1.1 Bituminous And Subbituminous Coal Combustion

1.1.1 General

Coal is a complex combination of organic matter and inorganic mineral matter formed over eons from successive layers of fallen vegetation. Coals are classified by rank according to their progressive alteration in the natural metamorphosis from lignite to anthracite. Coal rank depends on the volatile matter, fixed carbon, inherent moisture, and oxygen, although no single parameter defines a rank. Typically, coal rank increases as the amount of fixed carbon increases and the amount of volatile matter and moisture decreases.

Bituminous coals are by far the largest group and are characterized as having lower fixed carbon and higher volatile matter than anthracite. The key distinguishing characteristics of bituminous coal are its relative volatile matter and sulfur content as well as its slagging and agglomerating characteristics. Subbituminous coals have higher moisture and volatile matter and lower sulfur content than bituminous coals and may be used as an alternative fuel in some boilers originally designed to burn bituminous coals.[1] Generally, bituminous coals have heating values of 10,500 to 14,000 British thermal units per pound (Btu/lb) on a wet, mineral-matter-free basis.[2] As mined, the heating values of typical U.S. bituminous coals range from 10,720 to 14,730 Btu/lb.[3] The heating values of subbituminous coals range from 8,300 to 11,500 Btu/lb on a wet, mineral-matter-free basis[2], and from 9,420 to 10,130 Btu/lb on an as-mined basis.[3] Formulae and tables for classifying coals are given in Reference 2.

1.1.2 Firing Practices[4]

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). The most common heat transfer method for coal-fired boilers is the watertube method 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 include pulverized coal, cyclone, stoker, fluidized bed, and handfed units. In stoker-fired systems and most handfed units, the fuel is primarily burned on the bottom of the furnace or on a grate. In a fluidized bed combustor (FBC), the coal is introduced to a bed of either sorbent or inert material (usually sand) which is fluidized by an upward flow of air. In pulverized coal-fired (PC-fired) boilers, the fuel is pulverized to the consistency of talcum powder (i.e., at least 70 percent of the particles will pass through a 200-mesh sieve) 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 (also referred to as slag tap furnaces), depending on whether the ash is removed in a 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.

Depending upon the type and location of the burners and the direction of coal injection into the furnace, PC-fired boilers can also be classified into two different firing types, including wall, and tangential. 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.

Tangential (or corner-fired) boilers have burners mounted in the corners of the furnace. The fuel and air are injected tangent to an imaginary circle in the plane of the boilers. Cyclone furnaces are often categorized as PC-fired systems even though the coal is crushed to a maximum size of about 4-mesh. The coal is fed tangentially, with primary air, into a horizonal 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.

Stoker-fired systems account for the vast majority of coal-fired watertube boilers for industrial, commercial, and institutional applications. Most packaged stoker units designed for coal firing are small and can be divided into three groups: underfeed stokers, overfeed stokers, and spreader stokers. Underfeed stokers are generally either the horizontal-feed, side-ash-discharge type or the gravity-feed, rear-ash-discharge type. An overfeed stoker uses a moving grate assembly in which coal is fed from a hopper onto a continuous grate which conveys the fuel into the furnace. In a spreader stoker, 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.

FBCs, 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. 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 pounds per square inch gauge). At this time, atmospheric FBCs are more advanced (or commercialized) than pressurized FBCs. The two principal types of atmospheric FBCs are bubbling bed and circulating bed. The feature that varies most fundamentally between these two types is the fluidization velocity. In the bubbling bed design, the fluidation velocity is relatively low in order to minimize solids carryover or elutriation from the combustor. Circulating FBCs, however, employ high fluidization velocities 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.

Small, coal-fired boilers and furnaces are found in industrial, commercial, institutional, or residential applications and are sometimes capable of being hand-fired. 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 handfed configuration. The HRT boilers are generally fired with gas or oil instead of coal. The boiler and furnace are contained in the same shell in a Scotch or shell boiler. Vertical firetube boilers are typically small singlepass units in which the firetubes come straight up from the water-cooled combustion chamber located at the bottom of the unit. 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 and employ mechanical stokers or are hand-fired.

1.1.3 Emissions[4]

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. The major pollutants of concern from bituminous and subbituminous coal combustion are particulate matter (PM), sulfur oxides (SO_x), and nitrogen oxides (NO_x). Some unburned combustibles, including carbon monoxide (CO) and numerous organic compounds, are generally emitted even under proper boiler operating conditions.

1.1.3.1 Particulate Matter[4] -

PM composition and emission levels are a complex function of boiler firing configuration, boiler operation, pollution control equipment, and coal properties. Uncontrolled PM emissions from coal-fired boilers include the ash from combustion of the fuel as well as unburned carbon resulting from incomplete combustion. In pulverized coal systems, combustion is almost complete; thus, the emitted PM is primarily composed of inorganic ash residues.

Coal ash may either settle out in the boiler (bottom ash) or entrained in the flue gas (fly ash). The distribution of ash between the bottom ash and fly ash fractions directly affects the PM emission rate and depends on the boiler firing method and furnace type (wet or dry bottom). Boiler load also affects the PM emissions as 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 also a source of intermittent PM emissions in coal-fired boilers. Steam soot and air soot blowing is periodically used to dislodge ash from heat transfer surfaces in the furnace, convective section, economizer, and air preheater.

Particulate emissions may be categorized as either filterable or condensable. 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. Vapors and particles less than 0.3 microns pass through the filter. Condensable particulate matter is material that is emitted in the vapor state which later condenses to form homogeneous and/or heterogeneous aerosol particles. The condensable particulate emitted from boilers fueled on coal or oil is primarily inorganic in nature.

1.1.3.2 Sulfur Oxides[4] -

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. These compounds form as the organic and pyritic sulfur in the coal are 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.

1.1.3.3 Nitrogen Oxides[5-6] -

NO_x emissions from coal combustion are primarily nitric oxide (NO), with only a few volume percent as nitrogen dioxide (NO_2). Nitrous oxide (N_2O) is also emitted at a few parts per million. NO_x 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 nitrogen concentration in the flame, the square root of oxygen concentration in the flame, and the gas residence time.[7] Cyclone boilers typically have high conversion of nitrogen to NO_x 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.

1.1.3.4 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 is 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 typically 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. Combustion modification techniques and equipment used to reduce NO_x can increase CO emissions if the modification techniques are improperly implemented or if the equipment is improperly designed.

1.1.3.5 Organic Compounds -

As with CO emissions, the rate at which organic compounds are emitted depends on the combustion efficiency of the boiler. Therefore, combustion modifications that change combustion residence time, temperature, or turbulence may increase or decrease concentrations of organic compounds in the flue gas.

Organic emissions include volatile, semivolatile, and condensable organic compounds either present in the coal or formed as a product of incomplete combustion (PIC). Organic emissions are primarily characterized by the criteria pollutant class of unburned vapor-phase hydrocarbons. These emissions include alkanes, alkenes, aldehydes, alcohols, and substituted benzenes (e.g., benzene, toluene, xylene, and ethyl benzene). [8,9]

Emissions of polychlorinated dibenzo-p-dioxins and polychlorinated dibenzofurans (PCDD/PCDF) also result from the combustion of coal. Of primary interest environmentally are tetrachloro- through octachloro- dioxins and furans. Dioxin and furan emissions are influenced by the extent of destruction of organics during combustion and through reactions in the air pollution control equipment. The formation of PCDD/PCDF in air pollution control equipment is primarily dependent on flue gas temperature, with maximum potential for formation occurring at flue gas temperatures of 450 degrees to 650 degrees Fahrenheit.

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). Polycyclic organic matter is more prevalent in the emissions from coal combustion because of the more complex structure of coal.

1.1.3.6 Trace Metals-

Trace metals are also emitted during coal combustion. The quantity of any given metal emitted, in general, depends on:

-       the physical and chemical properties of the metal itself;

-       the concentration of the metal in the coal;

-       the combustion conditions; and

-       the type of particulate control device used, and its collection efficiency as a function of particle size.

Some trace metals become concentrated in certain particle streams from a combustor (e.g., bottom ash, collector ash, and flue gas particulate) while others do not.[10] Various classification schemes have been developed to describe this partitioning behavior.[10-12] These classification schemes generally distinguish between:

-       Class 1: Elements that are approximately equally concentrated in the fly ash and bottom ash, or show little or no small particle enrichment. Examples include manganese, beryllium, cobalt, and chromium.

-       Class 2: Elements that are enriched in fly ash relative to bottom ash, or show increasing enrichment with decreasing particle size. Examples include arsenic, cadmium, lead, and antimony.

-       Class 3: Elements which are emitted in the gas phase (primarily mercury and, in some cases, selenium).

Control of Class 1 metals is directly related to control of total particulate matter emissions, while control of Class 2 metals depends on collection of fine particulate. Because of variability in particulate control device efficiencies, emission rates of these metals can vary substantially. Because of the volatility of Class 3 metals, particulate controls have only a limited impact on emissions of these metals.

1.1.3.7 Acid Gases-
In addition to SO_2 and NO_x emissions, combustion of coal also results in emissions of chlorine and fluorine, primarily in the form of hydrogen chloride (HCl) and hydrogen fluoride (HF). Lesser amounts of chlorine gas and fluorine gas are also emitted. A portion of the chlorine and fluorine in the fuel may be absorbed onto fly ash or bottom ash. Both HCl and HF are water soluble and are readily controlled by acid gas scrubbing systems.

1.1.3.8 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.

1.1.3.9 Greenhouse Gases[13-18] -
Carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions are all produced during coal combustion. Nearly all of the fuel carbon (99 percent) in coal is converted to CO_2 during the combustion process. This conversion is relatively independent of firing configuration. Although the formation of CO acts to reduce CO_2 emissions, the amount of CO produced is insignificant compared to the amount of CO_2 produced. The majority of the fuel carbon not converted to CO_2 is entrained in bottom ash. CO_2 emissions for coal vary with carbon content, and carbon content varies between the classes of bituminous and subbituminous coals. Further, carbon content also varies within each class of coal based on the geographical location of the mine.

Formation of N_2O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. Formation of N_2O is minimized when combustion temperatures are kept high (above 1575°F) and excess air is kept to a minimum (less than 1 percent). N_2O emissions for coal combustion are not significant except for fluidized bed combustion (FBC), where the emissions are typically two orders of magnitude higher than all other types of coal firing due to areas of low temperature combustion in the fuel bed.

Methane emissions vary with the type of coal being fired and firing configuration, but are highest during periods of incomplete combustion, such as the start-up or shut-down cycle for coal-fired boilers. Typically, conditions that favor formation of N_2O also favor emissions of CH_4.

1.1.4 Controls[4]

Control techniques for criteria pollutants from coal combustion may be classified into three broad categories: fuel treatment/substitution, combustion modification, and postcombustion control. Emissions of noncriteria pollutants such as particulate phase metals have been controlled through the use of post combustion controls designed for criteria pollutants. Fuel treatment primarily reduces SO_2 and includes coal cleaning using physical, chemical, or biological processes; fuel substitution involves burning a cleaner fuel. Combustion modification includes any physical or operational change in the furnace or boiler and is applied primarily for NO_x control purposes, although for small units, some reduction in PM emissions may be available through improved combustion practice. Postcombustion control employs a device after the combustion of the fuel and is applied to control emissions of PM, SO_2, and NO_x for coal combustion.

1.1.4.1 Particulate Matter Control[4] -
The principal control techniques for PM are combustion modifications (applicable to small stoker-fired boilers) and postcombustion methods (applicable to most boiler types and sizes). Uncontrolled PM emissions from small stoker-fired and hand-feed combustion sources can be minimized by employing good combustion practices such as operating within the recommended load ranges, controlling the rate of load changes, and ensuring steady, uniform fuel feed. Proper design and operation of the combustion air delivery systems can also minimize PM emissions. The postcombustion control of PM emissions from coal-fired combustion sources can be accomplished by using one or more or the following particulate control devices:

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

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 and should have no adverse effect on combustion system performance. 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 micrometer) and coarse particles (greater than 10 micrometers). These data show a reduction in collection efficiency for particle diameters between 0.1 and 10 micrometers.

Fabric filtration has been widely applied to coal combustion sources since the early 1970s and consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. 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, operating pressure loss, cleaning sequence, interval between cleanings, cleaning method, and cleaning intensity. In addition, the particle collection efficiency and size distribution can be affected by certain fabric properties (e. g., structure of fabric, fiber composition, and bag properties). Collection efficiencies of fabric filters can be as high as 99.9 percent.

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. Scrubber collection efficiency depends on particle size distribution, gas side pressure drop through the scrubber, and water (or scrubbing liquor) pressure, and can range between 95 and 99 percent for a 2-micron particle.

Cyclone separators can be installed singly, in series, or grouped as in a multicyclone or multiclone collector. These devices are referred to as mechanical collectors and 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. 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 particles less than 10 micron (PM-10). The typical overall collection efficiency for mechanical collectors ranges from 90 to 95 percent.

The side-stream separator combines a multicyclone 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. AFBC particles are also, on average, smaller in size, and 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.

1.1.4.2 Sulfur Oxides Control[4] -
Several techniques are used to reduce SO_x emissions from coal combustion. Table 1.1-1 presents the techniques most frequently used. 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.

Post combustion flue gas desulfurization (FGD) techniques can remove SO_2 formed during combustion by using an alkaline reagent to absorb SO_2 in the flue gas. 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. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers 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. Particulate reduction of more than 99 percent is 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.[18] Also, the volume of scrubber sludge is reduced with separate fly ash removal, and contamination of the reagents and by-products is prevented.

The lime and limestone wet scrubbing process uses a slurry of calcium oxide or limestone 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 are possible. Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide or sodium carbonate to absorb SO_2 from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs and can have SO_2 removal efficiencies of up to 96.2 percent. 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. SO_2 removal efficiencies of 90 to 96 percent are possible.

1.1.4.3 Nitrogen Oxide Controls[4] -
Several techniques are used to reduce NO_x emissions from coal combustion. These techniques are summarized in Table 1.1-2. The primary techniques can be classified into one of two fundamentally different methods—combustion controls and postcombustion controls. Combustion controls reduce NO_x by suppressing NO_x formation during the combustion process, while postcombustion controls reduce NO_x emission after their formation. Combustion controls are the most widely used method of controlling NO_x formation in all types of boilers and include low excess air (LEA), burners out of service (BOOS), biased burner firing, overfire air (OFA), low NO_x burners (LNBs), and reburn. Postcombustion control methods are selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). Combustion and postcombustion controls can be used separately or combined to achieve greater NO_x reduction from fluidized bed combustors in boilers.

Operating at LEA involves reducing the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compliant boiler operation. NO_x formation is inhibited because less oxygen is available in the combustion zone. BOOS involves withholding fuel flow to all or part of the top row of burners so that only air is allowed to pass through. This method simulates air staging, or OFA conditions, and limits NO_x formation by lowering the oxygen level in the burner area. Biased burner firing involves more fuel-rich firing in the lower rows of burners than in the upper row of burners. This method provides a form of air staging and limits NO_x formation by limiting the amount of oxygen in the firing zone. These methods may change the normal operation of the boiler and the effectiveness is boiler-specific. Implementation of these techniques may also reduce operational flexibility; however, they may reduce NO_x by 10 to 20 percent from uncontrolled levels.

OFA is a technique in which a percentage of the total combustion air is diverted from the burners and injected through ports above the top burner level. OFA limits NO_x by (1) suppressing thermal NO_x by partially delaying and extending the combustion process resulting in less intense combustion and cooler flame temperatures and (2) suppressing fuel NO_x formation by reducing the concentration of air in the combustion zone where volatile fuel nitrogen is evolved. OFA can be applied for various boiler types including tangential and wall-fired, turbo, and stoker boilers and can reduce NO_x by 20 to 30 percent from uncontrolled levels.

LNBs limit NO_x formation by controlling the stoichiometric and temperature profiles of the combustion process in each burner zone. The unique design of features of an LNB may create (1) a reduced oxygen level in the combustion zone to limit fuel NO_x formation, (2) a reduced flame temperature that limits thermal NO_x formation, and/or (3) a reduced residence time at peak temperature which also limits thermal NO_x formation.

LNBs are applicable to tangential and wall-fired boilers of various sizes but are not applicable to other boiler types such as cyclone furnaces or stokers. They have been used as a retrofit NO_x control for existing boilers and can achieve approximately 35 to 55 percent reduction from uncontrolled levels. They are also used in new boilers to meet New Source Performance Standards (NSPS) limits. LNBs can be combined with OFA to achieve even greater NO_x reduction (40 to 60 percent reduction from uncontrolled levels).

Reburn is a combustion hardware modification in which the NO_x produced in the main combustion zone is reduced in a second combustion zone downstream. This technique involves withholding up to 40 percent (at full load) of the heat input to the main combustion zone and introducing that heat input above the top row of burners to create a reburn zone. Reburn fuel (natural gas, oil, or pulverized coal) is injected with either air or flue gas to create a fuel-rich zone that reduces the NO_x created in the main combustion zone to nitrogen and water vapor. The fuel-rich combustion gases from the reburn zone are completely combusted by injecting overfire air above the reburn zone. Reburn may be applicable to many boiler types firing coal as the primary fuel, including tangential, wall-fired, and cyclone boilers. However, the application and effectiveness are site-specific because each boiler is originally designed to achieve specific steam conditions and capacity which may be altered due to reburn. Commercial experience is limited; however, this limited experience does indicate NO_x reduction of 50 to 60 percent from uncontrolled levels may be achieved.

SNCR is a postcombustion technique that involves injecting ammonia (NH_3) or urea into specific temperature zones in the upper furnace or convective pass. The ammonia or urea reacts with NO_x in the flue gas to produce nitrogen and water. The effectiveness of SNCR depends on the temperature where reagents are injected; mixing of the reagent in the flue gas; residence time of the reagent within the required temperature window; ratio of reagent to NO_x; and the sulfur content of the fuel that may create sulfur compounds that deposit in downstream equipment. There is not as much commercial experience to base effectiveness on a wide range of boiler types; however, in limited applications, NO_x reductions of 25 to 40 percent have been achieved.

SCR is another postcombustion technique that involves injecting NH_3 into the flue gas in the presence of a catalyst to reduce NO_x to nitrogen and then water. The SCR reactor can be located at various positions in the process including before an air heater and particulate control device, or downstream of the air heater, particulate control device, and flue gas desulfurization systems. The performance of SCR is influenced by flue gas temperature, fuel sulfur content, ammonia-to-NO_x ratio, inlet NO_x concentration, space velocity, and catalyst condition. Although there is currently very limited application of SCR in the U.S. on coal-fired boilers, NO_x reductions of 75 to 86 percent have been realized on a few pilot systems.

1.1.5 Emission Factors

Emission factors for SO_x, NO_x, and CO are presented in Table 1.1-3. Tables in this section present emission factors on both a weight basis (lb/ton) and an energy basis (lb/Btu). To convert from lb/ton to lb/MMBtu, divide by a heating value of 26.0 MMBtu/ton. 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 other source categories. For NO_x emissions, the data collected from test reports were considered to be baseline (uncontrolled) 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.

Particulate matter and particulate matter less than, or equal to, 10 micrometers in diameter (PM-10) emission factors are presented in Table 1.1-4. Cumulative particle size distributions and particulate size-specific emission factors are given in Tables 1.1-5, 1.1-6, 1.1-7, 1.1-8, 1.1-9, and 1.1-10. Particulate size-specific emission factors are also presented graphically in Figures 1.1-1, 1.1-2, 1.1-3, 1.1-4, 1.1-5, and 1.1-6.

Controlled emission factors for PCDD/PCDF and PAHs are provided in Tables 1.1-11 and 1.1-12, respectively. Controlled emission factors for other organic compounds are presented in Table 1.1-13. Emission factors for hydrogen chloride and hydrogen fluoride are presented in Table 1.1-14.

Table 1.1-15 presents emission factor equations for nine trace metals from controlled and uncontrolled boilers. Table 1.1-16 presents uncontrolled emission factors for seven of the same metals, along with mercury, POM and formaldehyde. Table 1.1-17 presents controlled emission factors for 13 trace metals and includes the metals found in Tables 1.1-15 and 1.1-16. The emission factor equations in Table 1.1-15 are based on statistical correlations among measured trace element concentrations in coal, measured fractions of ash in coal, and measured particulate matter emission factors. Because these are the major parameters affecting trace metals emissions from coal combustion, it is recommended that the emission factor equations be used when the inputs to the equations are available. If the inputs to the emission factor equations are not available for a pollutant, then the emission factors provided in Table 1.1-16 and 1.1-17 for the pollutant should be used.

Greenhouse gas emission factors, including CH_4, non-methane organic compounds (NMOC), and N_2O are provided in Table 1.1-18. In addition, Table 1.1-19 provides emission factors for CO_2.

1.1.6 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section. These and other documents can be found on the CHIEF electronic bulletin board (919-541-5742), or on the new EFIG home page (http://www.epa.gov/oar/oaqps/efig/).

Supplement A, February 1996

- SCC's were corrected from 1-01-002-17, 1-02-002-17, and 1-03-002-17, to 1-01-002-18, 1-02-002-18, and 1-03-002-18 in the tables with SO_x, NO_x, CO, and PM/PM10 emission factors.

- For SO_x factors, clarifications were added to the table footnotes to clarify that "S" is a weight percent and not a fraction. Similar clarification was added to the footnote for the CO_2 factor.

- For fluidized bed combustors (bubbling bed and circulating bed), the PM10 factors were replaced with footnote "m." The revised footnote "m" directs the user to the emission factor for spreader stoker with multiple cyclones and no flyash reinjection.

- In the table with filterable PM factors, the misspelling of "filterable" was corrected.

- In the cumulative particle size distribution table, text was added to the table footnotes to clarify that "A" is a weight percent and not a fraction.

- In the cumulative particle size distribution for spreader stokers, all of the factors were corrected.

- The N_2O emission factor for bubbling bed was changed from 5.9 lb/ton to 5.5 lb/ton.

Supplement B, October 1996

- Text was added concerning coal rank/classification, firing practices, emissions, and controls.

- The table for NO_x control technologies was revised to include controls for all types of coal-fired boilers.

- SO_x, NO_x, and CO emission factors were added for cell burners.

- The PM table was revised to recommend using spreader stoker PM factors for FBC units.

- Tables were added for new emission factors for polychlorinated toxics, polynuclear aromatics, organic toxics, acid gas toxics, trace metal toxics, and controlled toxics.

- N_2O emission factors were added.

- Default CO_2 emission factors were added.

Table 1.1-1. POSTCOMBUSTION 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%	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 are completed
Duct injection	Dry sorbent injection into duct, sometimes combined with water spray	25 - 50+%	Several research and development, and demonstration projects underway, not yet commercially available in the United States.

Table 1.1-2. NO$_x$ CONTROL OPTIONS FOR COAL-FIRED BOILERS[a]

Control Technique	Description of Technique	Applicable Boiler Designs	NO$_x$ Reduction Potential[b] (%)	Commercial Availability/R & D Status	Comments
Combustion Modifications					
Load reduction	Reduction of coal and air	Stokers	Minimal	Available	Applicable to stokers that can reduce load without increasing excess air; may cause reduction in boiler efficiency; NO$_x$ reduction varies with percent load reduction.
Operational modifications (BOOS, LEA, BF, or combination)	Rearrangement of air or fuel in the main combustion zone	Pulverized coal boilers (some designs); Stokers (LEA only)	10 - 20	Available	Must have sufficient operational flexibility to achieve NO$_x$ reduction potential without sacrificing boiler performance.
Overfire Air	Injection of air above main combustion zone	Pulverized coal boilers and stokers	20 - 30	Available	Must have sufficient furnace height above top row of burners in order to retrofit this technology to existing boilers.
Low NO$_x$ Burners	New burner designs controlling air-fuel mixing	Pulverized coal boilers	35 - 55	Available	Available in new boiler designs and can be retrofit in existing boilers.
LNB with OFA	Combination of new burner designs and injection of air above main combustion zone	Pulverized coal boilers	40 - 60	Available	Available in new boiler designs and can be retrofit in existing boilers with sufficient furnace height above top row of burners.
Reburn	Injection of reburn fuel and completion air above main combustion zone	Pulverized coal boilers, cyclone furnaces	50 - 60	Commercially available but not widely demonstrated	Reburn fuel can be natural gas, fuel oil, or pulverized coal. Must have sufficient furnace height to retrofit this technology to existing boilers.

Table 1.1-2 (cont.).

Control Technique	Description of Technique	Applicable Boiler Designs	NO$_x$ Reduction Potential[b] (%)	Commercial Availability/R & D Status	Comments
Post-Combustion Modifications					
SNCR	Injection of NH$_3$ or urea in the convective pass	Pulverized coal boilers, cyclone furnaces, stokers, and fluidized bed boilers	30 - 60	Commercially available but not widely demonstrated	Applicable to new boilers or as a retrofit technology; must have sufficient residence time at correct temperature (1,750°±90°F); elaborate reagent injection system; possible load restrictions on boiler; and possible air preheater fouling by ammonium bisulfate.
SCR	Injection of NH$_3$ in combination with catalyst material	Pulverized coal boilers, cyclone furnaces	75 - 85	Commercially offered, but not yet demonstrated	Applicable to new boilers or as a retrofit technology provided there is sufficient space; hot-side SCR best on low-sulfur fuel and low fly ash applications; cold-side SCR can be used on high-sulfur/high-ash applications if equipped with an upstream FGD system.
LNB with SNCR	Combination of new burner designs and injection of NH$_3$ or urea	Pulverized coal boilers	50-80	Commercially offered, but not widely demonstrated as a combined technology	Same as LNB and SNCR alone.
LNB with OFA and SCR	Combination of new burner design, injection of air above combustion zone, and injection of NH$_3$ or urea	Pulverized coal boiler	85-95	Commercially offered, but not widely demonstrated as a combined technology	Same as LNB, OFA, and SCR alone.

[a] References 20-21.
[b] NO$_x$ reduction potential from uncontrolled levels.

Table 1.1-3. UNCONTROLLED EMISSION FACTORS FOR SO_x, NO_x, AND CO
FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	SCC	SO_x[b]		NO_x[c]		CO[d,e]	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
PC-fired, dry bottom, wall-fired	1-01-002-02/22 1-02-002-02/22 1-03-002-06/22	38S (35S)	A	21.7	A	0.5	A
PC-fired, bituminous coal, dry bottom, cell burner fired[f]	1-01-002-15	38S (35S)	A	31.1	C	0.5	A
PC-fired, dry bottom, tangentially fired	1-01-002-12/26 1-02-002-12/26 1-03-002-16/26	38S (35S)	A	14.4	A	0.5	A
PC-fired, wet bottom	1-01-002-01/21 1-02-002-01/21 1-03-002-05/21	38S (35S)	D	34.0	C	0.5	A
Cyclone furnace	1-01-002-03/23 1-02-002-03/23 1-03-002-03/23	38S (35S)	D	33.8	C	0.5	A
Spreader stoker	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	38S (35S)	B	13.7	A	5	A
Spreader stoker, with multiple cyclones, and reinjection	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	38S (35S)	B	13.7	A	5	A
Spreader stoker, with multiple cyclones, no reinjection	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	38S (35S)	A	13.7	A	5	A

Table 1.1-3 (cont.).

Firing Configuration	SCC	SO_x[b]		NO_x[c]		CO[d,e]	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
Overfeed stoker[g]	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	38S (35S)	B	7.5	A	6	B
Feed stoker, with multiple cyclones[g]	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	38S (35S)	B	7.5	A	6	B
Underfeed stoker	1-02-002-06 1-03-002-08	31S	B	9.5	A	11	B
Underfeed stoker, with multiple cyclones	1-02-002-06 1-03-002-08	31S	B	9.5	A	11	B
Hand-fed units	1-03-002-14	31S	D	9.1	E	275	E
FBC, circulating bed	1-01-002-18 1-02-002-18 1-03-002-18	—[h]	E	3.9	E	18	E
FBC, bubbling bed	1-01-002-17 1-02-002-17 1-03-002-17	—[h]	E	15.2	D	18	D

[a] Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired. SCC = Source Classification Code. To convert from lb/ton to kg/Mg, multiply by 0.5.

[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. For example, if fuel is 1.2% sulfur, then S = 1.2. 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 22-23). 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 1.1-3 (cont.).

c Expressed as NO_2. Generally, 95 volume % or more of NO_x present in combustion exhaust will be in the form of NO, the rest NO_2 (Reference 6). To express factors as NO, multiply factors by 0.66. All factors represent emissions at baseline operation (i. e., 60 to 110% load and no NO_x control measures).

d Nominal values achievable under normal operating conditions. Values 1 or 2 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 lb CO_2/ton coal = 72.6C, where C is the weight % carbon content of the coal. For example, if carbon content is 85%, then C equals 85.

f References 24-27.

g Includes traveling grate, vibrating grate, and chain grate stokers.

h SO_2 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 SO_2 emissions. In this case, the emission factor ratings are E for both bubbling and circulating units.

Table 1.1-4. UNCONTROLLED EMISSION FACTORS FOR PM AND PM-10
FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	SCC	Filterable PM[b]		PM-10	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
PC-fired, dry bottom, wall-fired	1-01-002-02/22 1-02-002-02/22 1-03-002-06/22	10A	A	2.3A	E
PC-fired, dry bottom, tangentially fired	1-01-002-12/26 1-02-002-12/26 1-03-002-16/26	10A	B	2.3A[c]	E
PC-fired, wet bottom	1-01-002-01/21 1-02-002-01/21 1-03-002-05/21	7A[d]	D	2.6A	E
Cyclone furnace	1-01-002-03/23 1-02-002-03/23 1-03-002-03/23	2A[d]	E	0.26A	E
Spreader stoker	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	66[e]	B	13.2	E
Spreader stoker, with multiple cyclones, and reinjection	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	17	B	12.4	E
Spreader stoker, with multiple cyclones, no reinjection	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	12	A	7.8	E
Overfeed stoker[f]	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	16[g]	C	6.0	E

Table 1.1-4 (cont.).

Firing Configuration	SCC	Filterable PM[b]		PM-10	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
Overfeed stoker, with multiple cyclones[f]	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	9[h]	C	5.0	E
Underfeed stoker	1-02-002-06 1-03-002-08	15[j]	D	6.2	E
Underfeed stoker, with multiple cyclone	1-02-002-06 1-03-002-08	11[h]	D	6.2[j]	E
Hand-fed units	1-03-002-14	15	E	6.2[k]	E
FBC, bubbling bed	1-01-002-17 1-02-002-17 1-03-002-17	m	E	m	E
FBC, circulating bed	1-01-002-18 1-02-002-18 1-03-002-18	m	E	m	E

[a] Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired. To convert from lb/ton to kg/Mg, multiply by 0.5. SCC = Source Classification Code.

[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 PC-fired, dry bottom unit, the PM emission factor would be 10 x 8, or 80 lb/ton. The "condensable" 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 28-32.

[c] No data found; emission factor for PC-fired dry bottom boilers used.

[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 2.

[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.

Table 1.1-4 (cont.).

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 4 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; emission factor for underfeed stoker used.
m No data found; use emission factor for spreader stoker with multiple cyclones and reinjection.

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

| Particle Size[b] (µm) | Cumulative Mass % ≤ Stated Size | | | | | Cumulative Emission Factor[c] (lb/ton) | | | | |
| | | Controlled | | | | | Controlled[e] | | | |
	Uncontrolled	Multiple Cyclones	Scrubber	ESP	Baghouse	Uncontrolled[d]	Multiple Cyclones[f]	Scrubber[g]	ESP[g]	Baghouse[f]
15	32	54	81	79	97	3.2A	1.08A	0.48A	0.064A	0.02A
10	23	29	71	67	92	2.3A	0.58A	0.42A	0.054A	0.02A
6	17	14	62	50	77	1.7A	0.28A	0.38A	0.024A	0.02A
2.5	6	3	51	29	53	0.6A	0.06A	0.3A	0.024A	0.01A
1.25	2	1	35	17	31	0.2A	0.02A	0.22A	0.01A	0.006A
1.00	2	1	31	14	25	0.2A	0.02A	0.18A	0.01A	0.006A
0.625	1	1	20	12	14	0.10A	0.02A	0.12A	0.01A	0.002A
TOTAL	100	100	100	100	100	10A	2A	0.6A	0.08A	0.02A

[a] Reference 33. Applicable Source Classification Codes are 1-01-002-02, 1-02-002-02, 1-03-002-06, 1-01-002-12, 1-02-002-12, and 1-03-002-16. To convert from lb/ton to kg/Mg, multiply by 0.5. Emission Factors are lb of pollutant per ton of coal combusted, as fired. ESP = Electrostatic precipitator.
[b] Expressed as aerodynamic equivalent diameter.
[c] A = coal ash weight percent, as fired. For example, if coal ash weight is 8.2%, then A = 8.2.
[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.

Table 1.1-6. 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] (lb/ton) | | |
| | | Controlled | | | Controlled[d] | |
	Uncontrolled	Multiple Cyclones	ESP	Uncontrolled	Multiple Cyclones	ESP
15	40	99	83	2.8A	1.38A	0.046
10	37	93	75	2.6A	1.3A	0.042
6	33	84	63	2.32A	1.18A	0.036
2.5	21	61	40	1.48A	0.86A	0.022A
1.25	6	31	17	0.42A	0.44A	0.01A
1.00	4	19	8	0.28A	0.26A	0.004A
0.625	2	—[e]	—[e]	0.14A	—[e]	—[e]
TOTAL	100	100	100	7.0A	1.4A	0.056A

[a] Reference 33. Applicable Source Classification Codes are 1-01-002-01, 1-02-002-01, and 1-03-002-05. To convert from lb/ton to kg/Mg, multiply by 0.5. Emission factors are lb of pollutant per ton of coal combusted as fired. ESP = Electrostatic precipitator.
[b] Expressed as aerodynamic equivalent diameter.
[c] A = coal ash weight %, as fired. For example, if coal ash weight is 2.4%, then A = 2.4.
[d] Estimated control efficiency for multiple cyclones is 94%, and for ESPs, 99.2%.
[e] Insufficient data.

Table 1.1-7. CUMULATIVE 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] (lb/ton) | | |
| | | Controlled | | | Controlled[d] | |
	Uncontrolled	Multiple Cyclones	ESP	Uncontrolled	Multiple Cyclones	ESP
15	33	95	90	0.66A	0.114A	0.013A
10	13	94	68	0.26A	0.112A	0.011A
6	8	93	56	0.16A	0.112A	0.009A
2.5	0	92	36	0	0.11A	0.006A
1.25	0	85	22	0	0.10A	0.004A
1.00	0	82	17	0	0.10A	0.003A
0.625	0	—[e]	—[e]	0	—[e]	—[e]
TOTAL	100	100	100	2A	0.12A	0.016A

[a] Reference 33. Applicable Source Classification Codes are 1-01-002-03, 1-02-002-03, and 1-03-002-03. To convert from lb/ton to kg/Mg, multiply by 0.5. Emissions are lb of pollutant per ton of coal combusted, as fired.
[b] Expressed as aerodynamic equivalent diameter.
[c] A = coal ash weight %, as fired. For example, if coal ash weight is 2.4%, then A = 2.4.
[d] Estimated control efficiency for multiple cyclones is 94%, and for ESPs, 99.2%.
[e] Insufficient data.

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

| Particle Size[b] (µm) | Cumulative Mass % ≤ Stated Size | | | | | Cumulative Emission Factor[c] (lb/ton) | | | | |
| | | Controlled | | | | | Controlled[d] | | | |
	Uncontrolled	Multiple Cyclones[c]	Multiple Cyclones[d]	ESP	Baghouse	Uncontrolled[e]	Multiple Cyclones[c,f]	Multiple Cyclones[d,e]	ESP[f,g]	Baghouse[e,g]
15	28	86	74	97	72	18.5	14.6	8.8	0.46	0.086
10	20	73	65	90	60	13.2	12	7.8	0.44	0.072
6	14	51	52	82	46	9.2	8.6	6.2	0.40	0.056
2.5	7	8	27	61	26	4.6	1.4	3.2	0.30	0.032
1.25	5	2	16	46	18	3.3	0.4	2.0	0.22	0.022
1.00	5	2	14	41	15	3.3	0.4	1.6	0.20	0.018
0.625	4	1	9	—[h]	7	2.6	0.2	1.0	-[h]	0.006
TOTAL	100	100	100	100	100	66.0	17.0	12.0	0.48	0.12

[a] Reference 33. Applicable Source Classification Codes are 1-01-002-04, 1-02-002-04, 1-03-002-09. To convert from lb/ton to kg/Mg, multiply by 0.5. Emissions are lb of pollutant per ton of coal combusted, as fired.
[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 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]

| Particle Size[b] (μm) | Cumulative Mass % ≤ Stated Size | | Cumulative Emission Factor (lb/ton) | | | |
| | | | Uncontrolled | | Multiple Cyclones Controlled[c] | |
	Uncontrolled	Multiple Cyclones Controlled	Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING
15	49	60	7.8	C	5.4	E
10	37	55	6.0	C	5.0	E
6	24	49	3.8	C	4.4	E
2.5	14	43	2.2	C	3.8	E
1.25	13	39	2.0	C	3.6	E
1.00	12	39	2.0	C	3.6	E
0.625	—[d]	16	—[d]	C	1.4	E
TOTAL	100	100	16.0	C	9.0	E

[a] Reference 33. Applicable Source Classification Codes are 1-01-002-05, 1-02-002-05, and 1-03-002-07. To convert from lb/ton to kg/Mg, multiply by 0.5. Emissions are lb of pollutant per ton of coal combusted, as fired.
[b] Expressed as aerodynamic equivalent diameter.
[c] Estimated control efficiency for multiple cyclones is 80%.
[d] Insufficient data.

Table 1.1-10. 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] (lb/ton)
15	50	7.6
10	41	6.2
6	32	4.8
2.5	25	3.8
1.25	22	3.4
1.00	21	3.2
0.625	18	2.7
TOTAL	100	15.0

[a] Reference 33. Applicable Source Classification Codes are 1-02-002-06 and 1-03-002-08.   To
convert from lb/ton to kg/Mg, multiply by 0.5. Emission factors are lb of pollutant per ton of coal
combusted, as fired.
[b] Expressed as aerodynamic equivalent diameter.
[c] May also be used for uncontrolled hand-fired units.

Table 1.1-11 EMISSION FACTORS FOR POLYCHLORINATED
DIBENZO-P-DIOXINS AND POLYCHLORINATED DIBENZOFURANS FROM CONTROLLED
BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION

Controls	FGD-SDA with FF[a]		ESP or FF[b]	
Congener	Emission Factor[c] (lb/ton)	EMISSION FACTOR RATING	Emission Factor[c] (lb/ton)	EMISSION FACTOR RATING
2,3,7,8-TCDD	No data	---	1.43E-11	E
Total TCDD	3.93E-10	E	9.28E-11	D
Total PeCDD	7.06E-10	E	4.47E-11	D
Total HxCDD	3.00E-09	E	2.87E-11	D
Total HpCDD	1.00E-08	E	8.34E-11	D
Total OCDD	2.87E-08	E	4.16E-10	D
Total PCDD[d]	4.28E-08	E	6.66E-10	D
2,3,7,8-TCDF	No data	---	5.10E-11	D
Total TCDF	2.49E-09	E	4.04E-10	D
Total PeCDF	4.84E-09	E	3.53E-10	D
Total HxCDF	1.27E-08	E	1.92E-10	D
Total HpCDF	4.39E-08	E	7.68E-11	D
Total OCDF	1.37E-07	E	6.63E-11	D
Total PCDF[d]	2.01E-07	E	1.09E-09	D
TOTAL PCDD/PCDF	2.44E-07	E	1.76E-09	D

[a] Reference 34. Factors apply to boilers equipped with both flue gas desulfurization spray dryer
    absorber (FGD-SDA) and a fabric filter (FF). SCCs = pulverized coal-fired, dry bottom boilers,
    1-01-002-02/22, 1-02-002-02/22, and 1-03-002-06/22.
[b] References 35-37. Factors apply to boilers equipped with an electrostatic precipitator (ESP) or a
    fabric filter.   SCCs = pulverized coal-fired, dry bottom boilers, 1-01-002-02/22, 1-02-002-02/22,
    1-03-002-06/22; and, cyclone boilers, 1-01-002-03/23, 1-02-002-03/23, and 1-03-002-03/23.
[c] Emission factor should be applied to coal feed, as fired. To convert from lb/ton to kg/Mg, multiply
    by 0.5. Emissions are lb of pollutant per ton of coal combusted.
[d] Total PCDD is the sum of Total TCDD through Total OCDD. Total PCDF is the sum of Total
    TCDF through Total OCDF.

Table 1.1-12 EMISSION FACTORS FOR POLYNUCLEAR AROMATIC
HYDROCARBONS (PAH) FROM CONTROLLED COAL COMBUSTION[a]

Pollutant	Emission Factor[b] (lb/ton)	EMISSION FACTOR RATING
Biphenyl	1.7E-06	D
Acenaphthene	5.1E-07	B
Acenaphthylene	2.5E-07	B
Anthracene	2.1E-07	B
Benzo(a)anthracene	8.0E-08	B
Benzo(a)pyrene	3.8E-08	D
Benzo(b,j,k)fluoranthene	1.1E-07	B
Benzo(g,h,i)perylene	2.7E-08	D
Chrysene	1.0E-07	C
Fluoranthene	7.1E-07	B
Fluorene	9.1E-07	B
Indeno(1,2,3-cd)pyrene	6.1E-08	C
Naphthalene	1.3E-05	C
Phenanthrene	2.7E-06	B
Pyrene	3.3E-07	B
5-Methyl chrysene	2.2E-08	D

[a] References 35-45. Factors were developed from emissions data from six sites firing bituminous coal, four sites firing subbituminous coal, and from one site firing lignite. Factors apply to boilers utilizing both wet limestone scrubbers or spray dryers with an electrostatic precipitator (ESP) or fabric filter (FF). The factors also apply to boilers utilizing only an ESP or FF. Bituminous/subbituminous SCCs = pulverized coal-fired dry bottom boilers, 1-01-002-02/22, 1-02-002-02/22, 1-03-002-06; pulverized coal, dry bottom, tangentially-fired boilers, 1-01-002-12/26, 1-02-002-12/26, 1-03-002-16/26; and, cyclone boilers, 1-01-002-03/23, 1-02-002-03/23, and 1-03-002-03/23.

[b] Emission factor should be applied to coal feed, as fired. To convert from lb/ton to kg/Mg, multiply by 0.5. Emissions are lb of pollutant per ton of coal combusted.

Table 1.1-13 EMISSION FACTORS FOR VARIOUS ORGANIC COMPOUNDS
FROM CONTROLLED COAL COMBUSTION[a]

Pollutant[b]	Emission Factor[c] (lb/ton)	EMISSION FACTOR RATING
Acetaldehyde	5.7E-04	C
Acetophenone	1.5E-05	D
Acrolein	2.9E-04	D
Benzene	1.3E-03	A
Benzyl chloride	7.0E-04	D
Bis(2-ethylhexyl)phthalate (DEHP)	7.3E-05	D
Bromoform	3.9E-05	E
Carbon disulfide	1.3E-04	D
2-Chloroacetophenone	7.0E-06	E
Chlorobenzene	2.2E-05	D
Chloroform	5.9E-05	D
Cumene	5.3E-06	E
Cyanide	2.5E-03	D
2,4-Dinitrotoluene	2.8E-07	D
Dimethyl sulfate	4.8E-05	E
Ethyl benzene	9.4E-05	D
Ethyl chloride	4.2E-05	D
Ethylene dichloride	4.0E-05	E
Ethylene dibromide	1.2E-06	E
Formaldehyde	2.4E-04	A
Hexane	6.7E-05	D
Isophorone	5.8E-04	D
Methyl bromide	1.6E-04	D
Methyl chloride	5.3E-04	D
Methyl ethyl ketone	3.9E-04	D
Methyl hydrazine	1.7E-04	E
Methyl methacrylate	2.0E-05	E
Methyl tert butyl ether	3.5E-05	E
Methylene chloride	2.9E-04	D

Table 1.1-13 (cont.).

Pollutant[b]	Emission Factor[c] (lb/ton)	EMISSION FACTOR RATING
Phenol	1.6E-05	D
Propionaldehyde	3.8E-04	D
Tetrachloroethylene	4.3E-05	D
Toluene	2.4E-04	A
1,1,1-Trichloroethane	2.0E-05	E
Styrene	2.5E-05	D
Xylenes	3.7E-05	C
Vinyl acetate	7.6E-06	E

[a] References 35-53. Factors were developed from emissions data from ten sites firing bituminous coal, eight sites firing subbituminous coal, and from one site firing lignite. The emission factors are applicable to boilers using both wet limestone scrubbers or spray dryers and an electrostatic precipitator (ESP) or fabric filter (FF). In addition, the factors apply to boilers utilizing only an ESP or FF. SCCs = pulverized coal-fired, dry bottom boilers, 1-01-002-02/22, 1-02-002-02/22, 1-03-002-06/22; pulverized coal, dry bottom, tangentially-fired boilers, 1-01-002-12/26, 1-02-002-12/26, 1-03-002-16/26; cyclone boilers, 1-01-002-03/23, 1-02-002-03/23, 1-03-002-03/23; and, atmospheric fluidized bed combustors, circulating bed, 1-01-002-18/38, 1-02-002-18, and 1-03-002-18.

[b] Pollutants sampled for but not detected in any sampling run include: Carbon tetrachloride- 2 sites; 1,3-Dichloropropylene- 2 sites; N-nitrosodimethylamine- 2 sites; Ethylidene dichloride- 2 sites; Hexachlorobutadiene- 1 site; Hexachloroethane- 1 site; Propylene dichloride- 2 sites; 1,1,2,2-Tetrachloroethane- 2 sites; 1,1,2-Trichloroethane- 2 sites; Vinyl chloride- 2 sites; and, Hexachlorobenzene- 2 sites.

[c] Emission factor should be applied to coal feed, as fired. To convert from lb/ton to kg/Mg, multiply by 0.5.

Table 1.1-14. EMISSION FACTORS FOR HYDROGEN CHLORIDE (HCl) AND HYDROGEN FLUORIDE (HF) FROM COAL COMBUSTION[a]

EMISSION FACTOR RATING: B

Firing Configuration	SCC	HCl	HF
		Emission Factor (lb/ton)	Emission Factor (lb/ton)
PC-fired, dry bottom	1-01-002-02/22 1-02-002-02/22 1-03-002-06/22	1.2	0.15
PC-fired, dry bottom, tangential	1-01-002-12/26 1-02-002-12/26 1-03-002-16/26	1.2	0.15
PC-fired, wet bottom	1-01-002-01/21 1-02-002-01/21 1-03-002-05/21	1.2	0.15
Cyclone Furnace	1-01-002-03/23 1-02-002-03/23 1-03-002-03/23	1.2	0.15
Spreader Stoker	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	1.2	0.15
Overfeed Stoker	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	1.2	0.15
Underfeed Stoker	1-02-002-06 1-03-002-08	1.2	0.15
FBC, Bubbling Bed	1-01-002-17 1-02-002-17 1-03-002-17	1.2	0.15
FBC, Circulating Bed	1-01-002-18/38 1-02-002-18 1-03-002-18	1.2	0.15
Hand-fired	1-03-002-14	1.2	0.15

[a] Reference 54. The emission factors were developed from bituminous coal, subbituminous coal, and lignite emissions data. To convert from lb/ton to kg/Mg, multiply by 0.5. The factors apply to both controlled and uncontrolled sources.

Table 1.1-15. EMISSION FACTOR EQUATIONS FOR TRACE ELEMENTS FROM COAL COMBUSTION[a]

EMISSION FACTOR EQUATION RATING: A[b]

Pollutant	Emission Equation (lb/10^{12} Btu)[c]
Antimony	$0.92 * (C/A * PM)^{0.63}$
Arsenic	$3.1 * (C/A * PM)^{0.85}$
Beryllium	$1.2 * (C/A * PM)^{1.1}$
Cadmium	$3.3 * (C/A * PM)^{0.5}$
Chromium	$3.7 * (C/A * PM)^{0.58}$
Cobalt	$1.7 * (C/A * PM)^{0.69}$
Lead	$3.4 * (C/A * PM)^{0.80}$
Manganese	$3.8 * (C/A * PM)^{0.60}$
Nickel	$4.4 * (C/A * PM)^{0.48}$

[a] Reference 55. The equations were developed from emissions data from bituminous coal combustion, subbituminous coal combustion, and from lignite combustion. The equations may be used to generate factors for both controlled and uncontrolled boilers. The emission factor equations are applicable to all typical firing configurations for electric generation (utility), industrial, and commercial/industrial boilers firing bituminous coal, subbituminous coal, and lignite. Thus, all SCCs for these boilers are assigned to the factors.

[b] AP-42 criteria for rating emission factors were used to rate the equations.

[c] The factors produced by the equations should be applied to heat input. To convert from lb/10^{12} Btu to kg/joules, multiply by 4.31 x 10^{-16}.

  C = concentration of metal in the coal, parts per million by weight (ppmwt).

  A = weight fraction of ash in the coal. For example, 10% ash is 0.1 ash fraction.

  PM = Site-specific emission factor for total particulate matter, lb/10^6 Btu.

Table 1.1-16. EMISSION FACTORS FOR TRACE ELEMENTS, POM, AND HCOH FROM UNCONTROLLED BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Emission Factor, $lb/10^{12}$ Btu									
	As	Be	Cd	Cr	Pb[b]	Mn	Hg	Ni	POM	HCOH
Pulverized coal, configuration unknown (no SCC)	ND	ND	ND	1922	ND	ND	ND	ND	ND	112[c]
Pulverized coal, wet bottom (1-01-002-01/21, 1-02-002-01/21, 1-03-002-05/21)	538	81	44-70	1020-1570	507	808-2980	16	840-1290	ND	ND
Pulverized coal, dry bottom (1-01-002-02/22, 1-02-002-06/22, 1-03-002-06/22)	684	81	44.4	1250-1570	507	228-2980	16	1030-1290	2.08	ND
Pulverized coal, dry bottom, tangential (1-01-002-12/26, 1-02-002-12/26, 1-03-002-16/26)	ND	ND	ND	ND	ND	ND	ND	ND	2.4	ND
Cyclone furnace (1-01-002-03/23, 1-02-002-03/23, 1-03-002-03/23)	115	<81	28	212-1502	507	228-1300	16	174-1290	ND	ND
Stoker, configuration unknown (no SCC)	ND	73	ND	19-300	ND	2170	16	775-1290	ND	ND
Spreader stoker (1-01-002-04/24, 1-02-002-04/24, 1-03-002-09/24)	264-542	ND	21-43	942-1570	507	ND	ND	ND	ND	221[d]
Overfeed stoker, traveling grate (1-01-002-05/25, 1-02-002-05/25, 1-03-002-07/25)	542-1030	ND	43-82	ND	507	ND	ND	ND	ND	140[e]

[a] References 56-61. The emission factors in this table represent the ranges of factors reported in the literature. If only 1 data point was found, it is still reported in this table. To convert from $lb/10^{12}$ Btu to pg/J, multiply by 0.43. SCC = Source Classification Code. ND = no data.

[b] Lead emission factors were taken directly from an EPA background document for support of the National Ambient Air Quality Standards.

[c] Based on 2 units; 133×10^6 Btu/hr and 1550×10^6 Btu/hr.

[d] Based on 1 unit; 59×10^6 Btu/hr.

[e] Based on 1 unit; 52×10^6 Btu/hr.

Table 1.1-17 EMISSION FACTORS FOR TRACE METALS FROM
CONTROLLED COAL COMBUSTION[a]

Pollutant	Emission Factor (lb/ton)[b]	EMISSION FACTOR RATING
Antimony	1.8E-05	A
Arsenic	4.1E-04	A
Beryllium	2.1E-05	A
Cadmium	5.1E-05	A
Chromium	2.6E-04	A
Chromium (VI)	7.9E-05	D
Cobalt	1.0E-04	A
Lead	4.2E-04	A
Magnesium	1.1E-02	A
Manganese	4.9E-04	A
Mercury	8.3E-05	A
Nickel	2.8E-04	A
Selenium	1.3E-03	A

[a] References 35-53, 62-70. The emission factors were developed from emissions data at eleven
facilities firing bituminous coal, fifteen facilities firing subbituminous coal, and from two facilities
firing lignite. The factors apply to boilers utilizing either venturi scrubbers, spray dryer absorbers, or
wet limestone scrubbers with an electrostatic precipitator (ESP) or Fabric Filter (FF). In addition,
the factors apply to boilers using only an ESP, FF, or venturi scrubber. SCCs = pulverized
coal-fired, dry bottom boilers, 1-01-002-02/22, 1-02-002-02/22, 1-03-002-06/22; pulverized coal, dry
bottom, tangentially-fired boilers, 1-01-002-12/26, 1-02-002-12/26, 1-03-002-16/26; cyclone boilers,
1-01-002-03/23, 1-02-002-03/23, 1-03-002-03/23; and, atmospheric fluidized bed combustors,
circulating bed, 1-01-002-18/38, 1-02-002-18, and 1-03-002-18.
[b] Emission factor should be applied to coal feed, as fired. To convert from lb/ton to kg/Mg, multiply
by 0.5.

Table 1.1-18. EMISSION FACTORS FOR CH_4, TNMOC, AND N_2O FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	SCC	CH_4[b]		TNMOC[b,c]		N_2O[d]	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
PC-fired, dry bottom, wall fired	1-01-002-02/22 1-02-002-02/22 1-03-002-06/22	0.04	B	0.06	B	0.03	B
PC-fired, dry bottom, tangentially fired	1-01-002-12/26 1-02-002-12/26 1-03-002-16/26	0.04	B	0.06	B	0.08	B
PC-fired, wet bottom	1-01-002-01/21 1-02-002-01/21 1-03-002-05/21	0.05	B	0.04	B	0.08	E
Cyclone furnace	1-01-002-03/23 1-02-002-03/23 1-03-002-03/23	0.01	B	0.11	B	0.09[e]	E
Spreader stoker	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	0.06	B	0.05	B	0.04[f]	D
Spreader stoker, with multiple cyclones, and reinjection	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	0.06	B	0.05	B	0.04[f]	E
Spreader stoker, with multiple cyclones, no reinjection	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	0.06	B	0.05	B	0.04[f]	E

Table 1.1-18 (cont.).

Firing Configuration	SCC	CH_4[b]		$TNMOC$[b,c]		N_2O[d]	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
Overfeed stoker[g]	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	0.06	B	0.05	B	0.04[f]	E
Overfeed stoker, with multiple cyclones[g]	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	0.06	B	0.05	B	0.04[f]	E
Underfeed stoker	1-02-002-06 1-03-002-08	0.8	B	1.3	B	0.04[f]	E
Underfeed stoker, with multiple cyclone	1-02-002-06 1-03-002-08	0.8	B	1.3	B	0.04[f]	E
Hand-fed units	1-03-002-14	5	E	10	E	0.04[f]	E
FBC, bubbling bed	1-01-002-17 1-02-002-17 1-03-002-17	0.06[h]	E	0.05[h]	E	3.5[h]	B
FBC, circulating bed	1-01-002-18 1-02-002-18 1-03-002-18	0.06	E	0.05	E	3.5	B

[a] Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired. SCC = Source Classification Code. To convert from lb/ton to kg/Mg, multiply by 0.5.

[b] Reference 32. Nominal values achievable under normal operating conditions; values 1 or 2 orders of magnitude higher can occur when combustion is not complete.

[c] TNMOC are expressed as C2 to C16 alkane equivalents (Reference 71). Because of limited data, the effects of firing configuration on TNMOC 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 14-15.

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

[f] No data found; emission factor for spreader-stoker boilers used.

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

[h] No data found; emission factor for circulating fluidized bed used.

Table 1.1-19. DEFAULT CO_2 EMISSION FACTORS FOR U. S. COALS[a]

EMISSION FACTOR RATING: C

Coal Type	Average %C[b]	Conversion Factor[c]	Emission Factor[d] (lb/ton coal)
Subbituminous	66.3	72.6	4810
High-volatile bituminous	75.9	72.6	5510
Medium-volatile bituminous	83.2	72.6	6040
Low-volatile bituminous	86.1	72.6	6250

[a] This table should be used only when an ultimate analysis is not available. If the ultimate analysis is available, CO_2 emissions should be calculated by multiplying the %carbon (%C) by 72.6 This resultant factor would receive a quality rating of "B".

[b] An average of the values given in References 2,76-77. Each of these references listed average carbon contents for each coal type (dry basis) based on extensive sampling of U.S. coals.

[c] Based on the following equation:

$$\frac{44 \text{ ton } CO_2}{12 \text{ ton } C} \text{ x } 0.99 \text{ x } 2000 \frac{\text{lb } CO_2}{\text{ton } CO_2} \text{ x } \frac{1}{100\%} \quad 72.6 \frac{\text{lb } CO_2}{\text{ton } \%C}$$

Where:

    44 = molecular weight of CO_2,
    12 = molecular weight of carbon, and
    0.99 = fraction of fuel oxidized during combustion (Reference 16).

[d] To convert from lb/ton to kg/Mg, multiply by 0.5.
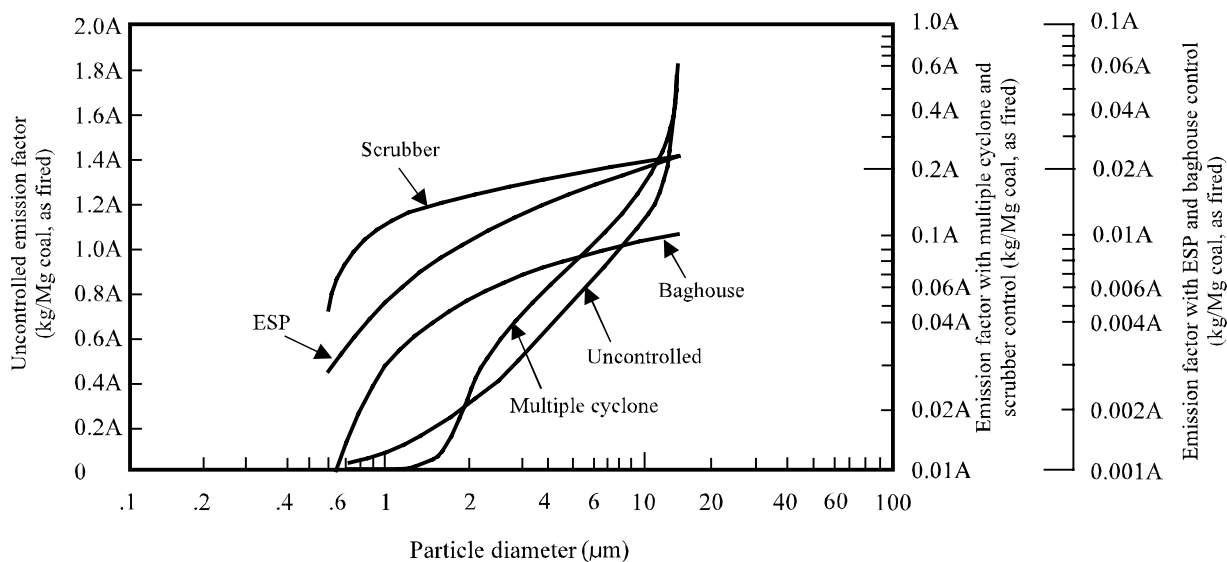
Figure 1.1-1. Cumulative size-specific emission factors for dry bottom boilers burning pulverized bituminous coal.
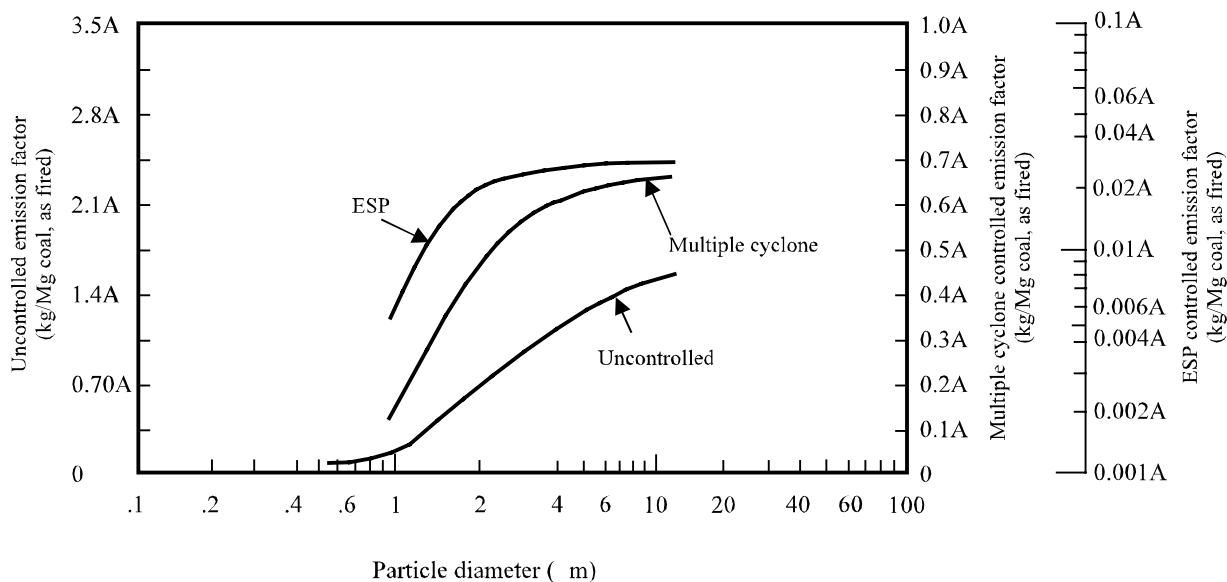

Figure 1.1-2. Cumulative size-specific emission factors for wet bottom boilers burning pulverized bituminous coal.
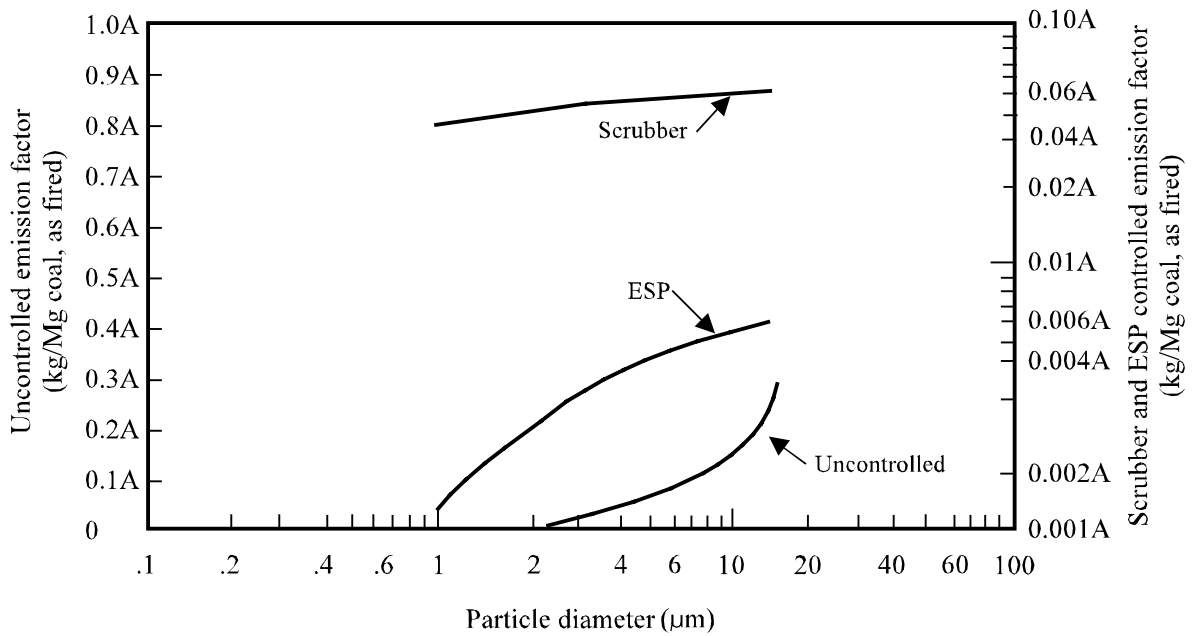
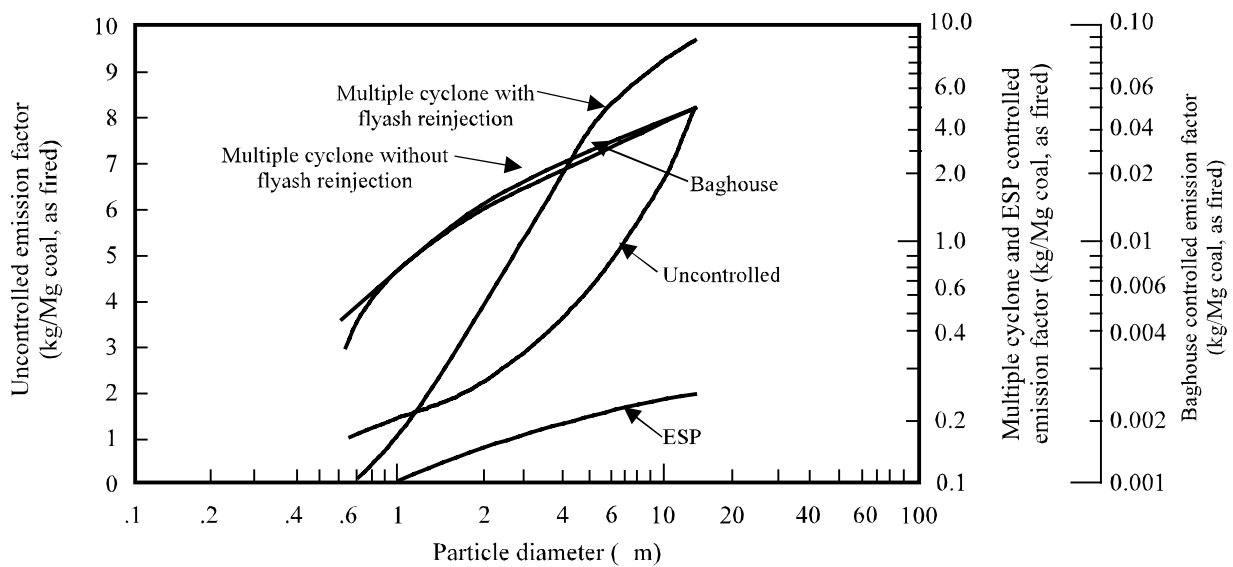Figure 1.1-3. Cumulative size-specific emission factors for cyclone furnaces burning bituminous coal.

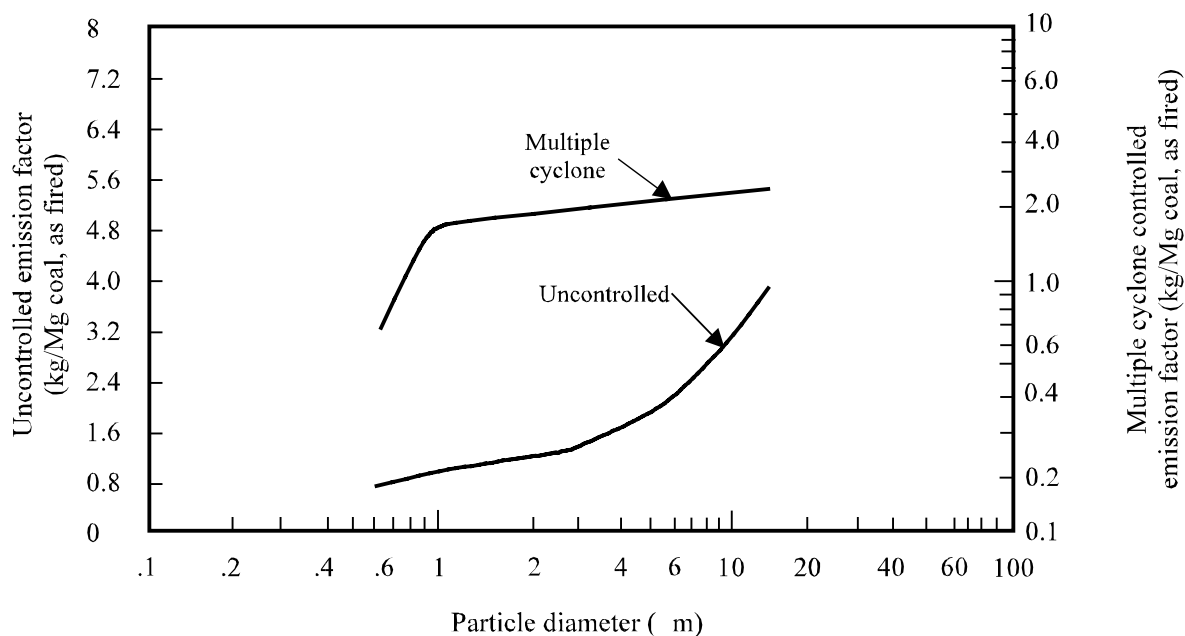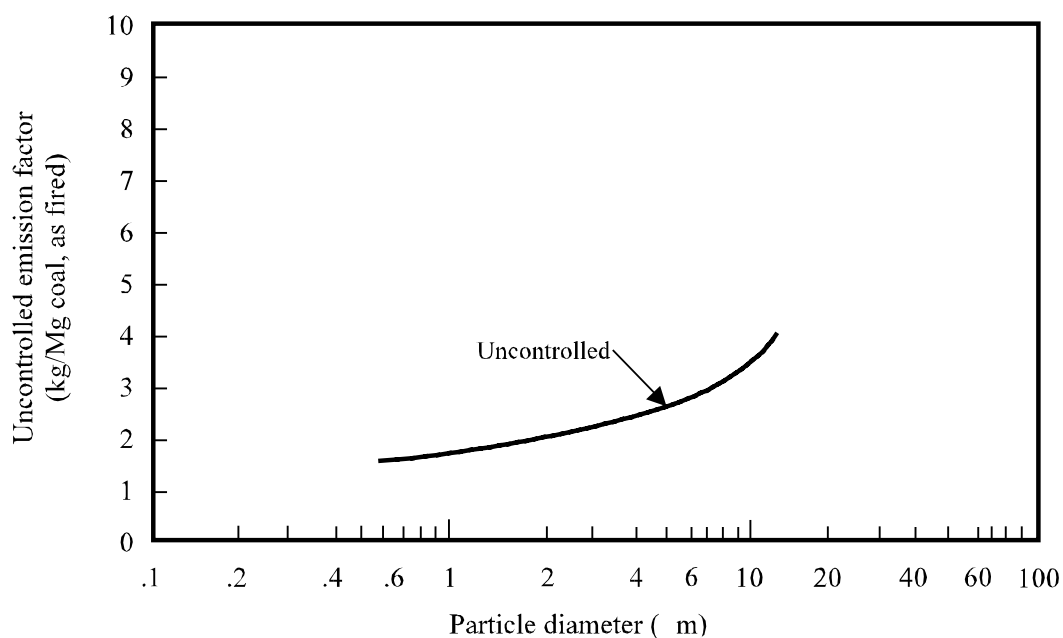Figure 1.1-4. Cumulative size-specific emission factors for spreader stokers burning bituminous coal.

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

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

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