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Boiler Fuels, Emissions and Efficiency

Course No: M02-028

Credit: 2 PDH

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This course was adapted from the Department of Energy (DOE), Publication "Guide to Low-Emission Boiler and Combustion Equipment Selection", Chapter 3, "Fuels, Emissions, and Efficiency", which is in the public domain.

3. FUELS, EMISSIONS, AND EFFICIENCY

Conversion of water to steam requires sufficient heat to cause the water to boil. Although a variety of energy sources, including nuclear energy and solar radiation, can produce the required amount of heat, combustion of a fuel in the presence of oxygen is the most common source. Combustion is a rapid chemical reaction between oxygen and a solid, liquid, or gaseous fuel. Oxygen required for this reaction is readily available in the air. As air and fuel are mixed at elevated temperatures, the oxygen reacts with carbon, hydrogen, and other elements in the fuel to produce heat. As long as fuel and air are both available, combustion will continue, and heat will be generated.

Heat produced during combustion is useful for a wide variety of applications; however, atmospheric emissions, which are also generated as by-products of the combustion process, must be controlled. Common gaseous emissions include SO₂, NO_x, water vapor, carbon dioxide (CO₂), and CO. The principle solid by-product of combustion is ash, the inorganic residue remaining after ignition of combustible materials.

Discussions that follow focus on fuels commonly fired in boilers to generate steam or hot water, atmospheric emissions associated with fuel combustion, and factors that influence how effectively the energy content of the fuel is transferred into usable heat.

3.1 FUELS

Many different solid, liquid, and gaseous fuels are fired in boilers. Sometimes, combinations of fuels are used to reduce emissions or improve boiler performance. Fuels commonly fired in boilers include fossil, biomass, and RDFs as well as other types of fuels and fuel combinations.

Coal, petroleum-based oils, and natural gas are fossil fuels commonly fired in ICI boilers. However, other forms of solid, liquid, or gaseous fuel derived from these fossil fuels are sometimes included in this category. One of these fuels, which is referred to as tire-derived fuel (TDF), consists of shredded vehicle tires.

Another boiler fuel is referred to as biomass. Biomass is renewable organic matter. Examples of biomass include fast-growing trees and plants, wood and wood waste, agricultural crops and residue, aquatic plants and algae, animal wastes, and organic municipal and industrial wastes.

RDF is a potentially valuable energy source. It consists of MSW that has been processed using size reduction and material recovery techniques to eliminate materials such as aluminum, steel, glass, plastic, and rock.

Common types of fuels fired in boilers are listed in Table 3.1 with key properties provided in Table 3.2. Additional information about some of the more common fuels is presented in the remainder of this section.

3.1.1 Coal

Coal is a brown-to-black combustible, sedimentary rocklike material composed primarily of consolidated and chemically altered plant material that grew in prehistoric forests.¹ The chemical composition of coal varies from one location to another, depending on the vegetation from which it was formed and the environmental conditions (such as temperature and pressure) to which the formation was exposed. In addition to its major chemical constituents of carbon, hydrogen, nitrogen, and oxygen, coal also contains some water and impurities of which ash, mercury, and sulfur are major concerns from an emissions viewpoint.

Table 3.1. Fuels fired in boilers to generate hot water or steam

Fuel	Description
By-product/waste	Any liquid or gaseous substance produced at chemical manufacturing plants or petroleum refineries (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. ²
Biomass	Organic matter that is used as fuel is called biomass; ³ biomass is a nonfossil fuel that includes materials such as wood, bagasse, nut hulls, rice hulls, corncobs, coffee grounds, and tobacco stems
Coal	Coal is a brown-to-black combustible sedimentary rocklike material composed principally of consolidated and chemically altered plant material that grew in prehistoric forests; ¹ it includes all solid fuel classified as anthracite, bituminous, subbituminous, or lignite coal, coal refuse, or petroleum coke. ²
Coal refuse	Waste products of coal mining, physical coal cleaning, and coal preparation operations containing coal, matrix material, clay, and other organic and inorganic materials. ⁴
Distillate oil	Fuel oils that contain 0.05 wt % nitrogen or less and comply with the specifications for fuel oil Nos. 1 and 2 as defined in ASTM D 396 (Refs. 2 and 5).
Municipal-type solid waste and RDF	Refuse, more than 50% of which is waste containing a mixture of paper, wood, yard waste, food wastes, plastics, leather, rubber, and other noncombustible materials such as metal, glass, and rock, which are usually removed prior to combustion. ²
Natural gas	A naturally occurring mixture of hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane, or LP gas as defined in ASTM D 1835 (Refs. 2 and 6).
Oil	Crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil. ²
Propane	Propane is a heavy gaseous fossil fuel processed from crude petroleum and natural gas. ⁶
Residual oil	Crude oil and fuel oil Nos. 1 and 2 that have nitrogen content greater than 0.05 wt %, and all fuel oil Nos. 4, 5, and 6 as defined in ASTM D 396 (Refs. 2 and 5).
Solvent-derived fuel	Any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent-refined coal, liquefied coal, and gasified coal. ⁴
Very low sulfur oil	Oil that contains no more than 0.5 wt % sulfur and that, when combusted without SO ₂ emission control, has a SO ₂ emissions rate equal to or less than 215 ng/J (0.5 lb/MBtu) heat output. ²
Wood	Wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest products. ²
Wood residue	Bark, sawdust, slabs, chips, shavings, mill trim, and other wood products derived from wood processing and forest management operations. ⁷

Table 3.2. Key properties for selected fuels

Fuel	High heating value	Carbon (%)	Hydrogen (%)	Ultimate CO ₂ (%)
Anthracite coal	12,680 Btu/lb	80.6	2.4	19.9
Bagasse	8,200 Btu/lb	45.0	6.4	20.3
Bark				
15% moisture	8,500 Btu/lb	52.0	5.5	20.0
30% moisture	8,500 Btu/lb	52.0	5.5	20.0
45% moisture	8,500 Btu/lb	52.0	5.5	20.0
60% moisture	8,500 Btu/lb	52.0	5.5	20.0
Bituminous coal	14,030 Btu/lb	80.1	5.0	18.5
Distillate No. 1	19,423 Btu/lb	86.6	13.3	15.4
	131,890 Btu/gal			
Fuel oil No. 2	18,993 Btu/lb	87.3	12.5	15.7
	137,080 Btu/gal			
Fuel oil No. 5	18,909 Btu/lb	88.7	10.7	16.3
	149,960 Btu/gal			
Fuel oil No. 6	18,126 Btu/lb	88.5	9.3	16.7
	153,120 Btu/gal			
Kerosene	19,942 Btu/lb	86.5	13.2	15.1
	137,000 Btu/gal			
Natural gas	21,830 Btu/lb	69.4	22.5	11.7
Propane	21,573 Btu/lb	81.6	18.4	13.8
Wood				
10% moisture	8,800 Btu/lb	50.0	6.5	20.0
20% moisture	8,800 Btu/lb	50.0	6.5	20.0
30% moisture	8,800 Btu/lb	50.0	6.5	20.0
40% moisture	8,800 Btu/lb	50.0	6.5	20.0

Source: Ref. 8.

A number of physical and chemical properties influence the coal selection process. These properties are determined by laboratory analysis of representative coal samples using test methods established by the American Society for Testing and Materials (ASTM). Important coal properties include⁹

- moisture;
- proximate analysis (fixed carbon, volatile matter, ash);
- ultimate analysis (carbon, hydrogen, nitrogen, oxygen, sulfur, and chlorine);
- gross caloric value (as received and on a dry basis);
- mineral matter in coal (ash, major and minor elements, fusibility of ash, trace elements, mercury, fluorine, arsenic, selenium, and sulfur in ash);
- petrographic analysis;
- grindability;
- free-swelling index;
- CO₂;
- forms of sulfur (pyritic, sulfate, organic); and
- ash abrasiveness.

The chemical composition of coal is also determined in a laboratory by chemical analysis. Results of these analyses are used for heat-balance calculations and the determination of theoretical air requirements.

Moisture represents an impurity that adds to the weight of coal but not to its heating value. The moisture may be a constituent of the coal, or it may be present on the surface of the coal because of precipitation or coal cleaning operations. Moisture content, which is expressed as a percentage, is defined as the difference between the weight of a coal sample before and after the sample is maintained in an oven at 220°F for 1 h. When moisture in coal is heated, some of the heat generated by the combustion process must be used to convert the water to steam. Normally it is more economical to burn coal with a low moisture content; but when coal is burned on certain grates, there are conditions that make it advantageous to have small amounts of moisture present. Moisture tends to accelerate the combustion process, keep the fuel bed even, and promote uniform burning. Coals having 7 to 12% moisture content are recommended for use in chain-grate and traveling-grate stokers.¹⁰ The addition of moisture to coal to enhance the combustion process is referred to as tempering.

When coal is heated, the gaseous substance that is driven off is “volatile matter.” This matter, which consists mostly of hydrocarbon gases, burns in the combustion space above the fuel. Coal with a relatively high percentage of volatile matter is termed “soft;” whereas coal with a relatively low percentage of volatile matter is termed “hard.” When soft coal is burned in a pulverized form, the volatile matter is distilled off and burns as a gas. This makes soft coal relatively easy to burn because ignition is maintained and complete combustion is achieved with minimum flame travel. Combustion of pulverized hard coal, which has less volatile matter, is more difficult to accomplish. To improve combustion, it may be necessary to pulverize hard coals with low volatility to a smaller particle size compared to soft coals or use more intense firing methods.

Inert solid matter that remains after combustion is called ash. It includes mineral or inorganic material, such as silica, that was introduced as the coal was being formed. Clay, silt, sand, shale, slate, and pyrite particles are other ash-forming materials commonly found in the stratified layers of coal seams. Because ash is inert, coal with a high ash content may have a lower heating value. Although ash is usually considered a waste product that must be transported for disposal, it can have value as a construction material. For example, fly ash has been used as a base for roadways, structural fill, waste stabilization, soil modification, and backfill. Fly ash that is produced in some coal-fired boilers may be suitable for use as a mineral admixture in concrete if it satisfies chemical and physical specification requirements established by the ASTM.¹¹ Ash from certain coal combustion processes is also used in the manufacture of concrete masonry units.

Sulfur is an impurity in coal that occurs in three forms: (1) organic sulfur, which is part of the plant’s molecular structure; (2) pyritic sulfur, which occurs as iron sulfide and is better known as the mineral pyrite; and (3) sulfate sulfur, which is primarily from iron sulfate.¹⁰ The highest sulfur source is from sulfates found in some freshwater and seawater. Bituminous coals that are found in the interior of the United States where oceans once covered the region are high in sulfur. When selecting coal and the equipment used for its combustion, consideration must be given to the sulfur content of the coal. The corrosive effects of sulfur can influence material selection, and the amount of SO₂ that is discharged into the atmosphere can dictate the need for pollution control equipment. In particularly corrosive environments such as those where low-temperature flue gas is present, corrosion-resistant materials are sometimes specified to minimize or avoid corrosion damage. For new units, installation of SO₂ scrubbing systems that remove more than 90% of the SO₂ in the flue gas may also be required, depending on the sulfur content of the coal. Switching from high- to low-sulfur coal can be an effective method for existing units to deal with sulfur-related issues.

A classification system for distinguishing one coal from another has been established by the ASTM. This system covers anthracitic, bituminous, subbituminous, and lignitic coals.¹² Classification is according to fixed carbon and gross caloric value expressed in British thermal units per pound (Btu/lb). Higher-ranking coals with at least 69% fixed carbon are classified on the dry basis. Lower ranking coals with a caloric value up to 14,000 Btu/lb are classified on the moist basis. The ASTM has established standard test methods for use in classifying coal.¹³⁻¹⁷ The four classes of coals and their associated groups are identified and summarized in the following paragraphs.

3.1.1.1 Lignite

Lignite is the lowest ranking coal with a heating value of 8,300 Btu/lb or less and a moisture content as high as 35%.¹⁰ Depending on the caloric value, lignitic coals are subdivided into the two classes shown in Table 3.3.

Lignitic coals have a high content of volatile matter, which makes them relatively easy to ignite, especially when the combustion air is preheated. Because lignite has a relatively low sulfur content, it emits low amounts of SO₂.

Table 3.3. Lignite coals

Class/group	Gross caloric value limits (Btu/lb) (moist, mineral-matter-free basis)	
	Equal or greater than	Less than
Lignite A (abbreviated ligA)	6,300	8,300
Lignite B (abbreviated ligB)	No limit	6,300

Source: Ref. 12.

3.1.1.2 Subbituminous

Subbituminous coals, which have a heating value between 8,300 and 11,500 Btu/lb, have a higher heating value than lignitic coals. They also have less ash and burn cleaner than lignitic coals, but the moisture content is relatively high, usually between 15 and 30%. Subbituminous coals are subdivided into three classes based on the caloric values listed in Table 3.4.

The sulfur content of most subbituminous coal is low, generally less than 1%. Because the sulfur content is low, many power plants have changed to subbituminous coal to limit SO₂ emissions.¹⁰ Low-sulfur coals, which are mined in Montana and Wyoming, are relatively low in cost.

Combustion of subbituminous coal results in reduced NO_x emissions, but generally exhibits high fouling and slagging ash characteristics. Burning subbituminous coal in a boiler that was designed for a different class of coal may require changes in the boiler design or operation to optimize performance.

Table 3.4. Subbituminous coals

Class/group	Gross caloric value limits (Btu/lb) (moist, mineral-matter-free basis)	
	Equal or greater than	Less than
Subbituminous A (abbreviated subA)	10,500	11,500
Subbituminous B (abbreviated subB)	9,500	10,500
Subbituminous C (abbreviated subC)	8,300	9,500

Source: Ref. 12.

3.1.1.3 Bituminous

Bituminous coals are used routinely by electric utilities and in some industrial applications to fire steam-generating boilers even though their sulfur content can be relatively high. Compared to lignitic and subbituminous coals, the heating value of bituminous coals range between 10,500 and 14,000 Btu/lb. This higher heating value and its relatively high volatile matter enable bituminous coals to burn easily when fired as PC. Bituminous coals are subdivided into the following groups in Table 3.5 based on fixed carbon, volatile matter, or gross caloric limits.

Table 3.5. Bituminous coals

Class/group	Fixed carbon limits (%) (dry, mineral-matter-free basis)		Volatile matter limits (%) (dry, mineral-matter-free basis)		Gross caloric value limits (Btu/lb) (moist, mineral-matter-free basis)	
	Equal or greater than	Less than	Greater than	Equal or less than	Equal or greater than	Less than
Low-volatile bituminous coal (abbreviated lvb)	78	86	14	22	No limit	No limit
Medium-volatile bituminous coal (abbreviated mvb)	69	78	22	31	No limit	No limit
High-volatile A bituminous coal (abbreviated hvAb)	No limit	69	31	No limit	14,000	No limit
High-volatile B bituminous coal (abbreviated hvBb)	No limit	No limit	No limit	No limit	13,000	14,000
High-volatile C bituminous coal (abbreviated hvCb)	No limit	No limit	No limit	No limit	11,500 (commonly agglomerating) 10,500 (agglomerating)	13,000 (commonly agglomerating) 11,500 (agglomerating)

Source: Ref. 12.

3.1.1.4 Anthracite

As a fuel, anthracitic coals are the highest ranking with fixed carbon contents ranging from 86 to 98%. In addition to their high carbon content, they have a moisture content that is only about 3% and a heating value that can be as high as 15,000 Btu/lb. Anthracitic coals are characterized as slow-burning fuels that are low in sulfur and volatile matter. These coals are used mostly to make coke for metallurgical processes.¹⁰ Anthracitic coals are subdivided into the following groups in Table 3.6 based on their fixed carbon and volatile matter content.

Table 3.6. Anthracitic coals

Class/group	Fixed carbon limits (%) (dry, mineral-matter-free basis)		Volatile matter limits (%) (dry, mineral-matter-free basis)	
	Equal or greater than	Less than	Greater than	Equal or less than
	Meta-anthracite (abbreviated ma)	98	No limit	No limit
Anthracite (abbreviated an)	92	98	2	8
Semianthracite (abbreviated sa)	86	92	8	14

Source: Ref. 12.

If the quality of coal from a particular location does not meet the applicable fuel specification, it can be processed in different ways to upgrade its quality. Operations such as washing, drying, sizing, and blending of coals from different sources are techniques that may be used to produce acceptable coal, but other methods that involve separation of foreign materials such as slate and pyrites from the coal may be necessary. Although one or more of these methods may produce coal with the desired quality, special equipment may be required to perform the operations.

3.1.2 Fuel Oil

Petroleum is a naturally occurring black liquid found floating on subterranean lakes of saltwater and located beneath dome-shaped nonporous rock formations. These deposits consist of natural gas, crude oil, and saltwater separated into layers by virtue of their difference in specific gravity. When a well is drilled through the rock formation, natural gas flows to the surface where it is either burned or transported by pipeline to a processing facility. Depending on the pressure, the crude oil either flows to the surface or is removed by pumping. Once above ground, the crude oil is transported by pipeline, truck, rail, barge, or ship to a refinery. At the refinery, the crude oil is processed into any number of petroleum-based products, including fuel oils.

Fuel oils burned in boilers include the heavier petroleum products that are less volatile than gasoline. They are divided into two classes, distillate and residual. Distillate oils are lighter than residual oils with a consistency between kerosene and lubricating oil. They have a low viscosity and are typically sediment- and ash-free. Because distillate oils are relatively clean fuels, they are used primarily for home heating and industrial applications where low ash and low sulfur are important. Smaller amounts of distillate oil are used in steam generation applications as a startup or supplemental fuel for certain solid-fuel combustion processes. Residual oils are products that remain after the more volatile hydrocarbons have been extracted. Residual oils, which are highly viscous, are usually free from moisture and sediment after processing. Some of the heavier residual oils must be heated to make the fuel easier to handle and burn. Sometimes, distillate and residual oils are blended to create a mixture with proportions that meet a desired fuel specification. As a liquid, fuel oils are relatively easy to handle and burn. In most oil burners,

the oil is atomized with air, steam, or pressure to enhance combustion. The characteristics of atomized oil approximate those of natural gas.¹⁰

The heating value of fuel oil is derived primarily from its two major constituents, hydrogen and carbon. Most fuel oils have a hydrogen content that ranges between 10 and 14%, and a carbon content that ranges between 86 and 90%.¹⁸ Heating values for fuel oils are expressed in units of either British thermal unit per pound (Btu/lb) or per gallon (Btu/gal) at 60°F. Complete combustion of 1 lb of carbon yields a gross heat of 14,500 Btu.¹⁹ Hydrogen has a very high heating value compared to carbon; but it is a very lightweight gas, so the heating value of 1 ft³ of hydrogen is low compared to other gaseous fuels. Heating values for commercial fuel oils vary from approximately 17,500 to nearly 20,000 Btu/lb.¹⁸ Other constituents in fuel oils include nitrogen, sulfur, ash, and impurities such as moisture and sediment. Compared to coal, the nitrogen and ash contents of most fuel oils are very low. Residual oils tend to have higher nitrogen contents than distillate oils.

A standard specification for five grades of fuel oil intended for use in different types of fuel-oil-burning equipment under various climatic and operating conditions has been developed by the ASTM.⁵ Requirements in this specification cover both distillate and residual oils. The various grade numbers into which fuel oils are subdivided are listed in Table 3.7. Fuel oil Grade No. 2 is considered a premium steam-generating fuel because its cleanliness and ease of handling are often used to justify its relatively high cost. The cost of Grade No. 6 fuel oil is relatively low, but heating of the fuel is required to facilitate handling and burning.

Sulfur found in fuel oil is very undesirable. Its products of combustion are very acidic and can cause corrosion in economizers, air heaters, induced draft fans, flue gas ducts, and stacks. The sulfur content of fuel oil can vary from a low of 0.01% for Grade No. 1 to as high as 3.5% for Grade No. 6 (Ref. 18). During combustion, some of the sulfur accumulates in the ash, but most is discharged with the flue gas into the atmosphere. If uncontrolled SO₂ emissions exceed established limits, it may be necessary to switch to a lower sulfur oil or install SO₂ scrubbers to meet applicable emissions standards.

3.1.3 Natural Gas

Natural gas is a colorless hydrocarbon fuel consisting primarily of methane (CH₄) and ethane (C₂H₆), its two principle combustible components. It is typically found under the earth's surface in porous rock and shale formations or above crude oil deposits located beneath dome-shaped nonporous rock formations. When a well is drilled through the formation, natural gas, which is under pressure, flows to the surface where it is either burned or transported by pipeline to a processing facility. This characteristic makes natural gas a very desirable boiler fuel because it can be piped directly into the boiler. In addition to its ease of distribution, use of natural-gas-fired boilers requires a relatively small boiler space, and the overall plant design is typically compact and simple. With a heating value of about 1,000 Btu/ft³ under standard conditions of 60°F at atmospheric pressure and low excess-air requirements that contribute to high efficiency, natural gas is perhaps very close to an ideal fuel.

When natural gas at the well head contains sulfur-bearing alcohols and phenols (mercaptans) and a high percentage of hydrogen sulfide, it is referred to as sour gas. By removing the objectionable constituents, sour gas can be converted to sweet gas. Sweet gas is required for distribution in pipelines to avoid corrosion problems caused by exposure to hydrogen sulfide. Removal of sulfur from the gas also eliminates the possibility of SO₂ emissions during combustion.

From an emissions viewpoint, natural gas is an excellent fuel choice. Although natural gas from some sources contains noncombustible gases such as nitrogen and carbon dioxide, it is practically free from solid residue. Because it is free of ash and mixes easily with air, combustion is usually complete without objectionable smoke or soot. The only significant problem with using natural gas as a fuel for boilers is related to its chemical composition. Natural gas has a relatively high hydrogen content (greater than 20% by weight) compared to other fossil fuels such as oil and coal. During combustion, the

Table 3.7. Fuel oil grades established by ASTM

Fuel oil	Description
Grade No. 1	Distillate fuel for use in domestic and small industrial burners. This grade is particularly adapted to vaporizing burners in which the oil is converted to a vapor by contact with a heated surface or by radiation or where storage conditions require low-pour-point fuel. High volatility is necessary to ensure that evaporation proceeds with a minimum of residue. The maximum allowable sulfur content is 0.5% by mass. The maximum allowable ash content is not specified.
Grade No. 2	Distillate fuel that is heavier than Grade No. 1. It is intended for use in atomizing burners that spray the oil into a combustion chamber where the tiny droplets burn while in suspension. This grade of fuel oil is used in most domestic burners and in many medium-capacity commercial-industrial burners where its ease of handling and ready availability sometimes justify its higher cost over residual fuels. The maximum allowable sulfur content is 0.5% by mass. The maximum allowable ash content is not specified.
Grade No. 4 (light)	Heavy distillate fuel or distillate/residual fuel blend used in commercial/industrial burners equipped for this viscosity range. This grade of fuel oil is intended for use both in pressure-atomizing commercial-industrial burners not requiring higher cost distillates and in burners equipped to atomize oils of higher viscosity. Its permissible viscosity range allows it to be pumped and atomized at relatively low storage temperatures. The maximum allowable sulfur content is not specified. The maximum allowable ash content is 0.05% by mass.
Grade No. 4	Heavy distillate fuel or distillate/residual fuel blend used in commercial/industrial burners equipped for this viscosity range. This grade of fuel oil is intended for use in burners equipped with devices that atomize oils of higher viscosity than domestic burners can handle. Its permissible viscosity range allows it to be pumped and atomized at relatively low storage temperatures. Thus, in all but extremely cold weather it requires no preheating for handling. The maximum allowable sulfur content is not specified. The maximum allowable ash content is 0.10% by mass.
Grade No. 5 (light)	Residual fuel oil of intermediate viscosity intended for use in industrial burners capable of handling fuel more viscous than Grade No. 4 without preheating. Preheating may be necessary in some equipment for proper atomization and in colder climates for handling. The maximum allowable sulfur content is not specified. The maximum allowable ash content is 0.15% by mass.
Grade No. 5 (heavy)	Residual fuel oil used in industrial burners with an increased viscosity and boiling range compared to Grade No. 5 (light). Preheating may be necessary in some types of equipment for proper atomization and in colder climates for handling. The maximum allowable sulfur content is not specified. The maximum allowable ash content is 0.15% by mass.
Grade No. 6	Residual fuel oil used in industrial burners with an increased viscosity and boiling range compared to Grade No. 5 (heavy). Preheating is required for handling and proper atomization. Extra equipment and maintenance required to handle this fuel usually preclude its use in smaller installations where cleanliness and ease of handling are important. The maximum allowable sulfur content and the maximum allowable ash content are not specified.

Source: Ref. 5.

hydrogen in natural gas combines with oxygen to form water vapor. As discussed in Sect. 3.3, formation of relatively large quantities of water vapor translates to lower boiler efficiency.

Like natural gas, other types of gases can also be used as fuels for boilers, but their processing costs generally make them too expensive for most large-scale applications. By-product substitutes for natural gas include producer gas, coke-oven gas, water gas, and blast-furnace gas derived from coal, refinery gas and oil gas derived from oil, and liquefied petroleum (LP) gas, including propane and butane, derived from either natural gas or oil.⁶

3.1.4 Biomass

Biomass is a nonfossil fuel suitable for steam generation in boilers. It is derived from plant material including wood, bagasse, nut hulls, rice hulls, corncobs, coffee grounds, and tobacco stems. Use of these by-product materials as fuel can be cost-effective especially when it solves a waste disposal problem.

Wood is a complex vegetable tissue composed principally of cellulose. Most wood burned in boilers is a by-product from manufacturing operations such as sawmills, paper mills, and factories that manufacture wood products. By-products from these operations may take the form of bark, sawdust, sanderdust, chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest products. Care must be used when burning fine wood dust because under certain conditions it can ignite quickly. Depending on the species and moisture content, the heating value of wood varies over a wide range.²⁰ Although certain types of wood are more suitable for steam production, sufficient supplies of the fuel may not always be available. In these situations, it may be necessary to burn supplementary fuels along with the wood to meet the total steam demand.

Bagasse is a by-product fuel produced when the juice is removed from cane in a sugar mill. Although its heating value can be as high as 8,000 to 9,000 Btu/lb, combustion of bagasse is only feasible in certain parts of the United States where sugar cane is processed. When bagasse is burned, it is usually supplemented with auxiliary fuels.

Other biomass fuels include

- nut hulls with a heating value of about 7,700 Btu/lb,
- rice hulls with a heating value between 5,200 and 6,500 Btu/lb,
- corncobs with a heating value between 7,500 to 8,300 Btu/lb, and
- coffee grounds from instant coffee production with a heating value between 4,900 to 6,500 Btu/lb (Ref. 20).

3.1.5 Refuse-Derived Fuel

Residential, commercial, and industrial solid waste that is transported to a landfill for disposal can be burned as a fuel in waste-to-energy boilers. MSW that contains mixtures of paper, wood, yard wastes, food wastes, plastics, leather, and rubber can have characteristics similar to wood. Use of MSW as a fuel can be accomplished by burning the as-received material, called mass burning; but processing is often required before it can be burned effectively. When MSW is processed using size-reduction and material-recovery techniques designed to shred the waste and remove noncombustible materials, it is called RDF.¹⁸ The highly variable nature of MSW presents challenges in designing a combustion system that can accommodate this high-ash, low-sulfur fuel.

3.1.6 Other Fuels

Heavy residuals from petroleum-cracking processes yield a solid residue that is suitable for use as a fuel for boilers.¹⁸ Solid fuels derived from oil include delayed coke, fluid coke, and petroleum pitch. Some cokes produced by the delayed coking process are easy to pulverize and burn in boilers. Fluid

cokes can also be pulverized and burned in boilers or burned in a cyclone furnace or a fluidized bed, but all three of these methods may require supplemental fuel to aid start-up. Petroleum pitch yields fuel with varying characteristics. Low-melting-point pitches can be heated and burned like heavy oil. Those with higher melting points must be pulverized or crushed and then burned.

Coal tar pitch is the residue resulting from the distillation and refining of coal tar. Although it can be used as a boiler fuel, it is somewhat difficult to handle. At ambient temperature, it is a solid that can be pulverized before it is delivered to the boiler. At about 300°F, it becomes a liquid and can be burned like oil. Because of its low ash content, use of coal tar pitch is sometimes preferable to coal.²⁰

Pulp mill sludge can be used as a fuel for boilers, but it must be dried before it can be effectively burned. This fuel typically has an ash content of approximately 10%. Sludges from deinking processes are less suitable because they have less heating value and significantly more ash. Unless sludge from the deinking process is dried before it enters the boiler, the combination of high moisture content and low heating value make it difficult to burn. Burning sludge with a high-moisture content in stoker-fired boilers presents some significant problems because removal of the moisture results in a lower combustion chamber temperature. For this reason, sludge is generally burned in stoker-fired boilers in combination with another fuel such as bark.¹⁰

3.1.7 Mixed Fuels

Environmental concerns about SO₂ and PM emissions from combustion of bituminous coals have led to the development of coal cleaning techniques known as beneficiation.¹⁸ These techniques involve removal of sulfur and mineral matter from coal prior to combustion. To achieve the cleaning level needed to meet sulfur standards, the form of the solid coal must first be altered. Most advanced cleaning processes use water as the separation medium and involve grinding the coal to fine particle size. Grinding allows pyritic sulfur and other minerals that are dispersed throughout the coal to be more easily separated from the coal. After these materials are removed, the fine, clean coal product must be dried, pelletized, or reconstituted into a coal-water slurry, which can be handled like oil prior to combustion in a boiler.

Coal-water slurries have potential as fuel oil substitutes in some combustion applications. Typical bituminous coal slurries contain approximately 70% PC, 29% water and 1% chemical additives. Slurries prepared from coals, which have been deep cleaned, can contain coal with finer particle sizes and a lower solids content (50 to 60%). Although coal-water slurries are produced from fine PC and are handled and fired like No. 6 fuel oil, they burn somewhat differently. Burners suitable for coal-water slurry combustion are often specially designed to accommodate the unique properties of the slurry. Viscosity and flow characteristics can affect the way the fuel is atomized and can increase wear and deterioration of piping and burner components.

Oil-water slurries can be used as fuel with combustion performance similar to residual oils. These liquid-fuel emulsions are composed of micron-size oil droplets dispersed in water.¹⁸ Although the heating value, ash content, and viscosity of oil-water slurries are similar to residual oil, they have a relatively high sulfur content.

3.2 EMISSIONS

Federal, state, and local government agencies regulate air pollutants emitted from steam generating units in accordance with the CAA.²¹ This legislation establishes primary and secondary National Ambient Air Quality Standards (NAAQS) for six criteria pollutants, including ground-level ozone, NO_x, SO₂, CO, PM, and lead.²² These standards address concerns about ground-level ozone, the accumulation of fine particles in the atmosphere, and acid rain. Emissions of criteria pollutants from steam generating units include NO_x, SO₂, CO, and PM.

The CAA, as amended in 1990, also requires EPA to establish standards for reducing toxic air pollutant emissions. The 1990 Act includes a list of 189 HAPs selected by Congress on the basis of their

potential health and environmental hazards, and it authorizes EPA to establish regulations for each of these pollutants. Toxic air pollutants, also known as HAPs, are those pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive effects or birth defects or adverse environmental effects. To regulate HAPs, EPA has identified categories of sources that release these listed chemicals. One of these categories includes ICI boilers. Toxic air pollutants that are emitted during the combustion of certain fuels include metals such as cadmium, mercury, chromium, and lead compounds.

3.2.1 Nitrogen Oxides

During the combustion process, NO_x is one of the primary pollutants emitted into the atmosphere. In this context, NO_x refers to the cumulative emissions of nitric oxide (NO), nitrogen dioxide (NO_2), and trace quantities of other species as shown in Table 3.8.²³ Although mobile sources are the largest contributor to NO_x formation in the United States, combustion of any fossil fuel generates some level of NO_x because of high temperatures and the availability of oxygen and nitrogen from both the air and fuel. The NO_x emissions from fired processes are typically 90 to 95% NO with the balance being predominantly NO_2 . Once the flue gas leaves the stack, the bulk of the emitted NO is eventually oxidized in the atmosphere to NO_2 .

Dispersed in the atmosphere, NO_2 reacts to form secondary pollutants, including ground-level ozone and acid rain. Chemical reactions between volatile organic compounds (VOCs) (hydrocarbon radicals) and NO_x create ground-level ozone, which is not to be confused with ozone found in the upper atmosphere. When these materials react in the presence of sunlight, they form ground-level ozone, a major ingredient of smog. When NO_x reacts with water vapor and air, it forms very dilute nitric acid. Control of acid rain has focused primarily on reducing SO_2 emissions because NO_x is estimated to contribute less than one-third of the acid rain generated.

There are two common mechanisms of NO_x formation, thermal NO_x and fuel NO_x (Ref. 18). Thermal NO_x refers to the NO_x that formed through high-temperature oxidation of nitrogen found in the combustion air. Fuel NO_x involves the conversion of fuel-bound nitrogen found in nitrogen-bearing fuels, such as coal and oil, to NO_x during combustion. A third type of NO_x that forms under certain conditions is known as prompt NO_x .

Table 3.8. Nitrogen oxides

Formula	Name	Properties
N_2O	Nitrous oxide	Colorless gas, water soluble
NO	Nitric oxide	Colorless gas, slightly water soluble
N_2O_2	Dinitrogen dioxide	Colorless gas, slightly water soluble
N_2O_3	Dinitrogen trioxide	Black solid, water soluble, decomposes in water
NO_2	Nitrogen dioxide	Red-brown gas, very water soluble, decomposes in water
N_2O_4	Dinitrogen tetroxide	Red-brown gas, very water soluble, decomposes in water
N_2O_5	Dinitrogen pentoxide	White solid, very water soluble, decomposes in water

Source: Ref. 23.

3.2.1.1 Thermal NO_x

The formation rate of thermal NO_x is a strong function of temperature as well as the residence time at temperature. Significant levels of NO_x are usually formed above 2,600°F. Above this temperature the rate of thermal NO_x increases exponentially. At these high temperatures, molecular nitrogen (N_2) and oxygen (O_2) in the combustion air can dissociate into their atomic states and participate in a series of

reactions. One product of these reactions is NO. At temperatures below 1,400°F, NO is either generated in much lower concentrations or not at all.^{23,24}

Thermal NO_x formation is typically controlled by reducing the peak and average flame temperatures. Although this approach is contrary to traditional methods of assuring complete combustion (i.e., high temperatures, long residence time, and high turbulence or mixing), some compromise between effective combustion and controlled NO_x formation is needed. This can be accomplished through a number of combustion system changes:

- Use of controlled mixing burners to reduce the turbulence in the near burner region of the flame and to slow the combustion process. This typically reduces the flame temperature by removing additional energy from the flame before the highest temperature is reached.
- Use of staged combustion where part of the combustion air is initially introduced to burn some of the fuel. The remaining air is added separately to complete the combustion process. This lowers the peak flame temperature by reducing the oxygen concentration. Combustion at very low excess air levels is an effective way to control NO_x formation.
- Use of staged combustion where a portion of the total fuel is added with an excessive amount of combustion air. The remaining fuel is then added at a later stage in the combustion process. Combustion at very high excess air levels is an effective way to control NO_x formation.
- Use of a technique known as flue gas recirculation (FGR) in which some of the flue gas is mixed with the combustion air at the burner. This increases the gas weight that must be heated by the chemical energy in the fuel, thereby reducing the flame temperature.
- Use of multiflame burners and lean premix combustion that breaks the total heat input into smaller flames with effective mixing. This lowers peak flame temperatures and allows the heat to be removed rapidly by placing the flame in close proximity to the heating surface.
- Use of a premixed blend of air and gaseous fuel with the option of adding flue gas to the mixture will cause combustion to occur at a relatively low temperature, thus reducing thermal NO_x formation. Burners that premix gaseous fuel and air to control thermal NO_x formation are described in Sect. 5.2.1.6.
- Use of combinations of these techniques.

These approaches have been used effectively with gas, oil, or coal firing to reduce NO_x formation. For fuels that do not contain significant amounts of chemically bound nitrogen, such as natural gas, thermal NO_x is the primary overall contributor to NO_x emissions. In these cases, the approaches previously described are particularly effective in NO_x emission control.

3.2.1.2 Fuel NO_x

The major source of NO_x emissions from nitrogen-bearing fuels such as coal and oil is the conversion of fuel-bound nitrogen to NO during combustion. Laboratory studies indicate that fuel NO_x contributes approximately 50% of the total uncontrolled emissions when firing residual oil and more than 80% when firing coal.¹⁸ Nitrogen found in fuels such as coal and residual oils is typically bound to the fuel as part of organic compounds. During combustion, the nitrogen is released as a free radical to ultimately form NO or N₂. Although it is a major factor in NO_x emissions, only 20 to 30% of the fuel-bound nitrogen is converted to NO.

Conversion of fuel-bound nitrogen to NO is strongly dependent on the fuel-air proportions, but it is relatively independent of variations in combustion zone temperature. Therefore, reducing oxygen availability during the initial stages of combustion can control this conversion. Techniques such as controlled fuel-air mixing and staged combustion can provide a significant reduction in NO_x emissions.

Removing nitrogen from fuel before it is burned is not easily achieved, but switching from a high-nitrogen-content fuel to a lower nitrogen-content fuel may be effective in reducing NO_x emissions. In

general, coal combustion produces the highest NO_x emissions with oil combustion generating less and gas combustion producing the least. For oil, a reduction in fuel nitrogen results in a decrease in NO_x formation; but for coal, reducing fuel nitrogen may not provide a corresponding reduction.

3.2.1.3 Prompt NO_x

A portion of the NO_x that is formed by oxidation of the fuel-bound nitrogen under fuel-rich conditions is referred to as prompt NO_x (Ref. 18). The name is derived from its formation very early during the combustion process. Prompt NO_x occurs through the formation of intermediate hydrogen cyanide (HCN) species and the reaction between molecular nitrogen and hydrocarbon compounds. This reaction is then followed by the oxidation of HCN to NO.

Although prompt NO_x formation normally has a weak temperature dependence, this dependence can become strong under fuel-rich conditions. Except for burners that fully premix air and gaseous fuel, most burners are designed to reduce peak flame temperatures by controlling the rate of fuel and air mixing. Combustion is initiated under fuel-rich conditions, and this fuel-rich zone is where prompt NO_x is formed. Prompt NO_x can contribute from near zero to more than 100 ppm of NO. Burners that are capable of controlling prompt NO_x formation by premixing fuel and air are described in Sect. 5.2.1.6.

3.2.2 Sulfur Dioxide

Sulfur in most fossil fuels is derived primarily from the decay of plant and animal matter. It originates as hydrogen sulfide, a by-product of the decay process. Other sources of sulfur in fuel include iron sulfite and iron sulfate.

Combustion of sulfur-bearing fuels results in the creation of SO₂. The two principle industrial sources of sulfur emissions are fossil fuel combustion and metallurgical ore refining.¹⁰ When SO₂ oxidizes in the atmosphere, it converts to sulfuric acid (H₂SO₄). There are two mechanisms by which sulfuric acid is formed.

1. Gaseous SO₂ can combine with liquid water to form a dilute aqueous solution of sulfurous acid (H₂SO₃), which oxidizes in the atmosphere to form H₂SO₄.
2. Gaseous SO₂ can also oxidize in the atmosphere to produce gaseous SO₃, which combines with water vapor to form H₂SO₄.

In 1970, the average sulfur content of coal burned by coal-fired power plants was 2.3%. Between 1970 and 1988, use of coals with less sulfur reduced this average to 1.34% (Ref. 18). Switching to low-sulfur coals can be an effective way to reduce SO₂ emissions and thereby permit utilities to comply with mandated SO₂ emissions limitations, but it can have adverse effects on boiler performance. As an example, consider the potential consequences of switching from eastern bituminous coal, which has a high heating value and low ash content to a low-sulfur western subbituminous coal with a high ash content, and lower heating value. Flame stability at various loads can be affected, higher slagging and fouling may occur, the ash loading will increase, changes in fuel handling equipment may be required, emissions control equipment may not perform satisfactorily, and emission levels will be different.

If switching to low-sulfur coal is not effective in reducing SO₂ emissions to an acceptable level, use of wet or dry scrubbers is often a viable option. These postcombustion techniques for controlling SO₂ emissions are very efficient, and their installation allows continued use of existing fuel sources, thereby making major changes in boiler operations unnecessary. Depending on the process, by-products from wet scrubbing can include mixtures of calcium sulfate or calcium sulfite that may be sold as gypsum or placed in landfills.¹⁰ Other methods that are effective in reducing SO₂ emissions include using FBC boilers, reducing the sulfur content of fuel directly, and switching to low-sulfur fuel oil or natural gas.

Coal cleaning can also be an effective method for lowering SO₂ emissions by reducing the amount of sulfur in coal before it is burned. After coal is mined, crushed, and screened to achieve size segregation, it may be processed using various techniques, including gravity concentration, flotation, and dry processing.¹⁸ Gravity concentration is a mechanical cleaning technique that uses the difference in specific gravity of the various coal constituents to separate ash and sulfur from the coal. Segregation is achieved when the more dense ash and sulfur particles settle farther and faster in a fluid medium than the less dense coal particles of the same size. The flotation method of coal cleaning uses differences in surface properties to achieve separation. As air passes over the surfaces of coal particles and mineral matter suspended in an aqueous solution, the coal particles float upward because their surfaces are more difficult to wet. This method is generally used for cleaning coal finer than 300 µm. Dry processing of coal is only suitable for material that has been crushed finer than 0.5 in. and has low surface moisture. This method involves pneumatic processing to achieve segregation.

3.2.3 Particulate Matter

Combustion of any fuel that contains noncombustible material results in the formation of ash. The ash as well as any unburned carbon particles are referred to collectively as PM or fly ash. Fine PM includes dust, smoke, and soot, which can be emitted during the combustion of certain fuels such as coal and wood.

Particle size is measured in micrometers or microns (one millionth of a meter). Depending on the concentration, these fine particles can adversely affect breathing and contribute to poor visibility. Separate PM emission limitations have been established for particles with an aerodynamic diameter less than or equal to a nominal 10 µm (PM₁₀) and for particles with an aerodynamic diameter less than or equal to a nominal 2.5 µm (PM_{2.5}).

All coals contain some amount of ash. Eastern bituminous coals typically contain 5 to 15% ash (by weight), while western subbituminous coals contain 5 to 30% ash. The ash content of fuel oils varies depending on whether the fuel is residual or distillate oil. Residual oils have more ash than distillate oils, but both types have much less ash than coal. Natural gas is essentially ash-free, but it can have some small amount of particulate emissions.

Before flue gas is discharged into the atmosphere, it is often necessary to remove as much of the PM as possible. Three techniques currently being used for this purpose, either alone or in combination, include: (1) mechanical collectors, (2) electrostatic precipitators (ESPs), and (3) fabric filters.¹⁰

3.2.4 Carbon Monoxide

Carbon monoxide (CO) is a colorless, odorless gas formed when carbon in fuels is not burned completely. Highway vehicles produce about 60% of all CO emissions in the United States. In certain cities, automobile exhaust causes as much as 95% of all CO emissions. Other sources of CO emissions include industrial processes and fuel combustion in boilers and incinerators. When combined, emissions from these sources can result in high concentrations of CO, particularly in local areas with heavy traffic congestion.

Control of the combustion process is very important to efficient boiler operation. Incomplete fuel combustion represents wasted energy and results in increased CO and PM emissions. Although combustion of liquid and gaseous fuels typically produces very low CO emissions, control of unburned carbon in boilers that burn solid fuel is an important design and operating concern. Carbon burnout is dependent on fuel properties, boiler and firing system characteristics, and unit operating conditions. Major factors influencing complete combustion of carbon include

- fuel reactivity,
- fuel fineness and particle size,

- efficiency of fuel-air mixing,
- excess air available for complete combustion,
- residence time, and
- temperature profile inside the boiler.

To minimize carbon loss, it is important to match these parameters with the fuel's combustion characteristics. In most instances, the loss due to unburned carbon from coal, wood, and other solid fuel combustion is controllable to below 0.5% of the fuel fired.²⁰

3.2.5 Hazardous Air Pollutants

When fuel is burned in a boiler, different types of HAPs can be emitted. In general, their formation depend on the composition of the fuel and the combustion process. Three factors that greatly influence the combustion process include time, turbulence, and temperature. The importance of each factor is a function of the boiler design and the fuel being burned.

Fuel-dependent HAPs can generally be reduced by either changing the composition of the fuel before it is burned or by removing the HAP from the flue gas after combustion occurs. Emissions of metals such as mercury are released along with PM whenever certain solid fuels are burned. Installation of a PM collection system is an effective way to reduce mercury emissions. Acid gases, such as hydrogen chloride, and organic compounds, such as formaldehyde, that can form when fuel combustion is incomplete are released along with the flue gas. Scrubbers designed to lower SO₂ emissions can be effective in reducing these emissions. In general, larger amounts of organic emissions are produced whenever liquid or gaseous fuels are fired compared to solid fuels.

3.3 EFFICIENCY

To minimize the cost of producing steam or hot water, boiler owners and operators are very interested in extracting as much energy from the fuel as possible. In addition to reducing fuel cost, using energy efficiently is an effective way to reduce emissions. When less fuel is burned to produce a given amount of steam or hot water, emissions are reduced. Achieving high efficiency is therefore an important consideration in selecting a low-emission boiler and combustion equipment. However, many of the methods used to reduce emissions come with a price, either in terms of impact to system efficiency or increased operating cost.^{25,26}

The meaning of the term “efficiency” can sometimes be confusing because there are several ways that efficiency can be quantified. When determining efficiency, it is important that all forms of heat loss are considered. Heat loss in this context is energy that is not transferred to the water to increase its energy content but discharged or vented from the system. The goal is to optimize system performance to increase operational flexibility and to minimize impact on the overall system.

In considering factors that influence boiler performance, note that efficiency is not constant throughout the entire operating range of a boiler. Peak efficiency generally occurs at a particular boiler output. Operations that deviate from this output often result in performance that is somewhat below peak efficiency.

Continuous operation at peak efficiency is often impractical because of seasonal demands and load variations, but operation at steady load and avoidance of cyclic or on-off operation can improve efficiency. However, on-off operation can and will reduce overall energy usage, depending on the output requirements.

While every boiler and burner arrangement will perform somewhat differently, it is possible to project variations in efficiency based on boiler load. It is important to understand that efficiency loss can vary as much as 10% when operations change from the maximum continuous rating (MCR) to reduced boiler output (30 to 40% of capacity). The key to increased efficiency involves minimizing all forms of

combustion and boiler losses. In addition, the overall system efficiency can be improved with attention to the application and uses of the steam and hot water produced by the boiler. Improving system efficiency means that less fuel is used to run the entire process, which in turn leads to lower overall emissions.^{25–28}

3.3.1 Combustion Losses

Combustion efficiency is a measure of the chemical energy available in fuel that is liberated by the combustion process. Quantifying combustion efficiency involves determining

- losses from unburned carbon in the flue gas (CO),
- losses from unburned carbon in the solid residue (bottom ash and fly ash), and
- losses from unburned hydrocarbons (UHCs) in the flue gases.

In its simplest form, combustion efficiency can be computed using the following equation:

$$\text{Combustion efficiency} = 100 - (\text{unburned-fuel losses}) . \quad (3.1)$$

Under perfect combustion conditions, the following phenomena can occur.

- Carbon in hydrocarbon fuel combines with oxygen in the combustion air to form CO₂.
- Hydrogen in the fuel combines with oxygen in the combustion air to form water vapor.

Achieving complete combustion requires precise proportioning of the fuel-air mixture. Incomplete combustion due to an imbalance in the fuel-to-air ratio can result in significant energy loss that translates to decreased combustion efficiency.

When insufficient combustion air (oxygen) is available for complete fuel combustion, some of the carbon remains unburned. Incomplete combustion can result in the formation of CO and carbon-laden PM known as soot. If no additional air is made available to complete the combustion process, two forms of energy are wasted. Heat is lost from the system as hot CO gas or soot particles leaving the stack, and energy is not extracted from the unburned or partially burned carbon.

Air supplied to a boiler in excess of that required for complete fuel combustion (excess air beyond stoichiometric conditions) is also detrimental to efficiency. The efficiency reduction results from excess air entering the boiler at ambient temperature and exiting the system at the stack temperature.

3.3.2 Boiler Losses

Boiler efficiency is a function of boiler losses and combustion losses. It can be characterized as the amount of heat captured by the boiler and transferred to the water, divided by the heat that was input. The heat that was not transferred to the water manifests itself in a number of losses that include

- flue-gas losses,
- radiant heat losses,
- blowdown losses, and
- unaccounted losses.

Flue-gas losses are often the primary cause for reduced boiler efficiency. Energy is wasted whenever heated flue gas is carried out of the boiler and up the stack. Flue-gas temperature is related to boiler load. In general, as boiler load increases, the flue-gas temperature increases. Hotter flue-gas temperatures increase flue-gas losses. Installation of equipment to recover some of this heat can have a beneficial effect on efficiency, but removing too much heat can cause problems such as corrosion,

especially when water condenses on boiler equipment. Corrosion of internal boiler components made from certain types of steel, such as carbon steel, can occur at locations where water condenses and combines with other constituents in the flue gas to form acids. Use of stainless steel or other alloys is sometimes required to avoid these corrosion problems. For most boiler systems, there is a practical limit that dictates the minimum flue-gas temperature.

Air in excess of that required for complete fuel combustion represents a major flue-gas loss. Because the fuel supplies energy required to increase the temperature of excess air, controlling the amount of air that is supplied to a boiler has a direct impact on boiler efficiency. The loss is a function of the amount of excess air that passes through the boiler and the temperature of the excess air that discharges from the stack. Energy required to raise the temperature of excess air is wasted because it is not used to heat water. If the water vapor content of the excess air is high, even more energy is required to superheat the water vapor. Although combustion of any fuel results in some degree of flue-gas loss, solid fuels require more excess air for complete combustion than do gaseous fuels.

Although combustion with insufficient air decreases combustion efficiency, it is a very effective technique for reducing NO_x formation. A lower flame temperature associated with incomplete combustion decreases the amount of thermal NO_x that forms. Selection of a low-emission boiler and combustion equipment often requires a compromise between efficiency and NO_x formation. For greatest efficiency, a boiler should be fitted with proper combustion equipment, including a control system that is capable of adjusting the fuel-air mixture so that little or no CO and soot are produced. Additional air that is required to complete the combustion process is sometimes provided in stages. Staged combustion is a NO_x control technique based on the fact that combustion at either very low or very high excess air levels results in reduced NO_x formation. By mixing air and fuel at two or more locations inside a boiler, it is possible to create zones with high and low excess air levels. Air that is injected into a boiler at different points or stages in the combustion process is known as staged combustion air (SCA). The NO_x control techniques based on this concept are described in Sect. 5.2.1. New boilers and combustion equipment that are well-designed are capable of achieving both high efficiency and low NO_x formation. However, for existing boilers, changes in firing profile may change the absorption profile, temperature profile, and carbon burnout of a boiler, thereby affecting boiler efficiency.

The reaction of hydrogen atoms in fuel with oxygen molecules in air produces heat and water vapor. When the water vapor leaves the stack, it reduces the available energy by carrying away the associated latent heat of vaporization. Reducing the temperature of the flue gas as a means of lowering the heat loss is an effective way to conserve energy, but it can lead to serious corrosion problems. Because natural gas has a relatively high hydrogen content when compared to coal, this form of heat loss is higher for natural-gas-fired boilers than for comparable size coal-fired boilers.

Moisture in fuel represents another form of heat loss. Like the phenomenon just described, the water vapor leaving the stack reduces the available energy by carrying away the associated latent heat of vaporization. As water vapor from the fuel is superheated, additional heat loss is experienced. The wasted energy from this form of heat loss can be significant for solid fuels but tends to be less for gaseous fuels, which usually have a lower moisture content.

Radiant heat loss consists of both radiant and convection heat losses from the outer surfaces of a boiler, which are typically above ambient temperature. These losses do not vary significantly in magnitude with boiler load because the outer surface temperature of the boiler remains essentially constant while in operation. However, these losses as a percentage of boiler output get worse whenever the load diminishes. Two ways to reduce radiant heat loss include adding thermal insulation to outer boiler surfaces and operating the boiler at the lowest temperature consistent with system and boiler manufacturer requirements.

Buildup of soluble salts and accumulation of other solids in the water passages of a boiler can impede heat transfer and eventually restrict flow through boiler passages. Use of chemicals that impede scaling and regular blowdowns can help control this problem, but the hot water and solid particles that discharge during a blowdown represent wasted energy. Installing a heat recovery system can reduce

boiler losses due to blowdowns. By using chemicals to control scaling, it may be possible to reduce the blowdown rate. Note that blowdown heat recovery equipment is usually cost-effective only for systems that use continuous rather than intermittent blowdown.

A relatively small but important form of heat loss is characterized as unaccounted losses. These losses, which are not related to the combustion process, are associated with cyclic rather than continuous boiler operations. They include prepurge and postpurge losses, natural-draft losses, and off-line shell losses. Prepurge and postpurge losses involve forcing air through the boiler to remove unburned combustibles before startup and after shutdown. When this operation is performed, the flowing air removes some thermal energy from the boiler. Similar to purging losses, natural-draft losses occur when the boiler is shut off and air circulates naturally through the boiler. Off-line shell losses are radiant heat losses that occur after the boiler is shut off. Firetube boilers typically have off-line shell losses much less than comparable size watertube boilers because the shell temperature of a firetube boiler is more of a function of the water temperature than the combustion gas temperature.

Heating systems for commercial buildings typically exhibit a wide range of heating demands throughout the heating season. To minimize unaccounted heat losses associated with cyclic operation, there may be advantages in selecting multiple boilers instead of one or two large boilers. In this approach, at least some of the smaller units operate more or less continuously.

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