Boiler Classification and Application

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2. INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS

Combustion boilers are designed to use the chemical energy in fuel to raise the energy content of water so that it can be used for heating and power applications. Many fossil and nonfossil fuels are fired in boilers, but the most common types of fuel include coal, oil, and natural gas. During the combustion process, oxygen reacts with carbon, hydrogen, and other elements in the fuel to produce a flame and hot combustion gases. As these gases are drawn through the boiler, they cool as heat is transferred to water. Eventually the gases flow through a stack and into the atmosphere. As long as fuel and air are both available to continue the combustion process, heat will be generated.

Boilers are manufactured in many different sizes and configurations depending on the characteristics of the fuel, the specified heating output, and the required emissions controls. Some boilers are only capable of producing hot water, while others are designed to produce steam. Various studies have been conducted to estimate the number of boilers in the United States, but no data source provides a complete representation of the existing boiler population.[1]

In the United States, boilers are typically designed and constructed as either power or heating boilers in accordance with applicable requirements adopted by the American Society of Mechanical Engineers (ASME). Rules for power boilers are provided in Sect. I of the *ASME Boiler and Pressure Vessel Code*.[2] These rules apply to steam boilers that operate above 15 psig and hot water boilers that operate above 160 psig or 250°F. Common design pressures are 150, 200, 250, and 300 psig, but higher pressures are possible. [3] For example, boilers for certain pulp and paper industry applications are now designed for pressures as high as 1,500 psig. Corresponding rules for heating boilers are provided in Sect. IV.[4] According to these rules, heating boilers that produce hot water are not allowed to operate above 160 psig or at temperatures above 250°F at or near the boiler outlet. Additional rules limit heating boilers that produce steam to a maximum operating pressure of 15 psig.

Many boilers with heat input capacities more than 250 million British thermal units per hour (MBtu/h) are classified as utility boilers because they are used at power plants to produce electricity. Some boilers of this size are also used at paper mills and institutions and for other industrial applications. Smaller boilers with less capacity are categorized as ICI boilers. Industrial boilers are used extensively by the chemical, food processing, paper, and petroleum industries. They have heat input capacities up to and sometimes more than 250 MBtu/h. Commercial and institutional boilers are used in many other applications including commercial businesses, office buildings, apartments, hotels, restaurants, hospitals, schools, museums, government buildings, and airports.

In the past when emissions were less regulated, choosing the right boiler and combustion equipment for a particular application generally involved matching the process requirements with the boiler's output capacity. Proper sizing and selection required knowledge of the peak process requirements and an understanding of the load profile. This boiler selection philosophy emphasized energy conversion at the lowest possible cost. Reduced emphasis was placed on controlling emissions. Public concerns about air and water quality and enactment of federal, state, and local regulations have shifted this emphasis. The current design objective is to provide low-cost energy with an acceptable impact on the environment. As discussed in an engineering manual published by ABMA, control of PM, NO_x, CO, and SO_2 emissions is now a significant consideration in the overall boiler and combustion equipment design and selection process.[3]

2.1 TYPES OF ICI BOILERS

Information in this guide focuses primarily on a broad class of steam and hot water generating units known as ICI boilers. Because of differences in their features and characteristics, ICI boilers can be classified in at least three ways.

- Boilers are commonly subdivided into watertube or firetube units. These designations reflect the way the water and combustion gases are designed to pass through the unit.
- Boilers are sometimes classified by their heat sources. For example, boilers are often referred to as oil-fired, gas-fired, coal-fired, or solid fuel-fired boilers. Coal-fired boilers can be further divided based on the equipment used to fire the boiler. The three major coal-fired boiler subclasses are pulverized-coal (PC) fired, stoker-fired, and fluidized-bed combustion (FBC) boilers.
- Boilers are occasionally distinguished by their method of fabrication. Packaged boilers are assembled in a factory, mounted on a skid, and transported to the site as one package ready for hookup to auxiliary piping. Shop-assembled boilers are built up from a number of individual pieces or subassemblies. After these parts are aligned, connected, and tested, the entire unit is shipped to the site in one piece. Field-erected boilers are too large to transport as an entire assembly. They are constructed at the site from a series of individual components. Sometimes these components require special transportation and lifting considerations because of their size and weight.

The basic purpose of any ICI boiler is to convert the chemical energy in fuel into thermal energy that can be used to generate steam or hot water. Inside the combustion chamber, two fundamental processes must occur to achieve this objective. First, the fuel must be mixed with sufficient oxygen to allow sustained combustion. The heated gases produced by the combustion process must then transfer the thermal energy to a fluid such as water or steam. Various components inside the boiler are required to promote efficient combustion and heat transfer. Their design depends on factors such as the type of fuel and the method selected to transfer thermal energy.

The ICI boilers are manufactured in a wide range of sizes to burn coal, oil, natural gas, biomass, and RDFs as well as other fuels and fuel combinations. Most ICI boilers are classified as either watertube or firetube boilers, but other designs such as cast iron, coil-type, and tubeless (steel shell) boilers are also produced. Descriptions of some of the more typical boiler designs are presented below. Additional details about ICI boilers and their design, construction, and operation are available from other sources.[3,5–7]

2.1.1 Firetube Boilers

Firetube boilers consist of a series of straight tubes that are housed inside a water-filled outer shell. The tubes are arranged so that hot combustion gases flow through the tubes. As hot gases flow through the tubes, they heat the water that surrounds the tubes. The water is confined by the outer shell of the boiler. To avoid the need for a thick outer shell, firetube boilers are used for lower-pressure applications. Generally, the heat input capacities for firetube boilers are limited to 50 MBtu/h or less,[5] but in recent years the size of firetube boilers has increased.

Firetube boilers are subdivided into three groups. Horizontal return tubular (HRT) boilers typically have horizontal, self-contained firetubes with a separate combustion chamber. Scotch, Scotch marine, or shell boilers have the firetubes and combustion chamber housed within the same shell. Firebox boilers have a water-jacketed firebox and employ, at most, three passes of combustion gases. Boiler configurations for each type are shown in Figs. 2.1–2.3, respectively.

Most modern firetube boilers have cylindrical outer shells with a small round combustion chamber located inside the bottom of the shell. Depending on construction details, these boilers have tubes configured in either one, two, three, or four pass arrangements. Because the design of firetube boilers is simple, they are easy to construct in a shop and can be shipped fully assembled as a package unit. Table 2.1 identifies various types of firetube boilers and the associated fuels that they typically burn.

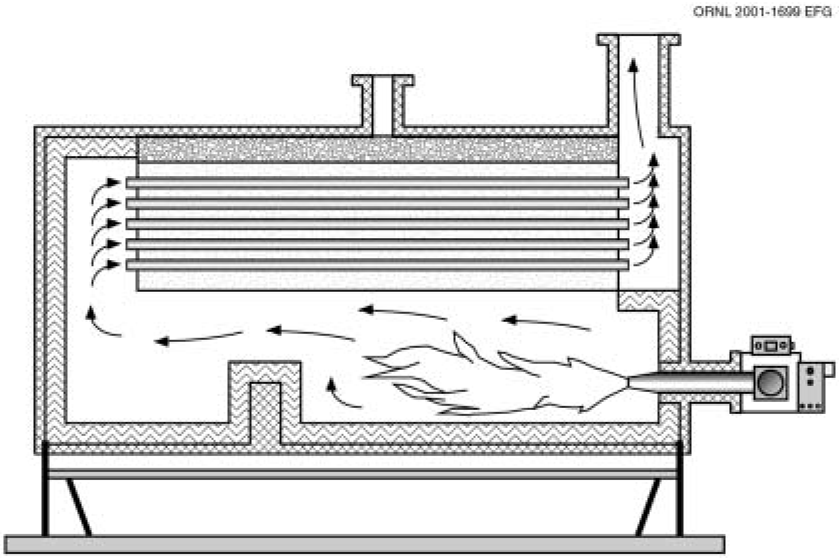

Fig. 2.1. Configuration of HRT firetube boiler.

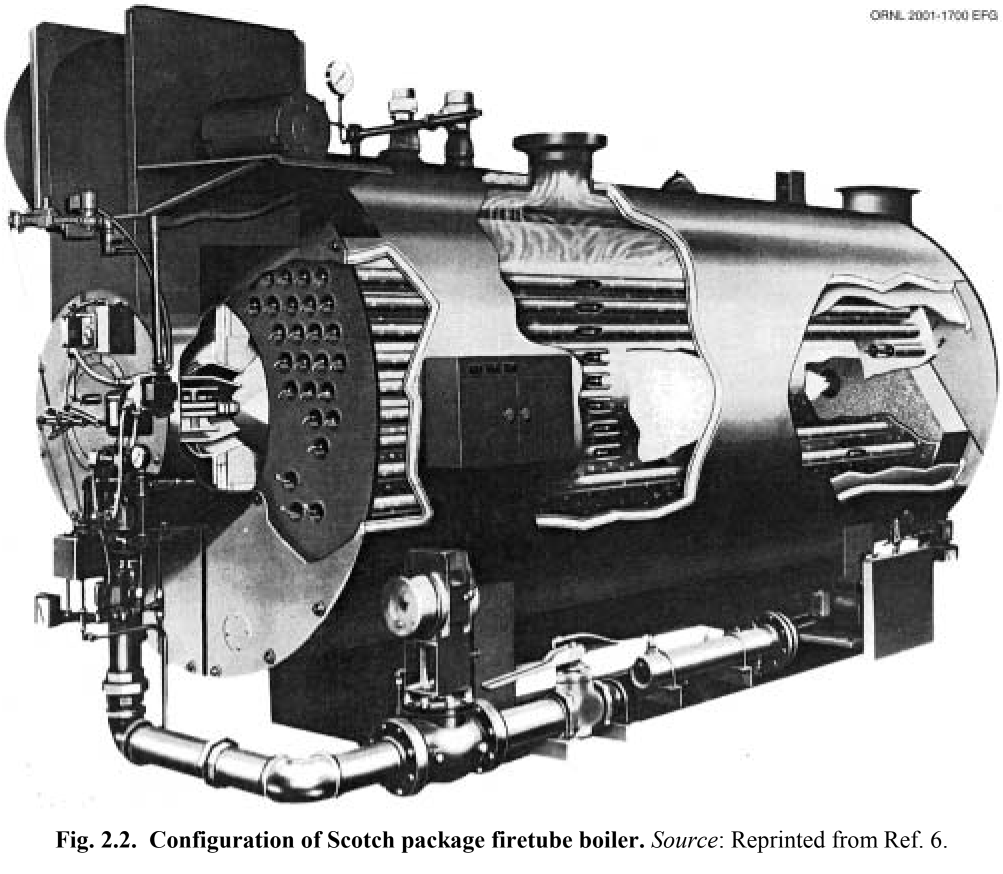

Fig. 2.2. Configuration of Scotch package firetube boiler. *Source*: Reprinted from Ref. 6.

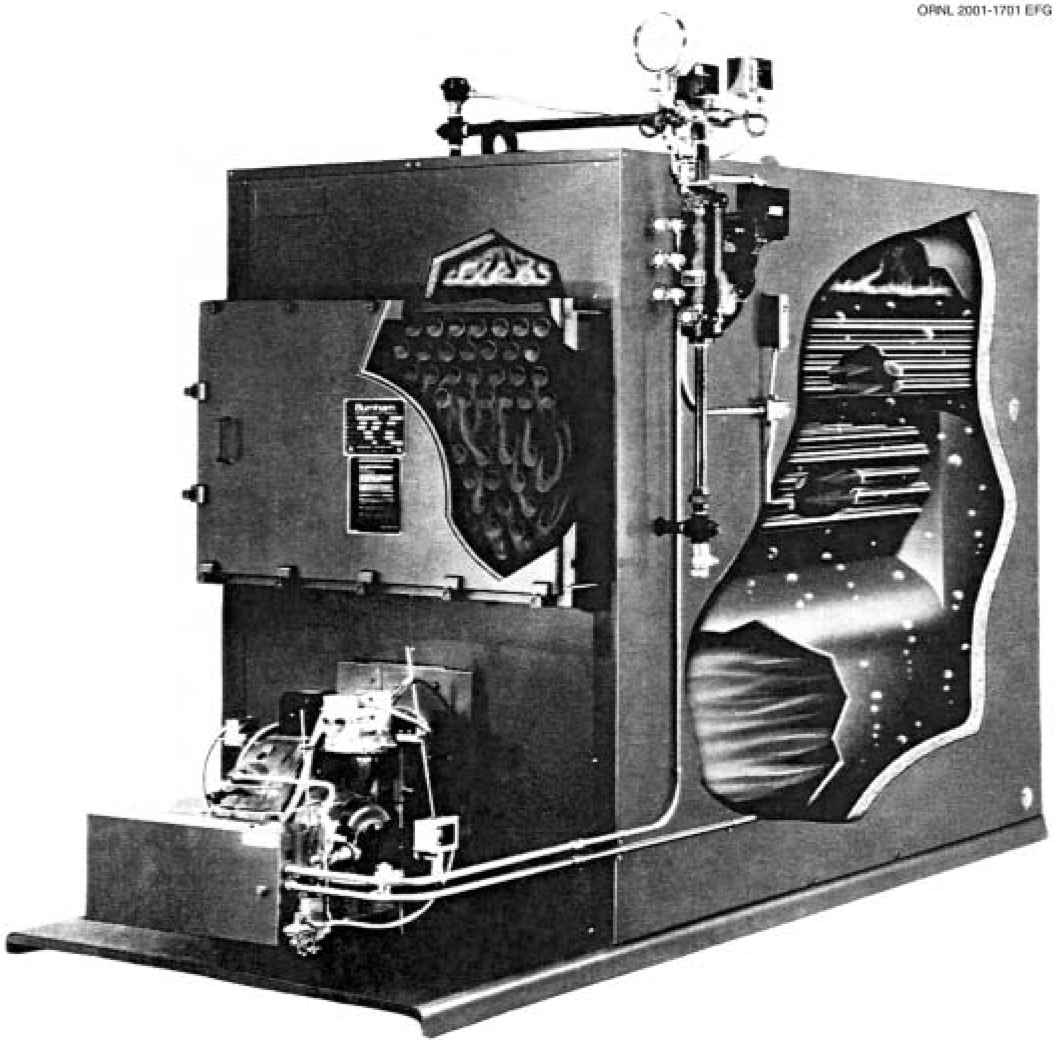

Fig. 2.3. Configuration of firebox firetube boiler. *Source*: Reprinted from Ref. 6.

Table 2.1. Fuels typically fired in ICI firetube boilers

Firetube boiler type	Fuel				
	Coal	**Fuel oil**	**Natural gas**	**Biomass**	**Refuse-derived**
HRT boilers	Yes	Yes	Yes	Yes	Yes
Scotch boilers	Yes	Yes	Yes	No	No
Firebox boilers	Yes	Yes	Yes	Yes	Yes

2.1.2 Watertube Boilers

Watertube boilers are designed to circulate hot combustion gases around the outside of a large number of water-filled tubes.[8] The tubes extend between an upper header, called a steam drum, and one or more lower headers or drums. In older designs, the tubes are either straight or bent into simple shapes. Newer boilers have tubes with complex and diverse bends. Because the pressure is confined inside the tubes, watertube boilers can be fabricated in larger sizes and used for higher-pressure applications. Small watertube boilers, which have one and sometimes two burners, are generally fabricated and supplied as packaged units. Because of their size and weight, large watertube boilers are often fabricated in pieces and assembled in the field. Configurations for packaged and field-erected watertube boilers are shown in Figs. 2.4 and 2.5, respectively.

Almost any solid, liquid, or gaseous fuel can be burned in a watertube boiler. Common fuels include coal, oil, natural gas, biomass, and other solid fuels such as municipal solid waste (MSW), tire-derived fuel (TDF), and RDF. Designs of watertube boilers that burn these fuels can be significantly different. Various watertube boilers and the fuels that they commonly burn are identified in Table 2.2. Configurations of boilers for burning RDF, MSW, and other solid fuel are shown in Figs. 2.6–2.8 (Ref. 9).

Coal-fired watertube boilers are classified into three major categories: stoker-fired units, PC-fired units, and FBC boilers.

Stoker-fired boilers include a mechanical system that is designed to feed solid fuel into the boiler. These stokers are designed to support the combustion process and to remove the ash as it accumulates. All stokers operate similarly. They use both undergrate and overfire air to burn fuel located on a grate. Different designs for stokers are described in Sect. 2.2.1.

The PC-fired boilers are generally large field-erected units such as the one shown in Fig. 2.9. During operation, finely ground coal is mixed with primary combustion air and fed to the burner or burners where it ignites. Secondary combustion air is then supplied to complete the combustion process. Depending on the location of the burners and the direction of coal injection, PC-fired boilers can be classified as single- or opposed-wall, tangential (corner), or cyclone boilers. Discussions about burners for PC-fired boilers are provided in Sect. 2.2.2. Depending on whether the ash is removed in a solid or

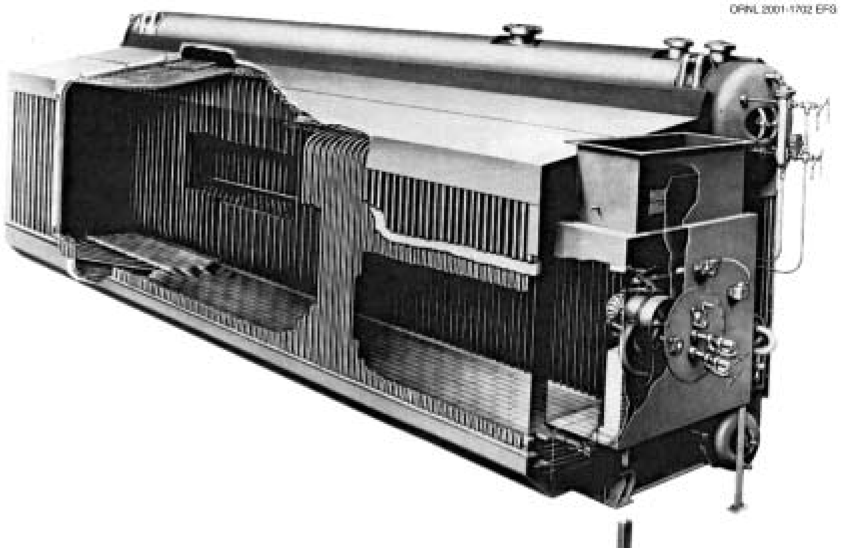

Fig. 2.4. Configuration of package watertube boiler. *Source*: Reprinted from Ref. 6.

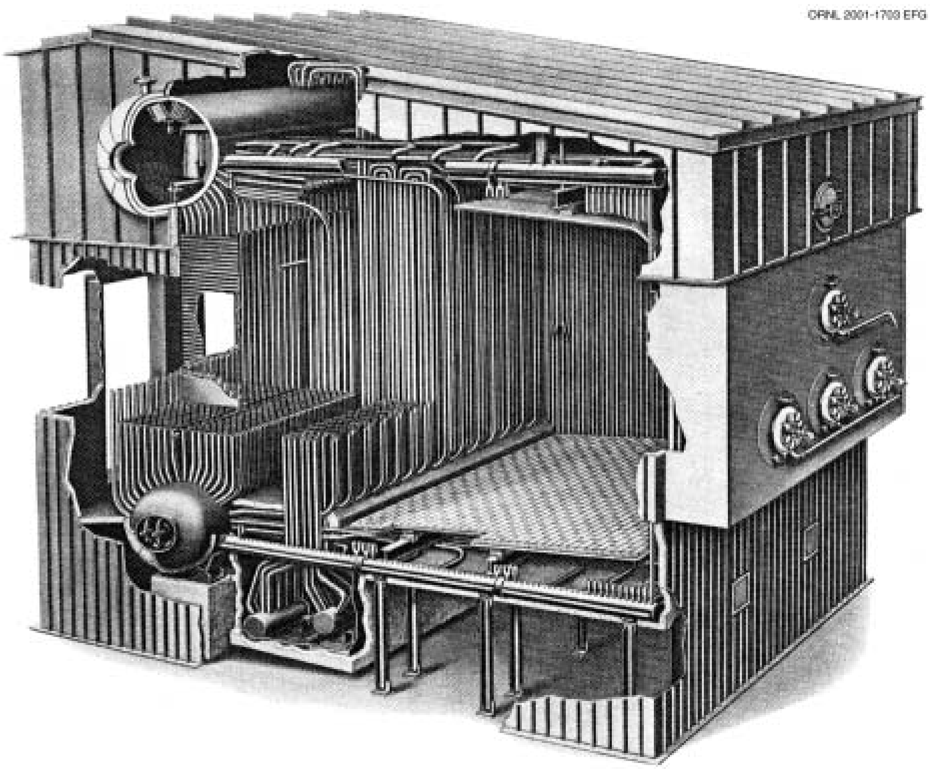

Fig. 2.5. Configuration of field-erected watertube boiler. *Source*: Reprinted from Ref. 6.

Table 2.2. Fuels typically fired in ICI watertube boilers

Watertube boiler	Fuel				
	Coal	Fuel oil	Natural gas	Biomass	Refuse-derived

Stoker-fired boilers
Underfeed stokers
• Horizontal feed side-ash discharge
• Gravity feed rear-ash discharge
Overfeed stokers
• Mass feed
  ✓ Water-cooled vibrating grate
  ✓ Moving (chain and traveling) grate
• Spreader
  ✓ Traveling grate
  ✓ Air-cooled vibrating grate
  ✓ Water-cooled vibrating grate
	Yes for boilers with the following types of stokers	No	No	Yes for boilers with the following types of stokers	Yes for boilers with the following types of stokers

PC-fired boilers • Single or opposed-wall • Tangential (corner) • Cyclone	Yes for the following types of PC-fired boilers	[a]	[a]	No	No

FBC boilers
• Atmospheric
  ✓ Bubbling
  ✓ Circulating
• Pressurized
	Yes for the following types of FBC boilers	[a]	[a]	Yes for the following types of FBC boilers	Yes for the following types of FBC boilers

Package boilers • "A" • "D" • "O"	No	Yes for the following types of package boilers	Yes for the following types of package boilers	No	No

[a] Gas or oil is often used at start-up.

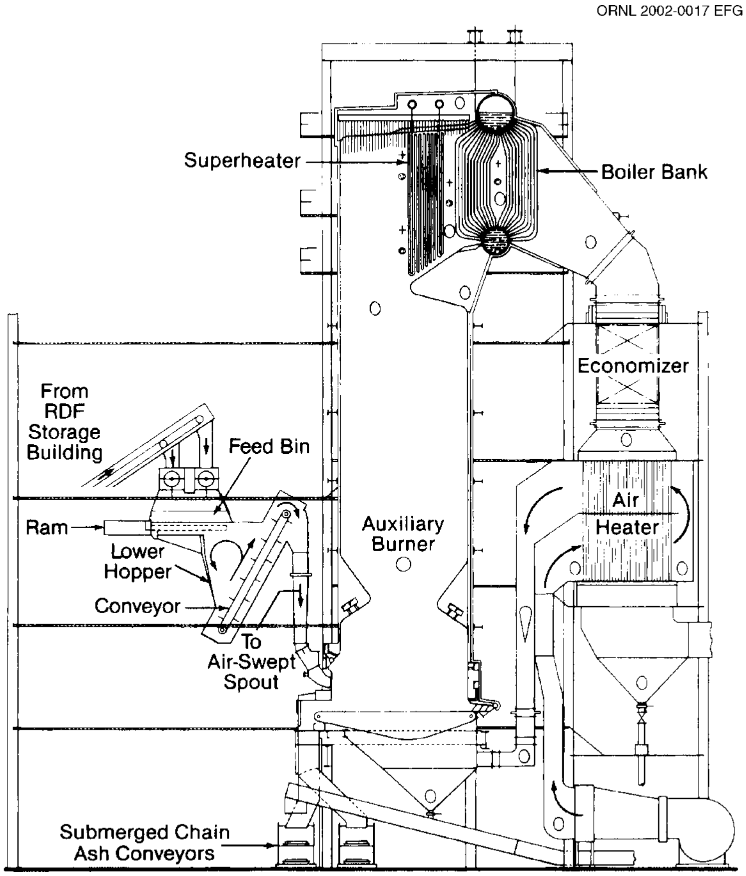

Fig. 2.6. Configuration of watertube boiler for burning RDF. *Source:* Reprinted from Ref. 9.

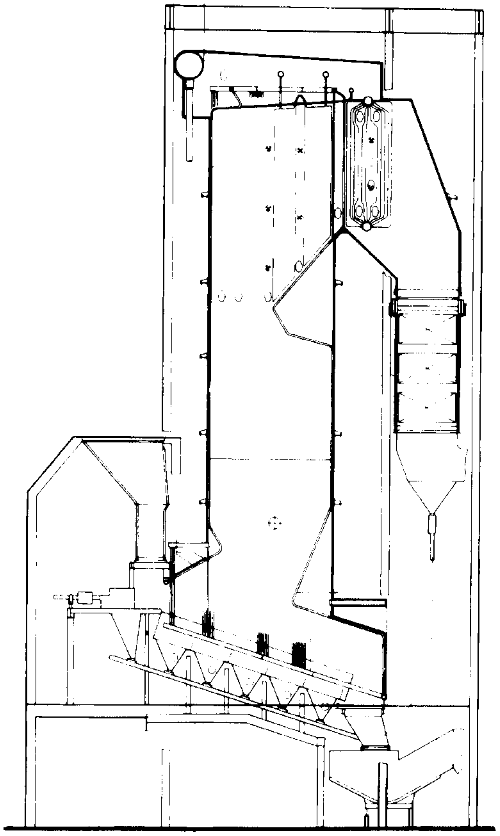

Fig. 2.7. Configuration of watertube boiler for burning MSW. *Source:* Reprinted from Ref. 9.

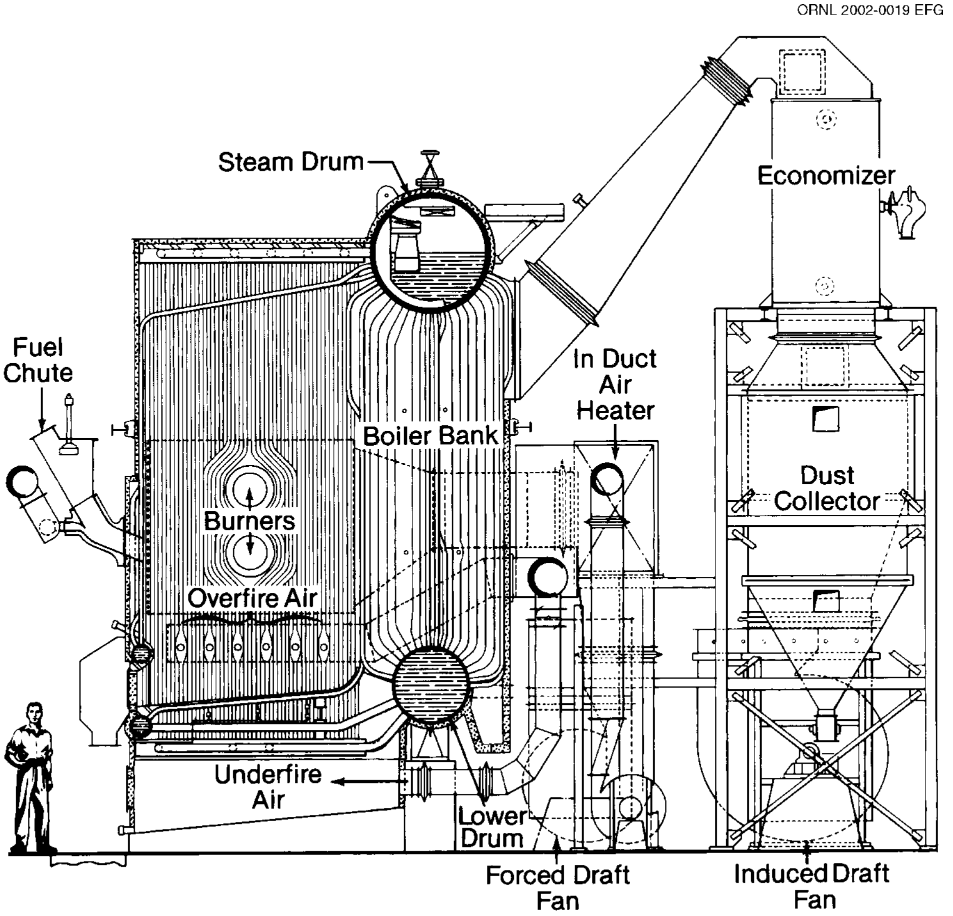

Fig. 2.8. Configuration of watertube boiler for burning solid fuel such as wood, biomass, or stoker coal. *Source:* Reprinted from Ref. 9.

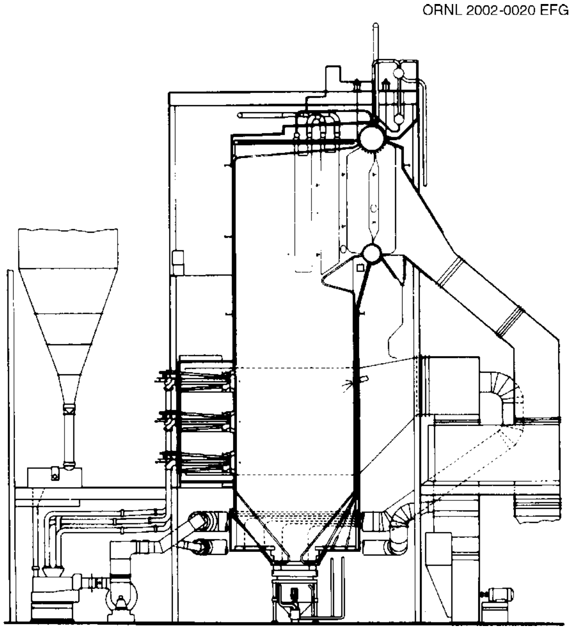

Fig. 2.9. Configuration of watertube boiler for burning PC. *Source:* Reprinted from Ref. 9.

molten state, PC-fired boilers are also classified as dry or wet bottom. Opposed-wall boilers are usually much larger than 250-MBtu/h heat input capacity. They are used primarily for utility but may be suitable for certain industrial applications. Coal burned in cyclone boilers is crushed rather than pulverized.

The FBC boilers are capable of burning a wide range of solid fuels. In this method of combustion, fuel is burned in a bed of hot incombustible particles suspended by an upward flow of fluidizing gas such as air. Fuels that contain a high concentration of ash, sulfur, and nitrogen can be burned efficiently while meeting stringent emission limitations. When sulfur capture is not required, inert materials such as alumina may be added to supplement the fuel ash and maintain the bed. In applications where sulfur capture is required, limestone is incorporated into the bed and used as the sorbent.[10] The FBC boilers are categorized as either atmospheric or pressurized units. Atmospheric FBC boilers are further divided into bubbling-bed and circulating-bed units; the fundamental difference between these two is the fluidization velocity. Coal is often burned in FBC boilers, but it is also possible to burn biomass and other solid fuels. Natural gas or fuel oil is used primarily as a start-up fuel to preheat the fluidized bed or as an auxiliary fuel when additional heat is required. Configurations of various types of FBC boilers are shown in Figs. 2.10–2.12.

Combustion of other solid fuels, including MSW and RDF, is often accomplished in a boiler with a stoker system. Fuels of this type generally have specially designed feed systems for supplying and distributing the fuel particles. Boilers that burn these fuels are also specially designed to interface with the fuel feed system and to burn the fuel as efficiently as possible. Many boilers that burn solid nonfossil fuels have some type of fossil fuel firing capability. These auxiliary fuels are used during start-up operations, as a supplementary fuel, or alone when the primary fuel is unavailable.

Nonfossil gaseous fuels that are rich in CO and hydrogen can also be burned in watertube boilers. These fuels can be generated by the partial combustion of biomass using gasification or pyrolysis techniques.

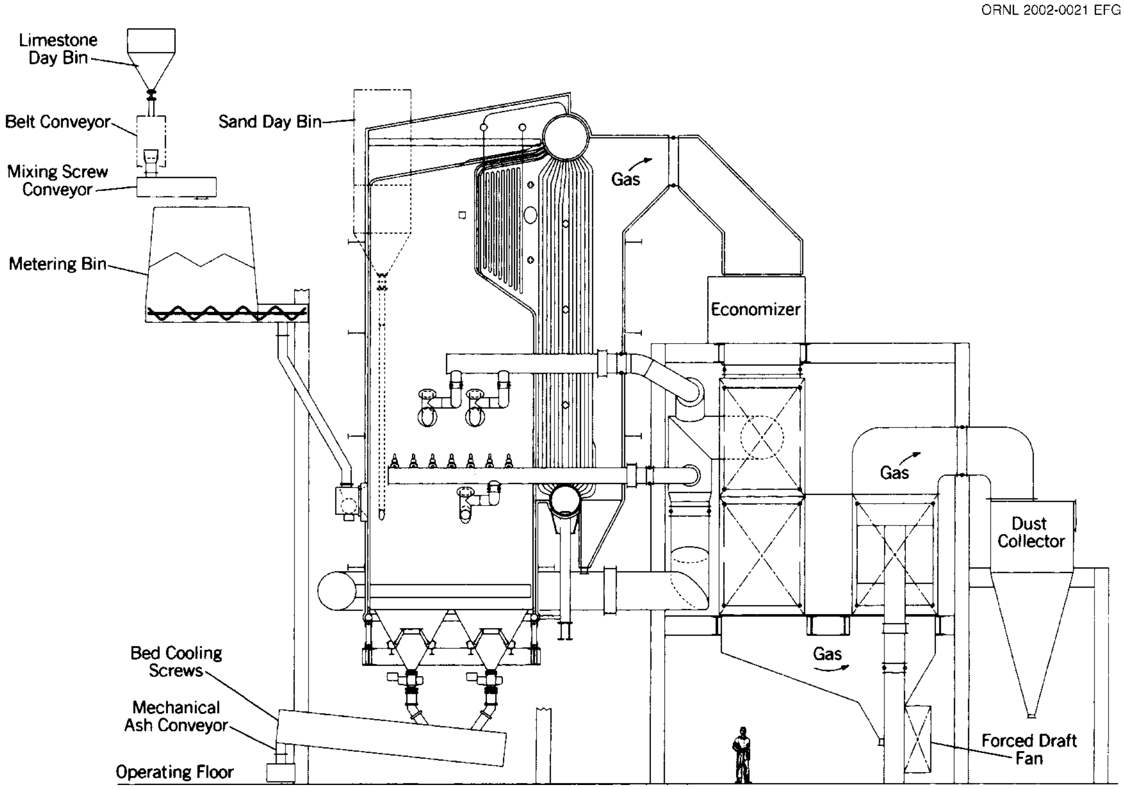

Fig. 2.10. Configuration of bubbling FBC watertube boiler. *Source:* Reprinted from Ref. 9.

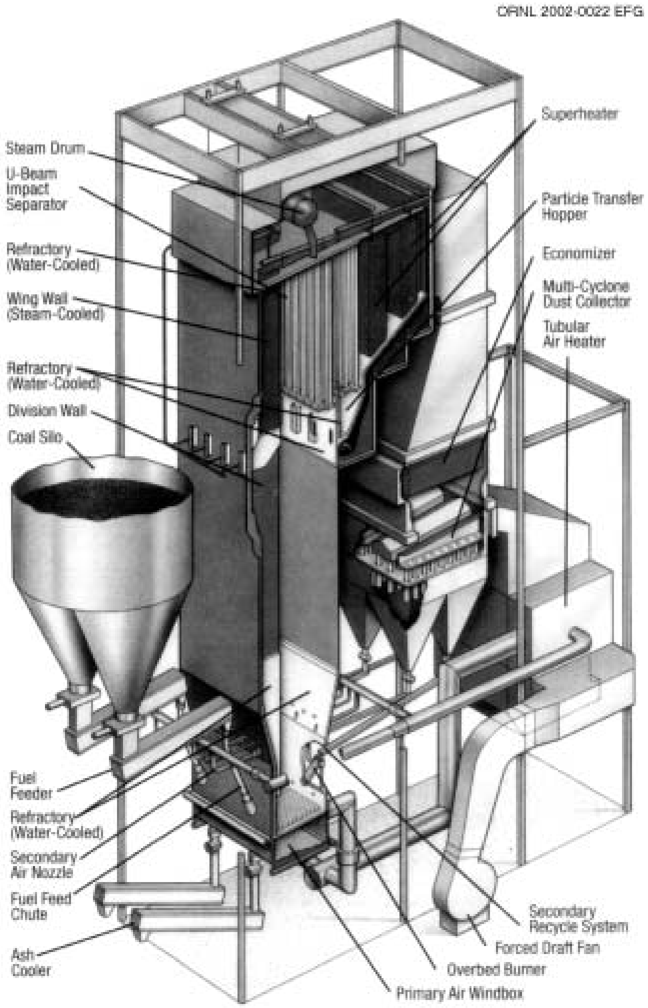

Fig. 2.11. Configuration of circulating FBC watertube boiler. *Source*: Reprinted from Ref. 9.

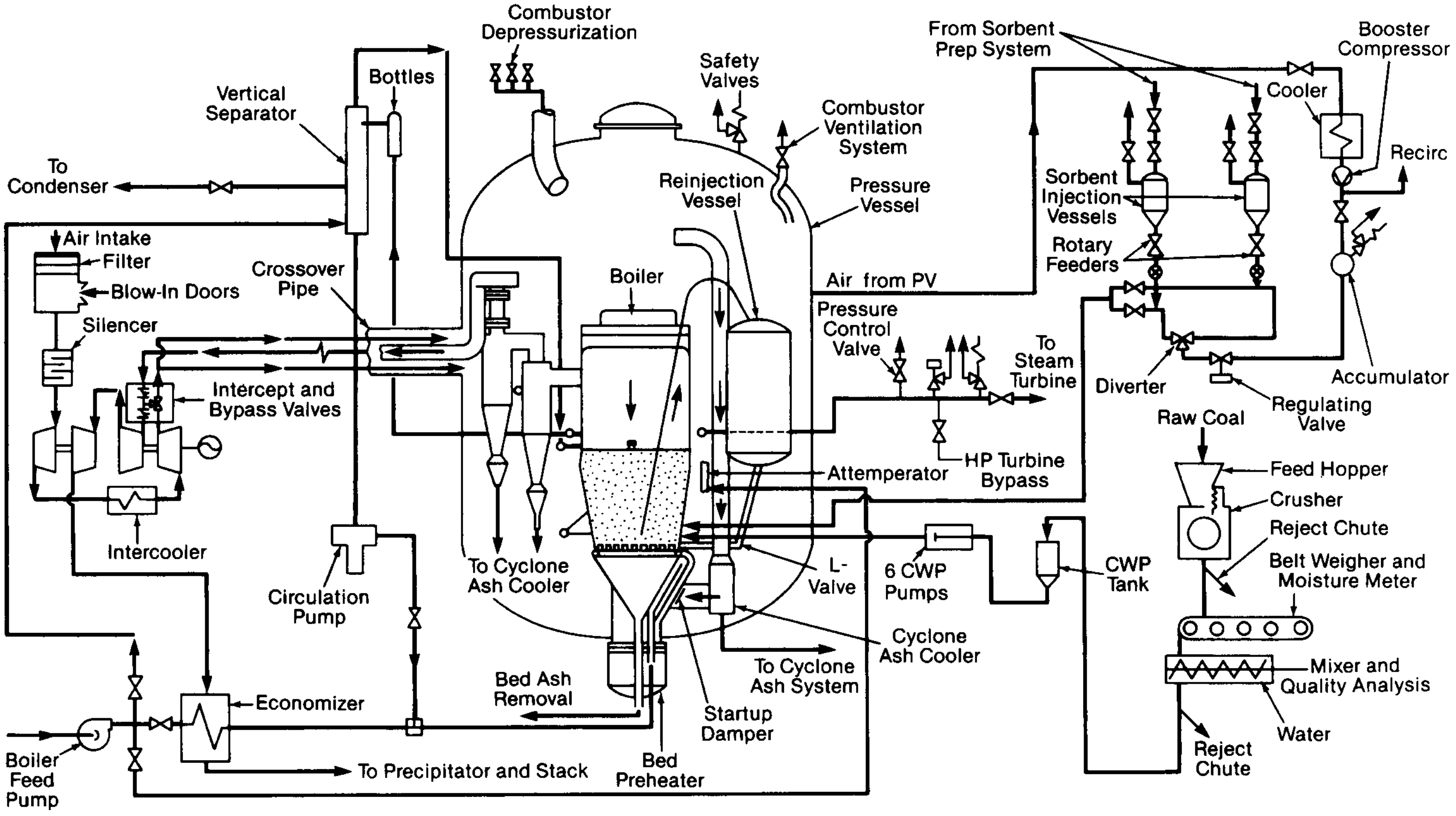

Fig. 2.12. Configuration of pressurized FBC boiler system. *Source:* Reprinted from Ref. 9.

Fuel oil-fired and natural gas-fired watertube package boilers are subdivided into three classes based on the geometry of the tubes. The “A” design has two small lower drums and a larger upper drum for steam-water separation. In the “D” design, which is the most common, the unit has two drums and a large-volume combustion chamber. The orientation of the tubes in a “D” boiler creates either a left- or right-handed configuration. For the “O” design, the boiler tube configuration exposes the least amount of tube surface to radiant heat. Rental units are often “O” boilers because their symmetry is a benefit in transportation. Figures 2.13–2.15 show tube configurations for each of these watertube package boiler designs.

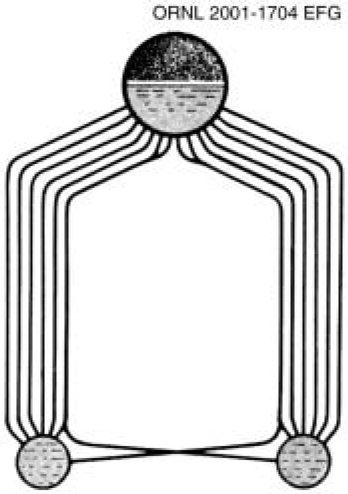

Fig. 2.13. Configuration of tubes for “A” package watertube boiler. *Source*: Reprinted from Ref. 11.

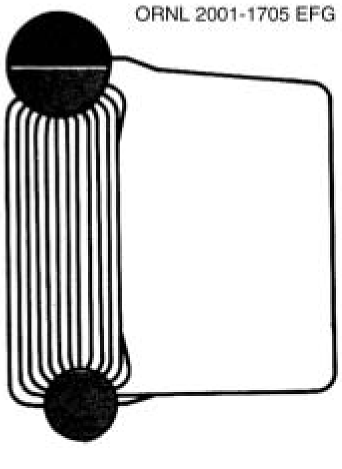

Fig. 2.14. Configuration of tubes for “D” package watertube boiler. *Source*: Reprinted from Ref. 11.

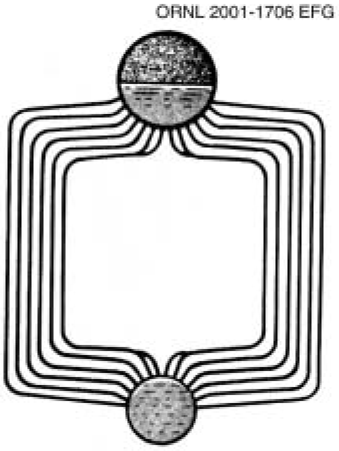

Fig. 2.15. Configuration of tubes for "O" package watertube boiler. *Source*: Reprinted from Ref. 11.

2.1.3 Other Combustion Boilers

Cast iron boilers are fabricated from a number of cast iron sections that are bolted together. The design of each section includes integral water and combustion gas passages. When fully assembled, the interconnecting passages create chambers where heat is transferred from the hot combustion gases to the water. These boilers generally produce low-pressure steam (15 psig) or hot water (30 psig) and burn either oil or natural gas. Only about 12% of the cast iron boilers in the United States are fired by coal.

Because of their construction, cast iron boilers are limited to smaller sizes. Only 37% have heat input capacities greater than 0.4 MBtu/h (Ref. 5). Because the components of these boilers are relatively small and easy to transport, they can be assembled inside a room with a conventional-size doorway. This feature means that cast iron boilers are often used as replacement units, which eliminate the need for temporary wall removal to provide access for larger package units. Cast iron boilers represent only about 10% of the ICI boiler capacity in the United States. The configuration of a cast iron boiler is shown in Fig. 2.16.

Another boiler that is sometimes used to produce steam or hot water in known as a tubeless boiler. The design of tubeless boilers incorporates nested pressure vessels with water located between the shells.[5] Combustion gases are fired into the inner vessel where heat is transferred to water located between the outside surface of the inner shell and the inside surface of the outer shell. For oil-fired and natural-gas-fired vertical tubeless boilers, the burner is typically located at the bottom of the boiler and fires into the inner pressure vessel. The configuration of a vertical tubeless boiler is shown in Fig. 2.17.

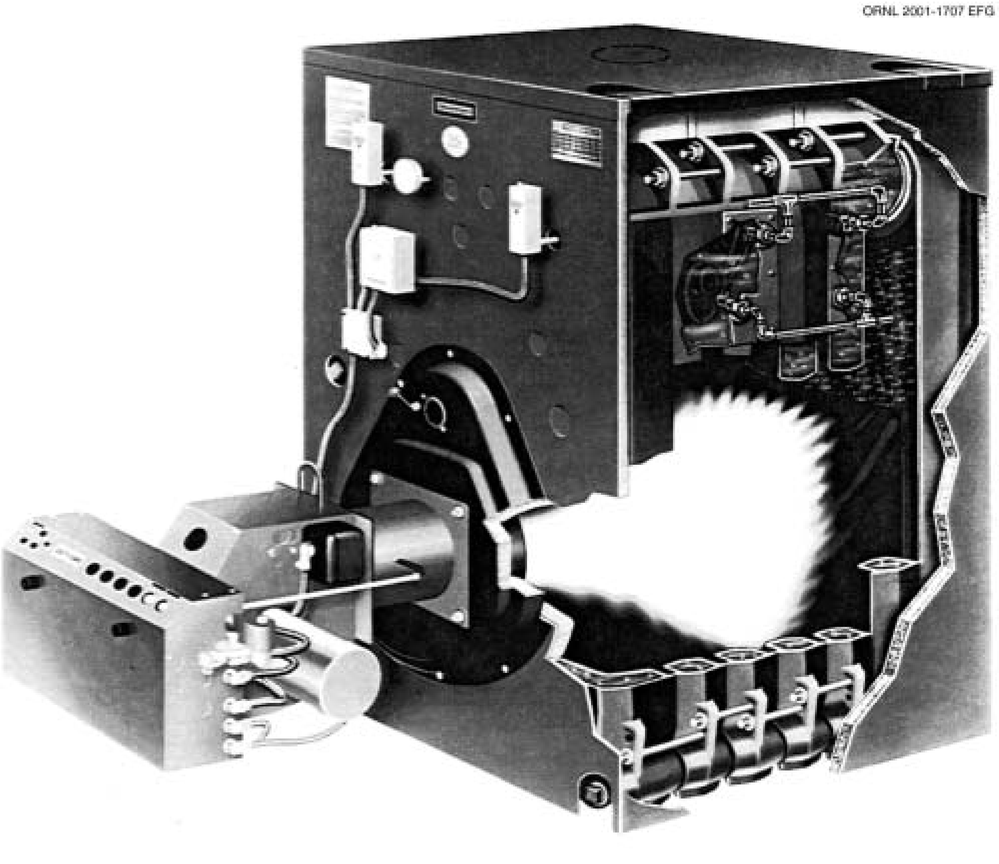

Fig. 2.16. Configuration of cast iron boiler. *Source*: Reprinted from Ref. 6.

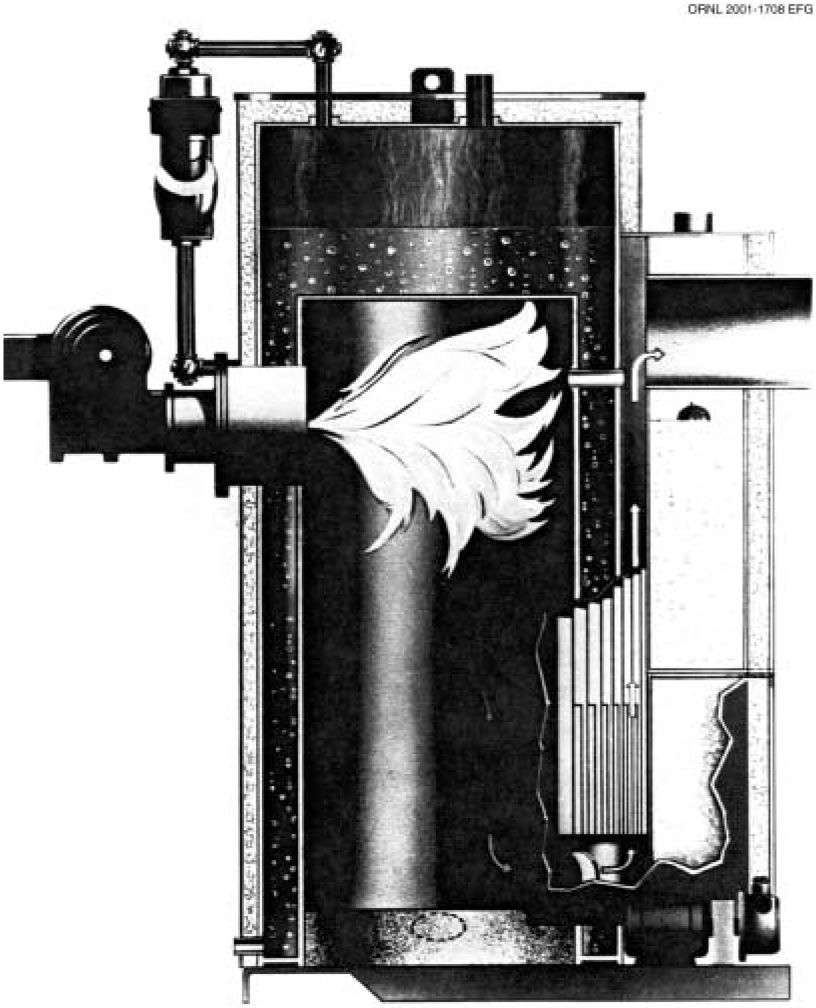

Fig. 2.17. Configuration of vertical tubeless boiler. *Source*: Reprinted from Ref. 6.

2.2 FUEL FEED SYSTEMS

Fuel feed systems play a critical role in the performance of low-emission boilers. Their primary functions include (1) transferring the fuel into the boiler and (2) distributing the fuel within the boiler to promote uniform and complete combustion. The type of fuel and whether the fuel is a solid, liquid, or gas influences the operational features of a fuel feed system.

Gaseous fuels are relatively easy to transport and handle. Any pressure difference will cause gas to flow, and most gaseous fuels mix easily with air. Because on-site storage of gaseous fuel is generally not feasible, boilers must be connected to a fuel source such as a natural gas pipeline. Flow of gaseous fuel to a boiler can be precisely controlled using a variety of control systems. These systems generally include automatic valves that meter gas flow through a burner and into the boiler based on steam or hot water demand. The purpose for the burner is to increase the stability of the flame over a wide range of flow rates by creating a favorable condition for fuel ignition and establishing aerodynamic conditions that ensure good mixing between the primary combustion air and the fuel. Burners are the central elements of an effective combustion system. Other elements of their design and application include equipment for fuel preparation and air-fuel distribution as well as a comprehensive system of combustion controls.

Like gaseous fuels, liquid fuels are also relatively easy to transport and handle by using pumps and piping networks that link the boiler to a fuel supply such as a fuel oil storage tank. To promote complete combustion, liquid fuels must be atomized to allow thorough mixing with combustion air. Atomization by air, steam, or pressure produces tiny droplets that burn more like gas than liquid. Control of boilers that burn liquid fuels can also be accomplished using a variety of control systems that meter fuel flow.

Solid fuels are much more difficult to handle than gaseous and liquid fuels. Preparing the fuel for combustion is generally necessary and may involve techniques such as crushing or shredding. Before combustion can occur, the individual fuel particles must be transported from a storage area to the boiler. Mechanical devices such as conveyors, augers, hoppers, slide gates, vibrators, and blowers are often used for this purpose. The method selected depends primarily on the size of the individual fuel particles and the properties and characteristics of the fuel. Stokers are commonly used to feed solid fuel particles such as crushed coal, TDF, MSW, wood chips, and other forms of biomass into boilers. Mechanical stokers evolved from the hand-fired boiler era and now include sophisticated electromechanical components that respond rapidly to changes in steam demand. The design of these components provides good turndown and fuel-handling capability. In this context, turndown is defined as the ratio of maximum fuel flow to minimum fuel flow. Although stokers are used for most solid fuels, PC combustion, which consists of very fine particles, does not involve a stoker. Coal in this form can be transported along with the primary combustion air through pipes that are connected to specially designed burners.

The following discussions about stokers and burners are only intended to provide background information about these devices. Because the characteristics of stokers and burners are very complex and highly technical, the information does not address detailed issues associated with their design, construction, theory of operation, or performance. Because of concerns about revealing proprietary information, these discussions are intentionally generic in nature. Specific details about a particular product or design should be obtained from the manufacturer.

2.2.1 Stokers

Firing systems that involve stokers must be integrated into the overall boiler design to optimize combustion and heat recovery while minimizing unburned fuel and atmospheric emissions. Modern mechanical stokers consist of (1) a fuel admission system, (2) a stationary or moving grate assembly that supports the burning fuel and provides a pathway for the primary combustion air, (3) an overfire air (OFA) system that supplies additional air to complete combustion and minimize atmospheric emissions, and (4) an ash discharge system.[12] Stoker-firing systems are typically categorized as either underfeed or overfeed stokers.

2.2.1.1 Underfeed stokers

Underfeed stokers supply both fuel and primary combustion air from beneath the grate. The fuel is moved into a hopper and onto the grate by either a screw or ram-driven mechanism. As the fuel moves out over the grate where it is exposed to air and radiant heat, it begins to burn. During the combustion process, ash accumulates. To reduce the tendency for clinker formation, it is sometimes necessary to use moving grates that agitate the burning fuel bed. The two basic types of underfeed stokers are the (1) horizontal-feed, side-ash discharge type and (2) the less popular gravity-feed, rear-ash discharge type.[12] The cross section of an underfeed, side-ash discharge stoker is shown in Fig. 2.18. Because of cost and environmental considerations, the demand for underfeed stokers has diminished.

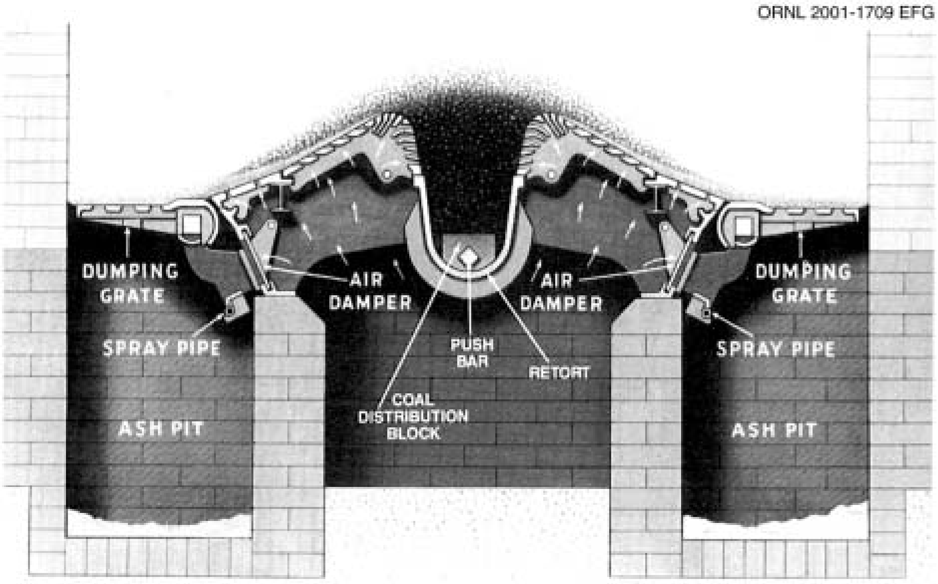

Fig. 2.18. Cross section of underfeed, side-ash discharge stoker. *Source*: Reprinted from Ref. 11.

2.2.1.2 Overfeed stokers

Overfeed stokers are generally classified as either mass-feed or spreader stokers. These designations reflect the way that the fuel is distributed and burned within the boiler.

Mass-feed stokers introduce fuel continuously at one end of a grate. As the fuel moves into the boiler, it falls onto the grate by gravity. The height of the fuel bed is controlled in two ways. A gate can be moved up or down to regulate the amount of fuel that is allowed to enter the boiler, and the speed at which the fuel moves beneath the gate can be adjusted. Inside the boiler, the fuel burns as it travels along the grate. Ash that forms and remains on the grate is discharged at the opposite end. Primary combustion air flows upward from beneath the grate and through the burning bed of fuel. The two primary mass-feed stokers are (1) water-cooled vibrating grate and (2) moving (chain and traveling) grate stokers.[12] Cross sections of (1) an overfeed, water-cooled, vibrating-grate, mass-feed stoker and (2) an overfeed, water-cooled, traveling-grate, mass-feed stoker are shown in Figs. 2.19 and 2.20, respectively.

Spreader stokers are very versatile and the most commonly used stoker. They are capable of distributing fuel evenly and to a uniform depth over the entire grate surface by using a device that propels the individual fuel particles into the air above the grate. Methods used to propel the fuel particles include air injection and underthrow and overthrow rotors. As the fuel is thrown into the boiler, fines ignite and burn in suspension. Because of suspension burning, response time of spreader stokers is better than mass-feed or underfeed stokers. The coarser particles fall onto the grate and burn in a thin bed. Primary combustion air is supplied from an air plenum located beneath the grate. The OFA ports supply the additional air that is needed to complete the combustion process. Grates for spreader stokers are generally designed to move rather than remain stationary. Traveling grates, air-cooled vibrating grates, and water-cooled vibrating grates are designs that have been used successfully. Cross sections of (1) an overfeed, traveling-grate, spreader stoker; (2) an overfeed air-cooled, vibrating-grate, spreader stoker;

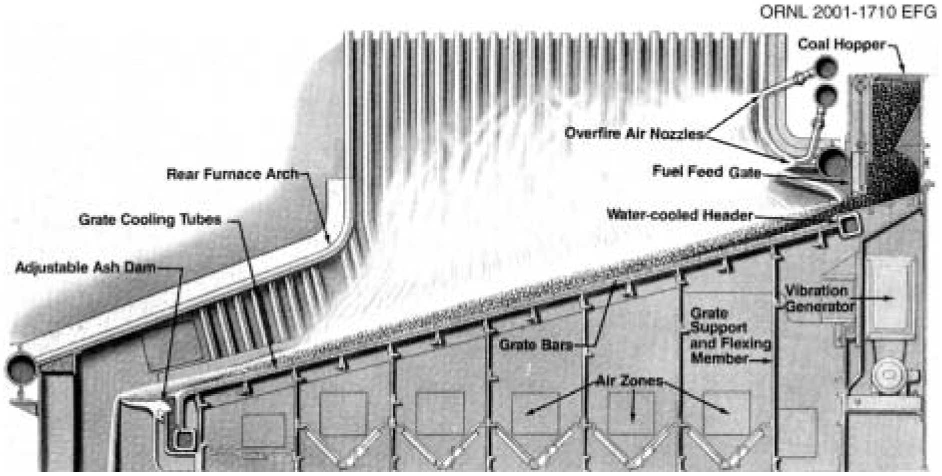

Fig. 2.19. Cross section of overfeed, water-cooled, vibrating-grate, mass-feed stoker. *Source*: Reprinted from Ref. 11.

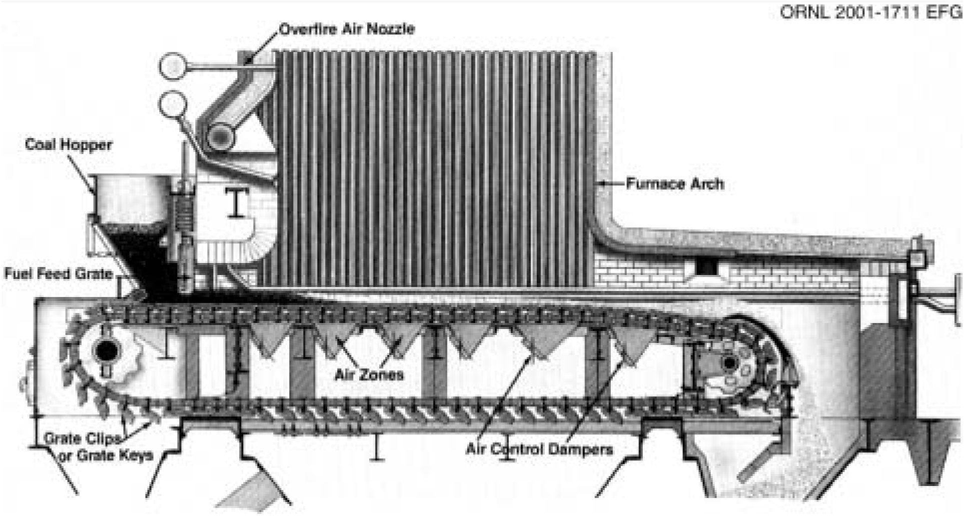

Fig. 2.20. Cross section of overfeed, traveling-grate, mass-feed stoker. *Source*: Reprinted from Ref. 11.

and (3) an overfeed water-cooled, vibrating-grate, spreader stoker are shown in Figs. 2.21–2.23, respectively. Spreader stokers with stationary water-cooled grates are used primarily in the sugar industry to burn bagasse. Modern boilers with spreader stokers consist of

- units that distribute fuel uniformly over the grate,
- specially designed air-metering grates,
- dust collection and reinjection equipment,
- blowers for OFA,
- forced draft fans for both undergrate and OFA, and
- combustion controls to coordinate fuel and air supply with steam demand.[12]

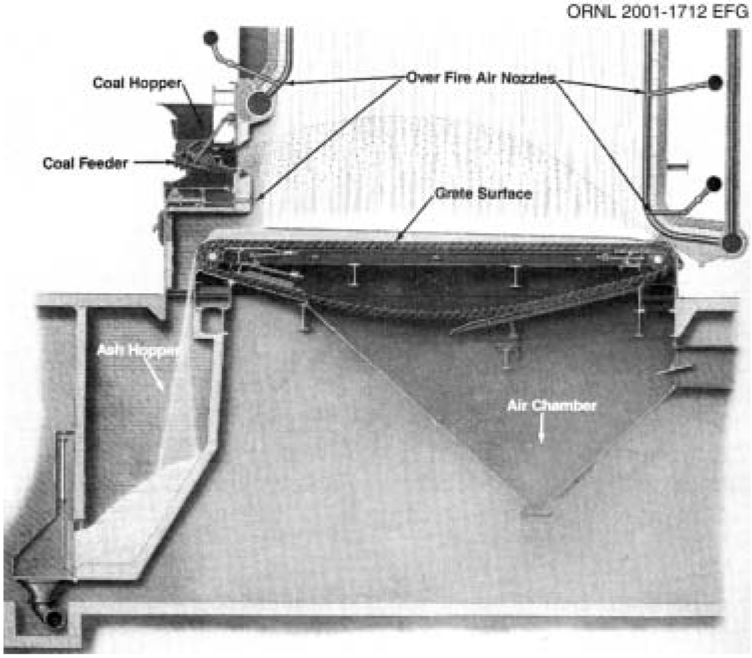

Fig. 2.21. Cross section of overfeed, traveling-grate, spreader stoker. *Source*: Reprinted from Ref. 11.

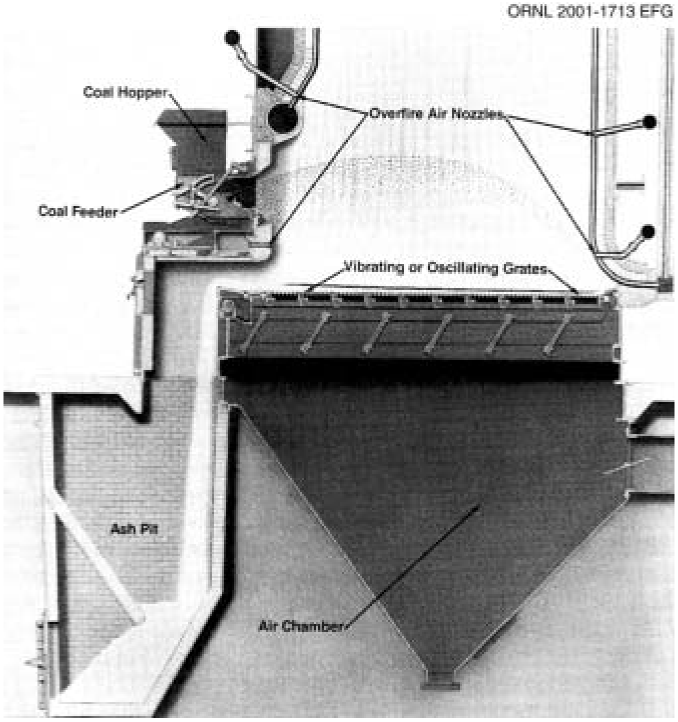

Fig. 2.22. Cross section of overfeed air-cooled, vibrating-grate, spreader stoker. *Source*: Reprinted from Ref. 11.

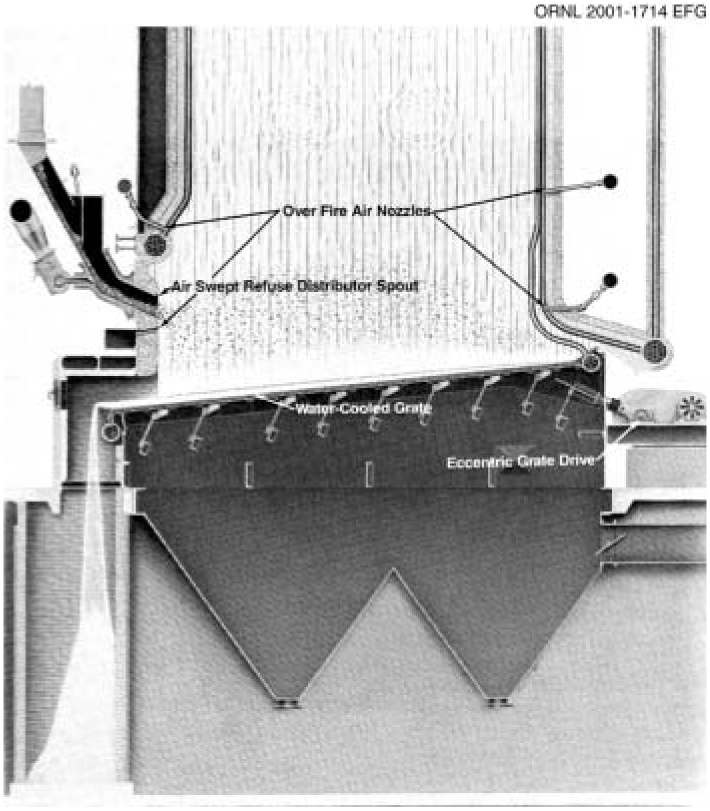

Fig. 2.23. Cross section of overfeed, water-cooled, vibrating-grate, spreader stoker. *Source*: Reprinted from Ref. 11.

2.2.2 Burners

A burner is defined as a device or group of devices for the introduction of fuel and air into a furnace at the required velocities, turbulence, and concentration to maintain ignition and combustion of fuel within the furnace. Burners for gaseous fuels are less complex than those for liquid or solid fuels because mixing of gas and combustion air is relatively simple compared to atomizing liquid fuel or dispersing solid fuel particles.

There is no formal classification system for burners, but attempts to combine desirable burner characteristics have given rise to a rich diversity in burner designs.[13] Terminology used to identify burners that have been in existence for a long time as well as advanced burners that are based on emerging technology is listed in Table 2.3.

The ability of a burner to mix combustion air with fuel is a measure of its performance. A good burner mixes well and liberates a maximum amount of heat from the fuel. The best burners are engineered to liberate the maximum amount of heat from the fuel and limit the amount of pollutants such as CO, NO_x, and PM that are released. Burners with these capabilities are now used routinely in boilers that must comply with mandated emission limitations. Emission control techniques that are effective in reducing NO_x, CO, SO_2, and PM emissions are described in Chap. 5.

An effective way to minimize NO_x emissions is to use a low-NO_x burner (LNB). These burners employ various strategies for mixing the fuel with combustion air to reduce the formation of NO_x. Two

Table 2.3. Terminology used to identify burners

Air-atomizing oil burner
Atmospheric gas burner
Dual-fuel burner
Forced internal recirculation (FIR) burner
Low-NO_X burner (LNB)
Modulating gas power burner
Modulating pressure-atomizing oil burner
Multistage pressure-atomizing oil burner
On-off burner
Premix burner
Premix radiant burner
Premix surface burner
Premix surface-stabilized burner
PC burner
Rapid-mix burner
Rotary cup oil burner
Single-stage gas power burner
Single-stage pressure-atomizing oil burner
Staged gas power burner
Steam-atomizing oil burner
Ultra low-NO_X burner (ULNB)

techniques often used for this purpose include (1) introducing the fuel and air at different stages, and (2) recirculating flue gas with fresh combustion air. The LNBs that can be retrofitted to existing boilers have been developed and are currently being marketed. Complete systems that integrate LNBs into new and efficient boiler designs are also available.

Ultra low-NO_X burners (ULNBs) use emerging technology to reduce NO_X and CO emissions to extremely low levels. These burners are specifically designed to burn clean gaseous fuels such as natural gas that are essentially free of fuel-bound nitrogen. Discussions about ULNBs and the techniques used to minimize thermal and prompt NO_X formation are presented in Sect. 5.2.1.6.

Many vendors of conventional LNBs and ULNBs are members of the ABMA. This organization represents the manufacturers of commercial, industrial, and utility steam-generating and fuel-burning equipment, as well as suppliers to the industry. In general, technical information about the design of a particular LNB and its in-service performance can only be obtained from the manufacturer.

2.3 EMISSION RATES

Use of boilers for steam and hot water production is not limited to any particular geographic location. Consequently, atmosphere emissions resulting from fuel combustion can affect the human and natural environment over a wide area.[14] In the United States, emissions of air pollutants from boilers are regulated under the CAA.[15] This federal legislation was amended in 1990 to address specific concerns about ground-level ozone, the accumulation of fine particles in the atmosphere, the development of acid rain, the acidification of aquatic systems, HAPs, and visibility limitations. To effectively achieve national ambient air quality goals, EPA is authorized to establish maximum emission rates for selected pollutants from new and existing steam-generating units. This action ensures that some level of emission control is applied in all areas, irrespective of ambient air quality considerations. The degree of emissions limitation is achieved through the application of the best system of emission reduction, which has been adequately demonstrated. Such systems are referred to as Best Available Control Technology (BACT). Conditions under which reasonably available control technology (RACT), BACT, and lowest achievable emissions rate (LAER) must be applied are discussed in Chap. 4. State and local governments are also authorized to establish emission limits that are more stringent than federal requirements.

Major emissions from combustion boilers include NO_x, SO_2, CO, and PM. The amount of each pollutant discharged into the atmosphere is influenced by factors such as the fuel consumed and the method by which it is fired, the design features of the boiler, the way the boiler is operated, and the completeness of combustion. Achieving the required emissions reductions involves the use of precombustion, combustion, or postcombustion emission control techniques, or a combination of techniques. Emissions limitations that have been established by EPA for electric utility and ICI steam-generating units are summarized in Appendix A.

One of the main reasons for selecting and installing low-emission boilers and combustion equipment is to reduce NO_x, SO_2, CO, and PM emissions. As discussed in Sect. 4.1, it may also be necessary in the near future to reduce HAP emissions from certain combustion boilers. Although suitable control techniques for reducing emissions vary from one unit to another, assessing the effectiveness of a particular technique requires knowledge about uncontrolled and controlled emission rates. From a regulatory viewpoint, maximum allowable emissions rates are typically specified in units of pounds per million British thermal units of heat input or as a percent of theoretical emissions.

2.3.1 Uncontrolled Emissions

Theoretical or uncontrolled emissions are defined as emissions that would result from combustion of a fuel in an uncleaned state without emission controls. The term used by EPA to quantify uncontrolled emissions is potential combustion concentration.[16] For utility boilers with at least 250-MBtu/h heat input capacity, EPA has defined the following potential combustion concentrations for specific types of fuel.

For PM:
- 7.0-lb/MBtu heat input for solid fuels
- 0.17-lb/MBtu heat input for liquid fuels

For NO_x:
- 0.67-lb/MBtu heat input for gaseous fuels
- 0.72-lb/MBtu heat input for liquid fuels
- 2.30-lb/MBtu heat input for solid fuels

Currently, there are no corresponding potential combustion concentrations for NO_x and PM emissions from ICI boilers. However, EPA has developed emission factors for a variety of pollutants emitted from external combustion sources, including SO_2 and HAPs.[17] External combustion sources include steam-generating plants for electricity, industrial boilers, and commercial and domestic combustion units. These emission factors are cited in numerous EPA publications and appear in various electronic databases. The process details and supporting reference materials on which these data are based have been compiled and published.[17] Uncontrolled emissions from combustion sources depend on the composition of the fuel and the type of boiler. For example, for SO_2, the emission factor representing uncontrolled emissions from a spreader stoker-fired boiler that burns bituminous coal is 38S lb/ton of coal, where S is the weight percent sulfur content of coal as fired.

Ranges of uncontrolled NO_x emissions are reported in ABMA and EPA publications.[5,6,17] Data reported in these sources provide valuable insight into the level of emissions that can be expected from different types of boilers and combustion equipment. Although NO_x emission factors for many boiler and fuel combinations are listed, it is not always possible to make meaningful data comparisons. Variations in reporting methods, presentation formats, and boiler classification schemes account for some of the uncertainty. Accurate determinations of NO_x emissions are most reliably obtained using standardized testing methods designed to minimize the influence of boiler design, method of firing, condition of combustion equipment, operational characteristics, fuel composition, and various other site-specific parameters on the test results. Test methods for determining NO_x emissions are published by ASTM and EPA.[18–25] These methods describe analytical techniques and procedures that are suitable for specific applications.

Uncontrolled emissions of SO_2 are directly influenced by the amount of sulfur contained in the fuel. Natural gas contains essentially no sulfur, while other fuels such as coal and fuel oil often contain significant amounts of sulfur-bearing compounds. Test methods for determining the sulfur content of coal, fuel oil, and liquefied petroleum (LP) gas are referenced in applicable fuel specifications published by ASTM.[26–28] Results of sulfur-content testing are useful in evaluating potential SO_2 emissions because any sulfur in fuel that is not removed along with the ash oxidizes to SO_2. Test methods for determining SO_2 emissions are published by EPA.[25,29–32]

The PM emissions are a function of the noncombustible material or ash contained in the fuel. As with SO_2, test methods for determining the ash content of coal, fuel oil, and LP gas are referenced in applicable fuel specifications published by ASTM.[26–28] Results of ash-content testing are useful in evaluating potential PM emissions because all noncombustible materials that enter the boiler and are not removed as ash become PM emissions. Test methods for determining PM emissions are published by EPA.[25,33–35]

2.3.2 Controlled Emissions

In the United States, emissions of NO_x, SO_2, and PM from most utility and ICI boilers must be controlled by the application of one or more emission control techniques. Because there is no practical way to totally eliminate all emissions from fuel combustion, emission limits have been established to address a variety of concerns about atmospheric pollution on the human and natural environment. These limits, which are specified in units of pounds per million British thermal units or as a percent of potential combustion concentration, are based on federal and, in certain cases, more stringent state emissions standards. Discussions about emission limits in federal regulations are presented in Chap. 4. Descriptions of emission control techniques are presented in Chap. 5.

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