

## 1.3 Fuel Oil Combustion

### 1.3.1 General<sup>1-3</sup>

Two major categories of fuel oil are burned by combustion sources: distillate oils and residual oils. These oils are further distinguished by grade numbers, with Nos. 1 and 2 being distillate oils; Nos. 5 and 6 being residual oils; and No. 4 being either distillate oil or a mixture of distillate and residual oils. No. 6 fuel oil is sometimes referred to as Bunker C. Distillate oils are more volatile and less viscous than residual oils. They have negligible nitrogen and ash contents and usually contain less than 0.3 percent sulfur (by weight). Distillate oils are used mainly in domestic and small commercial applications, and include kerosene and diesel fuels. Being more viscous and less volatile than distillate oils, the heavier residual oils (Nos. 5 and 6) may need to be heated for ease of handling and to facilitate proper atomization. Because residual oils are produced from the residue remaining after the lighter fractions (gasoline, kerosene, and distillate oils) have been removed from the crude oil, they contain significant quantities of ash, nitrogen, and sulfur. Residual oils are used mainly in utility, industrial, and large commercial applications.

### 1.3.2 Firing Practices<sup>4</sup>

The major boiler configurations for fuel oil-fired combustors are watertube, firetube, cast iron, and tubeless design. Boilers are classified according to design and orientation of heat transfer surfaces, burner configuration, and size. These factors can all strongly influence emissions as well as the potential for controlling emissions.

Watertube boilers are used in a variety of applications ranging from supplying large amounts of process steam to providing space heat for industrial facilities. In a watertube boiler, combustion heat is transferred to water flowing through tubes which line the furnace walls and boiler passes. The tube surfaces in the furnace (which houses the burner flame) absorb heat primarily by radiation from the flames. The tube surfaces in the boiler passes (adjacent to the primary furnace) absorb heat primarily by convective heat transfer.

Firetube boilers are used primarily for heating systems, industrial process steam generators, and portable power boilers. In firetube boilers, the hot combustion gases flow through the tubes while the water being heated circulates outside of the tubes. At high pressures and when subjected to large variations in steam demand, firetube units are more susceptible to structural failure than watertube boilers. This is because the high-pressure steam in firetube units is contained by the boiler walls rather than by multiple small-diameter watertubes, which are inherently stronger. As a consequence, firetube boilers are typically small and are used primarily where boiler loads are relatively constant. Nearly all firetube boilers are sold as packaged units because of their relatively small size.

A cast iron boiler is one in which combustion gases rise through a vertical heat exchanger and out through an exhaust duct. Water in the heat exchanger tubes is heated as it moves upward through the tubes. Cast iron boilers produce low pressure steam or hot water, and generally burn oil or natural gas. They are used primarily in the residential and commercial sectors.

Another type of heat transfer configuration used on smaller boilers is the tubeless design. This design incorporates nested pressure vessels with water in between the shells. Combustion gases are fired into the inner pressure vessel and are then sometimes recirculated outside the second vessel.

### 1.3.3 Emissions<sup>5</sup>

Emissions from fuel oil combustion depend on the grade and composition of the fuel, the type and size of the boiler, the firing and loading practices used, and the level of equipment maintenance. Because the combustion characteristics of distillate and residual oils are different, their combustion can produce significantly different emissions. In general, the baseline emissions of criteria and noncriteria pollutants are those from uncontrolled combustion sources. Uncontrolled sources are those without add-on air pollution control (APC) equipment or other combustion modifications designed for emission control. Baseline emissions for sulfur dioxide (SO<sub>2</sub>) and particulate matter (PM) can also be obtained from measurements taken upstream of APC equipment.

#### 1.3.3.1 Particulate Matter Emissions<sup>6-15</sup> -

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 van. 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.

Filterable particulate matter emissions depend predominantly on the grade of fuel fired. Combustion of lighter distillate oils results in significantly lower PM formation than does combustion of heavier residual oils. Among residual oils, firing of No. 4 or No. 5 oil usually produces less PM than does the firing of heavier No. 6 oil.

In general, filterable PM emissions depend on the completeness of combustion as well as on the oil ash content. The PM emitted by distillate oil-fired boilers primarily comprises carbonaceous particles resulting from incomplete combustion of oil and is not correlated to the ash or sulfur content of the oil. However, PM emissions from residual oil burning are related to the oil sulfur content. This is because low-sulfur No. 6 oil, either from naturally low-sulfur crude oil or desulfurized by one of several processes, exhibits substantially lower viscosity and reduced asphaltene, ash, and sulfur contents, which results in better atomization and more complete combustion.

Boiler load can also affect filterable particulate emissions in units firing No. 6 oil. At low load (50 percent of maximum rating) conditions, particulate emissions from utility boilers may be lowered by 30 to 40 percent and by as much as 60 percent from small industrial and commercial units. However, no significant particulate emission reductions have been noted at low loads from boilers firing any of the lighter grades. At very low load conditions (approximately 30 percent of maximum rating), proper combustion conditions may be difficult to maintain and particulate emissions may increase significantly.

#### 1.3.3.2 Sulfur Oxides Emissions<sup>1-2,6-9,16</sup> -

Sulfur oxides (SO<sub>x</sub>) emissions are generated during oil combustion from the oxidation of sulfur contained in the fuel. The emissions of SO<sub>x</sub> from conventional combustion systems are predominantly in the form of SO<sub>2</sub>. Uncontrolled SO<sub>x</sub> emissions are almost entirely dependent on the sulfur content of the fuel and are not affected by boiler size, burner design, or grade of fuel being fired. On average, more than 95 percent of the fuel sulfur is converted to SO<sub>2</sub>, about 1 to 5 percent is further oxidized to sulfur trioxide (SO<sub>3</sub>), and 1 to 3 percent is emitted as sulfate particulate. SO<sub>3</sub> readily reacts with water vapor (both in the atmosphere and in flue gases) to form a sulfuric acid mist.

#### 1.3.3.3 Nitrogen Oxides Emissions<sup>1-2,6-10,15,17-27</sup> -

Oxides of nitrogen ( $\text{NO}_x$ ) formed in combustion processes are due either to thermal fixation of atmospheric nitrogen in the combustion air ("thermal  $\text{NO}_x$ "), or to the conversion of chemically bound nitrogen in the fuel ("fuel  $\text{NO}_x$ "). The term  $\text{NO}_x$  refers to the composite of nitric oxide (NO) and nitrogen dioxide ( $\text{NO}_2$ ). Test data have shown that for most external fossil fuel combustion systems, over 95 percent of the emitted  $\text{NO}_x$  is in the form of nitric oxide (NO). Nitrous oxide ( $\text{N}_2\text{O}$ ) is not included in  $\text{NO}_x$  but has recently received increased interest because of atmospheric effects.

Experimental measurements of thermal  $\text{NO}_x$  formation have shown that  $\text{NO}_x$  concentration is exponentially dependent on temperature, and proportional to  $\text{N}_2$  concentration in the flame, the square root of  $\text{O}_2$  concentration in the flame, and the residence time. Thus, the formation of thermal  $\text{NO}_x$  is affected by four factors: (1) peak temperature, (2) fuel nitrogen concentration, (3) oxygen concentration, and (4) time of exposure at peak temperature. The emission trends due to changes in these factors are generally 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  $\text{NO}_x$  production.

Fuel nitrogen conversion is the more important  $\text{NO}_x$ -forming mechanism in residual oil boilers. It can account for 50 percent of the total  $\text{NO}_x$  emissions from residual oil firing. The percent conversion of fuel nitrogen to  $\text{NO}_x$  varies greatly, however; typically from 20 to 90 percent of nitrogen in oil is converted to  $\text{NO}_x$ . Except in certain large units having unusually high peak flame temperatures, or in units firing a low nitrogen content residual oil, fuel  $\text{NO}_x$  generally accounts for over 50 percent of the total  $\text{NO}_x$  generated. Thermal fixation, on the other hand, is the dominant  $\text{NO}_x$ -forming mechanism in units firing distillate oils, primarily because of the negligible nitrogen content in these lighter oils. Because distillate oil-fired boilers are usually smaller and have lower heat release rates, the quantity of thermal  $\text{NO}_x$  formed in them is less than that of larger units which typically burn residual oil.<sup>28</sup>

A number of variables influence how much  $\text{NO}_x$  is formed by these two mechanisms. One important variable is firing configuration.  $\text{NO}_x$  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), reduced air preheat (RAP), low  $\text{NO}_x$  burners (LNBs), burning oil/water emulsions (OWE), or some combination thereof may result in  $\text{NO}_x$  reductions of 5 to 60 percent. Load reduction (LR) can likewise decrease  $\text{NO}_x$  production. Nitrogen oxide emissions may be reduced from 0.5 to 1 percent for each percentage reduction in load from full load operation. It should be noted that most of these variables, with the exception of excess air, only influence the  $\text{NO}_x$  emissions of large oil-fired boilers. Low excess air-firing is possible in many small boilers, but the resulting  $\text{NO}_x$  reductions are less significant.

#### 1.3.3.4 Carbon Monoxide Emissions<sup>29-32</sup> -

The rate of carbon monoxide (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 well 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 a higher ratio of heat transfer surface area to flame volume than larger combustors have; this leads to reduced flame temperature and combustion intensity and, therefore, lower combustion efficiency.

The presence of CO in the exhaust gases of combustion systems results principally from incomplete fuel combustion. Several conditions can lead to incomplete combustion, including insufficient oxygen ( $\text{O}_2$ ) availability; poor fuel/air mixing; cold-wall flame quenching; reduced combustion temperature; decreased combustion gas residence time; and load reduction (i. e., reduced

combustion intensity). Since various combustion modifications for NO<sub>x</sub> 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.

#### 1.3.3.5 Organic Compound Emissions<sup>29-39</sup> -

Small amounts of organic compounds are emitted from combustion. As with CO emissions, the rate at which organic compounds are emitted depends, to some extent, 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 (TOCs) include VOCs, semi-volatile organic compounds, and condensable 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 all alkanes, alkenes, aldehydes, carboxylic acids, and substituted benzenes (e. g., benzene, toluene, xylene, and ethyl benzene).

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 (PAH or PNA). There are also PAH-nitrogen analogs. Information available in the literature on POM compounds generally pertains to these PAH groups.

Formaldehyde is formed and emitted during combustion of hydrocarbon-based fuels including coal and oil. 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 retention times) have lower formaldehyde emission rates than do smaller, less efficient combustion units.

#### 1.3.3.6 Trace Element Emissions<sup>29-32,40-44</sup> -

Trace elements are also emitted from the combustion of oil. 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 are considered. The quantity of trace elements entering the combustion device depends solely on the fuel composition. The quantity of trace metals emitted from the source 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 separation of emissions into bottom ash and fly ash. In general, the quantity of any given metal emitted depends on the physical and chemical properties of the element itself; concentration of the metal in the fuel; the combustion conditions; and the type of particulate control device used, and its collection efficiency as a function of particle size.

Some trace metals concentrate in certain waste particle streams from a combustor (bottom ash, collector ash, flue gas particulate), while others do not. Various classification schemes to describe this partitioning have been developed. The classification scheme used by Baig, et al.<sup>44</sup> 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 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. For example, several NO<sub>x</sub> controls for boilers reduce peak flame temperatures (e. g., SC, FGR, RAP, OWE, and LR). If combustion temperatures are reduced, fewer Class 2 metals will initially volatilize, and fewer will be available for subsequent condensation and enrichment on fine PM. Therefore, for combustors with particulate controls, lower 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.

Lower local O<sub>2</sub> concentrations is also expected to affect segregating metal emissions from boilers with particle controls. Lower O<sub>2</sub> availability decreases the possibility of volatile metal oxidation to less volatile oxides. Under these conditions, Class 2 metals should remain in the vapor phase as they enter the cooler sections of the boiler. More redistribution to small particles should occur and emissions should increase. Again, Class 1 metal emissions should remain unchanged.

#### 1.3.3.7 Greenhouse Gases<sup>45-50</sup> -

Carbon dioxide (CO<sub>2</sub>), methane (CH<sub>4</sub>), and nitrous oxide (N<sub>2</sub>O) emissions are all produced during fuel oil combustion. Nearly all of the fuel carbon (99 percent) in fuel oil is converted to CO<sub>2</sub> during the combustion process. This conversion is relatively independent of firing configuration. Although the formation of CO acts to reduce CO<sub>2</sub> emissions, the amount of CO produced is insignificant compared to the amount of CO<sub>2</sub> produced. The majority of the fuel carbon not converted to CO<sub>2</sub> is due to incomplete combustion in the fuel stream.

Formation of N<sub>2</sub>O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. Formation of N<sub>2</sub>O is minimized when combustion temperatures are kept high (above 1475°F) and excess air is kept to a minimum (less than 1 percent). Additional sampling and research is needed to fully characterize N<sub>2</sub>O emissions and to understand the N<sub>2</sub>O formation mechanism. Emissions can vary widely from unit to unit, or even from the same unit at different operating conditions. Average emission factors based on reported test data have been developed for conventional oil combustion systems.

Methane emissions vary with the type of fuel and firing configuration, but are highest during periods of incomplete combustion or low-temperature combustion, such as the start-up or shut-down cycle for oil-fired boilers. Typically, conditions that favor formation of N<sub>2</sub>O also favor emissions of CH<sub>4</sub>.

#### 1.3.4 Controls

Control techniques for criteria pollutants from fuel oil combustion may be classified into three broad categories: fuel substitution/alteration, 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 substitution reduces SO<sub>2</sub> or NO<sub>x</sub> and involves burning a fuel with a lower sulfur or nitrogen content, respectively. Particulate matter will generally be reduced when a lighter grade of fuel oil is burned.<sup>6,8,11</sup> Fuel alteration of heavy oils includes mixing water and heavy oil using emulsifying agents for better atomization and lower combustion temperatures. Under some conditions, emissions of NO<sub>x</sub>, CO, and PM may be reduced significantly. Combustion modification includes any physical or operational change in the furnace or boiler and is

applied primarily for NO<sub>x</sub> control purposes, although for small units, some reduction in PM emissions may be available through improved combustion practice. Postcombustion control is a device after the combustion of the fuel and is applied to control emissions of PM, SO<sub>2</sub>, and NO<sub>x</sub>.

#### 1.3.4.1 Particulate Matter Controls<sup>51</sup> -

Control of PM emissions from residential and commercial units is accomplished by improving burner servicing and improving oil atomization and combustion aerodynamics. Optimization of combustion aerodynamics using a flame retention device, swirl, and/or recirculation is considered effective toward achieving the triple goals of low PM emissions, low NO<sub>x</sub> emissions, and high thermal efficiency.

Large industrial and utility boilers are generally well-designed and well-maintained so that soot and condensable organic compound emissions are minimized. Particulate matter emissions are more a result of emitted fly ash with a carbon component in such units. Therefore, postcombustion controls (mechanical collectors, ESP, fabric filters, etc.) or fuel substitution/alteration may be used to reduce PM emissions from these sources.

Mechanical collectors, a prevalent type of control device, are primarily useful in controlling particulates generated during soot blowing, during upset conditions, or when a very dirty heavy oil is fired. For these situations, high-efficiency cyclonic collectors can achieve up to 85 percent control of particulate. Under normal firing conditions, or when a clean oil is combusted, cyclonic collectors are not nearly so effective because of the high percentage of small particles (less than 3 micrometers in diameter) emitted.

Electrostatic precipitators (ESPs) are commonly used in oil-fired power plants. Older precipitators, usually small, typically remove 40 to 60 percent of the emitted PM. Because of the low ash content of the oil, greater collection efficiency may not be required. Currently, new or rebuilt ESPs can achieve collection efficiencies of up to 90 percent.

In fabric filtration, a number of filtering elements (bags) along with a bag cleaning system are contained in a main shell structure incorporating dust hoppers. The particulate removal efficiency of the fabric filter system is dependent on a variety of particle and operational characteristics including particle size distribution, particle cohesion characteristics, and particle electrical resistivity. Operational parameters that affect collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleaning, and cleaning intensity. The structure of the fabric filter, filter composition, and bag properties also affect collection efficiency. Collection efficiencies of baghouses may be more than 99 percent.

Scrubbing systems have also been installed on oil-fired boilers to control both sulfur oxides and particulate. These systems can achieve SO<sub>2</sub> removal efficiencies of 90 to 95 percent and particulate control efficiencies of 50 to 60 percent.

Fuel alteration of heavy oil by mixing with water and an emulsifying agent has reduced PM emissions significantly in controlled tests.

#### 1.3.4.2 SO<sub>2</sub> Controls<sup>52-53</sup> -

Commercialized postcombustion flue gas desulfurization (FGD) processes use an alkaline reagent to absorb SO<sub>2</sub> in the flue gas and produce a sodium or a calcium sulfate compound. These solid sulfate compounds are then removed in downstream equipment. 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 nonregenerable (in which case all waste streams are de-watered and discarded).

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 a saleable sulfur product. Some of the current nonregenerable 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  $\text{SO}_x$  absorbent medium and can be designed to remove greater than 90 percent of the incoming  $\text{SO}_x$ . Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbing are among the commercially proven wet FGD systems. Effectiveness of these devices depends not only on control device design but also on operating variables.

#### 1.3.4.3 $\text{NO}_x$ Controls<sup>41,54-55</sup> -

In boilers fired on crude oil or residual oil, the control of fuel  $\text{NO}_x$  is very important in achieving the desired degree of  $\text{NO}_x$  reduction since fuel  $\text{NO}_x$  typically accounts for 60 to 80 percent of the total  $\text{NO}_x$  formed. Fuel nitrogen conversion to  $\text{NO}_x$  is highly dependent on the fuel-to-air ratio in the combustion zone and, in contrast to thermal  $\text{NO}_x$  formation, is relatively insensitive to small changes in combustion zone temperature. In general, increased mixing of fuel and air increases nitrogen conversion which, in turn, increases fuel  $\text{NO}_x$ . Thus, to reduce fuel  $\text{NO}_x$  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  $\text{N}_2$  rather than  $\text{NO}$ .

Several techniques are used to reduce  $\text{NO}_x$  emissions from fuel oil combustion. Fuel substitution consists of burning lower nitrogen fuels. Fuel alteration includes burning emulsified heavy oil and water mixtures. In addition to these, the primary techniques can be classified into one of two fundamentally different methods — combustion controls and postcombustion controls. Combustion controls reduce  $\text{NO}_x$  by suppressing  $\text{NO}_x$  formation during the combustion process while postcombustion controls reduce  $\text{NO}_x$  emissions after their formation. Combustion controls are the most widely used method of controlling  $\text{NO}_x$  formation in all types of boilers and include low excess air, burners out of service, biased-burner firing, flue gas recirculation, overfire air, and low- $\text{NO}_x$  burners. Postcombustion control methods include selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). These controls can be used separately, or combined to achieve greater  $\text{NO}_x$  reduction.

Operating at low excess air involves reducing the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compliant boiler operation.  $\text{NO}_x$  formation is inhibited because less oxygen is available in the combustion zone. Burners out of service 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 overfire air conditions, and limits  $\text{NO}_x$  formation by lowering the oxygen level in the burner area. Biased-burner firing involves firing the lower rows of burners more fuel-rich than the upper row of burners. This method provides a form of air staging and limits  $\text{NO}_x$  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  $\text{NO}_x$  by 10 to 20 percent from uncontrolled levels.

Flue gas recirculation involves extracting a portion of the flue gas from the economizer section or air heater outlet and readmitting it to the furnace through the furnace hopper, the burner windbox, or both. This method reduces the concentration of oxygen in the combustion zone and may reduce  $\text{NO}_x$  by as much as 40 to 50 percent in some boilers.

Overfire air 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. Overfire air limits  $\text{NO}_x$  by (1) suppressing thermal  $\text{NO}_x$  by partially delaying and extending the combustion process resulting in less intense combustion and cooler flame temperatures; (2) a reduced flame temperature that limits thermal  $\text{NO}_x$  formation, and/or (3) a reduced residence time at peak temperature which also limits thermal  $\text{NO}_x$  formation.

Low  $\text{NO}_x$  burners are applicable to tangential and wall-fired boilers of various sizes. They have been used as a retrofit  $\text{NO}_x$  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 NSPS limits. Low  $\text{NO}_x$  burners can be combined with overfire air to achieve even greater  $\text{NO}_x$  reduction (40 to 60 percent reduction from uncontrolled levels).

SNCR is a postcombustion technique that involves injecting ammonia or urea into specific temperature zones in the upper furnace or convective pass. The ammonia or urea reacts with  $\text{NO}_x$  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  $\text{NO}_x$ ; and the sulfur content of the fuel that may create sulfur compound 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,  $\text{NO}_x$  reductions of 25 to 40 percent have been achieved.

SCR is another postcombustion technique that involves injecting ammonia into the flue gas in the presence of a catalyst to reduce  $\text{NO}_x$  to nitrogen and 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  $\text{NO}_x$  ratio, inlet  $\text{NO}_x$  concentration, space velocity, and catalyst condition.  $\text{NO}_x$  emission reductions of 75 to 85 percent have been achieved through the use of SCR on oil-fired boilers operating in the U.S.

Fuel alteration for  $\text{NO}_x$  reduction includes use of oil/water emulsion fuels. In controlled tests, a mixture of 9 percent water in No. 6 oil with a petroleum based emulsifying agent reduced  $\text{NO}_x$  emissions by 36 percent on a Btu basis or 41 percent on a volume basis, compared with the same fuel in unaltered form. The reduction appears to be due primarily to improved atomization with a corresponding reduction of excess combustion air, with lower flame temperature contributing slightly to the reduction.<sup>84</sup>

Tables 1.3-1 and 1.3-3 present emission factors for uncontrolled criteria pollutants from fuel oil combustion. Tables in this section present emission factors on a volume basis ( $\text{lb}/10^3\text{gal}$ ). To convert to an energy basis ( $\text{lb}/\text{MMBtu}$ ), divide by a heating value of  $150\text{ MMBtu}/10^3\text{gal}$  for Nos. 4, 5, 6, and residual fuel oil, and  $140\text{ MMBtu}/10^3\text{gal}$  for No. 2 and distillate fuel oil. Table 1.3-2 presents emission factors for condensible particulate matter. Tables 1.3-4, 1.3-5, 1.3-6, and 1.3-7 present cumulative size distribution data and size-specific emission factors for particulate emissions from uncontrolled and controlled fuel oil combustion. Figures 1.3-1, 1.3-2, 1.3-3, and 1.3-4 present size-specific emission factors for particulate emissions from uncontrolled and controlled fuel oil combustion. Emission factors for  $\text{N}_2\text{O}$ , POM, and formaldehyde are presented in Table 1.3-8. Emission factors for speciated organic compounds are presented in Table 1.3-9. Emission factors for trace elements in distillate oil are given in Table 1.3-10. Emission factors for trace metals residual oil are given in Table 1.3-11. Default emission factors for  $\text{CO}_2$  are presented in Table 1.3-12. A summary of various  $\text{SO}_2$  and  $\text{NO}_x$  controls for fuel-oil-fired boilers is presented in Table 1.3-13 and 1.3-14, respectively. Emission factors for CO,  $\text{NO}_x$ , and PM from burning No. 6 oil/water emulsion fuel are presented in Table 1.3-15.



### 1.3.5 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 background report for this section. These and other documents can be found on the CHIEF website (<http://www.epa.gov/ttn/chief/ap42/>).

#### Supplement A, February 1996

- The formulas presented in the footnotes for filterable PM were moved into the table.
- For SO<sub>2</sub> and SO<sub>3</sub> emission factors, text was added to the table footnotes to clarify that “S” is a weight percent and not a fraction. A similar clarification was made to the CO and NO<sub>x</sub> footnotes. SCC A2104004/A2104011 was provided for residential furnaces.
- For industrial boilers firing No. 6 and No. 5 oil, the methane emission factor was changed from 1 to 1.0 to show two significant figures.
- For SO<sub>2</sub> and SO<sub>3</sub> factors, text was added to the table footnotes to clarify that “S” is a weight percent and not a fraction.
- The N<sub>2</sub>O, POM, and formaldehyde factors were corrected.
- Table 1.3-10 was incorrectly labeled 1.1-10. This was corrected.

#### Supplement B, October 1996

- Text was added concerning firing practices.
- Factors for N<sub>2</sub>O, POM, and formaldehyde were added.
- New data for filterable PM were used to create a new PM factor for residential oil-fired furnaces.
- Many new factors were added for toxic organics, toxic metals from distillate oil, and toxic metals from residual oil.
- A table was added for new CO<sub>2</sub> emission factors.

#### Supplement E, September 1998

- Table 1.3-1, the sub-heading for "Industrial Boilers" was added to the first column.
- Table 1.3-3, the emission factor for uncontrolled PM less than 0.625 micron was corrected to 1.7A, the emission factor for scrubber controlled PM less than 10 micron was corrected to 0.50A, and the relationships for each content in various fuel oils was corrected in footnote C.
- Table 1.3-4 and 1.3-6, the relationship for ash content in various fuel oils was corrected in the footnote C of each table.
- Table 1.3-9, the emission factors for trace metals in distillate oil were updated with newer data where available.

- Table 1.3-10, the title of the table was changed to clarify these factors apply to uncontrolled fuel oil boilers.
- Text and emission factors were added pertaining to No. 6 oil/water emulsion fuel.
- Table 1.3-1 was revised to include new NOx emission factors.
- Emission factors for condensable particulate matter were added (Table 1.3-2).

Update May 2010 - updates were originally published as erratas on the CHIEF website on April 28, 2000.

- In Table 1.3-1 corrections to SO<sub>2</sub> factors were made for No. 2 oil fired and No.2 oil fired, LNB/FGR boilers. An editorial correction was made to PM filterable factors for boilers < 100 million BTU/hr for No. 5 and No. 6 oil.
- In Table 1.3-8 the correct N<sub>2</sub>O factor is 0.53 lb/1000 gal for No 6 oil and 0.26 lb/1000 gal for distillate oil.

Table 1.3-1. CRITERIA POLLUTANT EMISSION FACTORS FOR FUEL OIL COMBUSTION<sup>a</sup>

Firing Configuration (SCC) <sup>a</sup>	SO <sub>2</sub> <sup>b</sup>		SO <sub>3</sub> <sup>c</sup>		NO <sub>x</sub> <sup>d</sup>		CO <sup>e</sup>		Filterable PM <sup>f</sup>	
	Emission Factor (lb/10 <sup>3</sup> gal)	EMISSION FACTOR RATING	Emission Factor (lb/10 <sup>3</sup> gal)	EMISSION FACTOR RATING	Emission Factor (lb/10 <sup>3</sup> gal)	EMISSION FACTOR RATING	Emission Factor (lb/10 <sup>3</sup> gal)	EMISSION FACTOR RATING	Emission Factor (lb/10 <sup>3</sup> gal)	EMISSION FACTOR RATING
Boilers > 100 Million Btu/hr										
No. 6 oil fired, normal firing (1-01-004-01), (1-02-004-01), (1-03-004-01)	157S	A	5.7S	C	47	A	5	A	9.19(S)+3.22	A
No. 6 oil fired, normal firing, low NO <sub>x</sub> burner (1-01-004-01), (1-02-004-01)	157S	A	5.7S	C	40	B	5	A	9.19(S)+3.22	A
No. 6 oil fired, tangential firing, (1-01-004-04)	157S	A	5.7S	C	32	A	5	A	9.19(S)+3.22	A
No. 6 oil fired, tangential firing, low NO <sub>x</sub> burner (1-01-004-04)	157S	A	5.7S	C	26	E	5	A	9.19(S)+3.22	A
No. 5 oil fired, normal firing (1-01-004-05), (1-02-004-04)	157S	A	5.7S	C	47	B	5	A	10	B
No. 5 oil fired, tangential firing (1-01-004-06)	157S	A	5.7S	C	32	B	5	A	10	B
No. 4 oil fired, normal firing (1-01-005-04), (1-02-005-04)	150S	A	5.7S	C	47	B	5	A	7	B
No. 4 oil fired, tangential firing (1-01-005-05)	150S	A	5.7S	C	32	B	5	A	7	B
No. 2 oil fired (1-01-005-01), (1-02-005-01), (1-03-005-01)	142S <sup>h</sup>	A	5.7S	C	24	D	5	A	2	A
No.2 oil fired, LNB/FGR, (1-01-005-01), (1-02-005-01), (1-03-005-01)	142S <sup>h</sup>	A	5.7S	A	10	D	5	A	2	A

Table 1.3-1. (cont.)

Firing Configuration (SCC) <sup>a</sup>	SO <sub>2</sub> <sup>b</sup>		SO <sub>3</sub> <sup>c</sup>		NO <sub>x</sub> <sup>d</sup>		CO <sup>e</sup>		Filterable PM <sup>f</sup>	
	Emission Factor (lb/10 <sup>3</sup> gal)	EMISSION FACTOR RATING	Emission Factor (lb/10 <sup>3</sup> gal)	EMISSION FACTOR RATING	Emission Factor (lb/10 <sup>3</sup> gal)	EMISSION FACTOR RATING	Emission Factor (lb/10 <sup>3</sup> gal)	EMISSION FACTOR RATING	Emission Factor (lb/10 <sup>3</sup> gal)	EMISSION FACTOR RATING
Boilers < 100 Million Btu/hr										
No. 6 oil fired (1-02-004-02/03) (1-03-004-02/03)	157S	A	2S	A	55	A	5	A	9.19(S)+3.22 <sup>i</sup>	B
No. 5 oil fired (1-03-004-04)	157S	A	2S	A	55	A	5	A	10 <sup>i</sup>	A
No. 4 oil fired (1-03-005-04)	150S	A	2S	A	20	A	5	A	7	B
Distillate oil fired (1-02-005-02/03) (1-03-005-02/03)	142S	A	2S	A	20	A	5	A	2	A
Residential furnace (A2104004/A2104011)	142S	A	2S	A	18	A	5	A	0.4 <sup>g</sup>	B

a To convert from lb/103 gal to kg/103 L, multiply by 0.120. SCC = Source Classification Code.

b References 1-2,6-9,14,56-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.

c References 1-2,6-8,16,57-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.

d References 6-7,15,19,22,56-62. Expressed as NO<sub>2</sub>. Test results indicate that at least 95% by weight of NO<sub>x</sub> is NO for all boiler types except residential furnaces, where about 75% is NO. For utility vertical fired boilers use 105 lb/103 gal at full load and normal (>15%) excess air. Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are related to fuel nitrogen content, estimated by the following empirical relationship: lb NO<sub>2</sub> /103 gal = 20.54 + 104.39(N), where N is the weight % of nitrogen in the oil. For example, if the fuel is 1% nitrogen, then N = 1.

e References 6-8,14,17-19,56-61. CO emissions may increase by factors of 10 to 100 if the unit is improperly operated or not well maintained.

f References 6-8,10,13-15,56-60,62-63. Filterable PM is that particulate collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. Particulate emission factors for residual oil combustion are, on average, a function of fuel oil sulfur content where S is the weight % of sulfur in oil. For example, if fuel oil is 1% sulfur, then S = 1.

g Based on data from new burner designs. Pre-1970's burner designs may emit filterable PM as high as 3.0 lb/103 gal.

h The SO<sub>2</sub> emission factor for both no. 2 oil fired and for no. 2 oil fired with LNB/FGR, is 142S, not 157S. Errata dated April 28, 2000. Section corrected May 2010.

i The PM factors for No.6 and No. 5 fuel were reversed. Errata dated April 28, 2000. Section corrected May 2010.

Table 1.3-2. CONDENSABLE PARTICULATE MATTER EMISSION FACTORS FOR OIL COMBUSTION<sup>a</sup>

Firing Configuration <sup>b</sup> (SCC)	Controls	CPM - TOT <sup>c, d</sup>		CPM - IOR <sup>c, d</sup>		CPM - ORG <sup>c, d</sup>	
		Emission Factor (lb/10 <sup>3</sup> gal)	EMISSION FACTOR RATING	Emission Factor (lb/10 <sup>3</sup> gal)	EMISSION FACTOR RATING	Emission Factor (lb/10 <sup>3</sup> gal)	EMISSION FACTOR RATING
No. 2 oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	All controls, or uncontrolled	1.3 <sup>d, e</sup>	D	65% of CPM-TOT emission factor <sup>c</sup>	D	35% of CPM-TOT emission factor <sup>c</sup>	D
No. 6 oil fired (1-01-004-01/04, 1-02-004-01, 1-03-004-01)	All controls, or uncontrolled	1.5 <sup>f</sup>	D	85% of CPM-TOT emission factor <sup>d</sup>	E	15% of CPM-TOT emission factor <sup>d</sup>	E

<sup>a</sup> All condensable PM is assumed to be less than 1.0 micron in diameter.

<sup>b</sup> No data are available for numbers 3, 4, and 5 oil. For number 3 oil, use the factors provided for number 2 oil. For numbers 4 and 5 oil, use the factors provided for number 6 oil.

<sup>c</sup> CPM-TOT = total condensable particulate matter.

CPM-IOR = inorganic condensable particulate matter.

CPM-ORG = organic condensable particulate matter.

<sup>d</sup> To convert to lb/MMBtu of No. 2 oil, divide by 140 MMBtu/10<sup>3</sup> gal. To convert to lb/MMBtu of No. 6 oil, divide by 150 MMBtu/10<sup>3</sup> gal.

<sup>e</sup> References: 76-78.

<sup>f</sup> References: 79-82.

Table 1.3-3. EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC), METHANE, AND NONMETHANE TOC (NMTOC) FROM UNCONTROLLED FUEL OIL COMBUSTION<sup>a</sup>

EMISSION FACTOR RATING: A

Firing Configuration (SCC)	TOC <sup>b</sup> Emission Factor (lb/10 <sup>3</sup> gal)	Methane <sup>b</sup> Emission Factor (lb/10 <sup>3</sup> gal)	NMTOC <sup>b</sup> Emission Factor (lb/10 <sup>3</sup> gal)
Utility boilers			
No. 6 oil fired, normal firing (1-01-004-01)	1.04	0.28	0.76
No. 6 oil fired, tangential firing (1-01-004-04)	1.04	0.28	0.76
No. 5 oil fired, normal firing (1-01-004-05)	1.04	0.28	0.76
No. 5 oil fired, tangential firing (1-01-004-06)	1.04	0.28	0.76
No. 4 oil fired, normal firing (1-01-005-04)	1.04	0.28	0.76
No. 4 oil fired, tangential firing (1-01-005-05)	1.04	0.28	0.76
Industrial boilers			
No. 6 oil fired (1-02-004-01/02/03)	1.28	1.00	0.28
No. 5 oil fired (1-02-004-04)	1.28	1.00	0.28
Distillate oil fired (1-02-005-01/02/03)	0.252	0.052	0.2
No. 4 oil fired (1-02-005-04)	0.252	0.052	0.2
Commercial/institutional/residential combustors			
No. 6 oil fired (1-03-004-01/02/03)	1.605	0.475	1.13
No. 5 oil fired (1-03-004-04)	1.605	0.475	1.13
Distillate oil fired (1-03-005-01/02/03)	0.556	0.216	0.34
No. 4 oil fired (1-03-005-04)	0.556	0.216	0.34
Residential furnace (A2104004/A2104011)	2.493	1.78	0.713

a To convert from lb/103 gal to kg/103 L, multiply by 0.12. SCC = Source Classification Code.

b References 29-32. Volatile organic compound emissions can increase by several orders of magnitude if the boiler is improperly operated or is not well maintained.

Table 1.3-4. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS  
FOR UTILITY BOILERS FIRING RESIDUAL OIL<sup>a</sup>

Particle Size <sup>b</sup> (μm)	Cumulative Mass % Stated Size			Cumulative Emission Factor lb/10 <sup>3</sup> gal)					
	Uncon- trolled	Controlled		Uncontrolled <sup>c</sup>		ESP Controlled <sup>d</sup>		Scrubber Controlled <sup>e</sup>	
		ESP	Scrubber	Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING
15	80	75	100	6.7A	C	0.05A	E	0.50A	D
10	71	63	100	5.9A	C	0.042A	E	0.50A	D
6	58	52	100	4.8A	C	0.035A	E	0.50A	D
2.5	52	41	97	4.3A	C	0.028A	E	0.48A	D
1.25	43	31	91	3.6A	C	0.021A	E	0.46A	D
1.00	39	28	84	3.3A	C	0.018A	E	0.42A	D
0.625	20	20	64	1.7A	C	0.007A	E	0.32A	D
TOTAL	100	100	100	8.3A	C	0.067A	E	0.50A	D

a Reference 26. Source Classification Codes 1-01-004-01/04/05/06 and 1-01-005-04/05. To convert from lb/103 gal to kg/m<sup>3</sup>, multiply by 0.120. ESP = electrostatic precipitator.

b Expressed as aerodynamic equivalent diameter.

c Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content where S is the weight % of sulfur in the oil. For example, if the fuel is 1.00% sulfur, then S = 1.

No. 6 oil:  $A = 1.12(S) + 0.37$

No. 5 oil:  $A = 1.2$

No. 4 oil:  $A = 0.84$

d Estimated control efficiency for ESP is 99.2%.

e Estimated control efficiency for scrubber is 94%

Table 1.3-5. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR INDUSTRIAL BOILERS FIRING RESIDUAL OIL<sup>a</sup>

Particle Size <sup>b</sup> (μm)	Cumulative Mass %, Stated Size		Cumulative Emission Factor <sup>c</sup> (lb/10 <sup>3</sup> gal)			
	Uncontrolled	Multiple Cyclone Controlled	Uncontrolled		Multiple Cyclone Controlled <sup>d</sup>	
			Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING
15	91	100	7.59A	D	1.67A	E
10	86	95	7.17A	D	1.58A	E
6	77	72	6.42A	D	1.17A	E
2.5	56	22	4.67A	D	0.33A	E
1.25	39	21	3.25A	D	0.33A	E
1.00	36	21	3.00A	D	0.33A	E
0.625	30	— <sup>e</sup>	2.50A	D	— <sup>e</sup>	NA
TOTAL	100	100	8.34A	D	1.67A	E

a Reference 26. Source Classification Codes 1-02-004-01/02/03/04 and 1-02-005-04. To convert lb/103 gal to kg/103 L, multiply by 0.120. NA = not applicable.

b Expressed as aerodynamic equivalent diameter.

c Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content where S is the weight % of sulfur in the oil. For example, if the fuel is 1.0% sulfur, then S = 1.

No. 6 oil: A = 1.12(S) + 0.37

No. 5 oil: A = 1.2

No. 4 oil: A = 0.84

d Estimated control efficiency for multiple cyclone is 80%.

e Insufficient data.



Table 1.3-6. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR UNCONTROLLED INDUSTRIAL BOILERS FIRING DISTILLATE OIL<sup>a</sup>

EMISSION FACTOR RATING: E

Particle Size <sup>b</sup> (μm)	Cumulative Mass %, Stated Size	Cumulative Emission Factor (lb/10 <sup>3</sup> gal)
15	68	1.33
10	50	1.00
6	30	0.58
2.5	12	0.25
1.25	9	0.17
1.00	8	0.17
0.625	2	0.04
TOTAL	100	2.00

<sup>a</sup> Reference 26. Source Classification Codes 1-02-005-01/02/03. To convert from lb/10<sup>3</sup> gal to kg/10<sup>3</sup> L, multiply by 0.12.

<sup>b</sup> Expressed as aerodynamic equivalent diameter.

Table 1.3-7. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS UNCONTROLLED COMMERCIAL BOILERS BURNING RESIDUAL OR DISTILLATE OIL<sup>a</sup>

EMISSION FACTOR RATING: D

Particle Size <sup>b</sup> (μm)	Cumulative Mass %, Stated Size		Cumulative Emission Factor <sup>c</sup> (lb/10 <sup>3</sup> gal)	
	Residual Oil	Distillate Oil	Residual Oil	Distillate Oil
15	78	60	6.50A	1.17
10	62	55	5.17A	1.08
6	44	49	3.67A	1.00
2.5	23	42	1.92A	0.83
1.25	16	38	1.33A	0.75
1.00	14	37	1.17A	0.75
0.625	13	35	1.08A	0.67
TOTAL	100	100	8.34A	2.00

<sup>a</sup> Reference 26. Source Classification Codes: 1-03-004-01/02/03/04 and 1-03-005-01/02/03/04. To convert from lb/10<sup>3</sup> gal to kg/10<sup>3</sup> L, multiply by 0.12.

<sup>b</sup> Expressed as aerodynamic equivalent diameter.

<sup>c</sup> Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content where S is the weight % of sulfur in the fuel. For example, if the fuel is 1.0% sulfur, then S = 1.

No. 6 oil: A = 1.12(S) + 0.37

No. 5 oil: A = 1.2

No. 4 oil: A = 0.84

No. 2 oil: A = 0.24

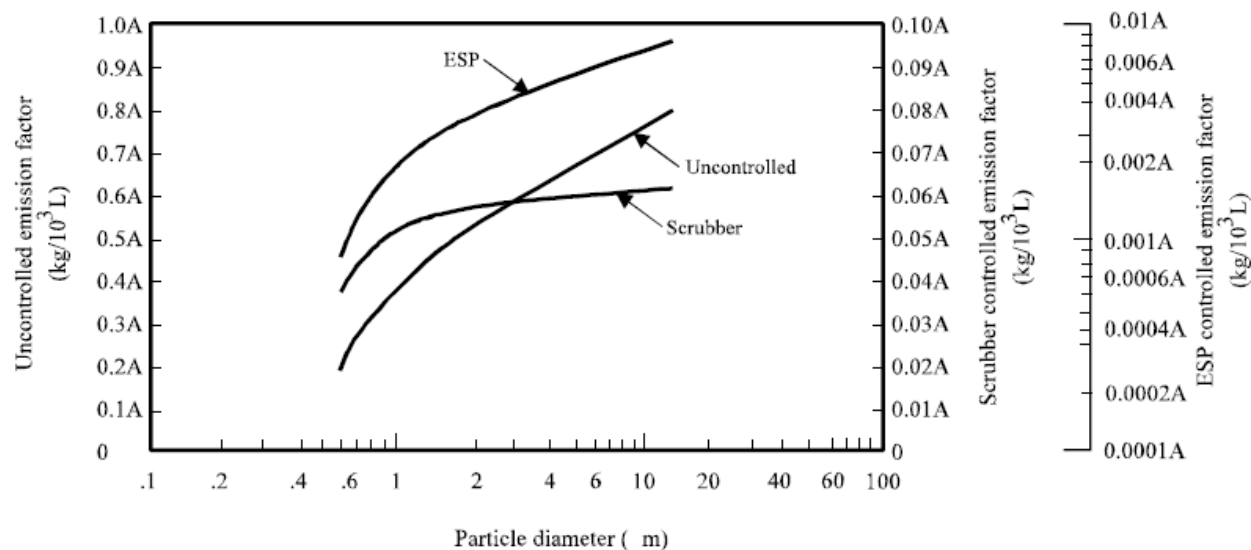


Figure 1.3-1. Cumulative size-specific emission factors for utility boilers firing residual oil.

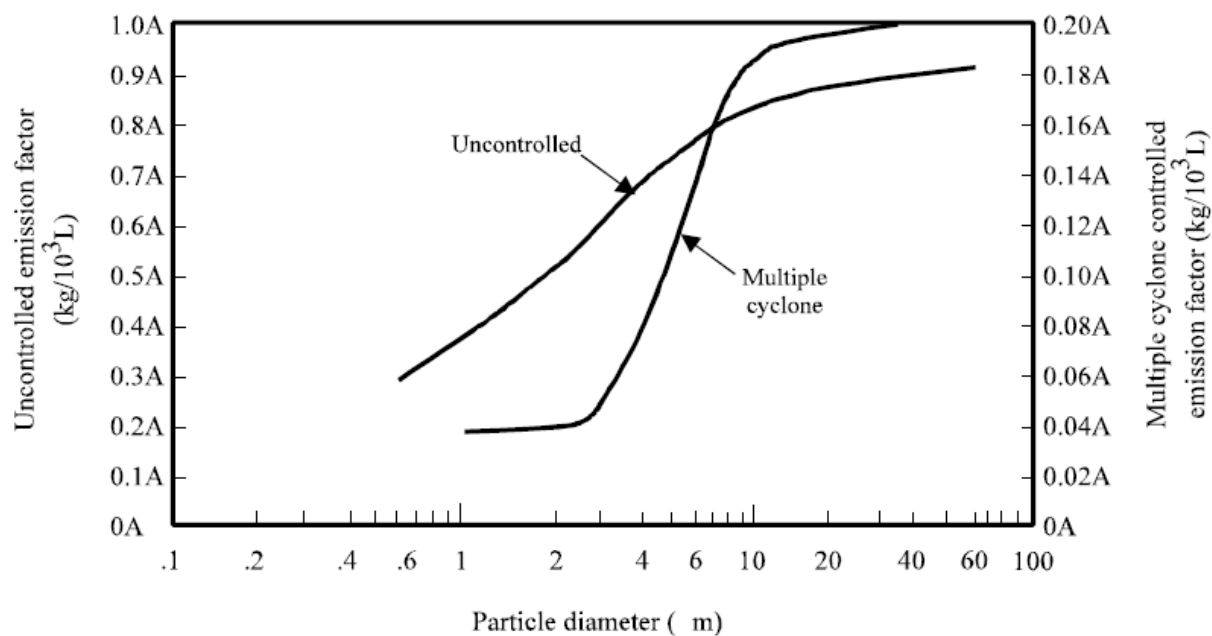


Figure 1.3-2. Cumulative size-specific emission factors for industrial boilers firing residual oil.

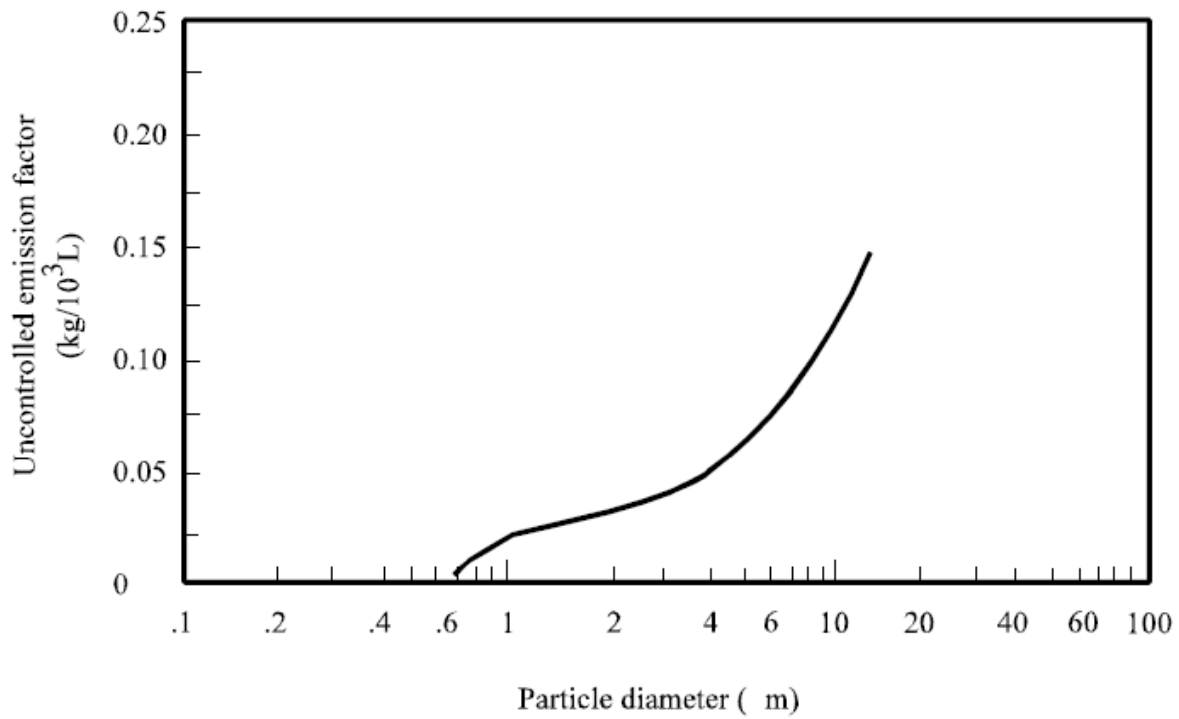


Figure 1.3-3. Cumulative size-specific emission factors for uncontrolled industrial boilers firing distillate oil.

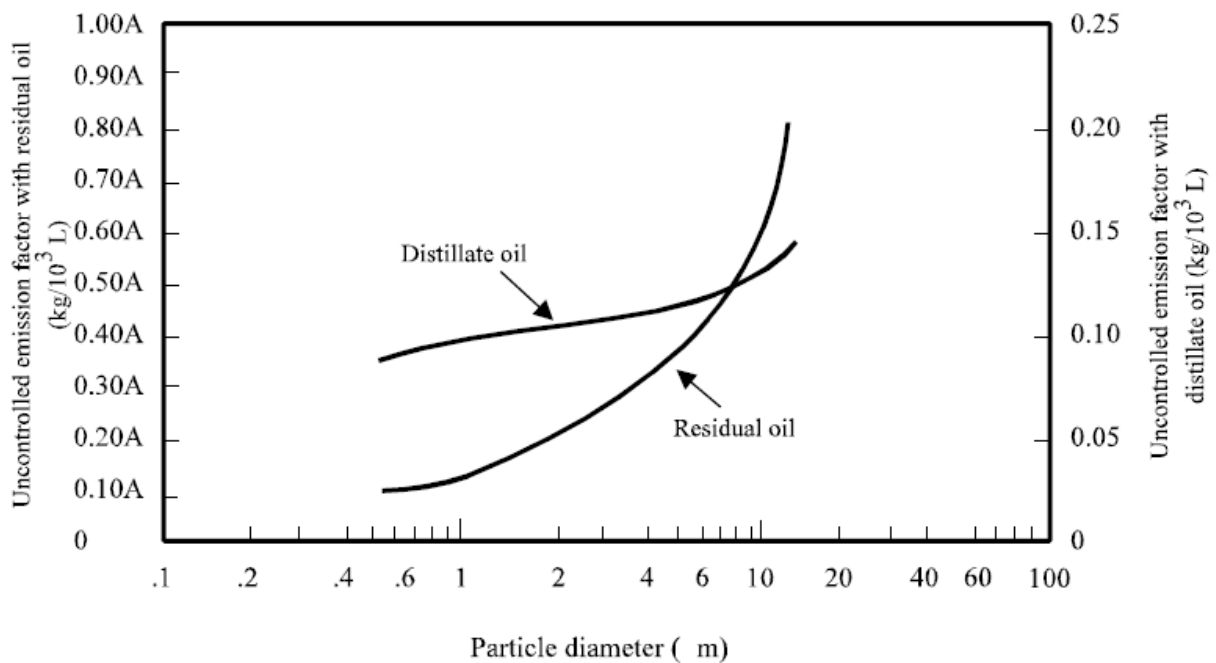


Figure 1.3-4. Cumulative size-specific emission factors for uncontrolled commercial boilers burning residual and distillate oil.

Table 1.3-8. EMISSION FACTORS FOR NITROUS OXIDE (N<sub>2</sub>O),  
POLYCYCLIC ORGANIC MATTER (POM), AND FORMALDEHYDE (HCOH)  
FROM FUEL OIL COMBUSTION<sup>a</sup>

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Emission Factor (lb/10 <sup>3</sup> gal)		
	N <sub>2</sub> O <sup>b</sup>	POM <sup>c</sup>	HCOH <sup>c</sup>
Utility/industrial/commercial boilers			
No. 6 oil fired (1-01-004-01, 1-02-004-01, 1-03-004-01)	0.53	0.0011 - 0.0013 <sup>d</sup>	0.024 - 0.061
Distillate oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	0.26	0.0033 <sup>e</sup>	0.035 - 0.061
Residential furnaces (A2104004/A2104011)	0.05	ND	ND

<sup>a</sup> To convert from lb/10<sup>3</sup> gal to kg/10<sup>3</sup> L, multiply by 0.12. SCC = Source Classification Code. ND = no data.

<sup>b</sup> References 45-46. EMISSION FACTOR RATING = B.

<sup>c</sup> References 29-32.

<sup>d</sup> Particulate and gaseous POM.

<sup>e</sup> Particulate POM only.

Table 1.3-9. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS  
FROM FUEL OIL COMBUSTION<sup>a</sup>

Organic Compound	Average Emission Factor <sup>b</sup> (lb/10 <sup>3</sup> Gal)	EMISSION FACTOR RATING
Benzene	2.14E-04	C
Ethylbenzene	6.36E-05 <sup>c</sup>	E
Formaldehyde <sup>d</sup>	3.30E-02	C
Naphthalene	1.13E-03	C
1,1,1-Trichloroethane	2.36E-04 <sup>c</sup>	E
Toluene	6.20E-03	D
o-Xylene	1.09E-04 <sup>c</sup>	E
Acenaphthene	2.11E-05	C
Acenaphthylene	2.53E-07	D
Anthracene	1.22E-06	C
Benz(a)anthracene	4.01E-06	C
Benzo(b,k)fluoranthene	1.48E-06	C
Benzo(g,h,i)perylene	2.26E-06	C
Chrysene	2.38E-06	C
Dibenzo(a,h) anthracene	1.67E-06	D
Fluoranthene	4.84E-06	C
Fluorene	4.47E-06	C
Indo(1,2,3-cd)pyrene	2.14E-06	C
Phenanthrene	1.05E-05	C
Pyrene	4.25E-06	C
OCDD	3.10E-09 <sup>c</sup>	E

<sup>a</sup> Data are for residual oil fired boilers, Source Classification Codes (SCCs) 1-01-004-01/04.

<sup>b</sup> References 64-72. To convert from lb/10<sup>3</sup> gal to kg/10<sup>3</sup> L, multiply by 0.12.

<sup>c</sup> Based on data from one source test (Reference 67).

<sup>d</sup> The formaldehyde number presented here is based only on data from utilities using No. 6 oil. The number presented in Table 1.3-7 is based on utility, commercial, and industrial boilers.

Table 1.3-10. EMISSION FACTORS FOR TRACE ELEMENTS FROM DISTILLATE FUEL OIL COMBUSTION SOURCES<sup>a</sup>

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Emission Factor (lb/10 <sup>12</sup> Btu)										
	As	Be	Cd	Cr	Cu	Pb	Hg	Mn	Ni	Se	Zn
Distillate oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	4	3	3	3	6	9	3	6	3	15	4

<sup>a</sup> Data are for distillate oil fired boilers, SCC codes 1-01-005-01, 1-02-005-01, and 1-03-005-01. References 29-32, 40-44 and 83. To convert from lb/10<sup>12</sup> Btu to pg/J, multiply by 0.43.

Table 1.3-11. EMISSION FACTORS FOR METALS FROM UNCONTROLLED NO. 6 FUEL OIL COMBUSTION<sup>a</sup>

Metal	Average Emission Factor <sup>b, d</sup> (lb/10 <sup>3</sup> Gal)	EMISSION FACTOR RATING
Antimony	5.25E-03 <sup>c</sup>	E
Arsenic	1.32E-03	C
Barium	2.57E-03	D
Beryllium	2.78E-05	C
Cadmium	3.98E-04	C
Chloride	3.47E-01	D
Chromium	8.45E-04	C
Chromium VI	2.48E-04	C
Cobalt	6.02E-03	D
Copper	1.76E-03	C
Fluoride	3.73E-02	D
Lead	1.51E-03	C
Manganese	3.00E-03	C
Mercury	1.13E-04	C
Molybdenum	7.87E-04	D
Nickel	8.45E-02	C
Phosphorous	9.46E-03	D
Selenium	6.83E-04	C
Vanadium	3.18E-02	D
Zinc	2.91E-02	D

<sup>a</sup> Data are for residual oil fired boilers, Source Classification Codes (SCCs) 1-01-004-01/04.

<sup>b</sup> References 64-72. 18 of 19 sources were uncontrolled and 1 source was controlled with low efficiency ESP. To convert from lb/10<sup>3</sup> gal to kg/10<sup>3</sup> L, multiply by 0.12.

<sup>c</sup> References 29-32,40-44.

<sup>d</sup> For oil/water mixture, reduce factors in proportion to water content of the fuel (due to dilution). To adjust the listed values for water content, multiply the listed value by 1-decimal fraction of water (ex: For fuel with 9 percent water by volume, multiply by 1-0.9=.91).

Table 1.3-12. DEFAULT CO<sub>2</sub> EMISSION FACTORS FOR LIQUID FUELS<sup>a</sup>

EMISSION FACTOR RATING: B

Fuel Type	%C <sup>b</sup>	Density <sup>c</sup> (lb/gal)	Emission Factor (lb/10 <sup>3</sup> gal)
No. 1 (kerosene)	86.25	6.88	21,500
No. 2	87.25	7.05	22,300
Low Sulfur No. 6	87.26	7.88	25,000
High Sulfur No. 6	85.14	7.88	24,400

<sup>a</sup> Based on 99% conversion of fuel carbon content to CO<sub>2</sub>. To convert from lb/gal to gram/cm<sup>3</sup>, multiply by 0.12. To convert from lb/10<sup>3</sup> gal to kg/m<sup>3</sup>, multiply by 0.12.

<sup>b</sup> Based on an average of fuel carbon contents given in references 73-74.

<sup>c</sup> References 73, 75.



Table 1.3-13. POSTCOMBUSTION SO<sub>2</sub> CONTROLS FOR FUEL OIL 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 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.

Table 1.3-14. NO<sub>x</sub> CONTROL OPTIONS FOR OIL-FIRED BOILERS<sup>a</sup>

Control Technique	Description Of Technique	NO <sub>x</sub> Reduction Potential (%)		Range Of Application	Commercial Availability/ R&D Status	Comments
		Residual Oil	Distillate Oil			
Low Excess Air (LEA)	Reduction of combustion air	0 to 28	0 to 24	Generally excess O <sub>2</sub> can be reduced to 2.5% representing a 3% drop from baseline	Available for boilers with sufficient operational flexibility.	Added benefits included increase in boiler efficiency. Limited by increase in CO, HC, and smoke emissions.
Staged Combustion (SC)	Fuel-rich firing burners with secondary combustion air ports	20 to 50	17 to 44	70-90% burner stoichiometries can be used with proper installation of secondary air ports	Technique is applicable on packaged and field-erected units. However, not commercially available for all design types.	Best implemented on new units. Retrofit is probably not feasible for most units, especially packaged ones.
Burners Out of Service (BOOS)	One or more burners on air only. Remainder of burners firing fuel-rich	10 to 30	ND	Most effective on boilers with 4 or more burners in a square pattern.	Available.	Requires careful selection of BOOS pattern and control of air flow. May result in boiler de-rating unless fuel delivery system is modified.
Flue Gas Recirculation (FGR)	Recirculation of portion of flue gas to burners	15 to 30	58 to 73	Up to 25-30% of flue gas recycled. Can be implemented on most design types.	Available. Best suited for new units.	Requires extensive modifications to the burner and windbox. Possible flame instability at high FGR rates.
Flue Gas Recirculation Plus Staged Combustion	Combined techniques of FGR and staged combustion	25 to 53	73 to 77	Maximum FGR rates set at 25% for distillate oil and 20% for residual oil.	Available for boilers with sufficient operational flexibility.	May not be feasible on all existing boiler types. Best implemented on new units.

Table 1.3-14 (cont.).

Control Technique	Description Of Technique	NO <sub>x</sub> Reduction Potential (%)		Range Of Application	Commercial Availability/ R&D Status	Comments
		Residual Oil	Distillate Oil			
Load Reduction (LR)	Reduction of air and fuel flow to all burners in service	33% decrease to 25% increase in NO <sub>x</sub>	31% decrease to 17% increase in NO <sub>x</sub>	Applicable to all boiler types and sizes. Load can be reduced to 25% of maximum.	Available in retrofit applications.	Technique not effective when it necessitates an increase in excess O <sub>2</sub> levels. LR possibly implemented in new designs as reduced combustion intensity (i. e., enlarged furnace plan area).
Low NO <sub>x</sub> Burners (LNB)	New burner designs with controlled air/fuel mixing and increased heat dissipation	20 to 50	20 to 50	New burners described generally applicable to all boilers.	Commercially available.	Specific emissions data from industrial boilers equipped with LNB are lacking.
Reduced Air Preheat (RAP)	Bypass of combustion air preheater	5 to 16	ND	Combustion air temperature can be reduced to ambient conditions.	Available.	Application of this technique on new boilers requires installation of alternate heat recovery system (e. g., an economizer).
Selective Noncatalytic Reduction (SNCR)	Injection of NH <sub>3</sub> or urea as a reducing agent in the flue gas	40 to 70	40 to 70	Applicable for large packaged and field-erected watertube boilers. May not be feasible for fire-tube boilers.	Commercially offered but not widely demonstrated on large boilers.	Elaborate reagent injection, monitoring, and control system required. Possible load restrictions on boilers and air preheater fouling when burning high sulfur oil. Must have sufficient residence time at correct temperature.
Conventional Selective Catalytic Reduction (SCR)	Injections of NH <sub>3</sub> in the presence of a catalyst (usually upstream of air heater).	Up to 90% (estimated)	Up to 90% (estimated)	Typically large boiler designs	Commercially offered but not widely demonstrated.	Applicable to most boiler designs as a retrofit technology or for new boilers.

Table 1.3-14 (cont.).

Control Technique	Description Of Technique	NO <sub>x</sub> Reduction Potential (%)		Range Of Application	Commercial Availability/ R&D Status	Comments
		Residual Oil	Distillate Oil			
Air Heater (SCR)	Catalyst-coated baskets in the air heater.	40-65 (estimated)	40-65 (estimated)	Boilers with rotating-basket air heaters	Available but not widely demonstrated	Design must address pressure drop and maintain heat transfer.
Duct SCR	A smaller version of conventional SCR is placed in existing ductwork	30 (estimated)	30 (estimated)	Typically large boiler designs	Available but not widely demonstrated.	Location of SCR in duct is temperature dependent.
Activated Carbon SCR	Activated carbon catalyst, installed downstream of air heater.	ND	ND	Typically large boiler designs	Available but not widely demonstrated.	High pressure drop.
Oil/Water Emulsified Fuel <sup>a,b</sup>	Oil/water fuel with emulsifying agent	41	ND	Firetube boilers	Available but not widely demonstrated	Thermal efficiency reduced due to water content

<sup>a</sup> ND = no data.

<sup>b</sup> Test conducted by EPA using commercially premixed fuel and water (9 percent water) containing a petroleum based emulsifying agent. Test boiler was a 2400 lb/hr, 15 psig Scotch Marine firetube type, fired at  $2 \times 10^6$  Btu/hr.

Table 1.3-15. EMISSION FACTORS FOR NO. 6 OIL/WATER EMULSION IN INDUSTRIAL/COMMERCIAL/INSTITUTIONAL BOILERS<sup>a</sup>

Pollutant	Emission Factor (lb/10 <sup>3</sup> gal)	Factor Rating	Comments
CO	1.90	C	33% Reduction from plain oil
NO <sub>x</sub>	38.0	C	41% Reduction
PM	14.9	C	45% Reduction

<sup>a</sup> Test conducted by EPA using commercially premixed fuel and water (9 percent water) containing a petroleum based emulsifying agent. Test boiler was a 2400 lb/hr, 15 psig Scotch Marine firetube type, fired at  $2 \times 10^6$  Btu/hr.

### References For Section 1.3

1. W. S. Smith, *Atmospheric Emissions From Fuel Oil Combustion: An Inventory Guide*, 999-AP-2, U. S. Environmental Protection Agency, Washington, DC, November 1962.
2. J. A. Danielson (ed.), *Air Pollution Engineering Manual*, Second Edition, AP-40, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1973. Out of Print.
3. *Fossil Fuel Fired Industrial Boilers — Background Information: Volume 1*, EPA-450/3-82-006a, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1982.
4. Emission Factor Documentation For AP-42, Section 1.3, Fuel Oil Combustion, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1993.
5. U. S. Environmental Protection Agency, "National Primary and Secondary Ambient Air Quality Standards", Code of Federal Regulations, Title 40, Part 50, U. S. Government Printing Office, Washington DC, 1991.
6. A. Levy, *et al.*, *A Field Investigation Of Emissions From Fuel Oil Combustion For Space Heating*, API Bulletin 4099, Battelle Columbus Laboratories, Columbia, OH, November 1971.
7. R. E. Barrett, *et al.*, *Field Investigation Of Emissions From Combustion Equipment For Space Heating*, EPA-R2-73-084a, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1973.
8. G. A. Cato, *et al.*, *Field Testing: Application Of Combustion Modifications To Control Pollutant Emissions From Industrial Boilers—Phase I*, EPA-650/2-74-078a, U. S. Environmental Protection Agency, Washington, DC, October 1974.
9. G. A. Cato, *et al.*, *Field Testing: Application Of Combustion Modifications To Control Pollutant Emissions From Industrial Boilers—Phase II*, EPA-600/ 2-76-086a, U. S. Environmental Protection Agency, Washington, DC, April 1976.
10. *Particulate Emission Control Systems For Oil Fired Boilers*, EPA-450/3-74-063, U. S. Environmental Protection Agency, Research Triangle Park, NC, December 1974.
11. C. W. Siegmund, "Will Desulfurized Fuel Oils Help?", *American Society Of Heating, Refrigerating And Air Conditioning Engineers Journal*, 11:29-33, April 1969.
12. F. A. Govan, *et al.*, "Relationships of Particulate Emissions Versus Partial to Full Load Operations for Utility-sized Boilers", *Proceedings Of Third Annual Industrial Air Pollution Control Conference*, Knoxville, TN, March 29-30, 1973.
13. Emission Test Reports, Docket No. OAQPS-78-1, Category II-I-257 through 265, Office Of Air Quality Planning And Standards, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1972 through 1974.
14. C. Leavitt, *et al.*, *Environmental Assessment Of An Oil Fired Controlled Utility Boiler*, EPA-600/7-80-087, U. S. Environmental Protection Agency, Washington, DC, April 1980.

15. W. A. Carter and R. J. Tidona, *Thirty-day Field Tests of Industrial Boilers: Site 2—Residual-oil-fired Boiler*, EPA-600/7-80-085b, U. S. Environmental Protection Agency, Washington, DC, April 1980.
16. *Primary Sulfate Emissions From Coal And Oil Combustion*, EPA Contract No. 68-02-3138, TRW, Inc., Redondo Beach, CA, February 1980.
17. W. Bartok, *et al.*, *Systematic Field Study Of NO<sub>x</sub> Emission Control Methods For Utility Boilers*, APTD-1163, U. S. Environmental Protection Agency, Research Triangle Park, NC, December 1971.
18. A. R. Crawford, *et al.*, *Field Testing: Application Of Combustion Modifications To Control NO<sub>x</sub> Emissions From Utility Boilers*, EPA-650/2-74-066, U. S. Environmental Protection Agency, Washington, DC, June 1974.
19. J. F. Deffner, *et al.*, *Evaluation Of Gulf Econojet Equipment With Respect To Air Conservation*, Report No. 731RC044, Gulf Research and Development Company, Pittsburgh, PA, December 18, 1972.
20. C. E. Blakeslee and H.E. Burbach, "Controlling NO<sub>x</sub> Emissions From Steam Generators," *Journal Of The Air Pollution Control Association*, 23:37-42, January 1973.
21. R. E. Hall, *et al.*, *A Study Of Air Pollutant Emissions From Residential Heating Systems*, EPA-650/2-74-003, U. S. Environmental Protection Agency, Washington, DC, January 1974.
22. R. J. Milligan, *et al.*, *Review Of NO<sub>x</sub> Emission Factors For Stationary Fossil Fuel Combustion Sources*, EPA-450/4-79-021, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1979.
23. K. J. Lim, *et al.*, *Technology Assessment Report For Industrial Boiler Applications: NO<sub>x</sub> Combustion Modification*, EPA-600/7-79-178f, U. S. Environmental Protection Agency, Washington, DC, December 1979.
24. D. W. Pershing, *et al.*, *Influence Of Design Variables On The Production Of Thermal And Fuel NO From Residual Oil And Coal Combustion*, Air: Control of NO<sub>x</sub> and SO<sub>x</sub> Emissions, New York, American Institute of Chemical Engineers, 1975.
25. R. Clayton, *et al.*, *N<sub>2</sub>O Field Study*, EPA-600/2-89-006, U. S. Environmental Protection Agency, Research Triangle Park, NC, February 1989.
26. *Evaluation Of Fuel-Based Additives For N<sub>2</sub>O And Air Toxic Control In Fluidized Bed Combustion Boilers*, EPRI Contract No. RP3197-02, Acurex Report No. FR-91-101-/ESD, (Draft Report) Acurex Environmental, Mountain View, CA, June 17, 1991.
27. *Code of Federal Regulations 40, Parts 53 to 60*, July 1, 1991.
28. James Ekmann, *et al.*, *Comparison Of Shale Oil And Residual Fuel Combustion*, In Symposium Papers, New Fuels And Advances In Combustion Technologies, Sponsored By Institute Of Gas Technology, March 1979.

29. N. F. Suprenant, *et al.*, *Emissions Assessment Of Conventional Stationary Combustion Systems, Volume I: Gas And Oil Fired Residential Heating Sources*, EPA-600/7-79-029b, U. S. Environmental Protection Agency, Washington, DC, May 1979.
30. C. C. Shih, *et al.*, *Emissions Assessment Of Conventional Stationary Combustion Systems, Volume III: External Combustion Sources For Electricity Generation*, EPA Contract No. 68-02-2197, TRW, Inc., Redondo Beach, CA, November 1980.
31. N. F. Suprenant, *et al.*, *Emissions Assessment Of Conventional Stationary Combustion System, Volume IV: Commercial Institutional Combustion Sources*, EPA Contract No. 68-02-2197, GCA Corporation, Bedford, MA, October 1980.
32. N. F. Suprenant, *et al.*, *Emissions Assessment Of Conventional Stationary Combustion Systems, Volume V: Industrial Combustion Sources*, EPA Contract No. 68-02-2197, GCA Corporation, Bedford, MA, October 1980.
33. *Particulate Polycyclic Organic Matter*, National Academy of Sciences, Washington, DC, 1972.
34. *Vapor Phase Organic Pollutants—Volatile Hydrocarbons And Oxidation Products*, National Academy of Sciences, Washington, DC, 1976.
35. H. Knierien, *A Theoretical Study Of PCB Emissions From Stationary Sources*, EPA-600/7-76-028, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1976.
36. *Estimating Air Toxics Emissions From Coal And Oil Combustion Sources*, EPA-450/2-89-001, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1989.
37. R. P. Hagebrauck, D. J. Von Lehmden, and J. E. Meeker, "Emissions of Polynuclear Hydrocarbons and Other Pollutants from Heat-Generation and Incineration Process", *J. Air Pollution Control Assoc.*, 14:267-278, 1964.
38. M. B. Rogozen, *et al.*, *Formaldehyde: A Survey Of Airborne Concentration And Sources*, California Air Resources Board, ARB Report No. ARB/R-84-231, 1984.
39. Seeker, W.R., *et al.*, *Municipal Waste Combustion Study: Combustion Control Of MSW Combustors To Minimize Emissions Of Trace Organics*, EPA-543-SW-87-021c, U. S. Environmental Protection Agency, Washington, D.C., May 1987.
40. *Clean Air Act Amendments of 1990*, Conference Report To Accompany S.1603, Report 101-952, U. S. Government Printing Office, Washington, DC, October 26, 1990.
41. K. J. Lim, *et al.*, *Industrial Boiler Combustion Modification NO<sub>x</sub> Controls - Volume I Environmental Assessment*, EPA-600/7-81-126a, U. S. Environmental Protection Agency, July 1981.
42. D. H. Klein, *et al.*, "Pathways of Thirty-Seven Trace Elements Through Coal-Fired Power Plants," *Environ. Sci. Technol.*, 9:973-979, 1975.
43. D. G. Coles, *et al.*, "Chemical Studies of Stack Fly Ash From a Coal-Fired Power Plant," *Environ. Sci. Technol.*, 13:455-459, 1979.



44. S. Baig, *et al.*, *Conventional Combustion Environmental Assessment*, EPA Contract No. 68-02-3138, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1981.
45. L. P. Nelson, *et al.*, *Global Combustion Sources of Nitrous Oxide Emissions*, Research Project 2333-4 Interim Report, Sacramento: Radian Corporation.
46. R. L. Peer, *et al.*, *Characterization of Nitrous Oxide Emission Sources*, Prepared for the U. S. EPA Contract 68-D1-0031, Research Triangle Park, NC: Radian Corporation, 1995.
47. S. D. Piccot, *et al.*, *Emissions and Cost Estimates for Globally Significant Anthropogenic Combustion Sources of  $NO_x$ ,  $N_2O$ ,  $CH_4$ ,  $CO$ , and  $CO_2$* , EPA Contract No. 68-02-4288, Research Triangle Park, NC: Radian Corporation, 1990.
48. G. Marland and R.M. Rotty, *Carbon Dioxide Emissions from Fossil Fuels: A Procedure For Estimation And Results For 1951-1981*, DOE/NBB-0036 TR-003, Carbon Dioxide Research Division, Office of Energy Research, U.S. Department of Energy, Oak Ridge, TN, 1983.
49. G. Marland and R.M. Rotty, *Carbon Dioxide Emissions from Fossil Fuels: A Procedure For Estimation And Results For 1950-1982*, *Tellus*, 36B: 232-261.
50. *Sector-Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992* (1994) DOE/PO-0028, Volume 2 of 3, U.S. Department of Energy.
51. G. R. Offen, *et al.*, *Control Of Particulate Matter From Oil Burners And Boilers*, EPA-450/3-76-005, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1976.
52. D. W. South, *et al.*, *Technologies And Other Measures For Controlling Emissions: Performance, Costs, And Applicability*, Acidic Deposition: State of Science and Technology, Volume IV, Report 25, National Acid Precipitation Assessment Program, U. S. Government Printing Office, Washington, DC, December 1990.
53. *EPA Industrial Boiler FGD Survey: First Quarter 1979*, EPA-600/7-79-067b, U. S. Environmental Protection Agency, April 1979.
54. J. H. Pohl and A.F. Sarofim, *Devolatilization And Oxidation Of Coal Nitrogen (Presented At The 16th International Symposium On Combustion)*, August 1976.
55. P. B. Nutter, *High Technology Low  $NO_x$  Burner Systems For Fired Heaters And Steam Generators*, Process Combustion Corp., Pittsburgh, PA, Presented at the Pacific Coast Oil Show and Conference, Los Angeles, CA, November 1982.
56. *Environmental Assessment Of Coal And Oil Firing In A Controlled Industrial Boiler, Volume I*, PB 289942, U. S. Environmental Protection Agency, August 1978.
57. *Environmental Assessment Of Coal And Oil Firing In A Controlled Industrial Boiler, Volume II*, EPA-600/7-78-164b, U. S. Environmental Protection Agency, August 1978.
58. *Environmental Assessment Of Coal And Oil Firing In A Controlled Industrial Boiler, Volume III*, EPA-600/7-78-164c, U. S. Environmental Protection Agency, August 1978.

59. *Emission Reduction On Two Industrial Boilers With Major Combustion Modifications*, EPA-600/7-78-099a, U. S. Environmental Protection Agency, August 1978.
60. *Emission Reduction On Two Industrial Boilers With Major Combustion Modifications, Data Supplement*, EPA-600/7-78-099b, U. S. Environmental Protection Agency, August 1978.
61. *Residential Oil Furnace System Optimization, Phase II*, EPA-600/2-77-028, U. S. Environmental Protection Agency, January 1977.
62. *Characterization Of Particulate Emissions From Refinery Process Heaters And Boilers*, API Publication No. 4365, June 1983.
63. *Industrial Boilers Emission Test Report, Boston Edison Company, Everett, Massachusetts*, EMB Report 81-IBR-15, U. S. Environmental Protection Agency, Office of Air Quality Planning and Standards, October 1981.
64. Field Chemical Emissions Monitoring Project: Site 13 Emissions Monitoring, EPRI Project RP3177-1, Radian Corporation, Austin, Texas, February, 1993.
65. Field Chemical Emissions Monitoring Project, Site 112 Emissions Report, Preliminary Draft, Carnot, Tustin, California, February 24, 1994. (EPRI Report)
66. Field Chemical Emissions Monitoring Project: Emissions Report For sites 103 - 109, Preliminary Draft Report, Radian Corporation, Austin, Texas, March 1993. (EPRI Report)
67. Field Chemical Emissions Monitoring Project: Site 118 Emissions Report, Preliminary Draft, Carnot, Tustin, California, January 20, 1994. (EPRI Report)
68. Emissions Inventory Testing at Long Beach Auxiliary Boiler for Southern California Edison Company, Carnot, May 1990.
69. Emission Inventory Testing at Alamitos Unit 5 for Southern California Edison Company, Carnot, May 1990.
70. Air Toxic emissions Testing at Morro Bay Unit 3 for Pacific Gas and Electric Company, Carnot, May 1990.
71. Emission Inventory Testing at El Segundo Generating Station 1, for Southern California Edison Company, Carnot, April 1990.
72. Electric Utility Fuel Oil Fired Electric Utility Boiler Emission Report, for Long Island Lighting Corporation, Entropy Incorporated, April 1994.
73. Perry, Robert H. and Don Green (1984) *Perry's Chemical Engineers' Handbook*, Sixth ed., New York: McGraw Hill.
74. *Steam: Its Generation and Use*, Babcock and Wilcox, New York, 1975.
75. *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources* (1995) U.S. Environmental Protection Agency, AP-42. Fifth Edition. Research Triangle Park, NC.

76. Results of the September 14 and 15, 1994 Air Emission Compliance Tests on the No. 11 Boiler at the Appleton Paper Plant in Combined Locks, Wisconsin. Interpoll Laboratories. October 10, 1994.
77. Compliance Emission Test Report for Lakewood Cogeneration, L.P. Lakewood Township, New Jersey. Environmental Laboratories, Inc. December 19, 1994.
78. Compliance Test Report Air Emissions from Utility Boilers A, B, and C. Mobile Oil Corporation. Paulsboro, New Jersey. ENSA Environmental, Inc. May 1995.
79. Boise Cascade Combined Power Boilers Title V Fuel Oil Compliance Test Report. St. Helens, Oregon Paper Mill. Bighorn Environmental Quality Control. August 8, 1996.
80. Results of the July 13, 1993 Particulate and Sulfur Dioxide Emission Compliance Testing at the Land O'Lakes Plant in Spencer, Wisconsin. Interpoll Laboratories, Inc. August 16, 1993.
81. Results of the May 31, 1995 Air Emission Compliance Tests of the No. 1 Boiler at the Land O'Lakes Plant in Spencer, Wisconsin. Interpoll Laboratories, Inc. July 12, 1995.
82. Boiler Emission Testing at KC-Neenah Paper, Whiting Mill, Stevens Point, WI. Badger Laboratories and Engineering. February 27, 1995.
83. Emissions Inventory Testing at Long Beach Turbine Combustion Turbine No. 3. CARNOT, Tustin, CA. May 1989.
84. C.A. Miller. *Hazardous Air Pollutants from the Combustion of an Emulsified Heavy Oil in a Firetube Boiler*. EPA-600/R-96-019. U.S. Environmental Protection Agency, Research Triangle Park, North Carolina. February 1996.