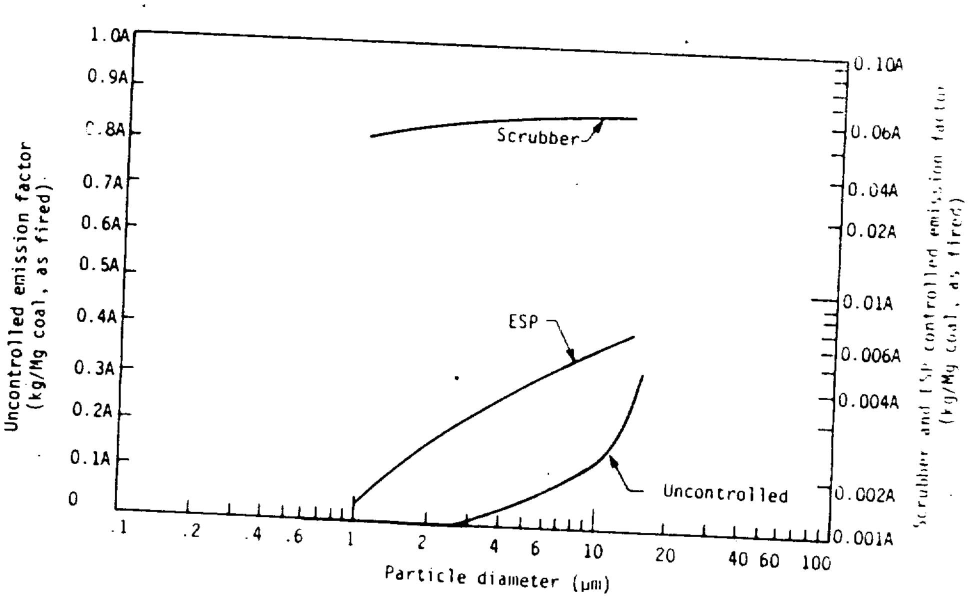

Figure 1.1-3. Cumulative size specific emission factors for cyclone furnaces burning bituminous coal

Add colums for ratings

TABLE 1.1-6. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR SPREADER STOKERS BURNING BITUMINOUS COAL[a]

EMISSION FACTOR RATING: C (uncontrolled and controlled for multiple cyclone without flyash reinjection, and with baghouse)
E (multiple cyclone controlled with flyash reinjection, and ESP controlled)

Particle size[b] (μm)	Cumulative mass % ≤ stated size					Cumulative emission factor [kg/Mg (lb/ton) coal, as fired]				
	Uncontrolled	Controlled				Uncontrolled	Controlled			
		Multiple cyclone[c]	Multiple cyclone[d]	ESP	Baghouse		Multiple cyclone[c]	Multiple cyclone[d]	ESP	Baghouse
15	28	86	74	97	72	8.4 (16.8)	7.3 (14.6)	4.4 (8.8)	0.23 (0.46)	0.043 (0.086)
10	20	73	65	90	60	6.0 (12.0)	6.2 (12.4)	3.9 (7.8)	0.22 (0.44)	0.036 (0.072)
6	14	51	52	82	46	4.2 (8.4)	4.3 (8.6)	3.1 (6.2)	0.20 (0.40)	0.028 (0.056)
2.5	7	8	27	61	26	2.1 (4.2)	0.7 (1.4)	1.6 (3.2)	0.15 (0.30)	0.016 (0.032)
1.25	5	2	16	46	18	1.5 (3.0)	0.2 (0.4)	1.0 (2.0)	0.11 (0.22)	0.011 (0.022)
1.00	5	2	14	41	15	1.5 (3.0)	0.2 (0.4)	0.8 (1.6)	0.10 (0.20)	0.009 (0.018)
0.625	4	1	9	e	7	1.2 (2.4)	0.1 (0.2)	0.5 (1.0)	e	0.004 (0.008)
TOTAL	100	100	100	100	100	30.0 (60.0)	8.5 (17.0)	6.0 (12.0)	0.24[f] (0.48)	0.06[f] (0.12)

[a] Reference 61. ESP = electrostatic precipitator.
[b] Expressed as aerodynamic equivalent diameter.
[c] With flyash reinjection.
[d] Without flyash reinjection.
[e] Insufficient data.
[f] Estimated control efficiency for ESP, 99.2%; baghouse, 99.8%.

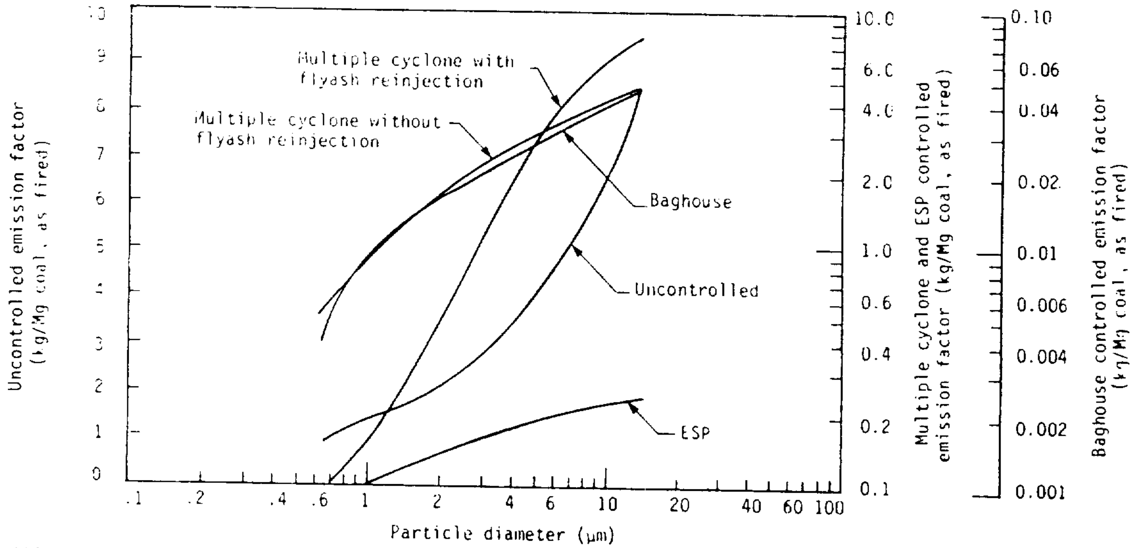

Figure 1.1-4. Cumulative size specific emission factors for spreader stokers burning bituminous coal

Add colums for ratings

TABLE 1.1-7. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR OVERFEED STOKERS BURNING BITUMINOUS COAL[a]

EMISSION FACTOR RATING: C (uncontrolled)
E (multiple cyclone controlled)

Particle size[b] (µm)	Cumulative mass % ≤ stated size		Cumulative emission factor [kg/Mg (lb/ton) coal, as fired]	
	Uncontrolled	Multiple cyclone controlled	Uncontrolled	Multiple cyclone controlled[d]
15	49	60	3.9 (7.8)	2.7 (5.4)
10	37	55	3.0 (6.0)	2.5 (5.0)
6	24	49	1.9 (3.8)	2.2 (4.4)
2.5	14	43	1.1 (2.2)	1.9 (3.8)
1.25	13	39	1.0 (2.0)	1.8 (3.6)
1.00	12	39	1.0 (2.0)	1.8 (3.6)
0.625	c	16	c	0.7 (1.4)
TOTAL	100	100	8.0 (16.0)	4.5 (9.0)

[a] Reference 61.
[b] Expressed as aerodynamic equivalent diameter.
[c] Insufficient data.
[d] Estimated control efficiency for multiple cyclone, 80%.

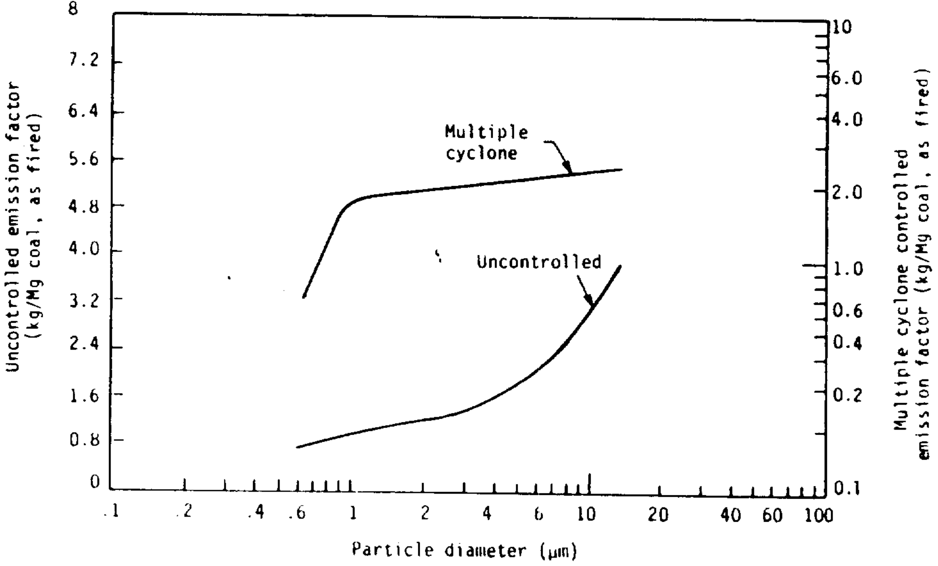

Figure 1.1-5. Cumulative size specific emission factors for overfeed stokers burning bituminous coal

TABLE 1.1-8. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR UNDERFEED STOKERS BURNING BITUMINOUS COAL[a]

EMISSION FACTOR RATING: C

Particle size[b] (µm)	Cumulative mass % ≤ stated size	Uncontrolled cumulative emission factor[c] [kg/Mg (lb/ton) coal, as fired]
15	50	3.8 (7.6)
10	41	3.1 (6.2)
6	32	2.4 (4.8)
2.5	25	1.9 (3.8)
1.25	22	1.7 (3.4)
1.00	21	1.6 (3.2)
0.625	18	1.4 (2.7)
TOTAL	100	7.5 (15.0)

[a] Reference 61.

[b] Expressed as aerodynamic equivalent diameter.

[c] May also be used for uncontrolled hand fired units.

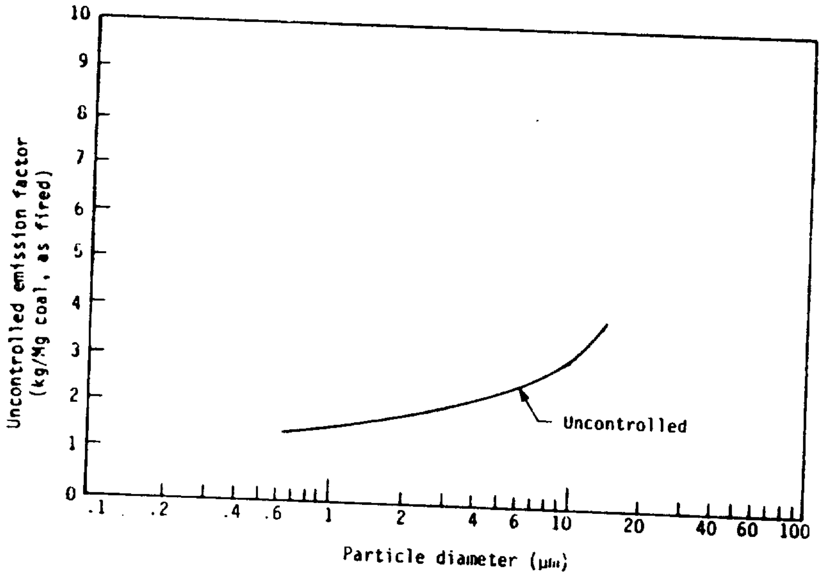

Figure 1.1-6. Cumulative size specific emission factors for underfeed stokers burning bituminous coal.

Add and delete references as required

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