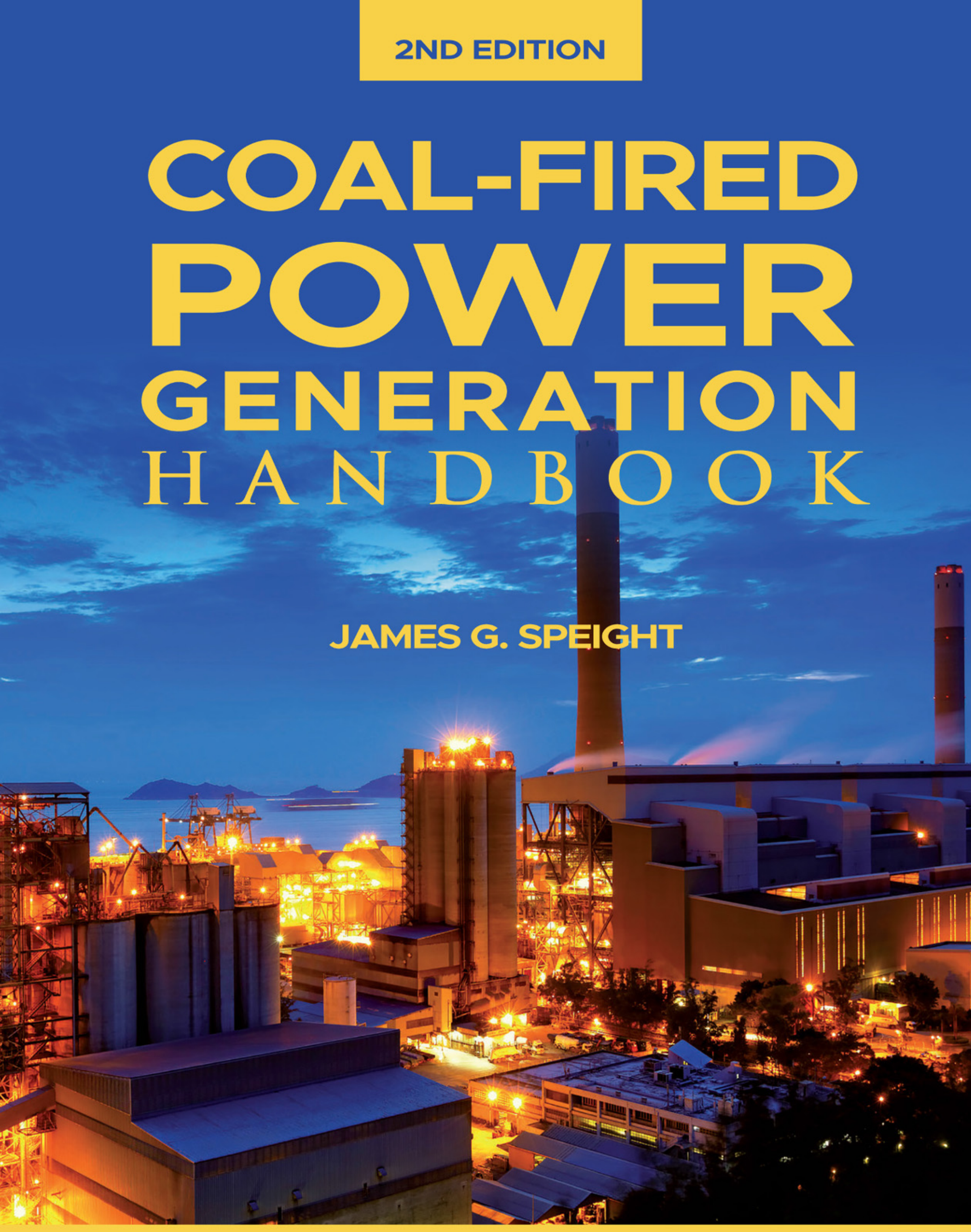
2ND EDITION

COAL-FIRED POWER GENERATION HANDBOOK

JAMES G. SPEIGHT



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Preface

This book describes the steps and challenges by which electricity is produced from coal and deals with the challenges for removing the environmental objections to the use of coal in future power plants. New technologies are described that could virtually eliminate the sulfur, nitrogen, and mercury pollutants that are released when coal is burned for electricity generation. In addition, technologies for the capture of greenhouse gases emitted from coal-fired power plants are described and the means of preventing such emissions from contributing to global warming concerns.

Also, the book introduces the use of the various types of biomass and waste that can be used for generating electricity at a commercial-scale facility rather than a utility-scale project. Biomass heat and biogas, including anaerobic digestion and landfill gas, are covered in other technology resource pages in this guide.

The book, which is written in an easy-to-read style and is also illustrated by diagrams and tables, describes the performance of power plants and the costs of power generation as influenced by many coal properties. Specifically, coal quality impacts not only coal cost but also net power output as well as capital and operating and maintenance costs and waste disposal costs. In fact, coal quality impacts the coal chain in a power plant and their relationship to power generation costs.

Part I of this book describes the steps and challenges by which electricity is produced from coal and deals with the challenges for removing the environmental objections to the use of coal in future power plants. New technologies are described that could virtually eliminate the sulfur, nitrogen, and mercury pollutants that are released when coal is burned for electricity generation.

Part II presents the various aspects of power generation including chapters on gas cleaning, clean coal technologies, and environmental issues arising from the use of coal.

Part III introduces the reader to the use of other fuels for the generation of electricity, including viscous feedstocks, biomass, and solid waste. A chapter relating to energy security and the future of power generation is also included.

There is also a comprehensive Glossary that will help the reader to understand the various terminologies that are used in this important energy field.

Dr. James G. Speight
Laramie, Wyoming
August 2020

PART I

ORIGIN AND PROPERTIES

1

History, Occurrence, and Resources

1.1 Introduction

An ever-expanding human population is matched by an ever-increasing demand for energy to the extent that the world is presently faced with the situation of energy demand exceeding the energy in circulation and the energy production even from a variety of sources (Speight, 2011a, 2020). The production and consumption of energy have been associated with adverse environmental impacts such that the United Nations conference in Kyoto, Japan, in 1997 had to have what is known as the Kyoto Protocol that sets limits on carbon dioxide emissions into the atmosphere (Hordeski, 2008; Irfan *et al.*, 2010).

Coal (the term is used generically throughout the book to include all types of coal), geographically spread across all inhabitable continents of the world, is a black or brownish-black organic sedimentary rock of biochemical origin which is combustible and occurs in rock strata (coal beds, coal seams) and is composed primarily of carbon with variable proportions of hydrogen, nitrogen, oxygen, and sulfur. Coal is the most plentiful fuel in the fossil family and, in the current context, the United States has more coal reserves than any other country in the world. In fact, one-fourth of all known coal in the world is in the United States, with large deposits located in 38 states, which represents almost as much energy in coal that can be mined as the rest of the world has in oil that can be pumped from the ground. Also, in the context of this book, the more efficient use of coal is the focus since electricity from coal represents more than 50% of current electricity generation in the United States.

Coal has been a vital energy source to human populations for millennia. For example, in approximately 1000 BC, the Chinese relied on coal to smelt copper that served as the basis for their currency, and the Greek philosopher Aristotle made reference to it in his writings when he alluded to a dark charcoal-like rock (World Coal Institute, 2008). Furthermore, the discovery of coal cinders among Roman ruins in England suggests that the Romans relied on coal as a source of energy prior to AD 400.

The first written record of coal in the Americas was taken in 1673 by Louis Joliet who noted *carbon de terra* while mapping out the Illinois River region. In more recent times, the Nanticoke Indians, a Native American tribe who lived in Pennsylvania, were using local anthracite coal as a source for energy and jewelry during the 1760s (Dublin and Licht, 2005). This energy resource that provided fuel for ancient civilizations is all but history. In the modern world, steam coal, metallurgical coal, and industrial coal all play a vital role in the economy of many countries, especially the United States.

Coal continues to power vital industries. The iron industry still relies on basic oxygen furnaces that require a special type of coal known as metallurgical or coking coal to produce steel. Coke from coking coal is combined with limestone in a furnace where iron ore is blasted with

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pure oxygen and converted to steel. However, more pertinent to the present text, the electricity that powers electric arc furnaces is usually generated by burning pulverized thermal coal.

Coal was the key energy source for the Industrial Revolution, which has provided amenities that most people in the modern world take for granted – including electricity, new materials (steel, plastics, cement, and fertilizers), fast transportation, and advanced communications. Coal replaced wood combustion because of (i) abundance of coal, (ii) higher volumetric energy density of coal, and (iii) the relative ease of transportation of coal (Ashton, 1969; Freese, 2003).

The Industrial Revolution itself refers to a change from hand and home production to machine and factory. The first Industrial Revolution was important for the inventions of spinning and weaving machines operated by water power which was eventually replaced by steam. This helped increase growth and changed late 18th century society and economy into an urban-industrial state. New fuels such as coal and crude oil were incorporated into new steam engines, which revolutionized many industries including textiles and manufacturing.

The demand for coal decreased for transportation and heating purposes due to intensified competition from crude oil, and activity increased in the post-World War II industrial sector as well as the electricity generation sector after the 1960s. As the demand for power increased, the demand for coal has continued to rise over the years.

The 1973 oil embargo renewed interest in the vast domestic coal reserves of the United States. This sharp rise in coal production helped solve the growing problem of scarce oil resources that were in high demand.

The demand for coal was also impacted by the Power Plant and Industrial Fuel Use Act (FUA) of 1978, which required most oil or natural gas burning power plants to switch to coal. As a result, the energy of the United States became significantly more dependent on coal. After repeal of FUA in 1987, natural gas use in electric power plants increased by 119% between 1988 and 2002. Indeed, the spike in natural gas consumption goes to show the influence the FUA had on increasing US reliance on coal as a source of energy.

As developing countries such as China and India require more energy to meet their rapidly growing demand, competition for coal will continue to increase. The United States has 96% of the coal reserves in North America, which accounts for approximately 26% of the total known coal reserves. As a result, the United States will be expected to export more coal to meet the strong demand from the world market. In doing so, the price of coal will remain stable, and developing countries will be able to meet their energy needs.

Coal is currently responsible for generating approximately 50% of the world electricity. In fact, the demand for coal in the United States is primarily driven by the power sector, which consumes 90% of all domestic coal production. In 1950 however, only 19% of coal was used by the power sector due to its high demand by other sectors such as industry, residential and commercial, metallurgical coke ovens, transportation, and electric power, which all accounted for an amount on the order of 5 to 25% of the total coal consumption at the time. Of the coal produced worldwide, approximately 65% is shipped to electricity producers and 33% to industrial consumers, with most of the remainder going to consumers in the residential and commercial sectors. The total share of total world energy consumption by coal is expected to increase to one-third (approximately 30 to 33%) in 2035, although growth rates of coal consumption are not expected to be even in all countries where coal is used as an energy source (International Energy Agency, 2010; Energy Information Administration. 2011, 2012a, 2012b).

Coal-fired power plants, also known as electricity generations plants and power stations, provide approximately 42% of US electricity supply and more than 42% of global electricity supply. In fact, the electricity generation sector is essential to meeting current and future energy needs (MIT, 2007; EIA, 2012a, 2012b; Speight; 2013, 2020).

Furthermore, global demand for electricity will continue to rise steeply until at least 2040, as the fuels used for electricity generation continue to shift to lower-carbon sources, such as natural gas, nuclear and renewables. Even now, the demand for electricity continues to rise in all parts of the world. Population and economic growth are two main reasons, just as they are for the projected demand growth in other fuels. There is a switch to electricity from other forms of energy, such as oil or biomass for lighting and heating in the home, or coal in the industrial sector. The key to this growing demand is to make electricity generation more efficient than is currently observed.

As a result of current trends in the electric power market, many coal-fired generators in the United States are slated for retirement (Energy Information Administration, 2010, 2011, 2012a, 2012b). Most of the coal-fired power plants projected to retire are older, inefficient units primarily concentrated in the Mid-Atlantic, Ohio River Valley, and southeastern United States where excess electricity generating capacity currently exists. Lower natural gas prices, higher coal prices, slower economic growth, and the implementation of environmental rules all play a role in the retirements. Coal-fired generators in these regions, especially older, less efficient ones that lack pollution control equipment, are sensitive to changing trends in fuel prices and electricity demand, which are two key factors that influence retirement decisions.

The coal-fired power plants vulnerable to retirement are older power plants generators with high heat rates (lower efficiency) that do not have flue gas desulfurization (FGD) systems installed. Approximately 43% of all coal-fired plants did not have flue gas desulfurization systems installed as of 2010 and such plants will be required to install either a FGD or a dry sorbent injection system to continue operating in compliance with the mercury and air toxics standards (MATS).

Coal capacity retirements are sensitive to natural gas prices. Lower natural gas prices make coal-fired generation less competitive with natural gas-fired generation. Because natural gas is often the marginal fuel for power generation, lower natural gas prices also tend to reduce the overall wholesale electricity price, further reducing revenues for coal-fired generators.

Installation of environmental control systems will add internal energy requirements, reducing the efficiency of the plant. There are some changes that can be employed to make an existing unit more efficient. However, these changes typically will only result in an improvement to efficiency of a percentage point or so. In order to produce higher efficiency ratings, higher pressure and temperatures are required. This increases the cost of the plant as special alloy materials will be needed. Technology improvements can assist by lowering the cost of these special materials through discovery and better manufacturing process.

Electricity generation in a coal-fired power station requires combustion of the coal, after which the energy released during the combustion is used to generate steam which is then used to drive the turbine generators that produce electricity. The power station can be conveniently divided in four separate but, in reality, integrated operations: (i) the combustor or firebox, (ii), the boiler, (iii) the turbine generator, and (iv) the condenser.

Before the coal is burned in the *combustor*, it is pulverized (often to an extremely small size that has been stated to have the appearance of a black talcum powder) after which the coal is mixed with hot air and blown into the combustor. The coal is burned in suspension and provides the most complete combustion and maximum heat possible.

In the *boiler*, purified water is pumped through pipes inside the boiler which converts the water to steam. At temperatures up to 540°C (1000°F) and under pressures up to 3500 psi, the steam is piped to the *turbine* where it contacts a series of turbine blades and turns the turbine shaft. The turbine shaft is connected to the shaft of the generator, where magnets spin within wire coils to produce electricity. The steam is then drawn into a condenser which condenses the steam back into water so that it can be used over and over again in the plant. Millions of gallons of cooling water are pumped through a network of tubes that runs through the condenser and after the steam is condensed, it is pumped to the boiler again to repeat the cycle.

Coal quality is the term used to refer to the properties and characteristics of coal that influence its behavior and use. Coal quality has an impact on many parts of a power plant including the coal handling facilities, pulverizing mills, boiler, air heater, electrostatic precipitator, ash disposal as well as stack emissions. Because coals have different characteristics and heat content, the behavior of a coal in a boiler is strongly influenced by the rank of the coal as well as and by the content (and type) of the mineral matter and other impurities associated with it. Coal properties can affect the efficiency, reliability, and availability of both the boiler and the emissions control units, and therefore, the properties affect the economics as well as the short- and long-term operation of the plant.

Among the coal-quality characteristics that are important for coal-fired power plants are the concentrations, distribution, and forms of the many elements contained in the coal feedstock. Knowledge of these quality characteristics in coal deposits may allow us to use this essential energy resource more efficiently and effectively and with less undesirable environmental impact.

In fact, the performance of power plants and the costs of power generation are influenced by many coal properties. Specifically, coal quality impacts not only coal cost but also net power output as well as capital and operating and maintenance costs and waste disposal costs. In fact, coal quality impacts the coal chain in a power plant and their relationship to power generation costs.

Thus, an essential part of power plant development is the rigorous analysis of information which should be internally consistent and verifiable, such as coal quality, coal consumption and electricity output. It is, therefore, necessary to understand operating information for units at coal-fired power plants not only for the purposes of determining, monitoring, reporting, comparing, and projecting coal-fired power plant efficiencies but also for monitoring carbon dioxide emissions (as well as the emission of other noxious gases and particulate matter).

Thus, to develop combustion technology for efficient production of electricity, the influences of the coal properties, such as the (i) the elemental composition of the coal, (ii) rank of the coal, the mineral matter content of the coal, (iii) the size of the pulverized coal particles, and (iv) the tendency of the combustion system to produce fly ash and bottom slag are all of considerable importance and need to be addressed in assessing the potential performance of a coal-fired electricity generating plant.

Briefly, the degree of alteration (or metamorphism) that occurs as a coal matures from peat to anthracite is referred to as the *rank* of the coal (Table 1.1). Low-coal includes lignite

Table 1.1 Coal ranks*.

Rank	Description
Lignite	The largest portion of the coal reserves of the world. A soft, brownish-black coal which is the lowest level of the coal family. The texture of the original wood can even be seen in some pieces primarily found west of the Mississippi River.
Subbituminous coal	A dull black coal which, when burned, releases more energy (heat) than lignite when burned; mined mostly in Montana, Wyoming, and a few other western states.
Bituminous coal	Sometimes called *soft coal*; found primarily east of the Mississippi River in midwestern states such as Ohio and Illinois and in the Appalachian mountain range from Kentucky to Pennsylvania.
Anthracite	The hardest coal and gives off the greatest amount of heat when burned; the reserves of anthracite in the United States are located primarily in Pennsylvania.

*As mined in the United States.

and sub-bituminous coal which have a lower energy content (because of the low carbon content) and relatively high moisture content. High-rank coals, including bituminous and anthracite coals, contain more carbon than lower-rank coals which results in a much higher energy content. The high-rank coals also have a more vitreous (shiny) appearance and lower moisture content then lower-rank coals.

However, before turning to a fuller description of coal properties and power generation (Chapters 5, 6, 11), it is necessary to understand the occurrence of coal and whether or not present estimates are sufficient to produce the electric power necessary for the next several decades.

Production of steel accounts for the second-largest use of coal. Minor uses include cement manufacture, the pulp and paper industry, and production of a wide range of other products (such as coal tar and coal chemicals). The steel industry uses coal by first heating it and converting it into coke, a hard substance consisting of nearly pure carbon (Speight, 2013). The coke is combined with iron ore and limestone, and then the mixture is heated to produce iron. Other industries use different coal gases emitted during the coke-forming process to make fertilizers, solvents, pharmaceuticals, pesticides, and other products.

Finally, in order to generate electric power using the maximum energy in coal, all aspects of a coal need to be understood, including (i) handling and storage characteristics, (ii) pulverizing behavior, (iii) combustion behavior, (iv) mineral matter and ash chemistry interactions in addition to the characteristics of the coal and its ash in terms of environmental factors such as dust, self-heating and emissions components. In order to ensure that quality is controlled, the coal chain must be regularly sampled and adjusted in accordance with the analytical results (Chapters 5, 6). Key control parameters, which when monitored, can provide a reliable indication of quality in terms of both specification and consistency requirements.

Finally, the International Energy Agency (IEA) predicts that world energy demand will grow around 60% over the next 30 years, most of it in developing countries. China and India are large countries in terms of both population and land mass, and both have substantial quantities of coal reserves – cumulatively, China and India account for 70% of the projected increase in world coal consumption. Strong economic growth is projected for both countries (averaging 6% per year in China and 5.4% per year in India from 2003 to 2030), and much of the increase in their demand for energy, particularly in the industrial and electricity sectors, is expected to be met by coal.

Even as demand grows, society expects cleaner energy with less pollution and an increasing emphasis on environmental sustainability. The coal industry recognizes it must meet the challenge of environmental sustainability. In particular the industry must reduce the greenhouse gas emissions if the industry is to remain a part of a sustainable energy future. The quality of coal needs to be assessed so that it can be suitably used in different industries. The mineral matter content and its type will give an idea related to the coal preparation practice that will be required to be adopted for coal cleaning and subsequent use.

Investigation of physical properties such as Hardgrove grindability index will help in deciding the type and capacity of crushing and grinding machine required in coal beneficiation plants. Spontaneous heating susceptibility studies of coal will help in deciding the coal in a judicious manner such that the coal is utilized before it catches fire. Keeping this in view the current text, it will become obvious that determination of coal quality and coal behavior are necessary to ensure that coal is utilized in the most optimum and environmentally acceptable manner.

1.2 Origin of Coal

Discussions of the origin of coal are typically restricted to geochemical texts or to more theoretical treatises that focus on coal chemistry. However, combustion of coal (as performed in a coal-fired power station) involves knowledge of combustion chemistry and the behavior of different coals in coal-fired power stations. Thus, it is the purpose of this section to focus on the origin of coal as it influences coal chemistry, particularly the combustion chemistry and behavior (Chapter 7).

Coal is a combustible sedimentary organic rock that is formed from decayed plant remains, and other organic detritus. Although coal forms less than 1% of the sedimentary rock record, it is of foremost importance to the energy requirements of many countries and the origin of coal as it influences behavior has received much attention (Speight, 2013, 2020). However, coal is also a compact stratified mass of plant debris which has been modified chemically and physically by natural agencies, interspersed with smaller amounts of inorganic matter. The natural agencies causing the observed chemical and physical changes include the action of bacteria and fungi, oxidation, reduction, hydrolysis, and condensation – the effect of heat and pressure in the presence of water.

Coal has also been considered to be a *metamorphic rock*, which is the result of heat and pressure on organic sediments such as peat. However, the discussion is in favor of coal as a sedimentary rock because most sedimentary rocks undergo some heat and pressure and the association of coal with typical sedimentary rocks and the mode of formation of coal usually keep low-grade coal in the sedimentary classification system. Anthracite, on the other hand, undergoes more heat and pressure and is associated with low-grade *metamorphic rocks* such as slate and quartzite. Subducted coal may become graphite in igneous rocks or even the carbonate rich rocks such as carbonatites, which are intrusive or extrusive igneous rocks characterized by mineralogical composition and consisting of greater than 50% w/w carbonate minerals).

Coal is a sedimentary black or dark-brown rock that varies in composition. Some types of coal burn hotter and cleaner, while others contain high moisture content and compounds that, when burned, contribute to acid rain and other pollution. Coals of varying composition are used around the world as a combustible fossil fuel for generating electricity and producing steel. Because peat is not a rock and the unconsolidated plant matter is lacking the metamorphic changes found in coal, it is not typically classified as coal. Thus, coal is classified into four main types, depending on the amount of carbon, oxygen, and hydrogen present (i) lignite, (ii) sub-bituminous coal, (iii) bituminous coal, and (iv) anthracite.

The degree of alteration (or metamorphism) that occurs as a coal matures from lignite to anthracite is referred to as the rank of the coal, which is the classification of a particular coal relative to other coals, according to the degree of metamorphism, or progressive alteration, in the natural series from lignite to anthracite (ASTM D388). However, because of the chemical process involved in the maturation of coal, it is possible to broadly classify into three major types namely (lignite, bituminous coal, and anthracite). However, because of other differences, and the lack of other differences (with overlap between borderline coals) there is no clear demarcation between the different coals and other classifications such as semi-anthracite, semi-bituminous, and subbituminous are also used.

There are two predominant theories that have been proposed to explain the formation of coal: (i) the plant remains which eventually form coal were accumulated in large freshwater swamps or peat bogs during many thousands of years, which supposes that growth-in-place of vegetable material – the *autochthonous theory*, also often referred to as the *swamp theory*, and (ii) the coal strata accumulated from plants which had been rapidly transported and deposited under flood conditions – the *allochthonous theory*, also often referred to as the *drift theory*.

It is believed that major autochthonous (*in situ*) coal fields generally appear to have been formed either in brackish or fresh water, from massive plant life growing in swamps, or in swampland interspersed with shallow lakes. The development of substantial *in situ* coal measures thus requires extensive accumulations of vegetable matter that is subjected to widespread submersion by sedimentary deposits.

However, the types of fossil plants found in coal do not clearly support the autochthonous theory – for example, the fossil lycopod trees (such as *Lepidodendron* and *Sigillaria*) and giant ferns (especially *Psaronius*) that are common in Pennsylvanian coals may have had some ecological tolerance to swampy conditions, yet other Pennsylvanian coal plants (e.g., the conifer *Cordaites*, the giant scouring rush *Calamites*, the various extinct seed ferns) by their basic construction may have preferred existence in well-drained soils and not in the proverbial *peat swamp*. The anatomy of coal-forming plants is considered by many coal geochemists to indicate that initiation of the coalification lay down occurred in a tropical or subtropical climate, a conclusion which can be used to argue against autochthonous theory, for modern swamps are most extensive and have the deepest accumulation of peat in the higher-latitude cooler climates.

By way of explanation, coalification or metamorphosis of coal is defined as gradual changes in the physical and chemical properties of coal in response to temperature and time. The coal changes from peat through lignite and bituminous coal to anthracite. With extreme metamorphism and the changes, with increasing rank, include an increase in carbon content, and decreases in moisture content and volatile matter (Table 1.2). However, the data presented in the table (Table 1.2) are for illustrative purposes only and should not be construed to be precise since other effects (such as the mix of the coal precursors) will also play a role in the coalification process and the process is site specific (Speight, 2013).

In more general terms, the coalification of coal is a consequence of thermal effects and pressure through compaction of the sediment, which depending upon the initial events – including the composition of the coal purposes, will be site specific. However, the coalification processes involved in coal formation are marked by a well-*defined progression* of *increasing* rank that does increase with depth, and the combination of depth of burial and geothermal gradient essentially determine the rank of coal. Water, carbon dioxide and methane are generated during the progressive coalification.

Methane is the predominant gas generated in the bituminous coal and anthracite stages of coalification, and the carbon dioxide produced at lower ranks is typically flushed out of the coal by methane. The sorption capacity of coal increases with rank. Typically, high-rank coal can absorb more gas and the adsorptive capacity of coal for methane increases with coal rank. The sorption capacity of coal can be influenced by different intrusions and by the tectonic events such as folding and faulting. Coals near igneous intrusions, such as dykes, may contain calcites and pyrites which are likely to influence the ability of gases to drain.

To follow on from above, it was the difference in coal properties of Gondwana (Indian) coals that led to the formation of the *drift theory*. The mode of deposition of coal forming can be explained as follows: (i) coal is formed largely from terrestrial plant material growing on dry land and not in swamps or bogs, (ii) the original plant debris was transported by water and deposited under water in lakes or in the sea, (iii) the transported plant debris, by its relative low density even when water logged, was sorted from inorganic sediment and drifted to a greater distance in open water – the sediments, inorganic and organic, settled

Table 1.2 Illustration of the effects that can contribute to the coalification process.*

Coal rank	**DoB**	**MT**	**C**	**VM**	**CV**	**M**
Lignite	650-4,900	25-45	60	49-53	23,000	30-50
Subbituminous	4,900-8,200	45-75	71-77	42-49	29,300	10-30
Bituminous	8,200-19,500	75-180	77-87	29-42	36,250	5-10
Anthracite	>19,500	>180	87-92	8-29	>38,000	<5

Key:
DoB: approximate depth of burial, feet.
MT: approximate maximum temperature during burial, °C.
C: approximate carbon content, % w/w dry ash-free basis.
VM: approximate volatile matter, % w/w dry, ash-free basis.
CV: approximate calorific value (heat content), ash-free basis.
M: approximate moisture content, % w/w (*in situ*).
*The data are for illustrative purposes only; the actual conditions may vary somewhat from the data presented here.

down in regular succession, (iv) the process of sedimentation of the organic and inorganic materials continues until the currents can deposit the transported vegetation in the locations, (v) these deposits are covered subsequently by mineral matter, sand, and results in coal seams, (vi) the depositions can also stop for a particular period and again begin to occur when tidal and current conditions are correct, and (vii) even within coal rank, coal properties vary widely due to the varied types of vegetation deposited.

It is also factual that marine fossils such as fish, mollusks, and brachiopods occur in coal. *Coal balls*, which are rounded masses of matted and exceptionally well-preserved plant and animal fossils (including marine creatures) are found within coal strata and associated with coal strata (Mamay and Yochelson, 1962). Since there is little anatomical evidence suggesting that coal plants were adapted to marine swamps, the occurrence of marine animals with non-marine plants suggests mixing during transport, thus favoring the allochthonous model (Rupke, 1969; Cohen, 1970).

Many factors determine the composition of coal: (i) the mode of accumulation and burial of the plant debris forming the deposits, (ii) the age of the deposits and the geographical distribution, (iii) the structure of the coal-forming plants, particularly details of structure that affect chemical composition or resistance to decay, (iv) the chemical composition of the coal-forming debris and its resistance to decay, (v) the nature and intensity of the peat-decaying agencies, and (vi) the subsequent geological history of the residual products of decay of the plant debris forming the deposits. In short, coal composition is subject to site-specific effects and is difficult to generalize on a global basis (Speight, 2013).

In summary, there are advantages and disadvantages of both theories. While the coal purist may favor one or the other, there are the pragmatists who will recognize the merits of both theories. Whichever theory is correct (if that is possible) and whatever the origin of coal, there are expected to be differences in properties and behavior.

Finally, *Hilt's law* is a geological term that states the deeper the coal seam, the deeper the rank (grade) of the coal – i.e., anthracite would be expected to lie in deeper buried seams than lignite (Figure 1.1) (Elphick and Suggate, 1964; Suggate, 1974; Ward, 2008). The law holds true if the thermal gradient is entirely vertical, but metamorphism may cause lateral changes of rank, irrespective of depth. Furthermore, increasing depth of burial results in a decrease in the oxygen content of the coal.

Chemically, coal is a hydrogen-deficient hydrocarbon with an atomic hydrogen-to-carbon ratio near 0.8, as compared to crude oil hydrocarbon derivatives, which have an atomic hydrogen-to-carbon ratio approximately equal to 2, and methane (CH_4) that has an atomic carbon-to-hydrogen ratio equal to 4. For this reason, any process used to convert coal to alternative fuels must add hydrogen or redistribute the hydrogen in the original coal to generate hydrogen-rich products and coke (Speight, 2013).

The chemical composition of the coal is defined in terms of its proximate and ultimate (elemental) analyses (Chapter 5) (Speight, 2013, 2020). The parameters of proximate analysis are moisture, volatile matter, ash, and fixed carbon while the ultimate analysis (also referred to as the elemental analysis) encompasses the quantitative determination of carbon, hydrogen, nitrogen, sulfur, and oxygen within the coal. Additionally, specific physical and mechanical properties of coal and particular carbonization properties are also determined.

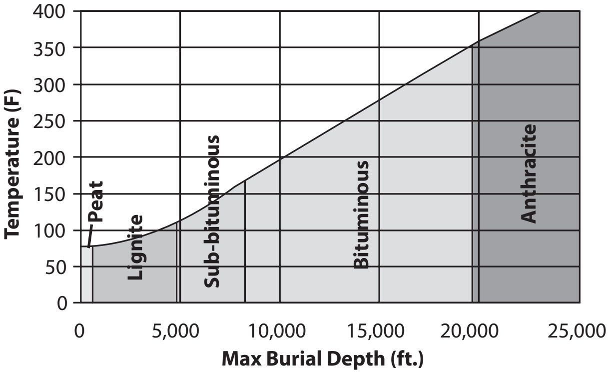

Figure 1.1 Schematic showing tendency of coal rank to increase with depth of burial*.
*Numbers are approximate and used for illustration only; peat is included only for comparison and it should not be construed for this diagram that peat is a type of coal.

1.3 Occurrence

The current estimates for the longevity of each fossil fuel are estimated from the reserves/production ratio (BP, 2019) which gives an indication (in years) of how long each fossil fuel will last at the current rates of production. The estimates vary from at least 50 years of crude oil at current rates of consumption with natural gas varying upwards of 100 years. On the other hand, coal remains in adequate supply and at current rates of recovery and consumption, the world global coal reserves have been variously estimated to have a reserves/production ratio of at least 155 years. However, as with all estimates of resource longevity, coal longevity is subject to the assumed rate of consumption remaining at the current rate of consumption and, moreover, to technological developments that dictate the rate at which the coal can be mined. But most importantly, coal is a fossil fuel and an *unclean* energy source that will only add to global warming. In fact, the next time electricity is advertised as a clean energy source just consider the means by which the majority of electricity is produced – almost 50% of the electricity generated in the United States derives from coal (Energy Information Administration, 2007; Speight, 2013).

Coal is the most abundant and widely distributed fossil fuel in the world and possibly the least understood in terms of its importance to the world economy. Currently, approximately five billion tons are mined in more than 40 countries. Coal provinces (clustering of deposits in one area) occur in regional sedimentary structures referred to as *coal basins*. More than 2,000 sedimentary, coal-bearing basins have been identified worldwide but less than a dozen contain reserves of more than 200 billion tons.

Although the majority of mined coal continues to be consumed within the country of production, the value of traded coal is increasing. The United States and Australia account for approximately 50% of world coal exports. This figure increases to 70% if exports from South Africa and Indonesia are included. Japan is the largest recipient of exported coal – approximately 25% of the world coal trade – and as such, agreements with coal suppliers and Japan can have a great influence the world coal price. Japan, Taiwan, and South Korea together import approximately 45% of all coal exports and countries of the European Union account for another 30% of total coal exports.

Coal is burned to produce energy – in the United States, coal still accounts for over 50% of the domestic electricity generating industry requirements, all from domestic production. The European Union, on the other hand, must import approximately 50% of its energy requirements (in the form of oil, gas, uranium, and coal).

Production of coal is both by underground and open pit mining (Speight, 2013). Surface, large-scale coal operations are a relatively recent development, commencing as late as the 1970s. Underground mining of coal seams presents many of the same problems as mining of other bedded mineral deposits, together with some problems unique to coal. Current general mining practices include coal seams that are contained in beds thicker than 27 inches and at depths less than 1,000 feet. Approximately 90% of all known coal seams fall outside of these dimensions and are, therefore, not presently economical to mine. Present coal mine technology in the United States, for instance, has only 220 billion tons (220×10^9 tons) of measured proven recoverable reserves out of an estimated total resource of three to six trillion tons (3 to 6×10^{12} tons) tons.

Problems specific to coal mining include the fact that coal seams typically to occur within sedimentary structures of relatively moderate to low strengths. The control of these host rocks surrounding the coal seams makes excavation in underground mining a much more formidable task than that in hard, igneous rocks in many metal mines. Another problem is that coal beds can be relatively flat-lying, resulting in workings that extend a long distance from the shaft or adit portal (an almost horizontal entrance to mine). Haulage of large tonnages of coal over considerable distance, sometimes miles, is expensive.

Coal, being largely composed of carbonaceous material can also catch fire, in some cases spontaneously (Speight, 2013). Coal, for the miner, has not been an attractive occupation. Interestingly though, the problem of methane, may in the future become a profitable by-product from closed coals mines. Many countries are reported to millions of cubic feet of coal bed methane trapped in abandoned coal mines.

As coal contains both organic and inorganic components, run-of-mine coal contains both these components in varying amounts. In many instances coal beneficiation is required to reduce the inorganic matter (ash) so that a consistent product can be more easily marketed. Most coal beneficiation consists of crushing in order to separate out some of the higher ash content, or washing that exploits the difference in density between maceral and inorganic matter.

Coal is far from being a worn-out faded commodity and offers much promise for future energy supply (Kavalov and Peteves, 2007; Malvić, 2011; Speight, 2011b, 2013, 2020). Much research has gone into improving the efficiency of coal use, especially the implementation of coal-fired plants based on clean coal technology (pressurized fluidized-bed combustion).

However, there is considerable uncertainty related to the actual amount of proved coal reserves in many coal-producing countries because there are often conflicting views among the experts related to the level of availability of coal. Although reserves are often defined for each coal field based on techno-economic-geological analysis, tentative estimates of extractable resources (i.e., reserves) can be presented by making various assumptions related to extractability and confidence levels for established coal inventory using a recognized organization with little error in the means of estimation. For example, it is only relatively recently that the crude oil reserves of several OPEC countries were adjusted upwards for reasons unknown – the truth of these adjusted data are subject to question (Speight, 2011b). Thus, any estimates (tentative or otherwise) of extractable coal resources need to be strengthened through sound and unquestionable better analysis rather than leaving the estimates subject to mathematical maneuvering.

Better energy planning and policies for any country require a good understanding of domestic coal reserves, and therefore it is important to reduce existing uncertainties related to coal by making better reserve assessments. It is likely that much of the uncertainty could be reduced when the current coal resource inventory is reclassified according to recognized and acceptable categories. Furthermore, uncertainty related to domestic coal resources will impact the long-term energy supply trajectory of any country, which in turn has significant implications for coal longevity.

1.4 Coal Utilization and Coal Types

Coal is a combustible organic sedimentary rock that is formed from the accumulation and preservation of plant materials, usually in a swamp environment (Speight, 2013). Along with crude oil and natural gas, coal is one of the three most important fossil fuels, such as for the generation of electricity and provides approximately 40% of electricity production on a worldwide basis.

For the past two centuries, coal played this important role – providing coal gas for lighting and heating and then electricity generation with the accompanying importance of coal as an essential fuel for steel and cement production, as well as a variety of other industrial activities. In fact, subject to environmental concerns, coal remains an important source of energy in many countries, but this does not give the true picture of the use of coal for electricity production. During that time, the coal industry has been pressured into serious considerations related to the environmental aspects of coal use and has responded with a variety of on-stream coal-cleaning and gas-cleaning technologies (Speight 2013, 2020).

In fact, coal has a long-term history of use (Table 1.3) (Freese, 2003). For example, outcrop coal was used in Britain during the Bronze Age (3000 to 2000 BC), where it has been detected as forming part of the composition of funeral pyres. The earliest recognized use (approximately 4000 BC) is from the Shenyang area where Neolithic inhabitants had begun carving ornaments from black lignite, but it was not until the Han Dynasty (202 BC to AD 220) that coal was also used for fuel.

Using Britain we find examples of the longevity of coal use. In Roman Britain the Romans exploited coal from all the major coalfields in England and Wales by the end of the 2nd century AD. Evidence of trade in coal (dated to approximately AD 200) has been found at the inland port of Heronbridge, near Chester, and in the Fenlands of East Anglia, where coal from the Midlands was transported for use in drying grain. Coal cinders have been found in the hearths of villas and military forts, particularly in Northumberland, dated to approximately AD 400. In the west of England contemporary writers described the wonder of a permanent brazier

Table 1.3 History of coal use.

Time frame	Use
Stone Age	Coal may have been used for heating and cooking.
AD 100-200	The Romans use coal for heating.
1300s	In the American southwest, Hopi Indians use coal for heating.
1673	Explorers to America discover coal.
1700s	The English find coal produces a fuel that burns cleaner and hotter than wood charcoal.
1740s	Commercial coal mines begin operation in Virginia.
1800s	James Watt invents the steam engine and uses coal to produce the steam to run the engine. The Industrial Revolution spreads to the United States as steamships and steam-powered railroads become the main forms of transportation, using coal to fuel their broilers. During the Civil War, weapons factories begin using coal. By 1875, coke replaces charcoal as the primary fuel for iron blast furnaces to make steel. 1880s: Coal is first used to generate electricity for homes and factories.
1900s	Coal accounts for more than three-quarters of the total energy used in the United States, but is later supplanted by oil and natural gas for transportation and residential applications. Coal reemerges later as an affordable, abundant domestic energy resource to support the growing demand for electricity. In the late 1900s, environmental issues force a reduction in the amount of coal used for power generation. Clean Coal technologies were developed in the United States to allow coal to be used in an environmentally friendly manner.

of coal on the altar of Minerva at Aquae Sulis (Waters of Sulis; modern-day Bath) although in fact easily accessible surface coal from what became the Somerset coalfield (southwest England) was in common use in quite lowly dwellings locally. There is also evidence of the use of coal for iron-working in the city during the Roman period.

The Somerset coalfield included pits in the north Somerset, England, area where coal was mined from the 15th century until 1973. It is part of a wider field which covered northern Somerset and southern Gloucestershire in England. There is documentary evidence of coal being dug from this coalfield in the 14th century and continuing until the 16th century. During the early part of the 17th century coal was largely obtained by excavating the outcrops or driving an incline, which involved following the seam into the ground. Only a small amount of coal could be obtained by these methods and so bell pits took their place – a bell pit is so-named because in cross section the pit resembles an upturned bell. The bell pit is a primitive method of mining coal where the coal lies near the surface on flat land.

A shaft is sunk to reach the coal which is then excavated and removed by means of a bucket (much like a well). No supports are used and mining continues outward until the mine becomes too dangerous (or collapses) at which point another mine is started.

Mineral coal came to be referred to as *sea coal* (seacoal), probably because it came to many places in eastern England, including the northeast coast 50 to 100 miles south of the Scottish border. This is accepted as the more likely explanation for the name of the coal, having fallen from the exposed coal seams above or washed out of underwater coal seam outcrops. These easily accessible sources had largely become exhausted (or could not meet the growing demand) by the 13th century when underground mining from shafts or adits was developed. An alternative name was *pit coal* (pit coal), because it came from mines. It was, however, the development of the Industrial Revolution (18th century to 19th century) that led to the large-scale use of coal, as the steam engine took over from the water wheel. Looked at from another angle, the Industrial Revolution was impossible without coal.

Currently, in the United States, coal is used primarily to generate electricity. The coal is burned in power plants to produce almost 40% of the electricity that is used each year. Coal is also used in the industrial and manufacturing industries. For example, the steel industry uses large amounts of coal – the coal is baked in hot furnaces to make coke, which is used to smelt iron ore into the iron needed for making steel. The high temperatures created from the use of coke gives steel the strength and flexibility needed for making bridges, buildings, and automobiles. The heat and the by-products produced from coal are also used to produce a variety of products such as methanol (methyl alcohol, CH_3OH) and ethylene ($CH_2=CH_2$) which can then be used to produce plastics, synthetic fibers, fertilizers, and medicines.

Certain characteristics of coal ensure its place as an efficient and competitive energy source and contribute to stabilizing energy prices. Key factors include (i) the large reserves without associated geopolitical or safety issues, (ii) the availability of coal from a wide variety of sources, (iii) the facility with which coal can be stored in normal conditions, and (iv) the non-special and relatively inexpensive protection required for the main coal supply routes. Furthermore, retirements of older units, retrofits of existing units with pollution controls, and the construction of some new coal-fueled units are expected to significantly change the coal-fueled electricity generating fleet, making it capable of emitting lower levels of pollutants than the current fleet but reducing its future electricity generating capacity (GAO, 2012).

Deposits of coal, sandstone, shale, and limestone are often found together in sequences hundreds of feet thick. This period is recognized in the United States as the Mississippian and Pennsylvanian time periods due to the significant sequences of these rocks found in those states (i.e., Mississippi and Pennsylvania) (Table 1.4). Other notable coal-bearing ages are the Cretaceous, Triassic and Jurassic Periods. The more recently aged rocks are not as productive for some reason, but lignite and peat are common in younger deposits but generally, the older the deposit, the better the *grade* (higher rank) of coal (Ward, 2008).

As with many industrial minerals, the physical and chemical properties of coal beds are as important in marketing a deposit as the *grade*. The grade of a coal establishes its economic value for a specific end use. Grade of coal refers to the amount of mineral matter that is present in the coal and is a measure of coal quality. Sulfur content; ash fusion temperatures, i.e., measurement of the behavior of ash at high temperatures; and quantity of trace elements in coal are also used to grade coal. Although formal classification systems have not been developed around grade of coal, *coal grade* is important to the coal user.

Table 1.4 The Geologic timescale.

Era	Period	Epoch	Duration (x 10^6)	Years ago (x 10^6)
Cenozoic	Quaternary	Holocene	10,000**	
		Pleistocene	2	.01
	Tertiary	Pliocene	11	2
		Miocene	12	13
		Oligocene	11	25
		Eocene	22	36
		Paleocene	10	58
Mesozoic	Cretaceous		71	65
	Jurassic		57	136
	Triassic		35	190
Paleozoic	Permian		50	225
	Carboniferous		65	280
	Devonian		60	345
	Silurian		25	405
	Ordovician		65	425
	Cambrian		70	500
Precambrian			3,400	600

Approximate
**To the present

In terms of *coal grade*, the grade of a coal establishes its economic value for a specific end use (Ward, 2008). Grade of coal refers to the amount of mineral matter that is present in the coal and is a measure of coal quality. Sulfur content, ash fusion temperature (i.e., the temperature at which measurement the ash melts and fuses), and quantity of trace elements in coal are also used to grade coal. Although formal classification systems have not been developed around grade of coal, grade is important to the coal user.

Another means by which coal is evaluated is through the *rank* of the coal, which is the most fundamental characteristic relating both coalification history and utilization potential of a coal. Volatile matter and maximum vitrinite reflectance are important values used to determine the worth of coking coals. However, because volatile matter is dependent on both rank and composition, coals of different composition may be assigned to the same rank value even though their levels of maturity may differ.

Volatile matter is not considered to be a component of coal as mined but a product of the thermal decomposition of coal. Volatile matter is produced when coal is heated to 950°C (1740°F) (ASTM D3175) in the absence of air under specified conditions and contains, in addition to moisture, typically a mixture of low-to-medium molecular weight aliphatic hydrocarbon derivatives, aromatic hydrocarbon derivatives, with higher boiling oil and low-volatile tar. Volatile matter decreases as rank increases and when determined by the standard test method (ASTM D3175) can be used to establish the rank of coals, to indicate coke yield on carbonization process, to provide the basis for purchasing and selling, or to establish burning characteristics.

All types of coal contain fixed carbon, which provides stored energy, plus varying amounts of moisture, ash, volatile matter, mercury, and sulfur. However, the physical properties of coal vary widely, and coal-fired power plants must be engineered to accommodate the specific properties of available feedstock and to reduce emissions of pollutants such as sulfur, mercury, and dioxins which reduce power plant efficiency. The efficiency of a coal-fired power plant is typically represented defined as the amount of heat content in (Btu) per the amount of electric energy out (kWh), commonly called a heat rate (Btu/kWh). Expected improvements in power plant efficiency mainly arise from the substitution of older power plants with new plants that have higher efficiency.

Calorific value is one of the principal measures of the value of a coal as a fuel and is directly influenced by mineral impurities. Coal mineralogy is not only important to combustion characteristics, but also as materials that can be passed on to secondary products such as metallurgical coke. Alkali-containing compounds derived from coal minerals can contribute to excessive gasification of coke in the blast furnace and attack of blast furnace refractories, whereas phosphorus and sulfur from coal minerals can be passed on to the hot metal, thus reducing its quality for steelmaking.

Mineral matter may occur finely dispersed or in discrete partings in coal and is generally grouped according to origin. A certain amount of mineral matter and trace elements are derived from the original plants. However, the majority enters to coal precursor either during the initial stage of coalification (being introduced by wind or water to the peat swamp) or during the second stage of coalification, after consolidation of the coal by movement of solutions in cracks, fissures, and cavities. Mineral components of plant origin are not easily recognized in coals because they tend to be disseminated on a submicron level. The primary mineral components incorporated during plant deposition tend to be layered with and intimately inter-grown with the organic fraction, whereas the secondary mineral matter tends to be coarsely inter-grown and associated with cleat, fractures, and cavities. Therefore, secondary minerals may be more readily separated (cleaned or washed) from the organic matrix to improve the value of the material.

More information related to coal character and properties is derived from geological studies of coal – which includes a wide variety of topics, including coal formation, occurrence, and properties but which is outside of the purview of this book but is described in detail elsewhere (Speight, 2013).

1.4.1 Lignite

Lignite (brown coal) is the least mature of the coal types and provides the least yield of energy; it is often crumbly, relatively moist, and powdery. It is the lowest rank of coal, with a heating value of 4,000 to 8,300 Btu per pound (ASTM D388) and is mainly used to produce electricity. With increasing rank (i.e., progressing from lignite to subbituminous coal to bituminous coal to anthracite) the moisture content decreases while the carbon content and the energy content both increase.

Lignite contains the lowest level of fixed carbon (25 to 35%) and highest level of moisture (typically 20 to 40% by weight, but can go as high as 60 to 70%) of all of the coal types (Chapters 2, 5). Ash produced from mineral matter during combustion varies up to 50% w/w. Lignite has low levels of sulfur (less than 1% w/w) and mineral matter (approximately 4% w/w), but has high levels of volatile matter (>32% w/w) and produces high levels of air pollution emissions. Because of its high moisture content, lignite may be dried to reduce moisture content and increase calorific fuel value. The drying process requires energy, but can be used to reduce volatile matter and sulfur as well.

Approximately 7% of coal mined in the United States is lignite and it is found primarily in North Dakota (McLean, Mercer, and Oliver counties), Texas, Mississippi (Kemper County), and to a lesser degree, Montana. The top 10 countries that produce brown coal are (ranked from most to least): Germany, Indonesia, Russia, Turkey, Australia, United States, Greece, Poland, Czech Republic, and Serbia.

With the growing concern for the environment due to emissions from coal utilization, lignite could as well be used in the production of combustible gases (including hydrogen) through underground coal gasification processes (Chapters 9, 10).

1.4.2 Subbituminous Coal

Subbituminous coal is often brown in color but more like bituminous coal than lignite. It typically contains less heating value (8,300 to 13,000 Btu per pound) and more moisture and volatile matter than bituminous coals, but lower sulfur levels (ASTM D388).

Subbituminous coal is considered a black coal, although its appearance varies from bright black to dull dark brown. Its consistency ranges from hard and strong to soft and crumbly, because it is an intermediate stage of coal between bituminous and brown coal (lignite). It is widely used for generating steam power and industrial purposes. Sometimes called *black lignite*, subbituminous coal is not stable when exposed to air and tends to disintegrate.

Subbituminous coal is non-coking and has less sulfur but more moisture (approximately 10 to 45% w/w) and volatile matter (up to 45% w/w) than bituminous coals. The carbon content is 35 to 45% w/w and mineral matter ranges up to 10% w/w. The sulfur content is generally under 2% w/w and the nitrogen content is on the order of 0.5 to 2% w/w. The combustion of subbituminous coal can lead to hazardous emissions that include particulate matter (PM), sulfur oxides (SOx), nitrogen oxides (NOx), and mercury (Hg).

Subbituminous coals produce combustion ash that is more alkaline than other coal ash. This characteristic can help reduce acid rain caused by coal-fired power plant emissions. Adding subbituminous coal to bituminous coal introduces alkaline by-products that are able to bind sulfur compounds released by bituminous coal and therefore reduce acid mist formation.

When subbituminous coal is burned at higher temperatures, its carbon monoxide emissions are reduced. As a result, small combustion units and poorly maintained ones are likely to increase pollution output. People who use subbituminous coal in a home furnace or firebox say that bigger lumps produce less smoke and no clinkers – however, high ash content can be a disadvantage.

Approximately 30% of available coal resources in the United States are subbituminous, a figure that surpasses other countries in its quantity of subbituminous coal resources, with estimated reserves of approximately 300,000 to 400,000 million ton (1 ton = 2,000 lbs) predominantly located in Wyoming, Illinois, Montana, and other locations west of the Mississippi river. Other countries with notable resources include Brazil, Indonesia, and Ukraine.

1.4.3 Bituminous Coal

Bituminous coal is the black, soft rock and the most common coal used around the world. Formed of many thin layers, bituminous coal looks smooth and sometimes shiny. It is the most abundant type of coal found in the United States and has two to three times the heating value of lignite. Bituminous coal contains 11,000 to 15,500 Btu per pound. Bituminous coal is used to generate electricity and is an important fuel for the steel and iron industries.

Bituminous coal lights on fire easily and can produce excessive smoke and soot (particulate matter) if improperly burned. The high sulfur content of the coal contributes to acid rain.

Bituminous coal commonly contains the mineral pyrite, which can serve as a host for impurities such as arsenic and mercury. Combustion of bituminous coal releases traces of mineral impurities into the air as pollution. During combustion, approximately 95% of the sulfur content of bituminous coal is oxidized and released as gaseous sulfur oxides.

Hazardous emissions from bituminous coal combustion include particulate matter (PM), sulfur oxides (SOx), nitrogen oxides (NOx), trace metals such as lead (Pb) and mercury (Hg), vapor-phase hydrocarbon derivatives (such as methane, alkane derivatives, alkene derivatives, and benzene derivatives) and polychlorinated dibenzo-p-dioxin derivatives and polychlorinated dibenzofuran derivatives. When burned, bituminous coal can also release hazardous gases such as hydrogen chloride (HCl), hydrogen fluoride (HF), and polycyclic aromatic hydrocarbon derivatives (typically represented as PAHs or PNAs). Incomplete combustion leads to higher levels of and polycyclic aromatic hydrocarbon derivatives (which are carcinogenic) but burning bituminous coal at higher temperatures reduces its carbon monoxide emissions. Therefore, large combustion units and well-maintained ones generally have lower pollution output. Bituminous coal has slagging and agglomerating characteristics.

Bituminous coal combustion releases more pollution into the air than subbituminous coal combustion, but due to its greater heat content, less of the fuel is required to produce a given output of electricity. Therefore, bituminous, and subbituminous coals produce approximately the same amount of pollution per kilowatt of electricity generated.

Bituminous coal is the most common coal – bituminous coal and subbituminous coal represent (cumulatively) more than 90% of all the coal consumed in the United States. When burned, bituminous coal produces a high, white flame. Bituminous coal includes two subtypes: thermal and metallurgical.

Thermal coal is sometimes called *steam coal* because it is used to fire power plants that produce steam for electricity and industrial uses. Locomotive trains that run on steam may also be fueled with *bit coal* (bituminous coal). However, *steam coal*, which is not a specific rank of coal, is a grade of coal that falls between bituminous coal and anthracite, once widely used as a fuel for steam locomotives. In this specialized use it is sometimes known as *sea coal* in the United States. Small steam coal (*dry small steam nuts*, DSSN) was used as a fuel for domestic water heating. In addition, the material known as *jet* is the gem variety of coal. Jet is generally derived from anthracite and lacks a crystalline structure so it is considered to be a mineraloid. Mineraloids are often mistaken for minerals and are sometimes classified as minerals, but lack the necessary crystalline structure to be truly classified as a mineral. Jet is one of the products of an organic process but remains removed from full mineral status.

Coking coal (also known as *metallurgical coal*) is able to withstand high heat and is used in the process of creating coke necessary for iron and steel-making. Coking coal is able to withstand high heat. Coking coal is fed into ovens and subjected to oxygen-free thermal decomposition (pyrolysis), a process in which the coal is heated to approximately 1100 C (2010°F). The high temperature melts the coal and drives off any volatile compounds and impurities to leave pure carbon. The purified, hot, liquefied carbon solidifies into coke (a porous, hard black rock of concentrated carbon) that can be fed into a blast furnace along with iron ore and limestone to produce steel.

Bituminous coal contains moisture up to approximately 17% w/w and has a fixed carbon content on the order of 85% w/w with a mineral matter content up to 12% w/w. Bituminous coal can be categorized further by the level of volatile matter it contains; high-volatile A, B, and C, medium-volatile, and low-volatile. Approximately 0.5 to 2% w/w of bituminous coal is nitrogen.

More than half of all available coal resources are bituminous and, in the United States occur in Illinois, Kentucky, West Virginia, Arkansas (Johnson, Sebastian, Logan, Franklin, Pope, and Scott counties), and locations east of the Mississippi river.

Particles of waste bituminous coal that are left over after preparation of commercial-grade coal (*coal fines*), which are light, dusty, and difficult to handle, traditionally were stored with water in slurry impoundments to keep them from blowing away.

New technologies have been developed to reclaim fines that were formerly considered waste. One approach is to use a centrifuge to separate the coal particles from slurry water. Other approaches have been developed to bind the fines together into briquettes that have low moisture content, making them suitable for fuel use.

1.4.4 Anthracite

Anthracite (also known as *hard coal*) is the highest rank of coal (ASTM D388) and is the oldest coal from geological perspective – it is actually considered to be metamorphic. It is a hard coal composed mainly of carbon with little volatile content and practically no moisture.

Anthracite is deep black and often appears to be of a metallic nature because of the glossy surface. Compared to other coal types, anthracite is much harder, brittle, and has a glassy luster, and is denser and blacker with few impurities. When burned, anthracite produces a hot blue flame and, as a result, is primarily used for space heating by residences and businesses in and around the northeastern region of Pennsylvania, where much of it is mined.

Anthracite is considered the cleanest burning of all coal types and produces more heat and less smoke than other coals, and is widely used in furnaces. It is largely used for heating domestically as it burns with little smoke. Some residential home heating stove systems still use anthracite, which burns longer than wood.

Anthracite burns at the highest temperature of any coal and typically produces up to 13,000 to 15,000 Btu per pound. Waste coal discarded during anthracite mining (called *culm*) and has a heat content has less than half the heat value of mined anthracite and a higher ash and moisture content. It is used most often in fluidized bed combustion (FBC) boilers.

Anthracite has a high fixed carbon value (80 to 95%) (Chapters 2, 5) and a low sulfur as well as a low nitrogen (less than 1% each). Volatile matter is low at approximately 5% w/w, with 10 to 20% w/w of mineral ash produced by combustion. The moisture content is approximately 5 to 15% w/w and the coal is slow-burning and difficult to ignite because of the high density – consequently few pulverized coal-fired plants use anthracite as the fuel.

Anthracite is considered *non-clinkering* and free burning because (when ignited) it does not coke or expand and fuse together. It is most often burned in underfeed stoker boilers or single-retort side-dump stoker boilers with stationary grates. Dry-bottom furnaces are used because of the high ash fusion temperature of anthracite. Lower boiler loads tend to keep heat lower, which in turn reduces nitrogen oxide emissions.

Particulate matter, or fine soot, from burning anthracite can be reduced with proper furnace configurations and appropriate boiler load, under-fire air practices, and fly ash reinjection. Fabric filters, electrostatic precipitators (ESP), and scrubbers can be used to reduce particulate matter pollution from anthracite-fired boilers. Anthracite that is pulverized before burning creates more particulate matter.

Furthermore, it is worthy of note that even in the terminology of anthracite there are several variations which, although somewhat descriptive, do not give any detailed indications of the character of the coal. For example, some of the terms which refer to anthracite are: black coal, hard coal, stone coal, which should not to be confused with the German *steinkohle* or the Dutch *steenbok*, which are terms that include all varieties of coal with a stone-like hardness and appearance, blind coal, Kilkenny coal, crow coal (from its shiny black appearance), and black diamond. However, as the importance of the coal trade increased, it was realized that some more definite means of classifying coals according to their composition and heating value was desired because the lines of distinction between the varieties used in the past were not sufficiently definite for practical purposes (Thorpe *et al.*, 1978; Freese, 2003).

Anthracite is scarce and only a small percentage of all remaining coal resources are anthracite. Pennsylvania anthracite was mined heavily during the late 1800s and early 1900s, and remaining supplies became harder and harder to access because of their deep location. The largest quantity of anthracite ever produced in Pennsylvania was in 1917.

Historically, anthracite was mined in a 480-square-mile area in the northeastern region of Pennsylvania, primarily in Lackawanna, Luzerne, and Schuylkill counties. Smaller resources are found in Rhode Island and Virginia.

1.5 Resources

As the 21st century matures, there will continue to be an increased demand for energy to support the needs of commerce industry and residential uses – in fact, as the 2040 to 2049 decade approaches, commercial and residential energy demand is expected to rise considerably – by approximately 30% over current energy demand. This increase is due, in part, to developing countries, where national economies are expanding and the move away from rural to city living is increasing. In addition, the fuel of the rural population (biomass) is giving way to the fuel of the cities (transportation fuels, electric power) as the lifestyles of the populations of developing countries change from agrarian to metropolitan. Furthermore, the increased population of the cities requires more effective public transportation systems as the rising middle class seeks private means of transportation (automobiles). As a result, fossil fuels will continue to be the predominant source of energy for at least the next 50 years.

In general terms, coal is a worldwide resource; the latest estimates, which seem to be stable within minor limits of variation (Hessley, 1990), show that there is in excess of 1,000 billion (109) tons of proven recoverable coal reserves throughout the world (Energy Information Administration, 2011). In addition, consumption patterns give coal approximately 30% or more (depending upon the source) of the energy market share (Energy Information Administration, 2011). Estimates of the total reserves of coal vary within wide limits, but there is no doubt that vast resources exist and are put to different uses (Horwitch, 1979; Hessley, 1990; EWG, 2007; Speight, 2013). However, it is reasonable to assume that, should coal form a major part of any future energy scenario, there is sufficient coal for many decades (if not hundreds of years) of use at the current consumption levels. Indeed, coal is projected as a major primary energy source for power generation for at least the next several decades and could even surpass oil in use, especially when the real costs of energy are compared to the costs of using the indigenous coal resources of the United States (Hubbard, 1991; Speight, 2020).

In order to understand the politics of coal use and production, it is necessary to put coal into the perspective of oil and gas. In the early days of the oil industry, the United States was the major producer and was predominantly an exporter of crude oil, thereby serving as the "swing" producer insofar as production was adjusted to maintain stability of world oil prices. However, oil production in the United States peaked in 1972 and has been in decline ever since and the mantle of oil power has shifted to the Middle East, leading to new political and economic realities for the world. From the 1970s, oil prices have been determined more by international affairs (geopolitics) than by global economics (Yergin, 1991).

In contrast to current US oil production and use patterns, the United States is not a significant importer of natural gas. Trade agreements with Canada and with Mexico are responsible for the import of natural gas but these are more of a convenience for the border states rather than for the nation as a whole.

In the United States, the use of coal increased after World War II with the majority of the production occurring in the eastern states close to the population centers. The majority of the recovery methods used underground mining techniques in the seams of higher quality, i.e., the minerals and water content of the coal was relatively low and the coal had a high heat-content (Chapters 5, 6). However, by the late 1960s, natural gas and crude oil had captured most of the residential, industrial, and commercial market, leaving only power generation and metallurgical coke production as the major uses for coal.

On a global scale, the United States is a major source of coal (Figure 1.2) as well as a coal producer and coal exporter (Chadwick, 1992). There are many coal-producing states in the United States but the passage, and implementation, of the Clean Air Act in the early 1970s opened up new markets for the easily (surface) mined low-sulfur coals (Table 1.5, Table 1.6, Figure 1.3) from the western United States and captured a substantial share of the energy

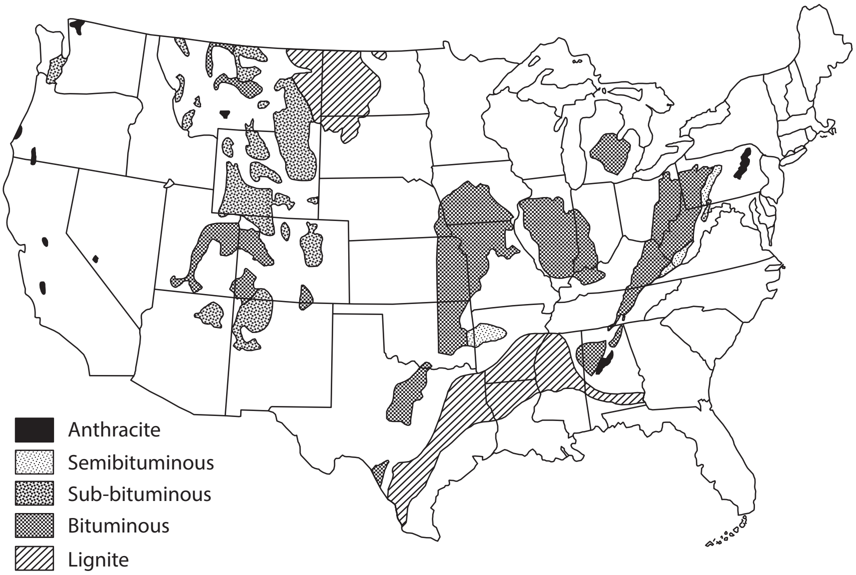

Figure 1.2 Coal types and distribution in the United States.

Table 1.5 Distribution of US Coal Reserves (% of total) (Energy information Administration, 2011).

Region*	Underground minable (%)	Surface minable (%)	Total (%)
Eastern United States	36.9	8.2	45.1
Western United States	30.8	24.1	54.9
Total United States	67.7	32.3	100.0

*Mississippi River is dividing line beteween East and West.

Table 1.6 Sulfur content of US Coals by Region (Energy information Administration, 2011).

Region	No. of samples	Organic S (%)	Pyritic S (%)	Total (%)
N. Appalachia	227	1.00	2.07	3.01
S. Appalachia	35	0.67	0.37	1.04
E. Midwest	95	1.63	2.29	3.92
W. Midwest	44	1.67	3.58	5.25
Western	44	0.45	0.23	0.68
Alabama	10	0.64	0.69	1.33

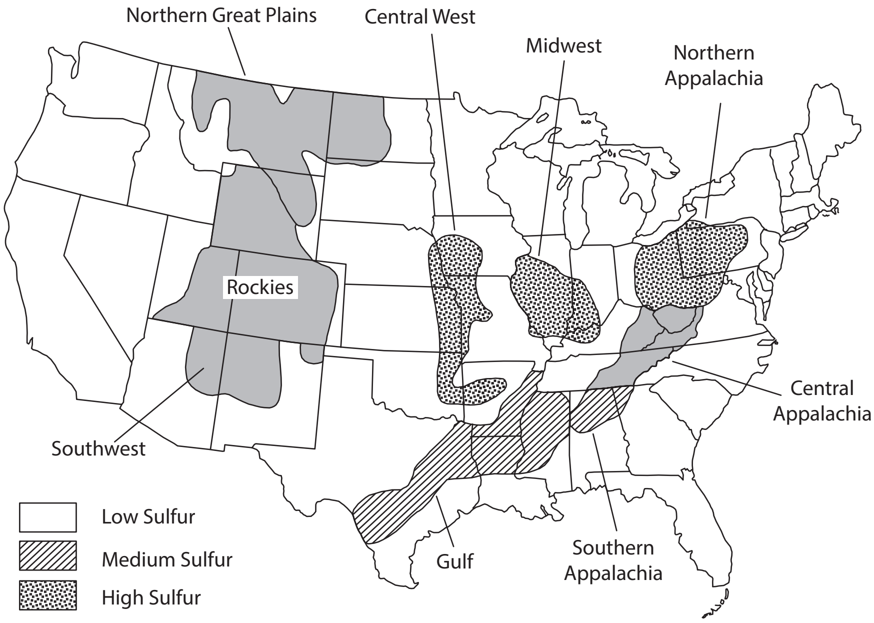

Figure 1.3 Distribution of Sulfur content of US Coals (Energy information Administration, 2011).

(specifically, the electrical utility) markets. In addition, states such as Wyoming were the major beneficiaries of the trend to the use of low-sulfur coal and occupy a significant position in the coal reserves and coal production scenarios of the United States (Speight, 2013, 2020).

Furthermore, the two oil shocks of 1973 and 1979, as well as the political shock that occurred in Iran in 1979, were related to the rediscovery of coal through the realization that the United States and other Western countries had developed a very expensive habit insofar as they not only had a growing dependence upon foreign oil but they craved the energy-giving liquid! The discovery of the North Sea oil fields gave some respite to an oil-thirsty Europe but the resurgence of coal in the United States continued with the official *rebirth* of coal in 1977 as a major contributor to the National Energy Plan of the United States. It is to be hoped that future scenarios foresee the use of coal as a major source of energy; the reserves are certainly there and the opportunities to use coal as a clean, environmentally acceptable fuel are increasing.

The question to be asked by any country, and Canada did ask this question in the early 1970s, is "What price are we willing to pay for energy independence?" There may never be any simple answer to such a question. But, put in the simplest form, the question states that if the United States, or, for that matter, any energy consumers, are to wean themselves from imported oil (i.e., nonindigenous energy sources) there will be an economic and environmental cost if alternate sources are to be secured (NRC, 1979; NRC, 1990). In this light, there is a study which indicates that coal is by far the cheapest fossil fuel. However, the costs are calculated on a cost per Btu basis for electricity generation only and whilst they do show the benefits for using coal for this purpose, the data should not be purported to be generally applicable to all aspects of coal utilization.

Nevertheless, the promise for the use of coal is there insofar as the data do show the more stable price dependability of coal. If price stability can be maintained at a competitive level and the environmental issues can be addressed successfully, there is a future for coal – a long future and a bright future.

Finally, the issues logic of distinguishing between *resources* (which include which include additional amounts of coal such as inferred/assumed/speculative reserves) and *proven reserves* (which are defined as being proved) is that over time production and exploration activities allow resources to be reclassified into *proven reserves*.

1.6 Reserves

The coal reserves and resources of the world are difficult to assess because of the lack of accurate data for individual countries. Two fundamental problems make these estimates difficult and subjective. The first problem concerns differences in the definition of terms such as *proven reserves* (generally only those quantities that are recoverable) and *geological resources* (generally the total amount of coal present, whether or not recoverable at present).

Thus, in any text dealing with coal, there must be recognition, and definition, of the terminology used to describe the amounts, or reserves of coal available for recovery and processing. But the terminology used to describe coal (and for that matter any fossil fuel or mineral) resource is often difficult to define with any degree of precision (Speight, 2011b, 2014, 2020).

Different classification schemes (Chapter 2) often use different words which should, in theory, mean the same but there will always be some difference in the way in which the terms can be interpreted. It might even be wondered that if the words themselves leave much latitude in the manner of their interpretation, how the resource base can be determined with any precision. The terminology used here is that more commonly found although other systems do exist and should be treated with caution in the interpretation.

Generally, when estimates of coal supply are developed, there must be a line of demarcation between coal *reserves* and *resources*. Reserves are coal deposits that can be mined economically with existing technology, or current equipment and methods. Resources are an estimate of the total coal deposits, regardless of whether the deposits are commercially accessible. For example, world coal reserves were estimated to be in excess of one trillion tons (1×10^{12} tons) and world coal resources were estimated to approximately 10 trillion tons (10×10^{12} tons) and are geographically distributed in Europe, including all of Russia and the other countries that made up the former Soviet Union, North America, Asia, Australia, Africa, and South America (Table 1.7).

However, there are definitions that go beyond *reserves* and *resources*. To begin at the beginning, the energy resources of the Earth are subdivided into a variety of categories (Figure 1.4) and the resources of coal (as well as each of the other fossil fuel resources) can be further subdivided into different categories (Figure 1.5) (Speight, 2013, 2014, 2020).

1.6.1 Proven Reserves

The proven reserves for any commodity should provide a reasonably accurate estimate of the amount that can be recovered under existing operating and economic conditions. To be economically mineable, a coal seam (coalbed, also called a coalbed, hence coal bed methane) bed

Table 1.7 Estimated Coal Reserves by Country (Energy information Administration, 2011).

Coal	
United States	27.5%
Russia	18.3%
1. China	13.3%
Other Non-OECD Europe and Eurasia	10.7%
Australia and New Zealand	8.9%
India	7.0%
OECD Europe	6.5%
Africa	3.7%
Other Central and South America	0.9%
Rest of World	3.2%
Total	100.0%

Source: US Energy Information Administration, International Energy Outlook, September 2011.

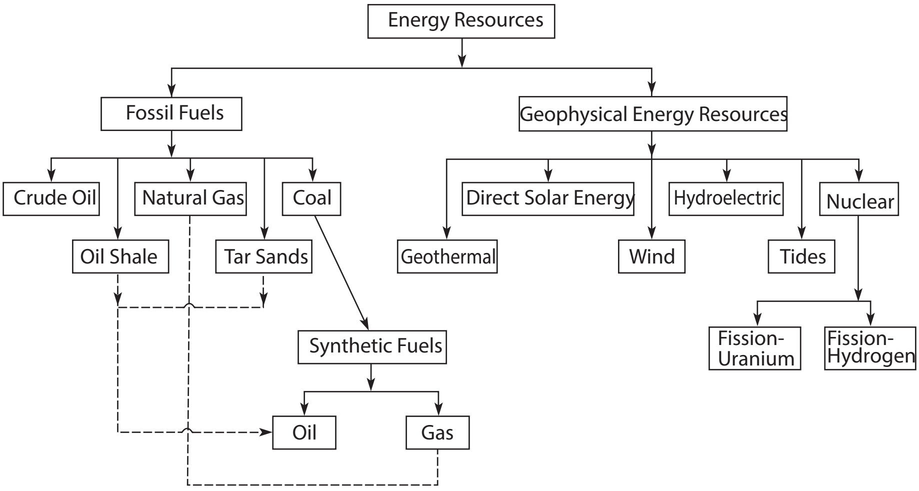

Figure 1.4 Energy Resources of the Earth (Speight, 2013).

must have a minimum thickness (approximately 2 feet) and be buried less than some maximum depth (approximately 6,600 feet) below the surface of the Earth. These values of thickness and depth are not fixed but change with criteria such as (i) coal quality, (ii) coal demand, (iii) the ease with which overlying rocks can be removed for surface mining or a shaft sunk to reach the coal seam for underground mining. The development of new mining techniques may increase the amount of coal that can be extracted relative to the amount that cannot be

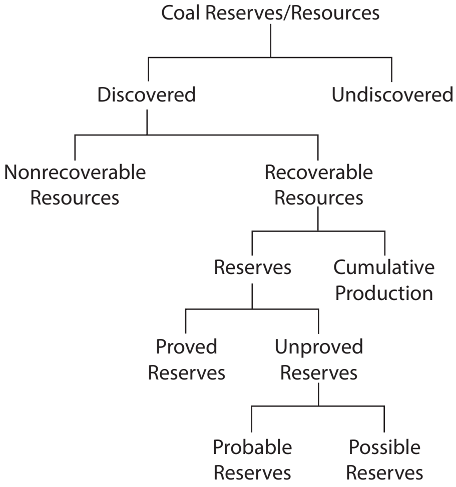

Figure 1.5 Resource and reserve terminology (Speight, 2013).

removed. For example, in underground mining, which accounts for approximately 60% w/w of world coal production, conventional mining (pillar mining) methods leave behind large pillars of coal to support the overlying rocks and recover only about half of the coal present. On the other hand, longwall mining, in which the equipment removes continuous parallel bands of coal, may recover almost all the coal present in the seam.

In addition, an issue which concerns the estimation of reserves, is the rate at which the coal is consumed. When considering the worldwide reserves of coal, the number of years that coal will be available may be more important than the total amount of coal resources. For example, the coal reserves may be estimated using the current rates of consumption, which may indicate that the world coal reserves should last more than 300 to 500 years. However, a large amount of additional coal is present in Earth but cannot be recovered using current technology and these resources, sometimes called geologic resources, are even more difficult to estimate, but may be much greater than the amount of proven reserves.

Thus, in the current context, the proven reserves (*proved reserves*) are those coal reserves that are actually found (proven), usually by drilling and coring. The estimates have a high degree of accuracy and are frequently updated as the mining operations proceed. However, even though the coal reserves may be proven, there is also the need to define the resources on the basis of what further amount of coal might be recoverable (using currently available mining technology without assuming, often with a very high degree of optimism) extravagantly, that new technology will miraculously appear or will be invented) and *non-recoverable* coal reserves will suddenly become *recoverable*.

If economic aspects are not considered, the term for the total technologically extractable amount of coal is the *producible fraction*, which is often confused with the *proven reserves*. The term *proven reserves* is further subdivided into *proved developed reserves* and *proved undeveloped reserves*. This should not be confused with *unproven reserves*, which are broken down into *probable reserves* and possible reserves – those reserves that only have a 10% likelihood of being recoverable.

These reserve categories can, as in the crude oil industry (Speight, 2011b, 2014), be cumulatively summed by the measures 1P, 2P, and 3P, which are inclusive, so include the previous safer measures as (i) 1P reserves – proven reserves consisting of both proved developed reserves plus proved undeveloped reserves), (ii) 2P reserves – consisting of 1P proven reserves plus probable reserves, and (iii) 3P reserves – consisting of the sum of 2P reserves plus possible reserves.

On the other hand, the estimated ultimate recovery of coal (or any resource) is the sum of the proven reserves at a specific time and the cumulative production up to that time.

1.6.2 Inferred Reserves

The term *inferred reserves* (*unproved reserves*) is commonly used in addition to, or in place of, *potential reserves*. The inferred coal reserves are regarded as being of a higher degree of accuracy than the potential reserves and the term is applied to those reserves that are estimated using an improved understanding of seam structure (see *Proven reserves* – above).

In the United States, inferred reserves (reserve growth) include those resources expected to be added to reserves as a consequence of extension of known fields, through revisions of reserve estimates, and by additions of seams (or coal strata) in discovered coal domains. Also included in this category are resources expected to be added to reserves through application of improved mining techniques.

This category thus includes both the *indicated reserves* and the *inferred reserves* described in earlier United States Geological Survey assessment publications. Predictions of reserve growth may refer to coal fields found before a specified year and the analysis of reserve growth in discrete conventional coal accumulations is based on the definitions and reports of the United States Energy Information Administration (EIA). In summary, inferred reserves are assessed by preliminary exploration and are part of probable reserves – the level of their probability assessment is low.

1.6.3 Potential Reserves

Potential reserves (*probable reserves*, *possible reserves*) are the additional reserves of coal that are believed to exist in the earth. The data are estimated (usually from geologic evidence) but have not been substantiated by any drilling or coring operations. Other terminology such as *probable reserves* and *possible reserves* are also employed but fall into the subcategory of being unproven.

In summary, potential reserves are those contingent reserves that, as of a specified date, are potentially recoverable from *known* accumulations coal fields but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Potential reserves may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality.

1.6.4 Undiscovered Reserves

One major issue in the estimation of coal (or for that matter any fossil fuel or mineral) resource is the all too frequent use of the term "undiscovered" resources. Caution is advised when using such data, as might be provided to "substantiate" such reserves, as they are very speculative and are regarded as many energy scientists as having little value other than being unbridled optimism. And perhaps, opportunism and/or charlatanism are being applied depending upon the resource under speculation and the potential market for the product.

The differences between the data obtained from these various estimates can be considerable but it must be remembered that any data related to the reserves of natural gas (and, for that matter, related to any other fuel or mineral resource) will always be open to questions related to the degree of certainty (Speight, 2104).

There are three important items that counteract the guesswork applied to *undiscovered* resources: (a) the actual discoveries of new coal reserves; (b) the development of improved mining technologies for already known coal reserves; and (c) estimates of the coal resource base that are derived from known resource properties where the whole of the resource is not explored.

It should also be remembered that the total resource base of any fossil fuel (or, for that matter, of any mineral) will be dictated by economics (Nederlof, 1988). Therefore, when coal resource data are quoted some attention must be given to the cost of recovering those reserves. And, most important, the economics must also include a cost factor that reflects the willingness to secure total, or a specific degree of, energy independence, including some serious consideration of the very real environmental aspects of coal usage.

On the basis of these definitions, the total recoverable reserves of coal around the world are estimated to be on the order of at 950 billion tons (950 x 10^9 tons), indicating a reserves-to-production ratio of 126 years (International Energy Agency, 2010; EIA 2010, 2011, 2012a, 2012b). Furthermore, because recoverable reserves are a subset of total coal resources, recoverable reserve estimates for a number of regions with large coal resource bases (notably, China and the United States) could increase substantially as coal mining technology improves and additional geological assessments of the coal resource base are completed.

Although coal deposits are widely distributed, the majority (approximately 79%) of the recoverable reserves of the world are located in five regions: (i) the United States, (ii) Russia, (iii) China, (iv) Europe and Eurasia outside of Russia, and (v) Australia and New Zealand. By rank, anthracite, and bituminous coal account for approximately 47% of the estimated worldwide recoverable coal reserves on a tonnage basis, subbituminous coal accounts for 30%, and lignite accounts for 23%. As these numbers indicate, the United States has a vast supply of coal (approximately 28% of world reserves and more than 1,600 billion tons – 1,600 x 10^9 tons – of the remaining coal resources. The United States is also the second-largest coal producer in the world (after China) and annually produces more than twice as much coal as India, the third-largest producer of coal (Höök and Aleklett, 2009; EIA, 2010, 2011, 2012a, 2012b).

The quality and geological characteristics of coal deposits are important parameters for coal reserves. Coal is a heterogeneous source of energy, with quality (for example, characteristics such as heat, sulfur, and ash content) varying significantly by region and even within individual coal seams. At upper levels of coal quality are premium-grade bituminous coals, or coking coals, used to manufacture coke for the steelmaking process. Coking coals produced in the United States have an estimated heat content of 26.3 million Btu per ton and relatively low sulfur content of approximately 0.9% by weight. At the other end of the spectrum are reserves of low-Btu lignite – on a Btu basis, lignite reserves show considerable variation (International Energy Agency, 2010; EIA, 2010, 2011, 2012a, 2012b).

1.6.5 Other Definitions

While the definitions presented above are in common use, there are other systems of resource/reserve definition and nomenclature that are similar to the definitions used above (EWG, 2007) and also deserve mention here.

The definition of *resources* according to the scheme of the World Energy Council (WEC) involves the *estimated additional amount in place*, which is the indicated and inferred tonnage of coal additional to the proved amount in place that is of foreseeable interest. This definition includes estimates of amounts that could exist in unexplored extensions of known deposits or in undiscovered deposits in known coal-bearing areas, as well as amounts inferred through knowledge of favorable geological conditions. Speculative amounts are not included.

The definition of *reserves* according to the scheme of the WEC is *the proved amount in place*, which is the resource remaining in known deposits that has been carefully measured and assessed as exploitable under present and expected local economic conditions with existing available technology. On the other hand the *proved recoverable reserves* is the tonnage of coal within the proved amount in place that can be recovered in the future under present and expected local economic conditions with existing available technology.

The *estimated additional reserves recoverable* is the tonnage of coal within the estimated additional amount in place that geological and engineering information indicates with reasonable certainty might be recovered in the future.

The International Energy Agency (IEA), BP Statistics (as in the BP Review of World Energy) and most other organization typically use the term *Proved reserve* (*proven reserve*) which is equivalent to the *proved recoverable reserves* as defined by the World Energy Council.

The US Energy Information Agency (EIA) uses nomenclature such as the *demonstrated reserve base*, which covers publicly available data on coal mapped to measured and indicated degrees of accuracy and found at depths and in thick coal-beds considered technologically minable at the time of determinations. On the other hand, the *estimated recoverable reserves* (which corresponds to the *proved recoverable reserves* of the World Energy Council and to the *proved reserves* of the BP Review of World Energy) cover the coal in the demonstrated reserve base considered recoverable after excluding the coal estimated to be unavailable due to land use restrictions or currently economically unattractive for mining, and after applying assumed mining recovery rates. In addition, the *recoverable reserves at producing mines* represent the quantity of coal that can be recovered (i.e., mined) from existing coal reserves at reporting mines.

Other national geological agencies use different definitions, such as the German *Bundesanstalt für Geowissenschaften und Rohstoffe (BGR),* which uses the terms (i) *reserves*, which is equivalent to the *proved recoverable reserves* (WEC), and (ii) resources, which include discovered but not yet economically producible amounts and undiscovered but estimated accumulations of coal. This includes the *resources* as defined by the WEC as well as any other possible coal deposits.

1.7 Energy Independence

Energy independence has been a political non-issue in the United States since the first Arab oil embargo in 1973. Since that time, the speeches of various presidents and the Congress of the United States have continued to call for an end to the dependence on foreign oil by the United States. The congressional rhetoric of energy independence continues but meaningful suggestions of how to address this issue remain few and far between.

Energy interdependence also makes the domestic economy more susceptible to disruptions in distant and unstable regions of the globe, such as the Middle East, South America, and Africa. In fact, in many countries with proven reserves, oil production could be shut down by wars, strikes, and other political events, thus reducing the flow of oil to the world market. If these events occurred repeatedly, or in many different locations, they could constrain exploration and production, resulting in a peak despite the existence of proven oil reserves.

Even in the United States, political considerations may affect the rate of exploration and production of energy sources. For example, restrictions imposed to protect environmental assets mean that some oil may not be produced. In addition, policies on federal land use need to take into account multiple uses of the land including environmental protection. Environmental restrictions may affect a peak in oil production by barring oil exploration and production in environmentally sensitive areas.

The government must adopt policies that ensure energy independence. The US Congress is no longer believable when the members of the Congress lay the blame on foreign governments or events for an impending crisis. In the United States, crude oil imports are considered a threat to national security but there is also the line of thinking that the level of imports has no significant impact on energy security, or even national security. However, the issue becomes a problem when import vulnerability increases as crude oil imports rise, which occurs when oil-consuming countries increase the share of crude oil imports from politically unstable areas of the world.

Currently, the United States is an exporter of crude oil and crude oil products but the question remains related to the longevity of such a situation. In addition, US dependence on crude oil has increased in recent years and this indicates two possible areas of concern regarding the extent to which crude oil influences energy security: (i) the increase in the crude oil share of energy use, and (ii) the inability or unwillingness of the United States to reduce dependence on oil. It is because of such variations that the potential of gasification must be considered as an option for energy production, particularly for the production of liquid fuels and chemicals.

For many decades, coal has been the primary feedstock for power generation but due to recent concerns related to the use of fossil fuels and the resulting environmental pollutants, irrespective of the various gas cleaning processes and gasification plant environmental cleanup efforts, there is a move to feedstocks other than coal for gasification processes (Speight, 2013). Indeed, the mounting interest in the use of mixed-coal feedstocks and non-coal feedstocks for power generation reflects the potential for lower cost control of greenhouse gases than other coal-based systems.

Furthermore, power generation units can accept a variety of feedstocks but the reactor must be selected on the basis of feedstock properties and behavior in the process. Also, the disposal of municipal and industrial waste has become an important problem because the traditional means of disposal, landfill, are much less environmentally acceptable than previously. Much stricter regulation of these disposal methods will make the economics of waste processing for resource recovery much more favorable. A method of processing waste streams is to convert the energy value of the combustible waste into a fuel. One type of fuel attainable from waste is a low heating value gas, usually 100 to 150 Btu/scf, which can be used to generate process steam or to generate electricity.

Waste may be municipal solid waste (MSW) which had minimal presorting, or refuse-derived fuel (RDF) with significant pretreatment, usually mechanical screening, and shredding. Other more specific waste sources (excluding hazardous waste) and possibly including crude oil coke, may provide niche opportunities for co-utilization. The traditional waste to energy plant, based on mass-burn combustion on an inclined grate, has a low public acceptability despite the reduction in the emissions achieved over the last decade with modern flue gas clean-up equipment. This has led to difficulty in obtaining planning permissions to construct needed new waste to energy plants. After much debate, various governments have allowed options for advanced waste conversion technologies (gasification, pyrolysis, and anaerobic digestion), but will only give credit to the proportion of electricity generated from non-fossil waste.

Co-utilization of waste and biomass with coal may provide economies of scale that help achieve the above identified policy objectives at an affordable cost. In some countries, governments propose mixed feedstock processes as being *well suited for community-sized developments,* suggesting that waste should be dealt with in smaller plants serving towns and cities, rather than moved to large, central plants (satisfying the so-called *proximity principal*).

Use of waste materials as feedstocks for power generation may attract significant disposal credits. Cleaner biomass materials are renewable fuels and may attract premium prices for the electricity generated. Availability of sufficient fuel locally for an economic plant size is often a major issue, as is the reliability of the fuel supply. Use of more-predictably available coal alongside these fuels overcomes some of these difficulties and risks. Coal could be regarded as the *flywheel* which keeps the plant running when the fuels producing the better revenue streams are not available in sufficient quantities.

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2
Classification

2.1 Introduction

Following from the statements in Chapter 1, coal is the biggest single source of energy for electricity production and plays an essential role in the energy mix of many countries, particularly for power generation, but there is an urgent need to use coal efficiently and reduce the environmental footprint of the coal. Thus, the measurement and reporting of efficiency performance and carbon dioxide emissions is a prerequisite to the more sustainable use of coal in power plants.

The direct and indirect utilization of coals for production of energy (and chemicals) is the foundation upon which interest in classifying coal resource is built. However, because of the complex, heterogeneous nature, and the variety of coals used throughout the world, classification is a difficult task. Identification of the most advantageous raw material, whether by quality, cost, availability or a combination of several such factors has always been one of the driving forces behind the development of classification systems. In fact, many of the systems currently in use in the coal industry were derived specifically from a need to identify quality coals for coke making, and in that respect only classify a relatively narrow range of coals. Other systems that have been developed to address the scientific need to understand the origin, constitution and fundamental properties follow the approach that any sound classification will identify all coals for all potential industrial uses (Speight, 2013).

Coal is a combustible dark-brown-to-black organic sedimentary rock that occurs in *coal beds* or *coal seams* (Chapter 1) and is composed primarily of carbon with variable amounts of hydrogen, nitrogen, oxygen, and sulfur as well as mineral matter and gases as part of the coal matrix. The types of coal, in increasing order of alteration, are lignite (brown coal), subbituminous, bituminous, and anthracite (Chapter 2).

Coal is the most abundant fossil fuel in the United States, having been used for several centuries, and occurs in several regions (Figure 2.1) (Speight, 2013). Knowledge of the size, distribution, and quality of the coal resources is important for governmental planning; industrial planning and growth; the solution of current and future problems related to air, water, and land degradation; and for meeting the short- to long-term energy needs of the country. Knowledge of resources is also important in planning for the exportation and importation of fuel.

Coal begins as layers of plant matter that has accumulated at the bottom of a body of water after which, through anaerobic metamorphic processes, changes in the chemical and physical properties of the plant remains occurred to create a peat-like solid material. It is believed that with further passing of time, lignite is formed from the peat-like product which is metamorphosed (due to thermal and pressure effects) to lignite. With the further passing of time, lignite increases in maturity to subbituminous coal thence to bituminous coal and finally to anthracite.

There are many compositional differences between the coals mined from the different coal deposits worldwide. The different types of coal are typically classified by *rank* which

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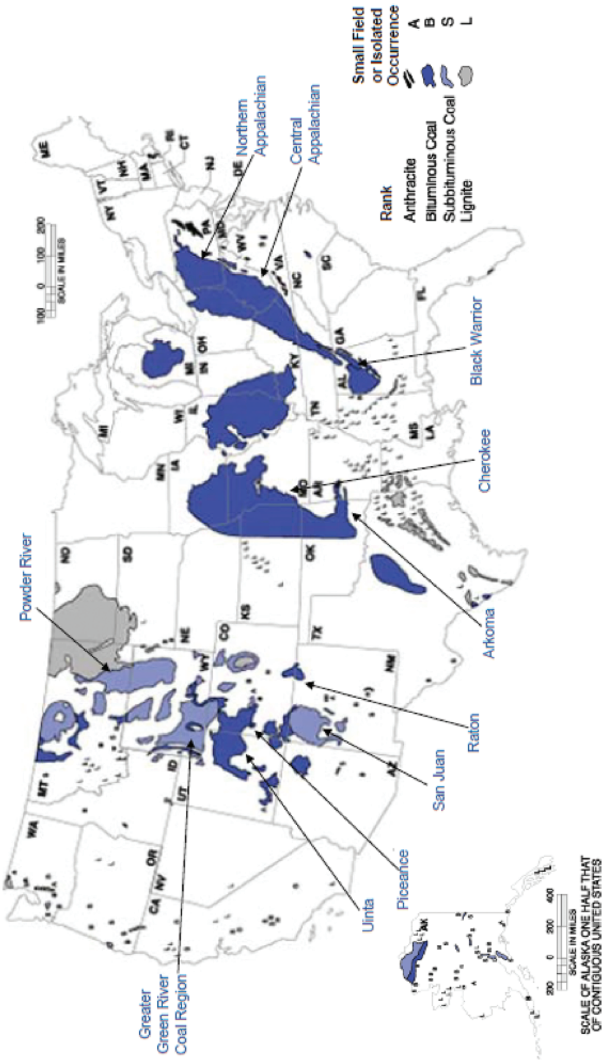

Figure 2.1 Coal reserves and distribution in the United States (DOE/EIA, 1995).

depends upon the degree of transformation from the original source (i.e., decayed plants) and is therefore a measure of the age of the coal (Chapter 1) (ASTM D2011). As the process of progressive transformation took place, the properties of the coal changed markedly, leading to the differentiation of coal based on rank (which is often cited incorrectly as carbon content but there are other factors involved in determining coal rank). Nevertheless, changes on properties can cause changes in efficiency of power plant operations.

Coal remains in adequate supply and at current rates of recovery and consumption, the world global coal reserves have been variously estimated to have a reserves/production ratio of at least 155 years. However, as with all estimates of resource longevity, coal longevity is subject to the assumed rate of consumption remaining at the current rate of consumption and, moreover, to technological developments that dictate the rate at which the coal can be mined. Moreover, coal is a fossil fuel and an *unclean* energy source that will only add to global warming. In fact, the next time electricity is advertised as a clean energy source, consider the means by which the majority of electricity is produced – almost 50% of the electricity generated in the United States is from coal (Speight, 2013, 2020).

However, there are considerations which can impact significantly on efficiency including: (i) moisture content, which influences latent and sensible heat losses, (ii) ash production from the mineral matter, which impacts on heat transfer and auxiliary plant load, (iii) sulfur content, which influences design limits on boiler flue gas discharge temperature, (iv) use of flue gas cleaning technologies, such as selective catalytic reduction (SCR), fabric filtration, flue gas desulfurization (FGD) and carbon dioxide capture, which increase on-site power demand, and (v) use of low-NOx combustion systems, which require excess combustion air and increases unburned carbon.

Thus, a plant designed for high-moisture, high-ash coal, fitted with flue gas desulfurization units and bag filters, and operating with a closed-circuit cooling system, could not be expected to achieve the same efficiency as one without flue gas desulfurization units using high-rank, low-ash, and low-moisture bituminous coal at a coastal site with cold seawater cooling. In most cases, there is little that can be done to mitigate these effects; it is sufficient to recognize that their impact is not necessarily a result of ineffective design or operation, but merely a function of real plant design constraints.

The efficiency of converting coal into electricity is of prime importance since more efficient power plants use less fuel and emit less climate-damaging carbon dioxide. However, with many different methods used to express efficiency and performance, it is often difficult to compare one coal-fired plant with another, even before accounting for any fixed constraints such as coal quality and cooling-water temperature. Guidelines are required that allow the efficiency and emissions of any plant to be reported on a common basis and compared against best practice. Such comparisons start with the classification of coal and, amongst other parameters, allow less efficient plants to be identified and steps taken to improve these plants. Having such information available will allow better monitoring of plant performance and, if necessary, regulate the means by which coal is used for power generation, leading to a more sustainable use of coal.

2.2 Nomenclature of Coal

Coal is classified into three major types, namely anthracite, bituminous, and lignite. However, there is no clear demarcation between them and coal is also further classified into subcategories as semi-anthracite, semi-bituminous, and subbituminous. Anthracite is the oldest coal from geological perspective and it is a hard coal composed mainly of carbon with little volatile content and practically no moisture. Lignite is the youngest coal from geological perspective and it is a soft coal composed mainly of volatile matter and moisture content with low fixed carbon. Fixed carbon refers to carbon in its free state, not combined with other elements. Volatile matter refers to those combustible constituents of coal that vaporize when coal is heated (Speight, 2013).

The different types of coal contain both organic and inorganic phases. The latter consist either of minerals such as quartz (SiO_2) and various clay minerals that may have been brought in by flowing water or by wind activity or minerals (such as pyrite, FeS2, and marcasite) that are formed in place (authigenic minerals). The minerals can have a major effect on the efficient use of coal and should be removed before use. Other properties, such as hardness, grindability, ash-fusion temperature, and free-swelling index (a visual measurement of the amount of swelling that occurs when a coal sample is heated in a covered crucible), may affect coal use (especially when coal is used for power generation). Hardness and grindability determine the kinds of equipment used for reducing the size of the coal that enters the combustor (or the gasification unit) and the ash-fusion temperature influences the design of the furnace as well as the operating parameters of the furnace. The free-swelling index provides preliminary information concerning the suitability of a coal combustion and gives an indication of the potential of the coal for coke production, which is another indication of the suitability of the coal for combustion that leads to power generation.

Because of all of these varying properties, the nomenclature of coal – as might be expected – is not straightforward and requires considerable thought to elucidate the precise meaning of some of the terminology (Chapter 1). However, since coal and coal products will play an increasingly important role in fulfilling the energy needs of society it is essential that coal types be understood before use. In fact, future applications will extend far beyond the present major uses for power generation and chemicals production (Speight, 2013, 2020). A key feature in these extensions will be the development of means to provide analytical data that will help in understanding the conversion of coal from its native form into useful gases, liquids, and solids in ways that are energy efficient, nonpolluting, and economical.

The design of a new generation of conversion processes will require the analyst to have a deeper understanding of the intrinsic properties of coal and the ways in which coal is chemically transformed to produce energy under process conditions. Coal properties – such as the chemical form of the organic material, the types and distribution of organics, the nature of the pore structure, and the mechanical properties must be determined for coals of different ranks (or degrees of coalification) in order to use each coal type most effectively.

First and foremost, *coal* is a sedimentary rock of biochemical origin and is formed from the accumulations of organic matter which occurred along the edges of shallow seas and lakes or rivers. Flat swampy areas that are episodically flooded are the best candidates for coal formation. During non-flooding periods of time, thick accumulations of dead plant material pile up. As the water levels rise, the organic debris is covered by water, sand, and soil. The water (often salty), sand and soils can prevent the decay and transport of the organic debris. If left alone, the buried organic debris begins to go through the coal series as more and more sand and silt accumulates above it. The compressed and/or heated organic debris begins driving off volatiles, leaving primarily carbon behind.

In addition to recognizing coal as an organic combustible sedimentary rock, another part of the challenge is to identify the chemical pathways followed during the thermal conversion of coal to liquids or gases (Speight, 2013, 2020). This is accomplished by tracing the conversion of specific chemical functional groups in the coal and studying the effects of various inorganic compounds on the conversion process. Significant progress has been made in this area by combining test reactions with a battery of characterization techniques. The ultimate goal is to relate the structure of the native coal to the resulting conversion products.

There is also a major challenge to the coal analyst and this involves recognizing the heterogeneity of coal – even during the formation of one coal seam, conditions vary and, hence, the types of coal vary depending upon the character of the original peat swamp (Speight, 2013, 2020). Within a swamp some areas might be shallow and other areas deep. Some areas might have woody plants and other areas grassy. The environment might be changing over time, making the bottom (the older part) of the coal seam different to the top (the younger part) of the seam. Varying water level and movement changes the degree of aeration and hence the activity of aerobic bacteria in bringing about decay. The different types of chemical substance present in plants (such as cellulose, lignin, resins, waxes, and tannins) are present in different relative proportions in living woody tissue, in dead cortical tissue as well as in seed and leaf coatings, In addition, these substances show differing degrees of resistance to decay.

Thus, as conditions fluctuate during the accumulation of plant debris, the botanical nature and chemical composition of the material surviving complete breakdown will fluctuate also, not only on a regional basis but also on a local basis. This fluctuation is the origin of the familiar banded structure of coal seams, which is visible to the naked eye, and provides strong support case for the different chemical and physical behavior of coals.

Furthermore, coal seams, sandstone, shale, and limestone are often found together in sequences hundreds of feet thick. The key to large productive coal beds or seams seems to be long periods of time of organic accumulation over a large flat region, followed by a rapid inundation of sand or soil, and with this sequence repeating as often as possible. Such events happened during the Carboniferous Period – recognized in the United States as the Mississippian and Pennsylvanian time periods due to the significant sequences of these rocks found in several states; other coal-forming periods are the Cretaceous, Triassic, and Jurassic Periods (Chapter 1).

To complicate matters even further, coal is also considered (perhaps without sufficient scientific foundation) to be a metamorphic rock – the result of heat and pressure on organic sediments such as peat – but most sedimentary rocks undergo some heat and pressure and the association of coal with typical sedimentary rocks and its mode of formation usually keep low-grade coal in the sedimentary classification system. On the other hand, anthracite undergoes more heat and pressure and is associated with low grade metamorphic rocks and is justifiably considered to be an organic metamorphic rock. Thus, the degree of natural processing results in different quality of coal including such coal types as (i) lignite, which is the least mature of the true coals and the most impure; it is often relatively moist and can be crumbled to a powdery, (ii) subbituminous coal, which is poorly indurated and can be brownish in color, but is more closely related to bituminous coal than to lignite, (iii) bituminous coal, which is the most commonly used coal; it occurs as a black, soft, shiny rock, and (iv) anthracite, which is the highest rank of coal and is considered to be a metamorphic organic rock; it is much harder and blacker than other ranks of coal, has a glassy luster, and is denser with few impurities (Table 2.1) (Chapters 1, 2).

As anticipated because of local and regional variations in the distribution of floral species (i.e., site specificity) the relative amounts can vary considerably from one site to another

Table 2.1 Types of coal.

Rank	Properties
Lignite	Also referred to as brown coal; the lowest rank of coal and used almost exclusively as fuel for steam-electric power generation. Jet is a compact form of lignite that is sometimes polished and has been used as an ornamental stone since the Iron Age – since (approximately) 1200 BC.
Subbituminous coal	The properties range from those of lignite to those of bituminous coal and are used primarily as fuel for steam-electric power generation.
Bituminous coal	A dense coal, usually black, sometimes dark brown, often with well-defined bands of bright and dull material, used primarily as fuel in steam-electric power generation, with substantial quantities also used for heat and power applications in manufacturing and to produce coke.
Anthracite	The highest rank; a harder, glossy, black coal used primarily for residential and commercial space heating.

(Chapter 1). In addition to variations in the types of flora, there is also the potential for regional variations in the physical maturation conditions – these include differences such as variations in the oxygen content of the water as well as acidity/alkalinity and the presence (or absence) of microbial life forms. Variations of the plant forms due to climatic differences between the geological eras/periods would also play a role in determining the chemical nature of the constituents of the mature coal (Chapter 1) (Bend *et al.*, 1991; Bend, 1992; Speight, 2013a).

Thus, it is not surprising that coal differs markedly in composition from one locale to another. Indeed, pronounced differences in analytical properties of coal from one particular seam are not uncommon (Speight, 2013a), due not only to the wide variety of plant debris that could have formed the precursor but also to the many different chemical reactions that can occur during the maturation process. Indeed, the continuation and development of analytical studies related to maturation indices may enable scientists to determine the precise pathways by which maturation occurred (Speight, 2013a and references cited therein).

Since the resurgence of coal science in the 1980s and the need for new and reconstituted environmental legislation, there has been a pronounced resurgence in the attempts to determine the composition of coal through the development of up-to-date analytical methods (Speight, 2015). But it is not obvious that there has been a concomitant increase in understanding and formulating the molecular make-up and molecular structure of coal. Indeed, the concept of *a coal structure* (often referred to as an *average structure for coal*) has continued for several decades and it is very questionable, in the minds of many scientists and engineers, as to whether any progress has been made down the highways and byways of uncertainty than was the case some 40 years ago. There are those who can, and will, argue convincingly for either side of this question. Or it might be wondered if (even denied that) there is a need to define coal in terms of a distinct molecular structure (Speight, 2013, 2020). In fact, this is a challenge for the analyst insofar as it is a challenge that may never be revolved. On the positive side, indications can be given by tracing the *possible* chemical precursors in the original *mess of pottage* that can lead to a variety of hydrocarbon and heteroatom chemical functional groups in coal and which can be determined by application of appropriate standard test methods.

2.3 Classification Systems

Coal (unless otherwise specified, the term is used generically throughout the book to include all types of coal) is a black or brownish-black *organic sedimentary rock* of biochemical origin which is combustible and occurs in rock strata (coal beds, coal seams) and is composed primarily of carbon with variable proportions of hydrogen, nitrogen, oxygen, and sulfur. Coal occurs in seams or strata and is a fossil fuel formed in swamp ecosystems where plant remains (often referred to as plant detritus) were preserved by water and by mud from oxidation and biodegradation (Speight, 2013, 2020).

The plant material (vegetal matter) is composed mainly of carbon, hydrogen, oxygen, nitrogen, sulfur, and some inorganic mineral elements. When this material decays under water, in the absence of oxygen, the carbon content increases. The initial product of this decomposition process is known as peat (which is not classed as a type of coal) and the transformation of peat to lignite is the result of pressure exerted by sedimentary materials that accumulate over the peat deposits. Even greater pressures and heat from movements of the crust of the Earth (as occurs during mountain building), and occasionally from igneous intrusion, cause the transformation of lignite to bituminous and anthracite coal (Chapter 1) (Speight, 2013, 2020).

Coal classification, which is based on coal properties and utilization, is at least 200 years old and was initiated by the need to establish order to the confusing terminology of different coals. However, in spite of the need to bring order to the confusion, several types of classification systems arose which are essential for the buyer to know and are (i) the scientific systems, which are concerned with the origin, composition, and fundamental properties of coal, and (ii) the commercial systems, which focused on market issues such as technological properties, and (iii) the suitability of coal for certain end uses (utilization). The latter systems were designed to assist coal producers and users, with many being specific to the properties and use of coal in a particular country.

It is helpful for the scientist or engineer working with coal to understand the various systems so that, for example, the scientist or engineer working with coal to produce electricity can immediately understand reference to coal type made by their counterparts working in other countries who use different classification systems.

Coal occurs in different forms or *types* (Table 2.1). Variations in the nature of the source material and local or regional variations in the coalification processes cause the vegetal matter to evolve differently. Thus, various classification systems exist to define the different types of coal. In addition to being defined as a sedimentary rock, coal has also been considered to be a *metamorphic rock*, which is the result of heat and pressure on organic sediments such as peat. However, the discussion in favor of coal as a sedimentary rock is because most sedimentary rocks undergo some heat and pressure and the association of coal with typical sedimentary rocks and the mode of formation of coal usually keeps low-grade coal in the sedimentary classification system.

Anthracite, on the other hand, undergoes more heat and pressure and is associated with low-grade *metamorphic rocks* such as slate and quartzite. Subducted coal may become graphite in igneous rocks or even the carbonate rich rocks (carbonatites).

The degree of metamorphosis results in differing coal types, each of which has different quality. However, peat is not actually a rock but no longer just organic matter and is a major source of energy for many non-industrialized countries. The unconsolidated plant matter is lacking the metamorphic changes found in coal. Thus, coal is classified into four main types, depending on the amount of carbon, oxygen, and hydrogen present. The higher the carbon content, the more energy the coal contains. Thus, as geological processes increase their effects over time, the coal precursors are transformed over time into coal, each coal type having different properties from the other types (Table 2.1).

Coal classification systems are based on the degree to which coals have undergone coalification. Such varying degrees of coalification are generally called coal *ranks* (or *classes*). The determination of coal rank has a number of practical applications such as the definition of the coal properties. The properties include the amount of heat produced during combustion, the amount of gaseous products released upon heating, and the suitability of the coals for producing coke.

Some of the classification systems are currently in use in several countries and include: the American Society for Testing and Materials (ASTM) system (used in North America), the National Coal Board (NCB) system (UK), the Australian system, and the German and International Systems (for both hard and soft coal) classifications (Carpenter, 1988; Speight, 2013). Each system involves use of selected coal properties (chemical, physical, mechanical and petrographic) as the determining factors leading to classification of coal but the variation of these properties can lead to a poor fit of a coal within the relevant classification system. It is not the purpose to enter into such details here but to give a general description of the ASTM system and the classification systems that relate to the United States through coal trade and other aspects of coal technology.

Generally and from the mineralogical aspects, coal can be defined (sometimes classified) as an organic sedimentary rock-like natural product. The resemblance of coal to a rock is due to the physical nature and composition of the coal as well as the inclusion of a *natural product* term in a general definition and is not an attempt to describe coal as a collection of specific, and separate, natural product chemicals. Such chemical species are universally recognized (for example, see Fessenden and Fessenden 1990; Ramawat and Merillon, 2013) and are more distinct chemical entities with more specific use than coal.

However, the designation of coal as a natural product is no stretch of the truth and arises because of the oft-forgotten fact that coal is the result of the decay and maturation of floral remains (which are natural product chemicals) over geologic time. Indeed, the organic origins and the organic constituents of coal are too often ignored (Speight, 2013). But there are more appropriate definitions of coal and the manner by which this complex natural product can be classified.

The need to classify coal arose in order to describe each individual sample of coal in terms that would accurately (even adequately) depict the physical and/or chemical properties (Kreulen, 1948; van Krevelen and Schuyer, 1957; Francis, 1961). Consequently, the terminology that came to be applied to coal essentially came into being as part of a classification system and it is difficult (if not impossible) to separate terminology from classification to treat each as a separate subject. This is, of course, in direct contrast to the systems used for the nomenclature and terminology of crude oil, natural gas, and related materials (Speight, 2011, 2014, 2020). Indeed, coal classification systems stand apart in the field of fossil fuel science as an achievement that is second to none insofar as the system allows classification (on the basis of standardized parameters) of all of the coals that are known.

Of particular importance here is the carbon content of the coal, which is part of the basis for the modern classification system of coal, Thus, whereas crude oil does not exhibit a wide variation in carbon content – all of the crude oil, heavy crude oil, extra heavy crude oil and tar sand bitumen (sometimes incorrectly referred to as natural asphalt) that occur throughout the world fall into the range of 82.0 to 88.0% w/w – coal, on the other hand exhibits a wide variation in carbon content – all of the coal types in the world have carbon contents varying over the range 75.0 to 95.0% w/w (Speight, 2013, 2014, 2020). While little room is left for the design of a standardized system of crude oil classification and/or nomenclature based on carbon content, the door is wide open for coal to be classified using carbon content as one of the parameters.

However, before launching into a discussion of the means by which coal is classified, it is perhaps necessary to become familiar with the nomenclature (the equivalent terms nomenclature and terminology are used synonymously here) applied to coal even though this terminology may be based on a particular classification system or may simply be described as the *grade of coal*.

Briefly, coal grade is a term used to indicate the value of coal material as determined by the amount and nature of ash yield and the sulfur content following the complete oxidation of the organic fraction. Calorific value is one of the principal measures of the value of coal as a fuel and is directly influenced by mineral impurities. Coal mineralogy is not only important to combustion characteristics, but also as materials that can be passed on to secondary products such as metallurgical coke. Alkalis-containing compounds derived from coal minerals can contribute to excessive gasification of coke in the blast furnace and attack of blast furnace refractories, whereas phosphorus and sulfur from coal minerals can be passed on to the hot metal, thus reducing the quality of the coal for steelmaking.

For example, within certain parts of the industry, coal is classified (or described) as two main categories: (i) high-grade coal and (ii) low-grade coal, which refers to the energy content of the coal. Among high-grade coals are anthracite and bituminous coal while low-grade coals include subbituminous coal and lignite. On the other hand, the grade of Indian coal is based on the calorific value of the coal (Table 2.2).

In the United States and many other countries the grade is determined mainly by the sulfur content and the amount and type or amount of mineral ash produced during combustion rather than on a single property. Such properties are not always of use or recommended for estimation of coal resources – definitive statements related to the sulfur content and the chemical types of the sulfur derivatives as well as the mineral matter (that produces the mineral ash that is formed during combustion) ash are preferable. Statements indicating high, medium, or low grade are inappropriate (and may even be subject to misinterpretation without supporting analytical data. Another means of classifying coal grade is using the mineral matter content or the propensity for ash production. Thus: 50% w/w yield of ash limit for coal, 80% w/w ash is the limit for middlings formed during coal washing, and 100% w/w/ yield applies to for shale.

This general system of nomenclature offers little, if anything, in the way of a finite description of the various coals. In fact, to anyone but an expert (who must be presumed

Table 2.2 Grades of coal as designated by the Indian System.

Grade	Calorific value (kcal/kg)
A	>6200
B	5600-6200
C	4940-5600
D	4200-4940
E	3360-4200
F	2400-3360
G	1300-2400

to be well versed in the field of coal technology) it would be extremely difficult to distinguish one piece of coal from another. Therefore, the terminology that is applied to different coals is much more logical when it is taken in perspective with the classification system from which it has arisen and becomes much more meaningful in terms of allowing specific definitions of the various types of coal that are known to exist.

The widespread occurrence and the diversity of coal for various uses have resulted in the development of numerous classification systems. Indeed, these systems have invoked the use of practically every chemical and physical characteristic of coal. Consequently, it will be useful to review the major classification systems in current use. In addition, several of the lesser known classification systems are also included because they often contain elements of coal terminology that may still be in current use by the various scientific disciplines involved in coal technology, although they may not be recognized as part of a more formalized classification system.

2.3.1 Geological Age

Coals have at various times been classified according to the geological age in which they were believed to have originated.

For example, coal paleobotanists have noted that three major classes of plants are recognizable in coal: coniferous plants, ferns, and lycopods. Furthermore, these plant types are not usually mixed in a random manner in a particular coal, but it has been observed that one particular class of these plant types usually predominates in a coal bed or seam. Thus, because of the changes in character and predominant types of vegetation during the 200 million years or so of the coal-forming period in the history of the Earth, it has often been found convenient and, perhaps, necessary to classify coal according to the age in which the deposit was laid down (Speight, 2013).

It should be noted, however, that deposits of vegetable matter are not limited to any particular era or period, but while these deposits occur even in pre-Cambrian rocks, the plants (i.e., terrestrial plants) that were eventually to become coal were not sufficiently abundant until the Devonian period and it appears that such deposits really became significant during the Carboniferous period.

2.3.2 Banded Structure

Reference has been made elsewhere to the three general classes of coal: banded coal, nonbanded coal, and impure coal (White, 1911; Thiessen, 1931) and further discussion is not warranted here. Nevertheless, the fact that many types of coal have a laminated structure consisting of layers which may vary considerably in thickness, luster, and texture has led to an attempt to classify coal by virtue of these differences (Table 2.3).

Since this banded structure persists in all types of coal from lignite to anthracite (although it is most obvious in the bituminous coals), there may, of course, be some merit in such a classification (Stach *et al.*, 1982). However, the failure of such a classification system to take into account the elemental composition of the coal is a serious deficiency. Indeed, a similar statement may be made relative to all of the classification systems that involve the physical appearance of the coal. To all but the well initiated, there is little, if any, difference between one piece of coal and another. Therefore, classification systems which rely on a physical property are not only difficult to rationalize but are even more difficult to accept.

Furthermore, the wide variation in the elemental (ultimate) composition of coals, irrespective of the banded structure, is the major objection to classification by physical methods alone.

2.3.3 Rank

There is a need to accurately describe the various coals in order to identify the end use of the coal and also to provide data which can be used as a means of comparison of the various worldwide coals. Hence, it is not surprising that a great many methods of coal classification have arisen over the last century or so (ASTM D388; ISO 2950; Montgomery, 1978; Speight, 2013).

An early method that attempted a definitive classification of coals on the basis of their composition and heating value was based on the ratio of the fixed carbon to the volatile combustible matter [C/(V.Hc)] (Frazer, 1877, 1879) in which the ratio of the volatile to fixed combustible matter was a logical basis for the classification of coals.

Table 2.3 Classification by banded structure.

Designation	Thickness of band (mm)	Remarks
Coarsely banded	>2	
Finely banded or stripped	2–0.5	
Microbanded or striated	<0.5	Bands not visible to naked eye
Mixed banded		Both coarse and fine bands
Nonbanded (little or no lamination)		Cannel and boghead coals that break with conchoidal fracture

Source: Davis *et al.* (1941).

After various attempts to make the fuel ratio of the different coals fit the descriptions of the varieties of coal, it was concluded that coal could be classified according to the fuel ratio within wide limits, and the following divisions were suggested:

Hard-dry anthracite:
C/(V.Hc) = 100-12

Semianthracite:
C/(V.Hc) = 12-8

Semibituminous coal:
C/(V.Hc) = 8-5

Bituminous coal:
C/(V.Hc) = 5-0

There are many compositional differences between the coals mined from the different coal deposits worldwide. The different types of coal are most usually classified by *rank*, which depends upon the degree of transformation from the original source (i.e., decayed plants) and is therefore a measure of the age of the coal. As the process of progressive transformation took place, the heating value and the fixed carbon value of the coal increased and the amount of volatile matter in the coal decreased.

Coal contains significant proportions of carbon, hydrogen, and oxygen with lesser amounts of nitrogen and sulfur. Thus, it is not surprising that several attempts have been made to classify coal on the basis of elemental composition. Indeed, one of the earlier classifications of coal, based on the elemental composition of coal (Seyler, 1899), was subsequently extended (Seyler, 1900, 1931, 1938). This system (Figure 2.2) offered a means of relating coal composition to technological properties and may be looked upon as a major effort to relate properties to utilization. Indeed, for coal below the anthracite rank, and with an oxygen content less than 15%, it was possible to derive relationships between carbon content (C% w/w), hydrogen content (H% w/w), calorific value (Q, cal gm), and volatile matter (VM, % w/w):

$$C = 0.59(Q/100 - 0.367VM) + 43.4$$
$$H = 0.069(Q/100 + VM) - 2.86$$
$$Q = 388.12H + 123.92C - 4269T$$
$$VM = 10.61H - 1.24C + 84.15$$

Since these relationships only apply to specific types of coal the application is often limited and it is unfortunate that composition and coal behavior do not exist in the form of simple relationships. In fact, classification by means of elemental composition alone is extremely difficult. Nevertheless, the attempt by Seyler to classify coal should not be ignored or discredited as it offered an initial attempt at an introspective look at coal behavior.

The American Society for Testing and Materials has evolved a method of coal classification over the years; it is based on a number of parameters obtained by various prescribed

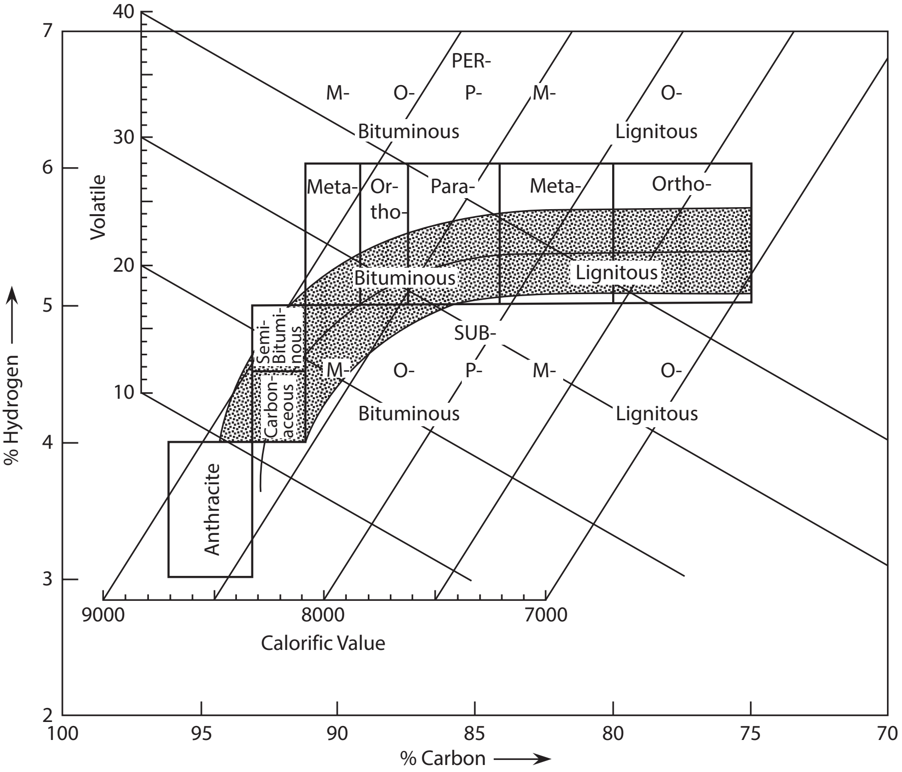

Figure 2.2 Classification by the Seyler System.

tests for the fixed carbon value as well as other physical properties which can also be related to coal use (Table 2.4, Table 2.5). In the ASTM system (ASTM, D388), coal is classified based on certain gradational properties that are associated with the amount of change that the coal has undergone while still beneath the earth. The system uses selected chemical and physical properties that assist in understanding how the coal will react during mining, preparation and eventual use.

Thus, coal can be divided into four major types; (i) anthracite coal, (ii) bituminous coal, (iii) subbituminous coal, and (iv) lignite coal which show considerable variation in properties (Table 2.5). For the purposes of this text, peat is not classified as being a member of the coal series and, therefore, in this book peat is not included in this system of coal classification (Chapters 1, 2).

Anthracite is coal of the highest metamorphic rank; it is also known as *hard coal* and has a brilliant luster, being hard and shiny. It can be rubbed without leaving a familiar coal dust mark on the finger and can even be polished for use as jewelry. Anthracite coal burns slowly with a pale blue flame and may be used primarily as a domestic fuel.

Bituminous coal ignites relatively easily coal burns with a smoky flame and may also contain 15-20% w/w volatile matter. If improperly burned, such as a deficiency of oxygen, bituminous coal is characterized with excess smoke and soot. It is the most abundant variety of coal, weathers only slightly, and may be kept in open piles with very little danger of spontaneous combustion, although there is evidence that spontaneous combustion is generally considered to be a factor of extrinsic conditions such as the mining and storage

Table 2.4 Coal classification according to rank (ASTM D388).

Class and group	Fixed carbon[a] (%)	Volatile matter[a] (%)	Heating value[b] (btu/lb)
Anthracitic			
1. Meta-anthracite	>98	<2	–
2. Anthracite	92–98	2–8	–
3. Semianthracite	86–92	8–14	–
Bituminous			
1. Low-volatile bituminous coal	78–86	14–22	–
2. Medium-volatile bituminous coal	69–78	22–31	–
3. High-volatile A bituminous coal	<69	>31	>14,000
4. High-volatile B bituminous coal	–	–	13,000–14,000
5. High-volatile C bituminous coal	–	–	10,500–13,000[c]
Subbituminous			
1. Subbituminous A coal	–	–	10,500–11,500[c]
2. Subbituminous B coal	–	–	9,500–10,500
3. Subbituminous C coal	–	–	8,300–9,500
Lignitic	–	–	
1. Lignitic A	–	–	6,300–8,300
2. Lignitic B	–	–	<6,300

[a] Calculated on dry, mineral-matter-free coal.

[b] Calculated on mineral-matter-free coal containing natural inherent moisture.

[c] Coals with a heating value of 10,500–11,500 btu/lb are classified as high-volatile C bituminous coal if they have agglomerating properties and as subbituminous A coal if they are nonagglomerating.

practices and the prevalent atmospheric conditions (Chapter 4) (Berkowitz and Schein, 1951; Berkowitz and Speight, 1973; Chakravorty, 1984; Chakravorty and Kar, 1986; Speight, 2013). Bituminous coal is used primarily as fuel in steam-electric power generation, with substantial quantities used for heat and power applications in manufacturing and also to produce coke.

Table 2.5 Typical properties of coal.

Sulfur content in Coal
• Anthracite: 0.6-0.77% w/w
• Bituminous coal: 0.7-4.0% w/w
• Lignite: 0.4% w/w
Moisture content
• Anthracite: 2.8-16.3% w/w
• Bituminous coal: 2.2-15.9% w/w
• Lignite: 39% w/w
Fixed carbon
• Anthracite: 80.5-85.7% w/w
• Bituminous coal: 44.9-78.2% w/w
• Lignite: 31.4% w/w
Bulk density
• Anthracite: 50-58 (lb/ft^3), 800-929 (kg/m^3)
• Bituminous coal: 42-57 (lb/ft3), 673-913 (kg/m^3)
• Lignite: 40-54 (lb/ft^3), 641-865 (kg/m^3)
Mineral matter content (as mineral ash)
• Anthracite: 9.7-20.2% w/w
• Bituminous coal: 3.3-11.7% w/w
• Lignite: 4.2% w/w

Subbituminous coal is not as high on the metamorphic scale as bituminous coal and has often been called black lignite. Lignite is the coal that is lowest on the metamorphic scale. It may vary in color from brown to brown-black and the properties of subbituminous coal range from those of lignite to those of bituminous coal. This coal is used primarily as fuel for steam-electric power generation and is also a source of low-boiling aromatic hydrocarbon derivatives that can be used as feedstocks in the chemical industry and in the petrochemical industry.

Lignite (*brown coal*) is often distinguished from subbituminous coal by having lower carbon content and a higher moisture content. It is the lowest rank coal (peat is not considered to be coal) and used almost exclusively as fuel for electric power generation. Lignite may dry out and crumble in air and is certainly liable to spontaneous ignition and combustion.

The ASTM system is based on proximate analysis in which coals containing less than 31% volatile matter on the mineral-matter-free basis (Parr formula) are classified only on the basis of fixed carbon, i.e., 100% volatile matter (Parr, 1922; Speight, 2013, 2015). Coal is divided into five groups: (i) >98% fixed carbon, (ii) 98% to 92% fixed carbon, (iii) 92% to

86% fixed carbon, (iv) 86% to 78% fixed carbon, and (v) 78% to 69% fixed carbon. The first three groups are anthracites, and the last two are bituminous coals (Speight, 2013, 2015). The subbituminous coals and lignite are then classified into groups as determined by the calorific value of the coals containing their natural bed moisture; i.e., the coals as mined but free from any moisture on the surface of the lumps.

The classification includes three groups of bituminous coals with moist calorific value from above 14,000 Btu/lb (32.5 MJ/kg) to above 13,000 Btu/lb (30.2 MJ/kg); three groups of subbituminous coals with moist calorific value below 13,000 Btu/lb to below 8,300 Btu/lb (19.3 MJ/kg); and two groups of lignite coals with moist calorific value below 8,300 Btu/lb. The classification also differentiates between consolidated and unconsolidated lignite and between the weathering characteristics of subbituminous coals and lignite.

These test methods used for this classification system are (as already stated) based on proximate analysis and are (Luppens and Hoeft, 1992; Speight, 2013):

- *Heating value (calorific value)*, which is the energy released as heat when coal (or any other substance) undergoes complete combustion with oxygen. *Moist calorific value* is the calorific value of the coal when the coal contains the natural bed moisture (i.e., the moisture content of the coal in the seam prior to mining). The natural bed moisture is often determined as the equilibrium moisture under prescribed standard test method conditions (Chapter 5). In addition, the agglomerating characteristics of coal are used to differentiate between certain adjacent groups.
- *Volatile matter*, which is the portion of a coal sample which, when heated in the absence of air at prescribed conditions, is released as gases and volatile liquids.
- *Moisture*, which is the water inherently contained within the coal and existing in the coal in the natural state in the seam. The moisture is determined as the amount of water released when a coal sample is heated at prescribed conditions but does not include any free water on the surface of the coal; such free water is removed by air-drying the coal sample being tested.
- *Ash yield, which is t*he inorganic residue remaining after a coal sample is completely burned and is largely composed of compounds of silica, aluminum, iron, calcium, magnesium and others. The ash may vary considerably from the mineral matter present in the coal (such as clay, quartz, pyrites and gypsum) before being burned.
- *Fixed carbon value,* which is the remaining organic matter after the volatile matter and moisture have been released. It is typically calculated by subtracting from 100 the percentages of volatile matter, moisture and ash. It is composed primarily of carbon with lesser amounts of hydrogen, nitrogen and sulfur. It is often simply described as a coke-like residue. The value is calculated by subtracting moisture, volatile matter, and ash from 100% (Chapter 5).

This system of classification, in fact, indicates the degree of coalification as determined by these methods of proximate; analysis with lignite being classed as low-rank coal; the converse applies to anthracite. Thus, coal rank increases with the amount of fixed carbon but decreases with the amount of moisture and volatile matter. It is, perhaps, easy to understand why coal rank is often (and incorrectly) equated to changes in the proportion of elemental carbon in coal (ultimate analysis; Chapter 5).

It is true, of course, that anthracite typically contains more carbon than bituminous coal which, in turn, usually contains more carbon than subbituminous coal, and so on. Nevertheless, the distinctions between the proportions of elemental carbon in the various coals are not so well defined as for the fixed carbon and extreme caution is advised in attempting to equate coal rank with the proportion of elemental carbon in the coal.

There have been criticisms of this method of classification because of the variability of the natural bed moisture and the numbering system for the classes of coal. With regard to the natural bed moisture, the fact that it may vary over extremely wide limits has been cited as a distinct disadvantage to using this particular property as a means of classifying coal. In fact, the natural bed moisture is determined under a set of prescribed, and rigorously standardized, conditions, thereby making every attempt to offset any large variability in the natural bed moisture. With regard to the numbering system, it has been indicated that the class numbering system should be reversed so that a high number would indicate a high rank.

Nevertheless, in spite of these criticisms, the method has survived and has been generally adopted for use throughout North America as the predominant method of classification (Speight, 2013 and references cited therein).

Thus, the *rank* of a coal indicates the progressive changes in carbon, volatile matter, and probably ash and sulfur that take place as coalification progresses from the lower-rank lignite through the higher ranks of sub-bituminous, high-volatile bituminous, low-volatile bituminous, and anthracite. The rank of a coal should not be confused with the grade of the coal (Table 2.6). A high rank (e.g., anthracite) represents coal from a deposit that has undergone the greatest degree of metamorphosis and contains minimal amounts of mineral matter (reflected as mineral ash in the combustion test) and moisture. On the other hand, any rank of coal, when cleaned of impurities through coal preparation will be of a higher grade.

2.3.4 Coal Survey

The use of coal as an essential fuel in Britain from the time of the Industrial Revolution has led to the development of a system of classification in which code numbers are used to denote the different types of coal. The coal survey system (developed by the National Coal Board of the United Kingdom) is based on the coke-forming characteristics of the various coals as well as on the types of coke produced by a standard of coking test (the Gray-King carbonization assay). The system also employs the amount of volatile matter produced thermally by the various types of coal (Table 2.7). In this classification system, a three-figure code number is used to describe each particular coal (Table 2.7) – the lower numbers are assigned to the higher rank coal, i.e., anthracite. However, because of the various divisions of this particular system, such approximations have to be made with extreme caution and with extremely careful cross-checking.

Although the English system does appear to have some merit because of the dependence on two simple physical parameters (i.e., the volatile matter content of the coal and the Gray-King carbonization assay), there are, nevertheless, disadvantages to the method, not the least of which is the susceptibility of the Gray-King assay data to oxidation (weathering) of the coal and, apparently, the time required to conduct the assay.

Table 2.6 Differentiation of coal rank, coal type, and coal grade.

Rank
• Indicative of the degree of metamorphism (or coalification) to which the original mass of plant debris (peat) has been subjected during its burial history.
• Dependent on the maximum temperature to which the *proto-coal* has been exposed and the time it has been held at that temperature.
• Also reflects the depth of burial and the geothermal gradient prevailing at the time of coalification in the basin concerned.
Type
• Indicative of the nature of the plant debris (*proto-coal*) from which the coal was derived, including the mixture of plant components (wood, leaves, algae) involved and the degree of degradation before burial.
• The individual plant components occurring in coal, and in some cases fragments or other materials derived from them, are referred to as *macerals*.
• The kind and distribution of the various macerals are the starting point for most coal petrology studies.
Grade
• Indicative of the extent to which the accumulation of plant debris has been kept free of contamination by inorganic material (mineral matter), before burial (i.e., during peat accumulation), after burial, and during coalification.
• A high-grade coal is coal, regardless of its rank or type, with a low overall content of mineral matter.

2.3.5 International System

The International System of coal classification came into being after the Second World War as a result of the greatly increased volume of trade between the various coal-producing and coal-consuming nations. This particular system, which still finds limited use in Europe, defines coal as two major types: hard coal and brown coal. For the purposes of the system, hard coal is defined as a coal with a calorific value greater than 10,260 Btu/lb (5700 kcal/kg) on a moist, but ash-free basis. Conversely, brown coal is defined as coal with a calorific value less than 10,260 Btu/lb (5,700 kcal/kg). In this system, the hard coals (based on dry, ash-free volatile matter content and moist, ash-free calorific value) are divided into groups according to their caking properties (Chapters 5, 6). These latter properties can be determined either by the free swelling test and the caking property is actually a measure of how a coal behaves when it is heated rapidly (Speight, 2013). The coal groups are then further subdivided into subgroups according to their coking properties (which may actually appear to be a paradox since the coking properties are actually a measure of how coal behaves when it is heated slowly).

Briefly, *coking coal* is a hard coal with a quality that allows the production of coke suitable to support a blast furnace charge. On the other hand, *steam coal* is all other hard coal not classified as coking coal. Also included are recovered slurries, middlings, and other

Table 2.7 National coal board (UK) system of coal classification.

Class	**Volatile matter* (% w/w)**	**Comments**	
101	< 6.1	Anthracite	
102	3.1 - 9.0		
201	9.1 - 13.5	Dry steam coal	Low volatile steam coal
202	13.6 - 15.0		
203	15.1 - 17.0	Cooking steam coal	
204	17.1 - 19.5		
206	19.1 - 19.5	Low volatile steam coal	
301	19.6 - 32.0	Prime cooking coal	Medium volatile coal
305	19.6 - 32.0	Mainly heat altered coal	
306	19.6 - 32.0		
401	32.1 - 36.0	Very strongly coking coal	High volatile coal
402	> 36.0		
501	32.1 - 36.0	Strongly coking coal	
502	> 36.0		
601	32.1 - 36.0	Medium coking coal	
602	> 36.0		
701	32.1	Weakly coking coal	
702	> 36.0		
801	32.1 - 36.0	Very weakly coking coal	
802	> 36.0		
901	32.1 - 36.0	Non-coking coal	
902	> 36.0		

*Volatile matter - dry mineral matter free basis. In coal, those products, exclusive of moisture, given off as gas and vapor determined analytically.

low-grade coal products not further classified by type. Coal of this quality is also commonly known as thermal coal.

A three-digit code number is then employed to express the coal in terms of this classification system. The first figure indicates the class of the coal, the second figure indicates the group into which the coal falls, and the third figure is the subgroup (Table 2.8). For example, by this system a 523 coal would be a class 5 coal with a free swelling index of 2.5 to 4 and an expansion (dilatation) falling in the range 0 to 50.

Table 2.8 Classification of coal by the International System.

Groups (determined by coking properties)			Code numbers										Subgroups (determined by coking properties)		
	Alternative group parameters		The first figure of the code number indicates the class of the coal, determined by volatile-matter content up to 33% volatile matter and by calorific parameter above 33% volatile matter. The second figure indicates the group of coal, determined by caking properties. The third figure indicates the subgroup, determined by coking properties.											Alternative subgroup parameters	
Group number	Free-swelling index (crucible-swelling number)	Roga index											Sub-group number	Audibert-Amu dilatometer	Gray-King
3	>4	>45					435	535	635				5	>140	$>G_g$
						334	434	534	634	734			4	>50–140	$G_3 – G_3$
						333	433	533	633	733			3	>0–50	$G_3 – G_3$
						332a 332b	432	532	632	732	832		2	=< 0	E–G
2	2 ½–4	>20–45				323	423	523	623	723	823		3	>0–50	$G_3 – G_4$
						322	422	522	622	722	822		2	=< 0	E–G
						321	421	521	621	721	821		1	Contraction only	B–D
1	1–2	>5–20			212	312	412	512	612	712	812		2	=< 0	E–G
					211	311	411	511	611	711	811		1	Contraction only	B–D

(*Continued*)

Table 2.8 Classification of Coal by the International System. (*Continued*)

Groups (determined by coking properties)			**Code numbers**											**Subgroups (determined by coking properties)**		
0	0–1/2	>0–5	000	100		200	300	400	500	600	700	800	900	0	Nonsoftening	A
				A	B											
Class number →			0	1		2	3	4	5	6	7	8	9	As an indication, the following classes have an approximate volatile-matter content of: Class 6: 33–41% volatile matter Class 7: 33–44% volatile matter Class 8: 35–50% volatile matter Class 9: 42–50% volatile matter		
Class parameters	Volatile matter (dry, ash-free) →		0–3	>3–10		>10–14	>14–20	>20–28	>28–33	>33	>33	>33	>33			
				>3-6.5	>6.5-10											
	Calorific parameter[a] →		—	—		—	—	—	—	>13,950	>12,960-13,950	>10,980-12,960	>10,260–10,980			
Classes: Determined by volatile matter up to 33% volatile matter and by calorific parameter above 33% volatile matter.																

[a] Gross calorific value on moist ash-free basis (86°F/96% relative humidity) Btu per pound.

Notes:

1. Where the ash content of coal is too high to allow classification according to the present systems, it must be reduced by laboratory float-and-sink method for any other appropriate means) The specific gravity selected for flotation should allow a maximum yield of coal with 5–10% of ash. 2. 323a > 14–16% volatile matter. 332b > 16–20% volatile matter.

Source: Considine (1977), pp. 1–23.

2.3.6 Coal as an Organic Rock

Coal, in the simplest sense, consists of vestiges of various organic compounds that were originally derived from ancient plants and have subsequently undergone changes in the molecular and physical structure during the transition to coal (Chapter 1) (Speight, 2013 and references cited therein).

Some mention will be made of the nomenclature and terminology of the constituent parts of coal, i.e., the lithotypes, the macerals, and the microlithotypes (Stopes, 1919, 1935; Spackman, 1958; Speight, 2013). It is unnecessary to repeat this discussion except to note that this particular aspect of coal science (petrography) deals with the individual components of coal as an organic rock whereas the nomenclature, terminology, and classification systems are intended for application to the whole coal. Other general terms that are often applied to coal include (i) coal rank and (ii) coal grade, which are employed to describe the particular characteristics of coal.

The kinds of plant material from which the coal originated, the kinds of mineral inclusions, and the nature of the maturation conditions that prevailed during the metamorphosis of the plant material give rise to different coal types. The rank of a coal refers to the degree of metamorphosis; for example, coal that has undergone the most extensive change, or metamorphosis, has the highest rank (determined from the fixed carbon or heating value (Chapters 1, 5, 6). The grade of a coal refers to the amount and kind of inorganic material (mineral matter) within the coal matrix (Chapter 1). Sulfur-containing organic structures are, perhaps, the most significant of the non-hydrocarbon constituents because of the potential to generate sulfur dioxide during combustion.

2.3.7 A Hydrocarbon Resource

There have also been attempts to classify coal as one of the hydrocarbon-type resources of the Earth (Figure 2.3) but the term *hydrocarbon* is used too loosely and extremely generally since coal is not a true hydrocarbon and contains atoms (nitrogen, oxygen, and sulfur) other than

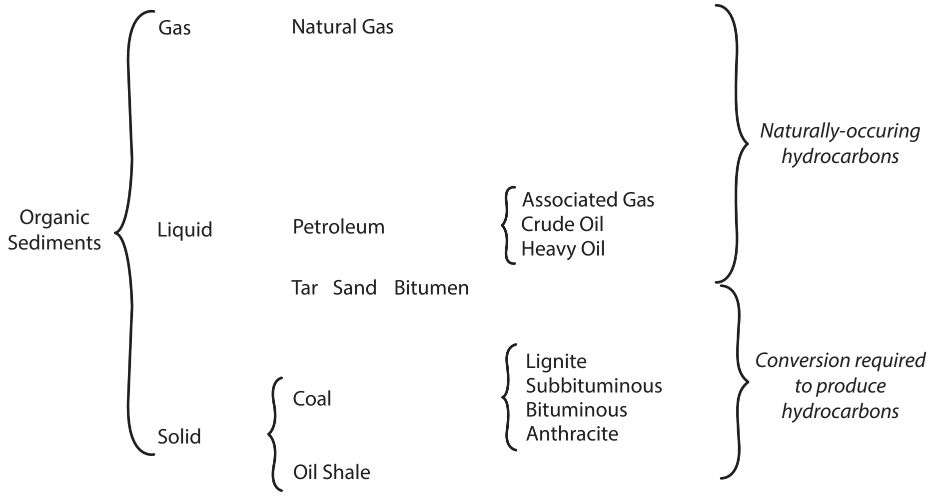

Figure 2.3 Classification of the various hydrocarbon and hydrocarbon-producing resources (Speight, 2013).

carbon and hydrogen – a hydrocarbon (by the true chemical definition) contains carbon and hydrogen only (Fessenden and Fessenden, 1990). Even crude oil, despite the errors of the general nomenclature, is not an assemblage of true hydrocarbon derivatives (because of the occurrence of nitrogen-containing, oxygen-containing, sulfur-containing, and metal-containing species) (Speight, 2014).

2.4 Coal Petrography

Coal is an extremely complex heterogeneous material that requires several parameters for chemical and physical characterization (Chapters 5, 6) – one single parameter is completely lacking for the true characterization of coal. However, the standard method of characterizing the organic (maceral) and the inorganic (mineral) constituents of coal is known as coal petrography (Speight, 2013 and references cited therein).

Coal petrography is the description of the components of coal as studied macroscopically and in thin and polished sections under the microscope. As the use of such methods became more common, coal petrography became concerned with the composition, structure, and origin of coals. In other words, it developed into the field of coal petrology. The principal task of coal petrology is the study of the elementary components of the organic matter of coal beds. These components are the remains of plants, which, in the process of biochemical decomposition into the peat stage of coal formation, lost or preserved to some extent their form and structure. A distinction is made here between the tissue elements and the matrix, which, taken together, constitute the components of coal. Also, macro-components, such as vitrain and fusain, are distinguished from micro-components, such as spores and cuticles.

Coal petrography employs various methods of investigation. In methods of optical microscopy, for example, the specimen may be viewed in air or in immersion; both transmitted-light and reflected-light methods are used, and the light may be ordinary, polarized, or ultraviolet. Specimens may be separated into groups of components of similar density in heavy liquids (mixtures, for example, of carbon tetrachloride tribromomethane). Depending on the source material and the conditions of the transformation of this material (in the so-called peat stage of coal formation) the micro-petrographic components are classified into three basic groups (vitrinite or gelinite, fusinite, and liptinite) (Table 2.9). The composition of the source plants and the quantitative relations between micro-petrographic components determine the genetic types of coal, which are characterized by definite chemical and technological properties within each stage of coalification.

Thus, coal petrology is the science in which coal type is related to the type of plant material in the peat and the extent of the biochemical and chemical alteration. Type can be assessed in terms of variety of petrographic analysis. Coal petrology is concerned with the origin, composition and properties of the distinct organic and inorganic components of different coals. To date, the principal practical application of coal petrology has been in the specification and selection of coals for carbonization (Speight, 2013 and references cited therein).

From the data obtained from coal petrology, the rank (defined by vitrinite reflectance) and composition (maceral proportions) of coal can be determined. Coal macerals are

Table 2.9 Nomenclature and Sub-division of the Various Maceral Groups.

Maceral group	Maceral	Origin
Vitrinite	Telinite	Humified plant remains typically derived from woody, leaf, or root tissue with well to poorly preserved cell structures
	Collinite	Humified material showing no trace of cellular structure, probably colloidal in origin
	Vitrodetrinite	Humified attrital or less commonly detrital plant tissue with particles typically being cell fragments
Liptinite (exinite)	Sporinite	Outer casing of spores and pollens
	Cutinite	Outer waxy coating from leaves, roots, and some related tissues
	Resinite	Resin filling in cells and ducts in wood; resinous exudations from damaged wood
	Fluorinite	Essential oils in part; some fluorinate may be produced during physicochemical coalification and represent nonmigrated petroleum
	Suberinite	Cork cell and related issues
	Bituminite	Uncertain but probable algal origin
	Alginite	Tests of some groups of green algae; material referred to alginate shows moderate to strong fluorescence
	Exudatinite	Veins of bitumen-related material expelled from organic matter during coalification
	Liptodetrinite	Detrital forms of liptinite that cannot be differentiated
Inertinite	Fusinite	Wood and leaf tissue oxidation
	Semifusinite	Wood or leaf tissue weakly altered by decay or by biochemical alteration
	Inertodetrinite	Similar to fusinite or semifusinite but occurring as small fragments
	Macrinite	Humic tissue probably first gelified and then oxidized by processes similar to those producing semifusinite
	Sclerotinite	Moderately relflecting tissue of fungal origin, largely restricted to Tertiary coals
	Micrinite	Largely of secondary origin formed by disproportionation of lipid of lipidlike compounds

optically homogenous, discrete microscopic constituents of the organic fraction of coal, and they constitute the building blocks of coal and are identified and classified on the basis of their morphology, source material, color/level of reflectivity, and nature of formation. Macerals differ because they represent different part of the plant material and microorganisms. From petrographic studies, coal is shown to comprise three main maceral groups: (i) the vitrinite group, (ii) the exinite group also known as the liptinite group, and (iii) the inertinite group.

2.4.1 Vitrinite Group

The maceral that fall into the *vitrinite group* are derived from the humification of woody tissues and can either possess remnant cell structures or be structureless. The structureless maceral could have resulted due to the degradation process that takes place during coal diagenesis. Chemically it is composed of natural (so-called) *polymers*, cellulose and lignin. Vitrinite has a shiny appearance resembling glass (vitreous).

The variation in vitrinite macerals is usually thought to be due to differences in the original plant material or to different conditions of alteration at the peat stage or during coalification. In this group, only three macerals are distinguished: (i) *telenite*, (ii) *collinite*, and (iii) *vitrodetrinite*. Vitrinite contains more oxygen than the other macerals at any given rank level and is prone to gas generation with densities ranging from 1.3 to 1.8 g/cm3 with a general tendency to increase with an increase in rank increases.

The telenite maceral came from different tree branches, trunks, stems, leaves and roots. The collinite maceral is formed from gel precipitated in humic solution obtained from humic particles that were degraded in the early stages of coalification. The vitrodetrinite maceral is also obtained from plants that were degraded from the early stages of coalification but this time around earlier than the stage in obtaining collinite. The concentration of hydrogen in this vitrodentrite is the range of 4.5 to 5.5%, w/w oxygen from 5 to 20% w/w, and carbon in the range of 75 to 95% w/w.

2.4.2 Liptinite Group

The members of the *liptinite group* are considered to originate from the resinous and waxy material of plants, including resins, cuticles, spores, pollen exines and algal remains. They tend to retain their original plant form, i.e., they resemble plant fossils, and are characterized by high reactivity and volatility, and are more aliphatic (Campbell *et al.*, 2010). The members of this maceral group can be distinguished from the members of the vitrinite group by higher hydrogen and lower oxygen content, and do have the highest calorific value of all coal macerals.

The liptinite group comprises the macerals which are (i) sporinite, (ii) cutinite, (iii) suberinite, (iv) resinite, (v) alginate, and (vi) liptodetrinite, which all appear to have resisted major changes during coalification as they are classified based on their respective fossil plant nature. The cuticles found in this maceral group came from the cuticles normally found in leaves and thin plant stems.

Sporinite is obtained from the waxy coating of fossil spores and pollen. These groups of macerals are the lightest, with their density ranging from 1.18 to 1.25 g/cm^3 and during devolatilization give a high yield of volatile matter, such as gas and volatile tar. The liptinite content is the least recognized of three maceral group because of the generally low content, which (in many international coals) may rarely exceed 7% v/v of the total maceral composition.

2.4.3 Inertinite Group

The members of the *inertinite group* are considered to be equivalent of charcoal and degraded plant material and originate from plant material, usually woody tissues, plant degradation products, or fungal remains. Inertinite macerals are characterized by high reflectance, as well as a distinct cell texture and are highly oxidized in nature with a high inherent carbon content that resulted from thermal or biological oxidation.

The inertinite group comprises the macerals (i) fusinite, (ii) semi-fusinite, (iii) macrinite, (iv) micrinite, (v) inertodetrinite, and (vi) scleronite. Fusinite originates from the oxidation of cellular woody tissues and they occur in varying quantities in peat, lignite and bituminous coals. Semi-fusinite is characterized by high reflectance and they are derived from cellular woody tissue as well. Inertodetrinite is derived from oxidized cell-wall fragments and they have reflectance that varies within broad limits, their reflectance being slightly higher than that of vitrinite and liptinite. They can almost be classified as non-reactive during carbonization and produces less volatile products during pyrolsis.

2.5 Correlation of the Various Systems

The above illustrations indicate that, with the exception of perhaps the geological classification and the banded structure classification system, coal classification can be a complex operation. While only the major classification systems (especially those relevant to the North American and British scenarios) have been illustrated in detail, there are, nevertheless, other systems which have in the past been used in various other countries. Indeed, these other systems for the classification of coal may still find use in the countries of their origin. No attempt has been made to illustrate these systems in the present context, but they are certainly very worthy of mention as an indication of the nomenclature and terminology applied to coals of the various types.

Currently, the class numbers derived by the International System of Coal Classification can be approximated to the coal rank derived by the ASTM system (Figure 2.4) except that the International System uses an ash-free calorific value while the ASTM system employs a mineral free calorific value, which could cause a slight discrepancy in the assignments (Speight, 2013). The error lies in the fact that the weight of ash obtained by ignition is not the same as the weight of the mineral impurities: present in the original coal. The expulsion of water of hydration from the clay and/or shale impurities and the expulsion of carbon

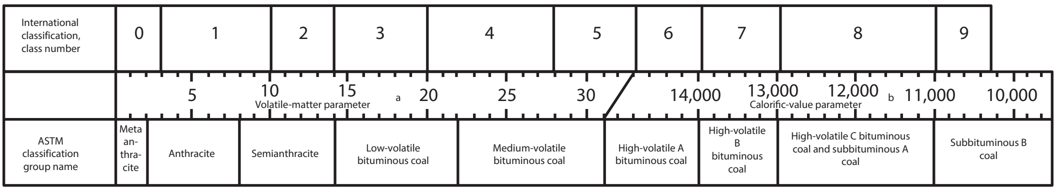

Figure 2.4 Comparison of class number (International System) with ASTM classification. Please note that (i) the parameters in the International System are on an ash-free Basis, ASTM parameters are mineral matter-free basis, mmf, (ii) there is no upper limit of calorific value for class 6 and high volatile bituminous coals (Speight, 2013).

dioxide from the carbonates introduce errors that are too large to be ignored. Consequently a number of correction formulas have been derived which assume that the percentage of mineral matter in coal is numerically equal to 108% of the amount of ash produced plus 55% of the amount of the sulfur. This latter value takes into consideration the conversion of iron pyrites to iron & oxide during the ashing procedure.

Brown coals, like the hard coals, are also defined in: terms of their calorific value (see above) and were also recognized as potential fuels. The International system for the classification of brown coals is based on two inherent characteristics which indicate the value of brown coals as fuels: (i) the total moisture that is determined on an ash-free basis, often represented as *af*, and (ii) the yield of tar that is determined on a dry-ash-free basis, often represented as *daf*. Thus, the six classes of brown coal based on the ash-free, equilibrium moisture content are divided into groups according to the yield of tar on a dry, ash-free basis. This system indicates the value of the brown coals either as a fuel or as a chemical raw material with the notation that brown coals with a propensity to produce high yields of thermal tar have found more general use in the chemical industry rather than as a fuel.

Critics of the International System note that the parameters used (as well as in some other national systems) to define degree of coalification (rank), i.e., volatile matter and calorific value, are dependent on variable maceral composition. On the other hand, the parameters used in the International Classification to determine the agglutinating and coking properties of coals are competing parameters, instead of following a hierarchy. In order to circumvent such conflicts classification scheme has been proposed which is based on two primary parameters determined with microscopic techniques: (i) mean maximum reflectance of vitrinite, which is a good single measure of rank, and (ii) petrographic composition – vitrinite and exinite – as an indication of the type of coal (Chapters 5, 6).

Vitrinite content – determined by vitrinite reflectance – is, in fact, an important rank parameter that is useful in the characterization of coking coal and may even be applicable to coal combustion during storage (Chapter 4) and in a power plant Chapter 7). The analytical technique is sensitive, persistently changing throughout coalification and is particularly important for accurately measuring minor differences in those coals used for coke making, i.e., high volatile A bituminous through low volatile bituminous. The technique measures the amount of incident light reflected from a polished surface of the main component of coal, vitrinite. Vitrinite is that component of coal principally derived from woody tissues and, at least in coals from North America, represents the dominant component.

A third parameter is chosen to qualify the different classes of coal: volatile matter for anthracitic coals; dilatation for semi-anthracite and bituminous coals; and calorific value for subbituminous coal and lignite. The scheme is expressed by mean of a code number of four digits, which refers to the rank (first digit), type (second and third digits) and qualification (fourth digit) of coal (Uribe and Pérez, 1985).

Even though there have been serious, and successful, attempts to define coal by means of a variable series of classification systems, there is now, in the modern world, a potential lapse in the information. And that relates to the environmental issues. Other than comparing data (such as is provided by elemental analyses) (Speight, 2013, 2015), there is no other means by which the potential environmental liability of coal usage can be determined. Nor, for that matter, might there ever be; but such a possibility is always worthy of consideration

Table 2.10 Comparison of Various Coal Classification Systems.

Classes of the International System			Classes of national systems							
	Parameters									
	Volatile matter content	Calorific value (calculated to stand moisture content)	Belgium	Germany	France	Italy	Netherlands	Poland	United Kingdom	United States
0	0–3		Maigre	Anthrazit	Anthracite	Antraciti speciali	Antraciet	Meta-antracyt	Anthracite	Meta-anthracite
1A	3–6,5					Antraciti comuni		Antracyt		Anthracite
1B	6,5–10							Polantracyt		
2	10–14		1/4 gras	Magerkohle	Maigre	Carboni magri	Mager	Chudy	Dry steam	Semianthracite
3	14–20		1/2 gras 3/4 gras	Esskohle	Demi gras	Carboni semi-grassi	Esskool	Polkoksowy Metakoksowy	Coking steam	Low volatile bituminous
4	20–28			Fettkhole	Gras a courte flamme	Carboni grassi corta flamma	Vetkool	Ortokoksowy	Medium volatile coking	Medium volatile bituminous
5	28–33			Gashkohle	Gras proprement dit	Carboni grassi media flamma		Gazowokoksowy	High volatile	High volatile bituminous A
6	> 33 (33–40)	8450–7750				Carboni da gas	Gaskool			High volatile bituminous B
7	> 33 (32–44)	7750–7200		Gas Flammakohle	Flambant gras	Carboni grassi da vapore	Gasvlamkool	Gazowy		High volatile bituminous C
8	> 33 (34–46)	7200–6100			Flambant sec	Carboni secchi	Vlamkool	Gazowoplomienny		
9	> 33 (36–48)	< 6100						Plomienny		Subbituminous

Source: van Krevelen and Schuyer (1957).

as coal science and technology evolves and moves into the era of clean coal technology (Speight, 2013).

Finally, it is difficult (if not impossible) to treat coal classification and coal terminology as separate entities. Indeed, the terms applied to the various coals as a result of a particular classification system invariably displace some of the older and less specific names of the coals. Thus, because of the various systems which have originated in the coal-producing (as well as the coal-consuming) nations, several names may have evolved for one) particular type of coal (Table 2.10).

Such a profusion of names can make cross-referencing very difficult and it is beneficial for the coal scientist to become as familiar as possible with the various terminologies that exist. The only means by which this problem could be alleviated would be the establishment of a truly international; system for the classification and nomenclature of coal.

In summary, all classification schemes have similar objectives. However, a classification system meant exclusively for combustion application (such as coal-fired power generation) does not exist and is unlikely to be developed with the present approaches. Many classification schemes are restricted to two or three coal (typically less than six properties) properties and so the picture of the suitability of coal for a power plant may not be complete. If too many properties are involved, the classification can become complicated (if not, confusing). In general, rank, calorific value, proximate and ultimate analyses, fuel and atomic ratios and petrography seem to be the most important variables for characterizing the behavior of coal during combustion. Such properties are highly interrelated. It may be possible to develop a classification system using all these properties and still achieve a reasonably simple grouping – to this end principal component analysis may offer a solution under certain conditions. However, the choice of the variables will be critical and the outcome is to determine if the methodology and the analysis can be repeated satisfactorily for other combinations of variables.

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3

Recovery, Preparation, and Transportation

3.1 Introduction

Coal is composed of complex mixtures of organic and inorganic compounds (Chapter 1) and must be handled in the correct manner to prevent accidents and spontaneous ignition as well as spontaneous combustion (Chapters 1, 4, 5) (Speight, 2013; CFR, 2012; Speight, 2020).

The organic compounds, inherited from the plants that live and die in the swamps cannot be counted with even a minute degree of accuracy. On the other hand, the more than 100 inorganic compounds in coal either were introduced into the swamp from water-borne or wind-borne sediment or were derived from elements in the original vegetation; for instance, inorganic compounds containing such elements as iron and zinc are needed by plants for healthy growth. After the plants decompose the inorganic compounds remain in the resulting peat. Some of those elements combine to form discrete minerals, such as pyrite (FeS_2). Other sources of inorganic compounds used by the plants may be the mud that coats the bottom of the mire, sediments introduced by drainage runoff, dissolved elements in the mire water, and wind-borne sand, dust, or ash.

Coal may contain elements in only trace amounts (on the order of parts per million). Occasionally, some trace elements may be concentrated in a specific coal bed, which may make that bed a valuable resource for those elements (such as silver, zinc, or germanium). Some elements, however, have the potential to be hazardous (for example, cadmium or selenium), particularly if they are concentrated in more than trace amounts. Although as many as 120 different minerals have been identified in coal, only approximately 33 of these minerals commonly are found in coal, and, of these, only approximately eight minerals are sufficiently abundant to be considered major constituents.

When coal is combusted, as in a coal-fired power plant to generate electricity, most of the mineral matter and trace elements generally form ash. However, some minerals break down into gaseous compounds, which go out through the furnace flue. Pyrite, for example, breaks down into the individual elements iron and sulfur and each element combines with oxygen to become, respectively, iron oxide and an oxide of sulfur – the sulfur oxides are emitted in the flue gases while the iron oxide become part of ash.

$$FeS_2 \rightarrow Fe + 2S$$

$$2Fe + O_2 \rightarrow 2FeO$$

$$S + O_2 \rightarrow SO_2$$

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In some highly oxidative conditions, ferric oxide (Fe_2O_3) may be formed.

Some trace elements also dissociate from their organic or mineral hosts when coal is burned – most become part of the ash, but a few of the more volatile elements, such as mercury and selenium, may be emitted in the flue gas.

The term *coal quality* is used to distinguish the range of different commercial steam coals that are produced directly by mining or are produced by coal cleaning (Speight, 2013). The factors considered in judging the quality of a coal are based on, but not limited to, (i) heat value, (ii) moisture content, (iii) mineral matter content, reflect as mineral ash after combustion, (iv) fixed carbon, (v) sulfur content, (vi) the content of major, minor, and trace elements, (vii) the coking properties, (viii) the petrologic properties, and (ix) the organic constituents considered both individually and in groups. The individual importance of these factors varies according to the intended use of the coal. These properties are determined in the United States according to standards established by the standard test methods developed and published by the ASTM International (formerly the American Society for Testing and Materials, ASTM) and are usually denominated in English units (e.g., Btu/lb for heating value on a mass basis) (ASTM, 2020).

As a side note at this point, in addition to the difference in heating value (i.e., Btu/lb), electricity generating units fueled with subbituminous and lignite coals tend to operate at lower efficiency (higher heat rate) than units fueled with bituminous coal. This can lead to differences in generating capacity when using different coals.

Generally, coal quality for steam coals (i.e., coal used for electricity generation) refers to differences in heating value (Btu/lb) and sulfur content (% w/w) although other characteristics such as grindability or ash fusion characteristics are also specified in coal sale agreements. While not as obvious as the impact of sulfur content on environmental emissions, differences in the moisture content and heating values among different coal types affect the emissions of carbon dioxide upon combustion, with higher-rank bituminous coals producing 7 to 14% lower emissions than subbituminous coals on a net calorific value basis (NRC, 2007).

Coal quality is now generally recognized as having an impact, often significant, on coal combustion, especially on many areas of power plant operation (Leonard, 1991). The parameters of rank, mineral matter content (ash content), sulfur content, and moisture content are regarded as determining factors in combustibility as it relates to both heating value and ease of reaction. In addition, although not always recognized as a form of cleaning or beneficiation, the size of the coal can also make a difference to its behavior in combustion (power plant) operations. Hence, the need for one, or more, forms of cleaning (pretreatment) prior to use.

Thus, run-of-mine coal (i.e., coal taken straight from the mine) is dirty and contains impurities that are not a part of the organic coal matrix. Part of this problem arises from the composition of coal while another part arises as a result of the inclusion of rock into the coal during mining operations.

Furthermore, uncertainty in the availability and transportation of fuel necessitates storage and subsequent handling of coal. Maintaining an available supply of coal at the mine site or, more appropriately at the power plant, has the advantage of availability when supply disruption occurs and tends to overcome the perceived disadvantages of build-up of inventory – space constraints, deterioration in quality, and potential fire hazards. Other minor losses associated with the storage of coal include oxidation (leading to spontaneous ignition and property changes), wind and ground loss. It is also worthy of note that a 1% oxidation of coal has the same effect as 1% mineral matter in coal and wind losses may account for nearly 0.5 to 1.0% of the total loss.

The main goal of good coal storage is to minimize ground loss and the loss (with the associated danger) due to spontaneous combustion. Formation of a soft carpet, comprising coal dust and soil causes ground loss (also referred to as *carpet loss*). On the other hand, gradual temperature builds up in a coal heap, on account of oxidation and may lead to spontaneous combustion of coal in storage. The measures that would help in reducing the carpet losses are (i) preparing a hard ground for coal to be stacked upon, and (ii) preparing standard storage bays out of concrete and brick. In process industry, modes of coal handling range from manual to conveyor systems and are designed according to the differences in the properties of the coal (Narasiah and Satyanarayana, 1984). It is often advisable to minimize the handling of coal so that further generation of fines and segregation effects (due to coal size) are reduced.

But before the issues regarding stockpiling of coal are presented (below) it is necessary to consider the means of recovery of coal (aka, coal mining).

3.2 Coal Recovery

Recovery of coal (*coal mining*, *coal recovery*) is the act of removing coal from the ground and has been practiced throughout history in various parts of the world and continues to be an important economic activity (NRC, 2007; Speight, 2013, 2020).

A modern coal mine is a highly mechanized industrial plant that has to meet strict standards of engineering design and operation. The size, power, strength, monitoring and control features, and automation of mining equipment dwarf those of even a few decades ago. The overall coal mining process consists of several sequential stages: (i) exploration of a potentially economic coal seam to assess minable reserves, environmental issues, marketable reserves, potential markets, and permitting risks, (ii) analysis and selection of a mining plan, (iii) securing the markets, (iv) developing the mine, (v) extracting the coal, (vi) processing the coal if necessary, and (vii) decommissioning the mine and releasing the property for post-mining use.

The uncertainties concerning resource and reserve estimates also apply to the grade or quality of the coal that will be mined in the future. At present, it is difficult to project spatial variations of many important coal quality parameters beyond the immediate areas of sampling (mostly drill samples). Almost certainly, coals mined in the future will be lower quality because current mining practices result in higher-quality coal being mined first, leaving behind lower-quality material (such as coal with a higher mineral content leading to higher yields of combustion ash yield, higher sulfur emissions, and/or higher concentrations of potentially harmful elements. The consequences of relying on poorer-quality coal for the future include (i) higher mining costs, such as the need for increased tonnage to generate an equivalent amount of energy, greater abrasion of mining equipment, (ii) transportation challenges, such as the need to transport increased tonnage for an equivalent amount of energy, (iii) beneficiation challenges, such as the need to reduce ash yield to acceptable levels, the creation of more waste, (iv) pollution control challenges, such as capturing higher concentrations of particulates, sulfur, and trace elements; dealing with increased waste disposal, and (v) environmental and health challenges. Improving the ability to forecast coal quality will assist with mitigating the economic, technological, environmental, and health impacts that may result from the lower quality of the coal that is anticipated to be mined in the future (NRC, 2007).

Furthermore, coal seams are located in a variety of geologic settings and their characteristics, including variability in thickness and continuity, can differ markedly from basin to basin. Therefore, any definition of geological reliability (measured, indicated, and inferred) that is intended for the entire country or for any specific region is not as precise as a system that takes into account the geological differences between regions and between coals of different geological ages. Thus, the two essential requirements that must be fulfilled before a prospective coal mine can enter the development stage are confirmation that there are (i) sufficient minable reserves of adequate quality with no unacceptable environmental or permitting risks, and (ii) confirmation of an assured or contracted market for a substantial fraction of the coal that will be mined.

Early coal mining (i.e., the extraction of coal from the seam) was small-scale, the coal lying either on the surface, or close to the surface. Typical methods for extraction included drift mining and bell pits. In Britain, some of the earliest drift mines (in the Forest of Dean) date from the medieval period. As well as drift mines, small-scale shaft mining was used. This took the form of (i) a bell pit mining technique in which the extraction of the coal worked outward from a central shaft, or (ii) the room and pillar mining technique in which rooms of coal were extracted with pillars left to support the roofs. Both of these techniques, however, left a considerable amount of usable coal behind.

Deep shaft mining started to develop in England in the late 18th century, and rapid expansion occurred throughout the 19th century and early 20th century. The English counties of Durham and Northumberland were the leading coal producers and they were the sites of the first deep pits. Before 1800, a great deal of coal was left in places as support pillars and, as a result in the deep pits (300 to 1,000 ft. deep) of these two northern counties (i.e., Durham and Northumberland) only approximately 40% w/w of the coal could be extracted. The use of wood props to support the roof was an innovation first introduced in 1800. The critical factor was circulation of air and control of explosive gases. In the current context, coal mining depends on the following criteria (i) the thickness of the seam, (ii) the thickness of the overburden thickness, (iii) the ease of removal of the overburden by surface mining, (iv) the ease with which a shaft can be sunk to reach the coal seam for underground mining, (v) the amount of coal extracted relative to the amount that cannot be removed, and (vi) the market demand for the coal.

It is important to recognize that coal quality control begins at the mine. The mining engineer is responsible for developing the mining plan, monitoring production, and managing operations. One objective of any mining plan is to maximize recovery of the deposit of suitable quality coal. This is an economic issue – it is cost effective to retrieve as much of a given resource that is economically possible. Mine development has sunk costs that should be spread over as much coal as possible. There are economic *cut-off* parameters that impact the mine plan. For open cast mines, the issues include strip ratios, how much overburden or interburden must be removed to expose a given quantity contained in a coal seam.

For underground mines, it can be parameters such as (i) the seam height, (ii) the pitch of the seam, (iii) the depth of the seam, and (iv) the roof stability.

Mine plans recognize the spatial attributes of coal quality; some seams will be better than others. As a result, the plan will typically manage mining areas to balance coal quality. Mining only the highest quality seams at the outset will truncate the life of the mine. Coal quality for any given mine can also change over time, as lower seams are used or new areas exposed. Long-term relationships with a mine should recognize how quality can change and continue to be vigilant, rather than complacent.

Exploration for coal is emerging as a future potential source for thermal coal. The process involves discovering new regions and extracting coal economically from earth. Various coal mining techniques include underground coal mining, surface coal mining and mountain top removal method (Speight, 2013).

The most economical method of coal extraction from coal seams depends on the depth and quality of the seams, the geology of the deposit, and environmental factors. Coal mining processes are differentiated by whether they operate on the surface or underground. Coal-mining operations can be described under three main headings (i) underground or deep mining, in which the coal is extracted from a seam without removal of the overlying strata, (ii) surface mining, in which the strata – the overburden – overlying the coal seam are first removed after which the coal is extracted from the exposed seam or partially covered seam.

Each mining technique has its own individual merits and the method eventually employed to extract the coal and the technical and economic feasibility of coal recovery are based on (i) the regional geologic conditions, (ii) the overburden characteristics, (iii) the continuity of the coal seam, (iv) the thickness of the coal seam, (v) the structure of the coal seam, (vi) the quality of the coal seam, (vii) the depth of the coal seam, (viii) the strength of the strata above and below the coal seam for roof and floor conditions, (ix) the topography – especially altitude and slope, (x) the climate, (xi) the ownership of the land as it affects the availability of land for access and subsequent mining, (xii) the surface drainage patterns, (xiii) the groundwater conditions, (xiv) the availability of labor and materials, (xv) the requirements of the coal purchaser in terms of tonnage, quality, and destination, and (xvi) the capital investment requirements (Cassidy, 1973; Lindberg and Provorse, 1977; Martin, 1978).

There are two predominant types of mining methods that are employed for coal recovery: (i) surface mining methods, in which the strata (overburden) overlying the coal seam are first removed, after which the coal is extracted from the exposed seam, and (ii) underground mining methods which currently account for recovery of approximately 60% w/w of the available coal for use.

3.2.1 Surface Mining

Surface mining is the application of coal removal methods to reserves that are too shallow to be developed by other mining methods (i) the open pit method and (ii) the drift mine method. Relatively shallow coal deposits are generally extracted by surface mining, and deeper deposits are extracted by underground mining. There are also situations in which a seam is mined by surface methods first, and then if adequate reserves are still available, the mine is developed for underground extraction. Where remaining reserves are limited, other methods of mining—such as auger mining or highwall mining—may be used.

Surface mining developed as a natural extension of the early mining techniques by which man recovered coal from a seam. In the early stages, the recovered coal would come from exposed ledges or outcrops. In time, this supply would be exhausted and the earth would be scraped away to lay bare more of the seams that led to these outcroppings, thereby exposing even larger amounts of coal. However, as the overburden to be removed became too much for the primitive equipment then in use, the workings would be abandoned and fresh outcrops sought.

Typically, seams relatively close to the surface, at depths less than approximately 200 feet, are surface mined. Coal that occurs at depths of 200 to 300 feet is usually deep mined but, in some cases, surface mining techniques can be used. For example, some coal in the western United States (such as coal in the Powder River basin of Wyoming) that occur at depths in excess of 200 feet are mined by open pit methods – the thickness of the seam (60 to 90 feet) renders the method economically feasible.

In surface mining, or strip mining, earth-moving equipment is used to remove the rocky overburden and then huge mechanical shovels scoop coal up from the underlying deposit (Speight, 2013). The modern coal industry has developed some of the largest industrial equipment ever made, including shovels (part of a piece of equipment known as a dragline) capable of holding in excess of 300 tons of coal.

To reach the coal, bulldozers clear the vegetation and soil. Depending on the hardness and depth of the exposed sedimentary rocks, these rocky layers may be shattered with explosives. To do this, workers drill *blast holes* into the overlying sedimentary rock, fill these holes with explosives, and then blast the overburden to fracture the rock. Once the broken rock is removed, coal is shoveled from the underlying deposit into giant earth-moving trucks for transport.

The characteristic that distinguishes *open pit mining* is the thickness of the coal seam insofar as it is virtually impossible to backfill the immediate mined out area with the original overburden when extremely thick seams of coal are involved. Thus, the coal is removed either by taking the entire seam down to the seam basement (i.e., floor of the mine) or by benching (the staged mining of the coal seam). Frequent use is made of a *drift mine* in which a horizontal seam of coal outcrops to the surface in the side of a hill or mountain, and the opening into the mine can be made directly into the coal seam. This type of mine is generally the easiest and most economical to open because excavation through rock is not necessary.

Another surface mine is a *slope mine* in which an inclined opening is used to trap the coal seam (or seams). A slope mine may follow the coal seam if the seam is inclined and outcrops, or the slope may be driven through rock strata overlying the coal to reach a seam that is below drainage. Coal transportation from a slope mine can be by conveyor or by track haulage (using a trolley locomotive if the grade is not severe) or by pulling mine cars up the slope using an electric hoist and steel rope if the grade is steep. The most common practice is to use a belt conveyor where grades do not exceed 18°. On the other hand *contour mining* prevails in mountainous and hilly terrain, taking its name from the method in which the equipment follows the contours of the earth.

Auger mining is frequently employed in open pit mines where the thickness of the overburden at the high-wall section of the mine is too great for further economic mining.

This, however, should not detract from the overall concept and utility of auger mining as it is also applicable to underground operations. As the coal is discharged from the auger spiral, it is collected for transportation to the coal preparation plant or to the market. Additional auger lengths are added as the cutting head of the auger penetrates further under the high wall into the coal. Penetration continues until the cutting head drifts into the top or bottom, as determined by the cuttings returned, into a previous hole, or until the maximum torque or the auger is reached.

In general, surface mining has many advantages compared to underground mining. In general, coal recovery is high (85 to 90%+ w/w of the available coal), compared to 40 to 70% w/w of the available coal in underground seams. Also, health and safety statistics for surface mining are also generally better than those of underground mining. Surface-mined coal from the Powder River Basin (Wyoming) is usually simply sized and screened in preparation for market, whereas underground-mined coal and surface-mined coal from the Interior and Appalachian basins often requires a greater amount of processing (see below) to improve its marketability. The cost per ton of mining coal by surface methods is generally lower than that by underground methods.

3.2.1.1 Strip Mining

Strip mining is a method of coal recovery in which the coal seam is exposed by removing the overburden (the earth above the coal seam) in long cuts or strips. The soil from the first strip is deposited in an area outside the planned mining area. Spoil from subsequent cuts is deposited as fill in the previous cut after coal has been removed.

Although certain coal deposits can be strip-mined without the use of explosives, some means of breaking the overburden is often necessary. This is usually accomplished by drilling horizontal or vertical blast holes (up to 14 inches in diameter) into the overburden whereupon explosive charges are employed to break the rock fragments for subsequent easy removal. This latter part of the operation can be achieved either by the use of a dragline, power shovel, excavators, bucket wheels, and trucks (Speight, 2013).

The overburden is then removed to a previously mined (and now empty) strip. When all the overburden is removed, the underlying coal seam will be exposed. The exposed coal (usually referred to as a *block of coal*) may be drilled and blasted (if hard) or otherwise loaded onto trucks or conveyors for transport to the coal preparation (or wash) plant. Once this strip is empty of coal, the process is repeated with a new strip being created next to it. This method is most suitable for areas with flat terrain.

The removed overburden (*spoil*) may, at some future time, be returned to the mined out areas and, in fact, legislators in the various countries where strip mining is in operation are seriously considering the passage of laws relating to the return of mine spoil to mined out areas so that the land can be restored for future productivity. On the other hand, caution is advised for such ventures since there are also laws which prohibit the "injection" or "burial" of any material that is not indigenous to the particular formations. Whilst mine spoil might be cited as being indigenous to the geologic formation from which it came, the effects of weathering (oxidation) and the interaction with acid materials (acid rain) must be given considerations and the extent of any chemical changes should be determined prior to return to the ground. It only takes one failure, or adverse environmental effect, to doom a concept to extinction.

3.2.1.2 Open Pit Mining

The characteristic that distinguishes this type of mine is essentially the thickness of the coal seam insofar as it is virtually impossible to backfill the immediate mined out area with the original overburden when extremely thick seams of coal are involved. Thus, the coal is removed either by taking the entire seam down to the seam basement (i.e., floor of the mine) or by benching. This latter technique involves the staged mining of the coal seam and has been employed with considerable success not only in many coal mines but also for the mining of the Athabasca oil sand deposits in northern Alberta (Canada), where the tar sand pay zone (ore body) may be some 200 feet (60 m) deep (Speight, 1990, 2013, 2020). If, however, significant parting exists on the floor of the mine from where the coal has recently been removed, this immediate worked out section will not be available for receipt of the overburden and in such a case the overburden may have to be transported from the area.

Frequent use is made of a *drift mine* in which a horizontal seam of coal outcrops to the surface in the side of a hill or mountain, and the opening into the mine can be made directly into the coal seam. This type of mine is generally the easiest and most economical to open because excavation through rock is not necessary.

3.2.1.3 Contour Mining

Contour mining occurs on hilly or mountainous terrain, where workers use excavation equipment to cut into the hillside along its contour to remove the overlying rock and then mine the coal. The depth to which workers must cut into the hillside depends on factors such as hill slope and coal bed thickness. For example, steeper slopes require cutting away more overburden to expose the coal bed.

The contour mining method consists of removing overburden from the seam in a pattern following the contours along a ridge or around a hillside and prevails in mountainous and hilly terrain. If a coal seam is visualized as lying level at an elevation of 100 feet above sea level, and the land surface elevation varies from 600 to 1400 feet above sea level, a contour-stripping situation exists. Mining commences where the coal and surface elevations are the same (the crop line) and proceeds around the side of the hill on the crop line elevation.

The earth (overburden) overlying the coal may be removed by shovel, dragline, scraper, or bulldozer, depending on the depth and overburden character. The overburden is cast (spoiled) downhill from this first pit, after which the exposed coal is then loaded into trucks and removed from the pit. A second pit can be excavated by placing the overburden from it into the first pit.

Succeeding pits, if any, would follow in the same sequence, with the amount of overburden increasing for each succeeding pit until the economic limit of the operation, or the maximum depth limit of the overburden machine, is reached. This economic limit is determined by many variables, some of which are thickness of the coal seam, quality, and marketability of the coal, nature of the overburden, capabilities of the equipment, and reclamation requirements.

The practice of depositing the spoil on the downslope side of the bench thus created has, for the most part, been terminated because the spoil consumed much additional land and created severe landslide and erosion problems. To alleviate these problems, a variety of methods were devised to use freshly cut overburden to refill mined-out areas. These haul-back or lateral movement methods generally consist of an initial cut with the spoil deposited downslope or at some other site and spoil from the second cut refilling the first. A ridge of undisturbed natural material is often left at the outer edge of the mined area to add stability to the reclaimed slope by preventing spoil from slumping or sliding downhill.

Once the hill slope prevents further cutting into the hillside, miners often switch to a technique known as *auger mining* to extract more coal along the contour.

3.2.1.4 Auger Mining

Auger mining is analogous to wood drilling; the coal is extracted from a seam (which outcrops to the surface) by the use of large-diameter augers.

This particular method for the recovery of coal was developed mainly in the period following World War II. An attractive aspect of the method is the relatively low cost of the equipment since the technique essentially involves boring a series of parallel horizontal holes into a coal seam.

The technique is frequently employed in open pit mines where the thickness of the overburden at the high-wall section of the mine is too great for further economic mining. This, however, should not detract from the overall concept and utility of auger mining as it is also applicable to underground operations. As the coal is discharged from the auger spiral, it is collected for transportation to the coal preparation plant or to the market.

In this technique, the miners drill a series of horizontal holes into the coal bed with a large auger (drill) powered by a diesel or gasoline engine. These augers are typically approximately 200 feet long and drill holes between 2 and 7 feet in diameter to depths of up to 300 feet in the coal seam and the coal is moved out as the drill turns farther into the seam. As these enormous drills bore into the coal seam, they discharge coal like a wood drill producing wood shavings.

Additional auger lengths are added as the cutting head of the auger penetrates further under the high wall into the coal. Penetration continues until the cutting head drifts into the top or bottom, as determined by the cuttings returned, into a previous hole, or until the maximum torque or the auger is reached. Penetration in an auger operation may vary from a few feet up to 200 feet, depending on the pitch of the coal seam, the seam thickness, and the physical characteristics of the strata immediately above the coal seam. The better the roof strata and the more level the coal seam, the deeper the penetration.

3.2.1.5 Mountain Top Removal

Mountaintop removal/valley fill coal mining is, as the name implies, the removal of mountain top to recover coal from the seam(s) underneath. In the method, power shovels are used to dig into the soil for trucks to haul away, after which a dragline is used to dig into the rock to expose the coal – explosives may also be used to make the overburden more amenable to removal. Other machines scoop out the layers of coal.

Unfortunately, the mountaintop method generates large amounts of solid waste that must be disposed in a sound environmental manner. Association of the waste with water (through heavy rains or river flooding) can cause the waste to move as a live mud stream causing serious environmental damage and danger to flora and fauna (including human life).

3.2.2 Underground Mining

To reach deeper coal beds, miners typically dig underground mines. Two or more shafts are tunneled down into a coal seam – typically, different shafts are used for the passage of miners and machinery and for the passage of mined coal. There are three types of underground mines: (i) shaft mine, (ii) slope mine, and (iii) drift mine. The type excavated in a particular case depends on the depth of the coal deposit, the angle of the coal bed, and the thickness of the coal seam.

A *drift mine* is one in which a horizontal (or nearly horizontal) seam of coal outcrops to the surface in the side of a hill or mountain, and the opening into the mine can be made directly into the coal seam. Thus, drift mines are used in cases where a coal seam outcrops on a hill or mountainside. A drift mine consists of a single passageway that follows the coal seam back into the mountain. Drift mines eliminate the need to tunnel through overlying rock to reach a coal deposit.

In the drift mine, mining is conducted using typically either longwall mining or room and pillar mining with continuous mining equipment. Coal is transported to the surface by conveyor belts. This method of mining is used when the coal seam outcrops at the surface, or when a bench has to be constructed on a mountain side to mine the coal. This type of mine is generally the easiest and most economical to open because excavation through rock is not necessary.

A *slope mine* is a mine in which an inclined opening is used to trap the coal seam (or seams). The mine opening is made by tunneling from the surface down to the elevation of the coal seam. Mining is conducted using typically either longwall mining or room and pillar mining with continuous mining equipment. Coal is transported to the surface by conveyor belts. This method of mining coal is usually utilized when the coal seam is not far from the surface, and the outcrop of the coal seam is not exposed. A slope mine may follow the coal seam if the seam is inclined and outcrops or the slope may be driven through rock strata overlying the coal to reach a seam which is below drainage.

Generally, the slope mines have not been under as much cover as shaft mines but, with the application of rock-tunneling machines, slopes can be extended to deeper coal seams. Coal transportation from a slope mine can be by conveyor or by track haulage (using a trolley locomotive if the grade is not severe) or by pulling mine cars up the slope using an electric hoist and steel rope if the grade is steep. The most common practice is to use a belt conveyor where grades do not exceed 18°.

A *shaft mine* enters the coal seam by a vertical opening from the surface. Shaft mines are dug to reach deep coal beds, usually at least 660 feet (200 meters) or more below the surface. A shaft mine uses two vertical shafts to reach the coal bed. Slope mines reach coal deposits that have been distorted or tilted by shifts in the crust of the Earth. A slope mine uses two angled shafts to reach the coal bed. The passageways of a slope mine typically begin where the inclined coal bed outcrops on the surface and follow the incline into the ground. Some slope mines angle down through the overburden to reach the sloping coal bed, then parallel the bed into the earth. If the grade of the slope mine passageway does not exceed 18°, the coal is usually transported from the mine by conveyor. For steeper grades, coal is typically removed by trolley or mine cars.

In both slope and shaft mines, ground support at the opening is dependent on several factors, such as the dimensions of the mine entry, the intended lifetime and use of the mine, the water, and climatic conditions, as well as the nature of the exposed strata. In slope mines, it is common practice to use rock bolting only when the exposed rock tends to fragment but is otherwise sturdy; the general practice is to cover the sides and roof of the slope with a thin coating of cement sprayed on to say, a wire mesh. If the ground is *heavy* (badly fractured or overstressed), it may be necessary to support the slope with a poured concrete lining; the prevailing practice in shaft mines is to use such a concrete lining.

Once a coal deposit has been reached by a slope mine, or a drift mine, workers mine the coal by one of two methods the *room-and-pillar* method or the *longwall* method. Room-and-pillar mines extract coal at greater depths and are usually left standing when the mine is abandoned. Longwall mines are used at shallower depths and are allowed to collapse as the mine progresses.

Miners use two processes, known as *conventional mining* and *continuous mining*, to remove coal from room-and-pillar underground mines. Conventional coal mining replaced hand mining (mining with pick and shovel) in the 1930s (Speight, 2013).

In spite of modern innovations, mining remains a hazardous occupation because of roof (amongst other issues) instability and gas evolution from the coal seams (Speight, 2013).

3.2.3 Mine Decommissioning and Closure

In the United States, federal regulations for decommissioning and closure of mining operations are administered by the Mine Safety and Health Administration (MSHA), the Office of Surface Mining Reclamation and Enforcement (OSM), and the Environmental Protection Agency (EPA) – in some cases state and local governments have additional requirements.

The major decommissioning and closure activities are: (i) sealing of all access to underground mine areas, (ii) removal of all surface facilities, and (iii) reclamation of surface mine areas that often are carried out concurrently with mining operations and the surface areas of underground mines. Underground and surface coal mines present different challenges for decommissioning and closure. The critical factors in underground mining are the effects of subsidence and hydrology, both of which require continued monitoring and control. For surface mines, the critical factors relate to drainage and treatment of water and to erosion and sedimentation of the slopes, the waste and spoil banks, and the final pit. Continued use of the surface mine infrastructure (such as roads, buildings, utilities) depends to a large extent on the post-mining requirements described in the mining plan. A mining plan that is well integrated with a community master plan can result in optimum post-mining use of this infrastructure.

Currently, mine closure is a rigorously regulated process requiring detailed technical and financial analysis during the planning and operation stages for a mine – and ensuring financial and legal responsibility for post-mining closure. There is the continued need to mitigate the effects of past mining practices and to demonstrate more effective and sustainable solutions to the problems of acid mine drainage, mine fires, and the utilization of waste piles from abandoned mine land sites (NRC, 2007).

3.3 Coal Preparation

As-mined coal (*run-of-mine coal*) contains a mixture of different size fractions, sometimes together with unwanted impurities such as rock and dirt (Table 3.1). The purpose of coal preparation (often referred to as (*coal cleaning, coal beneficiation*) is to improve the quality of coal by cleaning to remove inorganic impurities and sizing for handling, process, and combustion requirements.

Thus, another sequence of events is necessary to make the coal a consistent quality and salable. Such events are called *coal cleaning*. Preparation of coal prior to feeding into the boiler is an important step for achieving good combustion. Large and irregular lumps of coal may cause the following problems: (i) poor combustion conditions and inadequate furnace temperature, (ii) higher excess air resulting in higher stack loss, (iii) increase of unburned carbonaceous material in the ash, and (iv) low thermal efficiency. Thus, effective preparation of coal prior to combustion improves the homogeneity of coal supplied, reduces transport costs, improves the utilization efficiency, produces less ash for disposal at the power plant, and may reduce the emissions of oxides of sulfur.

The relative density, friability, hardness, and strength of different elements within the coal matrix are key parameters for mechanical cleaning processes. The specific gravity of coal ranges from 1.23 to 1.72, depending on rank, moisture, and ash content. Mineral impurities have higher densities and this property is employed by a variety of separation methodologies. A coal preparation plant typically contains different circuits delineated by particle size. The larger particle fraction from 6 to 18 mm will normally contain coarse rock that can be separated by a vibrating jig or dense medium bath. For the smallest particles, those that are <0.5 mm, froth flotation is used. In this process, a conditioned feed pulp is introduced onto the top of the froth bed. Hydrophobic coal particles attach to rising bubbles and stay in the

Table 3.1 Added value to coal through processing (cleaning).

Method	Comment
Mineral matter	Removal of the mineral matter, which is largely noncombustible and may constitute up to 65% w/w of the raw coal, increases the heating value of the coal on a per unit mass basis. Some combustible material may be lost as part of the cleaning process but the removal of unwanted material reduces the mass and volume of coal for a given heating value thereby reducing shipping costs as well as minimizing coal handling and ash management costs for the end user.
Processing	Principally mineral matter removal and drying to remove moisture allows greater control over the quality of the coal, which improves the consistency of the coal for the end user, such as an electricity generator or coke manufacturer. Improved and consistent quality of the coal increases the efficiency and availability of steam boilers and is particularly important for the quality of metallurgical coke.
Physical processing	Physical processing methods can, to some extent, reduce sulfur and trace element contents, particularly on a heating value basis. Typically, coal cleaning is not practiced primarily for this purpose except for the metallurgical coal market.

froth while hydrophilic mineral particles pass through it and discharge at the bottom of the floatation cell. Cyclones are used and the lighter coal particles swirl upward to a clean coal discharge while higher density impurities sink to the funnel outlet. Various dewatering screens, thickeners, and filters are used to separate the product and recover the medium.

Coal preparation is the stage in coal production when the run-of-mine coal is processed into a range of clean, graded, and uniform coal products suitable for the commercial market. In some cases, the run-of-mine coal is of such quality that it meets the user specification without the need for beneficiation, in which case the coal would merely be crushed and screened to deliver the specified product. The decision whether or not to process a particular raw coal depends on the coal and its intended market. The subbituminous coal of the Powder River Basin (Wyoming) is almost always shipped to market raw because it has inherently low mineral matter content (low ash-producing propensity) and poor washability. The region has low water availability, which is a critical requirement for conventional coal beneficiation.

By way of definition, the term *washability* is used to describe the ease with which mineral matter can be separated from the coal, and depends on the degree of incorporation of the mineral matter in the organic matrix of the coal and its specific gravity relative to the coal.

The purpose of coal preparation is to improve the quality of coal by cleaning to remove inorganic impurities and sizing for handling, process, and combustion requirements (Skea and Rubin, 1988; Speight, 2013). The relative density, friability, hardness, and strength of different elements within the coal matrix are key parameters for mechanical cleaning processes. The specific gravity of coal ranges from 1.23 to 1.72, depending on rank, moisture, and mineral matter content. Mineral impurities have higher densities and this property is employed by a variety of separation methodologies.

A coal preparation plant typically contains different circuits delineated by particle size. The larger particle fraction from 6 to 18 mm will normally contain coarse rock that can be separated by a vibrating jig or dense medium bath. For the smallest particles, those that are <0.5 mm, froth flotation is used. In this process, a conditioned feed pulp is introduced onto the top of the froth bed. Hydrophobic coal particles attach to rising bubbles and stay in the froth while hydrophilic mineral particles pass through it and discharge at the bottom of the floatation cell. Cyclones are used and the lighter coal particles swirl upward to a clean coal discharge while higher density impurities sink to the funnel outlet. Various dewatering screens, thickeners, and filters are used to separate the product and recover the medium.

The output from any coal mine usually consists of raw coal (run-of-mine coal, ROM coal) that is wetter and finer, and also contains more impurities than in the past due to (i) mining of lower quality coals, (ii) advanced, continuous and non-selective mining techniques that cause more coal being broke up, and (iii) more impurities being included, and (iv) extensive water utilization for minimizing dust (Lockhart, 1984). While the quality of run-of-mine (ROM) coals is generally decreasing, the necessity for efficient coal beneficiation technology is significantly increasing, resulting in an increased demand for high-quality coals that meet both market and environmental standards.

Thus, the coal delivered to the coal preparation plant consists of coal, rocks, minerals, and any other form of material that is not coal. The coal also varies widely in size, ash content, moisture content, and sulfur content. Thus, coal preparation serves several purposes. One important purpose is to increase the heating value of the coal by mechanical removal of impurities. This is often required in order to find a market for the product. Run-of-mine coal from a modern mine may incorporate as much as 60% reject materials.

Thus, after coal is mined it generally goes through a process known as preparation or coal cleaning to (i) remove the impurities in order to boost the heat content of the coal and thereby improve power plant capacity, which also reduces maintenance costs at the power plant and extends plant life, and (ii) to reduce potential air pollutants, especially sulfur dioxide – the extent to which sulfur dioxide emissions can be reduced varies, depending upon the amount of sulfur in the coal and the form of its occurrence.

Briefly, the grade of a coal establishes its economic value for a specific end use. Grade of coal refers to the amount of mineral matter that is present in the coal and is a measure of coal quality. Sulfur content, ash fusion temperature (measurement of the behavior of ash at high temperatures), and quantity of trace elements in coal are also used to grade coal. Although formal classification systems have not been developed around grade of coal, grade is important to the coal user.

Coal preparation (coal cleaning) is the means by which impurities such as sulfur, ash, and rock are removed from coal to upgrade its value (Speight, 2013). In the process, the undesirable material is removed from the run-of-mine (ROM) coal by employing separation processes which are able to differentiate between the physical and surface properties of the coal and the impurities. The result is a relatively clean uniform coal product.

The energy content of coal is related to its rank (degree of coalification) (Table 3.2) which is influenced by the content of nonfuel components (e.g., minerals and moisture) (Speight, 2013). Thus, a primary objective of coal cleaning is to maximize the recovery of the heat value of the coal, consistent with achieving standard specifications for mineral matter content (as mineral ash), moisture content, and sulfur content.

Furthermore, since transportation costs are usually charged on a ton-per-mile basis (which does not distinguish between coal substance and moisture content), it is preferential to remove as much as possible of the extraneous mineral matter and water prior to shipping thereby reducing transportation costs for an "inferior" grade of coal and providing a higher energy material to the consumer.

Table 3.2 Typical properties of different rank coals (Speight, 2013).

Coal type	Carbon (%)	Hydrogen (%)	Limits of volatile matter (%)	Fixed carbon (%)	Calorific value (Btu/lb)
Lignites	73–78	5.2–5.6	45–50	50–55	<8,300
Subbituminous	78–82.5	5.2–5.6	40–45	55–60	8,300–11,500
High-volatile bituminous	82.5–87	5.0–5.6	30–40	60–70	11,500–14,000
Medium-volatile bituminous	87–92	4.6–5.2	20–30	70–80	>14,000
Low-volatile bituminous	91–92	4.2–4.6	15–20	80–85	>14,000
Anthracite	95–98	2.9–3.8	5–10	91–95	>14,000

In fact, long-range transportation of lignite, more than one-third of which consists of water, can more than triple the initial mine-mouth costs calculated on an energy basis. There may, however, be some trade-off in transportation costs if the low-rank coal is sufficiently low in sulfur which, in turn, means a lower cost in terms of stack gas clean-up (Nowacki, 1980).

The need for coal cleaning can be reduced by choice of suitable mining methods, many mines include the methods by which oversize coal is reduced in size but the cleaning of run-of-mine coal is, more often than not, a separate operation which is performed as a surface operation that is usually close to the mine-mouth. However, the term *coal preparation* includes, by definition, not only sizing (i.e., crushing and breaking) methods but also all of the handling and treatment methods that are required to prepare the coal for the market.

Thus, by providing a higher concentration of heat in the fuel (lower mineral matter and moisture content), the associated costs of transportation, handling, crushing, pulverizing and residual waste (fly ash) disposal in the electricity generation are reduced because fewer weight units per kilo-watt hour generation will be required.

Coal preparation processes are categorized as either *physical cleaning* or *chemical cleaning*. Physical coal cleaning processes, the mechanical separation of coal from its contaminants using differences in density, are by far the major processes in use in modern coal-cleaning plants. Physical coal cleaning techniques take advantage of the differences in specific gravity of the coal and its impurities. Hydrocyclones and gravity concentration devices are examples of such systems. When coal is finely ground, physical processes that take advantage of the surface properties of the coal materials can be used. For example, froth flotation exploits the hydrophilic surface characteristics of mineral impurities and the hydrophobic nature of coal particles to achieve separation.

Chemical coal cleaning processes are currently being developed, but their performance and cost are undetermined at this time. For example, some of the sulfur in coal is actually chemically connected to the carbon backbone of coal instead of existing as separate particles. Several process have been tested to mix the coal with chemicals that break the sulfur away from the coal backbone but most of these processes have proven too expensive and have not been applied to commercial coal cleaning operations (Speight, 2013).

The direct objectives of coal-cleaning practices are reduction (within predetermined limits) of size, moisture, ash, as well as sulfur (Williams, 1981; Couch, 1991). However, coal properties have a direct bearing not only on whether but also on how coal should be cleaned. Indeed, coal rank (rank being a complex property that is descriptive of the nature of the coal and its properties) (Chapters 2, 5, 6) can, and usually does, play an important role in determining the feasibility and the extent of cleaning. Thus, the type of coal beneficiation technology and the extent of beneficiation depend mostly on the type of coal, the means of mining, and the clean coal utilization.

Run-of-mine (ROM) coal has no size definition and consists of pieces ranging from fine dust to lumps as large as 2 feet (0.6 meter) square, or larger depending on the rank of coal (Baafi and Ramani, 1979). It is often wet and may be contaminated with rock and/or clay; as such, the coal is unsuitable for commercial use. At best, the coal seams being worked may be relatively thick, without faults, and uniform, free of associated rock partings, and dry. In such cases the coal may require only some breaking or crushing and screening to produce a *pure* coal.

Mineral matter content ranges from three to 60% (mineral ash) at different mines. Most of the ash is introduced for the roof or bottom of the mine or from partings (small seams of slate) in the coal seam. This mineral matter (extraneous ash) is heavier than 1.80 specific gravity; the remaining mineral matter is inherent in the coal. The density of coal increases with the amount of mineral matter ash present.

The moisture content of the coal is also of two types. The surface moisture, that which was introduced after the coal was broken loose from the seam, is the easier to remove. This moisture is introduced by exposure to air, wet mining conditions, rainfall (in stockpiles), and water sprays. The remaining moisture (*bed moisture*, *cellular moisture*, *inherent moisture*) can be removed only by coking or combustion. This moisture was included during formation of the coal.

Sulfur in coal occurs as sulfates, organic sulfur, and pyrites (sulfides of iron). The sulfates usually are present in small quantities and are not considered a problem. Organic sulfur is bound molecularly into the coal and is not removable by typical coal preparation processes. Pyrites generally are present in the form of modules or may be more intimately mixed with the coal. Coal preparation plants remove only a portion of the pyritic sulfur; therefore the degree of sulfur reduction depends on the percentage of pyrites in the coal, the degree to which this is intimately mixed with the coal, and the extent of coal preparation.

The size of the pieces of coal ranges upward to that of the size of foreign materials, such as a chunk of rock that has fallen from the mine roof or a metal tie; large pieces of coal from a hard seam are sometimes included. Foreign materials are introduced into the coal during the mining process, the most common being roof bolts, ties, car wheels, timber, shot wires, and cutting bits.

Air pollution control often requires partial removal of pyrites with the ash to reduce the sulfur content of the coal (Godfrey, 1994). Ash content often must be controlled to conform to a prescribed quality stipulated in contractual agreements. Because of firing characteristics, it is often as important to retain the ash content at a given level as it is to reduce it. Freight savings are substantial when impurities are removed prior to loading. Finally, the rejected impurities are more easily disposed of at the mine site remote from cities than at the burning site, which is usually in a populated area.

Coal preparation is carried out at a facility that washes coal to remove soil and rock, preparing it for transport to market – a *coal preparation facility* may also be called a *coal handling and preparation plant*. During the *preparation process*, as much waste as possible is removed from the coal to increase the market value of the coal and reduce the transportation costs.

Coal needs to be stored at various stages of the preparation process, and conveyed around the preparation plant facilities. Stored coal (*stockpiled coal*) provides surge capacity to various parts of the preparation plant. A simple stockpile is formed by machinery dumping coal into a pile, either from dump trucks, pushed into heaps with bulldozers, or from conveyor belt booms. More controlled stockpiles are formed using a stacker (a large machine used to pile the coal into a stockpile) or multiple stackers to form piles along the length of a conveyor, and reclaimers (a large machine used to recover coal from a stockpile) to retrieve the coal when required for product loading. Taller and wider stockpiles reduce the land area required to store a set tonnage of coal. Larger coal stockpiles have a reduced rate of heat lost, leading to a higher risk of spontaneous combustion.

Briefly, the mined coal is loaded into a stockpile, with a reclaim tunnel beneath it. Then, the coal is transported to a raw coal silo, usually 10,000-ton capacity, for feed to the plant at a constant rate. Generally, the first stage is a crushing/screening plant (Figure 3.1), with heavy media processing (for coarse coal sizes – 2-inch x 10 mesh), spirals for the middling sizes (10 mesh x 60 mesh), flotation for the -60 mesh fine coal feed.

Most conventional coal cleaning operations utilize gravity methods for the coarser size fractions and surface treatment methods for the finest particle sizes (Riley and Firth, 1993). The selection of equipment, especially for the finer sizes, depends on the mining method, coal hardness, and size distribution and amounts thereof. Typical of these is a dense media cleaning process (Fourie, 1980) which uses dense media vessels or jigs for the coarsest size, usually +3/8", dense media cyclones, concentrating tables or jigs for the 3/8" x 28 mesh size, water-only cyclones or spirals and sometimes flotation for the 28 x 100 mesh size and flotation for the -100 mesh coal.

Screening and centrifugal dryers dewater the coarser products while screen-bowl centrifuges and sometimes thermal dryers are utilized to reduce the moisture content of the finest sizes. If the percentage of fines in the coal is high, wetting of coal can decrease the percentage of unburned carbon and the excess air level required to be supplied for combustion (Table 3.3). In cases where the coal lots have excessive fines, it may be advisable to blend the predominantly lumped coal with lots containing excessive fines. Coal blending may thus help to limit the extent of fines in coal being fired to not more than 25%. Blending of different qualities of coal may also help to supply a uniform coal feed to the boiler.

Metallurgical coal cleaning plants utilize thermal dryers – the coal is softer and more friable and thus has a finer size distribution after extraction by the mining machines. Coals

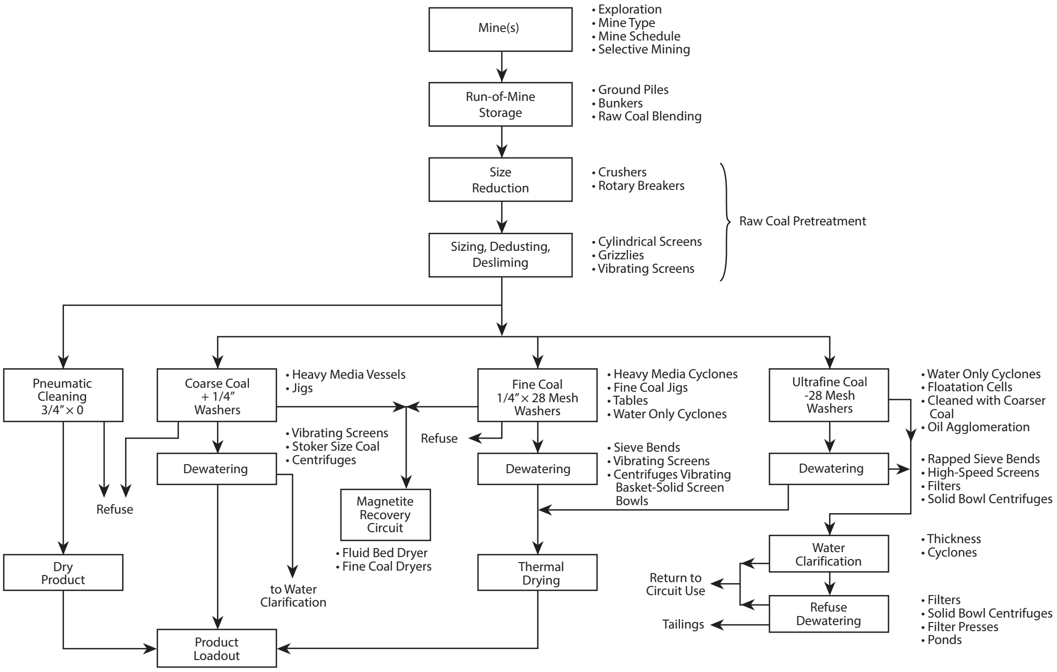

Figure 3.1 General layout of a coal preparation/coal cleaning plant (Speight, 2013).

Table 3.3 Extent of coal wetting based on fines and surface moisture.

Fines (% w/w)	Surface moisture (% w/w)
10-15	4-5
15-20	5-6
20-25	6-7
25-30	7-8

for metallurgical use must be thoroughly processed and dried to meet the end user requirements. Additionally, flotation is typically utilized in these circuits due to the quantity of coal and quality of the needed end product (low ash, low sulfur) (Aplan, 1993; Burchfield, 1993).

Powder River Basin coal (Wyoming), although desirable because of other properties that do not leave a large footprint on the environment, is extremely friable and will break down into smaller particles virtually independent of how the coal is transported or handled. The coal represents the extremes of handling problems; *dust* is an issue when the coal is fine and dry; *plugging* in bunkers and chutes is an issue when the same fine coal is wet. Once Powder River Basin coal is exposed by mining, the degradation process begins and the majority of the damage can occur in a short time, even as short as a few days. The extent of the degradation that occurs depends in large part on the distance to the plant from the mine, such as the length of time that the coal is exposed to the atmosphere during transportation. Additional factors such as crushed run of mine size and specific handling procedures also impact the degradation process. Additional decomposition occurs during handling and storage in a pile and bunker, bin, or silo. The root cause of the degradation is believed loss of moisture that impacts the coal both mechanically and chemically, through the generation of additional surface reaction area (Hossfeld and Hatt, 2006).

On the other hand some steam coals, especially the harder ones (low Hardgrove index), and some coals produced from surface mines have smaller quantities of the –100 mesh size. In many plants there is such a small quantity of the -100 mesh size that this material is sent to disposal and is considered uneconomical to recover.

Coal flotation is a physiochemical process which exploits the differences in the wettability of hydrophobic clean coal and that of hydrophilic foreign particles (Arnold and Aplan, 1989; Fecko *et al.*, 2005). It is, therefore, subject to the surface properties of coal pyrite and other types of commercially worthless material present in coal which plays a major role in determining separation of such material from coal (Luttrell and Yoon, 1994; Luttrell *et al.*, 1994).

Oxidation also leads to the formation of various oxygen functional groups and soluble inorganic that can adsorb on the coal surface and modify its wettability and floatability. These groups have remarkable impacts on surface charge, which controls film-thinning process and thus flotation kinetics (Sokolović *et al.*, 2006). Decreased coal recovery and increased concentrate ash content may be explained by oxidation of coal. In fact, a good correlation exists between the zeta potential and floatability and electrochemical tests confirm the negative effect of oxidation on the coal recovery and also the final effect of coal flotation process (Fonseca *et al.*, 1993; Sokolović *et al.*, 2006).

The scheme used in physical coal cleaning processes varies among coal cleaning plants but can generally be divided into four basic phases: (i) initial preparation, (ii) fine coal processing, (iii) coarse coal processing, and (iv) final preparation (Figure 3.1).

For most coal-fired power plants, coal is prepared for use by first crushing the delivered coal into pieces less than 5 cm in size. The crushed coal is then transported from the storage yard to in-plant storage silos by rubberized conveyor belts. In the initial preparation phase of coal cleaning, the raw coal is unloaded, stored, conveyed, crushed, and classified by screening into coarse and fine coal fractions. The size fractions are then conveyed to their respective cleaning processes.

In plants that burn pulverized coal, coal from the storage silos is fed into pulverizing units that grind the crushed coal into the consistency of talcum and mix it with primary combustion air which transports the pulverized coal to the steam generator furnace (Chapters 7, 8). A 500 MW coal-fired power plant will have approximately six such pulverizing units, five of which will supply the steam generator at full load with approximately 225 tons per hour. In plants that do not burn pulverized coal, the crushed coal may be directly fed into cyclone burners, a specific kind of combustor that can efficiently burn larger pieces of coal (Chapters 7, 8). In plants fueled with slurried coal, the slurry is fed directly to the pulverizing units and then mixed with air and fed to the steam generator. The slurry water is separated and removed during pulverizing of the coal.

Fine coal processing and coarse coal processing use similar operations and equipment to separate the contaminants. The primary difference is the severity of operating parameters. The majority of coal cleaning processes use upward currents or pulses of a fluid such as water to fluidize a bed of crushed coal and impurities. The lighter coal particles rise and are removed from the top of the bed. The heavier impurities are removed from the bottom. Coal cleaned in the wet processes then must be dried in the final preparation processes.

Final preparation processes are used to remove moisture from coal, thereby reducing freezing problems and weight and raising the heating value. The first processing step is dewatering, in which a major portion of the water is removed by the use of screens, thickeners, and cyclones (Hee and Laskowski, 1994; Nowak, 1994). The second step is normally thermal drying, achieved by any one of three dryer types: (i) fluidized bed drying, (ii) flash drying, and (iii) multi-louvered drying. In the fluidized bed dryer, the coal is suspended and dried above a perforated plate by rising hot gases. In the flash dryer, coal is fed into a stream of hot gases for instantaneous drying. The dried coal and wet gases are both drawn up a drying column and into a cyclone for separation. In the multi-louvered dryer, hot gases are passed through a falling curtain of coal, which is then raised by flights of a specially designed conveyor.

Although inherent moisture cannot be changed, the surface moisture can be reduced to any level that is economically practicable. Considerations include the possibility of re-exposure to moisture during transportation and subsequent storage and the fact that intense thermal drying increases ideal conditions for re-adsorption of moisture.

The free sulfur in the coal is subject to removal only by chemical treatment, which is not a coal preparation process, or by combustion. The reason that the pyrites can be partially removed in washing processes is that they are heavy enough to be removed with the ash. The processes can remove only 30 to 60% of the pyrites, however, because some pyrites are not broken free of the coal and are present in a given piece in a quantity too small to increase its weight enough to be rejected.

Foreign metals can be removed relatively easily. Most wood fragments can be removed although a few small pieces of wood cause no particular harm because they are combustible.

Thus, coal preparation is, of necessity, an integral part of the production and use of coals. The effect on costs can be as important as the planning of mine layouts; decisions concerning mining systems should be an essential element in all mining feasibility studies, especially in view of new (and/or renewed) environmental regulations such as the Clean Air Act Amendments in the United States (Elliott, 1992; Tumati and DeVito, 1992; Rosendale *et al.*, 1993; Paul *et al.*, 1994).

In more general terms, the primary aims of preparing coal for the market depend upon the nature of the raw coal (Table 3.4; Figure 3.1) but, essentially, are (i) the reduction in size and control of size within the limits determined by the needs of transportation, handling, and utilization; and (ii) the removal of extraneous mineral matter to a point that is satisfactory for the customer and specifications are met. This latter operation is more often referred to as control of ash content.

In the early days of the industry, coal was sold as it came from the ground but as the century advanced there was always the possibility of dispute related to payment if the coal contained visible impurities, including excess water above the amount specified in the purchasing contact. Thus, in the early-to-middle decades of the last century, some effort was

Table 3.4 General methods of coal preparation and levels of cleaning (Speight, 2013).

Level	Raw coal weight (%)	Raw coal content (%)	Reduction potential		Comments
			Ash	**Sulfur**	
1	98–100	99–100	None to minor	None	Crushing and breaking of raw coal to 3-in. size
2	75–85	90–95	Fair to good	None to minor	Coarse coal cleaning of 3 in. × 3/8 in. coal
3	60–80	80–90	Good	Fair	Moderate coal cleaning of 3 in. × 28 mesh coal
4	60–80	80–90	Good to excellent	Fair to good	Fine coal cleaning of 3 in. × 0 mesh coal
5	60–80	85–95	Deep-cleaned coal: excellent; middle-cleaned coal: none so far		Multiple-stream coal preparation of two cleaned coal products: "deep-cleaned" coal and "middle grade" coal

made to physically remove the impurities from the coal as evidenced by the employment of *belt boys*. It was the sole purpose of these boys, hired straight from school, at age 12 to 15 (sometimes even younger!) to stand at the side of the underground conveyer belts and remove (by hand) the pieces of rock and slate as the coal passed to the mine cars. By this means, much of the large-sized impurities were sorted and left in the waste area.

In many mines, the waste areas are called tipples because of the operation which transferred the coal from the mine cars to picking or sorting screens and where visible impurities were removed by hand. Tipples also segregated the run-of-mine coal into size groups and, as the larger sizes could be more carefully hand-cleaned and were burned with greater ease and cleanliness in fireplaces and hand-stoked furnaces, size became associated with quality. The tipples grew to become environmentally unsuitable mountainous heaps of rock which still disfigure many coal-mining areas. Recently, there have been efforts to take back much of the tipple rock into the worked-out underground seams for storage.

The importance of adequate coal pretreatment technologies must be emphasized; many of the operating problems in cleaning plants are attributed to inadequate (inefficient) pretreatment, which results in large quantities of oversize (or undersize) material in the feeds to the various cleaning units which cause loss of cleaning efficiency, blockages, and even plant shutdown.

Conventional coal cleaning plants are quite efficient for Btu recovery, as well as ash and pyritic sulfur reduction. Btu recovery is generally between 85 and 90% and the ash reductions on a lb. of ash/MM Btu basis are usually in the 70 to 80% range for Pittsburgh seam coals, and in the 85 to 90% range for Illinois and central Appalachian coals (Rosendale *et al*., 1993).

Thus, preparation of coal prior to feeding into the boiler is an important step for achieving good combustion. Large and irregular lumps of coal may cause the following problems: (i) poor combustion conditions and inadequate furnace temperature, (ii) higher excess air resulting in higher stack loss, (iii) increase of unburned coal constituents in the ash, and (iv) low thermal efficiency.

3.4 Size Reduction

Size reduction (sometimes called *pretreatment*) is, simply, breaking, crushing, and screening of the run-of-mine coal in order to provide a uniform raw coal feed of predetermined top size thereby minimizing the production of material of ultrafine size by excessive crushing or handling.

Size reduction of coal plays a major role in enabling run-of-mine coal to be utilized to the fullest possible extent for power generation, production of coke, as well as other uses such as the production of synthetic fuels (Bevan, 1981). Run-of-mine coal is the *as-received* coal from the mine, whether the mining process is stripping, auger mining, continuous mining, short- or longwall mining, or any other method currently practiced (Speight, 2013 and references cited therein).

Most conventional coal cleaning facilities utilize gravity methods for the coarser size fractions and surface treatment methods for the finest particle sizes (Riley and Firth, 1993). The selection of equipment, especially for the finer sizes, depends on the mining method, coal hardness, and size distribution and amounts thereof.

The first operations performed on run-of-mine coal are removal of tramp iron and reduction of size to permit mechanical processing. The run-of-mine coal is first exposed to a high-intensity magnet, usually suspended over the incoming belt conveyor which pulls the iron impurities out of the coal. This magnet sometimes follows the breaker, but always precedes a screen-crusher. The coal then goes to the breaker, which is a large cylindrical shell with interior lifting blades; the shell is perforated with holes (two to eight inches in diameter) to permit passage of small material.

The breaker rotates on a horizontal axis, receiving material in one end, tumbling it as it passes through the holes in the shell, and permitting the hard, large, unbroken material to pass out the rear of the machine. The small material (four inches) goes to the cleaning plant, and the large rejected material falls into a bin to be hauled away.

Most commercial circuits utilize dense media vessels of jigs for the coarsest size usually +3/8", dense media cyclones, concentrating tables or jigs for the 3/8" x 28 mesh size, water-only cyclones, or spirals and sometimes flotation for the 28 x 100 mesh size and flotation for the −100 mesh.

Since the mining processes differ in operation and since size reduction actually begins at the coal face (i.e., during mining), the mined coal will exhibit different characteristics. In fact, the mining process has a direct bearing on the size and on the size consistency of the coal. Thus, prior to final utilization of the coal, some degree of size reduction, or size control, is usually required. The number of stages in the size reduction process depends upon the specific utilization of the coal as well as the condition of the coal.

For example, coal which is destined for power generation may undergo size reduction to produce a product with a top size of 4 inch (1 mm). On the other hand, the size of the coal needed for a coking operation is coarse and the number of stages of *size reduction* involved in preparing a coal feed for a coking is somewhat less than required to prepare coal as the feedstock for power generation utilization.

Coal is reduced in size by crushing and pulverizing. Pre-crushed coal can be economical for smaller units, especially those which are stoker fired. In a coal handling system, crushing is limited to a top size of 6 or 4 mm. The devices most commonly used for crushing are the rotary breaker, the roll crusher, and the hammer mill.

It is necessary to screen the coal before crushing, so that only oversized coal is fed to the crusher. This helps to reduce power consumption in the crusher. Recommended practices in coal crushing are (i) incorporation of a screen to separate fines and small particles to avoid extra fine generation in crushing, and (ii) incorporation of a magnetic separator to separate iron pieces in coal, which may damage the crusher.

The fines in coal produced during the crushing (sizing) operation can present problems in combustion on account of segregation effects. Segregation of fines from larger coal pieces can be reduced to a great extent by conditioning coal with water. Water helps fine particles to stick to the bigger lumps due to surface tension of the moisture, thus stopping fines from falling through grate bars or being carried away by the furnace draft. While tempering the coal, care should be taken to ensure that moisture addition is uniform and preferably done in a moving or falling stream of coal. If the percentage of fines in the coal is high, wetting of coal can decrease the percentage of unburned carbon and the excess air level required to be supplied for combustion. In cases where the sized coal has an excessive amount of fine coal, blending with predominantly lump coal (depending upon the coal-fired system) may be an option. This may thus help to limit the extent of fines in coal being fired to not more than a specified maximum. In fact, blending of coals of different quality may also help to supply a uniform coal feed to the boiler (Chapters 7, 8).

The size of a coal particle is defined in terms of a surface opening through which the particle will barely pass or will not pass at all. In sizing a material, the individual particles are presented to the surface openings numerous times. However, the size of a particle mut be recognized because a three-dimensional particle is presented to a two-dimensional opening. In the case of a narrow, elongated particle, the particle will be sized according to the orientation of the particle with respect to the surface opening (ASTM D431) defines the top size or upper limit of a quantity of material as the smallest sieve (smallest opening) upon which is retained a total of less than 5% of the sample. In practice, the term *nominal top size* is used extensively when describing the output range of a size reduction device. The nominal top size of a quantity of material is the smallest sieve (smallest opening) upon which is retained a total of 5 to 20% of the sample.

Reduction ratio is the ratio between the feed top size and the product top size, or the ratio between the feed and product sizes at which a specific percentage of the material passes. For size reduction units that produce a product top size larger than 1 mm, size reduction ratios are normally of the order of 8-to-1 while for units where the product top size is smaller than 1 mm, size reduction ratios can range from 200-to-1 and higher.

The *top size* upper limit of the crushed (sized) material is defined by the smallest sieve opening upon which is retained a total of less than 5% of the sample (ASTM D431). The term nominal top size is used to describe the product of a size reduction operation and is the smallest sieve opening upon which is retained a total of 5 to 20% of the sample. The reduction ratio is the ratio between the feed top size and the product top size or the ratio between the feed and product sizes at which a determined percentage of the material passes. The relative ease with which a coal can be comminuted (reduced in top size) by mechanical action affects the design of a size reduction unit or operation. The term used to refer to this relative ease is the grind ability index of the coal.

The *specific energy* for size reduction is proportional to the *grindability index* of the coal (Hardgrove grindability index, ASTM D409) and is also a function of the reduction ratio. Thus, the energy required for the size reduction of coal increases with increasing throughput as well as with the reduction ratio. For a "standard" throughput of coal, the energy required varies with the reduction ratio and the relationship between the specific energy and the grindability is dependent upon the type of device (Speight, 2013).

Moisture in coal is not just an issue in terms of whether the coal is dry or not and whether the transportation costs warrant coal drying. Indeed, moisture content is a factor that must be taken into account when considering the energy requirements of a size reduction unit. Excessive moisture, but more particularly excessive surface moisture, can cause a lesser efficiency in fines removal (due to fines agglomeration) and the formation of emulsions can also be a problem in the selective agglomeration process (Bensley *et al.*, 1977).

In general, five types of equipment are used for the size reduction of run-of-mine coal: (i) rotary breakers, (ii) roll crushers, (iii) hammer mills, also called ring mills, (iv) impactors, and (v) tumblers. At best, the crushing operation produces the desired (sized) product in a single stage. However, there are cases where the size reduction of coal entails multiple stage size reduction units. The final stage of coal pretreatment is to screen it into size fractions convenient for handling by the various process streams.

3.4.1 Rotary Breaker

The rotary breaker essentially consists of an outer cylinder with an inner rotating perforated cylinder fitted with lifters which is operated at the lowest speed that will cause a small particle on the liner to centrifuge (Speight, 2013). Coal is fed into one end of the rotating cylinder where it breaks because of the tumbling action due to gravity fall, and pieces less than the hole sizes [typically 1% in. (38 mm)] pass out to a bottom collection trough, giving a product with positive upper size control. The flow rate through the breaker is adjusted so that pure coal has broken through and rock passes through the exit; in practice, some coal will pass out with the rock. Large pieces of hard, dense rock will also act as grinding media. Because of the relatively mild breakage action, the production of fines is minimized. For hard coal, the length-to-diameter ratio is increased, and the diameter is increased to give a higher force due to the greater fall.

The raw coal from the rotary breaker can be utilized directly, undergo further size reduction, or the quality of the product can be upgraded in a coal-washing facility (Speight, 2013).

3.4.2 Roll Crusher

Roll crushers are size reduction devices that shear and (or compress) the material that is to be reduced in size. The single-roll crusher is a popular piece of equipment and primarily consists of a heavy cast iron or steel fabricated frame on which are mounted the crushing roll and the stationary breaker plate. The breaker plate is provided with renewable wear plates bolted to the breaker plate. The roll usually has a series of long teeth spaced at intervals and various short teeth covering the entire crushing surface. The coal is squeezed between the revolving roll and the breaker plate. The long teeth act as feeders and also penetrate the lumps of coal, splitting them into smaller pieces, while the smaller teeth make the proper size reduction (Roman, 1967).

Double-roll crushers consist of two rolls that rotate in opposite directions. A double roll crusher can reduce run-of-mine coal (maximum top size 36 inches, 0.9 m) to a product with a top size in the range of 14 inches (350 mm) to 3/4 inch (19 mm). The roll size can vary from 12 x 18 inches to 60 x 60 inches and capacity may vary up to 2,000 tons/hour. Double-roll crushers generally produce minimal amounts of fines (Roman, 1967).

3.4.3 Hammer Mill

The hammer mill is a device in which the feed coal is contacted (impacted) by rotating hammers and then further impacted by contact with grid breaker plates. The grinding that occurs in the hammer mill results from the rubbing action of feed material between two hardened surfaces i.e., the hammers and the grid or screen plates. The hammer mill usually produces a relatively high proportion of fine material (Roman, 1967). The fineness obtained can be varied by adjustments of revolutions per minute or the spacing between the hammer tips and the grate bars.

The ring-type hammer mill is a modification of the hammer mill which was developed to help minimize the amount of fines in the product. In these units, the hammers have been replaced by rings (alternately toothed and plain) which revolve and cause size reduction by a rolling compression action rather than by a grinding action (Roman, 1967). The unit emphasizes *nipping* particles between the hammer and the grate bars. The hammer mill is a versatile unit and has a capacity up to 2,500 tons/hour for industrial units.

3.4.4 Impactor

An impactor is a size reduction device that strikes (impacts) the coal which is then thrown against a hard surface or against other coal particles. The coal is typically contained within a cage, with openings on the bottom, end, or side of the desired size to allow pulverized material to escape.

The rotor-type impact mill uses rotors to effect size reduction. In the mill, the coal drops into the path of the rotor, where it is shattered, driven against the impact surface, and further reduced in size. The material rebounds into the path of the rotor and the cycle repeats itself until the product is discharged from the base.

There are two types of impact crushers: (i) horizontal shaft impactor and (ii) the vertical shaft impactor.

3.4.5 Tumbler

The tumbler (*tumbling mill*) is a grinding and pulverizing machine consisting of a shell or drum rotating on a horizontal axis. The material coal is fed into one end of the tumbler where it comes into contact with grinding material, such as iron balls. As the tumbler rotates, the material and grinding balls tumble against each other, the material being broken chiefly by attrition.

Tumblers are cylindrical size reduction devices and are essentially lined drums supported by hollow trunnions at each end. The units are manufactured with overflow, grate, or peripheral, discharge arrangements.

In summary, proper coal sizing is one of the key measures to ensure efficient combustion (Table 3.5). Proper coal sizing, with specific relevance to the type of firing system, helps

Table 3.5 Approximate size dimensions of coal for combustion in various coal-fired systems.

System	Size, inches (mm)
Hand Firing	
(a) Natural draft	1-3 (25-75)
(b) Forced draft	1-1.6 (25-40)
Stoker Firing	
(a) Chain grate	
i) Natural draft	1-1.6 (25-40)
ii) Forced draft	0.6-1.0 (15-25)
(b) Spreader Stoker	0.6-1.0 (15-25)
Pulverized Fuel Fired	75% below 75 microns*
Fluidized bed boiler	<0.4 (<10 mm)

*1 Micron = 1/1000 mm

towards even burning, reduced ash losses and better combustion efficiency. As described above, coal is reduced in size by crushing and pulverizing. Pre-crushed coal can be economical for smaller units, especially those which are stoker fired. In a coal handling system, crushing is limited to a top size of 6 or 4 mm. The devices most commonly used for crushing are the rotary breaker, the roll crusher, and the hammer mill.

It is necessary to screen the coal before crushing, so that only oversized coal is fed to the crusher. This helps to reduce power consumption in the crusher. Recommended practices in coal crushing are (i) incorporation of a screen to separate fines and small particles to avoid extra fine generation in crushing, and (ii) incorporation of a magnetic separator to separate iron pieces in coal, which may damage the crusher.

3.5 Coal Cleaning

Run-of-mine coal generally has mineral matter on the order of 5 to 40% w/w and sulfur on the order of content of 0.2 to 0.8% w/w% depending on the geologic conditions and mining technique used. Coal cleaning, therefore, is often required to remove excessive impurities for efficient and environmentally safe utilization of coal. One important purpose of coal preparation is to increase the heating value of the coal by mechanical removal of impurities. This is often required in order to find a market for the product. Run-of-mine coal from a modern mine may incorporate as much as 60% reject materials. In the United States, the coal cleaning is most common at eastern and midwestern mines.

Current commercial coal cleaning methods are invariably based on physical separation; chemical and biological methods tend to be too expensive. Typically, density separation is used to clean coarse coal while surface property-based methods are usually preferred for fine coal cleaning (Davis, 1993; Dodson *et al.*, 1994). In the density-based processes, coal particles are added to a liquid medium and then subjected to gravity or centrifugal forces to separate the organic-rich (float) phase from the mineral-rich (sink) phase.

Density-based separation is commercially accomplished by the use of jigs, mineral spirals, concentrating tables, hydrocyclones, and heavy media separators. The performance of density-based cleaning circuits is estimated by using laboratory float-sink tests. In the surface property-based processes, ground coal is mixed with water and a small amount of collector reagent is added to increase the hydrophobicity of coal surfaces. Subsequently, air bubbles are introduced in the presence of a frothing agent to carry the coal particles to the top of the slurry, separating them from the hydrophilic mineral particles. Commercial surface property-based cleaning is accomplished through froth or column flotation.

Other physical coal cleaning methods include selective agglomeration, heavy and medium cycloning, and dry separation with electrical and magnetic methods (Couch, 1991, 1995). Selective agglomeration and advanced cycloning have the high probability of commercialization, particularly for reducing the sulfur content of coal (Couch 1995). In selective agglomeration, the coal is mixed with oil. The oil wets the surface of coal particles and thus causes them to stick together to form agglomerates. The agglomerated coal particles are then separated from the mineral particles that stay in suspension because they do not attract oil to their surfaces.

3.5.1 Effect of Composition and Rank

When coals are combusted or pyrolyzed, there is the near complete elimination of hydrogen and oxygen – the carbon residue that remains, however, still contains small quantities of nitrogen and sulfur. Typical values for carbon, hydrogen, volatile matter (i.e., low molecular weight products of the pyrolysis), and residual (fixed, non-volatile) carbon of the various classes of coal (Table 3.2) provide the basis of a system for describing coal rank (Speight, 2013).

In the context of coal cleaning, oxygen is often considered unimportant because it is nonpolluting! But some consideration should be given to the effect of oxygen on the fate of its nitrogen and sulfur compatriots as well as its effect when water (a product of the combustion of hydrocarbons which also contain oxygen) condenses with other by-products on the cooler parts of combustion systems; corrosive, aqueous acids can be the result.

Sulfur is a special case because it is considered to be, and actually is, a more a serious pollutant than oxygen. Sulfur occurs in various forms and is distributed throughout the organic matrix and in the minerals. As organic sulfur, it occurs in the organic structure of the coal and as pyritic sulfur, it occurs as discrete particles of pyrite (Fe). In addition, sulfates are occasionally found in the minerals. In summary, the bulk of the sulfur (organic and/or inorganic) present in coal has the potential to occur as gaseous combustion products.

Rank has been assumed to have an effect on the extent of hydrophobic character of coal (Speight, 2013). However, recent work on the prediction of coal hydrophobicity indicates that this property correlates better with the moisture content than with the carbon content and better with the moisture/carbon molar ratio than with the hydrogen/carbon or oxygen/carbon atomic ratios (Labuschagne *et al.*, 1988). Thus, it appears that there is a relationship between the hydrophobicity of coal and the moisture content. But there are differences in the behavior of coals and the differences are usually referred to as wettability, which can be quantified by measurement of the contact angle of the solid with water.

3.5.2 Methods

Methods employed for the removal of impurities from coal depend on the physical differences between the impurity and the coal; one such example is the difference in specific gravity.

Coal preparation plants generally use gravity process equipment to separate the refuse from the coal. Most of the extraneous impurities mined with coal are much heavier than the coal itself – coal has a specific gravity between 1.35 and 1.5, while the refuse rock has a specific gravity on the order of 2.1 to 2.3 – and separation can be effected by immersing the run-of-mine coal in a fluid having a specific gravity greater than that of the coal but less than that of the impurity (*heavy media process*). This allows the coal to float and the heavy waste material to sink and the two products are collected separately (Figure 3.2) (Couch, 1991).

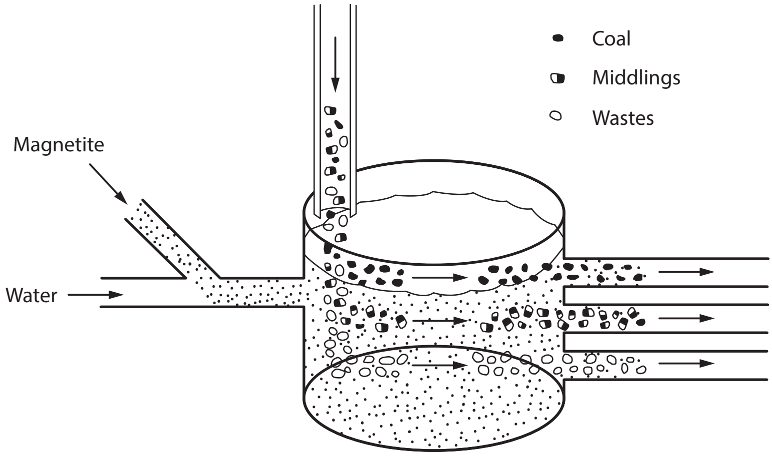

Figure 3.2 A dense-medium separation method (Speight, 2013).

3.5.2.1 Dense Media Washing

The *dense media washing process* (*heavy media washing process*) is the most popular method of cleaning coarse sizes and jig plants are probably the second most common method used for coarse coal.

In a heavy-media washing plant, all the cleaning is done by flotation in a medium of selected specific gravity, maintained by a dispersion of finely ground magnetite in water. The incoming raw coal is separated at 1/4 inch on an inclined screen. The oversize material (*overs*) proceeds to a flat pre-wet screen, where the fine dust particles are sprayed off from the +1/4-inch coal. This increment is discharged into a heavy-medium vessel or bath, where the refuse is separated from the coal. The refuse is discharged to a "refuse rinse" screen, where it is dewatered. The use of magnetite has also been investigated in cyclone cleaning of coal (Klima *et al.*, 1990).

The freed medium is divided into two parts, one returning directly to circulation via the heavy-medium sump and the other pumped to magnetite recovery. The refuse is discharged from the screen for disposal. The coal is discharged from the washer to a coal-rinse screen, where the coal is dewatered and the medium is treated as from the refuse screen. The clean coal is then centrifuged, crushed, and loaded. The fine coal (less than 1/4 inch) from the raw coal screens is combined with magnetite and water and pumped to a heavy-media vessel in that the magnetite is finer and the effective specific gravity is different.

The refuse is dewatered and the medium is recovered, as in the coarse coal selection. The coal is discharged over a sieve bend and then proceeds to a centrifuge for final dewatering prior to transfer to a thermal dryer or to loading.

Sand processes employ suspensions, often unstable, of sand in liquids whose effectiveness can be maintained only by high rates of agitation and recirculation. Specific gravity separations up to 1.90 are obtainable, but specific gravities of 1.45 to 1.60 are more commonly employed for bituminous coals.

The most successful commercial application of this process has been the Chance sand process (Figure 3.3) which is one of the most widely adopted heavy-medium cleaning

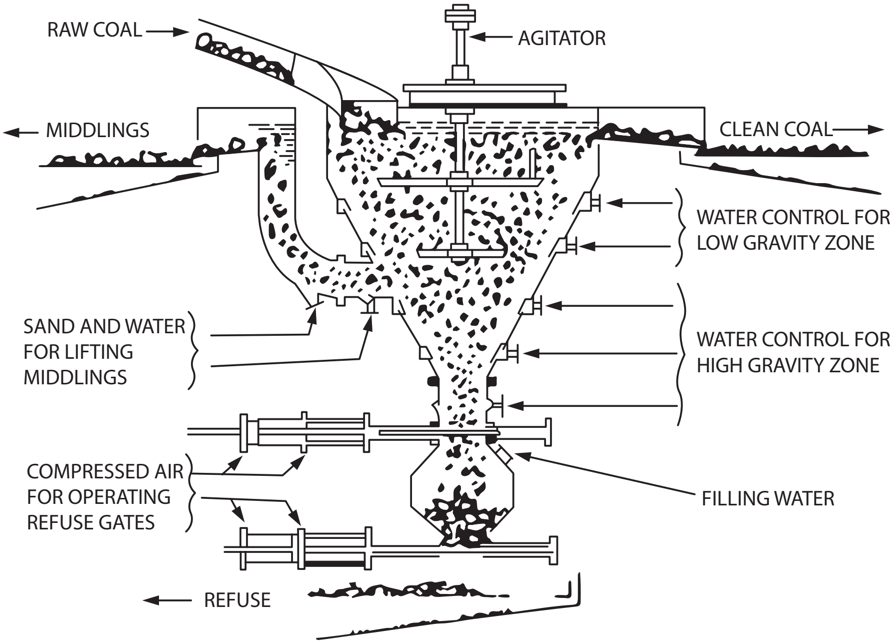

Figure 3.3 The chance sand flotation process (Speight, 2013).

processes and consists of a large, inverted conical vessel in which sand is maintained in suspension in an upward current of water. The density of the fluid can be varied by increasing or decreasing the amount of sand held in suspension.

Some heavy-medium flotation plants use finely crushed barium sulfate or magnetite in suspension in water. In some processes, termed dry, or pneumatic, cleaning air is used as the separating medium. Because densities are additive properties, the specific gravity of a suspension may be calculated from the concentration of solids in unit weight of suspension and the true density of the solids are known. However, the effective specific gravity of a suspension is strongly dependent on the stability of the suspension, which is, in turn, dependent on the fineness of the suspended particles.

3.5.2.2 Pneumatic Cleaning

Pneumatic cleaning devices, or air tables, are applied to the small fractions (less than 3/8 inches). In these devices, currents of air flow upward through a perforated bottom plate over which a layer of coal passes. The extreme fines are entrapped in the air and must be recaptured by cyclones and bag filters for return without quality improvement. As the coal reaches the end of the tables, the bottom layer is heavy (high-ash) material, a center layer is medium-weight coal and bone (high-ash), and the top layer is coal (low-ash). The middle layer must be incorporated with the refuse (and rewashed) or with the coal.

The efficiency of these devices is poor. Their ability to remove ash is limited to 2 to 3%, regardless of how much is present. These devices represent the lowest capital investment of all cleaning devices, and they entail no problems of water supply and disposal.

The incoming coal must be screened, and, because feed to the tables must be dry, thermal drying of the raw feed is required at some plants. The thermal dryers, in turn, require cyclones and scrubbers for control of particulate emissions.

3.5.2.3 Jig-Table Washing

Jig-table washing plants are so named because jigs are used to clean the >0.25 inch increment and Diester tables (oscillating table-sized sluices with a flat, riffled surface, approximately 12 feet square, which oscillates perpendicular to the riffles, in the direction of the flow of coal) are used to clean the <0.25 inch increment. Froth cells and/or thermal dryers may be used in conjunction with this equipment.

The raw coal, restricted to sizes smaller than eight inches, is separated on a wet screen (usually 0.25 inch mesh). The large-sized increment goes into the jig; the remaining coal is sent to a separate cleaning circuit. The coal is dewatered on screens and in centrifuges, crushed to the desired size, and loaded. The jig makes the *equivalent* gravity separation on the principles of settling in rising and falling currents. The small-sized coal (less than 1/4 inch) is combined with the proper amount of water and distributed to the tables, where the refuse is separated from the coal. The refuse is dewatered on a screen and discarded. The cleaned coal is dewatered on a sieve bend (a stationary gravity screen), where the extreme fines are removed and discharged into a centrifuge for final dewatering and removal of the fines. The cleaned coal (+28 meshes) is then loaded or conveyed to a thermal dryer where the heavy rejects are discharged off one end of the discharge side of the table. The light coal is discharged from the opposite end, and the *middlings* are distributed between.

3.5.2.4 Water Clarification

The water clarification plant receives all the slurry from the washing plant, separates the -48 mesh fraction for cleaning, and returns the water for reuse. The 48 mesh fraction flows to froth flotation cells, where it is mixed thoroughly with a reagent (light oil). The coal accepts a coating of oil and floats off the top of the liquid to a disc filter, where the excess water is drawn through a fabric by a vacuum. The water is recirculated to the washer, and the fine coal is transported to loading or to a dryer.

The refuse does not accept the oil coating and sinks, to be removed with most of the incoming water to a static thickener. The thickener is a large, circular, open tank, which retains the water long enough to permit the particles of refuse to sink to the bottom. Clarified water is removed from the surface by "skimming troughs" around the perimeter of the tank and is recirculated to the cleaning plant.

The tank is equipped with a rotating rake, which rakes the fine refuse from the bottom of the tank to the center of the tank, where it is collected by a pump and transferred to a disc filter. The filter removes part of the water for recirculation and discharges the solids as refuse.

3.5.2.5 Other Processes

Washability is a concept that exploits the differences that exist between the specific gravity of different coals and the associated minerals as a basis for predicting the yields and qualities of the products obtained for any given partition density (Mazumdar *et al.*, 1992; Ryan, 1992). Washability data are always reported in terms of mean specific gravities of particles and those of the liquids used to effect separation. Some degree of predictability during washing operations has become available (Vassallo *et al.*, 1990) which affords a degree of luxury in the determination of recovery and overall behavior of the coal.

Separation of coal and mineral matter can also be achieved by exploiting differences in the surface properties. Froth flotation and oil agglomeration methods (Mehrotra *et al.*, 1983; Schlesinger and Muter, 1989; Couch, 1991; Carbini *et al.*, 1992) are examples of how such separations can be achieved and although differences exist in the surface properties of the coal components.

In coal cleaning by cyclone (Figure 3.4), raw coal and fluid enter tangentially close to the top of the cylindrical section, forming a powerful vertical flow (Meyers, 1981; Couch, 1991). The separation of the impurity from the coal occurs due to a buoyancy effect which arises because of the difference between the mass of any particle and mass of an equivalent volume of displaced fluid. When the fluid is water, this factor is equivalent to the specific gravity. The densest particles therefore move to the wall and downward, and exit with the cyclone underflow. Conditions can be adjusted so that less dense particles remain

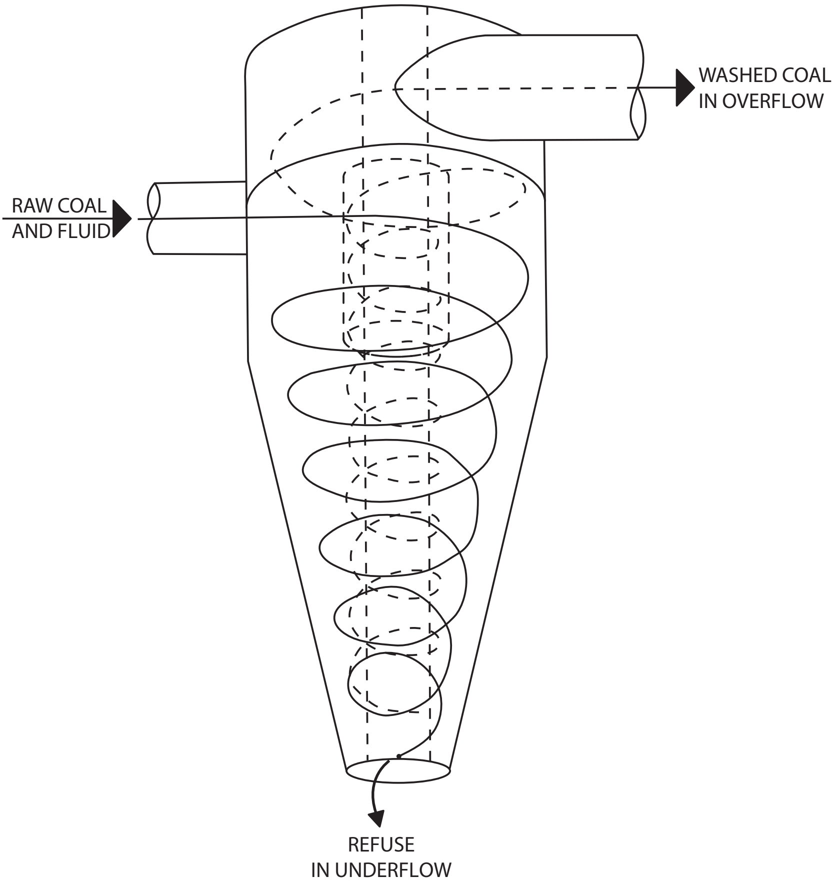

Figure 3.4 Cyclone separation (Speight, 2013).

suspended in the vertical flow and exit from the top of the cyclone. This density separation can be controlled with great precision.

In practice, a material such as magnetite is reduced to fine sizes, usually in ball mills. The viscosity of the suspension increases with increasing fineness of particle size and particle concentration. The settling rates may be reduced and the stability of the suspension improved by the presence of clays and it may be necessary to recondition the suspension by bleeding off part of the circulating volume and recovering the magnetite in magnetic drums and rejecting the clays. Indeed, there is cause for optimism that magnetic methods of coal cleaning (pyrite removal) will be successful and be applicable as a complement to other methods (Kester *et al.*, 1967; Ergun and Bean, 1968; Trindade *et al.*, 1974; Oder, 1978, 1984, 1987).

Various polymeric flocculants exhibit some degree of selectivity for coal against mineral matter and include chemicals such as partially hydrolyzed polyacrylamide, nonionic polyacrylamide, polystyrene sulfonate, and polyacrylamide containing chelating and complexing groups. In some cases, selective flocculation processes suffer from relatively low selectivity. Thus, selective flocculation processes are usually run in multiple stages to remove the entrained ash-forming minerals.

Traditionally, precombustion cleaning has been concentrated on two major categories of cleaning technology: physical cleaning and chemical cleaning (Wheelock, 1977). A new category of coal cleaning, biological cleaning, has recently attracted much interest as advances have been made in microbial and enzymatic techniques for liberating sulfur and ash from coal (Dugan *et al.*, 1989; Beier, 1990; Couch, 1987, 1991).

Microbes are effective in converting organic sulfur compounds such as thiophene derivatives and dibenzothiophene derivatives. Organic sulfur removal is in the neighborhood of 25% (there are claims of higher removal of sulfur) and the combined use of microbes, either simultaneously or sequentially, could potentially improve organic sulfur rejection. The limiting factors appear to be those of accessibility and residence time. Therefore, finer size coal should be used not only to improve accessibility of microbes to coal particle surfaces but also to reduce the overall retention time in the bioreactor.

3.6 Coal Drying

The water content of a coal reduces its heating value, causes handling difficulties, increases handling and transportation costs, and reduces yields in carbonization and other conversion processes. Reduction of the water content is often desirable. In fact, drying coal helps the coal to burn cleaner and more efficiently but because of the unique properties of each type of coal this drying process must be done differently.

Combined reserves of subbituminous coal and lignite (brown coal) make up approximately one-half of the world coal reserves and about one-half of the coal resources of the United States and these coals are rarely processed before shipment or use. However, the oxygen and moisture contents of low-rank coals are greater than those of bituminous coals, which reduces the heating value of the coal as mined, which increases the transportation cost on a heating value basis and reduces the thermal efficiency of the steam boilers that use these coals. One way to offset these disadvantages is to dry the coal before transportation or utilization. However, the characteristics of dried low-rank coal – it is friable, has a tendency to spontaneously heat, and readily reabsorbs moisture – constitute major obstacles that must be overcome to produce a saleable, transportable, dry coal product.

Water occurs in coals in three ways: (i) as inherent moisture contained in the internal pores of the coal substance, including water associated with the mineral impurities, (ii) as surface moisture wetting the external surfaces of the coal particles in which adsorption may play a small part, and (iii) as free water held by capillary forces in the interstices between the coal particles.

Inherent moisture is related to coal rank, being greatest for lignite and brown coals. However, the inherent moisture in coal can make a significant impact on the performance of low-rank coals (which are primarily used for electricity generation) and drying is generally restricted to (i) washed bituminous coals that are required to meet user specifications, and (ii) lignite or subbituminous coals that are employed for the manufacture of briquettes or of other specialty products such as absorbent carbon.

Surface moisture is related to the amount of available surface and the wettability of the coal but moisture contents are lower than might be expected from the available surface area because of the low wettability of coal compared with the surfaces of minerals. Surface moisture can be removed from washed higher rank (bituminous and anthracite) coals by drainage on a screen while the dewatering of washed small coal or coal fines can he accomplished by use of cyclones or centrifuges. If the moisture content must be reduced to lower levels there are two alternate methods which involve the use of rotary kilns or fluidized bed dryers. But such dried coal will reabsorb moisture on exposure to the atmosphere which may give rise to fire hazards as well as (explosion) hazards.

Furthermore, the water in the low-rank coals is progressively more strongly bound to the coal surface as the coal dries and equilibrium relative vapor pressure (or humidity) decreases. The water initially removed from the as-mined coal at close to the saturated vapor pressure (or 100% humidity) is water filling the large pores and inter-particle spaces in the coal. This water has the normal thermodynamic properties of free water. As the coal dries further, capillary water is removed with significant decrease in relative vapor pressure. Below 50% humidity, the water adsorbed in layers on the coal surface is progressively removed with increasing heat of vaporization required and lower vapor pressures due to the increasingly strong hydrogen bonding of the water molecules to the oxygen functional groups on the coal surface.

A distinction can also be made between water in larger pores and capillaries which passes through a liquid-solid freezing phase transition if the temperature is lowered in contrast to water in the smaller pores and surface layers which does not pass through this transition. However this is not significant to drying as the non-freezing water can still be evaporated if heat is applied or the vapor pressure lowered.

It is progressively more difficult to remove the more strongly bound water at lower moisture content. Also note that if a coal is dried to below the equilibrium moisture content (Chapter 5) and then exposed to a humid atmosphere it will re-adsorb moisture until it is in equilibrium with the ambient humidity. This can raise the temperature and exacerbate the propensity of low-rank coals and their upgraded products to spontaneous ignition and thence to spontaneous combustion during transport and storage (Chapters 3, 4).

Loss of volatile organic compounds (VOC) as a result of drying coal at high temperatures is another issue that must be addressed. The loss of useful volatile matter from coal reduces the calorific value while at the same time increases the risk of fire from the combustion of volatile organic compounds. Drying at lower temperature or by using a slight vacuum environment can minimize the loss of volatile organic compounds but such approaches result in a lower rate of drying.

Thermal drying, particularly of metallurgical coals, has found extensive application in some parts of the "coal" world and there is growing interest in the development of efficient methods for drying low-rank coals. Thermal drying entails contacting wet coal particles with hot gases, usually combustion products, under conditions that promote evaporation of the surface moisture without causing degradation or incipient combustion of the coal.

In the process, the clean coal from various wet cleaning processes is wet and requires drying to make it suitable for transportation and final consumption. Thermal drying is employed to dry the wet coal. Drying in the thermal dryer is achieved by a direct contact between the wet coal and currents of hot combustion gases. Various dryers marketed by different manufacturers work on the same basic principle.

The fluid-bed dryer operates under negative pressure in which drying gases are drawn from the heat source through a fluidizing chamber. Dryer and furnace temperature controllers are employed in the control system to readjust the heat input to match the evaporative load changes.

The multi-louver dryer is suitable for large volumes and for the coals requiring rapid drying. The coal is carried up in the flights and then flows downward in a shallow bed over the ascending flights. It gradually moves across the dryer, a little at each pass, from the feed point to the discharge point.

In the cascade dryer, wet coal is fed to the dryer by a rotary feeder; as the shelves in the dryer vibrate, the coal cascades down through the shelves and is collected in a conveyor at the bottom for evacuation. Hot gases are drawn upward through and between the wedge wire shelves.

In the flash dryer the wet coal is continuously introduced into a column of high-temperature gases and moisture removal is practically instantaneous.

Table 3.6 Different types of moisture in coal and methods for removal (Karthikeyan *et al.*, 2009).

Category	Location	Common name	Removal method
Interior adsorption water	Micropores and microcapillaries within each coal particle.	Inherent moisture	Thermal or chemical
Surface adsorption water	Particle surface.	Inherent moisture	Thermal or chemical
Capillary water	Capillaries in coal particles.	Inherent moisture	Thermal or chemical
Interparticle water	Small crevices found between two or more particles.	Surface moisture	Mechanical or thermal
Adhesive water	Film around the surface of individual or agglomerated particles.	Surface moisture	Mechanical or thermal

Finally, understanding the composition of water in coal facilitates the effective removal of coal moisture: as the moisture exits in different states the corresponding method must be chosen for moisture removal (Table 3.6) (Karthikeyan *et al.*, 2009). As a result, dryer type must be chosen according to the task at hand to produce the most effective feedstock for the power plant (Osman *et al.*, 2011).

3.6.1 Rotary Dryers

The rotary dryer is the most established dryer type and one of the most common for general applications. The basic design consists of an insulated cylindrical shell that is mounted on rollers and rotates at a low speed. Rotary dryers allow direct and/or indirect contact between the drying medium and the wet particles, although the former is more common in industry.

In the direct rotary dryers, the wet material is in direct contact with the drying medium. Direct heat transfer is usually provided by a hot gaseous medium blown into the vessel from the gas inlet. For drying of low-rank coal, the drying medium must be free of oxygen to prevent spontaneous ignition and combustion during storage (Chapter 4). Flue gases or heated air are the most common drying medium and in principal suitable for application to low-rank coal. However, there are reports of fires and explosions from oxygen contacting hot coals especially during start-up and shut down from such a system (Wilver and Brumbaugh, 1985). To avoid such accidents, one must ensure that the coal is sufficiently cooled before exposure to the environment.

Gas can flow in the direction of feed progression (parallel flow), or in the opposite direction (counter-flow). Although counter-current flow offers higher thermal efficiency, parallel flow prevents the overheating of the coal near the exit of the dryer.

Typically, an indirect rotary dryer consists of a jacketed shell through which steam or other heating medium flows. At any one time, a small fraction of solids are exposed to the heated wall, resulting in low heat transfer rates and low drying efficiency. One way to improve the performance of an indirect dryer is to increase the area of contact between the heated wall and the particles. This is accomplished by introducing a series of tubes through the rotary shell and passing steam through the tubes. In the steam-tube dryer, wet solids are lifted and showered within the rotary shell in the usual sense, and heated by radiant heat and contact with the outer surfaces of the tubes.

Rotary dryers designed for continuous processing are usually slightly inclined so that as the main vessel rotates, feed material progresses from the higher end of the vessel to its lower end. In such a system, the particles are conveyed by repetitive lifting and falling action provided by the circumferentially mounted flights and the force of gravity. The periodic lifting and showering of the material creates a curtain of particles through which hot gas flows. This agitation leads to higher efficiencies, increased heat transfer rate, and reduced processing time compared to stationary units. Thus, feed material is heated and dried as it progresses through the dryer.

3.6.2 Fluidized Bed Dryers

Fluidized bed drying is ideal for a wide range of particulate or granular solids and has found widespread usage in various industries, including those dealing with chemicals, pharmaceuticals and bio-chemicals, food and dairy products, and polymers. This is mainly due to high temperatures and high rates of mass transfer as a result of vigorous gas-solid mixing. Fluidized bed dryers can compete successfully with more conventional dryer types (e.g., rotary, tunnel, conveyor) in the drying of powders, granules, agglomerates, and pellets, with particles averaging between 50 to 5000 microns. Both heat sensitive and non-heat sensitive products can be dried using one or more of the variations of fluidized bed dryers (Osman *et al.*, 2011).

Each design has strengths and weaknesses and implementation is highly dependent on feed and product requirements. Other advantages include smaller footprint, relatively lower capital and maintenance cost, and ease of control. Among the major issues in fluidized bed drying are (i) high power consumption, (ii) increased gas handling requirements, (iii) tendency to cause product attrition, and (iv) low flexibility in terms of feed type (size and shape) that can be handled.

The performance of fluidized beds, usually characterized by the quality of fluidization, depends on the size and shape of the feed particles, which is apparent in coal drying. To facilitate fluidization of the bed, the most straightforward way is to grind and sieve raw coal before feeding into the drying vessel. Fluidization quality can also be improved by employing mechanical vibrations, agitation, or use pulsating flow of fluidizing gas (Osman *et al.*, 2011).

3.6.3 Microwave Dryers

There has been, and continues to be, high interest in the utilization of microwave. Such overwhelming interest is understandable considering the advantages microwave-related drying systems offer over conventional ones. Conventional drying methods employ surface heating, and are generally a slow process since the rate of heat transfer from the surface to the core of the material is dependent on (i) the process parameters, (ii) the particle size of the coal, and (iii) the properties or type of the coal.

In microwave heating, volumetric heating is achieved and energy is preferentially transferred to moisture in the material without the need to heat the material first, resulting in shorter drying time. Capital and operating costs due to use of the highest form of energy (electricity) in microwave drying remain an impediment despite its technical advantages. It has been reported that the use of microwave energy for drying coal can also result in hot spots and, thus, local overheating of the coal and can be a disadvantage in the selection of this type of dryer for coal application (Osman *et al.*, 2011).

In most microwave drying applications, the feed is usually not stationary – microwave heating is known to be uneven, and tends to form regions of underexposure (*cold spots*) and overexposure (*hot spots*). By keeping the material in constant motion relative to the microwave-guides, more even heating can be achieved. This relative movement is usually achieved by placing the material on a rotating plate or conveyor, and passing it under the microwave guides.

Advantages of microwave heating can be accrued in one of three ways: (i) as a pre-dryer, (ii) as a booster dryer, or (iii) as a post-dryer. When used as a pre-dryer, volumetric heating due to microwave quickly forces internal moisture to the surface, facilitating the optimal operation of a conventional dryer. In booster drying, microwave energy is added as the drying rate begins to fall off, thereby sustaining or even increasing the drying rate. When used as a post-dryer, the microwave system greatly improves drying efficiency of the conventional dryer since the last one-third of water is most difficult to remove by the conventional dryer alone.

Microwave drying also produces clean coal with low-sulfur content using the ability to preferentially direct the microwave energy at the pyrite (FeS_2) in coal giving rise to localized thermo-desulfurization reaction between pyritic sulfur and other neighboring reactive compounds present in the solid (Weng and Wang, 1992). The polarization of microwave fields results in the cleavage of the iron-sulfur bonds, releasing sulfur in the form of hydrogen sulfide (H_2S), carbonyl sulfide (COS), or sulfur dioxide (SO_2).

3.6.4 Screw Conveyor Dryers

When there is need for simultaneous conveying and heating or cooling, a screw conveyor can be easily converted to a dryer or heat exchanger by providing the necessary heat to the moving solids either directly or indirectly and by removing the evaporated moisture by gentle gas flow or by application of vacuum (Osman *et al.*, 2011).

Typically, a screw conveyor dryer consists of a jacketed vessel (generally cylinder or U-trough) in which material is simultaneously heated and dried as it is conveyed. The heating medium, usually hot water, steam, or any thermal fluid, may also flow through the hollow flights and shaft to provide high heat transfer area without the need for additional space or material.

The screw conveyor dryer is essentially a modified screw conveyor system. Therefore successful implementation of the screw conveyer dryer not only depends on the target output properties of the processed coal, but also on the screw dynamics and physical attributes. To determine a suitable screw configuration, physical characteristics of the material to be handled such as flow pattern (related to angle of repose), abrasiveness, and size must be known beforehand. Subsequently, the volumetric feed rate, screw speed, screw size, power requirement, heat requirement, and length of screw can be determined.

3.6.5 Superheated Steam Dryer

Although the concept of drying using superheated steam was conceived more than a century ago, serious interest in superheated steam drying has emerged in the last three decades (Mujumdar, 1990). Many benefits are associated with superheated steam drying, which include (i) the reduced risk of spontaneous combustion, (ii) the increased drying rates, (iii) the better energy efficiency, and (iv) the improved grindability of the coal (Osman *et al.*, 2011).

In the process, the optimum pressure and drying time depend on the size of the coal particles and the resulting moisture content of the dried particle depends on the steam pressure and temperature, the particle size and moisture content of the coal feedstock.

Superheated steam drying requires less energy than hot gas dryer because there is no need to supply coal moisture with latent heat of vaporization. Drying in superheated steam also increases the apparent density of low-rank coal due to shrinkage of the particles on moisture removal. In addition, the decomposition of sulfur functional groups during steam drying process produces cleaner coal with high heating value. Because fire hazards associated with the spontaneous combustion of coal are eliminated in the superheated steam drying process, the target moisture content can be achieved in a short time by using higher steam temperature.

3.7 Desulfurization

The total sulfur content of a raw coal is distributed throughout the macerals and minerals present and may occur as elementary sulfur, as sulfates, as sulfides, or in organic combination in the coal (Speight, 2013).

It has been customary to classify the forms of sulfur as inorganic, pyritic, and organic; inorganic sulfur comprising the sulfates, pyritic the sulfides, and organic the remainder, including any elemental sulfur that may be present. Standard methods of analysis have been devised for direct determination of total sulfur, sulfate sulfur, and pyritic sulfur, the organic sulfur being reported as the difference between the total sulfur content and the sum of sulfate content plus pyritic sulfur content. On a more localized basis such as in the United States (Chapter 1), the sulfur content will vary significantly by region (Table 3.7) thereby creating issues arising from sales to regional power producers because of the various laws relating to emission of sulfur oxides.

Even when coal has been prepared to meet the specifications for size, mineral (ash), and moisture contents, it may still be *dirty* by environmental standards. In this case, the important contaminant is sulfur, which is converted, during combustion, to gaseous product(s):

$$S_{coal} + O_2 \rightarrow SO_2$$

$$2SO_2 + O_2 \rightarrow SO_3$$

Table 3.7 Sulfur distribution in selected US Coals (Speight, 2013).

Region	Total sulfur (%)	Inorganic sulfur (%)	Organic sulfur (%)	Inorganic/total sulfur (%)
Northern Appalachia	3.01	2.01	1.00	67
Southern Appalachia	1.04	0.37	0.67	36
Alabama	1.33	0.69	0.64	52
Eastern Midwest	3.92	2.29	1.63	58
Western Midwest	5.25	3.58	1.67	68
Western	0.68	0.23	0.45	34
Total United States	3.02	1.91	1.11	63

Unless removed, the sulfur oxides end up as stack gas emissions.

In recent years, deliberate attempts been made to achieve coal desulfurization on an industrial scale by modification of the coal preparation practices. In part, this has been due to development of more precise methods for the separation of coal and minerals. However, these practices are usually very dependent upon the coal properties. Thus, where low-sulfur coal feedstock is a necessity, the deliberate selection of naturally occurring low-sulfur coal has been the most effective solution and has been the practice followed in producing metallurgical coals, political aspects notwithstanding as evidenced by the selection of higher sulfur (and inappropriate) coal for politically sensitive, rather than market, satisfaction.

There are strong incentives to develop processes for removing sulfur from coal before combustion (precombustion cleaning), during combustion or after combustion (post combustion cleaning) (Chapters 12, 13, 14).

Indeed, since the passage of the original Clean Air Act of 1970, subsequently amended in November 1990, coal preparation efforts in the United States have emphasized development of technology for the reduction of sulfur.

Coal desulfurization can be achieved on a commercial scale by means of physical or physicochemical methods which generally use the principal of density separation techniques or other techniques that exploit the surface properties of coals and minerals. For example, the methods exploit the difference in properties that exist between the various forms of inorganic sulfur [pyrite and/or marcasite ($FeS_{2)}$ and occasionally including galena (PbS)] and sulfur in the organic matrix of the coal.

Desulfurization by chemical techniques is somewhat less well developed than desulfurization by physical methods. However, a number of methods are under serious consideration and they can be divided into three general groups: (i) those which remove pyritic sulfur; (ii) those which remove organic sulfur; and (iii) those methods which remove either the pyritic sulfur or the organic sulfur or both (Couch, 1991; Ali *et al.*, 1992).

Therefore, effective desulfurization requires that three criteria should be satisfied: (i) the reagent must be highly selective to either pyritic or organic sulfur for both) and not significantly reactive with other coal components, (ii) the reagent must be regenerable so that once-through reagent cost is not a major factor, and (iii) the reagent should be either soluble or volatile in both its unreacted and reacted form so that it can be near totally recovered from the coal matrix.

The use of strong bases (alkali, caustic) appears to offer some solution to the problem of organic sulfur removal and this approach continues to be investigated (Chatterjee and Stock, 1991).

3.8 Transportation

There are many occasions when coal is transported by rail, road, and water in its journey from mine to market. In some mining areas near the coast the coal was taken by conveyors directly from the mine to the holds of large coastal vessels. For example, in Britain, much of the coal from the northern coalfields is taken to the south in coastal cargo vessels called colliers. Large-scale haulage of coal by truck is normally economic only over relatively short distances.

There has, however, been the tendency during recent years to construct large industrial (chemical or power) plants close to the mine site in order to reduce coal-hauling costs and the coal is carried directly to the plant either by high-capacity truck on conveyor belts. In fact, the oil sand processing plants in northern Alberta employ this concept and transport the sand on several miles of conveyor belt to the processing plant (Speight, 1990).

It is easier (and more economical) to transport synthetic crude oil to market than to transport low-value oil sand. Similarly, it is much cheaper to transmit electricity over long distances by means of high-voltage wires than to move the equivalent tonnage of coal. However, the capital costs (and inconvenience) of constructing a plant in a remote area with a hostile environment near to a mine may dictate that this concept he impractical. Thus, the suggestion that coal be transported from the mine site completely or, in part, as a coal/water or coal/oil slurry in pipeline systems may have some merit and could afford a ready means of moving coal to markets using already existing pipeline system(s).

Generally speaking, the majority of mined coal is transported to market by railroad, the remainder being shipped or trucked to its destination or used at the mine. Shipping coal by rail has become a major industry in many parts of the world.

3.8.1 Unit Train

The *unit train* is the most common form of long-distance coal transportation. A unit train is a group of railcars that operate in a dedicated shuttle service between a coal mine and a power plant.

A typical unit train consists of 100 to 120 railcars and 3 to 5 locomotives, with each railcar holding approximately 100 to 110 tons of coal. Carefully coordinated loading and unloading terminals are necessary to minimize costs. A unit train making a round trip from mine to plant has a typical turnaround time of 72 hours, including a 4-hour loading and 10-hour unloading and servicing time per train.

The system is designed so that the trains can be loaded and unloaded without stopping the train, thereby providing a continuous means of shipping the coal as well as an increase in the rate at which the coal can be moved from the mine site to the consumer (Lindberg and Provorse, 1977). As a typical example, it is difficult to drive on many roads in eastern Wyoming, on any given day, without passing several such trains carrying coal to market. In fact, rail service is the lifeline of the large majority (95%) of the western coal mines.

Modern unloaders use rotary dump devices, which eliminate problems with coal freezing in bottom dump cars. The unloader includes a train positioner arm that pulls the entire train to position each car sequentially over a coal hopper. The dumper clamps an individual car against a platform that swivels the car upside down to dump the coal. Swiveling couplers enable the entire operation to occur while the cars are still coupled together. Unloading a unit train typically takes approximately three hours.

Shorter trains may use railcars with an *air-dump*, which relies on air pressure from the engine plus a *hot shoe* on each car. When the *hot shoe* comes into contact with a *hot rail* at the unloading trestle, it shoots an electric charge through the air dump apparatus and causes the doors on the bottom of the car to open, dumping the coal through the opening in the trestle. Unloading one of these trains takes anywhere from an hour to an hour and a half. Older unloaders may still use manually operated bottom-dump rail cars and a “shaker” attached to the cars to dump the coal.

The cost of shipping coal by train is often more than the mining costs. Using a barge or ship to move coal is a lot less expensive. In the United States there are 25,000 miles of waterways, but not enough to reach all destinations in the country. To reduce transportation costs, power plants are sometimes constructed near coal mines.

3.8.2 Barge

Barges on rivers and lakes play an important role in coal transport in the United States and Europe. Coal-carrying barges move in tows of fifteen to forty barges, pulled by a single towboat of 2,000 to 10,000 hp. A "jumbo"-size barge carries 1,800 tons of coal, so a large tow can move 72,000 tons of coal, as much as five unit trains. These large volumes result in significant economies of scale and lower costs. Barge rates can run (on a cost-per-mile or cost-per-kilometer basis) a quarter or less of rail rates. However, waterways often follow circuitous routes, resulting in slow delivery times.

3.8.3 Pipeline

Another method to transport coal is through a slurry pipeline. This connects a mine with a power plant where the coal is used to generate electricity. *Coal slurry pipelines* use a slurry of water and pulverized coal. For pipeline shipment, the coal is ground to approximately the size of coffee grounds and mixed with water to form the slurry. At the power plant the coal is either fed directly to the fuel preparation system or to a pond where the coal settles out and, at a later date, is re-slurried and then pumped to the fuel preparation system. The ratio of coal to water is approximately 1 to 1.

The coal removed from the mine is crushed to a diameter of around one millimeter, and is mixed with water in holding tanks with agitators, which keep the coal in suspension in the water. The pipeline consumes around a billion gallons of water annually. After three days the slurry reaches the end of the pipeline, at the Mohave power plant, where it is held in agitated tanks, for immediate use, and in drying ponds, for later use. Heated centrifuges are used to get the water out. As of 2006, the plant was shut down because the coal and water supply terms are being renegotiated.

Coal slurry pipelines are potentially the least costly available means for transporting coal to any location, measured in economic terms. Whether this is true with reference to any particular pipeline can only be determined by detailed evaluation of the conditions of the route. The current coal transportation scenario does not offer any choices between slurry pipelines and rail-road, which undoubtedly will necessarily minimize the cost of transporting coal. In this context the present times warrant assessment of the potential economic, environmental, and social implications of coal slurry pipeline development and transportation of coal through it.

However, there is need for caution. The large water and energy requirements for coal slurry pose a significant barrier to further deployment, especially in arid regions of Australia and the western United States.

The *coal log pipeline* is another technology for transporting coal in which coal at the mine site is treated and compacted into cylindrical shapes (coal logs) (Liu *et al.*, 1993). Then the coal logs are injected into an underground pipeline filled with water for transportation to destination which may be one or more than one power plants, or to a train station, a barge terminal, or a seaport, for intermodal transportation.

The coal must have been cleaned and crushed, with a binding agent comprised of coal pitch, bitumen, or wax. The coal mixture is then tightly compressed and compacted as coal logs that are 5% to 10% thinner than the transportation pipeline. The logs are injected into a pipeline and pumped along using water. The pipeline can deliver the coal to coal-fired electric power stations or coal storage areas. The coal logs must then be crushed for use in fluidized bed, cyclone, or chain-grate stoker coal-burning boilers or pulverized for use in pulverized-coal combustors.

Proponents of the coal log technology claim that in addition to being more cost effective than coal slurry, the capsule pipeline is also more environmentally sound because the coal logs eliminate coal dust erosion of the pipe interior and erosion of coal fines by rain at the power plant storage site.

Since coal must be relatively dry before it can be burned efficiently, so the coal must be dried after it arrives at the power plant. Coal transported as slurry requires drying and electricity generation will be substantially less if it is not dried effectively.

Coal logs do not require as much drying because they are packed so tightly that they do not absorb much water, and any water originally in the coal is squeezed out during compression.

3.8.4 Truck

Coal-carrying vehicles are typically end-dump trucks with a carrying capacity of roughly 25 to 50 tons. Truck delivery is used extensively for small power plants in the eastern United States.

Coal can be moved by truck over regular highways in vehicles with 15 to 30 tons capacity. Coal can also be transported by large off-road trucks with capacities ranging from 100 to 200 net tons. These trucks are almost always diesel-powered with back or bottom dump.

Specially constructed roads for coal hauling are extensively used for mine-mouth power plants in the west, south, and east, while the hauling of coal by trucks on highways is more concentrated at surface mines. Truck hauls on public highways in the United States typically range from approximately 50 to 75 miles while off-road hauls are approximately 5 to 20 miles.

Trucks are the most versatile of all transportation modes for coal hauling because they can operate over the widest areas where roads are available.

However, adverse environmental impacts resulting from truck coal hauling are coal dust particle releases during coal loading or unloading, and coal dust entrainment during transport. Some coal will escape from the trucks during transport because the loads are normally uncovered. The coal dust tends to wash off roadways during rainstorms, causing aesthetic unsightliness and contamination of runoff waters. The air pollutant emissions from diesel fuel combustion add to the emissions.

3.8.5 Ocean

Ocean transport of coal requires a system of (i) transportation from the mine to the port, (ii) coal-handling facilities at the export port, (iii) ocean carrier networks with adequate number and size of ships, contractual obligations, management of the fleet, and route decisions, (iv) coal-handling facilities at the importing port, and (v) transportation from the port to the customer.

Ships are commonly used for international transportation, in sizes ranging from (i) handy size vessel, which is approximately 40,000 to 45,000 dead weight tons, DWT, a term normally taken to mean a vessel of approximately 10,000 to 40,000 DWT, (ii) a panamax-size vessel, which is approximately 60,000 to 80,000 DWT; technically, the maximum size vessel that can pass through the Panama Canal is restricted to a 105-foot beam, and (iii) a cape-size vessel which is capable of carrying >80,000 DWT; this is a vessel that is too large to transit the Panama Canal and thus has to sail via Cape of Good Hope from Pacific to Atlantic, and vice versa.

However, the ability of coal to variously self-heat (spontaneous ignition), emit flammable gases, corrode, and deplete oxygen levels has made the ocean transport of this commodity a particularly hazardous exercise. This is particularly the case in situations where loading is staggered or delayed and the potentially disastrous consequences of a shipboard coal fire can be realized.

3.8.6 Conveyer Belt

Conveyor belts are normally used in mine-mouth power plants to bring coal from the mining area to the storage or usage area. Conveyor belts can be used for coal transport in hilly terrain where roads are relatively inaccessible, typically being used to move coal over distances of 5 miles to 15 miles.

Conveyors have the advantage of being relatively maintenance free but have the disadvantage of location inflexibility, making a truck haul still necessary. Movable conveyor belts have been developed and used. The only adverse environmental impacts of conveyor belts for coal transport are coal dust losses during loading, unloading, or transport.

Conveyor belts do not use water, except for belt cleaning; they can use plant electricity and do not require crude oil as the energy source. However, conveyor belts tend to be very energy-intensive. As a result, conveyor belt transport of coal has been limited to shorter distances.

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4

Storage

4.1 Introduction

Coal storage in stockpiles is essential in ensuring continuous supply of feedstock for large capacity power units. In fact, it has been estimated that coal stockpiles at electric power plants in the United States in March 2012 (EIA, 2012) were approximately 196 million tons, almost 18% w/w above the level in March 2011 and above the five-year range. Coal stockpile levels typically decline during summer and winter months as power plants burn through stocks to meet seasonal peak electric demand for cooling and heating load, respectively. However, mild weather during the winter of 2011/2012 combined with decreasing natural gas prices decreased the demand for coal-fired electricity. There are disadvantages to storing large quantities of coal because of the characteristics of coal and important problems may emerge because of its long time storing in open areas.

By way of explanation, there are other forms of coal storage – while coal is typically stored in stockpiles, which are piles or storage locations for the bulk materials. More controlled stockpiles are used in many different areas and are formed using stackers to form piles along the length of a conveyor and reclaimers to retrieve coal when required for product loading. On the other hand, a coal bin or a coal bunker is a storage container for coal awaiting use or transportation. This can be either in domestic, commercial, or industrial premises, or on a ship or locomotive tender, or at a coal mine or processing plant. Domestic coal bunkers are associated with the use of coal in open fires or for solid-fuel central heating. Free-standing bunkers were commonly made of wood or concrete and are currently sold in materials including plastic or galvanized metal. Coal bins or bunkers could also be partly or fully underground. Coal bins formed part of industrial plants and were also used for coal storage on steam ships.

A stockpile (stockpiling machine, commonly referred to in this text as a stacker) is a bulk stockpiling machine that is used to stockpile coal either at the mine site before transportation or at the power plant before use. The stockpiling machines come in different shapes according to specific requirements and the function of the machine is to pile or stack the coal on to a stockpile for later reclamation and use – a reclaimer is generally used to reclaim or recover the stockpiled material. The stockpiling unit typically moves on a rail between stockpiles in a yard and usually has three directions of movement, depending on requirements (i) horizontally along the rail, (ii) vertically by raising or lowering the boom, sometime referred to as *luffing*, and (iii) slewing, which is rotation of the stacker around its central axis and may not always be a requirement.

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Because of the tendency of coal to self-heat followed by spontaneous ignition and spontaneous combustion (Sloss, 2015), there are cautions that need to be observed and stockpiling (sometimes referred to as stacking) of coal has to be done consciously and by respecting basic rules and procedures. The storage site must be properly prepared in order to minimize the risk of fire. Several rules of thumb in coal storage can be enumerated: the coal should be stored in several small piles instead of a large one in order to prevent temperature buildup and facilitate the inspection; stockpiles should not be higher than 12 feet and should not contain more than 1,500 tons of coal; storage of coal with high content of moisture should be avoided. The storage volume and the storage time are parameters depending on safety and continuity of coal supply to the power plant. Since the coal stockpile acts as a buffer between the coal extraction unit and power plant the stockpile volume and storage time cannot be properly controlled.

Although stockpiling is generally done in open areas, there are also covered stockpile areas or completely closed coal silos. Storage of coal is an important part of coal handling systems at coal-fired power plants, particularly since the advent of the unit-train concept in transportation. With this in mind, coal storage is generally practiced in order to accomplish one, or a combination, of the following objectives: (i) to be ready for use in the power plant promptly, (ii) to facilitate blending in order to even out chemical and physical inconsistencies that exist in such a heterogeneous material and to produce a combustible feedstock that has the necessary uniform quality, and (iii) to store coal of preferential sizes where the demand is seasonal (Barkley, 1942; Berkowitz and Speight, 1973).

In a very general sense, the self-ignition process occurs naturally due to the low-temperature oxidation reaction. The main factors that favor the self-heating are humidity and presence of oxygen. Continuous supply of oxygen as in the case of a coal stockpile exposed to wind increases the rate of the low-temperature oxidation reaction. Significantly higher temperature values and hot-spot sites can occur in the vicinity of the side slope of the stockpile that is exposed on the windward side.

Oxygen penetration depth in the coal bed is influenced by the coal porosity and hence the hot-spots may occur at different depths in coal stockpiles with different values of the coal porosity. In addition, the humidity of the coal plays an important role in the dynamics of the self-ignition process. Low-grade coal with high humidity content is more prone to self-heating. In such case, the temperature increases rapidly at the beginning of the storage process. As the temperature increases the evaporation will absorb heat and the temperature may approach a steady state (Akgun and Essenhigh, 2001).

Coal stockpiles are prone to spontaneous combustion especially where large quantities are stored for extended periods. Coals that exhibit the greatest tendency to self-heat (that is lignite, subbituminous coal, and brown coal) are rarely stored for any length of time at the power station. Self-heating of coal is a naturally occurring process caused by the oxidation of coal. Natural oxidation is uncontrolled and can lead to emissions and spontaneous combustion (Berkowitz and Schein, 1951; Berkowitz and Speight, 1973; Carras and Young, 1994; Arisoy *et al.*, 2006; Speight, 2013). Unless handled correctly, the results can be catastrophic in damage to power plant equipment. This is a reflection on the relative length of storage time involved at each stage. Spontaneous combustion in stockpiles poses significant safety, environmental, economic, and handling problems.

4.2 Stockpiling

As with the other fossil fuels – natural gas and crude oil-based fuels – there is the need to store coal in order to accommodate the possibility of a disruption in supply. Like the other fossil fuels, coal is a material which can be stored in large quantities because of some necessities. For safety reasons and for convenience, stockpiling of coal is typically done in open areas but there are also covered stockpile areas or completely closed coal silos. Some reasons for coal storage are (i) decrease of demand for coal in the market, (ii) to be ready for the bottlenecks caused by the interruptions that may occur during production, (iii) to meet the demand by the consumer without interruption, (iv) to produce the coal in more congenial climate conditions – such as during the non-winter seasons of spring, summer, and autumn – to be available for the winter market, (v) to decrease the moisture content of coal through the elevated temperature or elevated winds of the non-winter seasons, (vi) to lessen any defects – disruptions in the operation – that may occur in coal washing plants and in thermal power stations, (vii) to ensure that the feedstock coal for the thermal power stations retains the specified properties. However, some negative developments are observed in various characteristics of coal and important problems may emerge because of its long time storing in open areas. Consequently, stockpiling of coal has to be done consciously and by respecting basing rules.

Initially, produced coal is generally loaded in trucks or wagons by excavators and loaders to be transported to the storage areas. Use of a conveyor belt system is another transportation alternative. In recent years, the increased capacity of trucks, their ability to function in topographic irregularities, and their easy adaptation to the changes in working areas are the reasons for preference of transportation by trucks.

In the enterprises where bucket wheel excavators are used, the transportation of coal to the storage area by means of conveyor belt bridges becomes possible. Same operations are relevant for the transportation of the coal carried by ships from the harbor to the storage area. The coal transported to the storage area is spread by movable or fixed belt systems and according to desired stockpile geometry.

Stockpiling is carried out at coal mines, coal preparation plants, transshipment facilities (including export/import facilities) and end user sites such as coal-fired power plants. Thus, after arrival at the destination (the power plant), it is often necessary to place the coal in stockpiles until it is required – this is not a long period and an approximate rule of thumb is to use within the week of arriving at the power plant site (Narasiah and Satyanarayana, 1984).

There is always economic pressure to minimize the amount of capital tied up in stockpiles with little return on the investment. Thus, there is a need to optimize coal inventories wherever coal is stockpiled. Issues such as (i) optimum stockpile size, (ii) stockpile turnover period, (iii) timely stock management, and (iv) the ability to take advantage of cheaper coal when such coal is available on the market have assumed greater importance. Thus, coal stockpile systems perform two main functions: (i) they serve as a buffer between coal material delivery and processing, and (ii) as a source of coal for blending.

The stockpile site must be carefully chosen and prepared – typically stockpiles are designed as open store areas. The ground should be cleared of any vegetation and refuse.

A hard packed clay or sandy soil is ideal; if not available, a concrete pad can be installed to keep dirt out of the coal. The site should be dry, level and well drained. If drainage is not a natural phenomenon, drains should be installed around the storage pile, not underneath it as this may produce upward air currents through the pile, aiding spontaneous combustion. The site should be away from any external heat sources as combustion liability increases with a rise in temperature.

However, if conditions dictate (such as heavy rainfall or melting snow (as happens frequently in North America) or if the stockpiles are near residential areas), there is the option to cover the stockpiles. However, the cost of storing large amounts (up to several hundred thousand tons of coal in an enclosed system can have a negative influence on the economic scale.

4.2.1 Stockpile Construction

The chief danger in storing coal is spontaneous combustion and its risk can be greatly reduced if dust and fine coal are kept out of the pile. Cleaned and sifted coal with uniformly large lumps stores better than mixed sizes. Sized coal should not be stored on top of a layer of fine coal and the coal should be handled carefully to prevent breakage and dust formation – friable dusty coal should be piled in small low piles. In addition, the coal should be piled so that any part of the pile can be promptly moved if heating occurs. It is preferable to spread the coal in horizontal layers and not in conical piles to prevent the finer coal from clustering in the center and the lumps rolling to the bottom. If practical, the coal should be stored in several small stockpiles instead of one large stockpile to prevent heat buildup and make inspection of the coal easier. Coal piles should not be stockpiled higher than 12 feet and should not contain more than 1,500 tons in a single pile. No point in the interior of the stockpile should be more than 10 feet from an air-cooled surface.

In many countries many stockpiling methods have to take into account climatic conditions, dimensions, and design of the stockpiling area, as well as the type of machinery used for the stockpiling operation. The coal stockpiles formed in open areas can be generally in the form of a cone, prism, or a variety of geometric shapes. Typically, the methods of stockpiling are (i) the windrow method, (ii) the cone shell method, and (iii) the Chevron method.

The general parameters that can affect coal storage are (i) the site, especially the base upon which the coal will be stored, (ii) mitigating the tendency of spontaneous ignition of the coal, and (iii) the moisture content of the coal.

The site must be carefully chosen and prepared – the ground should be cleared of any vegetation and refuse. A hard packed clay or sandy soil is ideal but, if this is not available, a concrete pad can be installed to keep dirt out of the coal. The site should be dry, level and well drained. If the site does not drain naturally, drains should be installed around the storage pile, not underneath it as this may produce upward air currents through the pile, aiding spontaneous combustion. Make sure the site is away from any external heat sources as combustion liability increases with a rise in temperature.

The chief danger in storing coal in stockpiles is the potential for spontaneous combustion – this risk can be greatly reduced if dust and fine coal are kept out of the pile. Cleaned and sifted coal with uniformly large lumps stores better than mixed sizes – sized coal should not be placed on a layer of fine coal and the coal should be handled carefully to prevent breakage and dust formation – friable dusty coal should be piled in small low piles. The coal should be piled so that any part of the pile can be promptly moved if heating occurs. The coal should be spread in horizontal layers and not in conical piles to prevent the finer coal from clustering in the center and the lumps rolling to the bottom. If practical, the coal should be stacked in several small piles instead of one large one, to prevent heat buildup and allow the coal to be inspected. Coal can be stored covered or in the open. Wetting and drying coal repeatedly may make it more susceptible to combustion. The actions of water may break up the coal, especially after freezing and thawing. Wet coal or mixed wet coal should not be stored with dry coal and coal should not be stored on a damp base. After heavy rains and snows the coal pile should be inspected and monitored carefully.

4.2.1.1 The Windrow Method

Windrow stockpiles can be created using different techniques of stockpiling. One method is to use a bridge and tripper conveyor system, though this alternative is feasible only for stationary applications. One significant disadvantage of stationary conveyor systems is that they are typically fixed in height, which can result in segregation by wind, as discussed earlier. Another method is to use a telescoping conveyor. Telescoping conveyors are typically preferred over stationary systems because they can be relocated when necessary, and many are actually designed to be road-portable.

In the process, the stockpiling machine moves on rails and spills the coal in parallel rows along the length of the silo by changing the boom angle from the ground level. The stockpiling operation is achieved by the back-and-forth movement of the unit along the stockpiling area and beginning to spill the first rows then the second, third rows, and as many rows are as required.

A good blend can be obtained when the coal is taken by a reclaimer from the stockpile formed with this method. The disadvantage of this method is collection of rain water between the coal rows and penetration in the stockpile as a result of long-lasting and continuous rainfall.

4.2.1.2 The Cone Shell Method

In *cone shell method*, coal is added to the pile in a cone shape until the final pile height is reached. The stockpiling unit begins to spill the first cone, then moves one step forward to spill the second cone until the stockpile height and continues the operation step by step. This method can be applied in areas where long and rigorous winter conditions prevail in order to ensure that stockpiled coal is affected by rain water at minimum level. Stockpiling in a single cone tends to cause size segregation, with coarser material moving out towards the base. In raw cone ply stockpiling, additional cones are added next to the first cone.

A good blend is obtained when the coal is taken from the stockpile by a reclaimer. For an optimum blend, the reclaimer has to work perpendicularly to the long axis of the stockpile. To adjust the calorific value of the blend, high calorific valued coal can be added during the stockpiling operation.

4.2.1.3 The Chevron Method

In the *Chevron method*, the stockpiling unit moves along the storage area on an axis which divides the area in equal parcels and spills the coal in triangular prism-shaped stockpiles (like the chevrons on a military uniform). The stockpiling operation is first performed along the first prism. The machine spills the second layer on its way back and continues the same operation until the desired final stockpile height is reached.

When this method is used, the rain water flows down on the slopes of the stockpiled coal. In summertime, since the surface area exposed to the hot air is larger, drying effect becomes more significant. In addition, the rock particles not picked out in the production process roll down on the slopes during stockpiling and consequently separate from the coal.

4.2.2 Stockpile Management

Other than the gernal adverse effect of the deterioration of the coal due to aerial oxidation, the most important aspect of stockpile management is avoidance of the fire caused by self-oxidation followed by self-ignition of the coal leading to combustion of the stockpile. Stockpile fires are a serious safety issue and cause an economic imbalance in the power plant operation. In addition, the gases formed during the fire and the wastes as a result have harmful effects on the environment (Okten *et al.*, 1998; Speight, 2013).

Furthermore, the growing economic constraints, the need for smaller stockyards with the ability to blend coals with the accuracy demanded by consumers, and the increasing use of timely delivery has increased the significance of stockpile management within the international coal market. Terminals are required to handle more throughput and more grades of coal, at higher handling rates and with less impact on the environment, and to do it at lower cost. All of these issues require improved stockpile management in order to avoid supply disruptions and the consequences of interruptions in the power supply.

The size of stockyards varies from several thousand tons to more than six million tons at coal export terminals. The level of stockpile management sophistication can, therefore, range from simple coal piles at some sites to highly automated stockyards used by major coal exporting ports or large tonnage consumers. Stockpiles are also employed for long-term storage, typically at coal-fired power plants, to guarantee supply. Thus the management of stockpiles is specific to the site and depends on the purpose of the facility. In addition, the actual cost of coal storage and security of supply can be difficult to determine.

Good stockpile management is an important part of the coal supply chain from mine to customer. In fact, most coal producers and consumers make use of stockpiles at their respective facilities. Typically, more coal is being produced and traded internationally, providing a wider choice of sources to consumers. In addition, excess production can (and does) drive prices down, which has forced a greater focus on stockpile management. Issues such as (i) optimum stockpile size, (ii) stockpile turnover periods, and (iii) timely stock management have assumed greater significance to coal producers and coal users. However, there is a balance between security of supply and the cost of the stored coal. The optimum inventory is site specific because each site is governed by a unique set of factors. For example, power plants that import coal need to carry larger inventories than mine-site power plants. There may also be safety or environmental issues. The amount of coal in stockpiles at the mine-site power plants will be kept to a minimum because of the potential for spontaneous ignition and ensuing combustion.

Responsible auditing is required to reconcile the actual amount of coal in the stockpiles to the inventory record. By precisely knowing the tonnage of coal present in a stockpile, it is possible to reduce coal inventories that are too large. In addition, coal consumers are more stringent in their demands to both quality and price. However, taking advantage of the cheaper coal available on the market involves purchasing lower quality coal – hence the need for on-site blending operations.

Coal in storage should be inspected regularly and if the temperature reaches 60°C (140°F), the pile should be very carefully watched. If the temperature continues to rise rapidly, the coal should be moved as promptly as possible and the coal thus moved should be thoroughly cooled before being replaced in storage, or still better, it should be used at once. If the temperature rises slowly the pile should be carefully watched, but it is not necessary to begin moving the coal at as low a temperature as when the rise is rapid, for the temperature may recede and the danger be past.

Coal should be moved before it actually smokes. Such smoking may begin at temperatures as low as 85°C (180°F) – steaming should not be confused with smoking since steam can be frequently seen coming from a pile and this does not necessarily indicate a danger point. Temperature tests of coal in storage should be made, if possible, and one should not depend on such indications of fire as odor or smoke coming from the coal.

Inflammable material, such as waste, paper, rags, wood, rosin, oil, and tar in a coal pile often form the starting point for a fire, and every effort should be made to keep such material from the coal as it is being placed in storage. Irregular admission of air into the coal pile around the legs of a trestle, through a porous bottom such as coarse cinders, or through cracks between boards, etc., should be avoided.

It is important that coal in storage should not be subject to such external sources of heat as steam pipes, because the susceptibility of coal to spontaneous combustion increases rapidly as the temperature rises. The effect of ventilating of coal remains a disputed point, but the weight of evidence in the United States seems to be against the practice. This may possibly be due to the fact that ventilation has been imperfect and has done more to promote oxidation than cooling of the stockpile.

The majority of the coal stockpile fires appear to have occurred within ninety days after the coal was placed in storage. Hence particular attention should be given to the pile during the first three months that it is in storage. The greater the area of the pile exposed to the air the more quickly will the danger be passed.

Finally, a storage plan must consider all of the conditions, and not only a part of the ambient conditions at the site. For example, clean, lump coal of a certain kind may be stored with safety in high piles – while the same coal, run-of-mine or unscreened, may not be safely stored at all, or at least only in smaller piles. Lack of attention to details during storage or failure systematically to inspect storage piles and to be ready for any emergency that may occur may result in safety hazards and losses from fires. It must also be obvious that as the amount of coal stored increases, increased care must be taken in the method of storing and in watching the coal after storage.

4.2.3 Coal Mixing, Homogenization, and Blending

Coal mixing is the random rearrangement of coal particles by means of mechanical energy, such as use of a rotary device in a fixed volume. Traces of individual components can still be located within a small quantity of the mixed material of two or more material types and is common for small-scale storage of coal.

Thus, coal homogenization refers to the process of mixing coal to reduce the variance of the product supplied. This homogenization process is performed during the coal stockpiling operation. Thus, coal homogenization is the systematic regrouping of the input flow in order to provide a more homogeneous output flow of one type of material so that inherent fluctuations of chemical or physical properties in time are evened out compared to the input flow. A common application of this method is when one batch of coal is homogenized.

Coal blending is the integration of a number of raw materials with different physical or chemical properties in time in order to create a required specification or blend. The aim is to achieve a final product from, for example, two or more coal types, that has a well-defined chemical composition in which the elements are very evenly distributed and no large pockets of one type can be identified. When sampled, the average content and the standard deviation from the average are the same. The method is used for different types of coal for specific purposes.

Although the terms blending and homogenization are often used interchangeably, there are differences. The most notable difference is that blending refers to stacking coal from different sources together on one stockpile. The reclaimed heap would then typically have a weighted average output quality of the input sources. In contrast, homogenization focuses on reducing the variation of only one source. A blending operation will cause some homogenization.

Blending is typically achieved through the stockpiling of different coals on a stockpile or within the hatch of the vessel (in the case of transportation by water) during ship loading. Stacking methodology (such as the windrow method, the cone shell method, the Chevron method) can also impact the homogeneity of the final blended material. Blending sometimes will take place prior to the coal handling and processing operations in order to achieve attributes (e.g., feed ash levels) that can improve coal handling and processing operations production rates.

Blending may take place in several locations within the demand chain including (i) before entering the processing plant, (ii) immediately after the processing plant, (iii) train load out, (iv) port stockyard, (v) ship loading, and (vi) at the customer stockyard. Blending decisions impact the total tonnes of each product that a mine site is able to sell. In addition, the quality attributes of a product can impact the final sale value of the product. Because blending has a significant impact on mine site revenue, several decision support systems have been developed with the aim of improving product reliability and profitability.

Blend analysis is the process of understanding what blending options exist within a specified schedule and how these options impact product quality, projected revenue, and scheduled mining decisions.

Sampling of coal is an important part of the process control. A grab sample is a sample of the coal at a point in the process stream, and tends not to be very representative. A routine sample is taken at a set frequency, either over a period of time or per shipment. Coal sampling consists of several types of sampling devices. A *cross cut* sampler mimics the *stop* *belt* sampling method the cross cut sampler mounts directly on top of the conveyor belt, the falling stream sampler is placed at the head section of the belt. There are several points in the wash plant that many coal operations choose to sample the raw coal before it enters the plant.

Coal blending in a power station scenario is mainly adopted to reduce the cost of generation and increase availability of coal. The low-grade coals can be mixed with better grade coal without deterioration in thermal performance of the boiler thus reducing the cost of generation. In many nations, blending of coal was being adopted for a long period mainly for increasing the availability of coal for power generation. To improve the availability of coal and also to improve the calorific value of coal being fired, some of the power stations look at the possibility of mixing high-grade imported coal with the low-grade high-ash coals.

There are many methods adopted for blending, which can be at coal mines, preparation plants, transshipment point and power stations. The method to be chosen will depend upon the site conditions, level of blending required, quantity to be stored and blended, accuracy required and end use of blended coal. Normally in large power stations, handling a large quantity of coal, the stacking method with fully mechanized system is followed.

To decide whether or not to blend different coals it is necessary to understand the composition of coals that are to be blended. This involves (i) an understanding the origin of coal, (ii) the chemistry of inorganic constituents, (iii) chemistry of the organic constituents, and (iv) the combustion properties of the coals as well as (v) the behavior of the coals to be included in the blend. Also, during combustion, it is really necessary to understand the physical conditions and coal properties during heating of the particles, devolatilization, ignition and combustion of the volatile matter and ignition and combustion of the char. It is also equally important to know the phase changes in mineral matter and other inorganics present in coal. The combustion efficiency and carbon loss will have to be also addressed during blending of coals. It is also necessary to investigate the various aspects of slagging, fouling, and the emission characteristics such as the sulfur oxides, the nitrogen oxides, and the particulate matter. However, caution is advised because of the complexity of the combustion process and the number of variables involved (Chapter 7), it may be difficult to extrapolate small-scale (laboratory) results to the full-scale plant. Also, predicting the risk of spontaneous combustion of coal stocks is another important aspect of coal behavior since the inherent dangers of uncontrolled burning can lead to the release of pollutants, while the economic issues associated with the loss of a valuable energy resource is also a concern.

The presence of trace elements in coal combustion has also received increased attention throughout the world during the last few years, with elements such as mercury of particular concern. One way to reduce trace element emissions is cleaning the coal prior to combustion. The use of cleaner coals – such as coals with a low content of mineral matter and low sulfur content – can have the added advantage of substantially reducing operating costs. Again, however, some effects may be detrimental since the effects on corrosion and precipitator performance are uncertain, which makes testing vital.

A limitation to blending coals is the compatibility of the coals themselves and problems are more likely when blending petrographically different coals or coals with different ash chemistry. Non-additive properties make blend evaluation for power generation inherently complex and it is necessary to understand the manner in which the inorganic components of coals in the blend interact and how this affects behavior of the ash.

In summary, blending decisions should be based on the knowledge of the specific behavior of a given pair of coals, rather than an assumption of linear variation of properties with blend traction. Stringent constraints (such as environmental regulations, maximum efficiency at a reduced cost of power generation, improved availability, and reliability) that are placed on coal-fired power stations and the continuing development of new technologies means that the issue of quality improvement of the feedstock will remain a primary factor.

4.3 Effect of Storage

Coal in storage in stockpiles (or in any from when it is exposed to the air) has a tendency to lose heating value and coking quality. In general, high-rank coal (safely stored so as to limit oxidation to a minimum) will lose only about 1% of the heat value per year. On the other hand, improper storage can result in a 3 to 5% loss in the heat value during the first year (Rees *et al.*, 1961).

In addition, the coking characteristics of many coals and coal blends are so seriously affected by aging in storage that they may be totally worthless as a coke oven charge (Landers and Donoven, 1961). However, the data and claims can vary and range from (i) there is no effect on the coking properties after months and years of storage to (ii) there is significant loss of coking properties in as little as one month of storage time. Storage of low-rank coal presents particular problems in that it is usually accompanied by loss of strength, degradation, and some loss of heating value (Jackman, 1957; Mitchell, 1963).

4.3.1 Long-Term Storage

When coal is stockpiled in the open and is to remain in storage for long periods of time, such as through a winter or during extended periods of diminished sales, the area(s) selected for storage should be dry and be constructed to permit good drainage. The area must then be made free of all combustible material having low ignition temperatures, such as wood, rags, dry hay, and the like (Allen and Parry, 1954).

Clay or firmly packed earth, upon which fine coal is rolled, should form the base of the storage pile and the coal should be spread over the entire area in thicknesses of approximately 1 to 2 feet and compacted. The formation of conical piles should be avoided and the top and sides of the pile should be compacted or rolled to form a seal and exclude air. An effective seal of a coal pile is afforded by a continuous layer of fine coal followed by a covering of lump coal to prevent loss of the seal through the action of wind and rain.

Larger sizes of screened coal can be stored with little difficulty. Loose storage that allows natural ventilation to dissipate the small amount of heat produced is usually adequate. In addition, seals of compacted fine coal may be employed. This can minimize the undesirable production of fines if the coal has a tendency to slack. Run-of-mine coal and stoker-sized coal should be stored by the layering method, with sides sloped for drainage. Oil treatment of smaller sizes of coal (at ambient temperature or by use of a thermal method) is at times desirable as it slows the absorption of moisture and oxygen (Berkowitz and Speight, 1973).

When heating and fires develop in storage piles and it is impractical to spread out the coal to cool, smothering by compaction with heavy equipment is generally the best procedure since water flooding may wash out voids in the pile, allowing the fire to spread. Heating in storage piles can be detected, before it becomes serious, by driving small-diameter pipes at intervals vertically into the pile and using thermometers or thermocouples to measure the temperature. The pipes should be driven completely through the pile to avoid a chimney effect.

4.3.2 Short-Term Storage

Similar actions to those described for long-term storage can (should) also be applied to the short-term storage of coal in stockpiles, particularly at unit train loading facilities with reclaiming tunnels. The major hazard associated with coal recovery tunnels is the possible formation of an explosive atmosphere originating from accumulation of methane and coal dust (Stahl and Dalzell, 1965). Methane often will accumulate despite what appears to be adequate ventilating practice; dust accumulations vary with the surface moisture of the coal.

The release of emanation of methane from coal forms a sluggish atmosphere and may inhibit low temperature oxidation, exceptionally in coals with high content of gas but methane is also a potential as a source of energy (Thomas, 1992). Furthermore, as the methane desorption decreases sharply with time, more of the coal surface will be exposed to oxidation.

Closed-end coal recovery tunnels should be equipped with adequate escape passages that, if properly constructed, can also serve as ventilation ducts. Tunnel walls should be washed down frequently to prevent dust accumulation and welding, and electrical repair work should not be conducted in the tunnel during reclaiming operations or if gas or dust is present in the tunnel. Fire-fighting and respiratory protective equipment should be readily available.

4.3.3 Disadvantages

In addtion to the benefits of having a ready source of coal for the plant, coal stockpiling also presents also some disadvantages, some of which are (i) stacked coal can be uneconomical because of the costs of the stockpiling operation and the maintenance of the stockpiles, (ii) as a result of oxidation, the coking propensity and the calorific value of the coal may be decreased, (iii) oxidation of coal causes an increase in ignition temperature, (iv) if the coal is fragile, it will be fragmented and the percentage of the small particle size material is increased, (v) oxidized coal decreases the performance of washing plants, and (vi) as a result of storage of the coals containing high percentage of methane in closed silos which are not ventilated as required, explosive gas compositions can be formed.

However, the most important of these disadvantages are the fires caused by oxidation and self-ignition of the coal. These fires in stockpiles cause the loss of feedstock to the power plant and the gases formed by the combustion of the coal (as well as any waste material formed, such as mineral ash) can result in harmful effects on the environment (Duzy and Land, 1985, Ökten *et al.*, 1998).

4.4 Spontaneous Ignition

The spontaneous ignition of coal (also variously referred to as the spontaneous combustion or autogenous heating of coal) has been recognized as a hazard for some time to the extent that, in the early years of the 20th century, guidelines were laid down for the strict purpose of minimizing the self-heating process (Haslam and Russell, 1926) and have been revised since that time (Allen and Parry, 1954).

Self-heating in coal stockpiles occurs naturally, especially in low-grade coal with a high content of volatile matter, although several contributory proeprties have been identified (Table 4.1). These properties primarily influence the rate of heat generation during the self-heating of coal. Since most of the combustible matter in coal is carbon, when coal is stored in an atmospheric environment, the carbon slowly oxidizes to form carbon dioxide and carbon monoxide. The oxidation reaction with hydrogen in the coal forms water and the production of both water and carbon gases in the coal will contribute to the self-heating. These reactions produce heat; since coal is a relatively good insulator, much of this heat is trapped, increasing both the temperature and the rate of oxidation. Depending on how the coal is stored, heat production may substantially exceed heat loss to the environment, and the coal can self-ignite.

The self-heating occurs when the rate of heat generation exceeds the rate of heat dissipation. Two mechanisms contribute to the rate of heat generation, coal oxidation and the adsorption of moisture. The reactivity of coal is a measure of its potential to oxidize when exposed to air. The moisture content of a coal is also an important parameter in the rate of heat generation of the coal. Drying coal is an endothermic process, in which heat is absorbed, and the temperature of the coal is lowered. The adsorption of moisture on a dry coal surface is an exothermic process, with a heat producing reaction. If it is partially dried during its mining, storage, or processing, coal has the potential to re-adsorb moisture, thus producing heat. Therefore, the higher the moisture content of the coal, the greater the potential for this to occur. The most dangerous scenario for spontaneous combustion is when wet and dry coals are combined; the interface between wet and dry coal becomes a heat exchanger. If coal is either completely wet or completely dry, the risk is substantially reduced. In general, the moisture content of coal increases with decreasing rank.

Table 4.1 General properties that contribute to spontaneous combustion.

Property	Comment
Moisture content	Related to the amount of drying and rewetting occurs during handling.
Friability	Related to the extent of size degradation occurs.
Particle size	Related to the exposed surface reaction area.
Rank	Related to the percentage of reactive components that tend to decompose as the coal rank increases to bituminous coal and anthracite.
Pyrite	Concentrations greater than 2% w/w have high effect.

Friability and previous oxidation of the coal are also important factors in the self-heating process. The friability of the coal is a measure of the coal's ability to break apart into smaller pieces. This exposes fresh coal surfaces to air and moisture, where oxidation and moisture adsorption can occur. Previous oxidation makes coal more friable. Although the oxidized matter is less reactive, the porous nature of the oxidized coal makes the coal more susceptible to air and water leakage when exposed to higher pressure differentials, such as in a pile or bunker. The oxidation of sulfur in pyrite is also a heat producing reaction. The heat generated can cause the temperature of the surrounding coal to increase, thus increasing the rate of oxidation. Also, as it oxidizes, the sulfur expands, causing coal degradation to occur.

The actual chemical process that results in self-heating is the low temperature oxidation, which is an irreversible exothermic reaction. The negative effect of self-heating is the decrease of coal quality (calorific value). If the self-heating is not controlled then a thermal avalanche type process occurs since increased temperature leads to a higher reaction rate. Spontaneous self-heating is a major problem during the transportation and storage of coal since the process, if not controlled, results in fire and important production loss.

Indeed, the phenomenon of spontaneous ignition is not limited to coal but has also been observed in other piles of organic debris (1983; Gray *et al*., 1984; Jones, 1990; Jones *et al*., 1990). However, By understanding how and why coal spontaneously combusts, coal users can plan, predict, and avoid accidents which could be costly in terms of coal lost, emissions of pollutants, and, ultimately, risk to the health and safety of those involved in the industry (Sloss, 2015).

Large coal stockpiles, especially those stored for long periods, may develop hot spots due to self-heating which, in some cases can lead to spontaneous combustion. The self-heating process depends on many factors including coal rank, temperature, airflow rate, the porosity of the coal pile, ash and moisture content of the coal, humidity as well as particle size of coal. Emissions of molecular hydrogen, carbon monoxide and low molecular weight hydrocarbons can also accompany the oxidation process. These processes raise environmental and economic problems for coal producers and consumers, who transport and store large coal piles (Nalbandian, 2010).

Thus, in the process, coal reacts with ambient oxygen, even at ambient temperatures and the reaction is exothermic. If the heat liberated during the process is allowed to accumulate within a stockpile due to inadequate ventilation, the rate of the oxidation reaction increases exponentially leading to an even more rapid rise in temperature. When the temperature within the stockpile reaches the ignition temperature of coal – typically on the order of 420 to 480°C (790 to 900°F) but under adiabatic conditions where all heat generated is retained in the sample, the minimum temperature at which a coal will self-heat is 35 to 140°C (95 to 285°F) (Smith and Lazzara, 1987) – the coal ignites (*spontaneous ignition*). This represents the onset of an exothermic chemical reaction and a subsequent temperature rise within the combustible material, without the action of an additional ignition source (*spontaneous combustion*) (US DOE, 1994; Medek and Weishauptová, 1999; Lyman and Volkmer, 2001).

Chemically, *combustion* falls into a class of chemical reactions categorized as *oxidation*, which is the chemical combination of a substance with oxygen or, more generally, the removal of electrons from an atom or molecule. Oxidation reactions are almost always exothermic, or release heat. Many materials react with oxygen to some degree. However, the rates of reactions differ between materials. The difference between slow and rapid oxidation reactions is that the latter occurs so rapidly that heat is generated faster than it is dissipated, causing the material being oxidized (coal) to reach its *ignition temperature*. Once the ignition temperature of coal is reached, it will continue to *burn* until it or the available oxygen is consumed.

Self-heating occurs when the rate of heat generation exceeds the rate of heat dissipation. Two mechanisms contribute to the rate of heat generation, coal oxidation and the adsorption of moisture. The reactivity of coal is a measure of its potential to oxidize when exposed to air. The mechanism of coal oxidation is not completely understood. The minimum *self-heating temperature* of the coal is sometimes used as a relative indication of the reactivity of the coal. There are various methods used to determine a minimum self-heating temperature of the coal, but determinations of the data all require running a test in real time and monitoring the temperature of the coal as any reaction occurs. These tests are typically a relative measure of the propensity of coal to self-ignite – in general, the reactivity of coal increases with decreasing rank.

Furthermore, the ability of coal to variously self-heat (spontaneous ignition), emit flammable gases, corrode, and deplete oxygen levels has made the ocean transport of this commodity a particularly hazardous exercise. This is particularly the case in situations where loading is staggered or delayed and the potentially disastrous consequences of a shipboard coal fire can be realized.

Generally, spontaneous ignition (often referred to as *self-ignition*) occurs when the thermal equilibrium between the two counteracting effects of heat release due to the oxidation reaction and heat loss due to the heat transfer to the ambient surroundings is disturbed. When the rate of heat production exceeds the heat loss, a temperature rise within the material will consequently take place including a further acceleration of the reaction.

The temperature at which the coal oxidation reaction becomes self-sustaining and at which spontaneous combustion occurs varies generally depending on the type (nature and rank) of coal and the dissipation (or lack thereof) of the heat. For low-quality coal and where the heat retention is high, the coal starts burning at temperatures as low as 30 to 40°C (86 to 104°F).

Spontaneous combustion, or self-heating, of coal is a naturally occurring process caused by the oxidation of coal. The self-heating of coal is dependent on a number of factors, some of which are controllable (Table 4.2). Controllable factors include close management in the power plant, of coal storage in stockpiles, silos/bunkers and mills and management during coal transport. Uncontrollable factors include the coal itself and ambient conditions.

Coal reacts with oxygen, even at ambient temperatures and the reaction is exothermic (Speight, 2013). If the heat liberated during the process is allowed to accumulate, the rate of the above reaction increases exponentially and there is a further rise in temperature. When this temperature reaches the ignition temperature of coal, the coal ignites (*spontaneous ignition* – the onset of an exothermic chemical reaction and a subsequent temperature rise within a combustible material, without the action of an additional ignition source) and starts to burn (*spontaneous combustion*).

Generally, self-ignition occurs when the thermal equilibrium between the two counteracting effects of heat release due to the oxidation reaction and heat loss due to the heat transfer to the ambient is disturbed. When the rate of heat production exceeds the heat loss, a temperature rise within the material will consequently take place including a further acceleration of the reaction.

Table 4.2 Examples of common methods of preventing spontaneous combustion.

Factor	Method
Tailings (plant rejects)	Tailings dams should be capped with at least 3 feet of inert (non-carbonaceous) material, topsoil should be added and the whole area revegetated.
Coarse reject (discard)	Problem material should be placed in layers and compacted using a roller, particularly on the edges of the dump, so that the infiltration of oxygen is minimal. The final landform should be such that erosion and runoff is minimized and new areas of discard coal are not exposed to the atmosphere.
Spoil heaps in strip-mining	The sequence of spoiling should result in accumulations of coal material, particularly the coal contains pyrite being buried under inert spoil. Although difficult to achieve, the most reactive material should be enclosed within less reactive material. If this is not possible then rehabilitation of the spoil heaps should take place as soon as possible and a thick layer of softs should be used before topsoil is added.
Product (coal)	Product stockpiles and coal inventory in the cut should not be left longer than the incipient heating period. The situation is particularly aggravated by prevailing hot, moist winds and this may lead to a higher risk of spontaneous combustion in the summer months.
Stockpile shape	The height of stockpiles and dumps may be a critical site-specific consideration. When the technique is feasible, considerable benefit can be obtained by building dumps in relatively thin compacted layers. Longer-term stockpiles, particularly of product coal, can be further safeguarded by spraying the surfaces with a thin (bituminous) coating to exclude air.
Highwalls at surface mines	Coal spalling from the seams should not be allowed to remain against the highwall. If the coal is liable to spontaneous combust, loose coal should be cleared away promptly and/or the highwall reinforced with soft, spoil material if it is to be left for an extended period. At the end of the life of mine complete rehabilitation and closing of the final void should take place. If this is not undertaken the highwall should be effectively sealed with water, clay, or a thick blanket of inert spoil.

The self-heating of coal is due to a number of complex exothermic reactions. Coal will continue to self-heat provided that there is a continuous air supply and the heat produced is not dissipated. The property of coal to self-heat is determined by many factors, which can be divided into two main types, properties of the coal (intrinsic factors) and environment/storage conditions (extrinsic factors). Self-heating results in degradation of the coal by changing its physical and chemical characteristics, factors that can seriously affect boiler performance.

The tendency of a coal to heat spontaneously in storage is primarily dependent upon the tendency of the coal to oxidize. This in turn is closely correlated with (i) coal rank (the higher the rank, the lower the tendency to oxidize), (ii) the size consistency or distribution of the coal in the pile (small pieces of coal have a higher surface area available for oxygen to react), (iii) the method by which the coal is stockpiled, (iv) the temperature at which the coal is stockpiled, (v) the amount and size of pyrite present, (vi) moisture content and ventilation conditions in the pile, (vii) time in storage, and (viii) the presence of foreign materials. In addition, the variability of coal, added to these factors does not allow accurate prediction of when spontaneous ignition (spontaneous combustion) will occur (Fieldner *et al*., 1945; Yoke, 1958; Feng, 1985; Medek and Weishauptová, 2004).

Oxidation is an exothermic reaction and, since the rate of a chemical reaction increases for each 10°C (18°F), the reaction will generate heat at a faster rate than can be dissipated or expelled from the stockpile by natural ventilation. Hence, the temperature will rise to a point where spontaneous ignition occurs and combustion ensues.

The risk of spontaneous combustion during final preparation such as in silos/bunkers and mills also presents concerns in some cases. Properties which influence the propensity of coal to self-heat include volatile content, coal particle size, rank, heat capacity, heat of reaction, the oxygen content of coal and pyrite content. The propensity of coal to self-heat and spontaneously combust tends to increase with decreasing rank. Thus, lignite and subbituminous coal are more prone to spontaneous combustion than bituminous coals and anthracites.

The temperature at which the coal oxidation reaction becomes self-sustaining and at which spontaneous combustion occurs varies generally depending on the type (nature and rank) of coal and the dissipation (or lack thereof) of the heat. For low-quality coal and where the heat retention is high, the coal start burning at temperatures as low as 30 to 40°C (86 to 104°F).

Thus, the temperature of coal increases due to self-heating until a plateau is reached, at which the temperature is temporarily stabilized. At this point, heat generated by oxidation is used to vaporize the moisture in the coal. Once all the moisture has been vaporized, the temperature increases rapidly. On the other hand, dry material can readily ignite following the sorption of water – dry coal in storage should not be kept in a damp place because this can promote self-heating. Therefore, it is recommended that dry and wet coal be stored separately.

Complications may also arise in the case of coals with high moisture and sulfur content and those with tendencies to degrade when exposed to aerial oxygen. This is a critical issue in the case of low-rank, high-sulfur coals. Lignite and subbituminous coal are difficult to store without occurrence of spontaneous combustion, in contrast to anthracite where the potential for spontaneous ignition to occur is minimal.

Thus, oxidation of the coal substance proper is the primary cause of spontaneous heating. This heating, however slight, is caused by slow oxidation of coal in an air supply which is sufficient to support oxidation but not sufficient to carry away all heat formed and proceeds whenever a fresh coal surface is exposed to air (Berkowitz and Speight, 1973).

Thus, coal presents hazards between the time it is mined and its eventual consumption in boilers and furnaces. Below are listed some of the characteristics of the factors that contribute to spontaneous ignition/combustion in coal stockpiles and which can be used to evaluate the potential for coal fires and as guidelines for minimizing the probability of a fire.

4.4.1 Oxidation and Rank

The relationship between the friability of coal and its rank has a bearing on its tendency to undergo spontaneous heating and ignition (Chakravorty, 1984; Chakravorty and Kar, 1986). The friable, low-volatile coals, because of their high rank, do not oxidize readily despite the excessive fines and the attendant increased surface they produce on handling. Coals of somewhat lower rank, which oxidize more readily, usually are relatively non-friable; hence they resist degradation in size with its accompanying increase in the amount of surface exposed to oxidation. But above all, the primary factor in coal stockpile instability is unquestionably oxidation by atmospheric oxygen whilst the role of any secondary factors such as friability is to exacerbate the primary oxidation effect (Jones and Vais, 1991).

Thus, spontaneous combustion is a rank-related phenomenon. The tendency of coal for self-heating decreases as the rank increases, with lignite and subbituminous coals being more susceptible to self-heating than bituminous coals and anthracite (Pis, 1996). As rank decreases, inherent moisture, volatile matter and oxygen and hydrogen contents increase. Medium- to high-volatile coal with the ability to produce yields of volatile matter content in excess of 18% w/w daf perform a faster oxidation rate coal that produces a lower yield of volatile matter and are therefore more prone to spontaneous combustion. Furthermore, low-rank coals often have a greater porosity than higher-rank coal and therefore more surface area is available for oxidation. Low-rank coals also contain long chain hydrocarbon derivatives, thereby rendering the coal less stable than, for example, the high-rank anthracite coal which has a lower hydrocarbon component. However, the oxidation rate for coals of the same rank may show variety within a wide range.

Coal is highly variable (due to the rank of the coal) in the ability to absorb oxygen (thereby weathering or causing combustion) and oxygen absorption generally decreases with increasing rank, i.e., low for anthracite and high for subbituminous coal and lignite (Fieldner *et al.*, 1945). Oxygen absorption is also higher for those coals with high bed moisture (natural bed moisture, determined as *capacity moisture*, *natural bed moisture, equilibrium moisture* (ASTM D1412), oxygen content, and volatile content, i.e., the low-rank coals (Speight, 2005, 2008, 2013).

It is generally (but not totally) accepted that the mechanism of the oxidation of coal oxidation takes place in five steps, each one chemically dependent upon the temperature. These steps are (i) the coal begins to oxidize slowly until a temperature of approximately 50°C (122°F) is reached, (ii) at this point, the oxidation reaction increases at an increasing rate until the temperature of the coal is approximately 100 to 140°C (212 to 285°F), (iii) at approximately 140°C (285°F), carbon dioxide and water vapor are produced and expelled from the coal, (iv) liberation of carbon dioxide increases rapidly until a temperature of 230°C (445°F) is reached, at which stage spontaneous ignition may occur and spontaneous combustion may take place, and (v) at 350°C (660°F), the coal spontaneously ignites and vigorous combustion occurs (Barkley, 1942; Parry, 1942; Roll 1963).

At low temperature, the first step is developed faster than others and is often recognized as the *rate determining step*. Oxygen molecules are connected to the coal surface physically (adsorption) and reaches to the passing pores by diffusion. In this stage, since the oxide layer formed with the exposure of coal surface to the air prevents the diffusion of oxygen partially, oxidation rate is decreased in time.

The overall reaction is exothermic (releasing 94 kcal/mole of thermal energy) and the heat produced is generally (or should be) carried away from the reaction site by airflow and there is not any significant change in ambient temperature. However, in some cases formed heat cannot be carried away from the environment and the temperature begins to increase. The reaction gets accelerated and spread over with the increasing temperature; produced heat takes the coal to ignition temperature (approximately 175°C, 345°F) in suitable conditions and open flamed fire begins. Thus, without removal of the heat from the stockpile, the oxidation and heat generation can be (and will be) self-perpetuating especially since the rates of organic chemical reactions usually double for every 10°C (18°F) rise in temperature. The time passed from the beginning of oxidation to reaching the ignition temperature is the *incubation period*.

Furthermore there has also been the suggestion that the heat release which accompanies the wetting of dried (or partially dried) coal may be a significant contributory factor in the onset of burning. Support for such a concept is derived from the observations that stored coal tends to heat up when exposed to rain after a sunny period (during which the coal has been allowed to dry) or when wet coal is placed on a dry pile (Berkowitz and Schein, 1951). Therefore, it may be unwise to stockpile wet coal or to store coal on a damp base if it can be avoided. After a rain or snowstorm a coal pile should be carefully inspected.

In general, the critical temperature for bituminous coal in storage is approximately 50 to 66°C (122 to 150°F). From this temperature, heating will usually increase rapidly and may be unstable after which ignition occurs, unless preventive steps are taken. The basic chemical premise is that for every 10°C (18°F) the rate of a chemical reaction approximately doubles (for coal oxidation, the factor is 2.2). Hence oxidation leading to spontaneous ignition may appear to be (and often is) irreversible unless steps are taken to modify the oxidation reaction and the ensuing liberation of heat.

The petrographic composition of a coal is determined by the nature of the original plant material from which it was formed and the environment in which it was deposited rather than the degree of coalification (i.e., rank). The homogenous microscopic constituents of coal (*macerals*, named by analogy of minerals in inorganic rocks) can be distinguished in three groups: (i) *vitrinite* consists of the remains of woody material, (ii) *liptinite* – formerly called *exinite* – consists of the remains of spores, resins and cuticles, and (iii) *inertinite* consists of the remains of oxidized plant material.

At constant rank, as the inertinite content of a coal increases, the self-heating propensity of the coal decreases. The general trend also indicates an increase in self-heating propensity with increasing vitrinite and/or liptinite content. Thus, the ease of oxidation of coal macerals is:

$$\text{Liptinite} > \text{Vitrinite} >> \text{Inertinite}$$

However, coal rank seems to play a more significant role in self-heating than the petrographic composition of coal (Speight, 2013).

Finally, spontaneous ignition and spontaneous combustion of coals also causes a serious problem for coal producers and users during transportation and storage (Chapters 3, 4) (Nugroho *et al.*, 2000). Improvements to low-rank coal are made by either thermal drying or through blend with higher-rank coals. Thermal drying of moist lower-rank coals could increase the calorific value of a product whilst blending of coals of different types offers a greater flexibility and economic benefit. However, the problem of spontaneous ignition and combustion assumes even greater significance since the removal of moisture can enhance the potential for spontaneous ignition and combustion. The risk of spontaneous combustion is also made greater during blending and when storage of such lower-rank coals takes place. This is particularly the case with low-sulfur subbituminous coals which are now used to meet emission limits.

The primary source of heat generation within coal stockpiles is the exothermic low-temperature oxidation reaction, while mass and heat transport play a major role in determining the magnitude of the temperature rise in a given situation. Despite the extensive previous works on spontaneous ignition of coal using various techniques, the effect of particle size in the case of single-type coals on the rate of low-temperature oxidation, remains controversial (Nugroho *et al.*, 2000).

4.4.2 Pyrite and Other Minerals

Sulfur, once considered a major factor, is now thought to be a minor factor in the spontaneous heating of coal. There are many very low-sulfur western subbituminous coals and lignite that have high oxidizing characteristics and there are high-sulfur coals that exhibit relatively low oxidizing characteristics.

However, pyrite (FeS_2) evolves heat from aerial oxidation and was believed to be the cause of the spontaneous heating of coal. The heat generation locally promotes the self-heating process of coal but the reaction products have a greater volume than the original pyrite, with the result of breaking open any coal in which they are embedded and thus exposing a greater surface of coal to the air.

The interaction of pyrite (FeS_2) with water and oxygen is also an exothermic reaction and results in the formation of iron sulfate ($FeSO_4$) and sulfuric acid (H_2SO_4). Thus, if coal is stored in the open, rain will most likely increase the rate of this reaction and for the same reason water-flooding (to extinguish fires) may also increase the rate of the reaction.

Pyrite, through its transformation to bulkier materials, has also been cited as responsible in some cases for slacking and the resultant production of fines. For these reasons, coal users are generally reluctant to stockpile high-sulfur coal for extended periods of time (Berkowitz and Schein, 1951). However, stockpiling low-sulfur content of coal is no guarantee of safe storage – coal with low sulfur content can also spontaneously ignite.

Many minerals affect the oxidation rate to some extent, either accelerating or inhibiting it. Alkali chemicals are capable of accelerating the rate of the oxidation reaction while borates and calcium chloride can act as retardants of the reaction rate. The oxidation process is also promoted if ankerite [a calcium, iron, magnesium, manganese carbonate mineral of the group of rhombohedral-shaped carbonates, i.e., $Ca(Fe.Mg.Mn)(CO_3)_2$] is a constituent of the coal mineral matter. In contrast to ankerite, the presence of silica and alumina minerals tends to retard the oxidation reaction.

4.4.3 Coal Size and Stockpile Ventilation

Oxidation increases with increasing fineness (decreasing size) of the coal pieces and the rate of oxidation of coal with oxygen of air is proportional to the specific internal surface (or external surface area). For the internal surface, the proportional coefficient at low temperatures is the cube root but analysis also shows that both rate and extent of oxidation increase with the decrease in particle size, until a critical particle diameter is reached, below which the rate remains fairly constant. For the external surface area, the surface area of a ton of half-inch particles is greater that the surface area of a ton of one-inch particles of coal.

The natural ventilation in coal storage piles is generally adequate to remove sensible heat as fast as it is liberated in the oxidation process. However, in situations where the ventilation is adequate to maintain oxidation but inadequate to dissipate the heat produced, the coal absorbs the heat, causing a rise in the internal temperature of the stockpile. A chain reaction follows in which the oxidation rate increases with increasing temperature and, if the temperature rise is allowed to proceed unchecked in the stockpile, the ignition temperature of the coal will eventually be reached and the stockpile will begin to burn. To an external observer, it will at first appear that the coal is smoldering die to emission of light barely visible *smoke* but in reality, the fire inside the stockpile may be vicious and vigorous.

Run-of-mine coal (ROM coal) is difficult to store because of the large percentages of fines mixed with the lump, of which some may be minerals that promote the oxidation and, thus, spontaneous ignition. On the other hand, there is usually less danger in storing lump coals that have been double-screened or closely sized. The uniform pieces of coal are honeycombed with passages through which air can circulate freely and carry off the heat generated. However, in stockpiles of coal fines sufficiently compacted so as to exclude air, the potential for spontaneous ignition is diminished. But it must be recognized that stockpiles of coal (whatever the size of the coal) are subject to some degree of oxidation and, when the auspices are correct, spontaneous ignition.

If coal is to be stored for prolonged periods of time, the pile should be constructed so that air (in the case of fine coal or mixed sizes such as run-of-mine coal) is excluded. On the other hand, if the coal is to be stored as lump coal, air should be allowed to circulate freely through the pile.

The total exposed surface area of the coal is of importance in that the more area exposed, the better the chance of oxygen interacting or reacting uniting with the coal and any heat liberated in a given time for a given weight of coal will be higher (Elder *et al.*, 1945; Berkowitz and Speight, 1973).

When coal stockpiles are constructed by allowing mixed varied size coal to fall, roll, or slide, the larger pieces tend to collect at the bottom outside of the pile and the fines will collect at the top and inside of the stockpile. As a result, air will move easily through the outer parts of the stockpile but with much less freedom in the interior of the stockpile. Such a pile will allow the development of *hot spots* which can (or will) lead to spontaneous ignition of the coal with subsequent combustion of stockpile.

4.4.4 Moisture Content

Moisture present in the coal is known to influence spontaneous heating in a stockpile insofar as the moisture affects ventilation (air flow) and pyrite reactivity. The higher the inherent (equilibrium) moisture content, the higher the heating tendency. The lower the ash free Btu, the higher the heating tendency. Coal with high oxygen content typically has a higher tendency to self-heat than coal of lower oxygen content. Thus, there appears to be an interaction between oxygen functions in the coal and aerial oxygen leading to a higher potential for formation of the coal-oxygen complex as the first stage of the self-heating process leading to a higher tendency for spontaneous ignition of the high-oxygen coal.

The effect of moisture on the self-ignition is twofold, thus (i) the vaporization of moisture consumes energy and hence the ignition process is impeded, (ii) promotion of self-ignition by the wetting of materials prone to evolution of heat during the moisture adsorption has been observed (Gray, 1990).

$$\text{Dry coal + moisture} \rightarrow \text{wet coal + heat}$$

In addition to the heat of wetting, moisture simply blocks the access of oxygen through the coal pores. The water vapor diffusing outwards through the pores reduces the oxygen partial pressure and hence lowers the rate of the reaction or the polar water molecules attach to the reactive sites in coal (Jones, 1998).

The heat of condensation of coal in a stockpile can cause a rise in temperature in the pile, which is dependent upon the coal rank (Berkowitz and Schein, 1951). In addition, if dry screened coal is used as a storage-pile base for a shipment of wet coal, ignition can (or will) occur at the wet-dry interface of the two loads (Berkowitz and Speight, 1973). However, the more rapid oxidation occurring in high-moisture coals may be basically a function of coal rank rather than moisture content, since low-rank (high-oxygen) coal is usually also higher in moisture content.

Wetting and drying coal repeatedly may make it more susceptible to combustion. The actions of water may break up the coal, especially after freezing and thawing. Wet coal should not be piled or mixed with dry coal. Nor should coal be stored on a damp base. After heavy rains and snows (with accompanying snow melt) the stockpile should be inspected and observed for potential fires.

Thus, the moisture content of coal is also an important parameter in the rate of heat generation of the coal. Drying coal is an endothermic process, in which heat is absorbed, and the temperature of the coal is lowered. The adsorption of moisture on a dry coal surface is an exothermic process, with a heat-producing reaction. If coal is partially dried during its mining, storage, or processing, coal has the potential to re-adsorb moisture, thus producing heat. Therefore, the higher the moisture contents of the coal, the greater the potential for self-heating to occur. The most dangerous scenario for spontaneous combustion is when wet and dry coals are combined; the interface between wet and dry coal becomes a heat exchanger (Berkowitz and Schein, 1951; Smith *et al.*, 1991). If coal is either completely wet or completely dry, the risk is substantially reduced. In general, the moisture content of coal increases with decreasing rank.

4.4.5 Time Factor

The oxidation process commences once a fresh coal surface is exposed to air; however, the oxygen absorption rate is inversely proportional to time if the temperature remains constant. Therefore, if the coal is stockpiled so that the temperature in the pile does not rise appreciably insofar as the heat is removed at least as fast as it is generated by the oxidation process, the oxidation rate and, thus, the deterioration or weathering rate of the coal will lessen with time, but nevertheless, deterioration of coal properties during storage may be a major issue for the ultimate use of the coal (Porter and Ovitz, 1917; Vaughn and Nichols, 1985).

4.5 Mechanism of Spontaneous Ignition

Spontaneous combustion of coal is an important problem in its mining, long-distance transportation, and storage, in terms of both safety and economics. This is because coal reacts with oxygen in the air and an exothermic reaction occurs, even in ambient conditions. A problem arises when the rate of heat release produced by this process is more than dissipated by heat transfer to the surroundings. The heat of reaction accumulates, the reaction becomes progressively faster, and thermal runaway may take place to the point of ignition. It is for these reasons that the phenomenon of spontaneous combustion of coal has been of fundamental and practical importance to scientists.

There have been considerable difficulties in understanding the mechanism of the spontaneous ignition and spontaneous combustion of coal because of the involvement of many internal and external factors which affect the initiation and development of the phenomenon (Kröger and Beier, 1962; Güney, 1968; Beier, 1973; Chamberlain and Hall, 1973; Didari and Ökten, 1994; Kim, 1997; Kaymakçi and Didari, 2002).

However, large-scale and laboratory studies of the spontaneous ignition and combustion of coal have shown that high-volatile C bituminous coals exhibited high spontaneous combustion potentials in laboratory-scale tests. The results of these tests showed that the self-heating of a large coal mass depends not just on the reactivity of the coal, but also on the particle size of the coal, the freshness of the coal surfaces, the heat-of-wetting effect, and the availability of oxygen at optimum ventilation rates (Smith *et al.*, 1991; Kim, 1997).

In addition, several theoretical and experimental studies have been performed on coal spontaneous combustion (Van Doornum, 1954; Nordon, 1979; Schmal *et al.*, 1985; Brooks and Glasser, 1986; Arisoy and Akgun, 1994; Akgun and Arisoy, 1994; Krishnaswamy *et al.*, 1996; Monazam *et al.*, 1998; Arisoy and Akgun, 2000; Akgun and Essenhigh, 2001; Diaconu *et al.*, 2011). The main purposes of modeling studies has been to develop methods for determining the conditions at which the coal pile could undergo spontaneous combustion, to predict the safe storage time under those conditions, and to determine the influences of factors contributing to the spontaneous ignition. However commendable such studies are, it is always necessary that, in order to achieve dependable results, theoretical models can only be successfully used to investigate coal self-heating and self-ignition if the theoretical models are supported by experimental investigations and by field investigations (Arisoy *et al.*, 2006).

First and foremost, the oxidation of coal is a solid-gas reaction, which happens initially when air passes over the coal surface. Attempts to model this phenomenon have met with some success (Akgun and Essenhigh, 2001; Sensogut and Ozdeniz, 2005). However, there is often the failure to recognize that the phenomenon of self-ignition followed by combustion is site specific and is dependent upon several criteria such as (i) the coal type, (ii) the construction of the stockpile, and, last but not least, (iii) the atmospheric conditions. Indeed, there is no reason to conclude that the self-ignition of coal in a surface stockpile has the same initiation mechanism as self-ignition of coal in an underground coal mine.

In the process, oxygen from the air combines with the coal, raising the temperature of the coal. As the reaction proceeds, the moisture in the coal is liberated as a vapor and then some of the volatile matter that normally has a distinct odor is released. The amount of surface area of the coal that is exposed is a direct factor in its heating tendency. The finer the size of the coal, the greater the surface area exposed to the air and the greater the tendency for spontaneous ignition.

Thus, the spontaneous ignition of coal is believed to center around the basic concept of the oxidation of carbon to carbon dioxide:

$$C + O_2 = CO_2$$

This particular reaction is exothermic (94 kcal/mole) and will be self-perpetuating especially since the rates of organic chemical reactions usually double for every 10°C (18°F) rise in temperature. Furthermore there has also been the suggestion that the heat release which accompanies the wetting of dried (or partially dried) coal may be a significant contributory factor in the onset of burning.

Support for such a concept is derived from the observations that stored coal tends to heat up when exposed to rain after a sunny period (during which the coal has been allowed to dry) or when wet coal is placed on a dry pile (Berkowitz and Schein B, 1951). Similar effects have been noted during the storage of hay in the conventional haystacks and ignition has been noted to occur. Thus, any heat generated by climatic changes will also contribute to an increase in the rate of the overall oxidation process. Obviously, if there are no means by which this heat can be dissipated, the continued oxidation will eventually become self-supporting and will ultimately result in the onset of burning.

Spontaneous ignition and the ensuing combustion of coal is usually the culmination of several separate chemical events and although precise knowledge of the phenomenon is still somewhat incomplete it is gradually becoming known (Kreulen, 1948; Dryden, 1963; Gray *et al.*, 1971; Faveri *et al.*, 1989; Vilyunov and Zarko, 1989; Jones and Wake, 1990; Shrivastava *et al.*, 1992); there are means by which the liability of a coal to spontaneously ignite can be tested (Schmeling *et al.*, 1978; Chakravorty, 1984; Chakravorty and Kar, 1986; Jones and Vais, 1991; Ogunsola and Mikula, 1991; Chen, 1992; Carras and Young, 1994).

The main factors which have significant effects on the process are (i) the pyrite content of the coal may accelerate spontaneous combustion, (ii) changes in moisture content; i.e., the drying or wetting of coal, have apparent effects, (iii) as the particle size decreases and the exposed surface area increases, the tendency of coal towards, spontaneous combustion increases, iv) lower-rank coals are more susceptible to spontaneous combustion than higher-rank coals – the abnormalities in this relationship may be attributed to the petrographic constituents of coal, and (v) mineral matter content generally decreases the liability of coal to spontaneous heating – certain constituents of the mineral matter, such as lime, soda and iron compounds, may have an accelerating effect, while others, such as alumina and silica, produce a retarding effect (Kaymakçi and Didari, 2002).

For example, exposure of coal (freshly mined) to air will bring about not only loss of moisture but also oxidation. The latter process, often referred to as auto-oxidation or autoxidation (Joseph and Mahajan, 1991), commences when the coal reacts with oxygen (of the atmosphere). Both processes result in an alteration of the properties of the coal, that is, there is a decrease in the calorific value of the coal through the introduction of oxygen functions while there is also a very marked, adverse, effect on the caking properties of the coal.

There are indications that the tendency for spontaneous ignition is reduced by thermal upgrading and further decreased with increase in treatment temperature (Ogunsola and Mikula, 1992). The decrease in the tendency to spontaneously ignite appears to be due to the loss of the equilibrium moisture as well as the loss of oxygen functional groups. The loss of the equilibrium moisture is an interesting comment because of the previous comment that the presence of indigenous moisture appears to enhance (i.e., increase the rate of) the oxidation reaction.

Coal tends to spontaneously ignite when the moisture within the pore system is removed, leaving the pores susceptible to various chemical and physical interactions (Berkowitz and Speight, 1973) that can lead to spontaneous ignition. It is a question of degree and the correct order of reactions being in place. It is obvious that the system is complex and, as noted earlier, spontaneous ignition is the culmination of several interrelated chemical and physical events. Finally, it has been estimated that under specific conditions considered subbituminous coal in a stockpile can reach thermal runaway in 4.5 days (Arisoy *et al*., 2006).

Thus, the results of spontaneous combustion are serious and negative because of (i) damaging economic effects, (ii) detrimental environmental consequences, and (iii) unwanted costs in health problems and, in some cases, human life (Nalbandian, 2010; Sloss, 2015). To prevent such events, the processes that lead to coal self-heating must be understood and precautions must be taken to avoid fires caused by spontaneous combustion. There is general agreement that there is a strong relationship between self-heating rate and coal rank – as coal rank decreases the self-heating rate increases. Thus, spontaneous combustion, or self-ignition, is most common in low-rank coals and is a potential problem in storing and transporting coal for extended periods. Major factors involved in spontaneous combustion include volatile content, the size of the coal (smaller sizes are more susceptible) and the moisture content.

The chemical reaction between coal and oxygen at low temperature is complex and remains not well understood despite many years of research. The gaseous reaction products, evolved during coal oxidation, are primarily carbon monoxide (CO), carbon dioxide (CO_2), and water (H_2O, as water vapor). Typically, three types of process are believed to occur including physical adsorption, chemical adsorption (which leads to the formation of coal-oxygen complexes and oxygenated carbon species), and oxidation (in which the coal and oxygen react with the release of gaseous products, typically carbon monoxide, carbon dioxide and water vapor). Oxidation is the most exothermic of these processes.

Physical adsorption can begin at ambient temperature where coal is exposed to oxygen whereas chemical adsorption takes place from ambient temperature up to 70°C (158°F). Initial release of oxygenated reaction products starts from 70 to 150°C (158 to 302°F), while more fully oxygenated reaction products occur between 150 and 230°C (302 and 446°F). Rapid combustion takes places over 230°C (446°F). The start of this rapid temperature rise is also known as thermal runaway. The time it takes to reach a thermal runaway stage is called induction time. The induction time can be used to indicate the potential hazard of coal self-heating. The temperature rise from ambient to 230°C (446°F) is a slow process compared to the fast temperature increase after 230°C (446°F), which can lead to major fire hazards and even explosions. In stockpiles, parametric model analysis indicates that parameters such as pile slope, the availability and movement of air through the pile, material segregation, coal reactivity, particle size, temperature and moisture play important roles in the occurrence of spontaneous combustion.

The significance of the greenhouse gas emissions resulting from the oxidation during transport and/or storage, especially CO2 were investigated. However there appears to be no emphasis in research work or published material specifically quantifying these emissions.

In summary, heat build-up in coal stockpiles can (i) degrade the quality of coal, (ii) cause the coal to smolder, and (iii) lead to a fire.

4.6 Preventing Spontaneous Ignition

Put simply, coal should be stored in specifically designed bunkers, silos, bins, or in outside piles (CFR, 2012). The most important aspects of coal storage are minimizing the flow of air through the pile, using the *first-in, first-out rule of thumb*, and minimizing the amount of finely divided coal in the pile. *Hot spots* should be removed or exposed to the atmosphere to allow cooling. Coal should be compacted if possible to reduce the amount of air in the pile. Water may be used to cool hot spots, but should be used with caution on large areas of hot coal to present accumulations of hazardous amounts of water. Coal should not be stored in outside piles located over utility lines, such as water lines and gas lines.

In order to prevent spontaneous ignition and combustion of coal, it is (first) necessary to understand coal properties and their influence on self-heating and ignition. Next (second), there is a group of additional factors that also play a major role in spontaneous ignition and combustion and these are (i) climatic conditions (temperature, relative humidity, barometric pressure and oxygen concentration), (ii) stockpile compaction, as related to height and method of stockpiling, and (iii) stockpile consolidation, which is influenced by height, the method of formation, and the equipment used for the stockpiling operation.

Spontaneous combustion resulting from spontaneous ignition can be detected fairly early in the development of the fire, i.e., before any obvious smoke and/or flame. Any of the following may assist in early detection, depending upon the particular circumstances. For example, the temperature difference – heat haze and steam/vapor plumes – may be observed on cold mornings and in times of high humidity. Efflorescence caused by the decomposition of pyrites and sublimation of sulfur is a strong indication of heating in pyritic (high-sulfur) coals. Also, *hot spots* may also be detected by infrared monitoring instruments or photography. Routine surveying of stockpiles using infrared scanning devices is an excellent precaution in situations where spontaneous combustion may be likely to occur.

Spontaneous ignition is a time-dependent phenomenon. Early attention to the potential sources of problems may prevent occurrences of heating progressing to full-scale spontaneous combustion. Examples of commonly used methods of dealing with spontaneous combustion in different circumstances are detailed: (i) tailings, which are the power plant rejects, (ii) dams should be capped with at least three feet of inert non-carbonaceous material, (iii) top soil should be added and the whole area vegetated, (iv) the coarse reject should be placed in layers and compacted using a roller, particularly on the edges of the dump, so that the infiltration of oxygen is minimal – the total layer thickness should be no greater than 15 feet and each layer should be covered by a 3-foot thick layer of inert (non-carbonaceous) material and the final landform should be such that erosion and runoff is minimized and new areas of discard coal are not exposed to the atmosphere, (v) spoil heaps in strip-mining should result in accumulations of coal material, particularly if pyritic, being buried under inert spoil – although difficult to achieve, the most reactive material should be enclosed within less reactive material but if this is not possible, rehabilitation of the spoil heaps should take place as soon as possible and a thick layer of softs should be used before topsoil is added, (vi) product stockpiles and coal inventory in the cut should not be left longer than the incipient heating period – there is considerable variation in the time taken for heating to occur, but most mines have an understanding, based on experience, of the time limits for the product, and (v) the shape and orientation of stockpiles and dumps is often a critical criterion and a site-specific consideration – when the technique is feasible, considerable benefit can be obtained by building dumps in relatively thin compacted layers and longer-term stockpiles can be further safeguarded by spraying the surfaces with a thin (bituminous) coating to exclude air.

In summary, stockpile management to mitigate spontaneous ignition and combustion can be achieved by actions such as (i) cooling by ventilation or by water spraying to avoid increase of coal stock temperature, (ii) storing the coal in smaller stockpile lots to enable better cooling to prevent heating up of the coal in the stockpile, (iii) reducing access to air, i.e., by storage in compressed piles (packing coal tightly and compacting) or storage in closely covered airtight enclosure, (iv) reducing the fine powder content in the coal, (v) limit the height of stockpile, (vi) avoid conical heaps, which tend to increase the surface area and, hence, the risk of fire, (vii) follow the practice of first-in, first-out in stockpile management – the old parts of the stockpile should be used first for consumption and the fresh coal should go for storage.

In summary, actions that could diminish the intensity of the self-ignition process and prevent production loss through fires are: (1) prevent access of fresh air by covering the stockpile with unreactive heavy oil, (2) storage of coal with small particle size, (3) storage of coal with low humidity, and, above all, (4) decreasing the storage interval of the coal to the minimum possible time.

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5
General Properties

5.1 Introduction

Coal was formed in wide, low-lying equatorial swamps crossed by large rivers and covered by forests of primitive trees. In such locations, the remains of trees and plants were saved from biodegradation and oxidation by mud and water. On an elemental basis, coal is primarily composed of carbon, along with a range of other elements, particularly sulfur (Speight, 2013, 2015).

Generally, coal is typically black in color but sometimes it occurs as a brownish-black color. There are four broad ranks or types of coal depending upon its age. Commencing with the youngest and lowest carbon content, these are (i) lignite, (ii) subbituminous coal, (iii) bituminous coal, and (iv) anthracite (Chapters 1, 2). Anthracite is classified as a metamorphic rock because of its subsequent exposure to elevated pressures and temperatures. The soluble material (often referred to as bitumen – which should not be confused with the bitumen in tar sand formations) (Speight, 2014) – obtained from bituminous coal is a black viscous material generally referred to as *tar*, which is also a misnomer since tar is the volatile product from the thermal decomposition of coal – pitch is the non-volatile product obtained from the therm decomposition of coal (Speight, 2013, 2015).

Since studies of coal chemistry took hold in the early part of the 20th century there have been many efforts (some would say *fanatical efforts*) to deduce coal structure, thereby producing a so-called average structure that leads to much frustration. Coals have many structural features such as aromaticity, a variety of oxygen, nitrogen, and sulfur functional groups, covalent and non-covalent cross-links, physical associations, and several surface structural features that determine physical properties and reactivity. However, the reality is that the use of coal in coal-fired power plants requires something more than hypothetical data to produce vague parameters that make little physical and chemical sense.

Structural studies aside, coal is an extremely complex material, the rapidly expanding use of coal throughout the 19th century and early part of the 20th century necessitated the design of acceptable methods for coal analysis with the goal of correlating fuel composition and properties with behavior – such data (and it must be quality data carried out by standard test method) are of value to combustion engineers to design power plants for energy production (Campbell and Gibb, 1951; Montgomery, 1978; Trent *et al*., 1982; Sen *et al*., 2009; Speight. 2015). With the increasing use of coal to produce electricity, it is even more essential that the analysis of coal to determine *coal quality* be recognized as an integral part of the power generation scenario.

In fact, the parameters and plant operating conditions which may be affected by changes in coal quality and its composition include (i) the handleability and flow characteristics in silos, stockpiles and conveyor belts which, in turn, depends on the surface moisture, and

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the range of ambient temperature conditions, the size distribution, and in particular the proportion of fine material, the nature of the mineral matter present which can affect particle stickiness – increased stickiness is often associated with surface moisture, the amount of fines, and presence of clay minerals, (ii) the behavior of the coal during preparation and in different sections of the plants, (iii) the conditions in the pulverizer, which are affected by the coal hardness which can be measured on an empirical and comparative basis and which is affected by the presence of hard minerals like quartz, SiO_2, and pyrite, FeS_2, (iv) the moisture content, as the mill inlet temperature needs to increase with higher moisture content coals, to ensure that the desired outlet temperature on the order of 70°C (158°F) is maintained, (v) the amount of coal required, which is affected by its heat content – also known as the heat value or the specific energy, (vi) the combustion and ash deposition characteristics when used in a pulverized coal combustion boiler or in a gasifier on an integrated gasification combined cycle (IGCC) unit, and (vii) the emissions from any combustion or gasification plant, which will be controlled to an extent by downstream flue gas cleaning units – for example, to reduce the emissions of sulfur oxides, nitrogen oxides, and particulate matter.

By way of a general comment, a power plant boiler is designed to burn a specification coal, which is commonly defined as the coal from a nearby mine or the coal most likely to be purchased from further afield. Also, it is necessary to note here that the variations in a coal from one deposit (a single coal seam) may be sufficient to affect the behavior of the coal in a boiler. In all cases a boiler unit is designed to operate in the optimum way when using a coal that meets the design specifications and boiler manufacturers usually define the guaranteed performance figures in terms of this coal. Coal-fired boilers can in practice use a range of coals, and often the decision to purchase from a specific source is balanced and is based on the delivered price for the coal and the implications for the running costs of the plant when using that coal (Nalbandian, 2011). Furthermore, the major issues in utilization in a coal-fired power plant are related to the conversion of the coal.

For example, in terms of the chemistry of the process, the various steps involved in conversion are preparation, conversion of coal to char/ash, and, eventually, char combustion or gasification. The issues pertinent to the preparation require information on the physical properties of coal such as density, hardness, and other mechanical properties of coal. The research on reactivity and conversion of coal has primarily been limited to experimentation on drop-tube furnaces and thermogravimetric analysis (TGA). The conversion issues are usually broken down into two steps: pyrolysis and char reactivity. In terms of devolatilization, coals of different types exhibit wide variations in their devolatilization behavior because of different extents of coalification. The degree of aromatization in the coal structure increases with the increase in the rank of the coal. The information on maceral composition of coal is of paramount importance on the devolatilization and char conversion issues. The primary physical changes that occur when any particular coal is heated depend on the melting and decomposition behavior of coal. Variables that influence devolatilization rates include temperature, residence time, pressure, particle size, and coal type, and final temperature is possibly the most important issue.

On the physical side of the conversion process, the physical structure of coal, including pore structure, surface area, and particle size is important in understanding and modeling combustion and char oxidation process. The conversion characteristics such as the calorific value, volatile and ash content, and other physical property values provided by the bulk analysis of coal are required for a better design of a combustion system. Char character has been extensively studied because of its importance in char combustion and gasification processes. Char burnout is critical in assessing the overall efficiency of the conversion process. The char burnout during the coal conversion process largely depends on the reactivity of char, and therefore, the accurate prediction of char behavior is of paramount importance.

Pore-size distribution within char is probably one of the most important aspects of char character because the conversion of char takes place by the diffusion of gas through the pore into the char. According to their morphology, the char can be categorized into cenosphere char, honeycomb char, and unfused char. Each char type has a different char structure and, consequently, a different reactivity. The petrography (maceral composition) and presence of mineral matter in coal have a significant influence on the character of the resulting char or ash. The most important issues related to char/ash are their movement through the boiler/gasifier and their deposition on various surfaces. These characteristics of char/ash depend on the structure of char/ash and its thermal and mechanical properties, which in turn are strong functions of the maceral composition and the mineral matter present in the parent coal.

Thus, the primary reason for analyzing coal is to determine whether it will meet the needs of a specific application, or to characterize the general quality of the coal for future reference (Gupta, 2007; Speight, 2015). If the coal has a high organic sulfur content, then it may have to be mixed or blended with a coal of lower sulfur content in order to meet sulfur emissions standards, or the sulfur may have to be cleaned out of the flue gas by flue-gas desulfurization (FGD), which is an expensive procedure. Similarly, analysis may determine whether a trace element, such as arsenic, may be eliminated from a coal by washing or whether it must be trapped in the flue gas. Finally, in extreme cases, analysis may determine that the coal cannot be used.

More pertinent to the present context, in order to achieve ultra-low regulatory emissions requirements, techniques used for sulfur oxide emission, nitrogen oxide emissions and emissions of particulate matter, emissions control are necessary to work in a coordinated fashion. In addition, in order for such emissions to form a coordinated emission control system that works efficiently and effectively, the impact of each type of device on downstream equipment and balance-of-plant should be investigated.

Selective catalytic reduction technologies are successful in removing nitrogen oxides from the flue gas but the impact of selective catalytic reduction technologies on other emissions control devices needs to be taken into account, such as submicron particle forming, particle cohesion increase as well as the production of sulfur trioxide (SO_3). Submicronic particle creation is a recognized issue arising from the use of selective catalytic reduction technologies for reduction of nitrogen oxide emissions. Submicron particles forming in selective catalytic reduction technologies can refer to ammonium sulfate [$(NH_4)_2SO_4$] and ammonia (NH_3). Fine particles are able to increase space charge load as well as change the voltage-current characteristics of an electrostatic precipitator. A wet flue gas desulfurization unit can remove some particulate matter as well as sulfur oxide emissions. However, this process is a function of (i) the type of wet flue gas desulfurization unit that is used, (ii) the particulate matter loading at the inlet of the wet flue gas desulfurization unit, and (iii) the particle size distribution..

Thus, once the coal is taken from the mine, it must be subject to a series of test methods to determine the relevant properties as a feedstock for a power plant as well as and suitability as environmentally benign (after cleanup of the coal as well as mitigation of the potential environmentally harmful emissions). Much work, and the formation of various national standards associations, has led to the development of methods for coal evaluation. For example, the ASTM International (formerly the American Society for Testing and Materials) has carried out uninterrupted work in this field for many years while investigations on the development of the standardization of methods for coal evaluation has occurred in all of the major coal-producing countries (Table 5.1) (Montgomery, 1978; for coke analyses see Patrick and Wilkinson, 1978).

As a noteworthy point, there are (in addition to the ASTM International) other organizations for methods development and standardization which operate on a national level; examples are the British Standards Organization (BS) and the German Standards Organization (DIN). Furthermore, the increased trade between various coal-producing countries that followed World War II meant that cross-referencing of the already accepted standards was a necessity and the mandate for such work fell to the International Standards Organization (ISO), located in Geneva, Switzerland; membership in this organization is allocated to participating (and observer) countries.

Analyses also may be reported on a *mineral-matter-free* basis or on a *dry, mineral-matter-free* basis. *Mineral-matter-free* means that the amount of mineral matter in the sample has been subtracted from the total analytical results to provide only the amount that is organic. *Dry, mineral-matter-free* means that the sample was received in a dry or nearly dry state, or was dried out before an analysis was made.

Table 5.1 Procedures and Purposes for Coal Testing using the Standard Test methods of the ASTM International (ASTM, 2020).

Procedure	Outcome
Calorific value	Potential for energy production.
Classification of coal by rank	Estimate of coal behavior in mining, preparation, and utilization.
Coal ash	Amount of ash produced at a given temperature.
Equilibrium moisture	Moisture-holding capacity of coal (natural bed moisture).
Forms of sulfur	Form of sulfur – organic sulfur, inorganic sulfur (pyrite, sulfate.
Major and minor elements	Identification of major and minor (trace) elements.
Proximate analysis	Amount moisture, volatile matter, ash, and fixed carbon.
Maceral analysis	Types and amounts of macerals in coal.
Total moisture	Inherent water and any other water present.
Trace elements	Identification of trace elements.
Ultimate analysis	Amount carbon, hydrogen, nitrogen, oxygen, sulfur, and ash.
Volatile matter	Products evolved as gases or vapors.

Also, assessment of any traits in coal properties is vital to ensuring a particular supply of coal is used in the most effective way. Thus, the data obtained from coal analyses are valuable not only for laboratory work but also, and perhaps more importantly, to establish the price of the coal by allocation of production costs as well as to control mine and cleaning operations and to determine plant efficiency (Speight, 2013, 2015). The effect of various coal properties such as mineral matter, moisture, fixed carbon, and calorific value on specific coal consumption can affect coal consumption. For example, an increase in moisture content by 2% w/w can increase coal consumption by as much as 8%. If, however, the mineral matter is increased by 2% w/w, the specific coal consumption can increase by as much as 5%. On the other hand, for a 4% w/w increase in fixed carbon, the specific coal consumption can decrease by as much as 25%.

In addition, coal properties have impacts on those parts of the power plant which are in direct contact with the coal handling when the coal is conveyed from the stockpile to the boiler bunkers and then to the pulverizing mills. These properties are: (i) specific energy, which determines the quantity of coal required for a given plant output, (ii) surface moisture, which affects flow characteristics, (iii) size distribution, especially proportion of fine material, which affects surface moisture, and (iv) the nature of the mineral matter, especially clay minerals, which affects flow characteristics.

It is also appropriate that in any discussion of the particular methods used to evaluate coal for coal products, reference should be made to the relevant test. Accordingly, the necessary ASTM test numbers have been included as well as those, where known, of the test numbers from the standards organizations of other countries. As a part of the multi-faceted program of coal evaluation, new methods are continually being developed and the already accepted methods may need regular modification to increase the *accuracy* of the method as well as the *precision* of the results (Speight, 2013, 2015).

At this point, it is advisable to note the differences which are inherent in the terms *accuracy* and *precision*.

The term *accuracy* is used to indicate the reliability of a measurement, or an observation; but it is, more specifically, a measure of the closeness of agreement between an experimental result and the true value. Thus, the *accuracy* of the measurement of coal properties is extremely important and is used to indicate the reliability of a measurement or an observation, but it is, more specifically, a measure of the closeness of agreement between an experimental result and the true value. Thus, the accuracy of a test method is the degree of agreement of individual test results with an accepted reference value. Accuracy, similar to precision, is often expressed inversely in terms of the standard deviation or variance.

Precision, by definition, does not include any systematic error or bias, but accuracy, by definition, does. The term *precision* indicates a measure of the degree to which replicate data and/or measurements conform to each other. Thus, it is possible that data can be very precise without necessarily being correct or accurate. These terms will be found throughout any text which is devoted to a description of standard methods of analysis and/or testing and have been (incorrectly) used interchangeably. Precision, by definition, does not include systematic error or bias.

For coal that is sampled in accordance with standard methods (ASTM D2234; ASTM D4596; ASTM D4916; ASTM D6315; ASTM D6518) and with the standard preparation of the samples for analysis (ASTM D346; ASTM D2013), the overall variance of the final analytical data is minimized and falls within the limits of anticipated experimental difference.

Both (i) repeatability, the precision with which a test can be repeated in the same laboratory, usually but not always by the same analyst using the same equipment and following the prescribed method(s), and (ii) reproducibility, the precision expected of results from different laboratories, are determined. Values quoted in test methods are the differences between two results that should be exceeded in only 5 out of 100 pairs of results, equal to 2/2 times the standard deviation of a large population of results.

Thus, in the current context, the primary reason for analyzing coal is to determine whether it will meet the needs of a combustion process. For instance, coal may be analyzed to determine how much sulfur (or other element) is present, the form of the sulfur (or other element), and how it is distributed. Again using sulfur as the example, if the sulfur is present in discrete pyrite grains, then much of it may be cleaned out of the coal. However, if the sulfur occurs as part of the organic matrix of coal, it (the sulfur) will be released during combustion as sulfur oxides. This effect can be partially mitigated if the high-sulfur coal is blended with a low-sulfur coal in order to meet sulfur emissions standards, or the sulfur may have to be cleaned out of the flue gas by flue-gas desulfurization (FGD).

Another potential emission is the production and failure of the combustion system to trap fly ash – the fine particles of ash that are carried by the gases through the flue system and into the atmosphere. In addition, fly ash from coal combustion may be a potential source of hazardous air pollutants such as polynuclear aromatic hydrocarbon derivatives (PNAs) – sometimes referred to as polyaromatic hydrocarbon derivatives (PAHs).

Many organic compounds (such as polynuclear aromatic compounds) formed by combustion of coal may be in the vapor phase at stack temperatures and there is also the potential for such compounds to be adsorbed on fly ash particles. Thus analysis of fly ash becomes an essential part of the analysis of coal combustion products. Similarly, analysis may determine whether a trace element, such as arsenic, may be eliminated from a coal by washing or whether it must be trapped in the flue gas. In extreme cases, the data from a series of analytical test methods may determine that the coal cannot be used for combustion leading to power generation.

Thus, analysis is an important part of attempts to reducing the *carbon footprint* of coal-fired power production. In the United States, the energy infrastructure encompasses an enormous investment in capital assets and systems to produce fuels and electric power for businesses, the transportation industry, and for domestic use. The long-term opportunity to reshape this infrastructure to have a low-carbon profile is promising and involves improving the efficiency of the existing coal-fired power plant fleet though knowledge of coal composition and the effects of this composition on combustion processes.

Accordingly, this chapter presents the various analytical methods that can be applied to determining the composition of coal. By analogy with the crude oil industry (Speight, 2014), some power plants may carry out a full analysis (full assay) of every new batch of feedstock (coal) received at the plant while other companies may perform a partial analysis (partial assay) of the coal to determine specific properties which have a stronger influence on the behavior of the coal during combustion (Chapter 7).

Finally, there are two methods of coal analysis: (i) the proximate analysis and (ii) the ultimate analysis. The proximate analysis (sometimes referred to as the coal assay) determines only the fixed carbon, volatile matter yield, moisture content, and ash yield as percentages of the original coal. On the other hand, the ultimate analysis determines all coal component elements in coal.

The types of analytical procedures needed to characterize and classify coals can roughly be divided into those that describe chemical composition/properties as well as those methods that describe petrographic composition and those that describe mechanical/physical properties. Some of these procedures are basic to the evaluation of all coal materials, whereas others are employed in the evaluation of their use in specific processes, like coke making.

In summary, the proximate and ultimate analysis of coal provides important information regarding the overall characteristic of a particular coal. Ultimate analysis includes elemental analysis of coal and has been used to assess its combustion characteristics and to estimate the maximum emission of sulfur and nitrogen oxides (Sharkey, and McCartney, 1981; Raask, 1985; Gupta, 2007; Speight, 2013, 2015).

5.2 Sampling

Samples submitted for chemical and physical analyses are collected for a variety of reasons, but the collection of each sample should always conform to certain guidelines (Golightly and Simon, 1989). Typically, coal submitted for chemical analysis is first received and prepared by the sample preparation (grinding) laboratory. The typical sizes of individual field samples vary from 3 to 15 kg. The preparation procedure usually requires that each air-dried coal sample pass through a jaw crusher; one subsample (split) of the crushed material (2 to 4 mm, or 5 to 10 mesh) is then taken for the ultimate and proximate analyses, and another split is reduced to approximately 150 mm (100 mesh) by a vertical grinder for chemical analysis. An additional split is kept for archival storage, and the excess sample is returned to the submitter.

As-mined coal contains a mixture of different size fractions, together with unwanted impurities such as rock and dirt (Speight, 2013, 2015). Coal preparation (beneficiation) is the stage in coal production when the mined coal is processed into a range of clean, graded, and uniform coal products that are suitable for the commercial market. In a few cases, the mined coal is of such quality that it meets the user specification without beneficiation, and it is merely crushed and screened to deliver the specified product. However, some power plants are fed from a single source of coal but many utilities buy coal from different suppliers, and some blend the coals in order to give a consistent feed to the power plant. Blending also enables selective purchasing of different grades of coal. More expensive, higher-quality supplies can be mixed with lower-quality coals to produce an average blend suited to the plant needs, at optimum cost. Effective preparation of coal prior to combustion improves the homogeneity of coal supplied, reduces transport costs, improves the utilization efficiency, produces less ash for disposal at the power plant, and may reduce the emissions of oxides of sulfur (Vaysman and Lu, 2012).

For homogeneous materials (coal is not one of these materials), sampling protocols are relatively simple and straightforward, although caution is always advised lest overconfidence cause errors in the method of sampling as well as introduce extraneous material. On the other hand, the heterogeneous nature of coal (Speight, 2013, 2015) complicates the sampling procedures. In fact, apart from variations in rank (Chapters 1, 2), coal is often visibly heterogeneous and there is strong emphasis on the need to obtain representative samples for testing and analysis (Gould and Visman, 1981).

Thus, the variable composition of coal offers many challenges to the analyst who needs to ensure that the sample under investigation is representative of the coal. Indeed, the substantial variation in coal quality and composition from the top to the bottom of the seam, from side to side, and from one end to the other, within an unmined bed offer challenges that are perhaps unprecedented in other fields of analytical chemistry. Hence the issues that arise during drilling programs that are designed to determine the size and extent of a coal bed or coal seam. This variability in coal composition and, hence, in coal quality is often significantly, and inadvertently, increased by mining, preparation, and handling.

Thus, coal sampling is an important part of the process control in a coal preparation plant. Most analyses of coal for both standard and research purposes are conducted on carefully collected samples (representative sample) of whole coal. On the other hand, a *grab sample* is a one-time sample of the coal at a point in the process stream, and tends not to be very representative. A *routine sample* is taken at a set frequency, either over a period of time or per shipment.

Coal samples are taken from a variety of places – individual coal beds in place (i.e., in the mine) and mined coal on coal-mine conveyor systems, trucks, train cars, or stockpiles – depending on the needs of the sampling and analytical programs. The goal of this process is to collect a sample that will be as representative as possible of the coal bed or coal stockpile or other source from which it is taken. Indeed, if the coal is stockpiled for an unusual length of time (i.e., time that exceeds the typical standing time for the coal in a stockpile), oxidation is possible and change in the coal properties can be anticipated. Hence analysis of coal sample will determine the extent of the oxidation and whether or not the coal needs to be blended with another coal to assure the desired performance in the combustor.

However, in order to produce reliable results from testing programs, sampling must be done very carefully. Samples must be taken without contamination from extraneous material, and location and orientation must be documented in the minutest detail so that the analytical data can be compared from one sample to another.

Thus, it should not be surprising that the purpose of the analysis often determines the type of sample that is collected. If the purpose is to characterize already mined coal, then gross samples may be taken at regularly or randomly spaced intervals from the stockpile, coal car, or conveyor belt. If the purpose is to examine some specific property of a coal bed, then a sample of only a small part of the bed may be taken. If the purpose of the sample is to study some directionally controlled characteristic, such as the orientation of mineral grains, the sample must be labeled to show top and bottom and, in some cases, compass directions. For some types of analyses (for example, by either petrographic or scanning-electron microscope, small blocks of coal are cut out of larger samples and one side is polished and examined. This technique is used when it is necessary to determine the microscopic details of the type, distribution, and arrangement of the macerals and minerals in a type of coal.

Coal sampling consists of several types of sampling devices. A cross cut sampler is used to mimic the *stop belt* sample according to standards test methods (Speight, 2013, 2015) which designate the manner in which coal must be sampled. A cross cut sampler mounts directly on top of the conveyor belt. The falling stream sampler is placed at the head section of the belt.

There are several points in the washing plant that many coal operations choose to sample the raw coal (i) before it enters the plant, (ii) any coal-related refuse, to determine the character of the coal reject, and (iii) the cleaned coal, to determine the quality of the coal to be shipped.

Once a gross sample has been taken, it is crushed, and then quartered to obtain a net sample which is then sent to an independent laboratory for testing where the results will be shared with the buyer as well as the supplier. In many cases, the buyer may request a repeat analysis or a second analysis by another laboratory to assure the quality of the data. Continuous measurement of ash, moisture, heat content (Btu/lb), sulfur iron, calcium sodium and other elemental constituents of the coal are reported.

5.2.1 Methods

Generally, there are two methods of coal sampling: (i) sampling in the mine, often referred to as *in situ sampling* or *seam sampling* and (ii) *ex situ sampling* which occurs after the coal has been mined. *In situ* sampling is often carried out by geologists who are investigating the nature of the coal before development of the coal seam by mining methods. The fundamental requirements of sampling are:

- All particles of coal in the lot to be sampled are accessible to the sampling equipment and each individual particle shall have an equal probability of being selected and included in the sample.
- The dimension of the sampling device used should be sufficient to allow the largest particle to pass freely into it.
- The first stage of sampling, known as primary increments, is the collection of an adequate number of coal portions from positions distributed over the entire lot to take care of the variability of the coal. The primary increments are then combined into a sample, as taken or after reducing the mass of the sample to a manageable size. From this gross sample, the required number and types of test samples are prepared by a series of processes jointly known as sample preparation.
- The minimum mass of the gross sample should be sufficient to enable particles to be present in the same proportions as in the lot of coal from which it is taken.
- To ensure that the result obtained has the *required precision* the following issues are to be considered: (i) variability of coal, (ii) number of samples from a lot, (iii) number of increments comprising each sample, and (iv) mass of sample relative to the nominal top size.

Thus, in order to test any particular coal, it is necessary (i) to obtain a sample of the coal and (ii) to endure that the sample is representative of the bulk material. Thus, sampling is, by convention, the operation of removing a portion (the sample) from the greater bulk (the whole) of the material. However, the removal of the sample must be such that it has the same qualities (properties) as the bulk (Visman, 1969; Gould and Visman, 1981; Speight, 2015). In addition, there must be a clear understanding of the methods which constitute good (and correct) sampling practice. In more general, terms the effectiveness of a sampling method is the degree to which the composition and properties of the bulk coal is sampled.

5.2.2 *In Situ* Sampling

Channel sampling is one of the best methods for sampling in-seam coal. When the coal sample is collected from an outcrop, the exposed area should be cleaned to avoid the weathered exposed coal surface. Normally a small is box cut is made at the coal outcrop exposing the entire thickness of the coal seam. For a relatively thin seam only one coal section is recommended. However, if the seam is thick, two or more coal sections may be necessary to sample entire seam.

In some cases, the strength of the coal becomes important mainly in the underground mining – such as from the pillars when the seam has been mined using the *room-and-pillar mining* method. A large block of undisturbed coal is usually sampled (*pillar sampling*) from some specific areas of potential problems or areas with known problems; the sampling scheme is similar to the channel sampling method.

Core sampling is mainly a part of the exploration and reserve evaluation stage. This is, however, important for the development of a future mine. A geologist is usually assigned to supervise a drilling program. Coal samples are collected in wooden boxed carefully in the field if not sampled at the field. Most of the time an e-log is prepared for each completed hole in recent time. A geologist checks the e-log for the coal thickness and adjusts the *core recovery* for the collected coal seam.

Cutting sampling (*chip sampling*) is a much less accurate sampling scheme than the core sampling. Cuttings are generated by rotary type drilling where no core is recovered except chips. Air flush or mud-flush rotary drilling is a much faster drilling and mostly used for gas wells. This kind of sampling can only give a very general analysis of the coal. It is difficult to collect samples and most of the time we have lots of impurities mixed in it. Also, the exact depth of coal cannot be accurately recorded unless generated from a geophysical log after drilling is completed.

Bulk samples are collected mainly for larger-scale tests, to check swelling the properties of various coal seams, to rank coal as *high-pressure coal* and *low-pressure coal*.

5.2.3 *Ex Situ* Sampling

Ex situ sampling (*non-in situ sampling*) is the method (or methods) of sampling coal from a stockpile, a coal train (or other means of transportation), or at the time of entry into the preparation plant, or into the power plant. Such methods are often not representative of the coal seam that is mined. The coal may be blended with *out-of-seam* products from the roof and floor strata or even with coal from two or more seams to meet certain quality standards specified by the client.

The procedure for sampling will, however, differ with the purpose and method of sampling. Samples may be required for technical evaluation, process control, quality control, or for commercial transactions. For quality assessment of coals from new sources, samples are to be drawn from *in situ* coal seams, either as rectangular blocks or pillars cut from full seam height, or from seam channels or from borehole cores.

While drawing increments great care should be taken to avoid the occurrence of bias in the results. The ideal method of sampling is the *stopped belt method*, which is considered free of bias. As implementation of such a method will affect the continuity of plant operations, it is not always practicable for routine sampling. However, any mechanical sampling device needs to be checked for bias by comparing with the results from the stopped belt reference method. In fact, the method of *stopped belt* sampling is often implemented to standardize any other mechanical automatic sampling systems.

Briefly, a *grab sample* is a sample of the coal at a point in the process stream, and tends not to be very representative. A *routine sample* is taken at a set frequency, either over a period of time or per shipment. In fact, coal sampling consists of several types of sampling devices. A *cross cut* sampler to mimic the *stop belt* sample – a cross cut sampler mounts directly on top of the conveyor belt. The *falling stream* sampler is placed at the head section of the belt.

Joint sampling is carried out at the loading end by the representatives of the producer and the customer, following a methodology mutually agreed upon by both parties. Depending on the nature of the agreement, the loading point results can be taken exclusively for commercial transactions. In some cases the mean value of the results of joint sampling at both the loading and unloading ends is considered. The tolerance values in the quality parameters are often defined, beyond which several bonus/penalty clauses are imposed but the tolerance value identified is compatible with the sampling scheme. Whether or not the tolerance value lies within the precision limit can be achieved by the implementation of a particular sampling scheme involving periodic testing.

Stream sampling and *flow sampling* are terms usually reserved for the collection of sample increments from a free-falling stream of coal as opposed to the collection of increments from a stopped conveyor belt. Coal that passes from one belt to another at an angle tends to become segregated, with a predominance of coarse particles on one side and a predominance of fine particles on the other side. There are also situations where coal must be sampled when there is no motion (sampling at rest) and it may be difficult, if not impossible, to ensure that the sample is truly representative of the gross consignment.

When a property of coal (which exists as a large volume of material) is to be measured, there will almost always ("always" being a term like "never") be differences between the data from a gross lot or gross consignment and the data from the sample lot. This difference, called the sampling error, has a frequency distribution with a mean value and a variance. Variance is a statistical term defined as the mean square of errors; the square root of the variance is more generally known as the *standard deviation* or *standard error* of sampling.

Furthermore, recognition of the issues involved in obtaining representative samples of coal has resulted in the designation of methods which dictate the correct manner for the sampling of coal (ASTM D346; ASTM D2013; ASTM D2234). The number of riffling stages required to prepare the final sample depends on the size of the original gross lot. However, it is possible by use of these methods to reduce an extremely large consignment (that may be of the order of several thousand pounds) to a representative sample that can be employed as a laboratory test sample.

Taking samples of coal from sampling storage piles at a power plant can raise problems. For example, in conical-shaped piles segregation affects result in fines predominating in the central core as well as a gradation of sizes down the sides of the pile from generally fine material at the top of the pile to coarser coal at the base of the pile. If at all possible, coal piles should be moved to be sampled which, in turn, will determine how the coal is sampled. Where it is not possible to move a pile, there is no choice but to sample it "as is" and the sampling regime usually involves incremental spacing of the samples over the entire surface. Alternatively, the sampling of large coal piles can be achieved by core drilling, or augering, or the coal can be exposed at various depths and locations (by means of heavy equipment such as a bulldozer) so that it can be manual sampling can be performed.

Sample preparation (ASTM D2013) includes drying (in air), as well as crushing, dividing, and mixing a gross sample to obtain an unbiased analysis sample. However, the procedure is usually accompanied by loss of moisture unless the sample increments are weighed as they are collected and then air-dried and reweighed before crushing and dividing.

The performance of coal preparation plants (Deurbrouck and Hucko, 1981) as well as the testing and routine quality control in mining operations and preparation plants requires sampling coal both *in situ* and at various stages of processing following removal from the seam. Monitoring of preparation plant performance, however, can be quite complex insofar as the feedstock to the plant may be taken from several streams with widely different sampling protocols. Such sampling may involve various manual sampling techniques.

The standard methods of sampling (ASTM D2234) usually apply to coal sales in which the purpose of the sampling is actually a method for valuation as a determinant of price or conformance with specifications (Janus and Shirley, 1975, 1975).

Coal sales are carried on in consignments or lots that are clearly definable as distinct units and can be sampled as such, but the size of such lots varies widely, from single truckloads to shiploads of 30-50 x 103 tons (30-50 x 106 kgm). The methods employed stipulate the minimum weight and minimum number of increments required, together with precautions, increment types, conditions of increment collection, and increment spacing.

Optimization of coal combustion in power plants and processes is a function of the many variable constituents of coal. Thus, it is not surprising, perhaps even anticipated, that sampling is conducted to determine efficiency, heat inputs, and operating needs.

The effect of fines content on the combustion of pulverized coal is quite dramatic (Field *et al.*, 1967; Essenhigh, 1981), and the problems that arise from the collection of an unbiased sample of pulverized coal require additional and special consideration (ASTM D197). Operating samples are often collected from the feedstocks to power plant boilers on a shift or daily basis for calculation of heat balances and operating efficiencies. Another objective of operating samples is to document compliance with air pollution emission regulations based on fuel composition.

5.3 Proximate Analysis

The proximate analysis of coal consists of a group of standard test methods which have been used widely as the basis for coal characterization in connection with coal utilization (ASTM D3172) (Speight, 2013, 2015). In reality, the test methods result in the determination of moisture content, volatile matter content, ash yield, and (by difference) fixed carbon yield, in contrast to the ultimate analysis of coal which provides the elemental composition (Figure 5.1).

The objective of the proximate analysis is to determine the amount moisture, volatile matter yield, ash yield, and fixed carbon from the coal sample. Mineral matter is not directly measured but may be obtained by one of a number of empirical formula either from the yield of mineral ash or from data derived from the ultimate analysis.

The variables are measured in percent by weight (% w/w) and are calculated on several different bases:

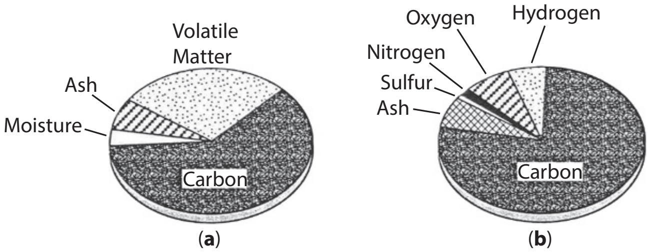

Figure 5.1 Data types obtained from (a) Proximate Analysis and (b) Ultimate Analysis (Speight, 2008, 2013, 2015).

- AR (as-received) basis, which is the most widely used basis in industrial applications and puts all variables into consideration and uses the total weight as the basis of measurement.
- AD (air-dried) basis, which neglects the presence of moistures other than inherent moisture.
- DB (dry-basis), which omits all moisture, including surface moisture, inherent moisture, and other moistures.
- DAF (dry, ash free) basis, which omits all moisture and mineral matter (determined as mineral ash) constituents in coal.
- DMMF (dry, mineral-matter-free), which omits the presence of moisture and mineral matter in coal, such as quartz, pyrite, calcite, and clay.

For a specific coal, that analytical data may be presented as one or all of the lines below:

Proximate Analysis	AR	AD	DB	DAF
Moisture (% w/w)	3.3	2.7		
Ash (% w/w)	22.1	22.2	22.8	
Volatile Matter (% w/w)	27.3	27.5	28.3	36.6
Fixed Carbon (% w/w)	47.3	47.6	48.9	63.4

In summary, the proximate analysis of coal indicates the percentage by weight of the fixed carbon, volatile matter, mineral matter (determined as mineral ash), and moisture content in coal. The amounts of fixed carbon and volatile combustible matter directly contribute to the heating value of coal. Fixed carbon acts as a main heat generator during burning. High volatile matter content indicates easy ignition of fuel. The ash production is important in the design of the furnace grate, combustion volume, pollution control equipment and ash handling systems of a furnace.

Traditionally, the various proximate analysis determinations involve heating the coal to constant weight under specified conditions (Speight, 2013, 2015; ASTM, 2020). These determinations, however, are time consuming and require a significant amount of laboratory equipment. An alternative method for proximate analysis is thermogravimetric analysis (TGA). Although this thermal analysis technique also involves heating the sample to constant weight under specified conditions, it does, because of smaller sample sizes and rapid temperature and atmosphere control, substantially reduce the analysis time as well as the equipment necessary for proximate analysis.

5.3.1 Moisture

Moisture content is an important property of coal since all coals are mined wet. Groundwater and other extraneous moisture are known as adventitious moisture and are readily evaporated. Generally, moisture in coal ranges from 3% in anthracites to as high as 45% in lignite. The determination of water content in coal is constrained to the rank of coal and equally dependent on the condition of the sample preparation and the condition of the coal. Moisture held within the coal itself is known as inherent moisture and is analyzed quantitatively.

However, moisture in a coal sample may be classified as follows: (i) surface moisture, which is water held on the surface of coal particles or macerals, (ii) hydroscopic moisture, which is water held by capillary action within the micro-fractures of the coal, (iii) decomposition moisture, which is water produced during the thermal decomposition of organic matrix of coal, and (iv) mineral moisture, which is water that comprises part of the crystal structure of the mineral matter in coal, such as hydrous silicates (i.e., clay minerals).

As a result of these several forms, the quantitative measurement of water is complicated because the water is present within the coal matrix in more than one form (Allardice and Evans, 1978). The *total* moisture in coal may be determined by means of a single-stage method or by means of a two-stage method in which the as-received sample is air-dried at approximately room temperature and the residual moisture is determined in the sample (ASTM D3302).

Total moisture is analyzed by loss of mass between an untreated sample and the sample once analyzed. This is achieved by any of the following methods: (i) heating the coal with toluene, (ii) drying in a minimum free-space oven at 150°C (300°F) within a nitrogen atmosphere, and (iii) drying in air at 100 to 105 °C (210 to 220 °F) and relative loss of mass determined. The first two methods are suitable with low-rank coals but the third method is only suitable for high-rank coals as free air drying low-rank coals may promote oxidation. Inherent moisture is analyzed similarly, though it may be necessary to use a vacuum.

In the simplest form of experimentation, moisture in coal is determined by placing a sample of powdered raw coal of size 200-micron size in an uncovered crucible and it is placed in the oven kept at 108 ± 2^{o}C (226 ± 4^{o}F) along with the lid. Then the sample is cooled to room temperature and weighed again, taking care not to allow the coal to adsorb atmospheric moisture during the cooling period. The loss in weight represents moisture. Other determinations of moisture are a little more complex and depend upon the form of the moisture in coal, such as the natural bed moisture.

Generally, the analytical methods in which an attempt is made to differentiate the moisture into different categories are as follows: (i) the thermal methods, (ii) a desiccator method, (iii) the distillation method, (iv) the extraction and solution methods, (v) the chemical methods, and (vi) an electrical method.

In the thermal methods, moisture may either be determined as the loss in weight when coal is heated to various temperatures (with the atmosphere and pressure variable) or by the determination of the weight gain of a vessel containing a desiccant through which passes the volatile materials evolved when the coal is heated. Similarly, the desiccator method involves a measure of the weight loss (of the coal) which occurs when the coal is maintained in a desiccator (in the presence of a desiccant) either at atmospheric pressure or at reduced pressure, but at ambient temperature. From the data, the type of moisture in the coal sample can be estimated.

Each of these methods has merit and the advantages or disadvantages of any particular method must be considered prior to the application or acceptance of the method. Indeed, it must be remembered that the applicability of any one method is not only dependent on accuracy (as well as the reproducibility of that accuracy) but also on the applicability of that method to the whole range of coal types.

Although the moisture as determined (particularly by the ASTM test) is, to all intents and purposes, moisture, it may, however, include some adsorbed gases while some strongly adsorbed moisture will not be included in the test data. Caution is also necessary to ensure that the coal sample is not liable to thermal decomposition at the temperature of the moisture determination.

Moisture in coal is an important property – more important than often recognized by the non-industrial coal theorists. Moisture that exists in coal (on the order of 0.5 to 15% w/w) must be transported, handled, and stored. Since the moisture replaces combustible matter, it (i) decreases the heat content of the coal, (ii) increases heat loss, due to evaporation and superheating of vapor, and (iii) aids radiation heat transfer. In fact, the moisture content of a coal is also an important parameter in the rate of heat generation of the coal. Drying coal is an endothermic process, in which heat is absorbed, and the temperature of the coal is lowered. The adsorption of moisture on a dry coal surface is an exothermic process, with a heat producing reaction. If it is partially dried during its mining, storage, or processing, coal has the potential to reabsorb moisture, thus producing heat.

Therefore, the higher the amount of moisture in coal, the greater the potential for the generation of heat leading to spontaneous ignition and spontaneous combustion (Chapter 4). The most dangerous scenario for spontaneous combustion is when wet and dry coals are combined; the interface between wet and dry coal becomes a heat exchanger (Berkowitz and Schein, 1951). If coal is either completely wet or completely dry, the risk is substantially reduced. In general, the moisture content of coal increases with decreasing rank.

5.3.2 Natural Bed Moisture

In the American Society for Testing and Materials system for the classification of coals by rank (Table 5.2) and in the International System for the classification of hard coal (Chapter 2), high-volatile coals are classified according to their calorific value on a moist basis. In this instance, the calorific value is quoted for the coal containing water that occurs with the coal in the seam, i.e., the natural bed moisture (equilibrium moisture; capacity moisture).

The natural bed moisture of coal is determined by wetting the coal, removing the excess water by filtration, and then allowing moisture equilibration to occur by standing the coal over a saturated solution of potassium sulfate in a closed vessel, thereby maintaining the relative humidity at 96 to 97% (ASTM D1412; Luppens and Hoeft, 1992; Speight, 2015). The vessel must be evacuated to a partial vacuum (approximately 30 mm mercury) and maintained at 30°C (86°F) for 48 hours – higher-rank coal than lignite while lignite will require 72 hours to reach equilibrium. The method can also be employed to estimate the

Table 5.2 Classification of Coal by Rank (see also Chapter 2).

Class/group	Fixed Carbon Limits (dry mineral-matter-free basis) %		Volatile Matter Limits (Dry Mineral-matter-free Basis) %		Gross Calorific Value Limits (Moist, mineral-matter-free Basis) Btu/lb		Gross Calorific Value Limits (Moist, mineral-matter-free Basis) Mj/kg	
	Equal or Greater Than	**Less Than**	**Equal or Greater Than**	**Less Than**	**Equal or Greater Than**	**Less Than**	**Equal or Greater Than**	**Less Than**
Anthracite:								
Meta-anthracite	98	---	---	2				
Anthracite	92	98	2	8				
Semianthracite	86	92	8	14				
Bituminous:								
Low Volatile	78	86	14	22				
Medium Volatile	69	78	22	31				
High Volatile A	---	69	31	---	14,000	---	32.6	---
High Volatile B					13,000	14,000	30.2	32.6
High Volatile C					11,500	13,000	26.7	30.2

(*Continued*)

Table 5.2 Classification of Coal by Rank (see also Chapter 2). (*Continued*)

Class/group	Fixed Carbon Limits (dry mineral-matter-free basis) %		Volatile Matter Limits (Dry Mineral-matter-free Basis) %		Gross Calorific Value Limits (Moist, mineral-matter-free Basis)			
					Btu/lb		Mj/kg	
	Equal or Greater Than	Less Than	Equal or Greater Than	Less Than	Equal or Greater Than	Less Than	Equal or Greater Than	Less Than
Subbituminous:								
Subbituminous A					10,500	11,500	24.4	26.7
Subbituminous B					9,500	10,500	22.1	24.4
Subbituminous C					8,300	9,500	19.3	22.1
Lignite:								
Lignite A					6,300	8,300	14.7	19.3
Lignite B					---	6,300	---	14.7

surface for extraneous moisture of wet coal – such moisture is the difference between the total moisture of the coal and the natural bed moisture.

5.3.3 Volatile Matter

Generally, coal does *not* contain much natural volatile matter. The volatile matter in coal refers to the components of coal, except for moisture, which are liberated at high temperature in the absence of air (i.e., during pyrolysis or during the initial stages of combustion). The volatile matter obtained during the heating of coal influences coal combustion (Chapter 7) and consists mainly of combustible gases such as hydrogen, carbon monoxide, methane plus other hydrocarbon derivatives and tar as well as incombustible gases such as carbon dioxide and steam. Thus, any coal which can generate substantial amounts of volatile matter (i) can ignite easily, (ii) has a high tendency to burn, (iii) will burn with long smoky yellow flame, and (iv) has low calorific value. The first item (i.e., the coal can ignite easily) is a significant factor for coal selected as a feedstock in a coal-fired power system.

Just like the moisture content, volatile matter depends on coal rank and ranges from <5% for anthracites to >50% w/w for subbituminous and lignite. There are large variations in gas content within a single coal at a single location. The gases in coal are located in pores and are retained on the surface of the pores by adsorption forces.

Based on different pore-filling mechanisms, the pores in coal are generally classified into three groups: (i) micropores, which are pores <2 microns in size, (ii) mesopores, which are pores on the order of 2 to 50 microns in size, and (iii) macropores, which are pores >50 microns in size. The size and volume of micropores, mesopores, and macropores in coal depend on many factors, and coal rank is one of the most important. In addition, accessibility to the pore systems also depends on the size of the throat (i.e., the entryway or doorway) into the pore systems, which can be smaller or larger than the actual pores themselves. As coal rank increases, the volume of macropores decreases, whereas the volume of micropores increases. Maceral composition is another factor that influences surface area, pore volume and pore size distribution in the volatile matter content in coal.

The determination of the volatile matter content of coal (ASTM D3175) is an important determination because volatile matter data are an integral part of coal classification systems (Chapter 2) and also form the basis of evaluating coals for their suitability for combustion and carbonization. The methods for determining volatile matter content are based on the same principle and consist of heating a weighed sample of coal (usually approximately 1 g) in a covered crucible to a predetermined temperature; the loss in weight (excluding losses due to water) is the volatile matter content (expressed as a weight percent). In this respect, it should be noted that the test method is similar to the test method for determining the Conradson carbon residue of crude oil and crude oil products (ASTM D189).

As for all standard test methods, the volatile matter of coal is determined under rigidly controlled standards. In Australian and British standard test methods, the procedure involves heating the coal sample to 900 ± 5 °C (1650 ±10 °F) for 7 minutes in a cylindrical silica crucible in a muffle furnace. The ASTM standard test method of analysis involves heating coal to 950 ± 25 °C (1740 ± 45 °F) in a vertical platinum crucible (ASTM D3175).

The composition of the volatile matter evolved from coal is substantially different for the different ranks of coal and the proportion of incombustible gases increases as the coal rank decreases. Furthermore, in macerals isolated from any one particular coal, the volatile matter content decreases in a specific order; thus, exinite produces more volatile matter than vitrinite which, in turn, yields more volatile matter than inertinite.

The chief differences in the methods are: (i) variations in the size, weight, and materials of the crucibles used, (ii) the rate of temperature rise, (iii) the final temperature, (iv) the duration of heating, and (v) any modifications that are required for coals which are known to decrepitate or which may lose particles as a result of the sudden release of moisture or other volatile materials. In essence, all of these variables are capable of markedly affecting the result of the tests and it is, therefore, very necessary that the standard procedures be followed closely.

In general terms, the temperature is in the range 875 to 1050°C (1605 to 1920°F), the duration of heating is 3 to 20 min. and the crucibles may be platinum, silica, or ceramic material. The German standard specifies a temperature of 875°C (1605°F) to be in accord with the industrial coking practice while other standards specify temperatures of 1000 to 1050°C (1830 to 1920°F) to ensure maximum evolution of volatile matter under the test conditions; a temperature of 950°C (1740°F) is specified by the ASTM standard (ASTM D3175).

Mineral matter may also contribute to the volatile matter by virtue of the loss of water from the clay minerals, the loss of carbon dioxide from carbonate minerals, the loss of sulfur from pyrite (FeS_2) and the generation of hydrogen chloride from chloride minerals as well as various reactions that occur within the minerals thereby influencing the analytical data (Given and Yarzab, 1978).

The characterization of coal either as agglomerating or as non-agglomerating for the purposes of rank classification (Chapter 2) is carried out in conjunction with the determination of the volatile matter content. Thus, if the residue remaining from the determination is in the form of an agglomerate button that is capable of supporting a 500-gram weight without pulverization of the button, the coal is classified as agglomerating. Similarly, if the button shows swelling or cell structure, the coal is classified as agglomerating.

Thus, the volatile matter produced during the thermal decomposition of coal typically contains methane, higher molecular weight hydrocarbon derivatives, hydrogen, carbon monoxide, and incombustible gases. The volatile matter yield (usually on the order of 20 to 35% w/w) can be considered to be an index of the gaseous fuels present. In addition, the volatile matter yield is an important property since volatile matter (i) proportionately increases flame length, and helps in easier ignition of coal, (ii) sets a minimum limit on the furnace height and volume, (iii) influences secondary air requirement and distribution aspects, and (iv) influences secondary oil support.

5.3.4 Ash

In spite of the commonly used and often abused terminology, coal does not contain ash (Speight, 2015). Ash refers to the inorganic materials that are left after all the combustible matter has been burned off (Table 5.3). Ash, as a by-product of combustion of coal, is further classified into fly ash and bottom ash.

Fly ash is the fine particle that rises with the flue gases during combustion while bottom ash is the ash that does not rise. The quantity of fly ash generated during coal conversion processes is also dependent on the rank of the coal. Thus, depending on the coal being burned, the composition of fly ash varies but all fly ash does contain substantial amounts

Table 5.3 Approximate Composition of Coal Ash (Speight, 2013).

Silica (SiO_2): 40–90%;
Aluminum oxide (Al_2O_3): 20–60%;
Iron (ferric) oxide (Fe_2O_3): 5–25%;
Calcium oxide (CaO): 1–15%;
Magnesium oxide (MgO): 0.5–4%;
Sodium oxide (Na_2O) plus potassium oxide (K_2O): 1–4%

of silicon dioxide (SO_2) and calcium oxide (CaO). Toxic constituents associated with ash ranging from trace amount to substantial quantities are arsenic, beryllium, boron, cadmium, chromium, chromium IV, cobalt, lead, manganese, mercury, molybdenum, selenium, strontium, thallium, and vanadium, along with dioxins and polynuclear aromatic hydrocarbon compounds (PNAs).

Though there is concern about the health implications of the composition of ash, it has found application in several sectors of the economy: concrete production, embankments and other road structural fills, grout and flowable fill production, waste stabilization and solidification, cement clinkers production, mine reclamation, stabilization of soft soils, mineral filler in asphaltic concrete, an aggregate substitute material for brick production, agricultural uses and several other industrial applications. The toxic constituents in coal ash can cause cancer and nervous system impacts such as cognitive deficits, developmental delays, behavioral problems, heart damage, lung disease, respiratory distress, kidney disease, reproductive problems, gastro-intestinal illness, birth defects, and impaired bone growth.

The presence of inorganic matter (mineral materials) in coal reduces the heating value of the coal and the mineral matter may also contribute to the volatile matter in coal by virtue of the loss of water from the clay minerals, the loss of carbon dioxide from the carbonate minerals, the loss of sulfur from pyrite (FeS_2), and the generation of hydrogen chloride from chloride minerals. The most commonly found minerals in coal are clay minerals, quartz minerals, sulfide minerals, and carbonate minerals.

Most inorganic elements in the periodic table can be found in fossil fuels, especially coal, although only a small number occur in significant concentrations to cause operational or environmental problems. Coal has by far the highest content of mineral matter (Speight, 2013, 2020), although the chemical composition of low mineral matter fuels such as crude oil may be problematic in some instances (Speight, 2011, 2014).

The most common minerals in coal (for example illite clay, pyrite, quartz, and calcite) are made up of the most common elements (in approximate order of abundance): oxygen, aluminum, silicon, iron, sulfur, and calcium which undergo thermal reactions that are specific to the mineral type (Table 5.4) (Figure 5.2) (Speight, 2013, 2015). These minerals and other less common minerals usually contain the bulk of the trace elements present in coal. Minerals in coal commonly occur as single crystals or clusters of crystals that are intermixed with organic matter or that fill void spaces in the coal; sizes of mineral grains range from submicroscopic to a few inches. Some clusters of mineral grains, however, such as coal balls or vein fillings, may reach sizes of as much as several feet across.

Table 5.4 Generalized Thermal Chemistry of Mineral Types (Speight, 2013).

Inorganic species	Behavior on heating
Clays	Loose structural OH groups with arrangements of structure and release of H_2O
Carbonates	Decompose with loss of CO_2; residual oxides fix some organic and pyritic S as sulfate
Quartz	Possible reaction with iron oxides from pyrite and organically held Ca in lignites; otherwise no reaction
Pyrite	In air, burns to Fe_2O_3 and SO_2; in VM test, decomposes to FeS
Metal oxides	May react with silicates
Metal carboxylates (lignites and subbituminous only)	Decompose; carbon in carboxylate may be retained in residue

VM = volatile matter.

Although much is known related to the minerals in coal, there is still much to be determined about the occurrence, abundance, origin, composition, and chemistry of the minerals (Weaver and Pollard, 1973; Sturz *et al.*, 1998). For example, the type of clay mineral in a coal, whether it is montmorillonite or illite, determines how a coal will react when burned.

Montmorillonite may or may not break down (dissociate) into its constituent parts when coal is burned. If it does dissociate, then, upon cooling, it may recombine with other elements or minerals to form mineral deposits on the inside surfaces of furnaces and boilers (*slagging* or *fouling*) produces barriers to heat exchange in the affected equipment, which can substantially reduce its efficiency and require costly repairs. Illite, however, with its simpler composition, does not cause such problems under normal furnace operating conditions.

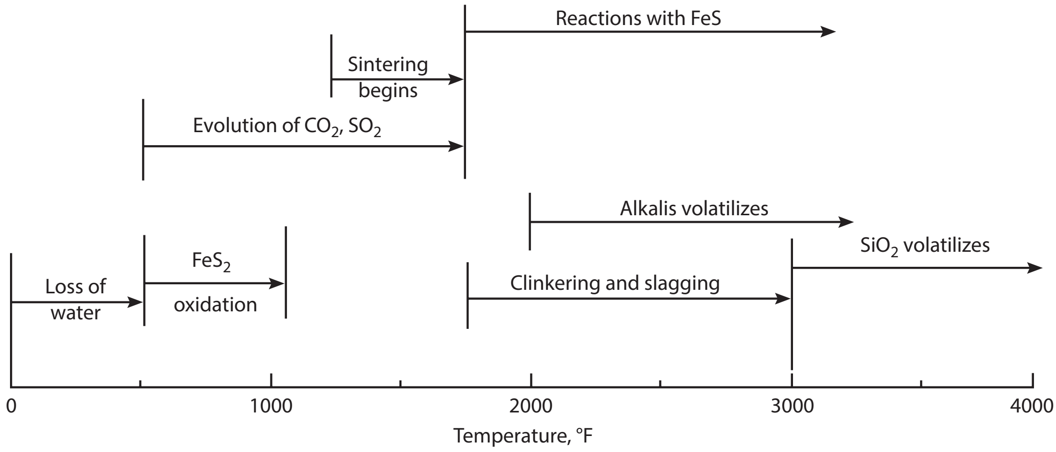

Figure 5.2 Reaction of minerals during coal heating (Speight, 2013).

Where these two clay minerals and others occur, their relative abundances, relationships to other minerals and exact compositions are subjects for continued research in coal quality.

When coal is burned, most of the mineral matter and trace elements generally form ash; however, some minerals break down into gaseous compounds, which leave through the furnace flue. Pyrite, for example, breaks down into the individual elements iron and sulfur. Each element then combines with oxygen to become, respectively, iron oxide and an oxide of sulfur, commonly referred to as SOx. Iron oxide, a heavy solid, becomes part of the ash, and SOx, a gas, is emitted as part of the flue gas. Some trace elements also dissociate from their organic or mineral hosts when coal is burned and follow separate paths. Most become part of the ash, but a few of the more volatile elements, such as mercury and selenium, may be emitted in the flue gas.

As a result of this complexity and the need to identify the constituents of coal before it is used in a power plant, considerable effort has been made to identify the amount and composition of the mineral matter in coal. Early methods for characterizing inorganic elements in coal were indirect, for example, mineral matter content and/or fusibility of the mineral ash. It was recognized in the early days of such investigations that the composition of the mineral matter ash strongly influenced the tendency to form deposits in the combustion system. Beginning in the 1930s, the contribution of specific minerals to slagging and fouling problems was recognized using methods of density separation to isolate mineral-rich fractions of coal. Mineralogical characterization of coal continued, resulting in a fairly comprehensive understanding of the occurrence and formation of the major minerals in coal by techniques such as physical separation, selective leaching, and x-ray diffraction analysis (Speight, 2013, 2015).

At this point, because of the relationship to the mineral matter in coal, it is appropriate to mention *slagging*, *fouling*, and *corrosion*.

Slagging is the deposition of fly ash (ash that does not descend to the bottom of the combustor) in the radiant section of the furnace, on both heat transfer surfaces and refractory surfaces. *Fouling* occurs in the convective heat transfer section and includes deposition of ash and volatiles as well as sulfidation reactions of ash. Fouling results in loss of heat transfer efficiency and blockage of the gas flow path. *Corrosion* occurs primarily on the water-wall tubes in the radiant section of the boiler and results in thinning of tubes with eventual leaks.

The coal mineral matter, upon combustion, yields a mixture of mineral oxides, which is called (correctly) *mineral ash*. Thus, *ash* is the non-combustible residue (metal oxides) left after coal is burned and represents the bulk mineral matter after carbon, oxygen, sulfur, and water (including from clay minerals) has been driven off during combustion (Given and Yarzab, 1978). Estimates of the mineral matter can be made using a standard formula such as the Parr formula or the King-Mavies-Crossley formula (see below) (Speight, 2013, 2015).

Determination of the mineral matter content (as the yield of mineral ash) ash yield content is necessary because it directly affects the combustion and boiler efficiency. The analysis for the *ash yield* is fairly straightforward, with the coal thoroughly burned and the ash material expressed as a percentage of the original weight (ASTM D 3174).

The chemical composition of the mineral ash is an important factor in fouling and slagging problems and in the viscosity of coal ash in wet bottom and cyclone furnaces. The potential for the mineral constituents to react with each other (Given and Yarzab, 1978) as well as undergo significant mineralogical changes is high (Helble, *et al.*, 1989). In addition, coal with high-iron (20% w/w ferric oxide) ash typically exhibit ash softening temperatures under 1205°C (2200°F). The use of coal with mineral matter that gives a high alkali oxide ash often results in the occurrence of slagging and fouling problems. As oxides, most ash elements have high melting points, but they tend to form complex compounds (often called *eutectic mixtures*) which have relatively low melting points. On the other hand, high-calcium-low-iron ash coals tend to exhibit a tendency to produce low-melting range slags, especially if the sodium content of the slag exceeds approximately 4% w/w.

Significant variations in the amount of ash can arise from the retention of sulfur. Thus, for high-rank coal, if the amount of pyrite and carbonate minerals is low, sulfur retention is not critical and ashing may be carried out rapidly. However, for coal with a considerable amount of pyrite (FeS_2) and calcite ($CaCO_3$), the procedure is to burn the coal at low temperatures to decompose the pyrite before the decomposition point of the carbonate mineral(s) is reached. Thus, less sulfur remains in the coal to react with the oxides that are formed at higher temperatures. Another method consists of (i) combustion of the coal to leave the mineral ash, often referred to as ashing the coal, (ii) treating the ash residue with sulfuric acid, and (iii) igniting the remainder to constant weight. The amount of ash is calculated back to the calcium carbonate basis by subtracting three times the equivalent of carbon present as mineral carbonate from the ash as weighed.

Several formulae have been proposed for calculating the amount of mineral matter originally in the coal using the data from ashing techniques as the basis of the calculations. Of these formulae, two have survived and have been used regularly to assess the proportion of mineral matter in coal and these are the Parr formula and the King-Mavies-Crossley formula.

In the Parr formula, the mineral matter content of coal is derived from the expression:

$$\%\ \text{w/w mineral matter} = 1.08A + 0.55S$$

A is the weight percent of ash produced by combustion of the coal and S is the total sulfur in the coal. On the other hand, the King-Mavies-Crossley formula is a little more complex:

$$\%\ \text{w/w mineral matter} = 1.09A + 0.5S_{\text{pyr}} + 0.8CO_2 - 1.1SO_{3(\text{in ash})} + SO_{3(\text{in coal})} + 0.5Cl$$

A, is the weight percent of ash produced by combustion of the coal, S_{pyr} is the percentage of pyritic sulfur in the coal, CO_2 is the percentage of mineral (non-organic) carbon dioxide in the coal, $SO_{3(\text{in ash})}$ is the percentage of sulfur trioxide in the ash; $SO_{3(\text{in coal})}$ is the percentage of sulfur trioxide in the coal, and Cl is the percentage of chlorine in the coal.

The Parr formula (which has been widely used in the United States) is obviously considerably simpler than the King-Mavies-Crossley formula (which has been in common use in Great Britain and other European countries) and requires less analytical data. However, the King-Mavies-Crossley formula will, because of the detail, provide more precise values of the mineral matter content of the coal. It is, however, a matter of assessing whether the slight improvement in precision is justifiable on the basis of the additional analytical effort.

The release of trace elements to the environment during coal combustion and disposal of coal ash, which often contains a wide range of trace elements, has become a matter of considerable concern (Speight, 2013, 2015). The determination of these elements in coal (and coke) ash is an important aspect of coal analysis and involves the use of atomic absorption

(ASTM D2795; ASTM D3682; ASTM D3683), X-ray fluorescence (Prather *et al*., 1979), and the electron probe microanalyzer (Raymond and Gooley, 1979).

The mineral matter content of coal, and hence the yield of ash during combustion (usually on the order of 5 to 40% w/w), insofar as mineral matter will not burn and (i) reduces handling and burning capacity, (ii) increases handling costs, (iii) affects combustion efficiency and boiler efficiency, and (iv) causes slagging, fouling, and clinkering.

Slagging, fouling, and clinkering difficulties have been found to correlate with the fusibility of the coal ash (ASTM 1857) and there have been attempts to predict the fusibility of coal ash from compositional data (Vorres, 1979). The test procedure provides for a controlled atmosphere; the test is first performed in a reducing atmosphere and is then repeated with a second set of cones in an oxidizing atmosphere. During combustion, there are zones in which the supply of oxygen is depleted or carbon dioxide is reversibly reduced to carbon monoxide in the presence of excess carbon. This can produce a reducing atmosphere in a hot zone where ash particles in an incipient state of fusion begin to melt. The significance of performing the test in reducing and oxidizing atmospheres is that most oxides of metals exhibit higher fusion temperatures in their highest state of oxidation.

Beside composition of coal ash, ash fusion point is also one significant parameter in ash analysis. The optimum operating temperature of coal processing will depend on the gas temperature and also the ash fusion point. In fact, the behavior of the constituents of coal ash at high temperature is a critical factor in selecting coals for steam power generation. Melting of the ash constituents may cause them to stick to the walls of the reactor/combustor resulting in a build-up of such inorganic constituents in specific places. Coal which has ash that fuses into a hard glassy slag known (*clinker*) is usually unsatisfactory in furnaces as it requires cleaning. However, furnaces can be designed to handle the clinker, generally by removing it as a molten liquid – many furnaces are designed to remove ash as a powdery residue.

Ash fusion temperatures are determined by viewing a molded specimen of the coal ash through an observation window in a high-temperature furnace (ASTM D1857). The ash, in the form of a cone, pyramid or cube, is heated steadily past 1000°C (1832°F) to as high a temperature as possible, preferably 1600°C (2910°F). The following temperatures are recorded: (i) *deformation temperature*, which is the temperature when the corners of the mold first become rounded, (ii) *softening (sphere) temperature*: the temperature when the top of the mold takes on a spherical shape, (iii) *hemisphere temperature*, which is the temperature when the entire mold takes on a hemisphere shape, and (iv) *flow temperature* or *fluid temperature*, which is the temperature when the molten ash collapses to a flattened button on the furnace floor.

The ash fusibility temperatures are used to predict whether the ash will perform properly (i.e., without initiating problems) in the combustor (or reactor) in which the coal was used.

Finally, low-rank coals contain large amounts of magnesium, potassium, calcium, and strontium as salts of organic acid group, as chelates, or as mineral grains (Benson and Holm, 1985). Carboxyl and associated oxygen groups decrease with the rank. Higher-rank coal contains mainly mineral grains of kaolinite, quartz, illite, calcite, and pyrite. Clay minerals that contain significant amounts of iron, calcium sodium or potassium cause low melting temperatures (1000 to 1200°C, 1830 to 2190°F), favoring slagging, which is also intensified by the pyrite, clay minerals (silicon and aluminum oxides) and alkalis (CaO, MgO) interaction with alumino-silicates to form low-viscosity products.

5.3.5 Fixed Carbon

The *fixed carbon content* (more correctly, the *fixed carbon yield* or *carbonaceous residue yield*) (FC) of the coal is the carbon found in the material which is left after volatile materials are driven off. Thus:

$$FC = FC = 100 - (\%H_2O + \%VM + \%Ash)$$

The value for the fixed carbon content of coal differs from the ultimate carbon content of the coal because some carbon is lost in hydrocarbon derivatives in the volatile matter.

The fixed carbon value is one of the values used in the determination of the efficiency of coal-burning equipment and also used as an indication of the yield of coke in a thermal process (Speight, 2015). Coal utilization processes tend to focus on a reliable understanding of the composition and internal structure of carbon. The dissolution of coal in solvent depends largely on the carbon content of the particular coal which could invariably means that it is coal-rank dependent.

In the determination of fixed carbon, the cover from the crucible used in the volatile matter last test is removed and the crucible is heated over the Bunsen burner until all the carbon is burned. The residue is weighed, which is the incombustible ash. The difference in weight from the previous weighing is the fixed carbon.

The fixed carbon value is determined by subtracting from 100 the resultant summation of moisture, volatile matter, and ash with all percentages on the same moisture reference base (ASTM 3172). Thus, the fixed carbon is the solid fuel left in the furnace after volatile matter is distilled off. It consists mostly of carbon but also contains some hydrogen, oxygen, sulfur, and nitrogen not driven off with the gases – typically located in polynuclear aromatic systems. The fixed carbon value can be used to give an estimate of heating value of the coal.

5.4 Ultimate Analysis

The various classification systems for coal variously involve either proximate analysis or ultimate analysis (elemental analysis) or a combination of both (Chapter 2). *Ultimate analysis* is an absolute measure of the elemental composition of coal whereas *proximate analysis* is essentially a determination of specific properties which allow determination of the suitability of coal for combustion purposes (as in coal-fired power plants) or for coking purposes (as in a coke oven) (Speight, 2013, 2015; ASTM, 2020).

The objective of ultimate analysis (ASTM D 5373 and ASTM D 4239) is to determine the constituents of coal in the form of the proportions of the chemical elements. Thus, the ultimate analysis (Figure 5.1) (ASTM D3176) determines the amount of carbon (C), hydrogen (H), oxygen (O), sulfur (S), and other elements within the coal sample. The amount of carbon includes that present in the organic coal substance as well as that originally present as mineral carbonates and, similarly, the amount of hydrogen includes that of the organic coal substance and the hydrogen present in the form of moisture and the water of constitution of the silicate minerals.

Table 5.5 Approximate relationship of ultimate analysis to proximate analysis.

%C	$0.97C + 0.7(VM - 0.1A) - M(0.6-0.01M)$
%H	$0.036C + 0.086 (VM - 0.1xA) - 0.0035M2 (1 - 0.02M)$
%N2	$2.10 - 0.020 VM$
Where	
C	% of fixed carbon
A	% of ash
VM	% of volatile matter
M	% of moisture

The ultimate analysis indicates the various elemental chemical constituents such as carbon, hydrogen, nitrogen, oxygen, sulfur, as well as trace elements and other elements (for example, chlorine and mercury) in coal. The data are useful in determining the quantity of air required for combustion and the volume and composition of the combustion gases, which is, in turn, required for the calculation of flame temperature and flue duct design.

Thus, the ultimate analysis of coal provides a convenient method for reporting the major organic elemental composition of coal (ASTM 2020). For this analysis, a coal sample is combusted in an ultimate analyzer, which measures the weight percent of carbon, hydrogen, nitrogen, sulfur, and ash from a coal sample. The total carbon, hydrogen, and nitrogen are determined at the same time from the same sample in the analyzer. Total oxygen is calculated from the other values.

Thus, for coal-fired power generation systems, ultimate analysis is used (along with the heating value of the coal) to perform combustion calculations including the determination of coal feed rates, combustion air requirements, weight of products of combustion to determine fan sizes, boiler performance, and sulfur emissions (Speight, 2011, 2013, 2015). In addition, there is an approximate relationship between the ultimate analysis and the ultimate analysis (Table 5.5).

5.4.1 Carbon and Hydrogen

Carbon and hydrogen, respectively, account for 70 to 95% w/w and 26% w/w (daf) of the organic substance of coal and are often thought to be the most important constituents of coal. As the rank of the coal increases from lignite to anthracite, the amount of hydrogen in the coal decreases (Figure 5.3) (Chapter 2).

The methods for determining carbon and hydrogen involve combustion of an exact amount of the coal in a closed system and the products of the combustion (CO_2/H_2O) determined by absorption (ASTM D3178). Complete conversion of the combustion gases to carbon dioxide and water can be achieved by passing the gases through heated cupric oxide.

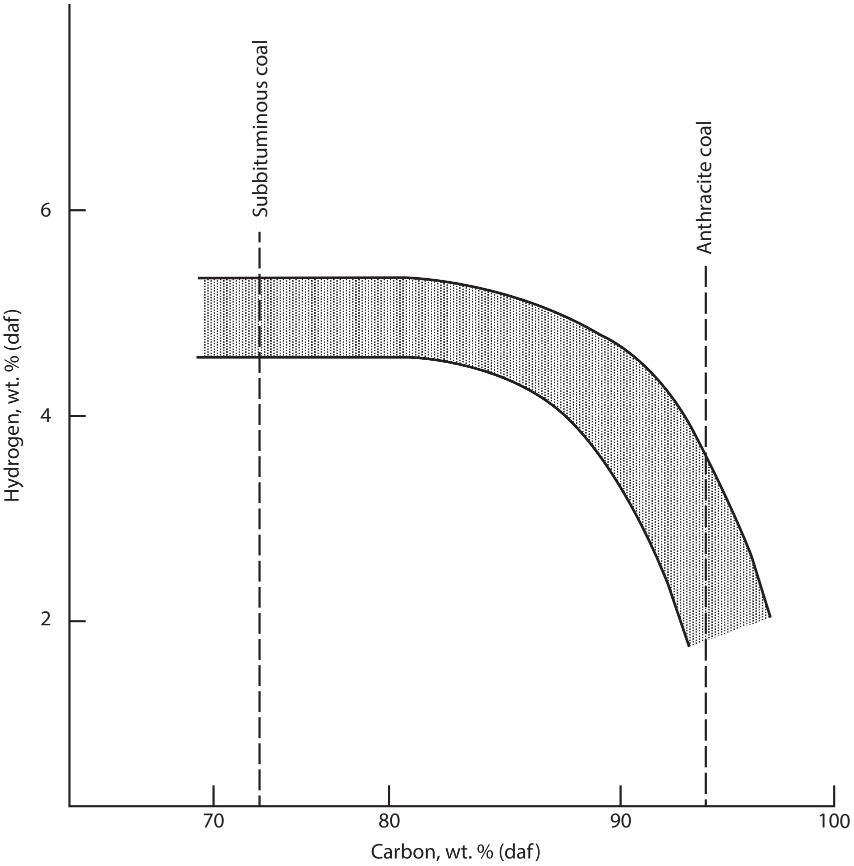

Figure 5.3 General relationship carbon and hydrogen content to rank (Speight, 2013).

5.4.2 Nitrogen

Until recently, there was little, if any, information related to the chemical type of the nitrogen in coal. Although a variety of nitrogen types are believed to exist in the coal matrix, it was thought to exist mainly in condensed heterocyclic structures (Kirner, 1945) and only fragmentary interest has been shown in this element as part of the coal substance. Other work has shown that nitrogen does, in fact, exist in ring systems in coal, particularly pyridine-type and pyrrole-type nitrogen (Speight, 2013, 2015).

The determination of nitrogen in coal is based on the principles of decomposition, oxidation, and reduction. The standard procedure in many laboratories is the Kjeldahl method (ASTM D3179). Neutron activation analysis has also been proposed for the determination of nitrogen in coal, coal ash, and related products (Volborth, 1979a, 1979b).

5.4.3 Oxygen

The lack of a satisfactory direct method for determining oxygen in coal and similar carbonaceous materials has dictated, historically (some would say hysterically), that oxygen be determined by subtracting the sum of the other components of, ultimate analysis from 100 (ASTM D3176):

$$\% \text{ Oxygen} = 100 - (\%C + \%H + \%N + \%S_{\text{organic}})$$

The disadvantage of such an indirect method is that all of the errors of the other determinations are accumulated in the oxygen data. However, there are several methods for the direct determination of oxygen that have met with some success when applied to coal and, therefore, deserve some mention here because it is conceivable that at some future date one of these methods (or a modification thereof) could find approval as a recognized standard method for the direct determination of oxygen in coal.

The most widely used procedure for oxygen determination consists of pyrolyzing coal in the presence of nitrogen and subsequent passage of the products over hot (1100°C; 2010°F) carbon. The oxygen in the volatile products is thereby converted to carbon monoxide, which can be determined by a variety of techniques (Gluskoter *et al.*, 1981). However, this particular method suffers from the errors induced by the mineral matter in the coal (especially the carbonate minerals and the water of hydration that is an integral part of many of the minerals) which can "increase" the determined oxygen. This particular problem may be resolved by first demineralizing the coal with a mixture of hydrofluoric and hydrochloric acids, but it must be presumed that the acid moieties are not incorporated into the coal.

However, in spite of the reliance on the difference method, over the last two decades the direct determination of oxygen in coal has been achieved by use of neutron activation (Volborth *et al.*, 1987; Volborth, 1979a, 1979b). The concentration of oxygen is determined by measuring the radiation from the sample. The method is nondestructive and rapid, but if only the organic oxygen is to be determined, then the sample must first be demineralized.

5.4.4 Sulfur

Sulfur is present in coal either as organically bound sulfur or as inorganic sulfur (pyrite or marcasite and sulfates) (Kuhn, 1977). The amount of organic sulfur is usually 3% w/w of the coal, but exceptional amounts of sulfur (up to 11%) have been recorded. The sulfates (mainly calcium and iron) rarely exceed 0.1% except in highly weathered or oxidized samples of coal; pyrite and marcasite (the two common crystal forms of FeS_2) are difficult to distinguish from one another and are often (incorrectly) designated simply as pyrite.

Sulfur is an important consideration in coal utilization and, hence, there is a considerable amount of published work relating to the development of methods to improve the efficiency of the techniques as well as improve the accuracy and precision of the sulfur determination (Ahmed and Whalley, 1978; Chakrabarti, 1978a; Attar, 1979; Raymond, 1982; Gorbaty *et al.*, 1992).

The three most widely used methods for sulfur determination are (i) the Eschka method, (ii) the bomb-combustion method, and (iii) the high-temperature combustion method, and all are based on the combustion of the sulfur-containing material to produce sulfate, which can be measured either gravimetrically or volumetrically.

The Eschka method for the determination of sulfur originated more than 100 years ago and has been accepted as a standard method in several countries. The method has distinct advantages in that the equipment is relatively simple and only the more convenient analytical techniques are employed.

Methods involving combustion of the organic material in a "bomb" are well known as a means of sulfur determination in solid fuels and are often cited as alternate methods for sulfur determination in several national standards. The method has the advantage because the sulfur is not "lost" during the process and is particularly favored when the calorific value of the coal is also required. The method of decomposition involves the Parr fusion procedure in the presence of sodium peroxide and oxygen at high pressures (300-450 psi).

A high-temperature combustion method for the determination of sulfur in solid fuels has also been adopted in many laboratories and is advantageous insofar as chlorine can be determined simultaneously. The method requires that the coal sample be heated to 1250 to 1350°C (2280 to 2460°F) in the presence of excess kaolin, ferric phosphate, or aluminum oxide to enhance the removal of the sulfur (as sulfate) from the ash. Oxygen is also included to produce oxides of sulfur which are absorbed in hydrogen peroxide (whereby sulfur dioxide is converted to sulfur trioxide). The solution is then titrated with standard alkali solution which gives the total acidity (due to the hydrochloric (and sulfuric acids that are formed).

The three methods of sulfur determination have all found application in various standards (ASTM D3177) with the modern variation of the Eschka procedure often being favored because of its relative simplicity. In all cases, the proportion of organically bound sulfur can be obtained by subtracting the inorganic sulfur (sulfate plus pyrite sulfur; which is determined by the conventional Powell and Parr method) from the total sulfur content, although it is possible to distinguish between the types of sulfur thereby allowing the separate determination of each sulfur type in coal (ASTM D2492).

The determination of the *forms of sulfur* forms (ASTM D2492) measures the quantity of sulfate sulfur, pyritic sulfur, and organically bound sulfur in the coal. The sulfur forms test measures sulfate and pyritic sulfur and determines organic sulfur by difference. Pyritic sulfur is an indicator of potential coal abrasiveness and is used for assessing coal cleaning because sulfur in the pyritic form is readily removed using physical coal cleaning methods.

The sulfur content of coal is typically in the range is 0.5 to 0.8% w/w but, in some instance by as much as 2.0% w/w. Sulfur in coal (i) affects the clinkering and slagging tendencies, (ii) corrodes the chimney and other equipment such as air heaters and economizers, and (iii) limits the exit flue gas temperature.

5.4.5 Chlorine

Chlorine occurs in coal (Chakrabarti, 1978b; Chakrabarti, 1982; Hower *et al.*, 1992) and is believed to be a factor not only in fouling problems but also in corrosion problems (Canfield *et al.*, 1979; Slack, 1981). The occurrence of chlorine in coal leads to the formation of hydrogen chloride and the condensation of water containing hydrogen chloride (hydrochloric acid) on the cooler parts of combustions equipment can lead to severe corrosion of the metal surfaces. The chlorine content of coal is low and occurs predominantly as sodium, potassium, and calcium chlorides, with magnesium and iron chlorides present in some coal types.

The generally accepted fouling classification of coal, according to total chlorine content (ASTM D2361; ASTM D4208) is as follows:

Chlorine, % w/w	*Fouling type*
<0.2	Low
0.2-0.3	Medium
0.3-0.5	High
>0.5	Severe

The test for the determination of chlorine is performed by burning the coal mixed with Eschka mixture in an oxygen bomb followed by potentiometric titration with silver nitrate solution or by a modified Volhard colorimetric titration.

5.4.6 Mercury

Mercury, which occurs in coal (Tewalt *et al*., 2001; S; Wang *et al*., 2010; Speight, 2013, 2015), has been identified as a dangerous environmental contaminant, largely by reason of the process of concentration in the food chain.

Mercury in coal is an extremely sensitive issue and of great environmental concern and has been identified as a dangerous environmental bio-accumulates in fish as methylmercury (CH_3Hg) and poses serious health hazards for contaminant, largely by reason of the process of concentration in the food chain. Exposure to high level of mercury can permanently damage the brain and kidneys, and lead to hair loss and loss of vision.

In the United States, Appalachian bituminous coal and Western subbituminous coal accounted for considerable amounts of mercury entering coal-fired power plants (Pavlish *et al*., 2003). The composition of these coals is quite different, which can affect their mercury emissions. Appalachian coals typically have high mercury, chlorine, and sulfur contents and low calcium content, resulting in a high percentage of oxidized mercury (i.e., mercuric oxide, HgO); in contrast, Western subbituminous coals typically have low concentrations of mercury, chlorine, and sulfur contents and high calcium content, resulting in a high percentage of elemental mercury (Hg).

The test for mercury (ASTM D3684) consists of burning the sample in an oxygen bomb with dilute nitric acid and determination of the mercury by flameless cold vapor atomic absorption.

Because of the different chemistry of mercury species, the fate of mercury in a coal-fired power plant is variable and requires treatment according to the mercury species present.

At the high temperatures in combustion zone of boilers, combustion releases the mercury in coal into the exhaust gas as elemental mercury (Hg^0). This vapor may then be oxidized by hydrogen chloride, sulfur dioxide, and fly ash in flue gas due to thermo-chemical processes (Meij *et al*., 2002; Lee *et al*., 2006; Park *et al*., 2008). Oxidized mercury (Hg^{2+}) is soluble and has a tendency to associate with the particles in flue gas to form particulate-bound mercury (Hg_p). Therefore, emissions of oxidized mercury may be efficiently controlled by typical air pollution control devices, such as electrostatic precipitators (ESP), fabric filter (FF), and flue gas desulfurization (FGD) systems (US EPA, 1997, 2002). However, because the relative proportions of oxidized mercury (Hg2+), particulate-associated mercury (Hg_p), and elemental mercury (Hg^0) can vary widely, the corresponding reduction in total mercury achieved by air pollution control devices vary (Pavlish *et al*., 2003; Srivastava *et al*., 2006; Lee *et al*., 2008; Cao *et al*., 2008a, 2008b).

For example, the removal efficiency of mercury from the flue gas by a combination of cold-side electrostatic precipitators and wet flue gas desulfurization units range from 24 to 70% w/w. Emission speciation is an important source of uncertainty when assessing the atmospheric fate of mercury because oxidized mercury (Hg^{2+}), particulate-associated mercury (Hg_p), and elemental mercury (Hg^0) have different physical-chemical characteristics and, consequently on a relative basis, different atmospheric lifetimes.

5.4.7 Minerals and Trace Elements

The most common minerals in coal (for example, clay minerals, pyrite, FeS_2, quartz, SiO_2, and calcite, $CaCO_3$) are made up of the most common elements (in the approximate order of abundance): oxygen, aluminum, silicon, iron, sulfur, and calcium. These minerals and other less common minerals usually contain the bulk of the trace elements present in coal. Minerals in coal commonly occur as single crystals or clusters of crystals that are intermixed with organic matter or that fill void spaces in the coal; sizes of mineral grains range from submicroscopic to a few inches. Some clusters of mineral grains, however, such as coal balls or vein fillings, may reach sizes of as much as several feet across.

Although much is known about the minerals in coal, much remains to be learned about their occurrence, abundance, origin, and composition. For example, the type of clay mineral in a coal, whether montmorillonite or illite, determines how a coal will react when burned. Montmorillonite may or may not break down (dissociate) into its constituent parts when coal is burned; if it does dissociate, then, upon cooling, it may recombine with other elements or minerals to form mineral deposits on the inside surfaces of furnaces and boilers. This process (called slagging or fouling) produces barriers to heat exchange in the affected equipment, which can substantially reduce its efficiency and require costly repairs. On the other hand, illite does not cause such problems under normal furnace operating conditions. Where these two clay minerals and others occur, their relative abundances, relationships to other minerals, and exact compositions are subjects for continued research in coal quality.

When coal is burned, most of the mineral matter and trace elements generally form ash; however, some minerals break down into gaseous compounds, which go out the furnace's flue. Pyrite, for example, breaks down into the individual elements iron and sulfur and each element (the iron and the sulfur) then combines with oxygen to become, respectively, iron oxide and an oxide(s) of sulfur (SOx). Iron oxide, a heavy solid, becomes part of the ash, and the sulfur oxides appear as a gas, is emitted as part of the flue gas. Some trace elements also dissociate from their organic or mineral hosts when coal is burned and follow separate paths. Most become part of the ash, but the more volatile elements, such as mercury and selenium, may be emitted in the flue gas.

The mineral content of coal determines what kind of ash will be produced as a product of the combustion process. The fusion temperature (melting point) of the ash dictates the design of furnaces and boilers. In general, if the fusion temperature is relatively low, then the molten ash is collected at the bottom of the furnace as bottom ash, requiring one design; however, if the fusion temperature is relatively high, then the part of the ash that does not melt easily (fly ash), is blown through the furnace or boiler with the flue gas and is collected in giant filter bags, or electrostatic precipitators, at the bottom of the flue stack, requiring a different design.

Coals that are relatively rich in iron-bearing minerals (such as pyrite, FeS_2, or siderite, $FeCO_3$) have low fusion temperatures, whereas coals relatively rich in aluminum-bearing minerals (such as kaolinite or illite) tend to have high fusion temperatures. If an electricity-generating or heating plant is designed to burn one type of coal, then it must continue to be supplied with a similar coal or undergo an extensive and costly redesign in order to adapt to a different type of coal. Similarly, furnaces designed to use coal that produces high amounts of heat will suffer severe losses in efficiency if they must accept coal that burns with substantially less heat.

Trace elements that occur in coal are often included as part of the ultimate analysis. All coals contain small concentrations of trace elements, though the mode of occurrence and distribution of the trace elements vary from coal to coal and are present in coal in both organic and inorganic forms, and most of these elements are found simultaneously in both forms (Chapters 1, 2) (Speight, 2013, 2015). The trace elements are released into the atmosphere during coal conversion and utilization processes as particulate matter, and studies have revealed the distributions and concentrations of trace elements in organic and inorganic components of coal impacts the quality of coal combustion by-products. Some of the trace elements classified as hazardous air pollutants (HAP) are antimony (Sb), arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), cobalt (Co), lead (Pb), manganese (Mn), nickel (Ni), selenium (Se). Other elements, such as barium (Ba), boron (B), molybdenum (Mo), vanadium (V), and fluorine (F) are also of interest when it comes to their negative impact on human health and the environment.

Arsenic is generally gray, metallic, soft, brittle, and toxic (even in small doses) in nature. The concern over arsenic is the probability of it being leached into groundwater. The concentration of boron in coal is low, in ppm; it is a dark powder that is essential for plants and animals as it serves as a micronutrient in agricultural farming, but can be toxic when in excess. Elemental fluorine, a pale yellow gas, is most reactive for all elements. While fluorine is considered as an essential element primarily due to its use in protecting the enamel of teeth, when it (as the fluoride form) is in excess, it can result in bone deformation, spinal curvature, limited movement of the joints and bow legs. Lead is generally silver or dark gray in coal, and exposure to lead occurs mainly through inhalation of air or ingestion in food, water, soil, or dust. The accumulation of lead in the body (blood, bones, soft tissues) results in neurological impairments such as seizures, mental retardation, and behavioral disorders. Most of the other trace elements not discussed here are actually carcinogenic and do have associated health implication effects.

5.5 Calorific Value

The calorific or heating value of a coal is a direct indication of the energy content and therefore is probably the most important property for determining the usefulness of coal in the context of a coal-fired power plant (Speight, 2013, 2015). It is the amount of energy that a given quantity of coal will produce when burned. Heating value is used in determining the rank of coals. It is also used to determine the maximum theoretical fuel energy available for the production of steam. It is used to determine the quantity of fuel that must be handled, pulverized, and fired in the boiler.

The calorific value is neither part of the proximate analysis nor part of the ultimate analysis and it is, in fact, one of the many physical properties of coal. In the present context, the importance of the calorific value as one of the means by which coal can be evaluated dictates that it be included in this particular section as well as in the section describing the general thermal properties of coal (Chapter 6). For the analysis of coal, the calorific value is determined in a bomb calorimeter either by a static (isothermal) (ASTM D3286) or by an adiabatic method (ASTM D2015). The computed value for the calorific value of coal is usually expressed in British thermal units per pound, kilocalories per kilogram, or in kilojoules per kilogram (1.8 Btu/lb = 1.0 kcal/kgm = 4.187 kJ/kgm).

The experimental conditions require an initial oxygen pressure of 300 to 600 psi and a final temperature in the range 20 to 35°C (68 to 95°F) with the products in the form of ash, water, carbon dioxide, sulfur dioxide, and nitrogen. Thus, once the gross calorific value has been determined, the net calorific value (i.e., the net heat of combustion) is calculated from the gross calorific value (at 20°C; 68°F) by deducting 1030 Btu/lb (2.4 x 103 kJ/kg) to allow for the heat of vaporization of the water. The deduction is not actually equal to the heat of vaporization of water (1055 Btu/lb) because the calculation is to reduce the data from a gross value at constant volume to a net value at constant pressure. Thus, the differences between the gross calorific value (GCV) and the net calorific value (NCV) are given by:

$$\text{NCV (Btu/lb)} = \text{GCV} - (1030 \times \text{total hydrogen} \times 9)/100.$$

In either form of measurement, the calorific value is reported as gross calorific value, with a correction made if net calorific value is of interest (ASTM D121; ASTM D2015; ASTM D3286; ASTM D5865). For solid fuels such as coal, the gross heat of combustion is the heat produced by the combustion of a unit quantity of the coal in a bomb calorimeter with oxygen and under a specified set of conditions. The unit is calories per gram, which may be converted to the alternate units (1.0 kcal/kgm = 1.8 Btu/lb = 4.187 kJ/kgm).

If a coal does not have a measured heat content (calorific value), it is possible to make a close estimation of the calorific value (cv) by means of various formulae, the most (popular of which are (Selvig, 1945):

The Dulong formula

$$\text{CV} = 144.4(\%\text{C}) + 610.2(\%\text{H}) - 65.9(\%\text{O}) - 0.39(\%\text{O})$$

The Dulong-Berthelot formula:

$$\text{CV} = 81370 + 345\,[\%\text{H} - (\%\text{O} + \%\text{N} - 1)/8] + 22.2(\%\text{S})$$

%C, %H, %N, %O, and %S are the respective carbon, hydrogen, nitrogen, oxygen, and organic sulfur contents of the coal (all of which are calculated to a dry, ash-free basis). In both cases, the calculated values are in close agreement with the experimental calorific values.

There are also reports of the use of differential thermal analysis for the determination of the calorific value of coal (Munoz-Guillena *et al.*, 1992).

Finally, and in order to remove any potential confusion, the chemical energy in coal is often stated as either the lower heating value (LHV) or the higher heating value (HHV) with units such as Btu/lb or MJ/kg or Btu/lb (1 MJ/kg is approximately equal to 430 Btu/lb. When coal is combusted, all of the hydrogen, which may be present in the various structures that constitute coal, will be converted to water vapor. The higher heating value (HHV) considers the heat released upon condensation of this water vapor (latent heat/heat of vaporization/condensation), while the lower heating value (LHV) excludes this heat.

Because of these choices of definitions, the lower heat value is always lower than the higher heat value by a certain amount depending on the amount of hydrogen in the fuel. An efficiency related to the chemical energy in the fuel should always state if the lower heat value or the higher heat value has been assumed. In Europe, the lower heat value tends to be more common than in the United States. However, in the gas turbine industry, the lower heat value is always used (also in the United States) but coal (or other fuel) prices normally use the higher heat value.

5.6 Reporting Coal Analyses

Analyses may be reported on different bases (ASTM D3180) with regard to moisture and ash content. Indeed, results that are "as determined" refer to the moisture condition of the sample during analyses in the laboratory; a frequent practice is to air-dry the sample, thereby bringing the moisture content to approximate equilibrium with the laboratory atmosphere in order to minimize gain or loss during sampling operations (ASTM D2013). Loss of weight during air-drying is determined to enable calculation on an "as received" basis (the moisture condition when the sample arrived in the laboratory). This is, of course, equivalent to the *as-sampled* basis if there is no gain or loss of moisture in the interim.

Analyses reported on a *dry* basis are calculated on the basis that there is no moisture associated with the sample. The moisture value (ASTM D3173) is used for converting the "as determined" data to the "dry" basis. Analytical data that are reported on a "dry, ash-free" basis are calculated on the theory that there is no moisture or ash associated with the sample. The values obtained for moisture determination (ASTM D3173) and ash determination (ASTM D3174) are used for the conversion. Finally, data calculated on an "equilibrium moisture" basis are calculated to the moisture level determined (ASTM D1412) as the equilibrium (capacity) moisture.

Hydrogen and oxygen reported on the moist basis may or may not contain the hydrogen and oxygen of the associated moisture, and the analytical report should stipulate which is the case because of the variation in the conversion factors (Table 5.6). These factors apply to calorific values as well as to proximate analysis (Table 5.7) and to ultimate analysis (Table 5.8).

When hydrogen and oxygen percentages do contain hydrogen and oxygen of the moisture, values on the dry basis may be calculated according to the formulae:

$$H_d = (H1 - 0.1111M1) \text{ x } 100/(100 - M1)$$

$$O_d = (O1 - 0.8881M1) \times 100/(100 - M1)$$

H_d and O_d are weight percent of hydrogen and oxygen on the dry basis, and H1 and O1 are the given or determined weight per cent of hydrogen and oxygen, respectively, for the given or determined weight percent of moisture M1. Rearrangement of these equations to solve for H1 and O1 yields equations for calculating moisture containing hydrogen and oxygen contents H1 and O1 at any desired moisture level M1.

The mineral matter in coal loses weight during ashing because of the loss of water of constitution of clay minerals, the loss of carbon dioxide from carbonate minerals such as calcite, and the oxidation of pyrite (FeS_2) to ferric oxide (Fe_2O_3). In addition, any chlorine in the coal is converted to hydrogen chloride but the change in weight may not be significant.

Analyses and calorific values are determined on a mineral matter-free basis by the Parr formulae (ASTM D388) with corrections for pyrite and other mineral matter. The amount of pyrite is taken to be equivalent to the total sulfur of the coal, which in spite of the potential error has been found to correlate well in studies of mineral matter. The remaining mineral matter is taken to be 1.08 times the weight of the corresponding (iron oxide free) ash:

$$MM = 1.08A + 0.55S$$

MM, A, and S are weight percent of mineral matter, ash, and total sulfur, respectively.

Such data are necessary for calculation of parameters in the classification of coal by rank (Chapter 2) and which are dry, mineral matter-free volatile matter (or fixed carbon) as well as moist mineral matter-free gross calorific value. For volatile matter and fixed carbon data, it is also necessary to assume that 50% of the sulfur is volatilized in the volatile matter test

Table 5.6 Conversion factors for components other than hydrogen and oxygen (ASTM D3180).

Given	**As determined (ad)**	**As received (ar)**	**Dry (d)**	**Dry ash-free (daf)**
As determined (ad)	—	$\frac{100-M_{ar}}{100-M_{ad}}$	$\frac{100}{100-M_{ar}}$	$\frac{100}{100-M_{ar}-A_{ad}}$
As received (ar)	$\frac{100-M_{ad}}{100-M_{ar}}$	—	$\frac{100}{100-M_{ar}}$	$\frac{100}{100-M_{ar}-A_{ar}}$
Dry (d)	$\frac{100-M_{ad}}{100}$	$\frac{100-M_{ar}}{100}$	—	$\frac{100}{100-A_{ad}}$
Dry ash-free (daf)	$\frac{100-M_{ad}-A_{ad}}{100}$	$\frac{100-M_{ar}-A_{ar}}{100}$	$\frac{100-A_{ad}}{100}$	—

M = percent moisture by weight; A = percent ash by weight.

[a] For example, given ad, to find ar use the formula

$$ar = ad \times \frac{100 - M_{ar}}{100 - M_{ad}}$$

Table 5.7 Examples of data (% w/w) obtained by proximate analysis (ASTM D3172).

Gain	Moisture	Ash	Volatile	Fixed Carbon
Air-dried	8.23	4.46	40.05	47.26
Dry	—	4.86	43.64	51.50
As received[a]	23.24	3.73	33.50	39.53

[a] Air-dry loss in accordance with ASTM Method D2013 = 16.36%.

Table 5.8 Examples of data (% w/w) obtained by ultimate analysis (ASTM D3176).

	Component (% w/w)							Total (%)
Basis	**Carbon**	**Hydrogen**	**Nitrogen**	**Sulfur**	**Ash**	**Oxygen[a]**	**Moisture**	
As determined[b,c]	60.08	5.44	0.88	0.73	7.86	25.01	9.00	100.0
Dry	66.02	4.87	0.97	0.80	8.64	18.70	0.00	100.0
As received[d]	46.86	6.70	0.69	0.57	6.13	39.05	(29.02)	100.0
As received[e]	46.86	3.46	0.69	0.57	6.13	13.27	29.02	100.0

[a] By difference.

[b] After air-dry loss (22.00%) in accordance with ASTM D2013.

[c] Hydrogen and oxygen include hydrogen and oxygen in sample moisture, M_{ad}.

[d] Hydrogen and oxygen include hydrogen and oxygen in sample moisture, M_{ar}.

[e] Hydrogen and oxygen do not include hydrogen and oxygen in sample moisture, M_{ar}.

and therefore should not be included as part of the organic volatile matter (nor should the loss from clay minerals and carbonate minerals):

$$FC_{dmmf} = [(FC - 0.15S)[/[100 - (M + 1.08A + 0.55S)$$

$$VM_{dmmf} = 100 - FC_{dmmf}$$

FC_{dmmf} and VM_{dmmf} are the fixed carbon and volatile matter, respectively, on a dry, mineral matter-free basis; FC, M, A, and S are the determined fixed carbon, moisture, ash, and total sulfur, respectively.

In the Parr formula for moist, mineral matter-free calorific value, the moisture basis used is that of the inherent moisture of the coal in the seam (natural bed moisture, capacity moisture):

$$\text{Moist, MM - free Btu} = [100(\text{Btu} - 50S)]/[100 - (1.08A + 0.55S)]$$

Btu is the calorific value (Btu/lb), is the ash (% w/w), and S is sulfur (% w/w); all are on the moist (natural bed) basis.

Finally, it is also possible to illustrate the relationship of the analytical data produced from proximate analysis and the calorific value to, the bulk coal and to coal rank (Figures 5.4, 5.5, 5.6) (ASTM, 2011).

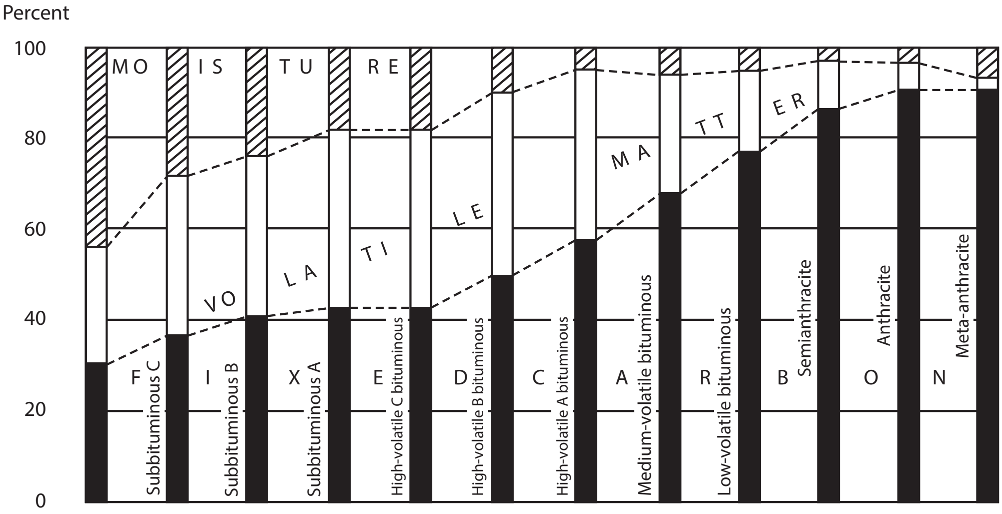

Figure 5.4 Proximate analysis and coal rank (ASTM, 2011).

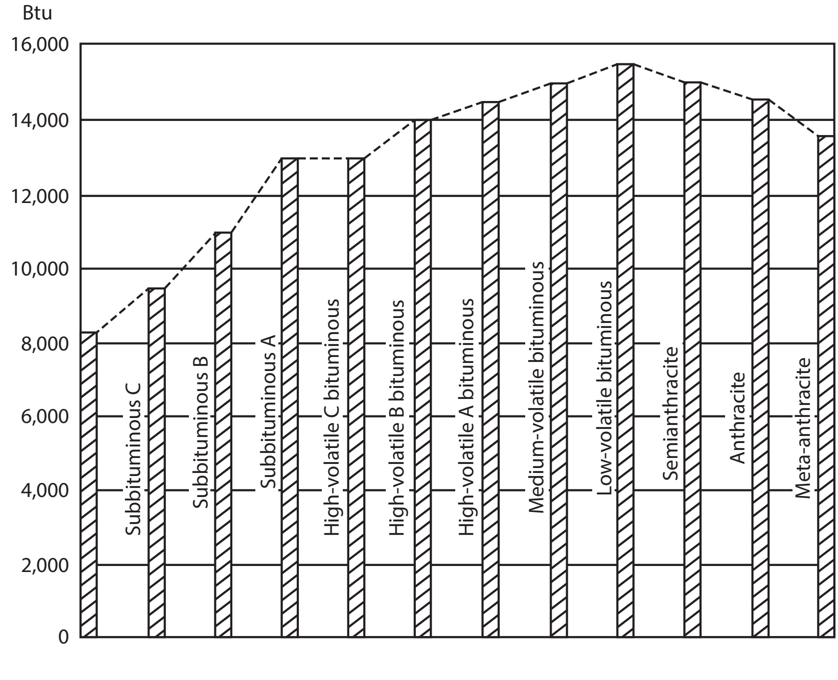

Figure 5.5 Calorific value and coal rank (ASTM 2011).

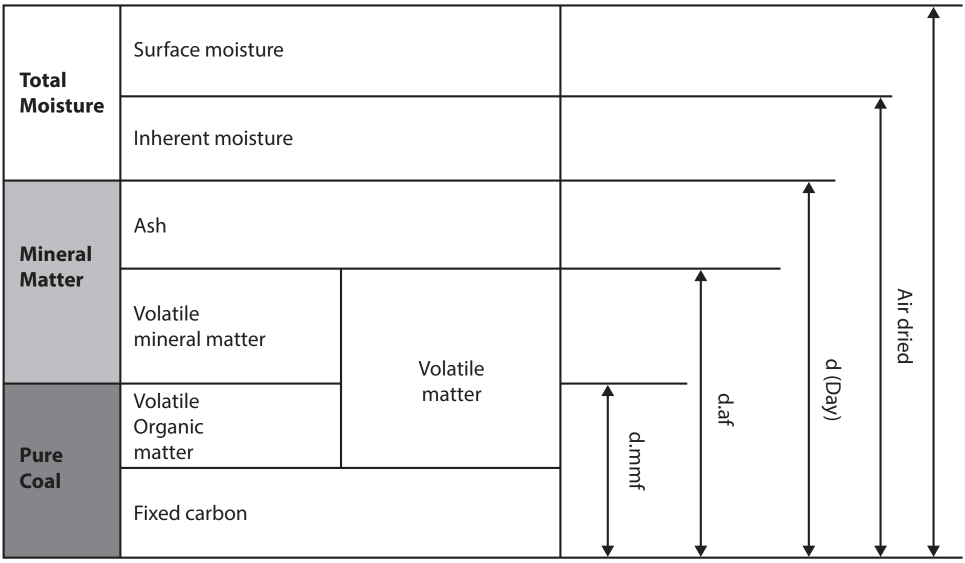

Figure 5.6 Illustration of the various segments of coal analysis (Ward, 1984). Code: d,af: dry, ash-free d,mmf: dry, mineral matter free.

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6

Physical, Mechanical, Thermal, and Electrical Properties

6.1 Introduction

Coal is a naturally occurring combustible material with varying composition and it not surprising that the properties of coal vary considerably from coal type to coal type and even from sample to sample within a coal seam. Reliable property data can only be ascertained by application of a series of standard test methods (Zimmerman, 1979; Speight, 2005). However, in addition to the general properties relevant to power generation from coal that are presented elsewhere (Chapter 5), there are physical properties, mechanical properties, and thermal properties of coal that are related to the behavior of coal as it is prepared for use in a coal-fired power plant.

The constituents of coal can be divided into two groups: (i) the organic fraction, which can be further subdivided into soluble and insoluble fractions as well as microscopically identifiable macerals, and (ii) the inorganic fraction, which is commonly identified as ash subsequent to combustion (Speight, 2008, 2013). Because of this complex heterogeneity it might be expected that, in addition to the variation of properties in a coal seam, the properties of coal can also vary within a specific rank of coal.

Evaluation of coal for any use can be achieved by the determination of several noteworthy properties, and there are also various other properties which provide even more valuable information related to the potential use for coal (Table 6.1) (van Krevelen, 1957; Speight, 2008, 2013). Indeed, there are also those properties of organic materials which offer valuable information related to the environmental behavior (Lyman *et al.*, 1990). Hence, environmental issues present an additional need to determine the various properties of coal.

In the broadest sense, it has been suggested that the granular nature of high-rank coals is of importance in understanding the physical nature and physical properties of coal if coal is modeled in terms of a granular medium which consists of graphite-like material embedded in an insulating organic matrix (Cody *et al.*, 1990). Indeed, there have been several earlier suggestions of the graphite-like nature of coal, particularly from X-ray diffraction studies (Speight, 1978, 2013) and perhaps this is a means by which the behavior of coal can be modeled. But, if this be the case, the precise role of the smaller aromatic hydrocarbon and heteroatom systems needs also to be defined more fully which can offer new lines of understanding that are related to the behavior of coal.

A coal-fired power plant is a thermal power plant in which coal is combusted to generate electricity. Moreover, coal-fired power plants generate the majority of the electricity used on the world. In the process of power generation, the coal is pulverized and then combusted via a pulverized coal-fired boiler which produced heat to convert water to steam which is

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Table 6.1 Physical, mechanical, and thermal properties of coal.

Physical properties		**Comments**
	Density	True density
	Porosity and Surface Area	Nature of pore structure
	Surface Area	Surface characteristics
Mechanical properties		
	Strength	Ability to withstand external forces
	Hardness Index	Measurement of scratch hardness
	Friability	Ability to withstand degradation during handling
	Grindability	Energy needed to pulverize or grind coal
	Dustiness Index	Amount of dust produced during handling
Thermal properties		
	Heat Capacity	Indication of energy content
	Thermal Conductivity	Rate of heat transfer through unit area
	Plastic Properties	Changes of coal on or during heating
	Agglutinating Properties	Changes of coal on or during heating
	Agglomerating Index	Determination of nature of residue after heating
	Free Swelling Index	Increase in volume when coal is heated
	Ash Fusion Temperature	Behavior of ash during combustion
Electrical properties		
Electrical Conductivity	A measure quantifies how strongly coal conducts an electric current	
Dielectric Constant	Ameasure of the amount of electric potential energy	
Dielectric Strength	The maximum electric field that coal can withstand under ideal conditions	

then used to spin turbines and turn generators. The overall effect is to convert the chemical energy stored in the coal into thermal energy, mechanical energy, and finally into electrical energy (Figure 6.1). Thus:

$$\text{Coal} \rightarrow \text{Boiler} \rightarrow \text{Turbine} \rightarrow \text{Generator} \rightarrow \text{Electricity} \rightarrow \text{User}$$

Thus, coal properties have impacts on those parts of the power plant which are in direct contact with the coal. For example, in the coal handling operation coal is conveyed from the stockpile (where it may have been subject to oxidation with subsequent spontaneous ignition followed by combustion; Chapter 4) thence to the boiler bunkers and then to the pulverizing mills.

Coal is continuously fed to the pulverizer from the boiler bunkers, and hot air is introduced into the pulverizer to dry and transport the pulverized fuel (PF) to the burners. The coal properties which have the most impact on the performance of the pulverizer unit are (i) specific energy, which determines the quantity of coal required for a given plant output and which governs the rate at which coal must be pulverized to achieve a required boiler load – low specific energy coals will cause higher mill power consumption due to the need for increased coal flow, (ii) moisture content, especially the surface which affects flow characteristics – generally, high coal moisture content will require higher mill inlet temperatures to maintain the desired mill outlet temperature of approximately 70°C/158°F, (iii) hardness and coal rank – hard coal may require more pulverizer power and/or capacity to achieve the required rate of production of pulverized fuel size distribution, (iv) size distribution of the coal – especially the proportion of fine material, which affects surface moisture, and (v) the nature of the mineral matter in the coal – especially the clay constituents, which affect flow characteristics.

The boiler, through combustion, converts the chemical energy in the coal to thermal energy and transfers the heat produced to convert water to superheated steam at high pressure and deliver it to the steam turbine/generator. The coal properties which have most impact on boiler performance are (i) moisture content – high moisture levels reduce boiler efficiency as energy from the coal is used in evaporation of the water, and the sensible heat loss from the flue gas is greater, (ii) coal reactivity – the reactivity of the coal (combustion rate) which is governed by the volatile content (rank) and petrographic composition of the

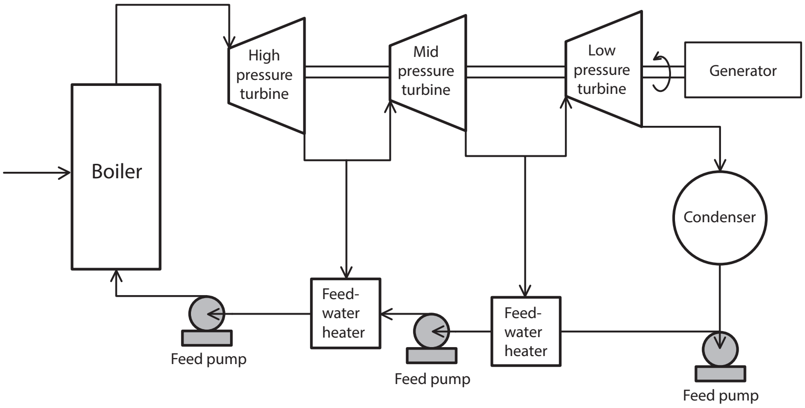

Figure 6.1 Schematic representation of a coal-fired power plant.

coal, affects boiler performance in terms of flame stability and efficiency of pulverized fuel burnout, and (iii) mineral matter composition and, thus, ash composition – the chemical composition of the ash governs the behavior of coal with regard to ash deposition on heat transfer surfaces, and can have a marked impact on boiler availability and maintenance costs – the presence of hard minerals (quartz and pyrite) can cause erosion damage to the boiler tubes depending on their nature and concentration.

Utilities are governed by statutory regulations as to the maximum allowable discharge of gaseous pollutants, nitrogen oxides (NOx) and sulfur oxides (SOx). Flue gas treating plants (Chapter 12) for removing nitrogen oxides and/or sulfur oxides may need to be incorporated into the power plant during the design and construction phase, and these will have a large impact on both capital and operation and maintenance costs. The coal properties which have the most impact on gaseous emissions are (i) the level of nitrogen oxide emissions which are governed by the distribution of nitrogen between the volatiles and the char, and (ii) emissions of sulfur dioxide which are directly related to coal sulfur content, with only a small portion being incorporated in the thermal ash for most bituminous coals.

Ash disposal, leachate containment, and ultimate rehabilitation are also cost items for coal-fired power plants. The coal properties affecting ash disposal are (i) coal reactivity, which influences the residual carbon in ash where fly ash is sold to the cement industry, and this level of carbon in ash must be less than prescribed limits (usually approximately 5% w/w) but if the carbon in ash is above this limit, then disposal by other means will be required, at increased cost, (ii) mineral matter content, which will affect the quality of ash to be disposed, and (iii) trace element levels and leaching to the environment, which may lead to breaching of environmental regulations.

Thus, in order to understand the behavior of coal as it pertains to coal-fired power production, characterizing and understanding its physical properties is of paramount importance (Xie, 2015). In addition, the microstructure and porosity of coal are intimately involved in the complex heterogeneous reactivity of coal during combustion (Chapter 7) and gasification (Chapter 9).

Accordingly, this chapter presents the various analytical methods that can be applied to determining the physical or mechanical properties of coal as they apply to coal combustion and power generation. By analogy with the crude oil industry (Speight, 2011, 2014, 2020), some power plants may carry out a full analysis (full assay) of every new batch of feedstock (coal) received at the plant while other companies may perform a partial analysis (partial assay) of the coal to determine specific properties which have a stronger influence on the behavior of the coal during combustion.

6.2 Physical Properties

Knowledge of the physical properties of coal is important in coal preparation and utilization. For example, the physical properties of coal, such as color, specific gravity, and hardness, vary considerably. This variance depends on the composition and the nature of preservation of the original plant material that formed the coal, the amount of impurities in the coal, and the amount of time, heat and pressure that has affected the coal since it was first formed. Time, heat, and pressure determine the rank of the coal, which is classified according to the increasing amount of carbon as lignite, subbituminous coal, bituminous coal, and anthracite.

At first consideration, there may appear to be little, if any, relationship between the physical, mechanical, and chemical behavior of coal but in fact the converse is true. For example, the pore size of coal (which is truly a physical property) is a major factor in determining the chemical reactivity of coal (Walker, 1981). And chemical effects which result in the swelling and caking of coal(s) have a substantial effect on the means by which coal should be handled either prior to or during a coal conversion operation.

The physical properties and the behavior of coal play an important part in dictating the methods by which coal should be handled and utilized. This section considers those properties such as, for example, density and hardness, which are definitely physical in nature, in contrast to the properties (e.g., spectroscopic properties) which arise by virtue of the molecular structural types that occur within the coal (Speight, 2013, 2015).

Just as coal evaluation can be achieved by the determination of several noteworthy properties (Chapter 5), there are also various mechanical and electrical properties that provide even more valuable information about the potential use for coal (van Krevelen, 1957; Evans and Allardice, 1978). Indeed, there are also those properties of organic materials that offer valuable information about environmental behavior (Lyman *et al.*, 1990). Hence, an additional reason to study the properties of coal. In fact, knowledge of the electrical properties of coal is also an important aspect of coal characterization and behavior. Electrical properties are useful for cleaning, mining, pyrolysis, and carbonizing processes.

The most important properties of coal to the combustion engineer are as follows: (i) coal type, (ii) proximate analysis – to determine the moisture, ash, volatile matter and fixed carbon, (iii) ultimate or elementary analysis – to determine the elemental composition of the coal, (iv) calorific value or heat content, (v) caking properties – for bituminous coals only, and (vi) grindability – to determine the ease of pulverization of the coal.

Proximate analysis is the simpler of the tests and is used to determine the moisture, ash, volatile matter, and fixed carbon content (Chapter 5). On the other hand, ultimate analysis is used to determine the elemental composition in terms of carbon, hydrogen, sulphur, nitrogen and (usually but not always) oxygen by difference (Chapter 5) (Speight, 2005, 2008, 2013). Mineral matter is not directly measured but may be obtained as *mineral ash* which is then converted by one of a number of empirical formulae based on the ultimate and proximate analysis (Chapter 5). Further empirical relationships are also possible between carbon, hydrogen, oxygen, and calorific value (Speight, 2013).

Thus, the physical and/or mechanical properties of coal are important aspects of coal testing prior to use in a power plant. Hence, a discussion of the effect of coal type – an extremely important aspect of power generation – is warranted.

6.2.1 Coal Type

The plant material from which coal is derived is composed of a complex mixture of organic compounds, including cellulose, lignin, fats waxes, and tannins. As coalification proceeds, these compounds, which have more or less open structures, are broken down, and new compounds which are primarily aromatic derivatives are produced (Chapter 1). The classification of coal by rank is based on these changes and, as coalification proceeds, the amount of volatile matter in the coal gradually decreases and the amount of fixed carbon increases. Thus, many of the properties of coal are strongly rank-dependent, although other factors such as the presence of mineral matter also influence the properties of coal.

The availability of a design-basis coal for conventional boilers is critical due to the depletion of coal quality and increasing demand unless dedicated mines are used. Each coal-fired utility boiler has been designed for a single source of coal which has a narrow range of characteristics for the required performance. This clearly indicates that variation in the coal characteristics will affect the performance of the boiler in many ways. It may hamper the unit heat rate to a greater magnitude and be detrimental to boiler operation in the case of deteriorated coal being used and vice versa in the case of moderately good coal. In more recent times, coal blending has been practiced to a great extent for many electricity generating units (Yin *et al.*, 2000).

The effect of particle size and physical nature of coal on the self-heating characteristics of high- and low-rank Indonesian coal and their blends concluded that the critical ambient temperature, activation energy, product of exothermic nature of the coal(s) and the pre-exponential factor of low- and high-rank coals are greatly affected by the particle size and the surface area of the particle (Nugroho *et al.*, 2000).

The size of a bulk material such as coal is described two ways – as the maximum lump size, or as the percent of particles that will pass a series of standard screens (or sieves). Size is often listed as the maximum lump width and breadth. A material with a maximum lump width and breadth of two-inch by two-inch would be described as *two-inch minus* material. This means the largest lump is two inches by two inches and the rest of the particles are smaller. It is common practice to assume the length of the lump can be as much as three times larger than its width – in the above example that would be six inches long. This information is useful in sizing various components and the width and height of chutes and skirt-boards.

A screen analysis gives the most complete representation of the size of the bulk solid. The particle size distribution is a tabulation of the percent represented in each size range as part of the total sample, usually shown as passing a given screen size and being retained on the next smaller screen. This information is useful for analyzing airflow in chutes, and the potential for the creation of airborne dust.

Furthermore, data from investigations on the slagging propensity of blended coals revealed that the worst deposit contained some moderately sintered material. As a result of an examination of ignition, flame stability, and carbon burnout of blended coals, it was concluded that as a result of blending a high-volatile coal with a low-volatile coal, the ignition, flame stability and burnout of the blends were improved (Su *et al.*, 2001a, 2001b, 2003).

Ignition tests of blends of subbituminous, low-volatile and high-volatile bituminous are carried out in two entrained flow reactors. It has been observed that the ignition of lower-rank coals enhanced the ignition of higher-rank coals. Also the ignition temperature of the blends of low-rank coals were found to be additive whereas for the other blends, the ignition temperature is found to be closer to that of the lower-rank coal in the blend (Faúndez *et al.*, 2007). Experimental investigation into the ignition behavior of pulverized coal and coal blends in a drop tube furnace has been carried out (Chi *et al.*, 2010). Seven different coals and coal blends of different mixing proportions were exported. From the results, it has been ascertained that the ignition behavior of a coal blend is proportional to the coal with the highest volatile matter content and its proportion in the blend. Therefore, cofiring can be used as a blend tool to simultaneously fire coals from different sources in boilers.

6.2.2 Density and Specific Gravity

Partly due to the intricate and heterogeneous nature of coal as well as the void volume, coal density not only varies with rank, but also depends on how it is measured (Speight, 2013, 2015). The term *coal density* therefore carries several different connotations, and a distinction must, in particular, be made among bulk densities which are determined by the average particle (or lump) size, size distribution, and packing density of the coal, and bear on handling, transportation, and storage.

Coal density ranges from approximately 1.1 to about 1.5 megagrams per cubic meter, or grams per cubic centimeter (1 megagram per cubic meter equals 1 gram per cubic centimeter). Coal is slightly denser than water (1.0 megagram per cubic meter) and significantly less dense than most rock and mineral matter (for example, shale has a density on the order of about 2.7 megagrams per cubic meter and pyrite has a density on the order of 5.0 megagrams per cubic meter). Density differences make it possible to improve the quality of a coal by removing most of the rock matter and sulfide-rich fragments by means of heavy liquid separation (fragments with densities greater than about 1.5 megagrams per cubic meter settle out while the coal floats on top of the liquid). Devices such as cyclones and shaker tables also separate coal particles from rock and pyrite on the basis of their different densities.

Generally the density (specific gravity) of coal (its weight compared with an equal volume of water) varies with rank and with amount of impurities. Generally, the higher the rank of coal and the higher the amount of impurities (mineral matter), the higher the density (specific gravity) of the coal. For porous solids, such as coal, there are three different density measurements, true density, particle density, and apparent density. The following formula is generally valid for many coal types:

$$S = k + A/100$$

S is the specific gravity, A is the percentage of ash, and k is a constant with a value of 1.25. The above formula assumes an overall specific gravity of 2.25 for the mineral matter of coal.

The *true density* is usually determined by displacement of a fluid, but because of the porous nature of coal and also because of physicochemical interactions, the observed density data vary with the particular fluids employed (Agrawal, 1959; Mahajan and Walker, 1978).

The apparent density of coal is determined by immersing a weighed sample of coal in a liquid followed by accurate measurement of the liquid that is displaced. For this procedure, the liquid should (i) wet the surface of the coal, (ii) not absorb strongly to the coal surface, (iii) not cause swelling, and (iv) penetrate the pores of the coal. As a by-the-way, the lower the rank of a coal, the greater is the wettability with water but the higher the rank, the greater the wettability with (coal) tar or the non-volatile pitch.

It is difficult (if not impossible) to satisfy all of these conditions as evidenced by the differing experimental data obtained with solvents such as water, methanol, carbon tetrachloride, benzene, and other fluids. Thus, there is the need to always specify the liquid employed for the determination of density by means of this (pycnometer) method. Furthermore, a period of twenty-four hours may be necessary for the determination because of the need for the liquid to penetrate the pore system of the coal to the maximum extent.

The true density of coal is usually determined by helium displacement and, therefore, is often referred to as the *helium density*. Helium is used because it has the ability to penetrate all of the pores of a given sample of coal without (presumably) any chemical interaction. Thus, in the direct-pressure method, a known quantity of helium and a weighed sample of coal are introduced into an apparatus of known volume, whereupon the pressure of the helium at a given temperature allows calculation of the volume of the coal. In the indirect method, mercury is used to compensate for the helium displaced by the introduction of the coal.

It is generally believed that use of helium gives a more accurate determination of coal density but there is evidence that part of the pore system may be inaccessible to the helium. Thus, when helium is used as the agent for determining coal density, the density (helium density) may differ from the true density and may actually be lower than the true density (Kotlensky and Walker, 1960).

The particle density is the weight of a unit volume of solid including the pores and cracks (Mahajan and Walker, 1978). The particle density can be determined by any one of three methods, which are (i) mercury displacement, (ii) gas flow, and (iii) silanization (Ergun, 1951; Ettinger and Zhupakhina, 1960; Gan *et al.*, 1982).

The density of coal shows a notable variation with rank for carbon content (Figure 6.2) and, in addition, the methanol density is generally higher than the helium density because

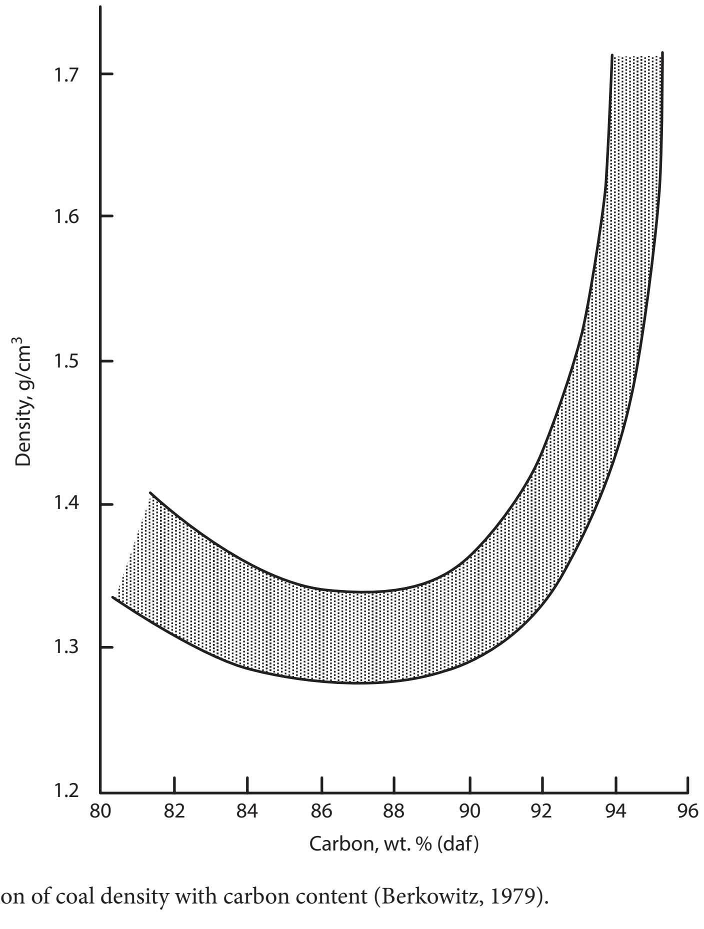

Figure 6.2 Variation of coal density with carbon content (Berkowitz, 1979).

of the contraction of adsorbed helium in the coal pores as well as by virtue of interactions between the coal and the methanol, which result in a combined volume that is notably less than the sum of the separate volumes. Similar behavior has been observed for the water density of coals having 80 to 84% carbon.

Coal with more than 85% carbon usually exhibits a greater degree of hydrophobic character than the lower-rank coals with the additional note that the water density may be substantially lower than the helium density; for the 80-84% carbon coals, there is generally little, if any, difference between the helium density and the water density.

However, on the issue of the hydrophobicity of coal, the prediction of this characteristic indicates that the hydrophobicity of coal correlates better with the moisture content than with the carbon content and better with the moisture/carbon molar ratio than with the hydrogen/carbon or oxygen/carbon atomic ratios (Labuschagne, 1987; Labuschagne *et al.*, 1988).

An additional noteworthy trend is the tendency for the density of coal to exhibit a minimum value at approximately 85% carbon. For example, a 50-55% carbon coal will have a density of approximately 1.5 g/cm and this will decrease to, say, 1.3 g/cm for an 85% carbon coal followed by an increase in density to ca. 1.8 g/cm for a 97% carbon coal. On a comparative note, the density of graphite (2.25 g/cm) also falls into this trend.

The *in-place density* of coal is the means by which coal in the seam can be expressed as tons per acre per foot of seam thickness and/or tons per square mile per foot of seam thickness. However, the *bulk density* of the solid is the mass of the solid particles per unit of volume they occupy. Major factors influencing the bulk density of coal are moisture content, particle surface properties, particle shape, particle size distribution, and particle density (Leonard *et al.*, 1992; Speight, 2013).

Generally, the manner the bulk sample packs into a confined space is reflected by its bulk density and is related to the size distribution as well as the effects of moisture on the packing ability of the particles. There will always be such a mixture of fine and coarse particles at which the bulk density will assume the highest value, higher than assumed by any of these fractions when packed separately. As the range of particle size is increased, the bulk density is also increased (Wakeman, 1975).

The *bulk density* is not an intrinsic property of coal and varies depending on how the coal is handled. Bulk density is the mass of many particles of coal divided by the total volume occupied by the particles – the total volume includes particle volume, inter-particle void volume and internal pore volume. This allows the density of coal to be expressed in terms of the cubic foot weight of crushed coal (ASTM D29l), which varies with particle size of the coal and packing in a container.

On the other hand, the *loose bulk density* of a bulk material is the weight per unit of volume kg/m3 (lb/ft^3) measured when the sample is in a loose or non-compacted condition. The loose bulk density must always be used when designing the load zone chutes and the height and width of the skirt-boards or the chute may not be able to handle the specified design capacity due to the increased volume of the material. The *settled bulk density* is the state of the coal as it is normally carried on the conveyor belt.

The bulk density of coal is a variable property and there are marked variations of this parameter with rank:

- Anthracite: 50-58 lb/ft^3 (800-929 kg/m^3)
- Bituminous coal: 42-57 lb/ft^3 (673-913 kg/m^3)

- Lignite: 40-54 lb/ft^3 (641-865 kg/m^3)

General formula used for soil samples (Tisdall, 1951; Birkeland, 1984; Blake and Hartge, 1986) may also be applied to coal. Thus:

$$Bulkdensity = \left(\frac{Weight}{Volume}\right) = \left(\frac{63}{35}\right)$$

$$Porosity(\%) = \left(1 - \frac{BulkDensity}{ParticleDensity}\right) * 100$$

$$Porosity(\%) = \left(1 - \frac{1.8}{2.65}\right) * 100$$

The bulk density of coal decreases with increasing moisture content until a minimum is reached (at approximately 6 to 8% moisture) but then increases with moisture content. With the use of aqueous solutions of wetting additives, the coal bulk density can be increased by up to 15% (Leonard *et al.*, 1993).

Due to the hydrophobic nature of higher-rank coal, the bulk density rapidly decreases with increasing moisture, as the water stays on the surface of the coal in between the particles, increasing the volume of the bulk solid (decreasing bulk density). Further increase in moisture leads to the minimum bulk density attained at a moisture content on the order of 6 to 8% w/w (Leonard *et al.*, 1992). Beyond this level of moisture, more water penetrates the spaces in between the particles and forms a water layer around the particles thereby allowing for aggregation of the particles which leads to tighter packing configuration. As a result particles are packed into smaller volume which further leads to an increase in bulk density of the sample. Furthermore, small additions of chemical reagents reducing surface tension of water resulted in an increased bulk density – the bulk density can be increased by 13% to 15% with the use of such additives (Leonard *et al.*, 1992).

The aggregation of fines, leading to tight packing of particles, affects the bulk density of coal samples. Wettability appears to be a controlling factor in the aggregation of fine coal particles. As a result, different patterns of bulk density can be anticipated with moisture increase for hydrophilic coal samples and also for hydrophobic coal samples (Holuszko and Laskowski, 2010).

Finally, the properties of a bulk solid such as coal can be used to predict the nature of the belt cleaning challenge the operation will face. The properties predict how much material will adhere to the belt past the discharge and how changes in conditions — such as an increase in moisture level from a rainstorm — can affect carryback levels and cleaning performance.

6.2.3 Petrographic Analysis

The rank of a coal is related to the carbon content, but unfortunately, the coal rank does not offer much information related to the chemical structure or the reactivity of the coal during combustion. The advent of microscopic analysis in coal research has resulted in the identification of different maceral components that make up coal and the effect which the petrographic composition has on the conversion properties and the reactivity of coal (Gupta, 2007; Speight, 2013).

The maceral components in coal are combined into three principal categories: vitrinite, exinite, and inertinite. Exinite is characterized by the highest hydrogen content, volatile matter content, and heating value, whereas inertinite displays the least of these properties (Howard, 1981). Inertinite has the highest density and the greatest degree of aromaticity. The proportion of these maceral groups in a coal determines its combustion properties significantly. Several advances in characterization techniques such as reflectance microscopy, nuclear magnetic resonance techniques, Fourier transform infrared (FTIR) spectroscopy, and X-ray techniques have also been applied to the study of organic matter in coal (Gupta, 2007; Speight, 2013).

6.2.4 Porosity and Surface Area

Coal is a porous material, thus the porosity and surface area of coal (Mahajan and Walker, 1978) have a large influence on coal behavior during mining, preparation, and utilization.

Porosity is the fraction (or percentage) of the volume of coal that is occupied by pores and can be calculated from the equilibrium moisture content (Chapter 5) (Berkowitz, 1979, 1985). For porous solids, such as coal, there are three different density measurements, true density, particle density, and apparent density. And, since coal is a porous material, porosity can have a large influence on coal behavior during mining, preparation, and utilization operations. In fact, the porosity and surface area of coal (Walker and Mahajan, 1978) have a large influence on coal behavior during mining, preparation, and utilization.

Although porosity dictates the rate at which methane can diffuse out of the coal (in the seam) and there may also be some influence during preparation operations in terms of mineral matter removal, the major influence of the porous nature of coal is seen during the utilization of coal. For example, during conversion chemical reactions occur between gas (and/or liquid) products and surface features, much of which exist within the pore systems.

Coal density is controlled in part by the presence of the pores that persist throughout coalification. Measurement of pore sizes and pore distribution is difficult; however, there appear to be three size ranges of pores: (i) macropores, which have a diameter greater than 50 nanometers – by definition, 1 nanometer = 10^{-9} meter, (ii) mesopores, which have a diameter on the order of 2 to 50 nanometers, and (iii) micropores, which have a diameter less than 2 nanometers. Most of the effective surface area of a coal (approximately 200 square meters per gram) is not on the outer surface of a piece of coal but is located inside the coal in its pores. The presence of pore space is important in the production of coke, gasification, liquefaction, and the generation of high-surface-area carbon for purifying water and gases. From the standpoint of safety, coal pores may contain significant amounts of adsorbed methane that may be released during mining operations and form explosive mixtures with air. The risk of explosion can be reduced by adequate ventilation during mining or by prior removal of coal-bed methane.

While the pore systems of coal have generally been considered to consist of micropores having sizes up to approximately 100 and macropores having sizes greater than 300 Å (Gan *et al.*, 1972; Mahajan and Walker, 1978). Other work, involving a small-angle X-ray investigation of porosity in coals, has thrown some doubt upon this hypothesis by bringing forward the suggestion that the data are not consistent with the suggestion that many pores have dimensions some hundreds of angstrom units in diameter but have restricted access due to small openings which exclude nitrogen (and other species) at low temperatures (Kalliat *et al.*, 1981).

As already noted with respect to coal density, the porosity of coal decreases with carbon content (Figure 6.3) (King and Wilkins, 1944) and has a minimum at coal containing approximately the 89% carbon followed by a marked increase in porosity. There are also differences in the pore size that make up the porosity of coal. For example, macropores are usually predominant in the lower-carbon (rank) coals while higher-carbon (rank) coals contain predominantly micropores. Thus, pore volume can be calculated from the relationship:

$$V_p = 1/\rho_{Hg} - 1\ \rho_{He}$$

In this equation, ρ_{Hg} is the mercury density and ρ_{He} is the helium density, decreases with carbon content (Figure 6.4). In addition, the surface area of coal varies over the range 10 to 200 m^2/g and also tends to decrease with the carbon content of the coal.

Porosity and surface area are two important properties with respect to the combustion (and gasification) of coal since the reactivity of coal increases as the porosity and surface area of the coal increases. The porosity of coal is calculated from the relationship:

$$\rho = 100\rho_{Hg}(1/\rho_{Hg} - 1\ \rho_{He})$$

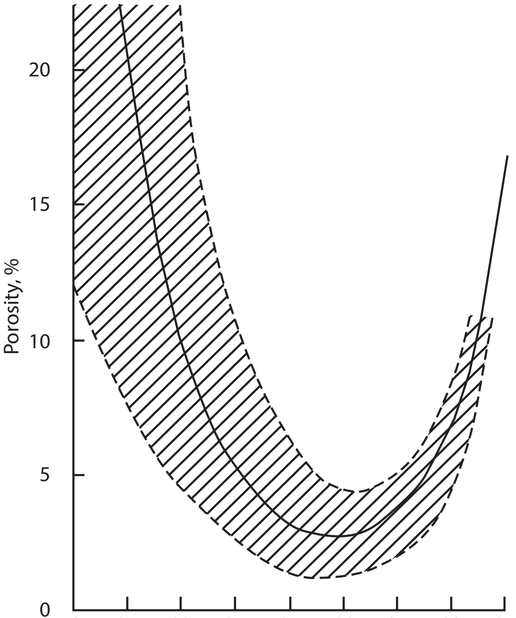

Figure 6.3 Variation of porosity with carbon content (Berkowitz, 1979).

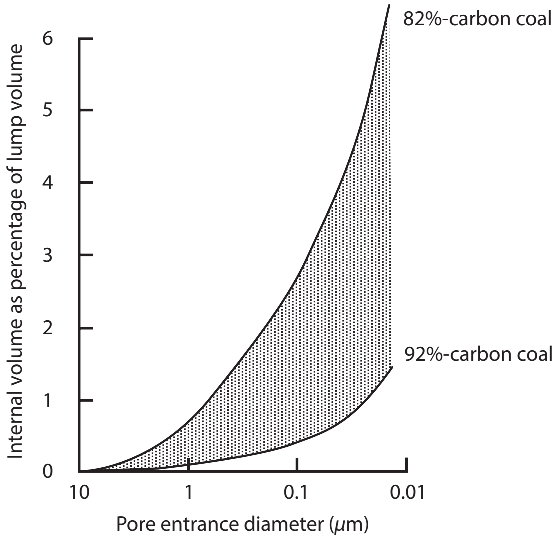

Figure 6.4 Variation of pore distribution with carbon content (Berkowitz, 1979).

By determining the apparent density of coal in fluids of different, but known, dimensions, it is possible to calculate the pore size (pore volume) distribution. The open pore volume (V), i.e., the pore volume accessible to a particular fluid, can be calculated from the relationship:

$$V = 1\rho_{Hg} - 1\rho_a$$

ρ_a is the apparent density in the fluid.

The size distribution of the pores within a coal can be determined by immersing the coal in mercury and progressively increasing the pressure. Surface tension effects prevent the mercury from entering the pores having a diameter smaller than a given value d for any particular pressure p such that

$$P = 4\sigma. \cos\theta/d$$

In this equation, σ is the surface tension and θ is the angle of contact (van Krevelen, 1957). However, the total pore volume accounted for by this method is substantially less than that derived from the helium density, thereby giving rise to the concept that coal contains two pore systems: (i) a macropore system accessible to mercury under pressure and (ii) a micropore system that is inaccessible to mercury but accessible to helium.

6.2.5 Reflectivity

An important property of coal is the reflectivity (or the reflectance) which is the ability of coal to reflect light. This property is determined by shining a beam of monochromatic light (with a wavelength of 546 nanometers, 546×10^{-9} meter) on to a polished surface of the vitrinite macerals in a coal sample and measuring the percentage of the light reflected with a photometer.

Vitrinite is used because its reflectivity changes gradually with increasing rank. On the other hand, the reflectivity of fusinite macerals is too high due to its origin as charcoal and liptinite macerals tend to disappear with increasing rank. Although little of the incident light is reflected (ranging from a few tenths of a percent to 12%), the value increases with rank and can be used to determine the rank of most coals without measuring the percentage of volatile matter present.

The study of coals in sedimentary basins containing crude oil and/or natural gas reveals a close relationship between coalification and the maturation of gaseous and liquid hydrocarbon derivatives. During the initial stages of coalification (to a reflectivity of almost 0.5 and near the boundary between subbituminous and high-volatile C bituminous coal), methane is the predominant hydrocarbon derivative that is produced. The maximum generation of liquid crude oil occurs during the development of high-volatile bituminous coals (in the reflectivity range from roughly 0.5 to about 1.3). With increasing depth and temperature, crude oil liquids break down and, finally, only methane) remains. These phenomena can be employed to anticipate the potential for finding liquid or gaseous hydrocarbons as they explore for crude oil.

6.2.6 Refractive Index

The refractive index of coal can be determined by comparing the reflectance in air with that in cedar oil (Cannon and George, 1943; Speight, 2013, 2015). For vitrinite, the refractive index usually falls within the range 1.68 (58% carbon coal) to 2.02 (96% carbon coal).

The refractive index of coal can be determined by comparing the reflectance in air with that in cedar oil. A standard test method (ASTM D2798) covers the microscopic determination of both the mean maximum reflectance and the mean random reflectance measured in oil of polished surfaces of vitrinite and other macerals in coal ranging in rank from lignite to anthracite. This test method can be used to determine the reflectance of other macerals. For vitrinite (various coals), the refractive index usually falls within the range 1.68 (58% carbon coal) to 2.02 (96% carbon coal).

6.3 Mechanical Properties

In addition to the properties presented above, other properties, such as strength, hardness, friability, grindability, and the dustiness index may affect coal mining and coal preparation, as well as the way in which a coal is used, especially for the production of power. Hardness and grindability determine the kinds of equipment used for mining, crushing, and grinding coals in addition to the amount of power consumed in these processes. In fact, in contrast to the proximate analysis, ultimate (elemental) analysis (Chapter 5) and certain of the physical properties (above), the mechanical properties of coal should be of consideration in predicting coal behavior during mining, handling, and preparation in the context of use in a coal-fired power plant.

First and foremost, most of the ancillary mechanical and physical tests used to characterize coals and often included in classification schemes, were developed in support of efforts to identify coals for coke making. As unique property that sets coking coal apart from other coal types is the caking ability (Chapter 6). There has been much effort to characterize the swelling, contracting and thermoplastic properties of coals using techniques that allow for the comparison of different coals and how these properties influence coke production and quality. Laboratory tests such as the crucible or free swelling index, Gray-King coke type, Roga Index, Audibert-Arnu dilatometer and Gieseler plastometer, provide some means of evaluating the relative strength of swelling, degree of contraction and how fluid a coal will become under heating conditions similar to those encountered during coke making.

For example, the mechanical properties of coal are of value as a means of predicting the strength of coal and its behavior in mines when the strength of coal pillars and stability of coal faces are extremely important factors. The mechanical properties of coal are also of value in areas such as coal winning (for the design and operation of cutting machinery), comminution (design and/or selection of mills), storage (flow properties, failure under shear), handling (shatter and abrasion during transport (Yancey and Geer, 1945; van Krevelen, 1957; Brown and Hiorns, 1963; Trollope *et al.*, 1965; Evans and Allardice, 1978).

6.3.1 Strength

There are different methods for estimating coal strength and hardness: compressive strength, fracture toughness, or grindability, all of which show a trend relative to rank, type, and grade of the coal. The measurement of coal strength is affected by the size of the test specimen, the orientation of stress relative to banding, and the confining pressure of the test (Hobbs, 1964; Zipf and Bieniawski, 1990; and Medhurst and Brown, 1998).

By its nature coal is a banded material which makes it weak by comparison to most other rocks. Intact rock strength is commonly defined as the strength of the rock material that occurs between discontinuities, which in coal are closely spaced and related to lithotype banding and cleat. For a given rank, individual lithotypes can have large compressive strength differences owing to wide ranges in maceral composition, banding texture, and cleat density (Medhurst and Brown, 1998).

Thus, the strength of a bituminous coal specimen is influenced also by its lateral dimension, the smaller specimens showing greater strength than the larger, which can be attributed to the presence in the larger specimen of fracture planes or cleats. In fact, it is the smaller samples which present a more accurate indication of the strength of the coal. The variation of strength with rank of coals has been noted and a plot of strength against volatile matter shows the customary minimum to be 20-25% dry, ash-free volatile matter (Figure 6.5) for compression both perpendicular and parallel to the bedding plane.

6.3.2 Hardness

The resistance of coal to abrasion may have little apparent commercial significance but the abrasiveness of coal is, on the other hand, a factor of considerable importance when coal is used in a power plant. The wear of grinding elements due to the abrasive action of coal results in maintenance charges that constitute one of the major items in the cost of grinding coal for use as pulverized fuel. Moreover, as coals vary widely in abrasiveness, this factor must be considered when coals are selected for plants that employ pulverized coal.

The abrasiveness of coal may be determined more by the nature of its associated impurities than by the nature of the coal substance. For example, pyrite is 20 times harder than coal, and the individual grains of sandstone, another common impurity (in coal, also are hard and abrasive.

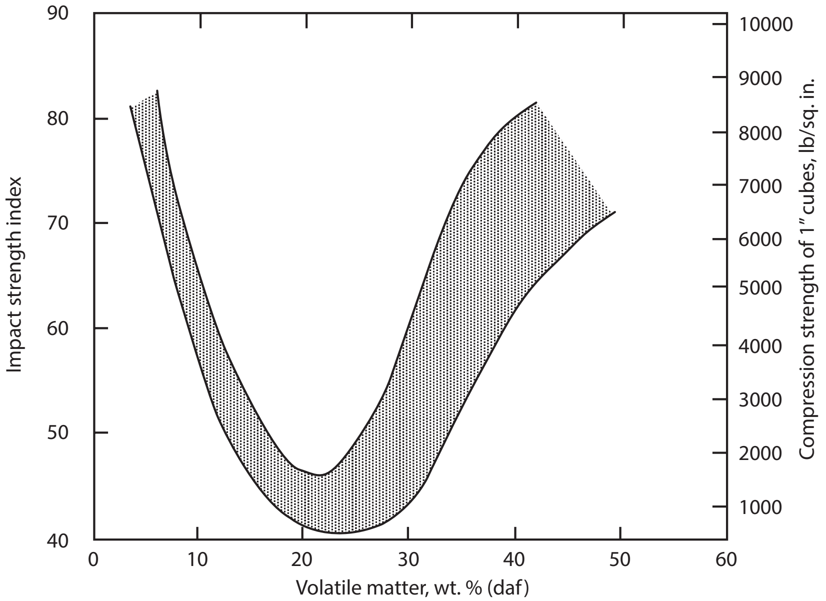

Figure 6.5 Variation of coal strength with volatile matter yield (Brown and Hiorns, 1963).

6.3.3 Friability

Coal must be able to withstand degradation in size during handling operations. The tendency toward breakage on handling (friability) depends on toughness, elasticity, and fracture characteristics as well as on strength, but despite this fact the friability test is the measure of coal strength used most frequently.

The friability of coal is of considerable interest because friable coals yield smaller proportions of the coarse sizes which may (depending on use) be more desirable and there may also be an increased amount of surface in the friable coals. This surface allows more rapid oxidation; hence conditions are more favorable for spontaneous ignition leading to combustion (Chapter 4), loss in coking quality in coking coals, and other changes that accompany oxidation.

The tumbler test for measuring coal friability (ASTM D441) employs a cylindrical porcelain jar mill (7.25 in., 18.4 cm. in size) fitted with three lifters that assist in tumbling the coal. A 1000-g sample of coal sized between 1.5-inch and 1.05-inch square-hole screens is tumbled in the mill (without grinding medium) for one hour at 40 rpm. The coal is then removed and screened on square-hole sieves with openings of 1.05 inch, 0.742 inch, 0.525 inch, 0.371 inch, 0.0369 inch, and 0.0117 inch.

Friability is reported as the percentage reduction in the average particle size during the test. For example, if the average particle size of the tumbled coal was 75% that of the original sample, the friability would be 25%.

A drop shatter test is also used for determining the friability of coal (ASTM D440) which is similar to the standard method used as a shatter test for coke (ASTM D3038). In this method, a 50-lb sample of coal (2 to 3 inch) is dropped twice from a drop-bottom box onto a steel plate 6 ft below the box. The materials shattered by the two drops are then screened over round-hole screens with 3.0 in. (76.2 mm), 2.0 in. (50.8 mm), 1.5 in. (38.1 mm), 1.0

Table 6.2 Variation of friability with rank.

Rank of coal	Number of tests	Friability (%)
Anthracite	36	33
Bituminous (lv)[a]	27	70
Bituminous	87	43
Subbituminous A	40	30
Subbituminous B	29	20
Lignite	16	12

[a] lv = low-volatile.

Source: Yancey and Greer (1968), p. 3.

in. (25.4 mm). 0.75in. (19.05 mm), and 0.5 in. (12.7 mm) openings and the average particle size is determined.

The average size of the material, expressed as a percentage of the size of the original sample, is termed the sizeability, and its complement, the percentage of reduction in average particle size, is termed the percentage friability. Provision is made for testing sizes other than that stipulated for the standard test to permit comparison of different sizes of the same coal.

Attempts have been made to correlate the friability of coal with rank (Table 6.2). Lignite saturated with moisture was found to be the least friable and friability increased with coal rank to a maximum for coals of the low-volatile bituminous coal. The friability of anthracites is comparable with that of subbituminous coals; both are stronger than bituminous coals and decidedly more resistant to breakage than some of the extremely friable semi-bituminous coals.

The relationship between the friability of coal and its rank has a bearing on its tendency to undergo spontaneous heating, ignition, and combustion in a stockpile (Chapter 4) (Chakravorty, 1984; Chakravorty and Kar, 1986). The friable, low-volatile coals, because of their high rank, do not oxidize readily despite the excessive fines and the attendant increased surface they produce on handling. Coals of somewhat lower rank, which oxidize more readily, usually are relatively non-friable and resist degradation in size with its accompanying increase in the amount of surface exposed to oxidation. But above all, the primary factor in coal stockpile instability is unquestionably oxidation by atmospheric oxygen (Chapter 4) whilst the role of any secondary factors such as friability is to increase the severity of the primary oxidation effect (Jones and Vais, 1991).

6.3.4 Grindability

Typically, in plants that burn pulverized coal, coal from the stockpiles (or storage silos) is fed into pulverizing units that grind the crushed coal into the consistency of talcum powder and mix it with primary combustion air which transports the pulverized coal to the steam generator furnace. A 500 MW coal-fired power plant will have approximately six such pulverizing units, five of which will supply the steam generator at full load with approximately 225 tons (450,000 lbs) per hour.

In plants that do not burn pulverized coal, the crushed coal may be directly fed into cyclone burners, a specific kind of combustor that can efficiently burn larger pieces of coal. In plants fueled with slurried coal, the slurry is fed directly to the pulverizers and then mixed with air and fed to the steam generator. The slurry water is separated and removed during pulverizing of the coal.

The grindability of coal (i.e., the ease with which coal may be ground fine enough for use as pulverized fuel) is a composite physical property embracing other specific properties such as hardness, strength, tenacity, and fracture. Several methods of estimating relative grindability utilize a porcelain jar mill in which each coal may be ground for, say, 400 revolutions and the amount of new surface is estimated from screen analyses of the feed and of the ground product. Coals are then rated in grindability by comparing the amount of new surface found in the test with that obtained for a standard coal.

A particularly important mechanical test designed to provide a measure of the ease of pulverization of a coal in comparison with other standard reference coals is the Hardgrove grindability index (HGI). Grindability changes with coal rank, i.e., coals of low and high rank are more difficult to grind than middle-rank coking coals. The test for grindability (Hardgrove, 1932; Edwards *et al.*, 1980) (ASTM D409; ISO 5074) utilizes a ball-and-ring-type mill in which a 50-g sample of closely sized coal is ground for 60 revolutions after which the ground product is screened through a 200-mesh sieve and the grindability index is calculated from the amount of undersize produced using a calibration chart (Table 6.3).

The results are converted into the equivalent HGI. High HGI numbers indicate easy-to-grind coals. There is an approximate relationship between volatile content and grindability in the low-volatile, medium-volatile, and high-volatile bituminous coals. Among these, the low-volatile coals exhibit the highest values for the HGI, often in excess of 100. The high-volatile bituminous coals range in HGI from approximately 54 to 56 and as low as 36 to 39. Soft, easily fractured coals generally exhibit relatively high HGI values. There are two standard text methods ASTM has for measuring friability (ASTM D440 – the drop shatter test – and ASTM D441 – the tumbler test, D441) which should be used where a more accurate estimation of friability is required.

A general relationship exists between the grindability of coal and rank (Figure 6.6) insofar as the easier-to-grind coals are in the medium- and low-volatile groups but, nevertheless, the relationship between grindability and rank is far too approximate to permit grindability to be estimated from coal analysis.

Finally, whatever the coal types used for a coal-fired boiler, grinding the coal to the correct size is one of the key measures to ensure efficient combustion. Correct sizing of the coal, with specific relevance to the type of firing system, helps towards even burning and higher combustion efficiency.

6.3.5 Dustiness Index

The concept of a *dustiness index* was proposed to enable comparison among dust producing capacities of different bulk materials, such as coal, which not only relate to safety issues (causing explosions) and environmental issues. The *dustiness index* of coal is a means of determining the relative values which represent the amount of dust produced when coal is

Table 6.3 Hardgrove grindability indexes of selected US coals.

State	County	Bed	Mine	Hardgrove grindability index
Alabama	Walker	Black Creek	Drummond	46
Colorado	Fremont		Monarch No. 4	46
	Mesa		Cameo	47
Illinois	Fulton	No. 2	Sun Spot	53
	Stark	No. 6	Allendale	61
	Williamson	No. 6	Utility	57
Indiana	Pike	No. V	Blackfoot	54
Iowa	Lucas	Cherokee	Big Ben	61
Kansas	Crawford	Bevier	Clemens	62
Kentucky	Bell	High Splint	Davisburg	44
	Muhlenburg	No. 11	Crescent	55
	Pike	Elkhorn Nos. 1 & 2	Dixie	42
Missouri	Boone	Bevier	Mark Twain	62
Montana	Richland		Savage	62
New Mexico	McKinley	Black Diamond	Sundance	51
North Dakota	Burke		Noonan	38
Ohio	Belmont	No. 9	Linda	50
	Harrison	No. 8	Bradford	51
Pennsylvania	Cambria	Lower Kittaning (bituminous)	Bird No. 2	109
	Indiana	Lower Freeport (bituminous)	Acadia	83
	Schuykill	Various (anthracite)		38
	Washington	Pittsburgh	Florence	55
	Westmoreland	Upper Freeport	Jamison	65
Tennessee	Grundy	Sewanee	Ramsey	59
Utah	Carbon	Castle Gate	Carbon	47
Virginia	Buchanan	Splash Dam	Harman	68

(*Continued*)

Table 6.3 Hardgrove grindability indexes of selected US coals. (*Continued*)

State	County	Bed	Mine	Hardgrove grindability index
	Dickenson	Upper Banner		84
	Wise	Morris	Roda	43
West Virginia	Fayette	Sewell	Summerlee	86
	McDowell	Pocahontas No. 3	Jacobs Fork	96
	Wyoming	Powellton	Coal Mountain	58
	Wyoming	No. 2 Gas	Kopperston	70
Wyoming	Campbell	Smith/Rowland	Wyodak	59

Source: Baughman (1978), p. 169.

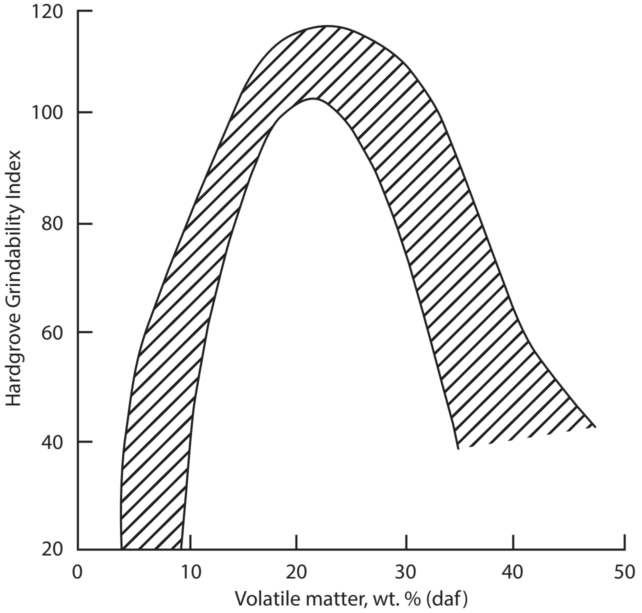

Figure 6.6 Variation of the Hardgrove grindability index with volatile matter yield (Berkowitz, 1979).

handled in a standard manner, or even in a non-standard manner. The latter aspect is particularly important when various methods of coal handling are available, as might be the case in a coal-fired power plant.

Estimations of the amount of dust produced during coal handling were developed with a view to establishing relative *dustiness indices* (BOHS, 1985; Lyons and Mark, 1994; Upton *et al.*, 1990; Vincent, 1995; Breum *et al.*, 1996). The objective of the dustiness index is to provide criteria for the selection of process options (in the case of a coal-fired power plant) that will lead to lower emissions of dust. It is important to note, however, that different test methods can produce different orderings of a dustiness index.

Dust removal from coal preparation plants is an important aspect of safety and there have been constant attempts to improve dust removal technology (Henke and Stockmann, 1992; Speight, 2013). As the techniques have been developed, the predictability of how coal will behave, in terms of the dust produced, under certain conditions – especially the conditions prevalent in a coal-fired power plant – has also been sought.

For the test method, a 50-lb sample of coal is placed on a slide plate in a metal cabinet of prescribed size. When the plate is withdrawn, the sample falls into a drawer and, after 5 sec, two slides are inserted into the box. The slides collect suspended dust particles for 2 minutes (coarse dust) or for 10 min (fine dust). The dustiness index is reported as 40 times the gram weight of dust that has settled after either 2 minutes or after an additional 8 minutes.

6.4 Thermal Properties

When a sample of powdered coal is heated out of contact with air, it loses occluded gases consisting of methane, ethane, nitrogen, and carbon dioxide (there may be other gases) at temperatures below 100°C (212°F); moisture is evolved between 100 and 150°C (212 and 300°F) (Speight, 2013; Stanger *et al.*, 2014; Deng *et al.*, 2017). The initial temperature of decomposition of bituminous coals is 200 to 300°C (390 and 570°F) while active decomposition starts at 300 to 375°C (570 and 705°F) for these coals. Pyrogenic water, primary tar and gases evolve during the primary devolatilization (at 300 to 550°C; 570 to 1000°F), while gases (mainly hydrogen) are evolved during the secondary devolatilization at approximately 700°C (1290°F).

The dynamic features of the devolatilization process, such as particle softening, bubbling, swelling, evolution of volatiles, and contracting. Furthermore, while the coal undergoes decomposition on heating, the residue becomes richer in carbon content. In the case of caking coals, the residue passes through a plastic state in the range 300 to 350°C (570 to 660°F) and to 500 to 550°C (930 to 1022°F). The fluidity of the plastic mass initially increases, attains a maximum and then decreases to zero. If coke is heated further, significant changes take place at temperatures on the order of 2000°C (3630°F) and graphite-like product is the result. Non-caking coals are not amenable to graphitization.

The porosity of coal decreases on heating and attains a minimum in the plastic state. After resolidification, porosity again rises considerably – the porosity of coke is 40% or above. This property ensures smooth burning of coke in furnaces. Because of the simultaneous formation of the plastic state and volatile products of thermal decomposition, the carbonaceous residue exhibits an initial contraction and fall in porosity followed by swelling, dilation and rise in porosity.

Thus, the thermal properties of coal are important in determining the applicability of coal to coal-fired power generation, as well as a variety of conversion processes (Speight, 2008, 2013). For example, the calorific value (also called the heat content or heating value) (Table 6.4) (Chapter 5) is often considered to be the most important thermal property. However, there are other thermal properties that are of importance insofar as they are required for the design of equipment that is to be employed for the utilization (conversion, thermal treatment) of coal in processes such as combustion, carbonization, gasification,

Table 6.4 Heat content of coal at various temperatures.

Temperature		Heat content		
		As tested		**Ash-free basis**
°C	°F	cal/g	Btu/lb	cal/g
Lignite (Texas)				
32.7	90.9	11.8	21.2	13.5
69.3	156.7	20.2	36.4	22.5
95.3	203.5	25.4	45.7	27.7
34.4	273.9	39.2	70.6	42.5
Subbituminous B (Wyoming)				
42.3	108.1	14.1	25.4	14.5
65.0	149.0	19.4	34.9	19.8
89.7	193.5	26.4	47.5	26.9
112.6	234.7	34.0	61.2	34.6

Source: Adapted from Baughman (1978), p. 173.

and liquefaction. Plastic and agglutinating properties as well as phenomena such as the agglomerating index give indications of how coal will behave in a reactor during a variety of thermal processes (Chan *et al.*, 1991).

6.4.1 Heat Capacity

The heat capacity of coal is the heat required to raise the temperature of one unit weight of a substance one degree and the ratio of the heat capacity of one substance to the heat capacity of water at 15°C (60°F) in the specific heat (see also calorific value, Chapter 5). The heat capacity of coal can be measured by standard calorimetric methods for mixtures (e.g., see ASTM C351).

The units for heat capacity are Btu per pound per degree Fahrenheit (Btu/lb/°F) or calories per gram per degree centigrade cal/gm/°C), but the specific heat is the ratio of two heat capacities and is therefore dimensionless. The heat capacity of water is 1.0 Btu/lb/°F (= 4.2 x 103 J/kg/°K) and, thus, the heat capacity of any material will always be numerically equal to the specific heat. Consequently, there has been the tendency to use the terms heat capacity and specific heat synonymously.

Specific heat strongly influences the rate of heating of pulverized fuel particles and this in turn affects the rate of devolatilization and the ease of ignition of coal. Accurate knowledge of the specific heat of coal as a function of temperature under rapid heating conditions is important to progress in coal combustion and to coal utilization technology in general. The specific heat of coal is closely related to the amount of heat required per unit mass of coal to raise its temperature to a given value and this is an important factor during rapid heating in the utilization of coal.

The specific heat of coal usually increases with its moisture content, decreases with carbon content, and increases with volatile matter content, with ash content exerting a somewhat lesser influence (Speight, 2013). While the values for the specific heat of coal falls into the general range 0.25 to 0.37, as with other physical data, comparisons should only be made on an equal basis (such as moisture content, mineral matter content, or thermal ash yield) basis.

Estimates of the specific heat of coal have also been made on the assumption that the molecular heat of a solid material is equal to the sum of the atomic heats of the constituents (Kopp's law). Briefly, the German chemist Hermann Franz Kopp (1817-1892) discovered that the molecular heat capacity of a solid compound is the sum of the atomic heat capacities of the elements composing it; the elements having atomic heat capacities lower than those required by the law of Dulong and Petit retain these lower values in their compounds – the atomic heat so derived is divided by the atomic weight to give the (approximate) specific heat.

Thus, from the data for various coals, it has been possible to derive a formula which indicates the relationship between the specific heat and the elemental analysis of coal (mmf basis):

$$C_p = 0.189C + 0.874H + 0.491N + 0.3600 + 0.215S$$

C, H, N, O, and S are the respective amounts (% w/w) of the elements in the coal.

6.4.2 Thermal Conductivity

Thermal conductivity is the rate of transfer of heat by conduction through a unit area across a unit thickness for a unit difference in temperature:

$$Q = kA(t_2 - t_1)/d$$

Q = heat, expressed as kcal/sec cm °C or as Btu/ft hr oF (1 Btu/ft hr °F = 1.7 J/s m °K), A = area, t_2 - t_1 = temperature differential for the distance (d), and k = thermal conductivity (Carslaw and Jaeger, 1959). However, the banding and bedding planes in coal (Speight, 2013) can complicate the matter to such an extent that it is difficult, if not almost impossible, to determine a single value for the thermal conductivity of a particular coal. Nevertheless, it has been possible to draw certain conclusions from the data available.

Thus, monolithic coal is considered to be a medium conductor of heat with the thermal conductivity of anthracite being on the order of 5-9 x 10-4 kcal/sec cm °C while the thermal conductivity of monolithic bituminous coal falls in the range 4-7 x 10 -4 kcal/sec/cm/°C. For example, the thermal conductivity of pulverized coal is lower than that of the corresponding monolithic coal. For example, the thermal conductivity of pulverized bituminous coal falls into the range 2.5-3.5 x 10-4*f* kcal/sec cm °C.

The thermal conductivity of coal generally increases with an increase in the apparent density of the coal as well as with volatile matter yield, ash yield, and temperature.

In addition, the thermal conductivity of the coal parallel to the bedding plane appears to be higher than the thermal conductivity perpendicular to the bedding plane.

There is little information related to the influence of water on the thermal conductivity of coal, but since the thermal conductivity of water is markedly higher (approximately three times) than that of coal the thermal conductivity of coal could be expected to increase if water is present in the coal.

6.4.3 Plastic and Agglutinating Properties

When coal is heated, it passes through a transient stage which is called a plastic state (caking). If a particular coal does not pass through a plastic state, it is called sintered mass (non-coking). While the plastic properties of coal are more definitive in terms of the production of metallurgical coke from coal blends, such properties can also influence coal combustion and whether or not the stickiness or fluidity of the coal will influence coal behavior in a combustor as used on a coal-fired power plant. Hence, consideration of these properties is warranted here.

Plasticity refers to the melting and bonding behavior of the coal which is (i) an indication of the initial softening, chemical reaction, gas liberation and resolidification process within the coke oven, (ii) an important requirement in the coke blend and is required for end product coke strength, and (iii) the fluidity of the plastic stage is a major factor in determining what proportions of a coal is used in a proportions of a coal is used in a blend.

When coal is heated, an unstable intermediate phase (*metaplast*) is formed after the moisture is driven from the coal. This intermediate phase is responsible for the plastic behavior of coal. On further heating a cracking process takes place in which tar is vaporized and non-aromatic groups are split off followed by condensation and formation of semicoke.

All coals undergo chemical changes when heated but there are certain types of coal which also exhibit physical changes when subjected to the influence of heat. These particular types of coals are generally known as "caking" coals, whereas the remaining coals are referred to as *non-caking coals*.

The caking coals pass through a series of physical changes during the heating process insofar as the coal softens, melts, fuses, swells, and resolidifies within a specific temperature range. This temperature has been called the "plastic range" of coal and thus the physical changes which occur within this range have been termed the *plastic properties* (*plasticity*) of coal.

The caking tendency of coals increases with the volatile matter content of the coal and reaches a maximum in the range 25 to 35% w/w volatile matter but then tends to decrease. In addition, the caking tendency of coal is generally high in the 81 to 92% w/w carbon coals (with a maximum at 89% carbon); the caking tendency of coal also increases with hydrogen content but decreases with oxygen content and with mineral matter content.

When non-caking coal (non-plastic coal) is heated, the residue is pulverent and noncoherent. On the other hand, the caking coals produce residues that are coherent and have varying degrees of friability and swelling. In the plastic range, caking coal particles have a tendency to form agglomerates (cakes) and may even adhere to surfaces of process equipment, thereby giving rise to reactor plugging problems. Thus, the plastic properties of coal are an important means of projecting and predicting how coal will behave under various process conditions as well as assisting in the selection of process equipment.

The Gieseler test is a standard test method in which the actual extent of the plasticity of fluidity attained is measured. The Gieseler test is used to characterize coals with regard to thermo plasticity and is an important method used for coal blending for commercial coke manufacture. The maximum fluidity determined by the Gieseler is sensitive to weathering (oxidation) of the coal.

Briefly, the Gieseler plastometer (ASTM Dl8l2; ASTM D2639) is a vertical instrument consisting of a sample holder, a stirrer with four small rabble arms attached at its lower end with the means of (1) applying a torque to the stirrer, (2) heating the sample that includes provision for controlling temperature and rate of temperature rise, and (3) measuring the rate of turning of the stirrer.

A sample of -60 mesh coal is packed in the sample holder; the holder is completely filled and the rabble arms of the stirrer are all in contact with the coal. The apparatus is then immersed in the heating bath and a known torque applied to the stirrer. During the initial heating, no movement of the stirrer occurs but as the temperature is raised the stirrer begins to rotate. With increasing temperature, the stirrer speed increases until at some point the coal resolidifies and the stirrer is halted (Berkowitz, 1979).

Data usually obtained with the Gieseler plastometer are (i) softening temperature (the temperature at which stirrer movement is equal to 0.5 dial divisions per minute) which may be characterized by other rates but if so the rate must be reported, (ii) maximum fluid temperature (the temperature at which stirrer movement reaches maximum rate in terms of dial divisions per minute), (iii) solidification temperature (the temperature at which stirrer movement stops), and (iv) maximum fluidity (the maximum rate of stirrer movement in dial divisions per minute).

Plastic properties of coal, as determined by the Gieseler plastometer, appear to be sensitive to oxidation, which can have a marked effect in decreasing the maximum fluidity. In fact, prolonged oxidation may completely destroy the fluidity of a coal (Chapter 4). To reduce oxidation, samples should be tested soon after collection or, if delay is unavoidable, storage under water or in a nonoxidizing atmosphere such as nitrogen is advisable.

The plasticity of individual coal macerals has also received some attention but the investigations can be complicated by the difficulties encountered in the isolation of the macerals in the “pure” state. In spite of this, there are reports of the behavior of the macerals. Thus, exinite tends to be quite plastic, with a low softening point, wide plastic range, high fluidity in the plastic state, and a high degree of swelling. This is understandable because exinite is a hydrogen-rich maceral and contains up to 70% volatile matter when isolated from high-volatile coal. It is almost impossible to plasticize fusinite insofar as this maceral is a fossil charcoal which is hard and friable; vitrinite generally shows an intermediate plasticity behavior (Speight, 2013).

In terms of the elemental composition of coal, there is a relative hydrogen deficiency, but there are theories that admit to the presence of hydrogen-rich liquid (and mobile) hydrocarbon derivatives that are enclosed within the coal matrix and which are often (erroneously) called *bitumen* and which should not be confused with the bitumen (natural asphalts) that occur in various deposits throughout the world (Speight, 1990, 2014, 2020). The application of heat results in the liberation of these hydrocarbon liquids and forms other hydrocarbon derivatives (often referred to as *thermobitumen*) by scission of hydrocarbon fragments from the coal structure, and the overall effect is the formation of a high-carbon coke and a hydrocarbon tar, the latter being responsible for the fluidity of the mass. With increased heating, the tar partly volatilizes and partly reacts to form nonfluid material ultimately leading to the coke residue.

When coal is heated in a vacuum, the plastic range is generally reduced substantially, perhaps because of the rapid evaporation of the bituminous hydrocarbon derivatives that are reputedly responsible for the fluidity of the plastic coal. Heating coal to the plastic range followed by rapid cooling yields coal with a lower softening point (if plasticized a second time) and this has been ascribed to the presence of liquid in the coal that arose from the first heating.

An additional property of coal that is worthy of mention at this time is the softening point, which is generally defined as the temperature at which the particles of coal begin to melt and become rounded. The softening point indicates the onset of the plasticity stage and is (as should be anticipated) a function of the volatile matter content of coal. For example, coal with 15% volatile matter will have a softening point of the order of 440°C (825°F) which will decrease to a limiting value of ca. 340°C (645°F) for coal with 30% volatile matter.

The material thought to be responsible for conferring the plastic properties on coal can be removed by solvent extraction to leave a non-plastic residue (Pierron and Rees, 1960). Plastic properties can be restored to the coal be recombining the solvents extracts with the insoluble residue.

6.4.4 Agglomerating Index

The agglomerating index is a grading index based on the nature of the residue from a one-gram sample of coal when heated at 950°C (1740°F) in the volatile matter determination (ASTM D3175).

The agglomerating index has been adopted as a requisite physical property to differentiate semi-anthracite from low-C volatile bituminous coal and also high-volatile C bituminous coal from subbituminous coal (Speight, 2013). From the standpoint of the caking action of coal in coal-burning equipment the agglomerating index has some interest. For example, coals having indexes NAa or NAb, such as anthracite or semianthracites, certainly do not give any problems from caking while those coals having a Cg index are, in fact, the high-caking coals.

The agglomerating (or agglutinating) tendency of coal may also be determined by the Roga test (ISO 335), and the Roga index (calculated from the abrasion properties when a mixture of a specific coal and anthracite is heated) is used as an indicator of the agglomerating tendencies of coal.

Briefly, abrasion is the property of the coal which describes its propensity and ability to wear away machinery and undergo autonomous grinding. While carbonaceous matter in coal is relatively soft, quartz and other mineral constituents in coal are quite abrasive. This is tested in a calibrated mill, containing four blades of known mass. The coal is agitated in the mill for 12,000 revolutions at a rate of 1,500 revolutions per minute (i.e., 1,500 revolution for 8 min). The *abrasion index* is determined by measuring the loss of mass of the four metal blades.

6.4.5 Free Swelling Index

The free swelling index (FSl) of coal is a measure of the increase in volume of a coal when it is heated (without restriction) under prescribed conditions (ASTM D720; ISO 335).

The ISO test (ISO 335, Roga test, measures mechanical strength rather than size profiles of coke buttons; another ISO test (ISO 501) gives a crucible swelling number of coal.

The nature of the volume increase is associated with the plastic properties of coal (Loison *et al.*, 1963) and, as might be anticipated, coals which do not exhibit plastic properties when heated do not, therefore, exhibit free swelling. Although this relationship between free swelling and plastic properties may be quite complex, it is presumed that when the coal is in a plastic (or semifluid) condition the gas bubbles formed as a part of the thermal decomposition process within the fluid material cause the swelling phenomenon which, in turn, is influenced by the thickness of the bubble walls, the fluidity of the coal, and the interfacial tension between the fluid material and the solid particles that are presumed to be present under the test conditions.

The test for the free swelling index of coal (ASTM D720) requires that several one-gram samples of coal be heated to 820°C (1508°F) within a specified time to produce buttons of coke. The shape, or profile, of the buttons determines the free swelling index of the coal (BSI, 2011). Anthracites do not usually fuse or exhibit a free swelling index whereas the free swelling index of bituminous coals will increase as the rank increases from the high-volatile C bituminous coal to the low-volatile bituminous coal.

Other effects which can influence the free swelling index of coal include the weathering (oxidation) of the coal. Hence, it is advisable to test coal as soon as possible after collection and preparation. There is also evidence that the size of the sample can influence the outcome of the free swelling test; an excess of fine (-100 mesh) coal in a sample has reputedly been responsible for excessive swelling to the extent that the FSI numbers can be up to two numbers higher than is the true case.

The free swelling index of coal is believed to be of some importance in assessing the coking properties of coal, but absolute interpretation of the data is extremely difficult. In general terms, the free swelling index of bituminous coals generally increases with an increase in rank (Rees, 1966) but the values for individual coals within a rank may vary considerably. The values for the lower-rank coals are normally less than those for bituminous coals; anthracite does not fuse and shows no swelling value. Furthermore, a coal exhibiting a free swelling index of 2, or less, will most likely not be a good coking coal, whereas a coal having a free swelling index of 4, or more, may have good coking properties.

6.4.6 Ash Fusion Temperature

The behavior of the coal ash residue at high temperature is a critical factor in selecting coals for steam power generation. Most furnaces are designed to remove ash as a powdery residue. Coal which has ash that fuses into a hard glassy slag (*clinker*) is usually unsatisfactory in furnaces as it requires cleaning. However, furnaces can be designed to handle the clinker, generally by removing it as a molten liquid.

Ash fusion temperatures are determined by viewing a molded specimen of the coal ash through an observation window in a high-temperature furnace (ASTM D1857). The ash, in the form of a cone, pyramid or cube, is heated steadily past 1000°C (1832°F) to as high a temperature as possible, preferably 1600°C (2910°F).

The following temperatures are recorded: (i) deformation temperature, which is the temperature at which the corners of the mold first become rounded, (ii) softening (sphere) temperature, which is the temperature when the top of the mold takes on a spherical shape,

(iii) hemisphere temperature, which is the temperature when the entire mold takes on a hemisphere shape, and (iv) flow (fluid) temperature, which is the temperature when the molten ash collapses to a flattened button on the furnace floor.

The fusibility of ash is important in understanding the process of slagging and fouling inside the boilers during the conversion of coal and coal blends. Ash fusion temperatures give an indication of the softening and melting behavior of fuel ash and, therefore, an estimation of the variability in fusibility characteristics among different coals. Ash fusion temperatures are also able to provide an indication of the progressive melting of coal ash to slag.

Ash fusion temperatures are widely cited in fuel specifications for boilers despite a relatively poor record of correlating with slagging or fouling behavior. Reasons for the poor predictive behavior include the following: (i) the fusion temperatures are based on fuel ash, whereas deposits commonly are enriched and depleted in several elements relative to the fuel, (ii) the fusion temperature is determined over short time periods while heating ash at a rate of 8 ± 3°C/15 ± 5°F per minute, whereas ash deposits typically accumulate for hours and are formed during cooling relative to the bulk gas temperature, (iii) fusion temperatures do not account for either boiler design or boiler operation, both of which strongly influence slagging and fouling behavior, and (iv) fusion behavior changes when samples are allowed to stand at a given temperature. Fusion temperatures generally significantly decrease if the samples equilibrate at a given temperature for an hour or so (Gupta, 2007).

However, despite the shortcomings, fusion temperatures are valuable guides to the high-temperature behavior of the fuel inorganic material. The ash fusion temperature has been correlated with the mineral and chemical composition of coal ash (Vassilev *et al.*, 1995).

6.5 Electrical Properties

Knowledge of the electrical properties of coal is also an important aspect of coal characterization and behavior for use (Speight, 2013, 2015). Electrical properties are useful for coal cleaning, coal mining, coal pyrolysis, and coal carbonizing processes. They are also of special interest in the electro linking process for permeability enhancement and as a means to locate regions with different physical properties during *in situ* coal gasification.

All electrical property values are strongly dependent on water content; for water, the dielectric constant is approximately 81 and resistivity is about 106 ohm-cm. The dielectric constant has been used as a measure of moisture in coal (Speight, 2013, 2015). However, it should be noted that the effect is not considered to be additive due to the different electrical properties of physically and chemically bound water. With an increase in moisture content, electrical conductivity, and dielectric constant increase, whereas resistivity and dielectric strength decrease. Hence, except for special purposes, for example, dielectric strength measurements of underground coal blocks; electrical measurements require the meticulous drying of coal prior to experiments.

6.5.1 Electrical Conductivity

Electrical conductivity is the inverse of resistivity. Induction logging systems were originally designed to facilitate resistivity measurements in oil-based drilling mud, where there is no conductive medium occurred between the tool and the formation. It is also often used in dry holes or when the borehole fluid is very fresh. The purpose is, as usual, to measure resistivity or conductivity in order to calculate porosity and to interpret lithology. Induction is useful in several types of ground investigation.

Coal usually has high resistivity (Verma *et al.*, 1983; Krishnamurthy *et al.*, 2009). This may be reduced according to its porosity, clay, and water content. The porosity of coal varies with rank and so its resistivity increases from lignite to semi-anthracite and then decreases slightly with anthracite. Clay inclusions reduce the resistivity of coal. Clay-rich formations, such as shale formations, have low resistivity. Clean, relatively dry sandstone has high resistivity, which may be reduced according to porosity, salinity, and clay content. Resistivity (or conductivity) logs may also indicate oxidation of a coal seam or alteration by an intrusion.

Electrical conductivity depends on several factors, such as temperature, pressure, and moisture content of the coal. The electrical conductivity of coal is quite pronounced at high temperatures (especially above 600°C, 1110°F), where coal structure begins to break down. Moisture affects electrical conductivity to a marked extent, resulting in a greatly increased conductivity. To prevent any anomalies from the conductance due to water, the coal is usually maintained in a dry, oxygen-free atmosphere and, to minimize the problems that can arise particularly because of the presence of water, initial measurements are usually taken at approximately 200°C (392°F) and then continued to lower temperatures.

Coal is a semiconductor (van Krevelen, 1961; Speight, 2013, 2015). Anthracite is a semiconductor with specific resistance ranging from 1 to 104 ohm-cm while the range is 105 to 1012 ohm-cm for bituminous coal. Subbituminous coal also behaves as a semiconductor. The highest resistances are observed with coals having 80 to 92% w/w carbon; they can be considered virtual insulators. Hence, electrical conductivity, a measure of electricity transportation, is generally handled in terms of electrical resistivity for coal. To eliminate quantities not characteristic for the material, the specific electrical resistance (resistivity) and the specific conductance are utilized. The former is the resistance that a cube with unit dimensions offers to current flow and is expressed in ohm-unit length, and the latter is reciprocal of the former.

The conductivity of coal is explained in part by the partial mobility of electrons in the coal structure lattice which occurs because of unpaired electrons or "free radicals" Mineral matter in coal may have some influence on electrical conductivity. The conductivities of coal macerals show distinct differences; fusains conduct electricity much better than clarain, durain, and vitrain.

The electrical conductivity of coal can be used to model conditions during *in situ* gasification (Duba, 1977). For example, from an initial value (at 24°C, 75°F) when the coal is saturated with formation water, the conductivity decreases to markedly when the coal is heated to 110°C (230°F) in vacuum. This low value, presumably due to dehydration of the coal, prevails for samples heated as high as 500°C (930°F) in dry argon. Samples of char recovered after pyrolysis to 800°C (1470°F) or more have a much higher conductivity. This contrast allows electrical probing to be sufficiently sensitive for monitoring the progress of the burn-front progress during *in situ* coal gasification.

The electrical conductivity of coal is generally discussed in terms of specific resistance, p (units of p are ohm-centimeters), and is the resistance of a block of coal 1 cm long and having a l-cm^2 cross-section and may vary from thousands of ohm-centimeters to millions of ohm-centimeters depending on the direction of measurement (Speight, 2013, 2015).

Substances having a specific resistance greater than approximately 1 x 10^{15} ohm-cm are classified as insulators while those with a specific resistance less than 1 ohm-cm are conductors; materials between these limits are semiconductors.

Finally, the *specific resistance* (*resistivity*) of coal is the electrical resistance of a body of a unit cross-section and of unit length (and is expressed in ohm-centimeters:

$$p = RA/L$$

In this equation, *p* is the specific resistance, R is the resistance of the substance, A is the cross-sectional area, and L is the length.

When wet coal is exposed to higher temperatures (0 to 200°C, 32 to 392°F), an increase of electrical resistivity (with a concurrent decrease of dielectric constant) is observed. This is due to moisture loss. After moisture removal, a temperature increase results in lower resistivity (and higher dielectric constant). The dependency of conductive properties on temperature is mainly exponential as in any semiconductor. At lower temperatures, the effect of temperature on electrical properties is reversible. The onset of irreversible effects is rank dependent and starts at 200 to 400°C (390 to 750°F) for bituminous coal and at 500 to 700°C (930 to 1290°F) for anthracite.

6.5.2 Dielectric Constant

The dielectric constant is more useful than electrical conductivity in characterizing coal and is a measure of the electrostatic polarizability of the dielectric coal. The dielectric constant of coal is believed to be related to the polarizability of the pi-electrons (π-electrons) in the clusters of aromatic rings within the chemical structure of coal (Speight, 2013, 2015).

The dielectric constant (specific inductive capacity) is a measure of electrostatic polarizability and of the amount of electricity that can be stored in coal. Dielectric constant is more useful than electrical conductivity in characterizing coal and is a measure of the electrostatic polarizability of the dielectric coal. The dielectric constant of coal is believed to be related to the polarizability of the Π-electrons in the clusters of aromatic rings in the coal chemical structure.

Experimental methods are applicable for a wide range of frequencies. High-frequency measurements employ commercially available dielectric constant meters, Q-meters, etc.; the impedance bridge method is widely employed at low frequencies. The levels of the frequencies experimentally applied are important for data interpretation and comparison.

The dielectric constant of coal is strongly dependent on coal rank (Van Krevelen, 1961; Speight, 2013, 2015). For dry coal, the minimum dielectric constant value is 3.5 and is observed at about 88% w/w carbon content in the bituminous coal range. The dielectric constant increases sharply and approaches 5.0 both for anthracite (92% carbon) and for lignite (70% carbon). The Maxwell Relation which equates the dielectric constant to the square of the refractive index for non-polar insulators generally shows a large disparity even for strongly dried coal.

Like conductivity, dielectric constant is strongly dependent on water content. Indeed, the dielectric constant can even be used as a measure of moisture in coal). Meaningful dielectric constant measurements of coal require drying to a constant dielectric constant and several forms of coal are used for dielectric constant measurements. These include precisely shaped blocks of coal, mulls of coal in solvents of low dielectric constant, or blocks of powdered coal in a paraffin matrix.

The dielectric constant varies with coal rank. The theorem that the dielectric constant is equal to the square of the refractive index (which is valid for non-conducting, nonpolar substances) holds only for coal at the minimum dielectric constant. The decreasing value of dielectric constant with rank may be due to the loss of polar functional groups (such as hydroxyl or carboxylic acid functions) but the role of the presence of polarizable electrons (associated with condensed aromatic systems) is not fully known. It also appears that the presence of intrinsic water in coal has a strong influence on the dielectric properties (Chatterjee and Misra, 1989).

6.5.3 Dielectric Strength

Dielectric strength indicates the voltage gradient at which dielectric failure occurs and it is generally measured at commercial power frequencies and is expressed in volts per sample thickness (Speight, 2013, 2015). This test method covers procedures for the determination of dielectric strength of solid insulating materials at commercial power frequencies, under specified conditions.

Experimental data strongly indicates that anthracite and bituminous coal are electrically anisotropic. Higher resistivity/lower conductivity is observed for specimens oriented perpendicular to the bedding plane relative to those with parallel orientation.

6.6 Epilog

Knowledge of coal properties is an important aspect of coal characterization and has been used as a means of determining the suitability of coal for commercial use for decades, perhaps even centuries.

Therefore the properties outlined in this chapter (and also in Chapter 5) must always be borne in mind when consideration is being given to the suitability of coal for use in a coal-fired power plant. It must also be borne in mind that a coal which at first appears unsuitable for use by a consumer might become eminently suitable by a relatively simple or convenient pretreating step or even by blending with another coal or coals.

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PART II

POWER GENERATION

7

Combustion

7.1 Introduction

Combustion (*burning*) is the sequence of exothermic chemical reactions between a hydrocarbon and an oxidant accompanied by the production of heat and conversion of chemical species. The release of heat can result in the production of light, usually in the form of a flame. Hydrocarbon derivatives of interest often include organic compounds (especially hydrocarbon derivatives) in the gas, liquid, or solid phase. For the most part, combustion involves a mixture of hot gases and is the result of a chemical reaction, primarily between oxygen in air and a hydrocarbon (or a hydrocarbon fuel). In addition to other products, the combustion reaction produces carbon dioxide (CO_2), steam (H_2O), light, and heat.

In its broad definition, combustion includes fast exothermic chemical reactions, generally in the gas phase but not excluding the reaction of solid carbon with a gaseous oxidant. Flames represent combustion reactions that can propagate through space at subsonic velocity and are accompanied by the emission of light. The flame is the result of complex interactions of chemical and physical processes whose quantitative description must draw on a wide range of disciplines, such as chemistry, thermodynamics, fluid dynamics, and molecular physics. In the course of the chemical reaction, energy is released in the form of heat, and atoms and free radicals, all highly reactive intermediates of the combustion reactions, are generated.

The physical processes involved in combustion are primarily transport processes: transport of mass and energy and, in systems with flow of the reactants, transport of momentum. The reactants in the chemical reaction are normally a hydrocarbon and an oxidant. In practical combustion systems the chemical reactions of the major chemical species, carbon and hydrogen in the hydrocarbon and oxygen in the air, are fast at the prevailing high temperatures (greater than 930^{o}C, 1700^{o}F) because the reaction rates increase exponentially with temperature. In contrast, the rates of the transport processes exhibit much smaller dependence on temperature and are, therefore, lower than those of the chemical reactions.

Thus, the rate of evolution of the main combustion products, carbon dioxide and water, and the accompanying heat release depends on the rates at which the reactants are mixed and heat is being transferred from the flame to the fresh hydrocarbon-oxidant mixture injected into the flame. However, this generalization cannot be extended to the production and destruction of minor species in the flame, including those of trace concentrations of air pollutants such as nitrogen oxides, polycyclic aromatic hydrocarbon derivatives, soot, carbon monoxide, and sub-micrometer-size inorganic particulate matter.

Thus, during combustion, new chemical substances (exhaust gases) are created from the hydrocarbon and the oxidizer. When a hydrocarbon-based fuel (such as gasoline) burns, the exhaust includes water and carbon dioxide. However, the exhaust gases can also include

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chemical combinations from the oxidizer alone. For example, if the gasoline is burned in air (21% v/v oxygen and 78% v/v nitrogen), the exhaust gases can also include nitrogen oxides (NOX). The temperature of the exhaust gases is high because of the heat that is transferred to the exhaust during combustion. Because of the high temperatures, exhaust usually occurs as a gas, but there can be liquid (tar and other high boiling products) or solid (soot, carbon).

The need to burn increasing amounts of coal and related materials mainly arises from the need to replace oil and natural gas as fuels for combustion in furnaces, such as the furnaces in coal-fired power plants. In addition to satisfying normal economic constraints, existing and new combustion processes must be able to burn low-grade fuels and satisfy local environmental requirements. Some requirements cause conflict, e.g., the combustion of low-grade fuels can be relatively costly due to reduced plant capacity and efficiency, and the costs incurred in controlling pollution levels.

Coal combustion is used in a range of applications which vary from domestic fires to large industrial furnaces and utility boilers. The oxidant is usually air and the coal may be in any degree of dispersion. In fact, coal combustion provides the majority of consumable energy to the world and despite the continuing search for alternate sources of energy (whether they are other fossil fuels or non-fossil fuels such as biomass) there is little doubt that coal combustion will remain an important source of energy throughout the 21st century.

A major concern in the present-day combustion of coal is the performance of the process in an environmentally acceptable manner through the use of a variety of environmentally acceptable technologies such as the use of a low-sulfur coal or through the use of post-combustion cleanup of the off-gases (Speight, 2013, 2014, 2020). Thus, there is a marked trend in the current marketplace to initiate and develop more efficient methods of coal combustion. In fact, the ideal combustion system would be s system that is able to accept coal without a precombustion treatment, and/or without the need for post-combustion treatment, and/or without emitting objectionable amounts of sulfur and nitrogen oxides and particulates! While such thoughts may represent the best of all worlds, the nature of coal dictates that this is unlikely, and process for coal pretreatment, post-combustion treatment, and flue gas cleaning remain necessary.

The need to burn increasing amounts of coal and related materials mainly arises from the need to replace oil and natural gas as fuels for combustion in furnaces. In addition to satisfying normal economic constraints, existing and new combustion processes must be able to burn low-grade fuels and satisfy local environmental requirements. Some requirements cause conflict, e.g., the combustion of low-grade fuels can be relatively costly due to reduced plant capacity and efficiency, and the costs incurred in controlling pollution levels.

In order to improve existing combustors and to develop new combustion techniques, it is necessary to gain an improved understanding of the complex processes that occur in and around particles during combustion. For example, better insights are needed into ignition stability, the attainment of rapid burnout of particles, the nature of the various homogeneous and heterogeneous processes involved in generating gaseous pollutants and the routes by which inorganic constituents of coals are converted into ash.

Thus, there are three major classes of issues in coal combustion: (i) conversion issues, (ii) operational issues, and (iii) environmental issues.

The various steps involved in combustion are (i) preparation, (ii) conversion of coal to power which is influenced by char formation and by ash production, and (iii) char combustion. The issues pertinent to coal preparation for combustion require information on the physical properties of coal such as density, hardness, and other mechanical properties of coal (Chapter 6).

In all major coal conversion processes, coal undergoes a devolatilization stage while it is heated to the reaction temperature, hence the importance of the volatile matter test in determining coal properties (Chapter 5). Devolatilization is an important initial step in virtually all commercial coal applications such as combustion (Chen and Niksa, 1992a; Chen *et al.*, 1992). In coal combustion devolatilization sets the flame front location; it also has a strong influence on product distribution (gas, liquid, tar, and char formation), soot production, and fuel-bound nitrogen and sulfur evolution.

Furthermore, coals of different types exhibit wide variations in their devolatilization behavior because of different extents of coalification. The degree of aromatization in the coal structure increases with the increase in the rank of the coal (Speight, 2013). In addition, information reacted to maceral composition of coal (Chapter 2) is of importance on the devolatilization during initial stages of combustion and for conversion of any char formed. The primary physical changes that occur when any particular coal is heated (in the initial stages of combustion) depend on the melting and decomposition behavior of coal. Variables that influence devolatilization rates include temperature, residence time, pressure, particle size, and coal type, and final temperature is possibly the most important issue (Saxena, 1990; Gupta, 2007; Speight, 2013, 2020).

The physical and mechanical structure of coal (such as pore structure, surface area, and particle size) (Chapter 6) is important in understanding and modeling the combustion process. In fact, the proper coal sizing is one of the key measures to ensure efficient combustion. Proper coal sizing, with specific relevance to the type of firing system, helps towards even burning, reduced ash losses and better combustion efficiency. Coal is reduced in size by crushing and pulverizing. Pre-crushed coal can be economical for smaller units, especially those which are stoker fired. In a coal handling system, crushing is limited to a top size of 4 to 6 mm. The devices most commonly used for crushing are the rotary breaker, the roll crusher, and the hammer mill.

Also, it is necessary to screen the coal before crushing, so that only oversized coal is fed to the crusher. This helps to reduce power consumption in the crusher. Recommended practices in coal crushing are (i) incorporation of a screen to separate fines and small particles to avoid extra fine generation in crushing, (ii) incorporation of a magnetic separator to separate iron pieces in coal, which may damage the crusher.

However, the fines in coal present problems in combustion on account of segregation effects. Segregation of fines from larger coal pieces can be reduced to a great extent by conditioning coal with water. Water helps fine particles to stick to the bigger lumps due to surface tension of the moisture, thus stopping fines from falling through grate bars or being carried away by the furnace draft. While tempering the coal, care should be taken to ensure that moisture addition is uniform and preferably done in a moving or falling stream of coal. If the percentage of fines in the coal is high, wetting of coal can decrease the percentage of unburnt carbon and the excess air level required to be supplied for combustion.

The conversion characteristics such as the calorific value, volatile and ash content, and other physical property values provided by the bulk analysis of coal (Chapter 5) are required for a better design of a combustion system, and char burnout is critical in assessing the overall efficiency of the conversion process. The char burnout during the coal combustion process largely depends on the reactivity of char, and therefore, the accurate prediction of char behavior is of paramount importance.

The petrography (maceral composition) (Chapter 2) and the presence of mineral matter in coal (leading to the formation of mineral ash) (Chapter 5) have a significant influence on the character of the resulting char or ash. The most important issues related to char and/or ash are related to (i) movement of char and/or ash through the coal-fired boiler and (ii) deposition of char and/or ash on various surfaces. These characteristics of char/ash depend on the structure of char/ash and its thermal and mechanical properties, which in turn are functions of the maceral composition and the mineral matter present in the parent coal (Chapters 2, 5).

Flame stability, erosion, slagging, and fouling characteristics are important aspects in the determination of the efficiency of the combustion. Flame instability and slagging/fouling can lead to excessive downtimes and, therefore, operational losses. Fouling and slagging occur because of the deposition of ash on the surface of coal-fired boilers. The molten ash then sinters and forms a deposit that is difficult to remove. Elemental information and mineral interactions of the parent coal provide important information regarding the propensity of a particular coal to form deposits. Analysis such as ash fusion temperature (Chapter 6) assists in understanding the process of slagging/fouling.

Instability in the flame can also lead to non-uniform heat flux and inefficient combustion. The volatile matter analytical data (Chapter 5) are used as a design parameter of the coal-fired boiler to obtain a continuous flame. However, it must be recognized that the volatile matter determined in this manner is not the same as is evolved in a coal-fired boiler. The estimate of volatile matter in a coal-fired boiler at high flame temperatures is obtained by experiments in a drop-tube furnace from which it is possible to estimate the volatile matter for a given time-temperature history based on some coal composition parameters (Table 7.1) which are based on the bulk properties of coal (Gupta, 2007).

The environmental issues in coal combustion can be categorized into gaseous emissions such as oxides of nitrogen and oxides, fine particulates, and greenhouse gas emissions (Chapters 12, 13, 14). The greenhouse gas emission is more related to the efficient use of coal rather than the properties of coal. The formation of nitrogen oxides during coal combustion is very much dependent upon the nature of the coal and the combustion system.

For example, in fluidized bed combustion, coal devolatilization occurs in less than 1 second, while the oxidation of the char may last for several minutes (Valentim *et al.*, 2006). During coal combustion, the fuel-based nitrogen is divided between the volatiles, the tar, and the char, and the availability of oxygen is mainly responsible for the reduced release of nitrogen oxides. As a result, and due to the low operation temperatures used in fluidized bed combustor, almost all oxides of nitrogen are formed from the reaction of coal-nitrogen with oxygen, leading to the formation of nitrogen oxides (Molina *et al.*, 2000). However, there are also variations in nitrogen oxide release originating from coal properties, such as rank, maceral composition, and mineral matter (Shimizu *et al.*, 1992; Gavin and Dorrington, 1993; Pels *et al.*, 1993; Wang *et al.*, 1994).

The nitrogen present in coal is almost exclusively associated with the organic matter (Burchill and Welch, 1989; Speight 2013, 2015). Furthermore, the amount of nitrogen in coal decreases with petrographic composition of the coal in the order: vitrinite>semifusinite>inertinite (Hindmarsh *et al.*, 1994). Of this nitrogen in various coals and chars, the relative

Table 7.1 Typical properties of the various types of coal.

Sulfur content in Coal
• Anthracite: 0.6-0.77% w/w
• Bituminous coal: 0.7-4.0% w/w
• Lignite: 0.4% w/w
Moisture content
• Anthracite: 2.8-16.3% w/w
• Bituminous coal: 2.2-15.9% w/w
• Lignite: 39% w/w
Fixed carbon
• Anthracite: 80.5-85.7% w/w
• Bituminous coal : 44.9-78.2% w/w
• Lignite: 31.4% w/w
Bulk density
• Anthracite: 50-58 (lb/ft^3), 800-929 (kg/m^3)
• Bituminous coal: 42-57 (lb/ft^3), 673-913 (kg/m^3)
• Lignite: 40-54 (lb/ft^3), 641-865 (kg/m^3)
Mineral matter content (as mineral ash)
• Anthracite: 9.7-20.2% w/w
• Bituminous coal: 3.3-11.7% w/w
• Lignite: 4.2% w/w

amounts of the various nitrogen functionalities in coal have been estimated as typically pyrrole-type (50 to 80%), pyridine-type (20 to 40%) and quaternary nitrogen (0 to 20%), as well as minor amounts of amino-type nitrogen in low rank coal (Hindmarsh *et al.*, 1994; Molina *et al.*, 2000).

Furthermore, the maceral composition and the microlithotype composition of coal determines the char morphology, the nitrogen oxide emissions, char reactivity, and surface area, which also have a direct influence on nitrogen oxide nitrogen oxide emissions and coal properties are also important aspects of the oxidation and reduction of nitrogen in the coal and nitrogen in the char (Shimizu *et al.*, 1992; Brown and Thomas, 1993; Crelling *et al.*, 1993; Gavin and Dorrington, 1993; Pels *et al.*, 1993; Gonzales de Andres and Thomas, 1994; Wang *et al.*, 1994; Harding *et al.*, 1996; Varey *et al.*, 1996; Xie *et al.*, 2001). Thus, with better understanding of the issue of emissions of oxides of nitrogen, methods of control are available in place (Chapters 12, 14).

With the increasing concern related to the environmental impact of hazardous trace elements from coal combustion, attention has been focused to the levels of these trace elements present in waste products released into the environment. The 1990 amendments to the Clean Air Act identified 11 trace elements commonly found in coal as potentially hazardous air pollutants.

The mineral matter and the maceral composition of coal also have a significant influence on the fine particle emissions from the combustion of coal. The proportion and size distribution of fine and submicron particles influence the distribution of these trace elements into fly ash, coarse ash, and those escaping into the environment. The formation of fine particles depends both on the inherent size distribution, the types of minerals, and the char character (Gupta *et al.*, 2000). Thus, an accurate determination of mineral and maceral composition of coal is required to predict the overall impact of coal combustion on the environment.

7.2 General Aspects

While the combustion of any organic material is dependent upon an oxygen source (Baukal, 1998), there are certain aspects of coal combustion that need to be considered (Glassman and Yetter, 2008).

Coal is an organic fuel and, when heated, the organic matter of coal is pyrolyzed, and then evolves as volatile. The remaining solid is a mixture of carbon and mineral matter (often referred to as *char*). The combustion of coal is primarily the combustion of carbon as well as the volatile matter. However, the coal combustion process involves three basic stages: (i) the release of the volatile matter resulting from the heating of coal, (ii) combustion of the released volatile matter and (iii) combustion of the remaining char. Depending upon specific combustion conditions, the combustion of the volatile matter and coal char may take place simultaneously, sequentially, or with some overlapping.

7.2.1 Coal Devolatilization and Combustion of Volatile Matter

The release of the volatile matter resulting from the heating of coal is part of the *devolatilization stage* during which moisture present in the coal will evolve as the temperature of coal rises (Chen *et al.*, 1992; Chen and Niksa, 1992a). As the temperature increases further, gases and higher-boiling products are emitted. The yield of the volatile materials can vary from a few percent up to 70 to 80% w/w of the total coal, but varying with the coal type and the heating conditions.

Coal pyrolysis leading to coal devolatilization is the first step in coal combustion. Although coal pyrolysis occurs on a time scale (up to several hundred milliseconds) much shorter than the subsequent char oxidation process (0.5 to 2 seconds for pulverized coal), it has a major impact on the overall combustion efficiency and pollutant production in coal-fired power plants. Coal pyrolysis has been studied extensively for more than a century. However, no general mechanism is universally accepted, nor can all observations be accounted for by any single model (Chen *et al.*, 1996). This is probably because of the numerous chemical and transport processes that occur simultaneously in the coal flame, making them difficult to distinguish and interpret. In addition, coal pyrolysis is sensitive to specific properties of coal type, which vary substantially among coal rank. Furthermore, the observed phenomena during coal pyrolysis are not only determined by the chemical structure of the coal, but are also influenced by physical properties (particle size, moisture content) and operating conditions.

Thus, depending on the size, type, and temperature condition of coal, devolatilization takes a few milliseconds or several minutes to complete. A variety of products including tar, hydrocarbon gases, and the like are produced during coal devolatilization. These products are combustible. They react with oxygen in the vicinity of coal particles and form bright diffusion flames.

In fact, in pulverized coal combustion, coal is injected in a dense stream conveyed in a jet of air. Initial heating is mainly by hot gases recirculated into the jet. Particles in the center of the jet are heated relatively slowly; those on the edge are heated rapidly and in the presence of high levels of oxygen. The amount of volatile matter produced the nature of the pore structure, and the size of the resulting char particles depend on the rate of heating and on the level of oxygen. During fluidized-bed combustion the injected fuel particles are heated rapidly, with much of the heating taking place by direct particle-to-particle contact. Over the temperature range 400 to 1000°C (750 to 1830°F) in the absence of oxygen, coking and non-coking bituminous coals, subbituminous coals, and lignite tend to show some degree of plastic behavior and adhesion to other particles.

Volatile tar is also produced during the initial stages of the thermal decomposition of coal and evolution of the tar from the coal is believed to be diffusion-controlled. However, tar yields vary with heating conditions and secondary reactions influence the composition and behavior of the primary tar. In addition, low heating rates allow secondary char-forming reactions of tars to take place within the coal particle while high heating rates introduce secondary cracking reactions and ring condensation reactions of the constituents of the primary tars. In fact, secondary reactions play an important role in the overall coal combustion process. However, most of the previous research in the field has been devoted to primary pyrolysis. Drying, which is also part of the devolatilization process, is also assumed to be diffusion limited and is described simply through vaporization of moisture from the surface of the coal particle.

In summary, the physical characteristics of coal devolatilizing in a given set of conditions vary significantly with chemical characteristics of the parent coal. In fact, for a particular coal, the physical characteristics during devolatilization are a function of the conditions of heating. The observed data imply that behavior of coal at the devolatilization stage is dictated by the chemical nature of the parent coal and the behavior of the coal under the particular thermal conditions.

7.2.2 Char Combustion

Once devolatilization of coal is complete, a porous char particle remains and is consumed through surface reactions of oxidizing species such as oxygen. The presence of pores in the char particle allows for penetration of reactant species into the particle and therefore for much greater surface area for reactions than is associated with the external surface of the particle. Char particles often have porosities or void fractions of greater than 0.3, depending on the amount of volatiles in the original particle and the extent of particle swelling or shrinkage during devolatilization.

Chemically, when coal is thermally decomposed, as is the case during the initial stages of combustion (or gasification), the predominant mechanism is the detachment or chemical formation of components of a volatile from the organic core of the *coal matrix* which then escape from the solid non-volatile coal matrix under varying thermal circumstances. If the volatile components are able to escape from the matrix as rapidly as they are formed, the overall rate of the thermal decomposition will be controlled by the chemical reaction which results in the formation of the volatile species.

When diffusional escape of volatile species takes a finite time (i.e., the escape is not *immediate*) which is long compared with the reaction time, the diffusion process determines the rate of thermal decomposition. For large particles or at higher heating rates (where a temperature gradient is generated within the particle) the rate of thermal decomposition rate is determined by the rate of heat input into the interior of the particle and not by the reaction rate or the rate of diffusional escape.

The residual char particles, enriched in carbon, containing most of the mineral matter of the original coal and some surplus nitrogen as well as sulfur, are often spherical (especially for small particles). They are usually very porous and have many cracks, which result from the escape of gaseous products and heat stress. The characteristics of the char depend on the type and size of the original coal as well as on the heating conditions.

The residual char particle can be burned out under an oxidizing condition at sufficiently high temperature. The reaction between the char and oxygen is a gas-solid heterogeneous reaction. The gaseous oxygen diffuses to, and into, the char particle, being absorbed, and reacting on the pore surface of the particle (Yang, 1993). This heterogeneous process is often much slower than the devolatilization process, requiring seconds to several minutes or more. The rate of this process varies with coal types, temperature, pressure, char characteristics (the size, surface area, etc.), and oxidizer concentration.

7.3 Chemistry and Physics

Coal combustion technology is a mature technology with potential for increasing the efficiency in progress of advanced materials. In the short term and medium term, it will play an important role in the world energy section. In the long term, the role of coal may be reduced but coal will be difficult to replace.

The combustion of a carbonaceous feedstock such as coal occurs, chemically, by initiation and propagation of a self-supporting exothermic (heat-producing) reaction. The physical processes involved in combustion are principally those which involve the transport of matter and the transport of energy. The conduction of heat, the diffusion of chemical species, and the bulk flow of the gas all follow from the release of chemical energy in an exothermic reaction. Thus, combustion phenomena arise from the interaction of chemical and physical processes.

In more simple chemical terms, the first requirement, somewhat difficult with coal because of its molecular complexity, is that the overall stoichiometry of the reaction must always be established. Thus for simple chemical purposes, coal is usually represented by carbon which can react with oxygen in two ways, producing either carbon monoxide or carbon dioxide.

$$2C_{coal} + O_2 \rightarrow 2CO$$

$$C_{coal} + O_2 \rightarrow CO_2$$

In direct combustion, coal is burned (i.e., the carbon and hydrogen in the coal are oxidized into carbon dioxide and water) to convert the chemical energy of the coal into thermal energy, after which the sensible heat in the products of combustion then can be converted into steam that can be external work or directly into shaft horsepower (e.g., in a gas turbine). In fact, the combustion process actually represents a means of achieving the complete oxidation of coal in which the elements occurring in coal (carbon, hydrogen, nitrogen, and sulfur) are converted to their respective oxides:

$$C_{coal} + O_2 \rightarrow CO_2$$

$$H_{coal} + O_2 \rightarrow H_2O$$

$$C_{coal} + H_2O \rightarrow CO + H_2$$

$$N_{coal} + O_2 \rightarrow NOx$$

$$S_{coal} + O_2 \rightarrow SOx$$

On a more formal basis (or informal basis, because of the complex and unknown chemical structure of coal), the combustion of coal may be simply represented as the staged oxidation of coal carbon to carbon dioxide with any reactions of hydrogen and the other elements in the coal being considered to be of secondary importance.

$$C_{coal} + O_2 \rightarrow 2CO$$

$$2CO + O_2 \rightarrow 2CO_2$$

However, it is the formation of oxides of nitrogen and sulfur (in addition to the carbon dioxide) that cause serious environmental problems and require removal from any product gas streams.

The stoichiometric reaction equations are quite simple but there is a confusing variation of hypotheses related to the sequential reaction mechanism which is caused by the heterogeneous nature (solid and gaseous phases) of the reaction. But for the purposes of this text, the chemistry will remain simple as shown in the above equations. Other types of combustion systems may be rate-controlled due to the onset of the Boudouard reaction.

$$CO_2 + C \rightarrow 2CO$$

In more general terms, the combustion of carbonaceous materials (which contain hydrogen and other elements as well as carbon) involves a wide variety of reactions between the many reactants, intermediates, and products (Table 7.2). The reactions occur simultaneously and consecutively (in both forward and reverse directions) and may at times approach a condition of equilibrium. Furthermore, there is a change in the physical and chemical structure of the fuel particle as it burns.

Table 7.2 Thermodynamics of coal combustion.

$C(s) + O_2(g) \rightarrow CO_2(g)$	–169,290 Btu/lb	–94.4 kcal/kg
$2\ C(s) + O_2(g) \rightarrow 2\ CO\ (g)$	–95,100 Btu/lb	–52.8 kcal/kg
$C(s) + CO_2(g) \rightarrow 2\ CO\ (g)$	–74,200 Btu/lb	–41.2 kcal/kg
$2\ CO(g) + O_2(g) \rightarrow 2\ CO\ (g)$	–243,490 Btu/lb	–135.3 kcal/kg
$2\ H_2(g) + O_2(g) \rightarrow 2\ H_2O\ (g)$	–208,070 Btu/lb	–115.6 kcal/kg
$C(s) + H_2O(g) \rightarrow CO(g) + H_2\ (g)$	+56,490 Btu/lb	+31.4 kcal/kg
$C(s) + 2\ H_2O(g) \rightarrow CO_2 + 2\ H_2\ (g)$	+38,780 Btu/lb	+21.5 kcal/kg
$CO(g) + H_2O(g) \rightarrow CO_2(g) + H_2\ (g)$	–17,710 Btu/lb	–9.8 kcal/kg

(g): gaseous state; (s): solid state.
Exothermic reaction: illustrated by a negative heat of reaction.
Endothermic reaction: illustrated by a positive heat of reaction.

The complex nature of coal as a molecular entity (Berkowitz, 1979; Meyers, 1981; Hessley *et al.*, 1986; Hessley, 1990; Speight, 2013) has resulted in the chemical explanations of coal combustion being confined to the carbon in the system and, to a much lesser extent with only passing acknowledgement of the hydrogen and other elements, but it must be recognized that the system is extremely complex and that the heteroatoms (nitrogen, oxygen, and sulfur) can exert an influence on the combustion and it is this influence that can cause serious environmental events.

For example, the conversion of the coal-bound sulfur and nitrogen (in addition to any reactions or aerial nitrogen with aerial oxygen under the prevailing conditions) to their respective oxides during combustion is a major environmental issue.

$$S_{coal} + O_2 \rightarrow SO_2$$

$$2SO_2 + O_2 \rightarrow 2SO_3$$

$$N_{coal} + O_2 \rightarrow 2NO$$

$$2NO + O_2 \rightarrow 2NO_2$$

$$N_{coal} + O_2 \rightarrow NO_2$$

The release of the sulfur and nitrogen from the coal is not as simple as represented here and the equations are simplifications of what are, presumably, much more complex processes (Crelling *et al.*, 1993; Gavin and Dorrington, 1993).

The sulfur dioxide that escapes into the atmosphere is either deposited locally or is converted to sulfurous acid and/or sulfuric acid by reaction with moisture in the atmosphere.

$$SO_2 + H_2O \rightarrow H_2SO_3$$

$$2SO_2 + O_2 \rightarrow 2SO_3$$

$$SO_3 + H_2O \rightarrow H_2SO_4$$

Thus:

$$2SO_2 + O_2 + 2H_2O \rightarrow 2H_2SO_4$$

Nitrogen oxides (Morrison, 1980; Crelling *et al.*, 1993) also contribute to the formation and occurrence of acid rain, in similar manner to the production of acids from the sulfur oxides, yielding nitrous and nitric acids.

$$NO + H_2O \rightarrow H_2NO_3$$

$$2NO + O_2 \rightarrow 2NO_2$$

$$NO_2 + H_2O \rightarrow HNO_3$$

Thus:

$$4NO_2 + O_2 + 2H_2O \rightarrow 4HNO_3$$

In addition to causing objectionable stack emissions, coal ash (Table 7.3) and volatile inorganic material generated by thermal alteration of mineral matter in coal (Figure 7.1) will adversely affect heat transfer processes by fouling the heat-absorbing and radiating surfaces and will also influence the performance of the combustion system by causing corrosion, and operating procedures must therefore provide for effective countering of all these hazards.

In spite of the simplified representation of coal combustion using simple equations (above), the processes involved in the pyrolysis and combustion of coal are complex.

Table 7.3 General ranges for the composition of coal ash (Speight, 2013).

Silica (SiO2): 40–90%;
Aluminum oxide (Al_2O_3): 20–60%;
Iron (ferric) oxide (Fe_2O_3): 5–25%;
Calcium oxide (CaO): 1–15%;
Magnesium oxide (MgO): 0.5–4%;
Sodium oxide (Na_2O) plus potassium oxide (K_2O): 1–4%

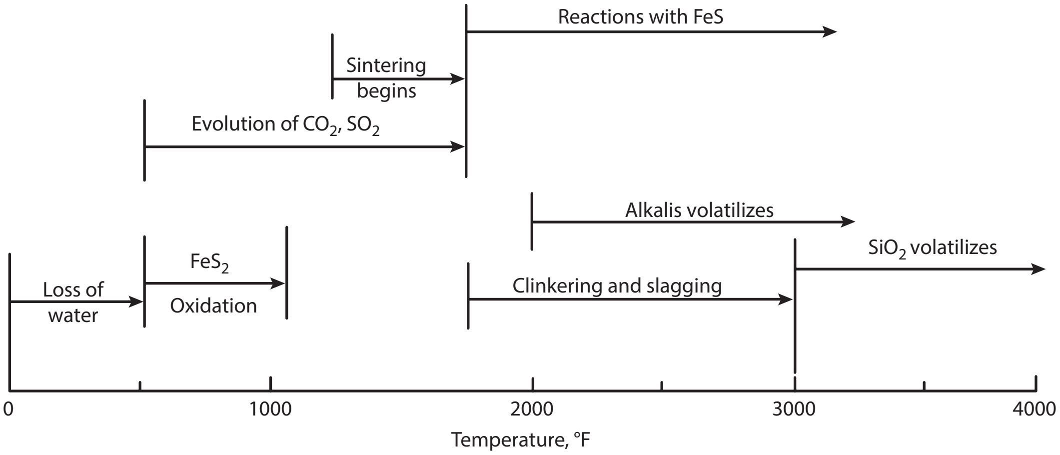

Figure 7.1 Changes occurring to the mineral matter during coal combustion (Reid, 1971).

Depending on the type of coal, the particle size, the relative rates of heating, decomposition, and oxygen transfer, volatile evolution, and combustion of the solid may occur in separate stages or simultaneously.

7.3.1 Influence of Coal Quality

Coal quality (coal rank) is now generally recognized as having an impact, often significant, on combustion, especially on many areas of power plant operation (Parsons *et al.*, 1987; Rajan and Raghavan, 1989; Bend *et al.*, 1992).

The parameters of rank, mineral matter content (leading to production of mineral ash), sulfur content, and moisture content are regarded as determining factors in combustion of coal as it relates to both heating value and ease of reaction. Thus, lower-rank coals (though having lower heat content) may be more *reactive* than higher-rank coals, so implying that rank does not influence coal combustibility. At the same time, anthracites (with a low volatile matter content) are generally more difficult to burn than bituminous coals. High moisture content is associated with a high unit surface area of the coal (especially for retained moisture after drying) and coals also become harder to grind as the percentage volatiles decreases).

Lignite usually serves as the more extreme example of low-grade fuel of high moisture content and the problems encountered in lignite combustion are often applicable to other systems (Nowacki, 1980). Lignite gives up moisture more slowly than higher-rank (harder) coal but the higher volatile content of lignite tends to offset the effect of high moisture. For the combustion of pulverized material, it appears essential to dry lignite and brown coal to approximately 15 to 20% w/w moisture; the lowest possible mineral matter and moisture contents are desired as well as high grindability, high heat content, and high fusion temperature.

Due to its low volatile matter content and non-clinkering characteristics, anthracite coal is primarily used in medium-sized industrial and institutional stoker boilers equipped with stationary or traveling grates. Anthracite coal is not used in spreader stokers because of its low volatile matter content and relatively high ignition temperature. This fuel may also be burned in pulverized coal-fired (PC-fired) units, but, due to ignition difficulties, this practice is limited to only a few plants in eastern Pennsylvania.

Anthracite coal has also been widely used in hand-fired furnaces. Culm has been combusted primarily in fluidized bed combustion (FBC) boilers because of its high ash content and low heating value.

Combustion of anthracite coal on a traveling grate is characterized by a coal bed three-to-five inches in depth and a high blast of under-fire air at the rear or dumping end of the grate. This high blast of air lifts incandescent fuel particles and combustion gases from the grate and reflects the particles against a long rear arch over the grate towards the front of the fuel bed where fresh or fuel enters. This special furnace arch design is required to assist in the ignition of the green fuel.

A second type of stoker boiler used to burn anthracite coal is the underfeed stoker. Various types of underfeed stokers are used in industrial boiler applications but the most common for anthracite coal firing is the single-retort side-dump stoker with stationary grates. In this unit, coal is fed intermittently to the fuel bed by a ram. In small units the coal is fed continuously by a screw. Feed coal is pushed through the retort and upward towards the tuyere blocks. Air is supplied through the tuyere blocks on each side of the retort and through openings in the side grates. Over-fire air (OFA) is commonly used with underfeed stokers to provide combustion air and turbulence in the flame zone directly above the active fuel bed.

In pulverized coal-fired boilers, the fuel is pulverized to the consistency of powder and pneumatically injected through burners into the furnace. Injected coal particles burn in suspension within the furnace region of the boiler. Hot flue gases rise from the furnace and provide heat exchange with boiler tubes in the walls and upper regions of the boiler. In general, pulverized coal-fired boilers operate either in a wet-bottom or dry-bottom mode; because of its high ash fusion temperature, anthracite coal is burned in dry-bottom furnaces.

For anthracite culm, combustion in conventional boiler systems is difficult due to the high mineral matter content of the fuel as well as the high moisture content and the low heating value. However, the burning of culm in a fluidized-bed combustor has been proven – the system consisted of inert particles (e.g., rock and ash) through which air is blown so that the bed behaves as a fluid. Anthracite coal enters in the space above the bed and burns in the bed. Fluidized beds can handle fuels with moisture contents approaching 70% (total basis) because of the large thermal mass represented by the hot inert bed particles. Fluidized beds can also handle fuels with ash contents as high as 75%. Heat released by combustion is transferred to in-bed steam-generating tubes. Limestone may be added to the bed to capture sulfur dioxide SO2 formed by combustion of fuel.

Coal quality has a particular influence on pulverized coal-fired units – affecting plant heat rates and boiler size. There is a significant cost impact for designing a pulverized coal-fired boiler to burn a subbituminous coal or lignite compared to lower-moisture, lower-ash, and lower-alkali bituminous coal. This is primarily because the pulverized coal-fired furnace heat transfer area must be increased in order to reduce furnace exit gas temperature as the ash softening temperature drops and thereby prevent slagging of the convective pass. Subbituminous coal and lignite generally have alkaline ashes with low ash softening temperatures, which require large pulverized coal-fired furnaces.

High moisture content and high mineral matter content also reduce boiler efficiency. Concern over corrosion in the cold end of the air heater and downstream ductwork (due to condensation of sulfur trioxide as sulfuric acid) sets a minimum value on the permissible boiler outlet temperature when higher sulfur coals are used, and thereby reduces the achievable boiler efficiency. Lower air heater exit temperatures can typically be achieved in plants designed for higher-quality, lower-sulfur coals, where sulfur trioxide levels and their resulting dew points are much lower. A 10°C (50°F) increase in air heater exit temperature reduces heat rate by approximately 0.2% (Booras and Holt, 2004).

Coal mineral matter constituents can have a major impact on boiler design and operation. Pulverized coal-fired boilers are designed to utilize coals with either low or high ash fusion temperatures. For low ash fusion temperatures, the ash constituents are in molten form (slag) at furnace temperatures (*wet-bottom boilers*). The molten slag must be cooled, usually in a water bath, then crushed and sluiced to disposal or for recovery as a by-product. When ash fusion temperatures are high, the bottom ash exits the bottom of the boiler in solid form (*dry-bottom boilers*), where it enters a water bath and is crushed and sluiced to disposal or storage. Over the past 30 years, many boilers designed for high-sulfur, low ash fusion coals have been converted to lower-sulfur coals due to the Clean Air Act. Many of these low-sulfur coals also have high ash fusion temperatures. In order to utilize these coals in wet-bottom boilers, operators have installed fluxing systems, which add a small percentage of materials such as limestone and iron oxide that chemically change the make-up of the ash, enough to lower the ash fusion temperature and allow it to melt at furnace temperatures. Blending coals of various sulfur and ash contents has become commonplace in the industry as a way to optimize boiler performance and environmental compliance (Booras and Holt, 2004).

Finally, since coal quality and coal blend quality can be affected by oxidation or weathering (Joseph and Mahajan, 1991; Nugroho *et al.*, 2000), the question is raised related to the effects of oxidation and weathering on combustion and whether oxidized or weathered coal could maintain a self-sustaining flame in an industrial boiler in a power plant scenario. The inhibition of volatile matter release due to changes in the char morphology, because of reduced thermoplastic nature of the coal – as a result of the oxidation/weathering – suggests that this may not be the case (Bend *et al.*, 1991).

One option for managing coal quality for power generation is to blend one particular coal with one or more coals until a satisfactory feedstock is achieved. This is similar to current crude oil refinery practice where a refinery typically accepts a blend of various crude oils and operates on the basis of *average* feedstock composition. The days of one crude oil or one coal as a feedstock to a refinery or power plant, respectively, are no longer with us. For example, in cases where the coal feedstock has excessive amounts of fine material (Chapter 3), it may be advisable to blend the predominantly lumped coal with lots containing excessive fines. Coal blending may thus help to limit the extent of fines in coal being fired to not more than 25%. Blending of different qualities of coal may also help to supply a uniform coal feed to the boiler.

Finally, whatever the coal types used for a coal-fired boiler; proper coal sizing is one of the key measures to ensure efficient combustion. Proper coal sizing of the coal feedstock (Chapter 3), with specific relevance to the type of firing system, helps towards even burning and higher combustion efficiency.

7.3.2 Mechanism

The combustion of most solid fuels involves two major steps: (i) the thermal decomposition – pyrolysis and devolatilization – that occurs during the initial heating, accompanied by drastic physical and chemical changes which usually involve the particle becoming plastic then re-hardening, and (ii) the subsequent combustion of the porous solid residue (char) from the first step. The burning rate of the solid depends in part on the size of the char particle and the nature of its pore structure. These physical properties, together with important chemical properties, are affected by changes during the first step. The first step is rapid, the second is slow.

The precise chemical nature of the coal combustion process is difficult to resolve but can be generally formulated as two processes: (i) the degradation of hydrogen, and (ii) the degradation of carbon (Barnard and Bradley, 1985). It is also necessary to understand the surface chemistry involved in the burning process and progress is being made in this direction. However, coal being a heterogeneous solid adds an increasingly difficult dimension to the combustion chemistry and physics; combustion actually occurs on the surface with the oxidant being adsorbed there prior to reaction. However, the initial reaction at the coal surface is not necessarily the rate-determining step; the process involves a sequence of reactions, any one of which may control the rate.

The initial step is the transfer of reactant (i.e., oxygen) through the layer of gas adjacent to the surface of the particle. The reactant is then adsorbed and reacts with the solid after which the gaseous products diffuse away from the surface. If the solid is porous, much of the available surface can only be reached by passage of the oxidant along the relatively narrow pores and this may be a rate controlling step. Rate control may also be exercised by: (a) adsorption and chemical reaction, which are considered as chemical reaction control; and (b) pore diffusion, by which the products diffuse away from the surface. This latter phenomenon is seldom a rate-controlling step.

In general, rate control will occur if the surface reaction is slow compared with the diffusion processes; whilst diffusion shows a lesser temperature dependence, reaction control predominates at low temperatures but diffusion control is usually more important at higher temperatures. In fact on a chemical basis, hydrogen degradation outweighs the slower-starting carbon degradation in the early, or initial, stage of combustion. But, at the same time, the carbon monoxide/carbon dioxide ratio is decreased.

After the initial stages of combustion, during which volatile material is evolved (which is also combustible), a nonvolatile carbonaceous residue (coke, char) remains, which can comprise up to 90% w/w of the original mass of the coal. During the combustion of the coke, three different zones (regimes) of combustion can be distinguished (Barnard and Bradley, 1985).

In the first zone, the rate of diffusion to and away from the surface is rapid compared with the rate of the surface reaction; such phenomena are observed at low temperatures. At much higher temperatures, the rate at which oxygen molecules are transported from the bulk gas to the external surface is slow enough to be rate controlling and the observed rate can be equated to the molar flux of oxygen to unit area of external surface. Finally, the oxygen transport to the external surface is rapid but diffusion into the pores before reaction is relatively slow (Mulcahy, 1978).

In practice there are considerable differences between the reactivity of different cokes, some of which can be assigned to variations in pore structure and others to the presence of impurities (such as alkali metal salts) which have a pronounced catalytic effect on the surface reaction. Consequently the temperature ranges corresponding to the three zones differ and are not constant for different cokes/chars (Mulcahy, 1978).

There are alternate ways to consider the mechanism of coal combustion and there is a variety of models proposed for this purpose (Jamaluddin *et al.*, 1987). For example, in a simple model for the combustion process, the initial step is assumed to be (i) devolatilization, (ii) ignition, and (iii) rapid burning of the volatile matter or products relative to the char. But the actual mechanism is considered to be somewhat more complex. The process is thought to consist of (i) diffusion of reactive gases to the carbon surface, (ii) adsorption, (iii) formation of transitory complexes, and (iv) desorption of the products.

However, the overall reaction mechanism for a devolatilized coal char particle is believed to be (i) transport of oxygen to the surface of the particle, (ii) reaction with the surface, and (iii) transport of the products away from the surface. As the pressure of the system is increased, the mechanism tends toward diffusion control. This is due to the mass transfer or diffusion rate coefficient being inversely proportional to pressure. The overall rate, however, will increase due to the increased oxygen partial pressure at the higher pressures.

The complexity of coal as a molecular entity (Speight, 2013) has resulted in treatments of coal combustion being confined to the carbon in the system and, to a lesser extent, the hydrogen, but it must be recognized that the system is extremely complex. Even with this simplification, there are several principal reactions that are considered to be an integral part of the overall combustion of coal (Table 7.2).

In summary, it is more appropriate to consider the combustion of coal (which contains carbon, hydrogen, nitrogen, oxygen, and sulfur) as involving a variety of reactions between (i) the reactants, (ii) the intermediate products, often referred to as the transient, species, and (iii) the products. The reactions can occur both simultaneously and consecutively (in both forward and reverse directions) and may even approach steady state (equilibrium) conditions. And there is a change in the physical and chemical structure of the fuel particle during the process.

7.3.3 Ignition

The lowest temperature at which coal can be ignited is referred to as the *ignition temperature* which, for a specific coal, is variable under different conditions because of the complexity of the ignition process.

The ignition of coal particles is an important preliminary step in the coal combustion process, which are important in designing the coal combustor, controlling combustion process efficiently (Chapters 7, 8) as well as estimating the spontaneous ignition and spontaneous combustion of coal stockpiles (Chapter 4). Thus, studies of the mechanism of ignition of coal particles has been instrumental in classifying ignition into three types: (i) homogeneous ignition, or the ignition of the volatile matter released from coal, (ii) heterogeneous ignition, or the ignition of the coal particle surface, and (iii) hetero-homogeneous ignition, which results from simultaneous ignition of the volatile matter and the coal particle surface (Chen *et al.*, 1996).

Furthermore, the ignition of coal has been described as occurring in just a few hundredths of a second with the onset of burning in less than half a second. The ignition distance has been observed to be on the order of 0.04 in (1 mm) with the carbon monoxide formed by reaction at the surface burning to carbon dioxide at distances close to the surface (0.5 to 4 mm). Water is evaporated in the initial stages and the ignition is propagated through a dry bed.

Other factors that influence the combustion process include (i) with increasing coal quality from lignite through bituminous coal to anthracite, the type of ignition changes from homogeneous ignition through heterogeneous-homogeneous ignition to heterogeneous ignition, and the ignition temperatures also increase, (ii) with increasing coal particle size coal can change from hetero-homogeneous to homogeneous ignition, and ignition of the char separates from that of the volatile matter and shifts to a higher temperature, whereas both types of ignition of anthracite coal are not affected by particle size. Furthermore, as the particle size increases, the rate of heating of the particle surface becomes slower than the rate of evolution of the volatile matter, and the combustion of the volatile matter prevents reaction of the char by screening the solid from access by oxygen (Chen, 1996).

Thus, for coal – depending on the coal type – the ignition temperatures are usually on the order 700°C (1290°F), but may be as low as 600°C (1110°F) or as high as 800°C (1470°F), depending on volatiles evolved. In fact, ignition temperatures depend on rank and generally range from 150 to 300°C (390 to 570°F) for lignite to 300 to 600°C (570 to 1110°F) for anthracite with some dependence on particle size being noted.

7.3.4 Surface Effects

The conditions under which coal ignites and the behavior during ignition will relate to (a) the structure of the volatilized coal and (b) the temperature in the coke-burning state. In addition, some consideration must be given to the manner in which the volatile matter is released. For example, the particle may burn by first releasing all the volatile matter which may burn simultaneously with the carbon. It does, however, seem unlikely that oxygen would reach the surface in the presence of volatiles and, thus, any oxygen attempting to diffuse through the volatiles layer would react instead.

Generally, it is possible to subdivide the overall reaction sequence into (a) those reactions which could conceivably occur at the surface of the coal char and (b) those reactions which may occur between the gaseous products themselves.

$$C + O_2 \rightarrow CO_2$$

$$2C + O_2 \rightarrow 2CO$$

$$C + CO_2 \rightarrow 2CO$$

$$C + H_2O \rightarrow CO + H_2$$

$$2CO + O_2 \rightarrow 2CO_2$$

$$2H_2 + O_2 \rightarrow 2H_2O$$

$$CO + H_2O \rightarrow CO_2 + H_2$$

During combustion, there are several possibilities for the mode in which the carbon reacts in the particle structure. The carbon may react only from the surface and reaction may proceed uniformly throughout the particle or, alternately, the particle may be regarded as a hollow sphere with burning occurring on both the outer and inner surfaces. In fact, there is evidence that coal particles do form hollow spheres during combustion and such spheres (cenospheres) are believed to be formed during volatilization while the coal is in the plastic stage, such as in the example of coking coals in an inert furnace atmosphere.

Measurements on coal particles of different sizes indicate that the burning times of both the volatiles and residue vary as the square of the initial particle diameter, which is in accord with the surface area proportionally. The porous structure of the char also exerts an effect on the burning operation (as does particle temperature) up to several hundred degrees above the gas temperature.

There are also indications that the adsorption of small molecules on coal, such as methanol, occurs by a site-specific mechanism (Ramesh *et al.*, 1992). In such cases, it appears that the adsorption occurs first at high-energy sites but with increasing adsorption the (methanol) adsorbate continues to bind to the surface rather than to other (polar) methanol molecules and there is evidence for both physical and chemical adsorption. In addition, at coverages below a monolayer, there appears to be an activation barrier to the adsorption process.

7.3.5 Reaction Rates

The combustion of coal involves two major steps: (i) the thermal decomposition (pyrolysis, devolatilization) that occurs during the initial heating, accompanied by drastic physical and chemical changes which usually involve the particle becoming plastic then re-hardening, and (ii) the subsequent combustion of the porous solid residue (char) from the first step. The burning rate of the solid depends in part on the size of the char particle (Figure 7.2) and the nature of the pore structure within the particle. These physical properties, together with other chemical and physical properties (Chapters 5, 6), are affected by changes during the first step. The first step is rapid, the second step is slow. In flames from pulverized coal the time for devolatilization to take place is of the order of 0.1 second and for char burn-out the time is 1 second. For particles burning in fluidized-bed combustors the corresponding orders may be as high as 10 seconds and 1,000 seconds, respectively (Smith, 1982), although lower burn-out times are often favored (Speight, 2013). Therefore the burning of the char has a major effect on the volume of the combustion chamber required to attain a given heat release.

Various combustion systems may be rate-controlled due to the occurrence/onset of the Boudouard reaction:

$$CO_2 + C \rightarrow 2CO$$

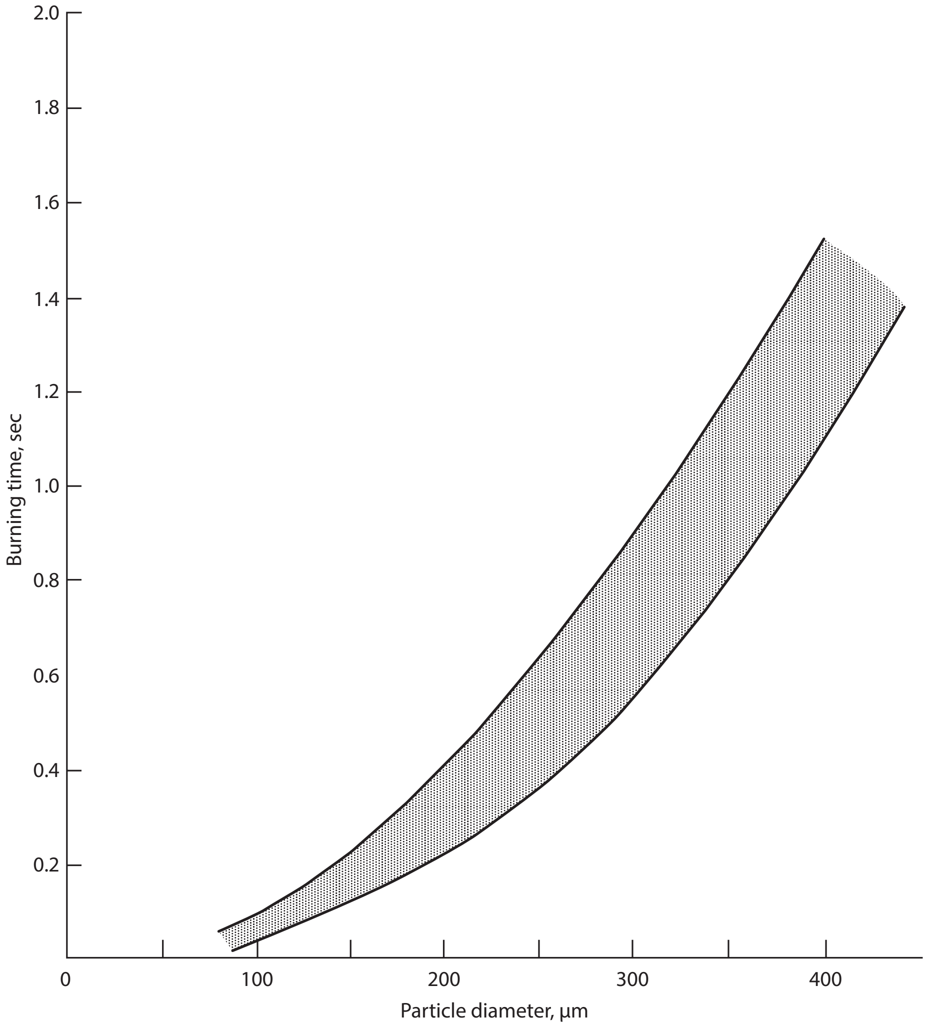

Figure 7.2 Relationship of burning time to particle size (Speight, 2013).

However, to accurately determine the reaction rates of coal combustion there is the need to acquire more information on the devolatilization process of coal, particularly on the devolatilization kinetics of different coal types and coal materials at sizes appropriate to pulverized fuel combustors fluidized bed combustors. In addition, any such investigations should involve atmospheres and heating environments appropriate to the combustors under consideration.

7.3.6 Heat Balance

The heat balance of the coal combustion process provides a relative weighting of the heat input into the system versus the heat output of the process and can be represented by:

$$dH_1 = dH_c + S_H + dH_e$$

where dH_1 is the heat input, S_H is a composite of the sensible and latent heats of air, fuel, and other materials, and dH_e is the heat from exothermic reactions (other than combustion) which may contribute to the overall combustion process; and by:

$$dH_o = dH_{cu} + S_{HC} + dH_{-E} + dS_{AG} + dH_L$$

In this equation, dH_o is the heat output, dH_{cu} is the heat of combustion of unburned fuel, S_{HC} is the sensible and latent heats in the carbonization products, dH_{-E} is the heat absorbed by endothermic reactions, dS_{AG} is the sensible and latent heats in the combustion products (ash and stack gases), and dH_L is the heat losses to the surroundings by convection, radiation, and combustion.

The presence of water vapor in the combustion system appears in the latent heat effects and one consequence of high moisture content in coal combustion is that a part of the heat is lost due to evaporation of the moisture in the coal and is not recouped from the combustion products. It is possible that a small amount (5% w/w) of water in the coal may not exert any marked effect on the overall heat requirements, since the sensible heat of the gases vaporizes the water.

7.3.7 Soot Formation

Soot formation is commonly observed in the pyrolysis or combustion process of simple hydrocarbon derivatives and coals.

In a conventional wall-fired, swirl-stabilized, pulverized coal combustor, coal particles with an average size around 50 microns are transported by primary air, and are injected into the furnace through the nozzles of a pulverized coal burner. When low NOx burners are used along with staged combustion configuration, the region near the burner is fuel rich; the particles are rapidly heated by convection from the recirculating hot gases and by radiation from the combustor walls and hot flame in the combustor.

Pyrolysis is the initial reaction step that occurs in a coal particle. Primary pyrolysis products include light gases, char, and tar, which is a gas mixture of heavy-molecular-weight hydrocarbon derivatives at high temperatures and condensable at room temperature. Simultaneously, the volatile matter released in the gas phase may also undergo secondary reactions. Soot is believed to be one of the products of these secondary reactions. The tar from primary pyrolysis consists of many polynuclear aromatic hydrocarbon derivatives (PNAs, also frequently referred to polyaromatic hydrocarbon derivative, PAHs), which are likely to undergo both cracking and polymerization processes at high temperature.

Soot in coal flames is important to combustion systems because of its radiative heat transfer effects. On a mass basis, there is much less soot present in a coal flame than other solid particles such as char and ash. However, the small size of soot particles results in a large total surface area. It can be expected that in the presence of a large radiant surface area of soot, the near-burner flame temperature could be lowered several hundred degrees due to the heat transfer to the surrounding walls. A major problem in pulverized coal combustion is the formation of nitrogen oxides (NOx) which are generated (a) through the reaction of nitrogen and oxygen in air at elevated temperatures (called thermal NOx), and (b) from the nitrogen-containing species or groups in the fuel (called fuel NOx). It has been found that the production of both thermal and fuel NOx in coal combustion is a strong function of reaction temperature. Therefore, the existence of soot in a coal flame will affect NOx formation. Also, it has been reported that soot from coal pyrolysis contains nitrogen (Chen and Niksa, 1992b), and therefore soot is an additional pathway for fuel nitrogen evolution.

Soot does great harm to human health through carcinogenic effects and the presence of soot in air also leads to visibility reduction, globe temperature decrease and acid deposition. Soot can suspend in the air for up to one month and can be delivered by wind to distant places, which causes wide-range pollution. Soot suspended in flames is important to combustion systems because it will significantly enhance radiative heat transfer due to their large surface area (Fletcher *et al.*, 1997).

High temperature is conducive to the formation of soot but soot yields are diminished due to soot oxidation when sufficient oxygen exists in the high temperature zone. Yields of soot are also diminished with the residence time because of more chances for volatiles reaction with oxygen at the longer residence time. Coal with a high yield of volatile matter and tar is easier to form soot due to the corresponding oxygen scarcity in the same conditions, and release more aromatic hydrocarbon derivatives.

7.3.8 Conduction, Convection, and Radiation

Conduction, convection, and radiation are the three major means of heat transfer and are important aspects of the operation of a coal-fired power plant. Briefly, *conduction* is the transfer of energy through solid matter from particle to particle. *Convection* is the transfer of heat energy through a *gas* or *liquid* by movement of currents. *Radiation* is electromagnetic waves which directly transport *heat energy* through space.

In a combustion chamber, radiation heat transfer from the flame and combustion products to the surrounding walls can be predicted if the radiative properties and temperature distributions in the medium and on the walls are available. Usually, however, temperature itself is an unknown parameter, and as a result of this, the total energy and radiant energy conservation equations are coupled, as in many heat transfer applications. The major processes which need to be considered in a combustion system in addition to radiation include the following: (i) chemical kinetics, (ii) thermochemistry, (iii) molecular diffusion, (iv) laminar and turbulent fluid dynamics, (v) nucleation, (vi) phase transitions such as evaporation and condensation, and (vii) surface effects (Viskanta and Mengüç, 1987).

The accuracy of radiative transfer predictions in combustion systems cannot be better than the accuracy of the radiative properties of the combustion products used in the analysis. These products usually consist of combustion gases such as water vapor, carbon dioxide, carbon monoxide, sulfur dioxide, and nitrous oxide, and particles, like soot, fly-ash, pulverized-coal, char, or fuel droplets. Considering the diversity of the products and the probability of having all or some of these in any volume element of the system, it can easily be perceived that the prediction of radiative properties in combustion systems is not an easy task. The wavelength dependence of these properties and uncertainties related to the volume fractions and size and shape distribution of particles cause additional complications.

In combustion operations, it has been estimated that 20% of the reaction heat is released directly as radiant energy. The remaining heat energy resides in the combustion products, from which approximately 30% of the energy is then released as radiation. The presence of water vapor in the combustion gases itself may have some appreciable effect upon the gas emissivity and radiation.

7.3.9 Slagging and Fouling

Slagging is the deposition of fly ash in the radiant section of the furnace, on both heat transfer surfaces and refractory surfaces. Fouling occurs in the convective heat transfer section and includes deposition of ash and volatiles as well as sulfidation reactions of ash. Fouling results in loss of heat transfer efficiency and blockage of the gas flow path. Corrosion occurs primarily on the water-wall tubes in the radiant section of the boiler and results in thinning of tubes with eventual leaks.

Most inorganic elements in the periodic table can be found in fossil fuels, although only a small number occur in significant concentrations to cause operational or environmental problems. Coal has by far the highest content of mineral matter, although the chemical composition of lower mineral matter fuels, such as biomass, can make co-firing of coal and biomass problematic in some instances. However, the majority of the elements on coal make a contribution slagging, fouling, corrosion, and environmental problems.

Coal ash is composed mostly of metal oxides (Table 7.3) and the composition affects the softening point (Speight, 2013). Iron oxides are a particular source of problems and the reducing atmosphere (CO + H2; produced by the water gas reaction) in the fuel bed serves to reduce ferric oxide (Fe2) to ferrous oxide Fe) with the production of *clinker* which will contribute to reactor fouling.

Fouling of combustion systems has also been related to the alkali metals content of coal. For example, coal with a total alkali metal content 0.5% w/w (as equivalent sodium oxide, Na_2O) produce deposits that can be removed by the action of a *soot blower* but for coals having more than 0.6% w/w alkali metal (as equivalent sodium oxide) the deposits increased markedly and can be a major problem.

To combat fouling, modern combustion equipment is designed to ensure that particles are cooled to well below their fusion temperatures before they can reach the banks of closely spaced tubes in the upper regions of the boiler. In pulverized fuel systems, provision is usually made for tilting the burners and thereby periodically altering the heat regime. In addition, tube deposits are routinely dislodged by frequent "soot blowing", i.e., by inserting perforated lances through which jets of high-pressure air or steam can be sent between boiler tubes.

7.3.10 Additives and Catalysts

In addition to causing objectionable stack emissions, coal ash and volatile inorganic material generated by thermal alteration of mineral matter in coal will adversely affect heat transfer processes by fouling heat-absorbing and radiating surfaces and will also influence the performance of the combustion system by causing corrosion. Operating procedures must therefore provide for effective countering of all these hazards (Mitchell, 1989).

Corrosion is mainly caused by oxides of sulfur; but in certain parts of a combustion system, specifically on furnace wall tubes with metal temperature of 290 to 425°C (550 to 800°F) and superheater or reheater tubes with temperatures in the range 600 to 700°C (1110 to 1300°F), corrosion can be induced by tube deposits that destroy protective surface oxide coatings.

Corrosion damage that is usually ascribed to sulfur is actually caused by sulfuric acid, which is generated from organic and inorganic sulfur-bearing compounds.

$$2SO_2 + O_2 \rightarrow 2SO_3$$

$$SO_3 + H_2O \rightarrow H_2SO_4$$

Oxidation of sulfur dioxide to sulfur trioxide occurs mostly in flames where (transient) atomic oxygen species are thought to be prevalent by interactions of hydrogen atoms with oxygen and by interactions of carbon monoxide with oxygen and therefore may not occur in the stoichiometric manner shown above. The process can, however, be catalyzed by the ferric oxides which form on boiler tube surfaces and show excellent catalytic activity for sulfur dioxide oxidation at approximately 600°C (1110°F), i.e., at temperatures which occur in the superheater section of a boiler.

The presence of water has a marked effect on combustion (by participating in various combustion reactions) and there is experimental evidence for the existence of active centers for chain reactions involved in the further combustion of carbon monoxide and hydrogen (which would be reaction intermediates in the combustion of coal). Thus, it is generally assumed that moisture plays a role (possibly through catalysis) in the oxidation of coal (Chapter 4).

The endothermic steam-carbon reaction is primarily responsible for cooling effects in furnaces, and the presence of moisture is believed to cause heat generation at the surface of the bed and in the combustion by virtue of the (endothermic) formation of carbon monoxide and hydrogen in the bed which then burn at the surface. On the other hand, the presence of water vapor appears to "assist" in the formation of carbon dioxide

$$H_2O + C \rightarrow CO + H_2 \qquad \text{(at surface)}$$

$$2CO + O_2 \rightarrow 2CO_2 \qquad \text{(in film)}$$

In fact, moisture appears to play a more integral role in the combustion of hydrogen-deficient carbonaceous fuels (such as coal) than has been generally recognized. The carbon-steam reaction to produce carbon monoxide and hydrogen (which are then oxidized to the final products) is an important stage in the combustion sequence as is the carbon monoxide *shift reaction* to yield carbon dioxide and hydrogen.

$$CO + H_2O \rightarrow CO_2 + H_2$$

Since the whole system involves reactions (and equilibria) between the fuel (i.e., carbon), water, carbon monoxide, hydrogen, and carbon dioxide, the rapid rates of the reactions render it difficult (if not impossible) to determine precisely which of the reactions are the major rate-controlling reactions. In addition, the heterogeneous nature of the system adds a further complication.

While the presence of inert gases would usually be expected to dilute the reactants and therefore diminish the reaction rates, such inert materials may actually, on occasion, accelerate the reaction(s). Indeed, the "addition" of nitrogen to the reaction mixture can be as effective as the addition of oxygen. The nitric oxide formed in the mixture is believed to act as a catalyst.

$$2CO + 2H_2O \rightarrow 2CO_2 + 2H_2$$

$$N_2 + O_2 \rightarrow 2NO$$

$$2NO + 2H_2 \rightarrow N_2 + 2H_2O$$

Thus:

$$2CO + O_2 \rightarrow 2CO_2$$

7.3.11 Excess Air

Coal combustion is, on the one hand, a balance of high reaction or flame temperatures which favor carbon monoxide at equilibrium and, on the other hand, the use of excess air which drives the conversion to carbon dioxide. Relative to these two opposing reactions, the rates of reaction are generally controlling and manifested by short residence times with rapid heat transfer such that the system temperature is lowered before equilibrium can occur. Hence the consideration that (complete) combustion is a non-equilibrium process. This is contrary to gasification by partial combustion, which occurs at lower temperatures and longer residence times without heat transfer (the system remains adiabatic), where equilibrium conditions tend to apply.

Though thermodynamic and rate calculations may be used to maximize flame temperatures and conversions, it is the empirical observation and evidence in each situation that will dictate the optimum air-to-fuel ratio and will depend on fuel analysis including moisture, air humidity and temperature, and other general operating variables. Although 15 to 25% v/v excess air is in the median range, the amount of air required for efficient combustion depends not only on the fuel but on the type of combustion system and the means by which the combustion is controlled (Speight, 2013).

7.3.12 Coal/Air Transport

The entrained transport of pulverized coal (200-mesh) is accomplished with ratios of approximately 1.4 pounds of air per pound coal, but pulverizer performance may sometimes require twice this ratio. If this fuel-air mixture is burned there is the possibility of flashback unless linear velocities are 55 feet/sec.

Furthermore, although gaseous flame speeds are only a few feet per second, the coal volatiles mixed with air can form a combustible gaseous boundary layer which is essentially stationary, allowing flame propagation. This propagation cannot occur unless the boundary layer is above a certain minimum, i.e., flames will not progress through (for example) a tube if the tube diameter is less than a certain minimum (depending on the combustibles), and a bulk velocity of at least 55 feet/sec. assures that the effective boundary layer thickness is less than this minimum.

7.4 Catalytic Combustion

Coal combustion is facing the challenge of energy saving and emission reduction (Balat, 2007). One outcome is that catalytic combustion, which can improve coal combustion efficiency, has been paid considerable attention (Gong *et al.*, 2010; Manquais *et al.*, 2011).

In catalytic combustion, fuels oxidize under lean conditions in the presence of a catalyst. Catalytic combustion is a flameless process, allowing fuel oxidation to occur at temperatures below approximately 930°C (1700°F), where NOx formation is low. The catalyst is applied to combustor surfaces, which cause the fuel-air mixture to react with the oxygen and release its initial thermal energy. The combustion reaction in the lean premixed gas then goes to completion at design temperature. Data from ongoing long-term testing indicates that catalytic combustion exhibits low vibration and acoustic noise, only one-tenth to one-hundredth the levels measured in the same turbine equipped with dry low NOx combustors (Barnes, 2011).

Current interest in the catalytic combustion of coal has dated from the 1950s. Most additives were used to catalyze oil combustion. In the 1960s and the 1970s, research on catalytic oxidation of carbon (graphite) by metal element was also of interest – although the aim of the research was to study catalyst carrier (carbon) stability during the catalytic reaction, the outcome helped to understand the catalytic mechanism of carbon oxidation (McKee, 1970). Since 1990, other work has also focused on catalytic pyrolysis and catalytic gasification and pyrolysis of coal in which alkali metals, earth alkaline earth metals, and transition metals were used as catalysts (Anita, 1992; Murakami *et al.*, 1996; Bozkurt *et al.*, 2008).

In fact, active interest in catalytic combustion for power generation increased during the early 1990s as it became clear that continued pressure for reduced emissions may not be met simply by redesign of conventional combustors (Smith, 2009). More recently, the effects of cerium oxide (CeO_2) and ferric oxide (Fe_2O_3) on the combustion of three ranks of coals by using a thermo-gravimetric analyzer has been investigated (Gong *et al.*, 2010). The reason was to reduce the amount of unburned carbon in the coal ash (Manquais *et al.*, 2011).

However, coal is a complex heterogeneous mixture and the effects of additives vary and are not guaranteed to be precisely the same from one coal to another (Gong *et al.*, 2010). In fact, the mechanism of the catalytic combustion of coal is far from clear.

7.5 Fuels

Coal-fired utilities are growing at a faster pace due to huge power demand. This upward trend will continue for some more decades due to abundance of coal and its economics involved. But the quality coals in terms of calorific value and mineral matter content are getting depleted at mines.

However, not all types of coal are applicable to the coal-fired power plants and selection of applicable coal type is an important process. Moreover, increase of applicable coal types is preferable for stable supply of coal (Goto *et al.*, 2011). Furthermore, variation in coal characteristics may hamper unit heat rate to greater magnitude and can be deterministic to boiler operation in the case of deteriorated coal being used and vice versa in the case of moderately designed coal. Low-grade coal can be mixed with higher-grade coal to take advantage of using low-grade coals without deterioration in thermal performance of the boiler thus reducing the cost of generation (Longwell *et al.*, 1995; Huang *et al.*, 2000; Buhre *et al.*, 2006; Huda *et al.*, 2006; Goto *et al.*, 2009). To circumvent any difference in coal character and properties, methods are being adopted for blending at coal mines, preparation plants, shipment point and power stations. In fact the method to be chosen will depend very much upon the site conditions and level of blending which, in turn, is related to coal character and properties (Nugroho *et al.*, 2000; Yin *et al.*, 2000).

Coals that are typically used for electric power production in the United States include high-sulfur and medium-sulfur bituminous coals from the Appalachian regions and the Illinois Basin, and low-sulfur subbituminous coal and lignite from the Northern Plains, the Powder River Basin (PRB), and the Gulf Coast regions. Anthracite is generally used only for metallurgical applications. Chinese coals are typically bituminous varieties with relatively high mineral matter content and varying sulfur content, and Indian coals are generally low-sulfur bituminous varieties with unusually high mineral matter content.

Nevertheless, generalities aside, the evaluation of fuel quality can have a major impact on power plant performance and it is important to ensure that the best-value coals are purchased, rather than simply the cheapest. This is because the adverse impacts on ash salability, emissions performance or unit efficiency can quickly negate the benefits of a slightly cheaper coal price. Thus coal quality and the type of coal-based fuel employed in a coal-fired power plant must be given serious consideration.

In general, optimal control of coal-fired power plant operations has to incorporate a number of individual contributions effectively involving control circuits covering all parts of the plant. These comprise principally (i) the quantity and quality of the coal being fed to the pulverizers and hence to the burners; (ii) the quantity and distribution of the air supplied to the burners and elsewhere, (iii) the temperature and quantity of water supplied to the boiler walls, (iv) the procedures for boiler and heat exchanger cleaning using soot blowers, (v) flue gas cleaning stages, including NOx reduction and removal as well as (vi) removal of particulate matter and sulfur dioxide removal plus the installation of carbon capture units to absorb most of the carbon dioxide produced (Chapters 12, 13).

7.5.1 Coal

Coal type (Chapter 1), coal quality (Chapter 5), and coal blends (Chapter 7) have a considerable influence on the performance of coal in a coal-fired power generating plant. In addition, generating unit technology choice and design, generating efficiency, capital cost also affect performance. Boiler designs usually encompass a broader range of typical coals than initially intended to provide future flexibility. Single coal designs are mostly limited to mine-mouth plants, which are typically only lignite, subbituminous, or brown coal plants. The energy, carbon, moisture, ash, and sulfur contents, as well the characteristics of the mineral matter and the mineral ash produced during the combustion process (Chapters 5, 6), all play an important role in the value and selection of coal, in its transportation cost, and in the technology choice for power generation.

As an example, anthracite, having more fixed carbon and generating less volatile matter than either bituminous coal or lignite, also has higher ignition temperatures and ash fusion temperatures than other coal types. In addition, anthracite typically contains approximately 5% w/w moisture, less than 1% w/w sulfur, less than 1% w/w nitrogen, yields 80% w/w fixed carbon and produces 4% w/w volatile matter and 10% w/w ash. The heating value of anthracite is usually in the range 12,000 to 14,000 Btu/lb.

Another form of anthracite coal burned in boilers is anthracite refuse (*culm*), which is produced as breaker reject material from the mining/sizing of anthracite coal and is often sent to dump heaps near operating mines. Relative to mined anthracite, culm is characterized by a higher ash production, higher moisture content, and lower heating value – on the order of 2,500 to 5,000 Btu/lb.

Due to its low volatile matter content, and non-clinkering characteristics, anthracite is, for the most part, used in medium-sized industrial and institutional stoker boilers using stationary and traveling grates. Anthracite is not used in spreader stokers because of its low volatile matter content and relatively high ignition temperature. This fuel may also be burned in pulverized coal-fired (PC-fired) units, but due to ignition difficulties, this practice is limited. Because of the high ash content and low heating value, culm tends to be used as a combustion feedstock in fluidized bed combustion (FBC) boilers.

Pulverized coal combustion systems are widely used in thermal power plants. Plant performances vary with coal properties and each of the coal properties interacts in a significant way to affect performance. For example, higher sulfur content reduces efficiency of pulverized coal combustion due to the added energy consumption and operating costs to remove sulfur oxides (SOx) from the flue gas.

In addition, coal having high mineral matter content (high ash production) requires combustor design changes to manage erosion. Fluid-bed combustion is more suited to coals that produce high yields of ash coals – these include low-carbon coal waste and lignite.

On the other hand, sulfur tends to decrease pulverized coal boiler efficiency, because of the need to maintain higher boiler outlet temperature to avoid condensation of sulfuric acid and resultant corrosion problems in downstream equipment. The higher outlet temperature carries thermal energy out of the boiler rather than converting it into steam to drive the steam turbine. High-sulfur content also increases power requirements and operating costs for flue gas desulfurization units.

For IGCC systems, sulfur content impacts the size of the clean-up process but has little effect on cost or efficiency. The biggest impact of sulfur to date has been to drive a shift from high-sulfur coal to low-sulfur coal to avoid installing flue gas desulfurization units on operating pulverized coal plants or to minimize flue gas desulfurization operating costs on new plants. For carbon dioxide capture, high-sulfur coals may cause increased complications with the capture technologies.

High mineral matter content (high ash yield) and ash properties affect boiler design and operation. High-ash-yield coal causes increased erosion and reduce efficiency, and may be more effectively handled in circulating fluid-bed boilers. Boilers are designed for the ash to exit the boiler either as a molten slag (wet-bottom boilers), particularly for low fusion temperature ash, or as a fly ash (dry-bottom boilers). Most boilers are dry ash designs. For IGCC plants, coal ash consumes heat energy to melt it, requires more water per unit carbon in the slurry.

Coal having high moisture content reduces generating efficiency in pulverized coal combustion plants and reduces gasifier efficiency in IGCC plants. Circulating fluidized bed boiler size and cost also increases with higher moisture coal, but the effect is less pronounced than for pulverized coal systems. Also, in IGCC systems, slurry-fed gasifiers have the same problems with high-moisture coal as with high-ash-yield coal. Both types of coal exert the following effects: (i) a decrease in the energy density of the slurry, (ii) an increase in the oxygen demand for evaporation of the excess moisture, (iii) an increase in the cost per unit of electricity produced, and (iv) a decrease in generating efficiency.

By way of explanation, the energy density is the amount of energy stored in a given system or region of space per unit volume – the term may also be used for energy per unit mass but in this case it is more correct to use *specific energy*. Thus:

$$\text{Energy density} = \text{the energy per unit volume of a fuel } (E_d) = E/V$$

$$\text{Specific energy} = \text{energy per unit mass of a fuel } (E_s) = E/m$$

Finally, there is one major area of concern that relates to the use of pulverized coal systems. While switching to pulverized coal burners and the accompanying switch from high-sulfur bituminous coal to low-sulfur subbituminous coal (such as the Wyoming Powder River basin coal) does address some of the environmental concerns, the degree of explosion hazard introduced by the subbituminous coal may be increased compared to bituminous coal. The possibility of spontaneous combustion is more likely, due to lower auto-ignition temperatures and shorter induction periods to the spontaneous ignition of the coal (Chapter 4).

There are two principle systems for processing, distributing, and burning pulverized coal: (i) a direct firing system and (ii) a storage firing system. In a direct firing system, the coal is gravity fed into the pulverizer from the coal bunker, where it is dried and pulverized, then pneumatically conveyed to the burners in a single continuous operation. A storage firing system also includes a cyclone separator, a dust filter, and a storage bin between the pulverizer and burners. The process equipment most susceptible to fire and explosion are the pulverizers, cyclones, dust collectors, storage bins, and conveying lines between these enclosures.

In either the direct firing system or the storage firing system the fly ash from the furnace/boiler is removed downstream by baghouses, electrostatic precipitators, or scrubbers. The available responsive techniques are pressure containment or explosion suppression, which can be applied to prevent internal damage as well as extinguish the ensuing fire. Explosion suppression utilizes pressure sensors to detect the initial pressure wave and release dry powder suppressant agent, within milliseconds, into the pulverizer. The suppression system controller interfaces with other process controls to initiate fan shutdown and other similar process changes.

7.5.2 Coal Blends

Coal blending as feedstock to power stations is mainly adopted to reduce the cost of generation and increase availability of coal. Low-grade coals can be mixed with better-grade coal without deterioration in thermal performance of the boiler thus reducing the cost of generation. In many nations, blending of coal was being adopted for a long period mainly for increasing the availability of coal for power generation. To improve the availability of coal and also to improve the calorific value of coal being fired, some of the power stations look at the possibility of mixing high-grade imported coal with the low-grade high ash coals.

Premium fuels usually have premium prices. Blending provides a tool to match coal quality more closely to user requirements. Depending upon the objectives, blending can be employed to (i) reduce fuel variability or (ii) combine different raw coals into a useful fuel product that meets process specifications. Coal blending is being used by a growing number of utilities to gain more control of fuel characteristics while maintaining or reducing fuel cost. There are two types of blending that can be used: bed blending and belt blending.

Bed blending is a technique used by process industries to convert heterogeneous raw materials into a stable homogenous product, which is important to optimizing plant performance and controlling product quality. It is used to reduce the random variability of raw materials by implementing stockpile management techniques. It can be advantageous for mine-mouth plants whose coal deposits have wide variations of heating value and other properties.

The design of the reclaimer is important for bed blending. The objective is to reclaim the cross section of the stockpile, to "slice" a section of the windrow from toe-to-toe of the stockpile. In this manner, multiple layers are simultaneously reclaimed, from the base of the stockpile to its surface. The variability of all layers is thereby blended by each reclaim slice of the cross section. Each slice contains elements from the first layer to the last. As a result, while the properties of each layer can vary significantly, the properties of each slice closely resemble the mean value of the stockpile. Wild hourly swings are blended into weekly averages. The number of layers is of statistical importance.

Belt blending is a second methodology and one that is most widely used by power plants. In this stockpile management technique, distinctly different receipts from known sources are stacked in segregated stockpiles. Combinations of stockpiles are reclaimed at predetermined rates to a recipe that best meets plant requirements. The recipe will normally consider heating value, total ash, sulfur content, and other elements such as iron and sodium, which affect the acceptability of coal for some boiler designs.

Belt blending combines the characteristics of two or more different grades of coal. Each grade is individually stockpiled and physically segregated. During reclaim, these stockpiles are proportionally combined most commonly by either volume or weight. Weight is the more accurate method since precise weigh feeders, weigh bins, or belt scales can be used to automatically monitor and control the output of reclaim feeders. Conventional sample systems are then employed to monitor input/output of the bed blending system. In belt blending, grades of coal can be combined on the basis of a number of characteristics. This can be energy value, mineral matter content and type, percent ash, and sulfur content.

The method to be chosen will depend upon the site conditions, level of blending required, quantity to be stored and blended, accuracy required and end use of blended coal. Typically in large power stations, handling large quantity of coal, the stockpile method with fully mechanized system is followed.

To decide blend or not, it is important to understand the composition of coals that are to be blended. This means it is necessary to understand (i) the origin of coal, (ii) the chemistry of the inorganic constituents, (iii) chemistry of the organic constituents, (iv) the combustion properties coal, and (v) the overall behavior of the coal in the process.

For example, there are indications that coal formed by *drift theory* and coal formed by the *swamp theory* need to be blended with caution. The main difference between drift theory and swamp theory is that the coal formed by drift theory exhibits pronounced regional variation in thickness and quality of seams – there are large variations in the mineral matter content with varying types of inorganic chemistry. The organics of the drift origin coal also exhibit blending problem because the vegetation that lead to forming of coal are drifted from different places having different kind of vegetation. However, the coals formed by swamp theory have more uniform organic property and much less ash content with consistent chemistry of inorganic.

During combustion, it is really necessary to understand the physical conditions and coal properties during heating of the particles, devolatilization, ignition and combustion of the volatile matter, and ignition and combustion of the char. It is equally important to know the phase changes in mineral matter and other inorganics present in coal. The combustion efficiency and carbon loss will have to be also addressed during blending of coals. It is also necessary to look into the aspects of slagging, fouling, and emissions such as nitrogen oxides, sulfur oxides, and particulate matter.

Irrespective of these challenges, it is extremely likely that coal blending to produce feedstocks for coal-fired power plants is expected to grow over the next two-to-three decades as electric utilities attempt to (i) reduce the cost, (ii) meet the emission limits for sulfur dioxide, and (iii) improve combustion performance of the coal feedstocks. All aspects of the behavior of a blend and the effect on all components of power stations, from the stockpile to the stack, should be considered before the most appropriate blend composition is chosen (Haykiri-Acma, *et al.*, 2000).

The quality and consistency of the blended materials are improved by using bed blending. Due to the variation in beds, monitoring is necessary (Poultney *et al.*, 1997) ash fusion characteristics and behavior of individual coal ash and blended coal ash have shown that the blended coal ash softening temperature does not vary linearly with blending ratio (Qiu *et al.*, 1999, 2000; Jin *et al.*, 2009). The properties of coal blends are calculated based on the weighted average properties of the individual coal that makes up the blend.

However, because of the complexity of the combustion process and the number of variables involved (which are still not fully understood), it is not always possible to extrapolate small-scale data (such as laboratory data) to a full-scale coal-fired power plant. Thus, power station operational experience in a wide range of plant configurations with a variety of coal feedstock is essential for determining the practical significance of results from bench scale and pilot scale tests.

With due deference to Mr. Shakespeare, the decision *to blend or not to blend* should be based on the knowledge of the specific behavior of a given pair of coals (or the number of coals to be blended), rather than an assumption of linear variation of properties with blend traction. The ever more stringent constraints like environmental regulations, maximum efficiency at reduced cost of power generation, as well as improved availability and reliability placed on coal-fired power stations worldwide and the continuing development of new technologies means that the issue of fuel quality improvement will remain a primary factor.

Most coal properties are additive when applied to coal blends. That is, the value of the property for the blend can be determined from the property of the individual coals involved.

Some tests used to determine particular coal properties do not use a representative sample of the whole coal (Hardgrove grindability index) or, because of the empirical test conditions, do not provide appropriate information for its use in the required application (crucible swelling number and volatile matter). Other tests do not provide a linear result for the blend when compared to the test result for the individual coals (ash fusion temperatures), ensuring that a test result for the blend itself must be obtained. Due to imperfect blending practices, these test results often do not provide an indication of the blend behavior in a pulverized coal furnace.

Current knowledge of plant behavior for combustion of individual coals in some areas is adequate for predicting the behavior of a blend. However, in many areas of a pulverized coal plant, prediction of performance of a blend is difficult and requires further research to provide acceptable accuracy in the prediction. In some cases, the behavior of individual coals, in terms of their handling, combustion and waste stream characteristics, cannot be explained adequately nor related to coal properties, and appropriate techniques need to be developed to provide the valuable information the industry looks for in these tests (Wall *et al.*, 2001).

For example, the Hardgrove grindability index has limitations in its use for explaining the behavior of coals in crushing and grinding mills. The coal is crushed to less than 0.05 inch (1.18 mm) and any portion of the coal that is less than 0.025 inch (0.6 mm) is rejected. As this size fraction represents the more friable material, the test provides results on the least friable materials in the coal. When weathered, the coal will lose strength and an increased proportion of the sample will be removed, thereby producing an erroneous result. Because a different fraction of the coal can be removed at each test, depending on the sample and the grinding method, a coal with a high proportion of friable material (up to 50%) could possibly be considered equivalent to a coal with only a small proportion of friable material, thereby throwing some doubt on the validity of using this test data for coal blends.

Another relevant test worthy of comment is the ash fusion (or ash fusibility) temperature test, which is highly relied upon by the coal-fired power plant industry to provide an indication of the likelihood of deposition within a pulverized fuel boiler. The test aims to provide the temperatures at which the coal ash first deforms or becomes sticky (deformation temperature), when it is likely to form dense deposits because it has a tendency to agglomerate (sphere and hemisphere temperatures) and when the ash will form a slag which will flow down a boiler wall (flow temperature) (Raask, 1985). However, at the deformation temperature, a significant amount of liquid may be present in some samples, significantly overestimating the temperature at which ash becomes sticky (Gupta, 1998). The significant variation in the amount of liquid present in ash samples suggests that this test cannot reliably predict difficult fouling and slagging problems in all cases, thus reducing the value of this test.

Indeed, to predict the behavior of coal blends in coal-fired power stations, it is now thought necessary to characterize the burning performance of coal blends prior to full-scale trials. With this in mind, a three-dimensional numerical model has been developed to simulate the flow and combustion of a binary coal blend (Shen *et al.*, 2006). Rather than treating the blend as a single coal with weighted-average properties of its components, the model (using a two-component coal blend, with individual properties) tracked each coal separately using individual kinetics. As a result, the model is capable of providing individual information of component coals. Thus, combustion behavior in the combustor could be predicted in terms of burnout, particle temperature and volatile content.

Finally, spontaneous ignition and spontaneous combustion of stored coal causes a serious problem for coal producers and users (Chapter 4). Improvements (that are directed to lengthening the induction period to spontaneous ignition) to low-rank coal are made by either thermal or through blend with higher-rank coals. Thermal drying of moist lower-rank coals could increase the calorific value of a product whilst blending of coals of different types offers a greater flexibility and economic benefit. However, the problem of spontaneous combustion assumes even greater significance since the removal of moisture can enhance the potential for spontaneous ignition and combustion. The risk of spontaneous combustion is also made greater during blending and when storage of such lower-rank coals takes place. This is particularly the case with low-sulfur subbituminous coals which are now used to meet emission limits.

The primary source of heat generation within coal stockpiles is the exothermic low-temperature oxidation reaction, while mass and heat transport play a major role in determining the magnitude of the temperature rise in a given situation. Despite extensive investigations on the spontaneous ignition and spontaneous combustion of coal using various techniques (Chapter 4), the effect of particle size (and, hence, increase in surface area available to oxygen) on the rate of low temperature oxidation, may not be fully resolved (Nugroho *et al.*, 2000).

Finally, caution is advised to those investigators who are firmly convinced that paper calculations of the properties of coal blends based on the properties of the individual coals is sufficient prior to use of the blend as the feedstocks for a coal-fired power plant.

Generally, the quality of coal or blended coal is assessed on the basis of certain parameters associated with the pyrolysis and combustion process. Often, the practice for determining the overall quality of blended coals is to use the weighted average values for the individual coals in the blend. While this approach may give accurate composite values for moisture content, total sulfur, and coal heating value of a coal blend, but not for volatile matter and ash yield, the calculated composite values for other coal blend parameters, such as the Hardgrove grindability index (HGI) (Chapter 6), ash fusibility (Chapter 6), and free-swelling index (FSI) (Chapter 6), are not always reliable. These parameters do not represent the properties of a blended coal sample since it is not always possible to determine if the various properties are additive or non-additive (Pan and Gan, 1991).

7.5.3 Coal-Oil Fuels

At this point it is appropriate to consider another form in which coal can be used as a slurry fuel as coal-coal mixtures (coal blends), coal-oil mixtures, or coal-water mixtures. A coal-liquid mixture (CLM) consists of finely crushed coal suspended in various liquids and typically small amounts of chemical additives that improve stability and other physical properties. The primary purpose of coal-liquid mixtures is to convert coal from a solid to an essentially liquid form, which with certain equipment modifications, allows the coal to be transported, stored, and burned in a manner similar to fuel oil.

Renewed interest and significant development efforts in *coal-oil mixtures* have emerged in the past two decades as a result of the search to find a replacement for dwindling oil supplies in the United States and other countries. The possibility of transporting liquefied coal by pipeline as an alternative to transporting solid coal by rail or barge has also stimulated recent development of coal-water mixtures.

Initial development work for coal-oil mixtures dates back to the previous century, with the earliest known coal-oil mixture patent being issued in the late 19th century. In fact, during World War I, coal-oil mixtures were evaluated as a fuel for submarines, and during the 1930s, coal-oil mixtures were successfully tested as a fuel oil substitute for locomotives and ocean liners (Argonne, 1990; Horsfall, 1990).

More extensive coal-oil mixture research was undertaken in the 1940s due to the wartime constraints on oil supply, and the data collected during this period still serve as a basic source of information, especially the types of coal suitable for use in coal-oil mixtures (Table 7.4). A resumption of readily available oil supplies at prices competitive with coal inhibited the widespread commercialization of the technology at that time. A subsequent constraint on oil supplies, initiated by the 1973 oil embargo, prompted the current era of increased coal-oil mixture research and development. A significant early development was the discovery of low-cost, effective chemical additives for stabilizing the mixture and enhancing other physical and chemical properties. An additional application of coal-oil mixtures was as a fuel for blast furnaces.

As a result of these activities, coal-oil mixtures have become mature commercial technologies. However, several areas have been identified for further research to improve performance, reliability, and market potential. Principal among these are advanced beneficiation of the coal to further reduce sulfur and ash content, demonstration in a compact boiler designed to burn oil, and increased percentage (by weight) of coal in the mixture.

The production of coal-liquid mixtures requires that the coal has to be ground to a specific size grading. For coal-oil mixtures simple pulverized fuel techniques appear to be acceptable but, for coal-water mixtures, it appears preferable to produce coal ground to a bimodal size distribution to get maximum solids loading of the suspension. In the making of coal-oil mixtures, the coal can be ground dry and then mixed with oil, or relatively coarse coal can be mixed with oil and wet ground (Horsfall, 1990).

To enable them to serve as a replacement fuel in oil-burning installations, coal-oil mixtures are usually prepared from a bituminous coal of medium to high volatility and low ash content, since oil burners have only limited capability for ash removal. To minimize ash deposition and fouling problems, it is also desirable that the feed coal is low in moisture and has a moderate-to-high ash fusion temperature (the temperature of initial deformation).

Table 7.4 Properties of bituminous coals suitable for use in coal-oil mixtures.

Characteristics	**Range of typical values**
Moisture (% w/w)	4.5–9.0
Ash (% w/w)	4.5–10.0
Volatiles (% w/w)	17–40
Sulfur (% w/w)	0.6–1.5
High heating value (Btu/lb)	12,500–14,500
Ash fusion temperature (°F)	2000–2800+

Low sulfur content is also required to maintain the low-sulfur emissions of the oil fuels being replaced.

The coal particle size in a coal-oil mixture is dependent on the application and equipment to be used in the transportation, storage, and combustion. For applications as an oil replacement in utility or industrial boilers or process heaters, where good atomization and stable flames are required, coals are typically ground to 70 to 80% minus 200 mesh (<74 microns). Ultrafine grinding to sizes as low as 10 micron can improve combustion efficiency, reduce ash deposition, and reduce or eliminate the need for stabilizing additives, but at a higher cost of fuel preparation. On the other hand, in applications such as blast furnaces where flame control is not as critical, coal-oil mixtures with coal particles as coarse as 70% minus 25 mesh have been successfully used. Pipeline and tanker transport of coal as a coal-oil mixture does not require fine grinding of the coal.

7.5.4 Coal-Water Fuels

The development of *coal-water mixtures* does not have the long history of coal-oil mixture development. In the 1960s, the Germans and Russians also conducted several major CWM combustion tests. However, despite the success of these tests, no further major efforts were undertaken in this country until the major test at 1 million Btu/h input (Argonne, 1990; Horsfall, 1990).

A coal-water fuel (*coal-water slurry fuel*) is a slurry of coal in water than is typically fed to a combustor for the generation of heat or power (Chapter 7). The coal-water fuel (CWF) represents a new type of clean fuel technology which emerged as a way of using coal as a substitute for fuel oil in the crude oil crises of the last century. The basic composition of the fuel is: 70% w/w coal, 30% w/w water, and 1% w/w additive to stabilize the slurry.

In the production of coal-water, the grinding can also be wet or dry and if the feed coal is of the required quality, little or no additional processing is necessary. Where a low mineral matter content of the coal is desirable, a beneficiation stage can be introduced. Froth flotation is favored because of the small particle size and consequently good liberation but, if pyrite sulfur is present, a gravity-treatment stage could be introduced (Chapter 3). If dry grinding has been carried out, the pulverized coal is then mixed with the fluid and, if necessary, the suspension is stabilized by chemical additives, which may themselves be dispersed by ultrasonic vibration. However, such addition may be unnecessary if the coal is fine and stabilizes by virtue of its small particle size. The mixture must then be brought to the maximum solids concentration. If wet grinding with beneficiation is used for coal-water, this step may require the use of a thickener and filter to remove surplus water (Horsfall, 1990).

However, if the mixture is not prepared sufficiently well (and this is a subject decision in the preparation process), the mixture will exhibit sedimentation of coal particles. This can occur during storage in a tank or during long-distance transportation of the coal-water mixture, which would cause problems for utilization processes of the mixture. Addition of stabilizers is often recommended to prevent sedimentation of the coal particles (Usui *et al.*, 1988; Hu, 2002; Li *et al.*, 2008; Mosa *et al.*, 2008).

The coal-water fuel can be used in place of oil and gas in small, medium, and large power stations. The coal-water fuel is suitable for existing gas, oil, and coal-fired boilers.

The presence of water in the fuel reduces harmful emissions into the atmosphere and makes the coal explosion-proof. By converting the coal into a liquid form, delivery and dispensing of the fuel can be simplified. One side effect of the coal-water fuel production process is the separation of non-carbon material mixed in with the coal before treatment. This results in a reduction of ash yield or the treated fuel, making it a viable alternative to diesel fuel #2 for use in large stationary engines or diesel-electric locomotives.

The advantages of coal-water fuels include (i) a complete burning fuel with a burn of 96% to 99%, and (ii) a noticeable effect in protecting the environment. Coal-water fuel produced from coal with low ash and sulfur content, with its burning fuel oil instead of coal or dry sharply declining education of sulfur oxides (up to 70 to 85%) and oxides of nitrogen (up to 80 to 90%). Combustion of the coal-water fuel results in hydro-agglomerates of the fly ash constituents, with a concomitant reduction in emissions of particulate matter of 80 to 90%. In addition, transportation (pipe, tank) of coal-water fuel reduces unjustified losses during transportation of coal and improves the ecological environment in areas of its use. Coal of almost any type could be used as a raw for coal-water fuels. In addition, coal waste slurries could be used for preparing coal-water fuels as long as the mineral matter content (ash-forming propensity) is less than 10% w/w if using on gas/oil boilers with much higher if coal boilers are used.

Coal-water fuel can be used in several different applications, in the largest particle form it is a viable substitute for heavy-grade fuel oils used to produce steam in boilers such as No. 6 fuel oil, Bunker C residual fuel oil, and Bunker D residual fuel oil. Additionally, when the particle size is 80 microns or less the coal-water fuel can be used as a co-fuel or substitute fuel in diesel engines. Low-speed marine or modular power plant diesel engines can operate on pure coal-water fuel. Medium-speed diesel engines, such as locomotive engines, sometimes need a co-injection of No. 2 diesel #2, which acts as an ignition source for the coal-water fuel. In regard to the particle size of the coal, the smaller the particle size the more versatile the coal-water fuel for application. However, the finer the particle size the more difficult it is to manufacture.

In addition to coal-oil and coal-water mixtures, coal-liquid mixture technology has been extended to include mixtures of coal-methanol, solvent-refined coal oil, crude oil-coke oil, and other solid-fuel liquid mixtures. However, for the purposes of this text, the contents of this section are limited to the more mature technologies involving coal-oil mixtures (COMs) and to coal-water mixtures (CWMs) (Morrison, 1980; Argonne, 1990).

The primary objective for developing coal-liquid mixture fuels is to produce a coal-based fuel that has many of the operational characteristics of oil and can thus serve as a replacement fuel in oil-burning applications, with only minor modifications to fuel storage, handling, and combustion equipment and procedures. To achieve this objective, the principal areas of technology development have been in process for coal-liquid mixture preparation; slurry pumps and other equipment components for storage, handling, and transport; and retrofit modifications or new designs for burners and boilers using coal-liquid mixtures (Table 7.5) (Argonne, 1990).

The basic steps in coal-oil mixture preparation are (i) fine grinding of the coal, (ii) mixing the pulverized coal with oil, and (iii) stabilizing the mixture by addition of various chemical additives. An additional step of beneficiating the coal to remove sulfur and ash is also typically required. Beneficiation may be performed as part of the preparation of the

Table 7.5 Technological aspects of the use of coal-liquid mixtures.

Processes	Characteristics	Representative technologies
Coal crushing and sizing	Major emphasis on eastern, medium-to-high-volatility bituminous coal	Crushing; screening
Grinding	Typically 200 mesh (74μm or finer); bimodal distributions are under study for CWMs.	Dry milling; wet milling; ultrasonic grinding
Beneficiation	Aiming for: 15,000 Btu/lb, 0.9% sulfur, 4.0% ash.	Physical cleaning Water Heavy media Froth flotation Oil agglomeration Chemical cleaning
Coal–liquid mixing	Additives minimize viscosity, increase solids loading capacity, and enhance mixture stability.	Proprietary preparation processes involving additives, grinding, and mixing
Transportation and storage	CLMs are high viscous, non-Newtonian fluids and must be stable with respect to sedimentation and subsidence.	Heating; pumping; remixing; agitation; recirculation
Combustion	Fuel parameters; abrasiveness (nozzle and pump wear); atomizability; carbon conversion; flame stability	Burner modification; boiler modifications to prevent fouling, reduce derating, and collect ash

input coal before it is sent to the coal-oil mixture preparation plant or, in some instances, may be integrated into the coal-oil mixture preparation process. Limits on viscosity and other physical properties affecting handling have limited the coal loading in the product coal-oil mixture to 40 to 50% by weight.

Coals for coal-water mixtures should be readily friable to reduce comminution costs. Hard, inertinite-rich coals may be costly to crush, except for coals which have a vitrinite content of more than 90% w/w. From the combustion point of view, there may be little merit in crushing below a certain size – ultra-fine particles may agglomerate and be difficult to atomize in the combustion chamber. However, the need for low mineral matter content and low-sulfur content may dictate the particle size since good liberation will be necessary.

Thus, comprised of finely pulverized coal particles suspended in water, coal-water mixtures may contain 65 to 80% w/w dry coal. The important and somewhat surprising characteristic of these highly loaded slurries is that they are quite fluid. They are also stable suspensions: the coal particles do not settle during storage for several weeks or even several months. Although producers differ in their methods, these properties are generally obtained by using a particular coal particle size distribution for efficient particle packing coupled with the use of certain chemical additives to provide good fluidity and stability.

The overall coal-water mixture preparation, however, tends to be more sophisticated and controlled than the preparation of a coal-oil mixture preparation so as to achieve a higher coal loading. Coal loadings in coal-water mixtures of 70% w/w (compared to approximately 50% w/w in coal-oil mixtures) with acceptable viscosity have been achieved, due in large part to the lower viscosity of water compared to oil. The lower water viscosity will, however, allow more rapid settling of the particles, thus presenting a somewhat greater challenge to obtaining mixture stability. Coal-water mixtures with a high solid loading and minimum viscosity also require appropriate dispersants and stabilizers. Characteristics that determine the suitability of stabilizing additives include (i) non-foaming, (ii) a structure with both hydrophobic and hydrophilic (water repelling and attracting) portions, (iii) water solubility, (iv) compatibility with stabilizers, and (v) effectiveness at low concentrations. Gums, salts, clays, and other materials have been used as stabilizers.

The chemical and physical properties of the coal have a major influence on the characteristics of coal-water mixtures. Experience has shown that coal-water mixtures with bituminous coals allow higher coal loadings than coal-water mixtures composed of subbituminous coal or lignite. Also, high-volatility bituminous coals are more desirable for coal-water mixtures because they provide favorable ignition and combustion characteristics (Speight, 2013). Since the fuel in coal-water mixtures is 100% coal, beneficiation to reduce ash and sulfur is relatively more important for coal-water mixtures compared to coal-oil mixtures. As with coal-oil mixture preparation, the elimination of the need for dewatering and other factors promote the integration of coal beneficiation with the other coal-water mixture preparation process.

Additives consist of dispersants and stabilizers. The dispersant functions to disperse coal particles in the liquid and produce a slurry using electrostatic repulsion effects or steric repulsion effects. Stabilizers such as sodium sulfonate from naphthalene, polystyrene, polymethacrylate, polyolefin, and the like are used to prevent the coal particles in the slurry from settling. The fluidity of coal-water mixtures has characteristics of a non-Newtonian fluid but can be characterized as approaching a Bingham fluid (a viscoplastic material that behaves as a rigid body at low stresses but flows as a viscous fluid at high stress). The fluidity characteristics also change, depending upon the type of coal, concentration, additives, and flow state.

Moreover, heavily loaded coal-water mixtures can be successfully fired in burners designed for oil. However, the tests also indicated areas needing development, including reducing air preheating requirements, extending burner turndown capability, increasing carbon conversion efficiency, and extending burner lifetime by reducing effects of erosion. These development needs are related to the slow burning and abrasive characteristics of coal-water mixtures relative to oil.

Developmental goals considered to be necessary for acceptable performance include a turndown ratio of 3:1 or better, minimum burner-tip life of 2,000 hours, air preheating of less than 150°C (300°F), maximum droplet size of 300 microns, and carbon conversion efficiencies of greater than 99%. Small-scale tests suggest that these coals are achievable, but what is yet required is long-term demonstration in large electric-utility-size boilers in the 100- to 500-MW range.

A major issue affecting decisions to convert burners from oil to coal-water mixtures is the *de-rating* in capacity compared to the original maximum continuous rating with oil firing. In small-scale tests, the capacity with a coal-water mixture has been maintained at

90-100% of maximum continuous rating by modifications, such as adding soot blowers to minimize loss of heat transfer, changing burner-tip design, and enlarging furnace volume. De-rating can also be minimized by using high-quality coal and advanced beneficiation in the coal-water mixture preparation. Preferred trade-offs between accepting some de-rating versus maintaining maximum continuous rating (by various facility modifications or use of more-refined coal-water mixtures) is a site-specific problem that in most cases will require actual boiler testing.

Finally, another opening for coal-mixture combustion involved the co-combustion of coal and natural gas. The combined combustion of coal and natural gas offers advantages compared to burning coal or natural gas alone. For example, low volatile coals or low volatile chars derived from treatment or gasification processes can be of limited use due to their poor flammability characteristics. However, the use of natural gas in conjunction with the coal can provide the necessary *volatile matter* to enhance the combustion. Additionally, natural gas provides a clean cofiring fuel source which can enhance the usefulness of coals with high sulfur content. Addition of natural gas may reduce emissions of sulfur oxides through increased sulfur retention in the ash and reduce emissions of nitrogen oxides by varying local stoichiometry and temperature levels.

Coal/water mixtures (CWM) can provide coal-fired power plant operators with the opportunity to replace natural gas or oil with coal in the form of coal-water mixtures which have significant advantage over the use of coal. However, unlike natural gas or oil, coal contains significant quantities of inorganic material (ash-producing minerals) which can adversely influence boiler performance and fuel handling equipment. Burners can be modified to provide satisfactory ignition and flame stability characteristics with coal-water mixtures. The problems associated with ash formation can be mitigated though effective beneficiation processes. The optimum level of coal beneficiation is dependent upon coal composition, as well as burner and configuration.

7.5.5 Coal-Biomass Fuels

The term *biomass* refers to materials derived from plant matter such as trees, grasses, and agricultural crops. The most common types of biomass that are available at potentially attractive prices for energy use at federal facilities are waste wood and waste paper. These materials, grown using sunlight energy, are suitable fuel supplements or fuel alternates for fueling many of modern energy needs (Speight, 2011a, 2011b). The most common types of biomass that are available at potentially attractive prices for energy use at federal facilities are waste wood and wastepaper.

Furthermore, in the present context, one of the most attractive and easily implemented biomass energy technologies is coal-biomass co-combustion (simultaneous combustion of both feedstocks) in existing coal-fired boilers (FEMP, 2004). In coal-biomass cofiring, the biomass can substitute for up to 20% w/w of the coal used in the boiler. When it is used as a supplemental fuel in an existing coal boiler, biomass can provide the following benefits: (i) lower fuel costs, (ii) avoidance of landfills with the associated costs, and (iii) reductions in sulfur oxide, nitrogen oxide, and greenhouse-gas emissions.

Co-combustion (often referred as co-firing or cofiring) is a near-term, low-cost option for efficiently and cleanly converting biomass to electricity by adding biomass as a partial substitute fuel in high-efficiency coal boilers. It has been demonstrated, tested, and proved in all boiler types commonly used by electric utilities. There is little or no loss in total boiler efficiency after adjusting combustion output for the new fuel mixture. This implies that biomass combustion efficiency to electricity would be close to 33%-37% when cofired with coal.

The opportunities for biomass cofiring with coal offers several environmental benefits. Cofiring reduces emissions of carbon dioxide, a greenhouse gas that can contribute to the global warming effect. Also, biomass contains significantly less sulfur than most coal. This means that cofiring will reduce emissions of sulfurous gases such as sulfur dioxide that will then reduce acid rain. Early test results with woody biomass cofiring showed a reduction potential as great as 30% in oxides of nitrogen, which can cause smog and ozone pollution.

The characteristics of biomass are different from those of coal, even when only the atomic hydrogen/carbon and hydrogen/oxygen ratios are compared (Figure 7.3) (Jenkins *et al.*, 1998; Speight, 2011b, 2020). The content of volatile matter in wood-based biomass is generally close to 80%, whereas in coal it is approximately 30% w/w. Wood char is highly reactive, which results in complete combustion of wood fuels in fluidized bed combustion. Nitrogen and sulfur contents of wood are low, which implies that blending wood biomass with coal lowers emissions because of dilution. Further, one important difference between

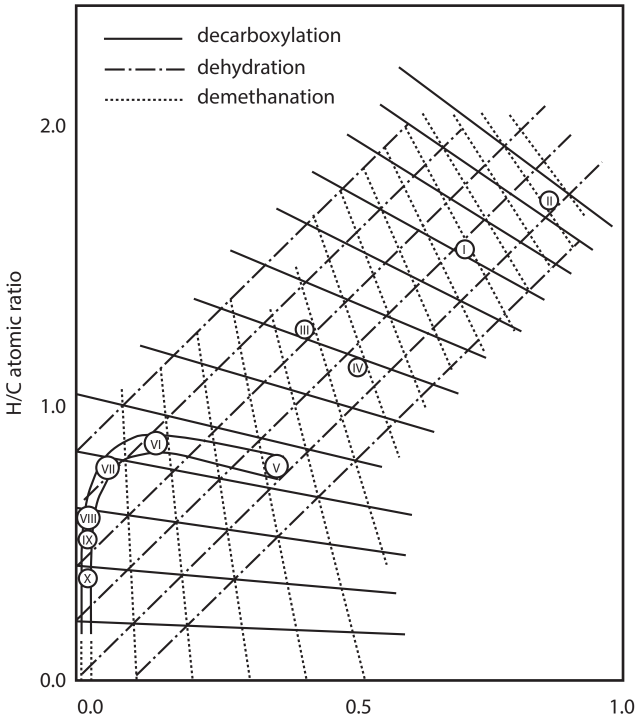

Figure 7.3 H/C-O/C diagram (Van Krevelen, D.W. 1950. Graphical-Statistical Method for the Study of Structure and Reaction Processes of Coal. *Fuel*, 29: 269-284. 1: Wood; II: Cellulose; III: Lignin; IV: Peat; V; Lignite; VI: Low-Rank Bituminous Coal; VII: Medium-Rank Bituminous Coal; VIII: High-Rank Bituminous Coal; IX: Semi-Anthracite; X: Anthracite.

coal and biomass is the net calorific value. Biomass fuels often have high moisture content which results in relatively low net calorific value.

The compositions of biomass among fuel types are variable, especially with respect to inorganic constituents important to the critical problems of fouling and slagging. Alkali and alkaline earth metals, in combination with other fuel elements such as silica and sulfur, and facilitated by the presence of chlorine, are responsible for many undesirable reactions in combustion furnaces and power boilers. Reductions in the concentrations of alkali metals and chlorine, created by leaching the elements from the fuel with water, yield remarkable improvements in ash fusion temperatures and confirm much of what is suggested regarding the nature of fouling by biomass fuels (Sami *et al.*, 2001; Jenkins *et al.*, 1998).

Because of the variability of composition, the combustion of biomass is different from coal. The yield of volatiles from coal is different from the yield of volatile matter from biomass – as examples there is an approximate 30% w/w yield of volatile matter from bituminous coal and approximately 5% w/w yield of volatile matter from anthracite as compared to approximately 50% w/w yield of volatile matter from wood. Due to this, most of the combustion air needed to burn coal has to be supplied from underneath the fire. A coal fire has to be started with wood, oil, or gas to bring it up to the ignition temperature. Once started, it will burn as long as fuel is supplied.

A global reaction for the combustion of a biomass fuel in air is difficult to formulate and might, in the simplest terms, take the form of the combustion reaction for coal:

$$2C_{\text{biomass}} + O_2 \rightarrow 2CO$$

$$C_{\text{biomass}} + O_2 \rightarrow CO_2$$

$$C_{\text{biomass}} + O_2 \rightarrow CO_2$$

$$H_{\text{biomass}} + O_2 \rightarrow H_2O$$

$$H_{\text{biomass}} + H_2O \rightarrow CO + H_2$$

$$N_{\text{biomass}} + O_2 \rightarrow NOx$$

$$S_{\text{biomass}} + O_2 \rightarrow SOx$$

Because of the complexity of biomass and the different types of biomass – where the differences in composition exceed the differences in coal composition (Speight, 2011b, 2020) – the inclusion of the range of elements in biomass is incomplete. In fact, there are many more, some of which are important to the issue of biomass combustion. Heavy metals, for example, have a strong influence on ash disposal, and must be taken into consideration when biomass is used in any power plant that uses the cofiring principle, but are not included in the elemental structure above (Jenkins *et al.*, 1998).

In spite of the differences in the composition and behavior of biomass, one of the most attractive and easily implemented biomass energy technologies is cofiring with coal in existing coal-fired boilers. In biomass cofiring, biomass can substitute for up to 20% of the coal used in the boiler. The biomass and coal are combusted simultaneously. Cofiring is a low-cost option for efficiently and cleanly converting biomass to electricity by adding biomass as a partial substitute fuel in high-efficiency coal boilers. Cofiring biomass with coal offers several environmental benefits: (i) the emissions of carbon dioxide are reduced, (ii) the emissions of sulfur oxides are reduced, and (iii) the emissions of nitrogen oxides are reduced.

The properties of wood biomass set additional requirements for use in a coal-fired power plant. These properties include total ash content, ash melting behavior and the chemical composition of ash (Speight, 2011b, 2020). Alkaline metals that are usually responsible for fouling of heat transfer surfaces are abundant in wood fuel ashes and will be easily released in the gas phase during combustion. In biomass fuels, these inorganic compounds are in the form of salts or bound in the organic matter, but in peat, for example, inorganic matter is bound mostly in silicates, which are more stable at elevated temperature. The elemental composition of ash (alkali metals, phosphorous, chlorine, silicon, and calcium) as well as the chemical concentration of the compounds affect ash melting behavior.

During combustion, the behavior of biomass fuel is influenced by the presence of other fuels. Even a small concentration of chlorine in the fuel can result in the formation of harmful alkaline and chlorine compounds on boiler heat transfer surfaces. The corrosion rate is increased with an increase in the metal temperature during the combustion for all three coals. Thus, apparent abnormalities or in the corrosion of metal surfaces could arise from different metal temperatures prevalent in the various coal-fired boilers. It may be possible to prevent such corrosion cofiring fuels containing sulfur and aluminum silicate peat or coal with chlorine bearing fuels (Chou *et al.*, 1998).

Residues from the wood processing industry form one specific group of risky wood fuels. By-products, such as plywood and particle board cuttings, are attractive fuels for energy producers: the fuel price may be even negative, as this material should otherwise be taken to a landfill site. But glue, coating and shielding materials may cause bed agglomeration, slagging, fouling, and unexpectedly high flue gas emissions.

Straw is a somewhat challenging fuel for co-combustion, as it has low bulk density and high chlorine and potassium content. Straw-fired boilers have had major operational problems because of rapid deposit accumulation and corrosion rates. Nevertheless, straw has been widely used for energy production in some countries for many years. An advanced logistic system and proper combustion technology are unquestionably fundamental requirements when straw combustion is considered.

Straw firing can be used in stoker or pulverized or fluidized bed boilers. The lowest levels of slagging, fouling and corrosion have been achieved with pulverized combustion. There are indications that in pulverized fuel installations there has been no major fouling or corrosion whereas experiences with fluidized bed boilers are more complex. Indications are that with steam temperatures above 565°C (1050°F), the lifetime of superheaters is unacceptably low, although problems start to occur even at lower temperatures.

In order to circumvent the issues that arise when biomass is used as a co-fuel with coal it is necessary to apply standard test methods to the biomass that lead to accurate and consistent evaluations of fuel properties (Table 7.6). Some of these methods were developed for other fuels, such as coal, but are more generally applicable and have been found to be adequate for biomass as well (Speight, 2011b, 2020).

Cofiring coal with biomass is a time-tested fuel-switching strategy that is particularly well suited to a stoker boiler – the type most often found at coal-fired facilities – but cofiring

Table 7.6 Methods of biomass fuel analysis (Jenkins *et al.*, 1998; Speight, 2008, 2011).

Property	Analytical method
General Properties	
Heating value	ASTM 5865
Particle size distribution	ASTM E828
Bulk density	ASTM E873
Proximate Composition	
Moisture	ASTM E871
Ash	ASTM E830
	ASTM D1102
Volatiles	ASTM E872
	ASTM E897
Fixed carbon	By difference
Elemental Composition	
C	ASTM E777
H	ASTM E777
N	ASTM E778
S	ASTM E775
Cl	ASTM E776
Ash elemental	ASTM D3682
	ASTM D2795
	ASTM D4278
Ash fusibility	ASTM E953
	ASTM D1857
Metals	ASTM E885

has been successfully demonstrated and practiced in all types of coal boilers, including pulverized-coal boilers, cyclones, stokers, and fluidized bed boilers (Sami *et al.*, 2001; Speight, 2011b, 2013, 2020).

The most economical sources of wood fuels are wood residues from manufacturers and mill residues, such as sawdust and shavings, bark and wood chips that are unsuitable for making paper discarded wood products, such as crates and pallets; woody yard trimmings; right-of-way trimmings diverted from landfills; and clean, nonhazardous wood debris resulting from construction and demolition work. Using these materials as sources of energy recovers their energy value and avoids the need to dispose of them in landfills, as well as other disposal methods.

To make economical use of captive wood waste materials, the pulp and paper industry in the United States has cofired wood on a regular basis, especially where biomass fuels provide more than 50% of the total fuel input. Thus, using solid biomass to replace a portion of the coal combusted in existing coal-fired boilers has been successfully demonstrated in coal-fired boilers such as stokers, fluidized beds, pulverized coal boilers, and cyclones.

One of the most important keys to a successful cofiring operation is to size the biomass appropriately and consistently according to the requirements of the type of boiler used. Biomass particles can usually be slightly larger than coal particles, because biomass is a more volatile fuel – biomass that does not meet these specifications is likely to cause flow problems in the fuel-handling equipment or incomplete burnout in the boiler.

Because of differences in the chemical composition of biomass and coal, emissions of acid rain precursor gases – sulfur oxides and nitrogen oxides – are reduced by replacing coal with biomass. Most biomass has nearly zero sulfur content, and sulfur oxide emission reductions occur on a one-to-one basis with the amount of coal (heat input) offset by the biomass.

In addition, using waste wood as a fuel diverts the material from landfills and avoids landfill disposal costs. Furthermore, the ability to operate an electricity-generating plant using an additional fuel source to replace part of the coal provides a hedge against supply disruptions (due to price increases and supply shortages) for existing fuels such as stoker coals. In a cofiring operation, biomass can be viewed as an opportunity fuel, used only when the price is favorable. Also, the most cost-effective biomass fuels are usually supplied from surrounding areas, so economic and environmental benefits will accrue to local communities.

There are also disadvantages such as the potential for the generation of excessive dust. While the incorporation of biomass into the fuel does allow greater fuel flexibility, it (the use of biomass) does not reduce the risk of fire and explosion. Coal-biomass mixtures are extremely hazardous because of the combustibility of the dust, the propensity for spontaneous combustion, and the reactivity of fuel mixtures.

It is a known fact that movement of coal to, or within, a plant generates fugitive dust – this might be a result of coal moving along on a conveyor, passing through a transfer point, or being discharged into or exiting a container. The main hazard introduced with biomass is that most biomass materials also produce combustible dust as they flow though the handling system. Adding combustible biomass dust to combustible coal dust can greatly increase an already hazardous condition.

A second hazard is that of spontaneous ignition and combustion which, well known for its contribution to fires at coal plants, especially during coal stockpiling (Chapter 4), can be just as prevalent with most biomass materials. Heat production in biomass typically begins as an aerobic process and, as the temperature rises, the chemical chain reaction takes over and the highest risk for spontaneous ignition would be in storage of moist biofuel (Blomqvist and Persson, 2003). If using moisture content as the operative criterion, the types of biofuels that would induce the highest risk for spontaneous ignition in storage, and that can be found in large quantities in storage, are wood chips, sawdust, and bark. Dry refined wood fuels as pellets, briquettes and pulverized wood would thus give a low risk for spontaneous ignition.

Also, self-ignition has been found to correlate with silo/bunker volume – the larger the volume of the silo, the lower the self-ignition temperature of the biomass. A third hazard arises from blending coal and biomass products. Generally, coal-biomass mixtures are less reactive than coal alone but more reactive than biomass alone. Thus, blending coal and biomass in the same silo will contribute to higher levels of reactivity than if the silo contained just biomass.

Specific requirements depend on the site that uses biomass in cofiring. In general, cofiring biomass in an existing coal boiler requires modifications or additions to fuel-handling, processing, storage, and feed systems. Modifications to existing operational procedures, such as increasing over-fire air, may also be necessary.

Briefly, over-fire is air that is injected into the furnace above the normal combustion zone. Over-fire air is generally used in conjunction with operating the burners at a lower than normal air-to-fuel ratio, which reduces formation nitrogen oxides. The over-fire air OFA completes the combustion at a lower temperature.

Increased fuel feeder rates are also needed to compensate for the lower density and heating value of biomass. When full rated output is needed, the boiler can be operated in a coal-only mode to avoid de-rating the unit. Expected fuel sources and boiler type dictate fuel processing requirements.

For suspension firing in pulverized coal boilers, biomass should be reduced to a particle size of 0.25 in. or smaller, with moisture levels less than 25% w/w when firing in the range of 5 to 15% w/w biomass on a heat input basis. Equipment such as hoggers (machines used to grind wood into chips for use as fuel), hammer mills, spike rolls, and disc screens may be required to properly size the feedstock. Other coal-fired boilers (cyclones, stokers, and fluidized beds) are better suited to handle larger fuel particles.

In actual practice, most modern coal-fired power stations burn pulverized coal, which is blown into the combustion chamber of a power plant through a specially designed burner. The burner mixes air with the powdered coal, which then burns in a flame in the body of the combustion chamber. This is suspension combustion and in this type of plant there is no grate. Finely ground wood, rice husk, bagasse, or sawdust can be burned in a similar way.

Suspension firing requires a special furnace – the size and moisture content of the biomass (wood) must also be carefully controlled. Moisture content should be below 15% w/w and the biomass particle size has to be less than 0.6 inch (15 mm). Suspension firing results in boiler efficiency of up to 80% and allows a smaller-sized furnace for a given heat output.

Aside from suspension firing of wood, the most efficient method of directly burning biomass is in a fluidized bed combustor (FBC). The combustion chamber of a fluidized bed plant is shaped so that above a certain height the air velocity drops below that necessary to entrain the particles. This helps retain the bulk of the entrained bed material towards the bottom of the chamber. Once the bed becomes hot, combustible material introduced into it will burn, generating heat as in a more conventional furnace. The proportion of combustible material such as biomass within the bed is typically on the order of 5% w/w.

There are different designs of fluidized bed combustors, which involve variations around this principle. The most common for biomass combustion is the circulating fluidized bed which incorporates a cyclone filter to separate solid material from the hot flue gases which leave the exhaust of the furnace. The solids from the filter are recirculated into the bed, hence the name.

The fluidized bed has two distinct advantages for biomass combustion: (i) it is the ability to burn a variety of different fuels without affecting performance, (ii) it has the ability to introduce chemical reactants into the fluidized bed to remove possible pollutants. In fluidized bed combustors that burn coal, limestone can be added to capture sulfur and prevent its release to the atmosphere as sulfur dioxide. Biomass tends to contain less sulfur than coal so this strategy may not be necessary in a biomass plant.

Cofiring biomass with coal is not likely to result in capacity additions (Spath *et al.*, 1999; Mann and Spath, 2001) but will instead take place in currently operating coal-fired power plants. Since the majority of coal-fired power plants in the United States use pulverized coal systems, it is likely that the pulverized coal system will be used to handle the biomass.

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8

Combustion Systems

8.1 Introduction

There are no documented records of when, or how, man *first discovered* that a certain *black rock* would burn but it can be surmised that coal combustion represents the first practical source of energy giving warmth and light, as well as extending the range of food which could be consumed, enabling humans to modify metals for a variety of uses (Speight, 2013).

Coal combustion is used in a range of applications which vary from domestic fires to large industrial furnaces and utility boilers. While, for reasons of economy, the oxidant is usually air, the coal may be in any degree of dispersion. In fact, coal combustion provides the majority of consumable energy to the world and despite the continuing search for alternate sources of energy (whether they are other fossil fuels or non-fossil fuels), coal appears to be so firmly entrenched that there is little doubt that coal combustion will remain important at least until the end of the 21st century, particularly where a convenient method of storing energy is required.

As power plants face a growing need to reduce costs and environmental impacts, coal quality is increasingly an issue of interest, as a means to do more with less. Coal quality affects plant performance in efficiency, emissions, and availability. At high combustion temperatures, fractions of ash can become partially fused and sticky. Depending upon the ash fusion temperature of a particular coal, the ash can adhere to heating surfaces building up as slag on water-walls and bridging tubes to obstruct the flow of combustion gases. Recognizing the importance of fuel quality, coal specifications have become more restrictive, monitoring more intensive, and penalties more expensive. This can lead to increasing fuel cost as the demand for the most desirable sources escalates.

For large, central power stations, pulverized coal-fired (PC) boilers have evolved as the technology of choice. Pulverized coal-fired boilers combust a suspension of finely ground coal, which is blown into the furnace in a gaseous matrix to form a large stable flame vortex.

In the system, the coal is ground (pulverized) to a fine powder, so that less than 2% is >300 micrometers (µm, microns) and 70 to 75% is below 75 microns, for bituminous coal. It should be noted that too fine a powder is wasteful of grinding mill power whereas if the powder is too coarse it will not burn completely in the combustion chamber and results in higher losses of unburned material (char on the ash). The pulverized coal is blown with part of the combustion air into the boiler plant through a series of burner nozzles – secondary and tertiary air may also be added. Combustion takes place at temperatures from 1300 to 1700°C (2370 to 3090°F), depending on the grade of coal. Particle residence time in the boiler is typically 2 to 5 seconds, and the particles must be small enough for complete combustion to have taken place during this time.

In a pulverized coal-fired boiler, the coal burners release the combustion energy in the form of intense flame zones directly in the furnace. The design of the furnace efficiently

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utilizes the concentrated heat release to generate most of the steam production within the water-wall surfaces of the furnace. Once out of the furnace, the high temperature exhaust gases continue to generate steam and superheat through the remaining boiler sections.

In considering the replacement of the coal by an alternate fuel, such as the use of a coal-oil fuel, a coal-water fuel or more likely a coal-biomass fuel (see below), the production capacity and steam superheat conditions of the boiler, both critical elements for the optimum plant performance, are intimately determined by the burner heat release rates and temperature profile. To maintain output conditions, any replacement of coal capacity must be accomplished by a suitable fuel which will burn in suspension within the furnace and at the burner levels established by the coal. In some instances, this can be accomplished by introducing some portion of the alternate fuel directly into the coal feed system, ahead of the pulverizers, and displace some of the coal feed directly into the burner unit.

Overall, the pulverized coal-fired system has many advantages, such as (i) the ability to fire varying quality of coal, (ii) quick responses to changes in load, and (iii) the use of high pre-heat air temperatures. One of the most popular systems for firing pulverized coal is the tangential firing using four burners corner to corner to create an intense burning zone (*fireball*) at the center of the furnace.

Fine coal particles react similarly to atomized particles of liquid fuels. The reaction time is measured in seconds. The amount of coal, its heating value, and the impurities determine the size and design of the furnace/boiler and placement of the heating surfaces. Coal ash/impurities can form deposits on heat transfer surfaces and the ash itself must be collected. Products of combustion including sulfur oxides (SOx) and nitrogen oxides (NOx) compounds must be controlled (Chapter 12). The amount of ash and its constituents are basic design parameters for the boiler and the back-end air quality control systems.

Thus, a major concern in the present-day combustion of coal is the performance of the process in an environmentally acceptable manner through the use of a variety of environmentally acceptable technologies such as the use of a low-sulfur coal or through the use of post-combustion cleanup of the off-gases (Chapters 12, 14). Thus, there is a marked trend in the modern research to more efficient methods of coal combustion. In fact, the ideal would be a combustion system that is able to accept any coal without a pre-combustion treatment, or without the need for post-combustion treatment, or without emitting objectionable amounts of sulfur and nitrogen oxides and particulates.

As a result of serious environmental concerns related to the use of coal as a fuel, coal combustion is being subjected to increasingly stringent emissions limits. The need to reduce emissions of sulfur dioxide and nitrogen oxides will be related to several issues: (i) the reduction in acid deposition, (ii) reductions in smog in major metropolitan areas, (iii) lowering ambient levels of fine particulate matter, and (iv) elimination of visibility impairment in many countries of the world. Furthermore, pressure to reduce emissions of mercury from coal-fired power plants is also subject to emissions limits.

Thus, development of a suite of combustion systems, including pressurized fluidized-bed combustion, integrated gasification combined cycle, indirect fired cycles, turbines, and combined cycles for application in central power generation is essential since coal will remain a major player in power generation for the foreseeable and distant future. This includes the development of technologies such as gasification and advanced combustion, as included in the clean coal technology program which are already on-stream and undergoing further development (Chapter 14) (Speight, 2011, 2013, 2020).

As noted previously (Chapter 7), coal combustion involves burning in the presence of oxygen to produce heat and carbon dioxide – in the absence of oxygen (or an oxygen-containing atmosphere) thermal decomposition of coal is referred to as *pyrolysis*. Over the years, the methods by which coal combustion has been accomplished have evolved to several types of systems, each with its own particular merits and use.

The basic coal combustion technology can be classified on the basis of the particle size of burning coal and coal-feeding methods, which mainly include the coal fixed-bed combustion, coal suspending combustion, and coal fluidized-bed combustion More modern coal-combustion systems are usually referred to as layer and chambered; the former refers to fixed beds while the latter refers to systems designed for pulverized coal. The feed systems applicable to the combustor are (a) overload, (b) front feed, and (c) under-feed (Merrick, 1984). However, caution is advised here as there may be overlaps in the naming of the technology as well as in operation of the various technologies.

Briefly, there is need for a comment related to coal properties and the effect of these properties on combustion systems. Coal properties that have the greatest effect on boiler operation are (i) mineral matter content of the coal, reflected in the yield of combustion ash, (ii) the composition of the ash composition, (iii) the sulfur content of the coal, and (iv) the moisture content of the coal.

High ash yield results in increased system throughput, increased erosion and shortened life of the coal, boiler, and ash handling systems. Ash composition affects the slagging of furnace walls and fouling of convection passes. Fouling decreases heat transfer and promotes wastage by external corrosion/erosion in the convection passes, air preheaters and the induced-draft fans. Excessive slagging blocks off the convection passes and plugs air preheaters. Sulfur content influences the operation and maintenance of feeders, pulverizers, furnace walls, platens, pendants, economizers, soot blowers, air preheaters, dust collectors, and induced-draft fans. Pyrite causes excessive wear of the pulverizer internals.

In the coal-fired power plant, coal is continuously fed to the pulverizers from the boiler bunkers, and hot air is introduced into the pulverizers to dry and transport the pulverized fuel to the burners. The coal properties which have the most impact on pulverizer performance are (i) the specific energy, which governs the rate at which coal must be pulverized to achieve a required boiler load – low specific energy coal will cause higher mill power consumption due to the need for increased coal flow, (ii) the moisture content – high moisture content will require higher mill inlet temperatures to maintain the desired mill outlet temperature of approximately 70°C (158°F), (iii) hardness of the coal and coal rank – hard coal may require more pulverizer power and/or capacity to achieve the required rate of production of pulverized coal and the size distribution may be coarser since coals of different rank behave differently due to effects such as different maceral composition, and may require less power, but generally produce a coarser product, (iv) mineral composition – hard minerals (especially, quartz and pyrite) present in coal increase wear of mill components and subsequent maintenance costs. All of these properties that are out of specification can cause pre-mature failure, forced outages and de-rating of the boiler system.

The boiler, through combustion, converts the chemical energy in the coal to thermal energy and transfers the heat produced to convert water to superheated steam at high pressure and deliver it to the steam turbine/generator. The coal properties which have most impact on boiler performance are (i) moisture content – high moisture content reduces boiler efficiency as energy from the coal is used in evaporation of the water, and the sensible heat loss from the flue gas is greater, (ii) furnace temperatures are generally lower reducing heat transfer rates, (iii) coal reactivity – the reactivity of the coal (combustion rate) which is governed by the volatile content (rank) and petrographic composition of the coal, affects boiler performance in terms of flame stability and efficiency of pulverized coal burnout, (iv) ash composition – the chemical composition of the ash governs the behavior of a coal with regard to ash deposition on heat transfer surfaces, and can have a marked impact on boiler availability and maintenance costs, and (v) mineral composition – the presence of hard minerals – such as quartz and pyrite – can cause erosion damage to the boiler tubes depending on their nature and concentration.

In fact, all aspects of coal properties and behavior need to be understood including (i) handling and storage characteristics (Chapters 3, 4), (ii) pulverizing behavior (Chapter 3), (iii) combustion behavior (Chapter 7), (iv) mineral matter and ash chemistry interactions in addition to the characteristics of the coal (Chapters 1, 5, 6) (v) the ash in terms of environmental factors such as dust (Chapter 1), (vi) spontaneous ignition (Chapter 4), and (v) the emissions of the various components (Chapters 12, 14). In order to ensure that quality is controlled, the coal chain must be regularly sampled and adjusted in accordance with the analytical results (Chapter 5). Key control parameters, which when monitored, can provide a reliable indication of quality flow in terms of both feedstock (coal) specification and consistency requirements.

It is the purpose of this chapter to present a review of the various combustion systems by which the energy incumbent in coal is released and applied to power generation. Advances to these technologies are included in the clean coal technology program (Chapter 13).

8.2 Combustion Systems

Converting coal to electric power appears, on paper, to be a relatively simple process. In most coal-fired power plants, coal is crushed into fine powder and fed into a combustion unit where it is burned. Heat from the burning coal is used to generate steam that is used to spin one or more turbines to generate electricity. But that is not the end of the story – various systems have been designed to fit the purpose of converting coal to power and as might be expected, the design of such systems varies with the nature of the coal feedstock.

A wide range of coal types having either high or low fusion temperatures can be burned using the various combustors. In general, bituminous coal, subbituminous coal, or lignite fit well into the spreader combustion process and these types of coal can be burned in a given unit with the same combustion heat release. However, there may be issues related to the attributes of each coal type as it relates to boiler furnace and gas pass design. There are plants that have substituted lower grades of coal for cost savings as well as substituting low sulfur bituminous or subbituminous coal to meet state or local emission requirements.

There are two major methods of coal combustion: fixed-bed combustion and combustion in suspension (Ceely and Daman, 1981; Merrick, 1984). The first fixed-bed systems (open fires, fireplaces, domestic stoves) were simple in principle and were the only known way of burning coal. The coal bed is supported on a grate, which may be fixed or movable, and the air needed for combustion, generally passes upward through the coal bed either by the chimney draught or by a fan. However, as an exception, in some hand-fired domestic appliances the combustion air is drawn downward through the coal bed for eliminating smoke. In general, coal may be fed to the bed in three modes: overfeed, underfeed, and cross-feed.

Suspension burning of coal began in the early 1900s with the development of pulverized coal-fired systems, and by the 1920s these systems were in widespread use. Spreader stokers, which were developed in the 1930s, combined both principles by providing for the smaller particles of coal to be burned in suspension and larger particles to be burned on a grate.

Coal combustion may be achieved using pulverized coal in entrained systems or as sized particles in fixed or slowly moving beds; larger pieces may, in certain instances, also be used. In the case of the fixed- or slowly-moving-bed combustor, it is usual to employ a mechanical stoker to feed the coal and a grate to support the coal particles as well as to admit air for the combustion process. With regard to the pulverized systems, coal that has been crushed to approximately 200 mesh is carried into the system by entrainment in the air.

Pulverized coal combustion (PCC) involves grinding the feed coal to approximately <70 mm and injecting the powdered coal into the combustor from either wall-mounted burners or corner-mounted (tangential) burners. Combustion takes place within a few seconds at flame temperatures up to 1500°C (2730°F). Supercritical pulverized coal combustion is a variation that seeks to improve thermal efficiency, from the typical values of up to approximately 40% for pulverized coal combustion to 43 to 47% in supercritical systems through higher steam temperatures and pressures.

In the pulverized coal combustion system, ash is formed in the combustion chamber while coal combusts. There are several configurations for commonly used pulverized coal furnaces, which can impact ash formation, but the primary advantage of pulverized coal combustion is the fine nature of the fly ash produced. In general, pulverized coal combustion results in approximately 65 to 85% w/w fly ash, and the remainder is coarser bottom ash or boiler slag. Bottom ash is a coarse material and falls to the bottom of the combustion system. Fly ash is finer than bottom ash and is carried along the combustion process with flue gas. Particulate collection devices generally capture fly ash before being discharged into the atmosphere.

At this time, some note should also be made of the various size designations and size limits for coal. For example, run-of-mine coal and large-lump coal are variable in size with no top or bottom limits whereas lump coal varies from a minimum size of 1 in. (2.5 cm) to a variable top size. On the other hand, cobble (egg or stove) coal varies in size from 2 in. (5 cm) to 6 in. (15 cm) whereas nut coal falls within the size limits 3/4 in. (2 cm) to 2 in. (5 cm). The coals designated as prepared stoker coals all fall into the size range 1/16 in. (0.2 cm) to 2 in. (5 cm) but they are further subdivided into three classes: large (1/4-2 in.; 0.6-5 cm), intermediate (1/8-1 in.; 0.3-2.5 cm), and small (1/16-3/4 in.; 0.2-2 cm). However, nut (nutty) slack, slack, and fines are only defined in terms of an upper size limit and these are 2 in. (5 cm), 1-1/4 in. (3 cm), and 1/2 in. (1.3 cm), respectively.

However, conventionally designed boilers are not suitable for burning high alkali fuels such as some types of biofuel feedstocks. Special boiler designs with low furnace exit gas temperatures (<815°C, <1500°F) are required for annual crops or residues, including grasses and straws. Designs should include (i) adequate waterwall surface area or parallel heat exchange surfaces, (ii) combustion air control to control gas temperatures, (iii) grates suitable for removing large quantities of ash, and (iv) soot blowing to remove tenacious deposits.

Limestone ($CaCO_3$) was the principal additive used in test boilers to maintain bed fluidization but while limestone improved operation the calcium appears as a constituent of deposits on convection surfaces (as $CaCO_3$, $CaSO_4$) and may reduce deposition but does not prevent deposition. High alumina (Al_2O_3) sand also reduced agglomeration in a circulating fluidized bed combustor but may not change the composition of deposits on the superheater tubes. Gasification at low temperatures (760°C;1400°F), with additives, may be necessary to inhibit alkali volatilization in order to burn large quantities of these biofuels.

8.2.1 Stoker Systems

The first type of furnace was the *spreader stoker*, in which a mechanical shovel moved between a fuel hopper and the fixed grate, spreading the coal onto the burning zone (Speight, 2013). Later improvements in ash handling and coal feeding, however, have made this early stoker design obsolete.

Stoker-fired boiler plants are less common than they were three decades ago. Generally, for those still in existence, small and mid-sized coal combustion plants utilize travelling grate stokers to produce steam for power. When these plants were first designed, reliability was the key concern but with considerable attention being paid to increasing efficiency and reducing emissions, many stoker systems have been replaced by more efficient coal-fired systems, which have lower emissions.

For stoker applications, combustion is governed by the physical properties of the fuel bed and air distribution throughout the bed and not by the inherent reactivity of the coal or even by the percentage of mineral matter in the coal. The physical properties of the coal bed are particle size, particle size distribution, caking properties, and ash fusion temperature of the coal, which govern the air flow through the bed.

For proper combustion, the air must rise up through the grate and diffuse through the bed of coal. The combustion air must have intimate contact with the coal particles throughout the combustion process. This principle of securing proper distribution of air through a stoker fuel is fundamental; most of the difficulties that arise in burning coal are the result of poor distribution of combustion air. Coal particle size and size distribution affect the air distribution within the bed, the void ratio and pressure drop. Void ratio and pressure drop can then be correlated to carbon burnout of the coal during combustion.

Thus, coal sizing has a significant effect on stoker operation and size distribution of the fuel is important from the standpoint of efficiency, availability, as well as low emissions.

Coals too coarse will not burn at the high rate required for optimum spreader operation and coals too fine can cause operational as well as emission problems without proper design and operating procedures. The theoretical size is equal proportions of 0.75 inch x 0.5 inch, 0.5 inch x 0.35 inch, and less than 0.25 inch. The equal gradation is to allow for the even combustion over the grate surface. This size is not available from a practical standpoint and the spreader feeders have the capabilities to adjust for coal sizing. However, as the amount of fines smaller than 0.10 inch there is a concomitant increase in fly ash carryover – precipitators or baghouses can readily handle the carry carryover from spreader stokers just as they do for pulverized coal-fired boilers and circulating fluid-bed-fired boilers.

Spreader stokers utilize a combination of suspension burning and grate burning. The coal is continually fed into the furnace above a burning bed of coal. The coal fines are burned in suspension; the larger particles fall to the grate, where they are burned in a thin, fast-burning coal bed. This method of firing provides good flexibility to meet load fluctuations, since ignition is almost instantaneous when firing rate is increased – as a result, the spreader stoker is favored over other types of stokers in many industrial applications.

Thus, the advantages of a stoker system include (i) the coal does not have to be pulverized, (ii) a low level of particulate emissions occurs, simplifying flue gas cleanup, (iii) a stoker is easy to operate and can be manually controlled if desired, (iv) the stokers can be built in small sizes. However, some disadvantages are (i) high maintenance is involved due to bulky moving parts, and (ii) the stoker does not provide efficient gas-solid contact and requires a relatively large furnace volume for a given steam production, due to the low heat release rate per unit area of grate and the fact that the grate takes up furnace volume, and (iii) although there may be claims to the contrary, no one stoker can burn all types of coal, mainly due to caking properties of the coal and ash clinker that can form, depending upon the ash fusion temperature – it is often desirable to wash the coal to make it more amenable to stoker firing.

In addition, a correctly specifically manufactured and configured stoker is an excellent combustor of cellulose waste, such as (i) wood, such as shredded trees and sawdust, (ii) industrial and domestic waste, such as refuse-derived fuel, (iii) bagasse, such as sugar cane residue, (iv) industrial residue, such as paper, plastics, and wood, (v) furfural residue, (vi) peanut shells, and (vii) shredded tires. Most of these fuels can be burned without auxiliary fuel with proper attention to fuel moisture, design heat release, combustion air system design, and preheated air temperature. Co-generation and the emphasis on renewable fuels have driven increased use of these fuels.

On the other hand, the stoker also has several disadvantages, such as (i) the high maintenance that is involved due to bulky moving parts, (ii) there is inefficient gas-solid contact and requires a relatively large furnace volume for a given steam production, due to the low heat release rate per unit area of grate and the fact that the grate takes up furnace volume, (iii) no stoker can burn all types of coal, mainly due to caking properties of the coal and ash clinker that can form, depending upon the ash fusion temperature. It is often desirable to wash the coal to make it more amenable to stoker firing.

8.2.2 Fixed-Bed Systems

In a *fixed-bed combustor*, the air passes upward through the pulverized coal at a low velocity. The coal is held on a grate, and the bed of hot coal may be several inches thick. The coal remains in a fixed bed since the air velocity is not sufficient to lift the coal particles upward. Ash removal is continuous or semi-continuous by mechanical means. This type of bed, however, does not afford very efficient gas-solid contact. High combustion rates are not possible with this system.

During the 19th century, virtually all methods for burning coal used the coal-bed-on-a-grate method. The first technological developments were oriented towards controlling the amount of air supplied to the bed, and developing mechanical devices to transfer coal into the burning zone and remove the ash from the same area to prevent clogging of the chamber.

8.2.2.1 Fixed- and Moving-Grate Systems

The original coal-burning system was a fixed bed on a grate – the fixed-grate system. An over-feed fixed bed on a fixed grate is the simplest way of coal combustion. Fresh coal is spread onto the surface of the burning coal bed manually or by a spreader. From the grate to the bed surface the bed is divided into several zones based on combustion reactions that take place. The fresh coal on the bed surface is heated rapidly by the hot combustion gas and the radiation from the high-temperature flames and furnace walls. It is advantageous to the ignition of the coal. The burning coal then descends in turn through the reducing region and the oxidization region, becoming ash on the grate, and is finally removed.

For fuel-bed burning on a grate, a distillation effect occurs and the result is that liquid components which are formed will volatilize before combustion temperatures are reached; cracking may also occur. The ignition of coal in a bed is almost entirely by radiation from hot refractory arches and from the flame burning of volatiles.

The combustion air is generally supplied from the grate, flowing upwards through the fuel-bed. The air is first heated by the coal ash, and then reacts with the high temperature coal char. The combustion reaction produces carbon dioxide and releases a large amount of heat, resulting in the rapid rise in the bed temperature. The oxygen will be finally used up with the progressing of the oxidizing reaction. The bed layer where the oxidizing reaction takes place is referred to as the oxidizing layer, which is the highest temperature zone in the bed. If the thickness of the coal-bed is greater than that of the oxidizing layer, a reducing layer will appear on top of the oxidizing layer, where carbon dioxide can react with carbon at high temperature, producing carbon monoxide:

$$CO_2 + C \rightarrow 2CO$$

Therefore, different combustion reactions may take place with different combustion products, depending on the bed thickness. For this reason, two different combustion methods were designed accordingly, i.e., the shallow-bed combustion and the thick-bed combustion.

In the shallow-bed combustion, the coal bed is approximately 4 to 6 inches (100 to 150 mm) thick for bituminous coal, so there is no occurrence of reducing reaction. All air needed in combustion is supplied from the bottom of the bed. In the thick-bed method, the bed thickness is approximately 8 to 16 inches (200 to 400 mm) for bituminous coal – the combustion air is provided separately. The primary air is provided from the bottom of the bed, and the secondary air is provided over the bed to burn out the combustible gas produced by the bed. The ratio of the primary air to the secondary air depends on the coal volatile content and the amount of combustible gases.

Coal can be fed not only onto the bed, but also under the bed. This is the underfeed mode. In this mode, burning coal moves in co-current flow with the combustion air. The released volatile matter, moisture, and combustion air pass up through the bed so that less smoke is emitted in part-load operations. The underfeed-stoker designed to burn bituminous and anthracite for firing boilers and warm-air furnaces is automatic and often used for residential purposes. In the stoker, coal is fed from a bin or hopper by a feed screw into the bottom of a conical retort, through the inner and outer walls from which air from a motor-driven fan is supplied for combustion. Typically, the underfeed-stoker is not used for the firing of huge boilers, because of the impossibility of building them large enough to burn coal at the required rate. In the intermediate sizes, the stoker tends to lose its favorable position due to its sensitivity to the caking and ash fusion characteristics of coal. Thus, the successful operation of this type of stoker lies in the careful selection of the coal used on it and a conservative rating to avoid a high rate of burning as well as an excellent mechanical design.

Another coal feed system is the *chain-grate stoker* in which coal is fed from hoppers by gravity to a grate which consists of an endless chain extending into the boiler (Figure 8.1).

In the chain-grate system, coal is fed onto one end of a moving steel grate. As grate moves along the length of the furnace, the coal burns before dropping off at the end as ash. When setting up the grate, air dampers and baffles, it is necessary to ensure that the unit promotes clean combustion leaving the minimum of unburned carbon in the ash. The coal-feed hopper runs along the entire coal-feed end of the furnace. A coal gate is used to control the rate at which coal is fed into the furnace by controlling the thickness of the fuel bed. Coal must be uniform in size as large lumps will not burn out completely by the time they reach the end of the grate.

More specifically, the horizontal movement of the grate carries the coal into the combustion chamber; the coal is carried forward as a thin layer on the top surface of the grate while air is delivered beneath it. As the coal enters the combustion chamber, the top surface is ignited by radiation from a hot refractory arch and the flame front then travels down through the coal bed while the air comes up through it. At the end of the grate the coal has been burned and any residual ash is dropped into a container as the grate turns for the return journey.

The chain-grate stoker (traveling-grate stoker) is a typical automatic moving stoker. Its moving grate carries the coal bed on it passing through the high temperature areas of furnaces. The coal overfeed mode combines with the moving grate, forming a spreader stoker, in which coal is spread onto a moving bed by a spreader. The moving grate moves from the rear wall to the front wall or vice versa depending on the type of the spreader. As in the

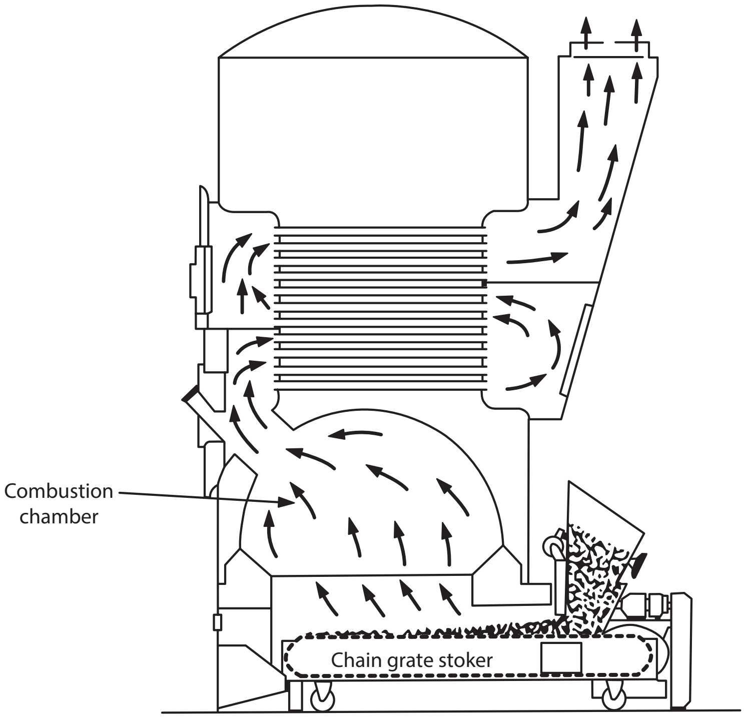

Figure 8.1 A Chain-grate stoker (Speight, 2013).

case of the fixed-grate system, most fresh coal falls onto the burning coal bed, getting better ignition condition. Spreader stokers are of adaptability to a wide range of types and sizes of coals, ability to respond quickly to the change of load, and relative freedom from slag and deposit problems in the furnace or on the heating surface. The disadvantages of this type of stoker are the tendency to excessive smoke emission at part loads, high carryover of fly ash and cinder at high loads, which can be minimized by an over-jet, for increasing the turbulence in the furnace to reduce smoke and by the use of dust collectors to reduce the emission of fly ash from the stack.

On a considerable number of these moving grates coal is fed not by spreaders, but from a hopper under an adjustable guillotine-type gate. The gate controls the thickness of the coal bed. This is referred to as the cross-feed mode. In the moving grate, the coal bed carried by the grate moves from the front wall to the rear wall in furnace, and the coal drying, devolatilization, volatile combustion, char combustion and ash removing take place in the bed with the bed moving. The coal on the surface of the bed is ignited by the radiation of the furnace, and the combustion is transmitted downwards. In general, a front arch and a long rear arch are used to insure stable ignition and fine mixing of fuel and oxygen. This type of equipment remains suitable for the plants which can be assured of a longtime supply of a suitable coal, and which do not require rapid changes of load. The problems of smoke at low loads and that of carry-over of fly ash are much less acute than they are with spreader feeding of coal.

Besides the chain-grate stoker, there are also some other types of moving-grate stokers, such as the sprinkler stoker, the vibrating-grate stoker, and the reciprocating-grate stoker.

The fixed-bed combustion of coal is particularly sensitive to coal properties, which is partly the reason why other methods of burning coal, less sensitive to fuel characteristics, have been developed. The fuel bed, however, is still an important method of burning coal especially in industrial boilers.

For example, strongly caking coals can cause problems with chain-grate units but not with underfeed or spreader units. Coal size is important with chain-grate stokers since fines lead to excessive caking and high unburned carbon losses. The amount of coal smaller than 1.4 inch is usually limited; spreader and underfeed stokers are less sensitive to particle size.

In fixed beds (slowly moving beds), the radiant heat above the bed can only penetrate a short distance into the bed. Consequently, convective heat transfer determines the intensity of warming up and ignition. In addition, convective heat transfer also plays an important part in the overall flame-to-surface transmission. The reaction of gases is greatly accelerated by contact with hot surfaces and, while the reaction away from the walls may proceed slowly, reaction at the surface proceeds much more rapidly.

8.2.2.2 Up-Draught Combustion

One of the simplest ways of achieving up-draught combustion involves lumps of coal in a bed supported by a grate. Provision is made for the supply of primary air beneath the bed and secondary air above it as there is a connection to a flue in order to provide a draught. This simple principle has provided good service in a number of applications ranging from the domestic fire to the furnace. A fire of this type is ignited at the base, after which the flame front spreads upward until the whole bed is incandescent; the system is usually termed *up-draught combustion*, but the important technical feature is that the flame front travels in the same direction as the primary air.

The best-known example of coal combustion is provided by the domestic fire and the majority of industrial coal burners operate on the same overfeed principle. Once combustion has commenced, a number of separate reaction zones can be distinguished (Figure 8.2). The fresh coal feedstock is placed on the upper surface and the heat transferred from the bed below causes evaporation of the volatile material which burns in the secondary air and leaves a residue of fixed carbon or coke.

Primary air enters the base of the grate and passes first through the ash zone. The ash performs a useful function in providing insulation between the high-temperature reaction zone and the grate. In the first oxidation zone, the oxygen reacts at the surface of the carbon to give carbon monoxide.

$$2C_{coal} + O_2 \rightarrow 2CO$$

The carbon monoxide is released from the solid and reacts on mixing with oxygen, in the second oxidation zone, to give carbon monoxide.

$$2CO + O_2 \rightarrow 2CO_2$$

Each of these reactions is strongly exothermic and some of the heat released promotes the initial carbon-oxygen reaction at what is usually the hottest part of the fuel bed. At this stage, the oxygen concentration is very much depleted and the carbon dioxide is reduced by the Boudouard reaction in the next layer of fuel:

$$CO_2 + C \rightarrow 2CO$$

This reaction is endothermic and, therefore, the bed temperature will decrease. When the carbon monoxide leaves the fuel, it mixes with secondary air and burns again to carbon dioxide. The concentration changes through the zones (Figure 8.2) (Thring, 1952) and the maximum temperature coincides approximately with the maximum carbon dioxide concentration.

The relative importance of the various factors which control the rate of combustion depend on the temperature of the bed and, in principle, Zone I, Il or III kinetics (as defined above) may apply (Mulcahy, 1978).

Many coals contain, or generate, considerable quantities of volatile matter and will also evolve tar at approximately 450°C (840°F) (Chapter 5). In this simple combustion method, heat is transferred ahead of the flame front by radiation and convection causing the distillation of the volatile tar matter at temperatures below the ignition temperature. The purpose of the secondary air is to burn the volatile matter and in simple appliances it is not difficult to supply the necessary air, but there is rarely sufficient turbulence to mix it with the volatiles and thus the temperature in the zone above the bed can easily fall below the value where ignition is possible. As a result there may be the emission of a yellow-brown smoke containing pollutants such as hydrocarbon derivatives and the oxides of sulfur and nitrogen.

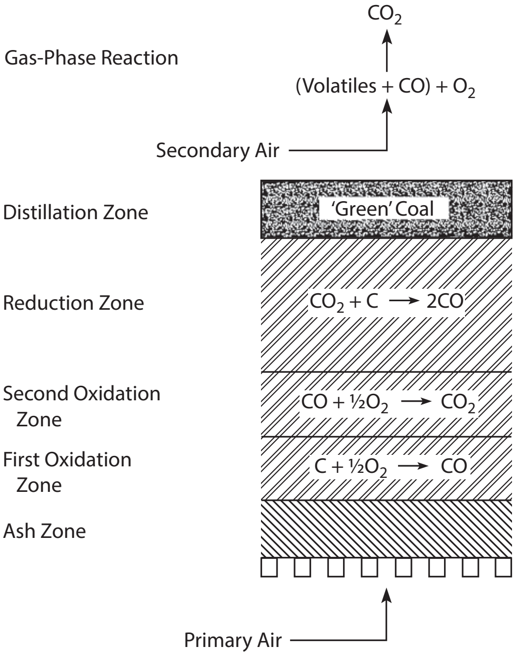

Figure 8.2 Combustion process occurring in a solid fuel bed.

8.2.2.3 *Down-Draught Combustion*

Down-draught combustion has been recognized for many centuries and one of the earliest records reports a method of controlling the emission of smoke which, in essence, involved inversion of the simple coal fire. Thus, air enters at the top of the container and combustion products leave at the bottom. This is generally called a "down-draught" system and an important technical feature is that the flame front travels in the opposite direction of the primary air. In this type of system, volatile matter which was evolved ahead of the flame front would be swept back by the air stream through the flame and into the incandescent part of the bed, where it is combusted, thereby reducing its contribution to the pollutants.

However, it is now known that volatile matter will only burn in these circumstances provided it (a) is mixed with oxygen, (b) is maintained at temperatures above 600°C (1110°F), and (c) has sufficient residence time (ca. 0.5 sec) for the oxidation to go to completion. Thus, it is essential that the system have sufficient turbulence, temperature, and time, and successful exploitation of the principle has been achieved in the form of a variety of mechanical stokers used in industrial steam raising.

In the *under-feed stoker*, coal is fed by a worm feeder into the bottom of a retort (Figure 8.3). The coal rises vertically in the retort and air enters through tuyeres in the sides. The fire is ignited at the top and the flame front moves downward and its speed is matched by the rising flow of coal, fulfilling the requirement of the flame front traveling in the opposite direction of the primary air. Volatile matter from the coal mixes with the air and ignites as it passes through the incandescent top layer of the bed thereby effectively controlling smoke emission.

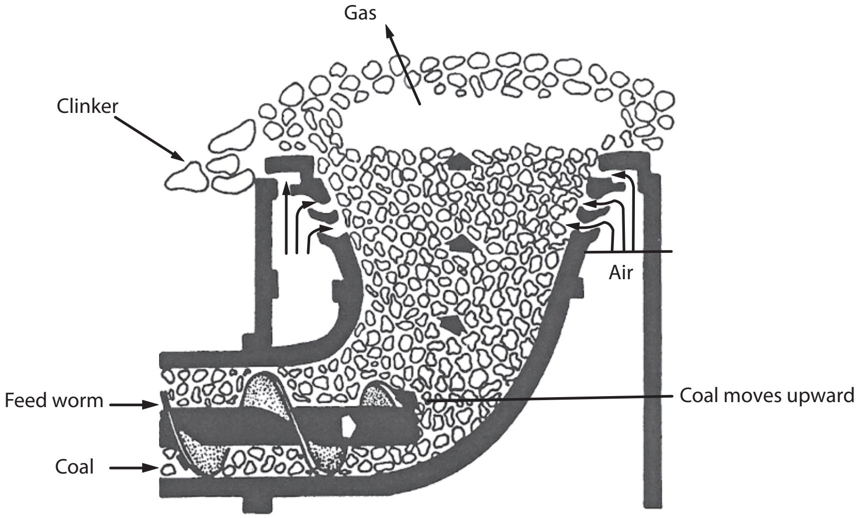

Figure 8.3 An under-feed stoker (Speight, 2013).

8.2.3 Fluidized Beds

There has been a strong surge of interest and work during the 1970s and 1980s in fluidized-bed combustion (FBC) as a means for providing high heat transfer rates, controlling sulfur, and reducing nitrogen oxide emissions due to the low temperatures in the combustion zone, which also favor the carbon dioxide equilibrium (Skinner, 1971).

Fluidized-bed combustion offers a technology that can be designed to burn a variety of fuels efficiently and in an environmentally acceptable manner with various forms. In fluidized-bed combustion units, coal is combusted in a hot bed of sorbent particles that are suspended by combustion air that is blown in from below through a series of nozzles. Depending on the gas velocity in the bed, fluidized beds can be classified into bubbling fluidized-bed (BFB) and circulating fluidized-bed (CFB) (Figure 8.4). The fluidized bed can be operated at atmospheric (AFB) and elevated pressure (PFB).

Circulating fluidized-bed (CFB) boilers are a more recent design option and their size has gradually increased since the technology was first commercially available. In a circulating fluidized-bed boiler, fuel is combusted at lower temperatures in an aerated/fluidized bed of material that typically includes crushed limestone. The lower combustion temperatures and calcium content of the limestone reduce the formation/discharge of sulfur oxides (SOx) and nitrogen oxides (NOx), so emission controls start in the combustion zone. Air quality control systems can further reduce emissions. The relatively long residence time for fuel within the combustion zone makes this combustion technology useful for lower-quality fuels – fuels that are difficult to ignite, take longer to fully combust, and contain large quantities of impurities that are problematic for suspension firing in a pulverized coal boiler.

In a fluidized bed, a gas passed slowly upwards through a bed of solid particles finds its way through the spaces between the particles and the pressure drop across the bed is directly proportional to the flow rate. If the flow rate is increased, a point is eventually reached at which the frictional drag on the particles becomes equal to their apparent weight (i.e., weight minus any buoyancy force); the bed then expands as the particles adjust their

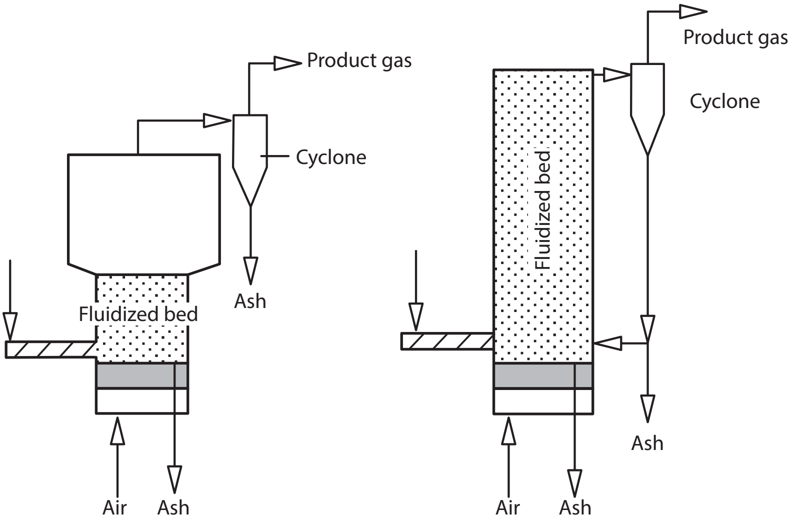

Figure 8.4 Schematic comparison of (a) a bubbling fluidized-bed reactor and (b) a circulating fluidized-bed reactor.

positions to offer less resistance to the flow. The bed is now said to be fluidized and further increase in flow is not accompanied by an increase in pressure drop. Above the minimum fluidization velocity, the extra gas over and above that required for fluidization passes through the bed as bubbles and the bed itself is agitated.

When an evenly distributed air or gas is passed upward through a finely divided bed of solid particles such as sand supported on a fine mesh, the particles are undisturbed at low velocity. As air velocity is gradually increased, a stage is reached when the individual particles are suspended in the air stream (the bed is *fluidized*). With further increase in air velocity, there is bubble formation, vigorous turbulence, rapid mixing, and formation of dense defined bed surface. The bed of solid particles exhibits the properties of a boiling liquid and assumes the appearance of a fluid (*bubbling fluidized bed*).

If sand particles in a fluidized state are heated to the ignition temperatures of coal and coal is injected continuously into the bed, the coal will burn rapidly and the bed attains a uniform temperature. The fluidized-bed combustion takes place at approximately 840 to 950°C (1545 to 1740°F). Since this temperature is much below the ash fusion temperature, melting of ash and associated problems are avoided.

The lower combustion temperature is achieved because of high coefficient of heat transfer due to rapid mixing in the fluidized bed and effective extraction of heat from the bed through in-bed heat transfer tubes and walls of the bed. The gas velocity is maintained between minimum fluidization velocity and particle entrainment velocity. This ensures consistent (stable) operation of the bed and avoids particle entrainment in the gas stream.

In a fluidized-bed combustor, heat and mass transfer between the fluidizing gas and the solid particles are extremely efficient and fluidized-bed reactors are used for carrying out many chemical reactions on an industrial scale (such as the catalytic cracking of hydrocarbon derivatives) (Speight, 2014). An additional advantage of fluidized-bed combustors is that they can use fairly coarse coal particles (ca. 0.04 in., ca. 1 mm diameter) and there is no need for much of the costly crushing equipment associated with the preparation of pulverized fuel.

A *fluid-bed combustor* (Figure 8.5) usually (in the initial stages) consists of sand or some similar inert material which is fluidized by an air stream and raised to the ignition temperature by an external heating source. When the requisite temperature is reached, coal is fed to the vigorously bubbling bed where it becomes thoroughly mixed with the sand. As combustion begins, volatile material is given off and usually burns in the freeboard above the bed. The solid residue, or char, remains in the bed where the temperature is approximately 900°C (1650°F). Fluidized-bed combustors are divided into two categories: (i) circulating fluidized-beds and (ii) bubbling fluidized-beds.

Circulating fluidized-bed technology uses higher air flows to entrain and move the bed material, and recirculating nearly all the bed material with adjacent high-volume, hot cyclone separators. The technology has the potential to improve operational characteristics by using higher air flows to entrain and move the bed material, and recirculating nearly all the bed material with adjacent high-volume, hot cyclone separators.

For example, in a circulating fluidized-bed combustion process (Figure 8.4), crushed coal is mixed with limestone and fired in a process resembling a boiling fluid. The limestone removes the sulfur and converts it into an environmentally benign powder that is removed with the ash. The relatively clean flue gas goes on to the heat exchanger. This approach theoretically simplifies feed design, extends the contact between sorbent and flue gas, reduces likelihood of heat exchanger tube erosion, and improves capture of sulfur dioxide and combustion efficiency.

Whereas pulverized combustion units operate at combustion temperatures on the order of 1400 to 1500°C (2550 to 2730°F), circulating fluidized-bed boilers operate at lower temperatures, ranging from 850 to 900°C (1560 to 1650°F), thereby suppressing thermal NOx emissions as the generation of NOx is dependent upon the combustion

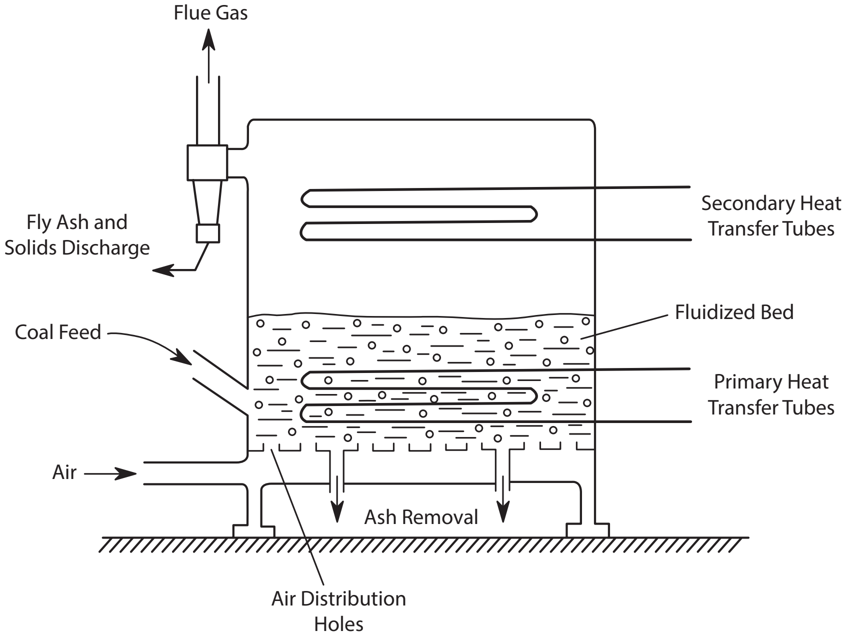

Figure 8.5 A Fluidized-Bed Combustor (Speight, 2013).

temperature. In addition, the circulating fluidized-bed two-stage combustion process: the reducing combustion at the fluidized-bed section, and the oxidizing combustion at the freeboard section. Next, the unburned carbon is collected by a high-temperature cyclone located at the boiler exit to recycle to the boiler, thus increasing the efficiency of reducing nitrogen oxide production.

In bubbling fluidized-bed combustion, the fluidized bed consists of a sand-like material with limestone added to it. Air is bubbled into the combustion chamber through a perforated plate in the bottom, similar to an aquarium bubbler. At the right air velocity, the particles of sand, limestone, and fuel are suspended in a fluid-like state. Water tubes are immersed within the bed to control the temperature and generate steam. Coal particles are burned away slowly until only an ash is left that leaves the bed with the hot gases. The gases pass through separators where the ash and any particulates are removed and then on to heat exchangers to produce more steam. The thermal efficiency of bubbling fluidized-bed combustion is approximately 30%, but bubbling fluidized-bed combustion systems are limited in size and require a high limestone-to-sulfur ratio for sufficient sulfur removal.

The first-generation pressurized fluidized-bed combustor uses bubbling fluidized-bed technology. A relatively stationary fluidized bed is established in the boiler using low air velocities to fluidize the material, and a heat exchanger (boiler tube bundle) is immersed in the bed to generate steam. Cyclone separators are used to remove particulate matter from the flue gas prior to entering a gas turbine, which is designed to accept a moderate amount of particulate matter (i.e., ruggedized).

Bubbling fluidized-bed units are a preferred choice for wood waste, bark, or sludge – coal is not always the primary choice for such units.

Since the late 1990s there has been increasing interest in bubbling fluidized-bed (BFB) combustion. The two fluidized-bed technologies are similar. Both use a bed of inert material (most typically sand) that is fluidized by high-pressure combustion air. The primary differences are that the bubbling fluidized-bed unit normally operates in a reducing atmosphere (less air than is needed for combustion), does not have as great an ability to absorb sulfur dioxide, and normally is used to burn lower-quality fuels with high volatile matter. Further, the bubbling fluidized-bed unit keeps most of the sand in the lower furnace.

Circulating beds fire fuels with high fixed carbon and circulate the hot gases, along with a high-density sand stream, through the entire furnace. By adding materials high in calcium (such as limestone), the bubbling fluidized-bed will efficiently absorb sulfur dioxide, reducing overall emissions.

Circulating fluidized-bed combustion systems use jets of air to suspend the coal and limestone mixture within the hot gases as the coal burns. The air used is at a higher velocity than in bubbling fluidized-bed combustion (BFBC) systems, so particles of coal are often lifted up into flue gases. As the flue gases are passed through a separator, the larger particles of coal drop back into the fluidized bed where they continue to burn. Individual particles may be recycled from 10 to 50 times depending on their size. The relatively clean flue gases then go on to a heat exchanger where they create steam. This design helps reduce the wear on the heat exchanger tubes, improves sulfur dioxide capture, and improves combustion efficiency. These combustors can be up to 40% efficient.

If coal is the desired fuel, bubbling fluidized-bed technology is not the first choice, and a mill should consider circulating fluidized-bed technology. If biomass and other high volatile/lower carbon-containing fuels are used, bubbling fluidized-bed technology should be considered as the preferred combustion process (KEMA, 2009). Pressurized fluidized-bed combustion (PFBC) systems are fluidized-bed combustion systems that operate at elevated pressures and produce a high-pressure gas stream at temperatures that can drive a turbine. As with atmospheric fluidized-bed combustion systems, two formats are possible, one with bubbling beds, the other with a circulating configuration.

In pressurized fluidized-bed combustion, the combustor and hot gas cyclones are all enclosed in a pressure vessel. Both coal and sorbent (for reduction of sulfur oxide emissions) have to be fed across the pressure boundary, and similar provision for ash removal is necessary. For hard coal (i.e., bituminous coal) applications, the coal and limestone can be crushed together, and then fed as a paste, with 25% water. As with atmospheric fluidized-bed combustion, a combustion temperature between 800 to 900°C (1500 to 1650°F) has the advantage of less NOx formation. In addition, the effectiveness of a carbon capture and sequestration system is increased due to the high pressure within the pressurized fluidized-bed combustor cycle and higher partial pressure of the carbon dioxide in the hot gas stream.

More advanced second-generation pressurized fluidized-bed combustion system designs use a pressurized carbonizing unit to first process the feed coal into fuel gas and char (solid material that remains after light gases and tar have been driven-out during the initial stage of combustion). The pressurized fluidized-bed combustion system burns the char to produce steam and to heat combustion air for the combustion turbine. The fuel gas from the carbonizing unit burns in a topping combustor linked to a combustion turbine, heating the gases to the rated firing temperature of the combustion turbine. Heat is recovered from the combustion turbine exhaust to produce steam, which is used to drive a conventional steam turbine. These systems are also called advanced circulating pressurized fluidized-bed combustion (APFBC) combined cycle systems.

The main features of circulating fluidized-bed combustors (CFBC) are (i) compatibility with wide range of fuels – conventional boilers for power generation can use only fossil fuels, such as high-grade coal, oil, and gas where the circulating fluidized-bed combustor is also capable of using low-grade coal, biomass, sludge, waste plastics, and waste tires as fuel, (ii) low polluting NOx and SOx emissions are significantly decreased without special environmental modifications. The operation of circulating fluidized-bed boilers involves a two-stage combustion process: the reducing combustion at the fluidized-bed section, and the oxidizing combustion at the freeboard section. Next, the unburned carbon is collected by a high-temperature cyclone located at the boiler exit to recycle to the boiler, thus increasing the efficiency of denitrogenation, and (iii) high combustion efficiency. Improved combustion efficiency is attained through the use of a circulating fluidization-mode combustion mechanism.

Ash from the coal and the residue from any limestone added to remove sulfur, together with the initial sand, are removed from the bottom of the bed, although organic and inorganic particles eventually become small enough to be carried over (entrained) in the flue gases. This fly ash has to be removed before these gases are discharged to the atmosphere; any unburned material represents a significant loss of efficiency and arrangements are often made for recirculation of the fly ash.

Briefly, *fly ash* is a product of burning finely ground coal in a boiler to produce electricity. It is removed from the plant exhaust gases primarily by electrostatic precipitators or baghouses and secondarily by scrubber systems. Physically, fly ash is a fine, powdery material composed mostly of silica; nearly all particles are spherical in shape. Fly ash is generally light tan in color and consists mostly of silt-sized and clay-sized glassy spheres. This gives fly ash a consistency somewhat like talcum powder.

Fly ash is a pozzolan – a siliceous material which in the presence of water will react with calcium hydroxide at ordinary temperatures to produce cementitious compounds. Because of its spherical shape and pozzolanic properties, fly ash is useful in cement and concrete applications. The spherical shape and particle size distribution of fly ash also make it good mineral filler in hot mix asphalt applications and improve the fluidity of flowable fill and grout when it is used for those applications.

Ash-forming elements (such as aluminum, Al, calcium, Ca, iron, Fe, potassium, K, magnesium, Mg, sodium, Na, and silicon, Si) occur in fossil or biofuels as internal or external mineral grains and simple salts such as sodium chloride (NaCl) or potassium chloride (KCl), which arise from the primeval brine, are also associated with the organic matrix of the fuel (Chapters 1, 2). In pulverized coal combustion, approximately 1% (w/w) of the inorganic metals is vaporized, while the rest remains in a condensed form as mineral inclusions (Flagan and Friedlander, 1978).

Depending on the gas/particle temperature and local stoichiometry during coal particle heat-up, devolatilization and char burnout, the mineral inclusions will undergo phase transformations and approach each other to form a fly ash fraction. The vaporized metal species may undergo several transformations: nucleation, subsequent coagulation, scavenging, heterogeneous condensation and/or interactions with mineral inclusions in the burning char or residual fly ash particles. The extent of transformation depends on the total specific surface area of the residual fly ash particles, the cooling rate of the flue gas, the local stoichiometry, and the mixing in the gas phase. Local supersaturation with respect to certain chemical species such as sodium sulfate (Na_2SO_4), potassium chloride (KCl), and potassium sulfate (K_2SO_4) may lead to the formation of submicron aerosol particles by homogeneous nucleation (Flagan and Friedlander, 1978).

Among the most significant environmental benefits of using fly ash over conventional cement is that greenhouse gas emissions can be significantly reduced. For every ton of fly ash used for a ton of Portland cement (the most common type of cement in general use around the world) approximately one ton of carbon dioxide is prevented from entering the atmosphere of the Earth. Fly ash does not require the energy-intensive kilning process required by Portland cement.

In the simplest terms, fluidized combustion occurs in expanded beds (Figure 8.6). Even though reaction occurs at lower temperatures (900°C; 1650°F), high convective transfer rates exist due to the bed motion. Heat loads higher than in comparably sized radiation furnaces can be achieved (i.e., smaller chambers produce the same equivalent heat load) and fluidized-bed systems can operate under substantial pressure (Figure 8.7), thereby allowing more efficient gas cleanup.

Mechanical problems associated with fluidized combustion are encountered with the feeding of coal and particularly with the withdrawal and separation of the ash from the char or unreacted coal for recycling back to the combustion chamber. There are also problems with pollution control. While the sulfur may be removed downstream with suitable ancillary controls, the sulfur may also be captured in the bed, thereby adding to the separations and recycle problems. Capture during combustion, however, is recognized as the ideal and is a source of optimism for fluidized combustion. And ash agglomeration is not guaranteed

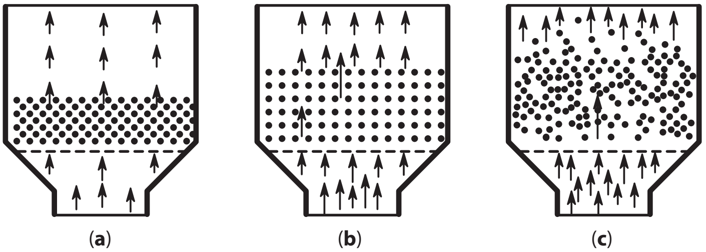

Figure 8.6 Illustration of the fluidized-bed concept: (a) Gas velocity less than the fluidizing velocity, (b) Gas velocity at the minimum fluidizing velocity, (c) Gas velocity greater than the fluidizing velocity (Speight, 2013).

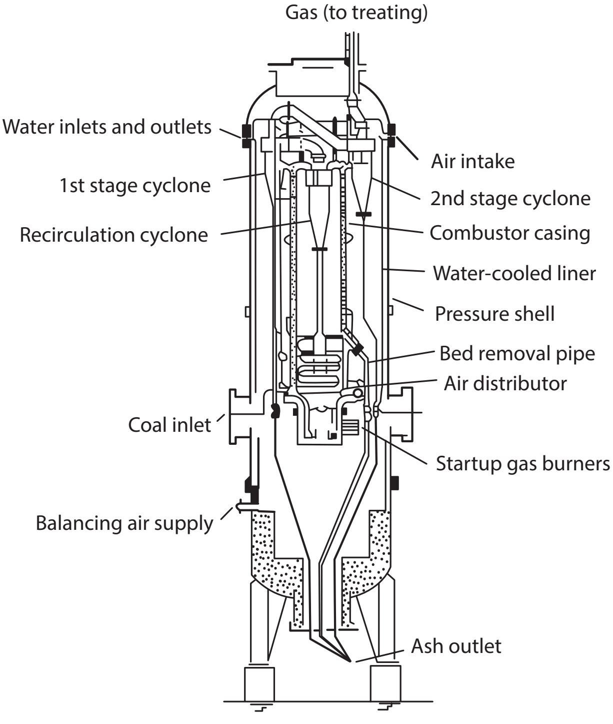

Figure 8.7 A pressurized fluidized-bed combustor (Speight, 2013).

as a means of ready separation and reducing bed carryover; attrition occurs and particulates occur in the off-gases that require controls. Thus, there remain issues related to sulfur and particulate control along with problems with feeding, withdrawal, separation, and recycle but, in spite of this, fluidized combustion presents an intriguing prospect for direct firing.

The major advantage of fluidized-bed combustion technologies is that fluidized-bed combustion boilers capitalize on the unique characteristics of fluidization to control the combustion process. The typical combustion temperature is around 850°C (1560°F), which is optimal condition for capturing sulfur dioxide *in situ* and the nitrogen oxide emission is limited. In addition, fluidized-bed combustion boilers are highly flexible to burn different ranks of fuels, including bituminous and subbituminous coals, coal waste, lignite, crude oil coke, with varying sulfur and ash contents, as well as a variety of waste fuels or *opportunity fuels*, such as biomass, which can be converted to synthetic fuels (Green, 2003; Johnson *et al.*, 2001; Tillman *et al.*, 2003; Maciejewska *et al.*, 2006; Speight, 2013, 2020) but cannot be accommodated by pulverized coal units.

An important aspect of a fluidized-bed combustor is that only a small concentration of coal (ca. 5%) is necessary to sustain combustion and at typical operating conditions the concentration is less than 1%. The coal feed will, of course, contain a proportion of fine material and inevitably some of these fines will be elutriated before they can be completely burned, but unburned material leaving the furnace is collected by cyclones and, if necessary, can be burned by re-firing to the original bed or a separate one.

A fluidized bed is an excellent medium for contacting gases with solids, and this can be exploited in a combustor since sulfur dioxide emissions can be reduced simply by adding limestone ($CaCO_3$) or dolomite ($CaCO_3.MgCO_3$) to the bed (Abelson *et al.*, 1978). The sulfur oxides react to form calcium sulfate, which leaves the bed as a solid with the ash. The theoretical additive requirement is that limestone amounting to 3% w/w of the coal feed should be added for each 1% w/w sulfur in the coal. Thus, with efficient fines recycling and a temperature of 800 to 850°C (1470 to 1560°F), the theoretical addition retains approximately 80% of the sulfur while double the theoretical rate retains approximately 95%.

Because the combustion temperature is low, the ash fusion characteristics of coals present problems usually only in exceptional circumstances. Since the coal concentration is so low in the bed, it should be possible to burn coals with excessive amounts of mineral matter. In fact, variation in the mineral content of the feed coal does not present a major problem providing that the coal feed rate can be varied sufficiently to cope with the changes in calorific value. Furthermore, a wide range of caking properties and of volatile matter contents are acceptable, ranging from very strongly caking coal to non-caking coals of high volatile matter content. The exception, however, is anthracite because of the low reactivity and the resulting higher proportion of fine carbon that is elutriated before it can be burnt.

Combustion in a fluidized bed has some particular benefits including suitability for use with low-grade, high-ash coals and the lower bed temperatures compared to those in a conventional furnace. As a result of this lower temperature the nitrogen oxide levels in the flue gas are reduced considerably. In addition, a reduction in sulfur dioxide emissions can also be achieved by mixing the coal with limestone (or dolomite). At the temperature of the bed the carbonate is converted to the oxide which reacts with any sulfur dioxide reacts to give calcium (or magnesium) sulfate.

$$CaCO_3 \rightarrow CaO + CO_2$$

$$2CaO + 2SO_2 + O_2 \rightarrow 2CaSO_4$$

$$MgCO_3 \rightarrow MgO + CO_2$$

$$2MgO + 2SO_2 + O_2 \rightarrow 2MgSO_4$$

The spent sorbent from fluidized bed combustion may be taken directly to disposal and is much easier than the disposal salts produced by wet limestone scrubbing. These latter species are contained in wet sludge having a high volume and a high content of salt-laden water. The mineral products of fluidized-bed combustion, however, are quite dry and in a chemically refractory state and, therefore, disposal is much easier and less likely to result in pollution.

The spent limestone from fluidized-bed combustion may be regenerated, thereby reducing the overall requirement for lime and thereby decreasing the disposal problem. Regeneration is accomplished with a synthesis gas (consisting of a mixture of hydrogen and carbon monoxide) to produce a concentrated stream of sulfur dioxide which can be used to synthesize sulfuric acid to produce elemental sulfur.

$$CaSO_4 + H_2 \rightarrow CaO + H_2O + SO_2$$

$$CaSO_4 + CO \rightarrow CaO + CO_2 + SO_2$$

$$CaSO_4 + 4H_2 \rightarrow CaS + 4H_2O$$

$$CaSO_4 + 4CO \rightarrow CaS + 4CO_2$$

The calcium oxide product is supplemented with fresh limestone and returned to the fluidized bed. Two undesirable side reactions in the regeneration of spent lime produce calcium sulfide and results in recirculation of sulfur to the bed.

As new technology is developed, emissions may be reduced by repowering in which aging equipment is replaced by more advanced and efficient substitutes (Hyland, 1991). Such repowering might, for example, involve an exchange in which an aging unit is exchanged for a newer combustion chamber, such as the atmospheric fluidized-bed combustor (AFBC) or the pressurized fluidized-bed combustor (PFBC) (Dainton, 1979; Thomas, 1986; Argonne, 1990a).

Most operational boilers of this type are of the atmospheric fluidized-bed combustion. This involves adding a fluidized-bed combustor to a conventional shell boiler. Such systems have similarly being installed in conjunction with conventional water tube boiler.

In the system, coal is crushed to a size of 1 to 10 mm depending on the rank of coal, type of fuel fed to the combustion chamber. The atmospheric air, which acts as both the fluidization and combustion air, is delivered at a pressure, after being preheated by the exhaust fuel gases. The in-bed tubes carrying water generally act as the evaporator. The gaseous products of combustion pass over the super heater sections of the boiler flow past the economizer, the dust collectors, and the air preheater before being exhausted to atmosphere.

In the pressurized fluid-bed combustor, pressure is maintained in the boiler, often an order of magnitude greater than in the atmospheric combustor, and additional efficiency is achieved by judicious use of the hot gases in the combustion chamber (combined cycle).

In the process, a compressor supplies the forced draft air and the combustor is a pressure vessel. The heat release rate in the bed is proportional to the bed pressure and hence a deep bed is used to extract large amount of heat. This will improve the combustion efficiency and sulfur dioxide absorption in the bed. The steam is generated in the two tube bundles, one in the bed and one above it. Hot flue gases drive a power generating gas turbine. The pressurized fluid-bed combustor system can be used for cogeneration (steam and electricity)

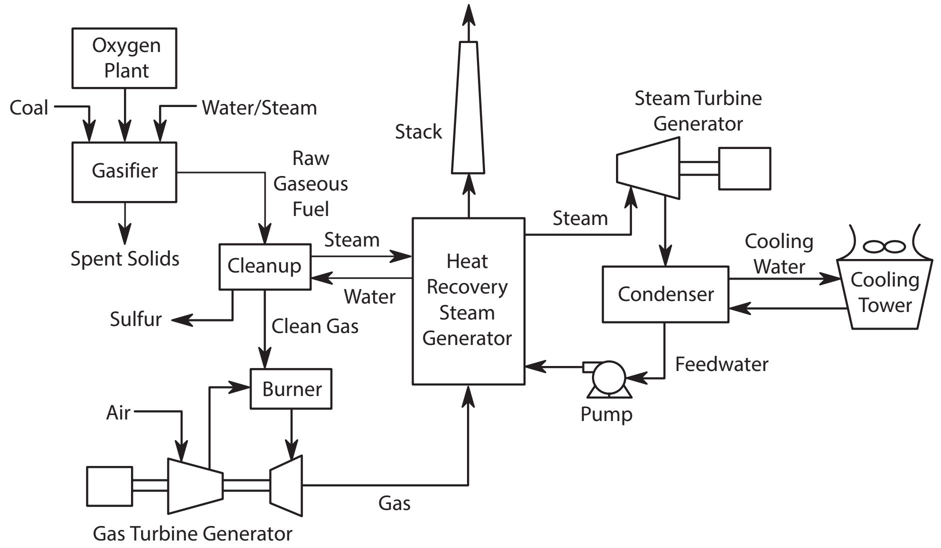

Figure 8.8 The Integrated Gasification Combined Cycle (IGCC) process (Speight, 2013).

or combined cycle power generation. The combined cycle operation (gas turbine & steam turbine) improves the overall conversion efficiency by 5 to 8%.

Briefly, in the utility industry, combined cycle technology refers to the combined use of hot combustion gas turbines and steam turbines to generate electricity. This process can raise, quite significantly, the overall thermal efficiency of power plants above the thermal efficiency of conventional fossil fuel power plants using either type of turbine alone. Combined cycle plants that incorporate a gasification technology are called integrated gasification combined cycle (IGCC) plants (Figure 8.8) (Argonne, 1990b; Takematsu and Maude, 1991).

Both the atmospheric and pressurized fluid-bed combustors burn coal with limestone or dolomite in a fluid bed which allows, with recent modifications to the system, the limestone sorbent to take up approximately 90% of the sulfur that would normally be emitted as sulfur dioxide. In addition, combustion can be achieved at a lower temperature than in a conventional combustor, thereby reducing the formation of nitrogen oxide(s).

8.2.4 Entrained Systems

In entrained systems, fine grinding and increased retention times intensify combustion but the temperature of the carrier and degree of dispersion are also important. In present-day practice, the coal is introduced at high velocities which may be greater than 100 feet/sec. and involve expansion from a jet to the combustion chamber. The pulverized coal is usually suspended in a stream of primary air (ca. 25% of the total air requirement) and the remainder of the air for combustion is introduced as secondary air. The secondary air may be introduced at an inlet region surrounding or adjacent to the primary air duet or may even be at some distance away. The temperature of the primary air should be regulated within limits; a temperature of at least 60°C (140°F) is required to prevent the condensation of moisture in the lines but at temperatures of 80 to 130°C (175 to 265°F) bituminous coal particles, for instance, will soften and stick.

Types of entrained systems include the *cyclone furnace* (which has been used successfully for various types of coal), and other systems have been developed and utilized for the injection of coal-oil slurries into blast furnaces or for the burning of coal-water slurries. The cyclone furnace (developed in the 1940s to burn coal having low ash-fusion temperatures) is a horizontally inclined, water-cooled, tubular furnace in which crushed, rather than pulverized, coal is burned with air entering the furnace tangentially (Figure 8.9). Temperatures may be of the order of 1700°C (3100°F) and the ash in the coal is converted to a molten slag that is removed from the base of the unit. Coal fines burn in suspension while the larger pieces are captured by the molten slag and burn rapidly. The heat release rate in a cyclone furnace is more than 50 times greater than in a pulverized coal-fired unit and the size of the unit may vary from 5 feet to 10 feet diameter.

Slag (sometimes referred to as *boiler slag*) is the molten bottom ash collected at the base of slag tap and cyclone type furnaces that is quenched with water. When the molten slag comes in contact with the quenching water, it fractures, crystallizes, and forms pellets. This boiler slag material is made up of hard, black, angular particles that have a smooth, glassy appearance.

Slag is generally a black granular material and the particles that are uniform in size, hard, and durable with a resistance to surface wear. In addition, the permanent black color of this material is desirable for asphalt applications and aids in the melting of snow. Slag is in high demand for beneficial use applications; however, supplies are decreasing because of the removal from service of aging power plants that produce boiler slag.

In the cyclone furnace, the crushed coal is conveyed into the burner by the primary air (20% of the total air) which enters the burner tangentially, thereby imparting a whirling motion to the coal. The secondary air is also introduced tangentially into the furnace at a velocity of 300 feet/sec. This imparts a whirling action to the coal particles which are thrown to the furnace wall by centrifugal force. These particles are held in the slag layer and burned. Most of the ash is retained in the slag layer which minimizes the amount of fly ash that is carried over into the boiler.

The slag layer ensures that the total amount of heat absorbed by the water-cooled shell of a cyclone furnace will be relatively small and a secondary furnace is necessary to recover thermal energy. This gas-cooling furnace is similar in construction to a pulverized coal-fired furnace with the possible addition of a slag screen to remove droplets of molten slag carried over from the cyclone unit. Several cyclone furnaces are commonly used with a single secondary furnace.

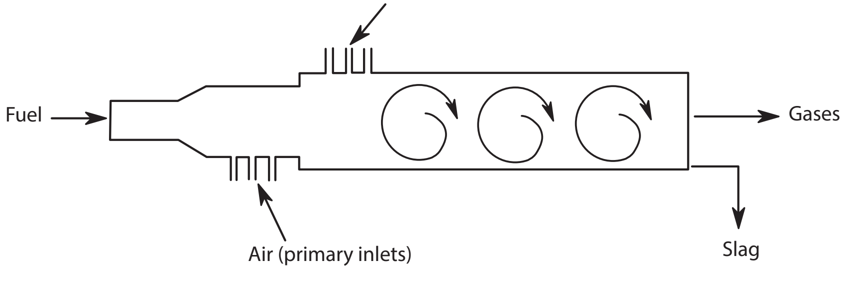

Figure 8.9 A Cyclone Furnace (Speight, 2013).

The cyclone offers the advantage of being able to burn low-ash-fusion coals that create problems when burned in conventional pulverized-coal burners. In addition the cyclone has an inherently low fly ash carryover and minimizes erosion and fouling problems in the boiler and reduces the size of a particulate collector.

An advantage of the cyclone furnace is its low dust burden in the secondary furnace and, hence, it exhibits a lower emission of particulate matter from the stack. Most cyclone furnaces capture approximately 90% of the ash in the coal and convert it to molten slag. In addition, crushing coal for cyclone furnaces requires less power than pulverization but, on the other hand, the high tangential air velocity for cyclone furnaces requires a wind-box pressure up to 100 cm. (40 in.) of water, and the total power requirements of a cyclone furnace may be comparable with those of a pulverized coal fired unit.

Cyclone furnaces have two major shortcomings: (a) the ash of the coal must be convertible to molten slag at furnace temperatures and (b) the nitrogen oxide emissions are excessive (ca. 1,000 ppm) because of the high furnace temperature. Cyclone furnaces have been widely used in areas where the coal contains ash with a low fusion temperature. For successful removal of slag, the slag viscosity cannot exceed 250 poise at 1420°C (2600°F) and many coals do not meet this requirement. However, addition of iron ore, limestone, or dolomite makes it possible to flux the coal ash, thereby decreasing the viscosity at furnace temperatures.

A major drawback, however, is that the ash particles in the coal are raised to temperatures near 1400°C (2550°F); some mineral constituents will soften and glaze at these temperatures while others will volatilize. If the ash particles are still soft when they enter the convective heat transfer part of the boiler, there is a possibility that they will form gluey deposits on the cooling tubes. Corrosive effects may also become more apparent at these high temperatures.

8.2.5 Miscellaneous Systems

The previous sections have given an indication of the combustion systems that are available and in use. There are, however, several other systems that are still in the experimental stage or have seen limited use insofar as they have not yet achieved a high degree of commercial acceptance. Nevertheless, these systems could well be the basis of future coal combustion operations and, as such, are worthy of mention here.

8.2.5.1 Advanced Power Systems

Advanced power systems address global climate change and hydrogen fuel initiatives by enhancing power generation efficiency, producing near-zero pollutant emissions, and providing for hydrogen separation and carbon dioxide (CO_2) capture and sequestration (United States Department of Energy, 2008).

Advanced power technologies include (i) integrated gasification combined cycle (IGCC) systems that convert coal to a clean synthesis gas (syngas) amenable for use by gas turbines and advanced fuel cells, (ii) provide conversion to chemicals and clean transportation fuels, (iii) separation into hydrogen and carbon dioxide, and (iv) transform residual gases and solids into salable by-products.

Circulating fluidized-bed (CFB) combustion systems that utilize low-grade fuels and waste materials (coal fines and even some types of biomass) to generate power at high efficiency and low emissions, without the power drain caused by add-on environmental controls. In a circulating system the bed parameters are so maintained as to promote solids elutriation from the bed. They are lifted in a relatively dilute phase in a solids riser, and a down-comer with a cyclone provides a return path for the solids. There are no steam generation tubes immersed in the bed. Generation and super heating of steam takes place in the convection section, water walls, at the exit of the riser.

Circulating fluidized-bed boiler systems are generally more economical than atmospheric fluidized-bed boilers for industrial. For large units, the taller furnace characteristics of circulating fluidized-bed boilers offers better space utilization, greater fuel particle and sorbent residence time for efficient combustion and sulfur dioxide capture, and easier application of staged combustion techniques for NOx control than atmospheric fluidized-bed steam generators.

Advanced combustion techniques are techniques that use oxygen in lieu of air or chemical means, such as chemical looping, to achieve the equivalent of combustion.

Integrated gasification combined cycle (IGCC) plants allow the combination of the production of hydrogen and electricity because the coal gasification process produces a syngas that can be used for the production of both commodities. This combination can be done mainly thanks to the shift reaction that converts the carbon monoxide contained in the synthesis (syngas) into hydrogen and carbon dioxide. Therefore, the IGCC plant, relying upon a coal gasification process that allows the coproduction of electricity and hydrogen, can provide combined quotas of these two energy carriers in a wide range of power outputs. Hence, it is able to operate in a *flexible mode* (*flexible operation*), which refers to the capacity of a plant to operate under specified conditions according to the needs of the market.

The IGCC system uses a gasifier to convert feedstocks into gaseous products by applying heat under pressure in the presence of steam. A partial oxidation of the feedstock (POx process), typically with pure oxygen, provides the heat. Together the heat and pressure break the bonds between feedstock constituents and precipitate chemical reactions, producing synthesis gas (syngas) – primarily hydrogen and carbon monoxide. Minerals in the feedstock (produced as a mineral ash product), separated in the gasifier, may be salable products, depending on local or regional market demands. For example, sulfur emerges from the gasifier primarily as hydrogen sulfide, which can be converted to either pure sulfur or sulfuric acid.

Furthermore, the most significant advantage gasification has over conventional coal to steam power plants is increased thermal efficiency. More power is produced per ton of coal consumed. The thermal efficiency in a conventional pulverized coal plant is on the order of 33 to 40%, but an integrated gasification combined cycle (IGCC) plant can achieve 42 to 50% efficiency – less coal is consumed to produce a unit amount of power with less solid waste and lower emissions per unit of power. The synthesis gas produced from a gasifier unit can be burned in a gas turbine for electricity generation or used as a fuel in other applications such as hydrogen-powered fuel cell vehicles.

Thus, benefits of IGCC plants include (i) an IGCC power plant produces only approximately half the solid wastes as that of a conventional coal power plant, (ii) the solid wastes include slag or sand-like materials that are inert and can actually be marketed as construction materials, (iii) the plant can use a variety of fuels including low-ranked coal, heavy oils, crude oil coke, biomass, and even waste, (iv) IGCC plants use 20-50% less water compared to a conventional coal power station, which is important due to the decreasing availability of water sources for power production, and (v) IGCC plants remove approximately 95% v/v of the sulfur emissions and nitrogen oxide (NOx) emissions are below 50 ppm – most of the carbon dioxide can be captured from an IGCC plant, making the technology suitable for carbon dioxide storage.

Circulating fluidized-bed systems (i) use jets of air to support combustion, (ii) effectively mix feedstocks with sulfur dioxide adsorbents, and (iii) entrain the mixture. The entrained mixture is transported to a cyclone that separates the solids from the flue gas. Hot separated solids are returned to the circulating fluidized-bed combustor. Relatively clean flue gas goes to a heat exchanger to produce steam that drives a steam turbine. The mixing and recycling action of the circulating fluidized bed allows high combustion efficiency at temperatures below the thermal NOx formation temperature, and achieves high-efficiency capture of sulfur dioxide through direct sorbent-sulfur dioxide contact.

8.2.5.2 Colloidal Fuel-Fired Units

Methods for burning mixtures of pulverized coal in oil (variously called colloidal fuel, coal-in-oil slurry, or coal-oil suspension) have been studied for nearly a century and require the production of coal-in-oil suspensions. Stable short-term suspensions of coal in residual fuel oil are easily attained if the coal is pulverized to 200 mesh (75 micron) and, by adding surfactants, long-term stability can be obtained so that the coal will not settle out of the mixture even over periods as long as a few months. The interaction between the coal and the hydrocarbon allows the apparent viscosity of the coal-oil mixture to be ten times greater than the fuel oil base and special precautions may be taken to provide adequate pump capacity, heating systems for the slurry, and properly sized burner nozzles.

The coal-water slurry fuel (CWSF or coal-water slurry. CWS, or coal-water fuel, CWF) is a fuel which consists of fine coal particles suspended in water. Presence of water in the coal-water slurry reduces harmful emissions into the atmosphere, makes the coal explosion-proof, makes use of coal equivalent to use of liquid fuel (e.g., heating oil), and gives other benefits (see below). A coal-water slurry consists of 55 to 70% w/w of fine dispersed coal particles and 30 to 45% w/w of water.

The coal-water slurry can be used in place of oil and gas in small, medium, and big heating and power stations. Coal-water slurry is suitable for existing gas, oil, and coal boilers.

The relatively low cost of coal when compared to other energy sources gives coal-water slurries a competitive alternative to heating oil and gas and a relatively environmentally friendly fuel for heat and power generation. One side effect of the coal-water slurry making process is the separation of non-carbon material (such as pyrite and other inorganic mineral matter) mixed in with the coal before treatment. This results in a reduction of ash yield to as low as 2% w/w for the treated coal water slurry fuel.

8.2.5.3 Cyclone Furnaces

Cyclone furnaces were developed after pulverized coal systems and require less processing of the coal fuel and can be employed to burn poorer grade coals with higher moisture contents and ash contents to 25% w/w. The furnace is basically a large cylinder jacketed with water pipes that absorb the some of the heat to make steam and protect the burner itself from melting down.

In the process, the crushed coal feed is either stored temporarily in bins or transported directly to the cyclone furnace. A high-powered fan blows the heated air and chunks of coal into one end of the cylinder. At the same time additional heated combustion air is injected along the curved surface of the cylinder causing the coal and air mixture to swirl in a centrifugal cyclone motion. The whirling of the air and coal enhances the burning properties producing high heat densities and high combustion temperatures.

The hot combustion gases leave the other end of the cylinder and enter the boiler to heat the water-filled pipes and produce steam. Like in the pulverized coal burning process, all the fuel that enters the cyclone burns when injected once the furnace is at its operating temperature. Some slag remains on the walls insulating the burner and directing the heat into the boiler while the rest drains through a trench in the bottom to a collection tank where it is solidified and disposed of. This ability to collect ash is the biggest advantage of the cyclone furnace burning process. Only 40% of the ash leaves with the exhaust gases compared with 80% for pulverized coal burning.

Cyclone furnaces are not without disadvantages. For example, the coal used must have a relatively low sulfur content in order for most of the ash to melt for collection. In addition, high-power fans are required to move the larger coal pieces and air forcefully through the furnace, and more nitrogen oxide pollutants are produced compared with pulverized coal combustion. Finally, the actual burner requires yearly replacement of its liners due to the erosion caused by the high velocity of the coal.

8.2.5.4 Ignifluid System

The *Ignifluid* system is a slight departure from the fixed-bed concept in that a certain amount of fluidization of the bed is permitted. As the air flow rate is increased to improve the rate of heat release, the particles can become suspended over the grate, causing great turbulence and of course higher burning rates. This permits use of fuels with low reactivity and high ash content. Since solids carryover may be high, fines must be recycled to the bed to enhance combustion efficiency. This system was the forerunner of fluidized-bed combustion units.

The Ignifluid fuel-burning concept (Schwarz, 1982) consists essentially of an inclined chain-grate stoker with combustion air supplied at high velocity (approximately 50 feet/sec) through the stoker bars at which the crushed coal, at the upper end of the chain-grate stoker, is blown off the grates and burns in suspension; the larger coal particles recirculate in the space above the grates until burning is complete. Ash is agglomerated into spheres approximately 1.0 in. (2.5 cm.) in diameter, some of which may remain in the space between the furnace walls and the chain grate to provide a sloping sidewall to redirect recirculating particles of coal into the combustion zone. The ash is eventually conveyed, by the moving stoker gates, to an ash pit.

8.2.5.5 Submerged Combustion Systems

There are several processes that have been proposed for the direct combustion (oxidation or gasification) of coal within a liquid medium, and three of these are described below. The Zimpro process is based on the oxidation of crushed coal suspended in an oxygen-saturated hot-pressurized aqueous medium and is an outgrowth of an attempt to produce oxidized chemical products from paper mill wastes and the development of wastewater reclamation systems. The process involves the injection of high-pressure air into a slurry of hot water and coal under high pressure. High rates of oxidation occur at temperatures between 200 and 350°C (390 and 660°F); the exact temperature required to complete oxidation with reasonable residence time is dependent on the coal. Since the energy released is used to vaporize water, there is a direct relationship between the liquid temperature and the reactor pressure to which the air used for oxidation must be compressed. After oxidation, the gases evolved from the slurry contain water vapor, carbon dioxide, nitrogen, and partially oxidized material; unoxidized material is removed from the bottom of the reactor and inevitably is accompanied by some water.

Part of the energy released by oxidation (combustion) can be recovered as work by expansion of the evolved gases. Because these gases contain nitrogen and carbon dioxide as well as some water vapor, a specially designed expansion turbine using corrosion-resistant materials is required. Process heat can be obtained from the gases either directly or by passing them over a heat exchanger before expansion with some loss of the available expansion work. However, if the primary objective is to produce work, the gases need to be heated to a temperature higher than the reactor temperature of 200 to 350°C (390 to 660°F).

Although the Atgas process has been developed mainly to produce substitute natural gas, it has also been proposed as a method for producing sulfur-free low heat-content gas for use in power plant boilers. The process depends on the reaction between coal, air, and steam within a bath of molten iron. Sulfur from the coal is retained by the iron from which it is transferred to an overlying high-calcium oxide slag. The proposed gasifier is a cylindrical, refractory line vessel filled with molten iron (l425°C; 2600°F) and a floating layer of slag. Coal and limestone are injected with steam through the slag layer into the molten bath of iron where the coal is devolatilized; the carbon and sulfur are dissolved in the iron. Air introduced just beneath the slag layer oxidizes the carbon to carbon monoxide. The injected steam contributes to the production of hydrogen; the dissolved sulfur is transferred to the slag layer where it forms calcium sulfide and is removed with the slag.

The super-slagging combustor invokes the concept of burning coal (to produce a low heat-content gas) within a bed of molten coal-ash slag fluxed with limestone; the sulfur in the coal reacts with the lime to form calcium sulfide. Thus, if such a super-slagging combustor were incorporated into a steam-generating boiler furnace with controlled addition of secondary air, the result might be a direct combustion system that produces flue gas with no sulfur or nitrogen oxides through staged combustion and maintains particulate emissions at a minimum. However, thermochemical calculations have shown that the product gas must be in equilibrium with excess carbon if sulfur is to be detained by the calcium oxide fluxed slag at 1540°C (2800°F) and that under even moderately oxidizing conditions sulfur would not be absorbed. This has been demonstrated in preliminary tests where the sulfur in the product gas can be as little as S% of the sulfur in the feed gas.

The magnetohydrodynamic process for the generation of electricity invokes the concept that a conducting gas (e.g. a high-temperature combustion gas) *seeded* with an easily ionizable metal (such as potassium or calcium) creates an electric current when flowing at high speed in a magnetic field (Morrison, 1988). The magnetohydrodynamic (MHD) process provides for several alternative generator configurations and operating procedures and can also use media other than a combustion gas. In a closed-cycle system, in which the working fluid would be recycled after reheating upon completion of a passage through the MHD channel, it could be a molten metal or metal vapor or a coal-fired venturi-type generator (Figure 8.10).

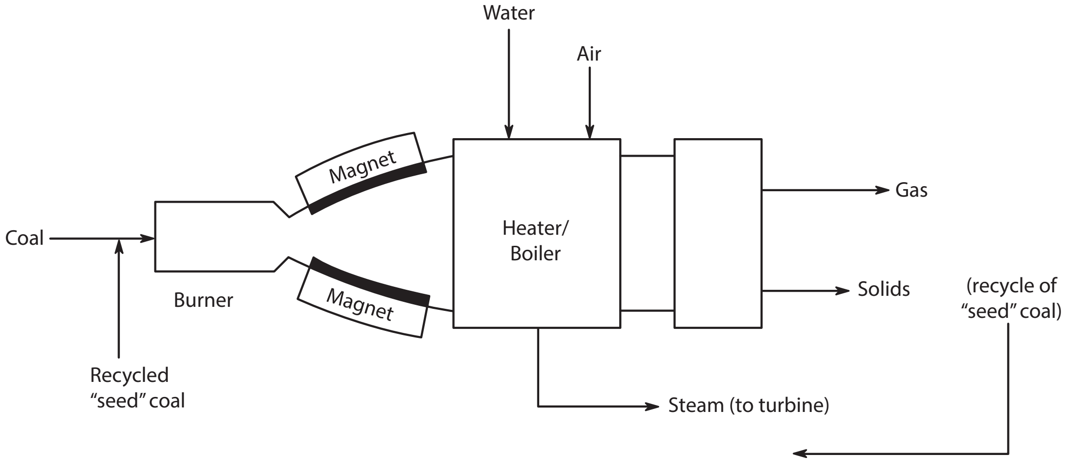

Figure 8.10 A Magnetohydrodynamic Generator (Speight, 2013).

8.2.5.6 Suspension-Bed Combustion

Suspension-bed combustion of pulverized coal was first used as a means of firing cement kilns. In the 1920s, it began to be applied to power generation. From 1930 onwards, nearly all coal-fired power plants and large industrial boilers have been fired by pulverized fuel rather than by a stoker system because of the two principal advantages: (i) the pulverized fuel combustion allows a wider range of coals than a stoker, and (ii) in practice, the stoker is limited to a maximum output of approximately 30 MW (thermal), whereas that of the pulverized fuel system can be two orders of magnitude higher.

8.3 Fuel Feeders

Fuel feeder/distributors which evenly feed the fuel over the entire grate surface are necessary for even energy rerelease. These feeder/distributors can be mechanical, pneumatic or a combination of both and must be placed across the width of the front of the stoker in sufficient quantity to achieve even lateral distribution of the fuel and have the means to longitudinally adjust fuel distribution for various types of fuels and sizing. They should be able to bias the feed rate one feeder to another, and to adjust for segregation of fuel sizing from one feeder to another. The performance of the fuel feeder/distributors can adapt to the different characteristics of solid fuels plays a major part in the ability to operate at lowest possible emissions and highest combustion efficiency (Johnson, 2002).

Coal feeders should have a non-segregating distributor interfacing between the coal bunker and the stoker feeder. A coal scale is recommended between the non-segregating spout and the coal bunker. A coal scale provides a method for tracking daily, weekly, or monthly coal usage. All modern coal scale electronics provide for real-time usage in terms of coal rate per hour, which is useful for tracking efficiency.

For maximum efficiency, best load following characteristics and lowest emissions, it is recommended that there be a separate metering device for each fuel distributor, and that the metering devices be kept full of fuel at all times. It is also important that the metering device be kept in a vertical plane from the front to prevent lateral poor distribution of the feedstock in the furnace (Johnson, 2002).

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9

Gasification

9.1 Introduction

The gasification of coal or a derivative (i.e., char produced from coal or any carbonaceous material) is, essentially, the conversion of feedstock (by any one of a variety of processes) to produce combustible gases (Fryer and Speight, 1976; Radovic *et al.*, 1983; Radovic and Walker, 1984; Garcia and Radovic, 1986; Calemma and Radovic, 1991; Kristiansen, 1996; Higman, and van der Burgt, 2008; Speight, 2020). With the rapid increase in the use of coal from the 15th century onwards (Nef, 1957; Taylor and Singer, 1957) it is not surprising the concept of using coal to produce a flammable gas, especially the use of the water and hot coal, became commonplace (Elton, 1958).

Coal gasification offers one of the most versatile methods (with a lesser environmental impact than combustion) to convert coal into electricity, hydrogen, and other valuable energy products. Gasification may be one of the most flexible technologies to produce clean-burning hydrogen for future automobiles and power-generating fuel cells. Hydrogen and other coal gases can also be used to fuel power-generating turbines, or as the chemical building blocks for a wide range of commercial products.

In fact, the production of gas from coal has been a vastly expanding area of coal technology for power generation and is, in reality, another form of coal-fired power generation in which coal is used as the feedstock to produce the hot gases to drive the turbines. As with combustion processes, coal characteristics such as rank, mineral matter, particle size, and reaction conditions are all recognized as having a bearing on the outcome of the gasification process – not only in terms of gas yields but also on gas properties (Massey, 1974; Hanson *et al.*, 2002).

Coal gasification, the chemical conversion of coal to gaseous products, was first used to produce gas for lighting and heat in the United Kingdom more than two hundred years ago. At the time that natural gas was discovered in abundance, gas from coal slowly fell into reduced demand by the end of the early 20th century. The energy crisis of the 1970s led to a resurgence of interest in coal gas as an energy alternative and, in many Western countries, a major effort began to commercialize the technology on a large scale for energy production and chemical feedstock production. The abundant coal reserves of the United States and other countries posed a challenge to utilize coal in a manner that did not cause the environmental harm of traditional methods of coal combustion (Chapters 7, 8) and gasification (see also Chapter 10).

Coal gasification processes combust coal in a measured supply of air (or pure oxygen) to generate a variety of gaseous product which can then be used to generate electrical energy using high-efficiency gas turbines that are engineered to eliminate soot and minimize formation of nitrogen oxides (NOx), precursors to ozone-related smog and acid rain.

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In addition, a coal-gasification power plant typically produces less solid waste than a coal-fired power plant.

Depending on the type of gasifier (e.g., air-blown, enriched oxygen-blown) and the operating conditions, gasification can be used to produce a fuel gas that is suitable for several applications. Coal gasification for electric power generation enables the use of a technology common in modern gas-fired power plants, the use of *combined cycle* technology to recover more of the energy released by burning the fuel.

The use of these two types of turbines in the combined cycle system involves (i) a combustion turbine and (ii) a steam turbine. This is one for gasification-based power systems being able to achieve high power generation efficiencies. For example, the combined cycle technology plant can an efficiency of 45 to 50% (efficiency as high as 60% is sometimes reported) compared to traditional power plants which only use one cycle to generate electricity at approximately 35 to 40% efficiency.

The issues inherent in coal combustion include (i) emission of particulate, matter, (ii) emission of sulfur oxides, (iii) emission of nitrogen oxides, (iv) emission of carbon dioxide, and (v) emissions of hazardous species such as mercury which must be cleaned from the gaseous products (Chapters 5, 7, 8, 9, 12, 14). One of the major environmental advantages of coal gasification is the opportunity to remove impurities such as sulfur and mercury and soot-generating constituents *before* burning the coal, using readily available process options. In addition the ash produced is in a vitreous or glasslike state which can be recycled as concrete aggregate, unlike pulverized coal-fired plants which generate ash that must be landfilled, potentially contaminating groundwater.

The increased efficiency of the combined cycle for electrical power generation results in a 50% v/v decrease in carbon dioxide emissions compared to conventional coal plants. As the technology required to develop economical methods of carbon *sequestration,* the removal of carbon dioxide from gaseous by-products to prevent its release to the atmosphere, coal gasification units could be modified to further reduce their climate change impact because a large part of the carbon dioxide generated can be separated from the other product gas *before* combustion.

The current state of IGCC technology already offers significant reductions in emissions of the major criteria air pollutants – nitrogen oxides, sulfur dioxide, particulate matter and carbon monoxide – when compared to pulverized coal plants; it seeks to achieve near-zero emissions of these pollutants and to simultaneously develop carbon dioxide sequestration technologies that can be readily commercialized.

Gasification has been considered for many years as an alternative to combustion of solid or liquid fuels. It is easier to clean gaseous mixtures than solid or high-viscosity liquid fuels. Clean gas can be used in internal combustion-based power plants that would suffer from severe fouling or corrosion if solid or low-quality liquid fuels were burnt inside them.

Recent developments in gas turbine technology have resulted in combined cycle units with efficiencies close to 60% when generating electricity from natural gas. This has led to the successful development of three types of gasifier classified by the configuration: entrained-flow gasifiers, fluidized-bed gasifiers and moving-bed (also called fixed-bed) gasifiers (Chapter 10) (Speight, 2013, 2020).

Gas turbine improvements lead to a number of power plants where the so-called dirty fuels (usually coal, residual oil, or crude oil coke that have high proportions of sulfur, nitrogen, and mineral matter) are gasified, the gas is cleaned and used in a combined cycle gas turbine power plant. Such power plants generally have higher capital cost, higher operating cost, and lower availability than conventional combustion and steam cycle power plants on the same fuel. Efficiencies of the most sophisticated plants have been broadly similar to the best conventional steam plants with losses in gasification and gas cleaning being balanced by the high efficiency of combined cycle power plants. Environmental aspects resulting from the gas cleaning before the main combustion stage have often been excellent, even in plants with exceptionally high levels of contaminants in the feedstock fuels.

In fact, the hot synthesis gas (syngas) can then be processed to remove sulfur compounds, mercury, and particulate matter before it is used to fuel a combustion turbine generator to produce electricity. The heat in the exhaust gases from the combustion turbine is recovered to generate additional steam. This steam, along with the steam produced by the gasification process, then drives a steam turbine generator to produce additional electricity. In the last decade, the primary application of gasification to power production has become more common due to the demand for high efficiency and low environmental impact.

9.2 General Aspects

Gasification differs from conventional coal combustion which takes place when coal is burned in excess oxygen to produce carbon dioxide and water and higher temperatures are generated during combustion than in gasification. Another important difference between coal combustion and coal gasification is in pollutant formation. The reducing atmosphere in gasification converts sulfur from coal to hydrogen sulfide and nitrogen to ammonia, whereas combustion (oxidation) produces sulfur dioxide and nitrogen oxides, respectively.

Gasification includes a series of reaction steps that convert the feedstock into *synthesis gas* (carbon monoxide, CO, plus hydrogen, H_2) and other gaseous products. This conversion is generally accomplished by introducing a gasifying agent (air, oxygen, and/or steam) into a reactor vessel containing the feedstock where the temperature, pressure, and flow pattern (moving bed, fluidized, or entrained bed) are controlled. The gaseous products – other than carbon monoxide and hydrogen – and the proportions of these product gases (such as carbon dioxide, CO_2, methane, CH_4, water vapor, H_2O, hydrogen sulfide, H_2S, and sulfur dioxide, SO_2) depends on the (i) type of feedstock, (ii) the chemical composition of the feedstock, (iii) the gasifying agent or gasifying medium, as well as (iv) the thermodynamics and chemistry of the gasification reactions as controlled by the process operating parameters. In addition, the kinetic rates and extents of conversion for the several chemical reactions that are a part of the gasification process are variable and are typically functions of (i) temperature, (ii) pressure, (iii) reactor configuration, and (iv) the composition of the product gases and whether or not these gases influence the outcome of the reaction (Johnson, 1979; Singh *et al.*, 1980; Penner, 1987; Müller *et al.*, 2003; Slavinskaya *et al.*, 2009; Pepiot *et al.*, 2010; Shabbar and Janajreh, 2013; Speight, 2013, 2020).

The influence of physical process parameters and the effect of coal type on coal conversion is an important part of any process where coal is used as a feedstock, especially with respect to coal combustion and coal gasification (Speight, 2013, 2020). The reactivity of coal generally decreases with increase in rank (from lignite to subbituminous coal to bituminous coal anthracite). Furthermore, the smaller the particle size, the more contact area between the coal and the reaction gases causing faster reaction. For medium-rank coal and low-rank coal, reactivity increases with an increase in pore volume and surface area, but these factors have no effect on reactivity for coals having carbon content greater than 85% w/w. In fact, in high-rank coals, pore sizes are so small that the reaction is diffusion controlled.

In a gasifier, the coal particle is exposed to high temperatures generated from the partial oxidation of the carbon. As the particle is heated, any residual moisture (assuming that the coal has been pre-dried) is driven off and further heating of the particle begins to drive off the volatile gases. Discharge of these volatiles will generate a wide spectrum of hydrocarbon derivatives ranging from carbon monoxide and methane to long-chain hydrocarbon derivatives comprising tars, creosote, and high-boiling oil. At temperatures above 500°C (930°F) the conversion of the coal to char and ash and char is completed. In most of the early gasification processes, this was the desired by-product but for gas generation the char provides the necessary energy to effect further heating and typically, the char is contacted with air or oxygen and steam to generate the product gases.

Variations in coal quality can have an impact on the heating value of the syngas produced by the gasification process. However, a desired throughput can be selected and then the size and number of gasifiers can be determined with the specific range of coal types under consideration in mind. For example, the reactivity of coal generally decreases with a rise in rank or type, such as when subbituminous coal (higher reactivity) and bituminous coal (lower reactivity) are compared. Also, the smaller the particle size, the more contact area between the coal and the reaction gases causing faster reaction. For medium- and low-rank coals, reactivity increases with an increase in pore volume and surface area, but for coals having a carbon content greater than 85%, w/w these factors have no effect on reactivity. In fact, in high-rank coals, pore sizes are so small that the reaction is diffusion controlled.

The volatile matter content of coal varies widely for the four main coal ranks and is low for high-rank coals such as anthracite and higher for low-rank coal. The higher the volatile matter content the more reactive a coal is, which means it can be more readily converted to gas while producing less char. Thus for high-rank coals, the utilization of char within the gasifier is much more of a concern. For low-rank coals, char is not a major concern; however, the ease with which they are gasified leads to high levels of tar in the syngas which makes syngas cleanup more difficult.

The mineral matter content of the coal (reflected as process ash) does not have much impact on the composition of the produced synthesis gas. A gasifier may be designed to remove the mineral ash in solid or liquid (slag) form. In fluidized- or fixed- bed gasifiers, the ash is normally removed as a solid, which limits operational temperatures in the gasifier to well below the ash melting point. In other designs, particularly slagging gasifiers, the operational temperatures are designed to be above the ash melting temperature. The selection of which design to employ often is dependent on the ash melting/softening temperature of the feedstock which is to be used at the facility.

The high moisture content of the feedstock lowers internal gasifier temperatures through evaporation and the endothermic reaction of steam and char which requires that a limit be set on the moisture content of coal supplied to the gasifier, which can be met by coal drying operations if necessary (Chapter 10). For a typical fixed-bed gasifier and moderate rank and ash content of the coal, this limit is on the order of 35% w/w. Fluidized-bed and entrained-bed gasifiers have a lower tolerance for moisture, limiting the moisture content to 5 to 10% for a similar coal feedstock. Oxygen supplied to the gasifiers must be increased with an increase in the mineral matter content or the moisture content in the coal.

However, the mineral matter content of the coal does not have much impact on the composition of the gas product. Gasifiers may be designed to remove the produced ash in solid or liquid (slag) form (Chapter 10). In fluidized- or fixed-bed gasifiers, the ash is typically removed as a solid, which limits operational temperatures in the gasifier to well below the ash melting point. In other designs, particularly slagging gasifiers, the operational temperatures are designed to be above the ash melting temperature. The selection of the most appropriate gasifier is often dependent on the melting temperature and/or the softening temperature of the ash and the type of coal that is to be used at the facility.

Furthermore, coal which displays caking, or agglomerating, characteristics when heated (Speight, 2013, 2020) is not usually amenable to use as feedstock for gasification processes that employ fluidized-bed or moving-bed reactors; in fact, caking coal is difficult to handle in fixed-bed reactors. Pretreatment of the caking coal by a mild oxidation process (typically consisting of low-temperature heating of the coal in the presence of air or oxygen) destroys the caking characteristics of the coal.

High moisture content of the feedstock lowers internal gasifier temperatures through evaporation and the endothermic reaction of steam and char. Usually, a limit is set on the moisture content of coal supplied to the gasifier, which can be met by coal drying operations if necessary. For a typical fixed-bed gasifier and moderate rank and ash content of the coal, this moisture limit in the coal limit is on the order of 35% w/w. Fluidized-bed and entrained-bed gasifiers have a lower tolerance for moisture, limiting the moisture content to approximately 5 to 10% w/w a similar coal feedstock. Oxygen supplied to the gasifiers must be increased with an increase in mineral matter content (ash production) or moisture content in the coal.

As anticipated, the quality of the gas generated in a system is influenced by coal characteristics, gasifier configuration, and the amount of air, oxygen or steam introduced into the system. The output and quality of the gas produced is determined by the equilibrium established when the heat of oxidation (combustion) balances the heat of vaporization and volatilization plus the sensible heat (temperature rise) of the exhaust gases. The quality of the outlet gas (BTU/ft.^{3}) is determined by the amount of volatile gases (such as hydrogen, carbon monoxide, water, carbon dioxide, and methane) in the gas stream.

With some coal feedstocks, the higher the amounts of volatile produced in the early stages of the process the higher the heat content of the product gas. In some cases, the highest gas quality may be produced at the lowest temperatures but when the temperature is too low, char oxidation reaction is suppressed and the overall heat content of the product gas is diminished.

As a very general *rule of thumb*, optimum gas yields and gas quality are obtained at operating temperatures of approximately 595 to 650°C (1100 to 1200°F). A gaseous product with a higher heat content (BTU/ft.^{3}) can be obtained at lower system temperatures but the overall yield of gas (determined as the *fuel-to-gas ratio*) is reduced by the unburned char fraction.

Coals of the western United States tend to have lower heating values, lower sulfur contents, and higher moisture contents relative to bituminous coals from the eastern United States. The efficiency loss associated with high moisture and ash content coals is more significant for slurry-feed gasifiers. Consequently, dry-feed gasifiers, such as the Shell gasifier, may be more appropriate for low-quality coals. There is also the possibility that western coals can be combined with petroleum coke in order to increase the heating value and decrease the moisture content of the gasification feedstock.

One of the advantages of the coal gasification technology is that it offers the polygeneration of a variety of products, such as (i) co-production of electric power, (ii) liquid fuels, (iii) chemicals, (iv) hydrogen and from the synthesis gas generated from the gasification process. Chemical gasification plants based on entrained flow and more especially on moving-bed technologies are at present operating all over the world with the biggest plants located in South Africa (Sasol) (Speight, 2013, 2020). In addition, gasification is an important step of the indirect liquefaction of coal for production of liquid fuels (Speight, 2013, 2020).

Power plants under (approximately) 350 MWe cannot use the latest high-efficiency combined cycle technologies. Those below (approximately) 250 MWe cannot use particularly high-efficiency steam turbines because of friction losses and leaks in small dimension gas paths. Those below (approximately) 100 MWe cannot economically use reheat steam cycles, giving a further efficiency drop. Moving further down in size gives a steady reduction in efficiency of the gas turbine, whichever manufacturer is selected. The scale effect of gas turbine efficiencies is due to flow paths and pressure drops and can only be partly compensated for with additional components such as intercoolers or reheaters.

At smaller sizes, reciprocating engines become relatively more attractive compared with rotating machinery. Their electricity generation efficiency is higher for power generation unit sizes of a few tens of MWe and less. Their major disadvantage is often the frequent and expensive maintenance required.

These technical considerations indicate some of the incentives for large unit size of power plant. Labor requirements per unit of installed capacity provide yet another driver towards large unit size. With the exception of power plants using easily handled fuels (generally natural gas) where there is a significant heat demand as well as a power demand, the trend has been towards larger power plants.

Gasification and pyrolysis processes can be classified as entrained gasifiers, fluidized-bed gasifiers (bubbling bed or circulating, atmospheric or pressurized), small industrial-scale gasifiers (fixed-bed or grate, which can be up-draught or down-draught) and hybrid systems.

Gasification agents are normally air, oxygen-enriched air, or oxygen. Steam is sometimes added for temperature control, heating value enhancement or to permit the use of external heat (allothermal gasification). The major chemical reactions break and oxidize hydrocarbon derivatives to give a product gas of carbon monoxide, carbon dioxide, hydrogen, and water. Other important components include hydrogen sulfide, various compounds of sulfur and carbon, ammonia, low-boiling hydrocarbon derivatives and high-boiling hydrocarbon derivatives (tars).

The products from the gasification of coal may be of low, medium, or high heat-content (high-Btu) content as dictated by the process as well as by the ultimate use for the gas (Figure 9.1). (Fryer and Speight, 1976; Mahajan and Walker, 1978; Anderson and Tillman, 1979; Cavagnaro, 1980; Bodle and Huebler; Argonne, 1990; 1981; Baker and Rodriguez, 1990; Probstein and Hicks, 1990; Lahaye and Ehrburger, 1991).

9.2.1 Feedstock Quality

Physical process parameters and feedstock type exert an influence on gasification. For example, the reactivity of coal generally decreases with increase in rank (from lignite to

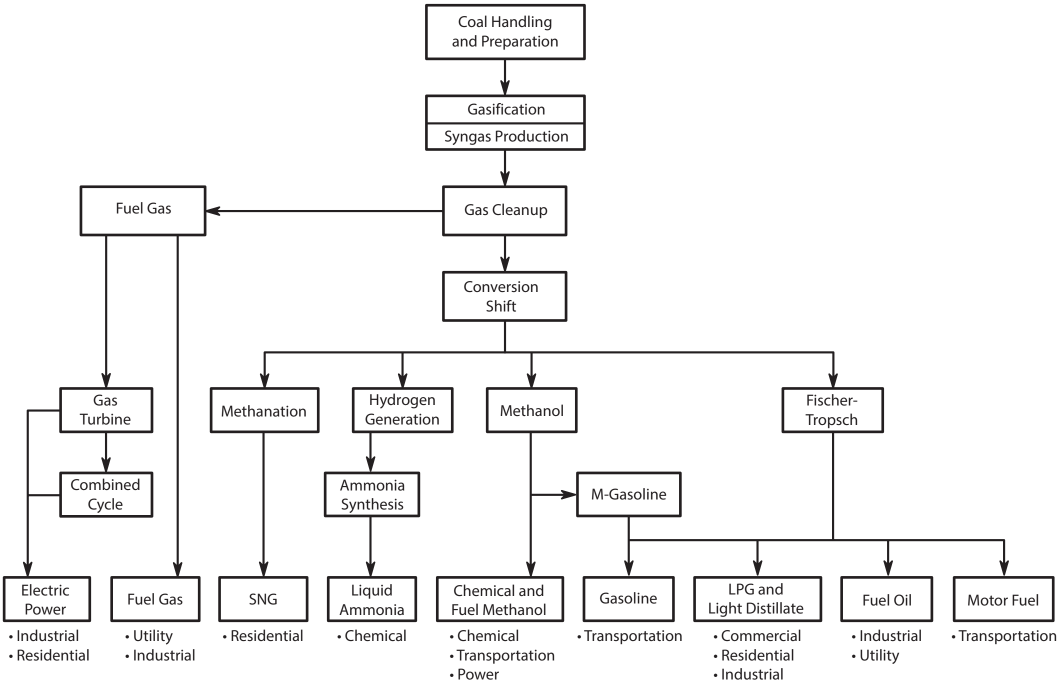

Figure 9.1 Uses of the various gaseous products from coal.

subbituminous coal to bituminous coal anthracite). Furthermore, the smaller the particle size, the more contact area between the coal and the reaction gases, leading to a more rapid reaction. For medium-rank coal and low-rank coal, reactivity increases with an increase in pore volume and surface area, but for coal having a carbon content greater than 85% w/w these factors have no effect on reactivity. In fact, in high-rank coal, pore sizes are so small that the reaction is diffusion controlled.

Other feedstocks (such as petroleum residua and biomass) are so variable that gasification behavior and products vary over a wide range. The volatile matter produced during the thermal reactions varies widely and the ease with which tar products are formed as part of the gaseous products makes gas cleanup more difficult.

The mineral matter content of the feedstock also has an impact on the composition of the produced synthesis gas. Gasifiers may be designed to remove the produced ash in solid or liquid (slag) form. In fluidized- or fixed-bed gasifiers, the ash is typically removed as a solid, which limits operational temperatures in the gasifier to well below the ash melting point. In other designs, particularly slagging gasifiers, the operational temperatures are designed to be above the ash melting temperature. The selection of the most appropriate gasifier is often dependent on the melting temperature and/or the softening temperature of the ash and the feedstock which is to be used at the facility.

High moisture content of the feedstock lowers internal gasifier temperatures through evaporation and the endothermic reaction of steam and char. Usually, a limit is set on the moisture content of feedstock supplied to the gasifier, which can be met by drying operations if necessary. For a typical fixed-bed gasifier and moderate carbon content and mineral matter content of the feedstock, the moisture limit may be on the order of 35% w/w.

Fluidized-bed and entrained-bed gasifiers have a lower tolerance for moisture, limiting the moisture content to approximately 5 to 10% w/w of the feedstock. Oxygen supplied to the gasifiers must be increased with an increase in mineral matter content (ash production) or moisture content in the feedstock.

Depending on the type of feedstock being processed and the analysis of the gas product desired, pressure also plays a role in product definition (Speight, 2011b, 2013). In fact, some (or all) of the following processing steps will be required: (i) pretreatment of the feedstock, (ii) primary gasification, (iii) secondary gasification of the carbonaceous residue – char – from the primary gasifier, (iv) removal of carbon dioxide, hydrogen sulfide, and other acid gases from the gas stream, (v) shift conversion for adjustment of the carbon monoxide/hydrogen mole ratio to the desired ratio, and (vi) catalytic methanation of the carbon monoxide/hydrogen mixture to form methane. If high heat-content (high-Btu) gas is desired, all of these processing steps are required since gasifiers do not yield methane in the concentrations required (Speight, 2013, 2020).

Thus, the reactivity of the feedstock is an important factor in determining the design of the reactor because feedstock reactivity, which determines the rate of reduction of carbon dioxide to carbon monoxide in the reactor, influences reactor design insofar as it dictates the height needed in the reduction zone.

In addition certain operational design characteristics of the reactor system (load following response, restarting after temporary shutdown) are affected by the reactivity of the char produced in the reactor. There is also a relationship between feedstock reactivity and the number of active places on the char surface, these being influenced by the morphological characteristics as well as the geological age of the fuel. The grain size and the porosity of the char produced in the reduction zone influence the surface available for reduction and, therefore, the rate of the reduction reactions which are facilitated by reactor design.

9.2.2 Mixed Feedstocks

Pyrolysis and gasification of fossil fuels, biomass materials and wastes have been used for many years to convert organic solids and liquids into useful gaseous, liquid, and cleaner solid fuels (Speight, 2011a; Brar *et al.*, 2012; Speight, 2020).

Both fixed-bed and fluidized-bed gasifiers have been used in cogasification of coal-biomass and coal-waste feedstocks – these include a downdraft fixed-bed gasifier (Kumabe *et al.*, 2007; Speight, 2011a, 2013, 2020). However, operational problems when a fluidized-bed gasifier was employed that included (i) defluidization of the fluidized bed gasifier caused due to agglomeration of low melting point ash present in the biomass, and (ii) clogging of the downstream pipes due to excessive tar accumulation (Pan *et al.*, 2000; Vélez *et al.*, 2009). In addition, cogasification and co-pyrolysis of birch wood and coal in an updraft fixed-bed gasifier as well as in a fluidized-bed gasifier has yielded overhead products with 4.0 to 6.0% w/w tar content while the fixed-bed reactor gave tar yields on the order of 25 to 26% w/w for cogasification of coal and silver birch wood mixtures (1: 1 w/w ratio) at 1000°C (1830°F) (Collot *et al.*, 1999, 2002, 2006).

From the perspective of the efficient operation of the reactor, the presence of mineral matter has a deleterious effect on fluidized-bed reactors. The low melting point of ash formed from the mineral matter present in woody biomass can lead to agglomeration which influences the efficiency of the fluidization – the ash can cause sintering, deposition, and corrosion of the gasifier construction metal. In addition, biomass containing alkali oxides and salts can cause clinkering/slagging problems (McKendry, 2002).

9.2.2.1 Coal-Biomass Feedstocks

Coal gasification is an established technology (Ishi, 1982; Hotchkiss, 2003; Speight, 2013). Biomass gasification has been the focus of research in recent years to estimate efficiency and performance of the gasification process using various types of biomass such as sugarcane residue (Gabra *et al.*, 2001), rice hulls (Boateng *et al.*, 1992), pine sawdust (Lv *et al.*, 2004), almond shells (Rapagnà *et al.*, 1997, 2000), wheat straw (Ergudenler and Ghali, 1993), food waste (Ko *et al.*, 2001), and wood biomass (Pakdel and Roy, 1991; Bhattacharaya *et al.*, 1999; Chen *et al.*, 1992; Hanaoka *et al.*, 2005).

Recently, there has been significant research interest in cogasification of various biomass and coal mixtures such as Japanese cedar wood and coal (Kamabe *et al.*, 2007), coal and saw dust (Vélez *et al.*, 2009), coal and pine chips (Pan *et al.*, 2000), coal and silver birch wood (Collot *et al.*, 1999), and coal and birch wood (Brage *et al.*, 2000). Cogasification of coal and biomass has some synergy – the process not only produces a low carbon footprint on the environment, but also improves the H_2/CO ratio in the produced gas which is required for liquid fuel synthesis (Sjöström *et al.*, 1999; Kumabe *et al.*, 2007). In addition, inorganic matter present in biomass catalyzes the gasification of coal. However, cogasification processes require custom fittings and optimized processes for the coal and region-specific wood residues.

While cogasification of coal and biomass is advantageous from a chemical point of view, some practical problems have been associated with the process on upstream, gasification, and downstream processes. On the upstream side, the particle size of the coal and biomass is required to be uniform for optimum gasification. In addition, moisture content and pretreatment (torrefaction) are important during upstream processing.

While upstream processing is influential from a material handling point of view, the choice of gasifier operation parameters (temperature, gasifying agent, and catalysts) decide product gas composition and quality. Biomass decomposition occurs at a lower temperature than coal and therefore different reactors compatible to the feedstock mixture are required (Brar *et al.*, 2012). Furthermore, feedstock and gasifier type along with operating parameters not only decide product gas composition but also dictate the amount of impurities to be handled downstream. Downstream processes need to be modified if coal is used with biomass in gasification. Heavy metal and impurities such as sulfur and mercury present in coal can make syngas difficult to use and unhealthy for the environment. Also, at high temperature, alkali present in biomass can cause corrosion problems in downstream pipes. An alternative option to downstream gas cleaning would be to process coal to remove mercury and sulfur before feeding it to the gasifier.

However, first and foremost, coal and biomass require drying and size reduction before they can be fed into a gasifier. Size reduction is needed to obtain appropriate particle sizes; however, drying is required to achieve moisture content suitable for gasification operations. In addition, densification of the biomass may be done to make pellets and improve density and material flow in the feeder areas.

It is recommended that biomass moisture content should be less than 15% w/w (in some cases, less than 15% w/w) prior to gasification. High moisture content reduces the temperature achieved in the gasification zone, thus resulting in incomplete gasification. Forest residues or wood has a fiber saturation point at 30 to 31% moisture content (dry basis) (Brar *et al.*, 2012). Compressive and shear strength of the wood increases with decreased moisture content below the fiber saturation point. In such a situation, water is removed from the cell wall which causes shrinkage of the cell wall. The long-chain molecules which make up the cell wall move closer to one another and bind more tightly. A high level of moisture, usually injected in form of steam in the gasification zone, favors formation of a water-gas shift reaction that increases hydrogen concentration in the resulting gas.

The torrefaction process is a thermal treatment of biomass in the absence of oxygen, usually at 250 to 300°C to drive off moisture, decompose hemicellulose completely, and partially decompose cellulose (Speight, 2011a, 2020). Torrefied biomass has reactive and unstable cellulose molecules with broken hydrogen bonds and not only retains 79 to 95% of feedstock energy but also produces a more reactive feedstock with lower atomic hydrogen-carbon and oxygen-carbon ratios than the original biomass. Torrefaction results in higher yields of hydrogen and carbon monoxide in the gasification process.

Finally, the presence of mineral matter in the coal-biomass feedstock is not appropriate for fluidized-bed gasification. Low melting point of ash present in woody biomass leads to agglomeration which caused defluidization of the slag and the ash causes sintering, deposition, and corrosion of the gasifier construction metal bed (Vélez *et al.*, 2009). Biomass containing alkali oxides and salts with the propensity of produce yield higher than 5% w/w ash causes clinkering/slagging problems (McKendry, 2002).

Thus, it is imperative to be aware of the melting of biomass ash, its chemistry within the gasification bed (no bed, silica/sand, or calcium bed), and the fate of alkali metals when using fluidized-bed gasifiers.

Most small to medium-sized biomass/waste gasifiers are air blown, operate at atmospheric pressure and at temperatures in the range 800 to 100°C (1470 to 2190°F). These gasifier units face different challenges than large gasification plants – the use of small-scale air separation plant should oxygen gasification be preferred. Pressurized operation, which eases gas cleaning, may not be practical.

Biomass fuel producers, coal producers and, to a lesser extent, waste companies are enthusiastic related to supplying cogasification power plant and realize the benefits of cogasification with alternate fuels. The benefits of a cogasification technology involving coal and biomass include use of a reliable coal supply with gate-fee waste and biomass which allows the economies of scale from a larger plant than could be supplied just with waste and biomass. In addition, the technology offers a future option for refineries for hydrogen production and fuel development. In fact, oil refineries and petrochemical plants are opportunities for gasifiers when the hydrogen is particularly valuable (Speight, 2011b).

9.2.2.2 Coal-Waste Feedstocks

Waste may be municipal solid waste (MSW) which has had minimal presorting, or refuse-derived fuel (RDF) which has had significant pretreatment, usually mechanical screening, and shredding. Other more specific wastes – but excluding hazardous waste – and possibly including crude oil coke, may provide niche opportunities for co-utilization.

The traditional waste to energy plant, based on mass-burn combustion on an inclined grate, has a low public acceptability despite the low emissions achieved over the last decade with modern flue gas clean-up equipment. This has led to difficulty in obtaining planning permissions to construct the new waste to energy plants that are needed. After much debate, various governments have allowed options for advanced waste conversion technologies (gasification, pyrolysis, and anaerobic digestion), but will only give credit to the proportion of electricity generated from non-fossil waste.

Co-utilization of waste and biomass with coal may provide economies of scale that help achieve the policy objectives identified above at an affordable cost. In some countries, governments propose cogasification processes as being *well suited for community-sized developments* suggesting that waste should be dealt with in smaller plants serving towns and cities, rather than moved to large, central plants (satisfying the so-called *proximity principal*).

In fact, at the current time, neither biomass nor wastes are produced, or naturally gathered at sites in quantities sufficient to fuel a modern large and efficient power plant. The disruption, transport issues, fuel use and public opinion all act against gathering hundreds of MWe worth of such fuels at a single location. Biomass or waste-fired power plants are therefore inherently limited in size and hence in efficiency, labor costs per unit electricity produced and in other economies of scale. The production rates of municipal refuse follow reasonably predictable patterns over time periods of a few years. Recent experience with the limited current *biomass for energy* harvesting has shown unpredictable variations in harvesting capability with long periods of zero production over large areas during wet weather and the foot and mouth outbreak.

The situation is different for coal. This is generally mined or imported and thus large quantities are available from a single source or a number of closely located sources, and supply has been reliable and predictable. However, the economics of new coal-fired power plants of any technology or size have not encouraged any new coal-fired power plant in the gas generation market.

Combining biomass, refuse and coal overcomes the potential unreliability of biomass, the potential longer-term changes in refuse and the size limitation of a power plant using only waste and/or biomass. It also allows benefit from a premium electricity price for electricity from biomass and the gate fee associated with waste. If the power plant is gasification-based, rather than direct combustion, further benefits may be available. These include a premium price for the electricity from waste, the range of technologies available for the gas to electricity part of the process, gas cleaning prior to the main combustion stage instead of after combustion and public image, which is currently generally better for gasification than for combustion. These considerations lead to the current study of cogasification of wastes/biomass with coal (Speight, 2013, 2020).

For large-scale power generation (>50 MWe), the gasification field is dominated by plant based on the pressurized, oxygen-blown, entrained flow or fixed-bed gasification of fossil fuels. Entrained gasifier operational experience to date has largely been with well-controlled fuel feedstocks with short-term trial work at low cogasification ratios and with easily handled fuels.

There is less single-fuel experience with the British Gas Lurgi (BGL) than with entrained gasifiers. However, the Lurgi gasifier is better suited to difficult-to-mill feedstocks than are entrained gasifiers and has the most operational experience with fuels of widely differing mechanical properties.

Use of waste materials as cogasification feedstocks may attract significant disposal credits. Cleaner biomass materials are renewable fuels and may attract premium prices for the electricity generated. Availability of sufficient fuel locally for an economic plant size is often a major issue, as is the reliability of the fuel supply. Use of more-predictably available coal alongside these fuels overcomes some of these difficulties and risks. Coal could be regarded as the "flywheel" which keeps the plant running when the fuels producing the better revenue streams are not available in sufficient quantities.

Coal characteristics are different from alternate fuels such as biomass and (industrial or domestic) wastes. Hydrogen-to-carbon ratios are higher for younger fuels, as is the oxygen content. This means that the reactivity is different under gasification conditions. Gas cleaning issues can also be different, with sulfur a major concern for coal gasification but chlorine compounds and tars more important for waste and biomass gasification. There are no current proposals for adjacent gasifiers and gas cleaning systems, one handling biomass or waste and one coal, alongside each other and feeding the same power production equipment. However, there are some advantages to such a design compared with mixing fuels in the same gasifier and gas cleaning system.

Electricity production or combined electricity and heat production remain the most likely area for the application of gasification or cogasification. The lowest investment cost per unit of electricity generated is the use of the gas in an existing large power station. This has been done in several large utility boilers, often with the gas fired alongside the main fuel. This option allows a comparatively small thermal output of gas to be used with the same efficiency as the main fuel in the boiler as a large, efficient steam turbine can be used. It is anticipated that addition of gas from a biomass or wood gasifier into the natural gas feed to a gas turbine to be technically possible but there will be concerns as to the balance of commercial risks to a large power plant and the benefits of using the gas from the gasifier.

The use of fuel cells with gasifiers is frequently discussed but the current cost of fuel cells is such that their use for mainstream electricity generation is uneconomic.

Furthermore, the disposal of municipal and industrial wastes has become an important problem because the traditional means of disposal, landfill, has become environmentally much less acceptable than previously. New, much stricter regulation of these disposal methods will make the economics of waste processing for resource recovery much more favorable. One method of processing waste streams is to convert the energy value of the combustible waste into a fuel. One type of fuel attainable from wastes is a low heating value gas, usually 100-150 Btu/scf, which can be used to generate process steam or to generate electricity (Gay *et al.*, 1980). Co-processing such waste with coal is also an option (Speight, 2013, 2020).

In summary, coal might be cogasified with waste or biomass for environmental, technical, or commercial reasons. It allows larger, more efficient plants than those sized for the biomass grown or waste arising within a reasonable transport distance; specific operating costs are likely to be lower; and fuel supply security is assured.

Cogasification technology varies and is usually site specific with high dependence on the feedstock. At the largest scale, the plant may include the well-proven fixed-bed and entrained-flow gasification processes. At smaller scales, emphasis is placed on technologies which appear closest to commercial operation. Pyrolysis and other advanced thermal conversion processes are included where power generation is practical using the on-site feedstock produced. However, the needs to be addressed are (i) the core fuel handling and gasification/pyrolysis technologies, (ii) the fuel gas clean-up, and (iii) the conversion of fuel gas to electric power (Ricketts *et al.*, 2002).

9.2.2.3 Reactors

Both fixed-bed and fluidized-bed gasifiers have been used in cogasification coal with biomass and waste – these include a downdraft fixed-bed gasifier (Kumabe *et al.*, 2007). However, operational problems when a fluidized-bed gasifier was employed included (i) defluidization of the fluidized-bed gasifier due to agglomeration of low melting point ash present in the biomass, and (ii) clogging of the downstream pipes due to excessive tar accumulation (Pan *et al.*, 2000; Vélez *et al.*, 2009). In addition, it was reported that cogasification and co-pyrolysis of birch wood and coal in an updraft fixed bed, possibly an updraft, as well as fluidized-bed gasifiers that the product gas produced from fluidized-bed gasification had 4.0 to 6.0% w/w tar content while the fixed-bed reactor gave tar yields on the order of 25 to 26% w/w for cogasification of coal and silver birch wood mixtures (1 : 1 ratio w/w) at 1000°C (1830°F) (Collot *et al.*, 1999).

From the perspective of the efficient operation of the reactor, and as already stated above, the presence of mineral matter has a deleterious effect on fluidized-bed reactors. The low melting point of ash formed from the mineral matter present in woody biomass can lead to agglomeration which influences the efficiency of the fluidization. The ash can cause sintering, deposition, and corrosion of the gasifier construction metal. Biomass containing alkali oxides and salts can cause clinkering/slagging problems (McKendry, 2002).

9.2.3 Bulk Density

The bulk density of a feedstock is the weight per unit volume of loosely packed feedstock and feedstocks with a high bulk density are advantageous because they represent a high energy-for-volume value. Consequently these fuels need less bunker space for a given refueling time. Feedstocks with a low bulk density fuels can give rise to insufficient flow under gravity, resulting in low gas heating values and ultimately in burning of the char in the reduction zone – inadequate bulk densities can be improved by briquetting or pelletizing.

9.2.4 Reactivity

Feedstock reactivity is an important factor determining the rate of reduction of carbon dioxide to carbon monoxide in a gasifier. Reactivity influences the reactor design insofar as it dictates the height needed in the reduction zone – fluidized-bed gasifiers show great promise in gasifying a number of agricultural wastes.

In addition, most wood species have ash production yields than 2% w/w of the feedstock and are therefore suitable fixed-bed gasifiers. However, because of the high volatile content of wood, updraught systems produce a tar-containing gas suitable mainly for direct burning. Cleaning of the gas to make it suitable for engines is rather difficult and capital and labor intensive. Downdraught systems can be designed to deliver a virtually tar-free product gas in a certain capacity range when fuelled by wood blocks or wood chips of low moisture content. However, most currently available downdraught gasifiers are not suitable for non-pelletized sawdust. Issues that are likely to require attention are (i) excessive tar production, (ii) inadmissible pressure drop, and (iii) lack of bunker flow. On the other hand, fluidized-bed gasifiers can accommodate small sawdust particles and produce burner quality gas.

In principle, many countries (especially developing countries) have a wide range of agricultural residues available for gasification but in practice, however, experience with most types of waste is extremely limited. Coconut shells and maize cobs are are the best documented and seem unlikely to create serious problems in fixed-bed gasifiers. Coconut husks can give rise to bridging problems in the bunker section, but the material can be gasified when mixed with a certain quantity of wood. Most cereal straws have ash contents above 10% and present slagging problems in downdraught gasifiers. In fact, rice husks can produce ash on the order of 20% w/w of the feedstock and, because of this, may be the most difficult feedstock for gasification.

It is possible to gasify most types of agricultural waste in updraught gasifiers. However, the capital, maintenance and labor costs, and the environmental consequences (disposal of tarry condensates) involved in cleaning the gas, prevent engine applications under most circumstances. Downdraught equipment is cheaper to install and operate and creates fewer environmental difficulties, but at present technology is inadequate to handle agricultural residues (with the possible exception of maize cobs and coconut shells) without installing expensive (and partly unproven) additional devices.

In addition certain operational characteristics of the gasification system (load following response, restarting after temporary shutdown) are affected by the reactivity of the char produced in the gasifier. Reactivity is dependent on the type of feedstock – feedstocks such as wood, charcoal and peat are far more reactive than coal.

After the initial reaction in the gasifier, the reactivity of the char becomes important since there is a relation between reactivity and the number of active sites on the char surface, these being influenced by the morphological characteristics of the char and the feedstock from which the char was produced. The grain size and the porosity of the char produced in the reduction zone influence the surface available for reduction and, therefore, the rate of the reduction reactions.

Another aspect of the properties of the char is the effect of various elements which act as catalysts on the rate of gasification. Small quantities of potassium, sodium and zinc can have a large effect on the reactivity of the fuel.

9.2.5 Energy Content

The choice of a fuel for gasification will in part be decided by its heating value. The method of measurement of the fuel energy content will influence the estimate of efficiency of a given gasification system. Reporting of fuel heating values is often confusing since at least three different bases are used: (i) fuel higher heating values as obtained in an adiabatic bomb calorimeter – these values include the heat of condensation of the water that is produced during combustion, and because it is very difficult to recover the heat of condensation in actual gasification operations these values present a too optimistic view of the fuel energy content, (ii) fuel higher heating values on a moisture-free basis, which disregard the actual moisture content of the fuel and so provide even more optimistic estimates of energy content, and (iii) fuel higher heating values on a moisture and ash free basis, which disregard the incombustible components and consequently provide estimates of energy content too high for a given weight of fuel, especially in the case of some agricultural residues (such as rice husks).

The only realistic way therefore of presenting feedstock heating values for gasification purposes is to give lower heating values (excluding the heat of condensation of the water produced) on an ash inclusive basis and with specific reference to the actual moisture content of the fuel.

Plastics waste, being a potential energy source, is another possible feedstock for fluid-bed gasifiers (Mastellone and Arena, 2007). Gasification of plastics can be subdivided into the following sequence of steps: (i) heating and melting of polymer particles, (ii) primary cracking of polymer chain with consequent formation of intermediate hydrocarbon fragments, and (iii) secondary cracking of intermediates with formation of methane, hydrogen, olefins, and oxidation/reduction reactions with the formation of carbon monoxide, carbon dioxide, and water. Ternary reactions can also occur with the subsequent formation of aromatic products and, in presence of metals, coke.

A suitable method to avoid or reduce tar formation during fluidized-bed gasification is the catalytic removal of tar precursors and intermediates. In particular, cycloparaffins, naphthenes, and aromatics, forming during ternary reactions of the intermediate species produced by primary cracking, can be decomposed to carbon and hydrogen by means of metal-based catalysts. These contain transition metals such as iron, cobalt, nickel, chromium, vanadium platinum, and magnesium, i.e., those metals typically used for the reforming of hydrocarbons (Wu and Williams, 2010).

9.2.6 Moisture Content

The heating value of the gas produced by any type of gasifier depends at least in part on the moisture content of the feedstock (Chapter 1). Moisture content can be determined on a dry basis as well as on a wet basis. In this chapter the moisture content on a dry basis will be used.

A high moisture content of the fuel reduces the thermal efficiency since heat is used to drive off the water and consequently this energy is not available for the reduction reactions and for converting thermal energy into chemical bound energy in the gas. Therefore high moisture contents result in low gas heating values. When the gas is used for direct combustion purposes, low heating values can be tolerated and the use of feedstocks with a moisture content (dry basis) of up to 40 to 50% w/w is feasible, especially when using updraught gasifiers.

In downdraught gasifiers high moisture contents give rise not only to low gas heating values, but also to low temperatures in the oxidation zone, and this can lead to insufficient tar converting capability if the gas is used for engine applications. Both because of the gas heating value and issues related to tar entrainment, downdraught gasifiers need reasonably dry fuels (less than 25% w/w moisture dry basis).

9.2.7 Particle Size and Distribution

Many feedstocks require drying and size reduction before they can be fed into a gasifier. Size reduction is needed to obtain appropriate particle sizes; however, drying is required to achieve moisture content suitable for gasification operations. In addition, densification of biomass may be done to make pellets and improve density and material flow in the feeder areas.

Up and downdraught gasifiers are limited in the range of fuel size acceptable in the feedstock. Fine grained and/or fluffy feedstock may cause flow problems in the bunker section of the gasifier as well as an inadmissible pressure drop over the reduction zone and a high proportion of dust in the gas. Large pressure drops will lead to reduction of the gas load of downdraught equipment, resulting in low temperatures and tar production.

Excessively large sizes of particles or pieces give rise to a reduced reactivity of the fuel, resulting in startup problems and poor gas quality, and to transport problems through the equipment. A large range in size distribution of the feedstock will generally aggravate the above phenomena. The presence of large-sized particles can cause gas channeling, especially in updraught gasifiers.

Acceptable sizes of the feedstocks for gasification systems depend to a certain extent on the design of the units. In general, wood gasifiers operate on wood blocks and woodchips ranging from 8 x 4 x 4 cm. to 1 x 0.5 x 0.5 cm. Charcoal gasifiers are generally fuelled by charcoal lumps ranging between 1 x 1 x 1 cm. and 3 x 3 x 3 cm. Fluidized-bed gasifiers are normally able to handle fuels with particle diameters varying between 0.1 and 20 mm.

9.2.8 Mineral Matter Content and Ash Production

Finally, gasification reactors are very susceptible to ash production and properties. Ash can cause a variety of problems particularly in up or downdraught gasifiers. Slagging or clinker formation in the reactor, caused by melting and agglomeration of ashes, at best will greatly add to the difficulty of gasifier operation. If no special measures are taken, slagging can lead to excessive tar formation and/or complete blocking of the reactor. A worst case is the possibility of air-channeling which can lead to a risk of explosion, especially in updraught gasifiers.

The presence of mineral matter in the coal-biomass feedstock is not appropriate for fluidized-bed gasification. Low melting point of ash present in woody biomass leads to agglomeration which causes defluidization of the ash and sintering, deposition as well as corrosion of the gasifier construction metal bed (Vélez *et al*., 2009). Biomass containing alkali oxides and salts are likely to produce clinkering/slagging problems from ash formation (McKendry, 2002). It is imperative to be aware of the melting of biomass ash, its chemistry within the gasification bed (no bed, silica/sand, or calcium bed), and the fate of alkali metals when using fluidized-bed gasifiers.

The occurrence of slagging in the gasifier occurs depends on (i) the ash produced from the fuel, (ii) the melting characteristics of the ash, and (iii) the temperature pattern in the gasifier. Local high temperatures in voids in the fuel bed in the oxidation zone, caused by bridging in the bed, may cause slagging even using fuels with a high ash melting temperature.

In general, no slagging is observed with fuels having ash production less than 6% w/w of the feedstock but severe slagging can be expected for feedstocks where the mineral matter content is higher than 12% w/w. For feedstocks with ash production from 6 to 12% w/w of the feedstock, the propensity for slagging depends on the ash melting temperature, which is influenced by the presence of trace elements giving rise to the formation of low melting point eutectic mixtures. For gasification purposes the melting behavior of the fuel ash should be determined in both oxidizing and reducing atmospheres.

Updraught and downdraught gasifiers are able to operate with slagging fuels if specially modified (continuously moving grates and/or external pyrolysis gas combustion).

Cross-draught gasifiers, which work at temperatures on the order of 1500°C (2730°F) and above, need special safeguards with respect to the ash formation from the feedstock. Fluidized-bed reactors, because of their inherent capacity to control the operating temperature, suffer less from ash melting and fusion problems.

Generally, slagging is not observed with fuels having mineral matter ash contents less than below 5 to 6% w/w. Severe slagging can be expected for fuels having mineral matter contents in excess of 12% w/w/. For fuels with mineral matter contents between 6 and 12%, the slagging behavior depends to a large extent on the mineral matter composition – reflected in the ash melting temperature – which is influenced by the presence of trace elements giving rise to the formation of low melting point eutectic mixtures.

Updraught and downdraught gasification reactors are able to operate with slagging fuels if specially modified (continuously moving grates and/or external pyrolysis gas combustion). Cross draught gasification reactors, which work at temperatures on the order of 1500°C (2700°F) and higher, need special safeguards with respect to the mineral matter content of the fuel. Fluidized-bed reactors, because of their inherent capacity to control the operating temperature, suffer less from ash melting and fusion problems.

9.2.9 Devolatilization and Volatile Matter Production

The devolatilization (or pyrolysis) process commences at approximately 200 to 300°C (390 to 570°F), depending upon the nature and properties of the feedstock (Chapter 2). Volatile products are released and a carbonaceous residue (char) is produced, resulting in up to 70% weight loss for many feedstocks. The process determines the structure and composition of the char, which will then undergo gasification reactions.

More specifically, as the feedstock particle is heated, any residual moisture (assuming that the feedstock has been pre-dried) is driven off and after all the moisture contained in the feedstock particle(s) has evaporated, the particles undergo devolatilization. The devolatilization and discharge of volatiles generates a range of products varying from carbon monoxide and methane to high molecular weight hydrocarbons comprising paraffin/olefin hydrocarbons, aromatic hydrocarbons, heavy oil, and tar, which are also feedstock dependent. As these products pass from the devolatilization (pyrolsis) zone further thermal reactions will occur and gasification of the volatile products will commence.

At temperatures above 500°C (930°F) the conversion of the feedstock to char and mineral matter ash is completed. The gasification of char particles occurs after the devolatilization process has finished (Silaen and Wang, 2008). For gas generation the char provides the necessary energy to promote further heating and – typically, the char is contacted with air or oxygen and steam to generate the product gases.

For some feedstocks, carbon conversion is believed to be independent of the devolatilization rate and less sensible to feedstock particle size, but it is sensitive to the heterogeneous char-oxygen, char-CO2, and char-steam reaction kinetics (Chen *et al.*, 2000).

The amount of volatile matter produced from the feedstock determines the necessity of special measures (either in design of the gasifier or in the layout of the gas cleanup train) in order to remove tars from the product gas in engine applications. In practice the only biomass fuel that does not need this special attention is good-quality charcoal.

The volatile matter produced by charcoal, however, is often underestimated and in practice may be anything from 3 to 30% w/w or more. As a general rule, if the fuel has the ability to produce more than 10% w/w volatile matter it should be used in downdraught gas producers, but even in this case the method of charcoal production should be taken into account. Charcoal produced in large-scale retorts is fairly consistent in volatile matter content, but large differences can be observed in charcoal produced from small-scale open pits or portable metal kilos that are common in most developing countries.

9.2.10 Char Gasification

The gasification process occurs as the char reacts with gases such as carbon dioxide and steam to produce carbon monoxide and hydrogen (Chapter 9). Also, corrosive ash elements such as chloride and potassium may be refined out by the gasification process, allowing the high temperature combustion of the gas from otherwise problematic feedstocks.

Although the initial gasification stage is completed in seconds or even less at elevated temperature, the subsequent gasification of the char produced at the initial gasification stage is much slower, requiring minutes or hours to obtain significant conversion under practical conditions and reactor designs for commercial gasifiers are largely dependent on the reactivity of the char, which in turn depends on nature of feedstock. The reactivity of char also depends upon parameters of the thermal process required to produce the char from the original feedstock. The rate of gasification of the char decreases as the process temperature increases due to the decrease in active surface area of char. Therefore a change of char preparation temperature may change the chemical nature of char, which in turn may change the gasification. The reactivity of char may be influenced by catalytic effect of mineral matter in the char.

Heat and mass transfer processes in fixed- or moving-bed gasifiers are affected by complex solids flow and chemical reactions. Moving-bed gasifiers are countercurrent flow reactors in which the feedstock enters at the top of the reactor and oxygen (air) enters at the bottom of the reactor (Beenackers, 1999). Because of the countercurrent flow arrangement of the reactor, the heat of reaction from the gasification reactions serves to pre-heat the coal before it enters the gasification reaction zone. Consequently, the temperature of the synthesis gas exiting the gasifier is significantly lower than the temperature needed for complete conversion of the feedstock. However, coarsely crushed feedstock may settle while undergoing (i) thermal drying, (ii) pyrolysis-devolatilization, (iii) gasification, and (iv) reduction. In addition, the particles change in diameter, shape, and porosity – non-ideal behavior may result from bridges, gas bubbles, channeling, and a variable void fraction may also change heat and mass transfer characteristics.

Though there is a considerable overlap of the processes, each can be assumed to occupy a separate zone where fundamentally different chemical and thermal reactions take place. The gasification technology package consists of a fuel and ash handling system, gasification system – reactor, gas cooling and cleaning system. There are also auxiliary systems namely, the water treatment plant to meet the requirements of industry and pollution control board. The prime mover for power generation consists of either a diesel engine or a spark ignited engine coupled to an alternator. In the case of thermal system, the end use device is a standard industrial burner.

Depending on the gasifier technology employed and the operating conditions, significant quantities of water, carbon dioxide, and methane can be present in the product gas, as well as a number of minor and trace components. Under the reducing conditions in the gasifier, most of the sulfur in the fuel sulfur is converted to hydrogen sulfide (H_2S) as well as to smaller yields of carbonyl sulfide (COS). Organically bound nitrogen in the feedstock is generally (but not always) converted to gaseous nitrogen (N_2) – some ammonia (NH_3) and a small amount of hydrogen cyanide (HCN) are also formed. Any chlorine in the feedstock (such as coal) is converted to hydrogen chloride (HCl) with some chlorine present in the particulate matter (fly ash). Trace elements, such as mercury and arsenic, are released during gasification and partition among the different phases, such as fly ash, bottom ash, slag, and product gas.

9.3 Chemistry and Physics

Chemically, gasification involves the thermal decomposition of the feedstock and the reaction of the feedstock carbon and other pyrolysis products with oxygen, water, and fuel gases such as methane. In fact, gasification is often considered to involve two distinct chemical stages: (i) devolatilization of the feedstock to produce volatile matter and char, (ii) followed by char gasification, which is complex and specific to the conditions of the reaction – both processes contribute to the complex kinetics of the gasification process (Sundaresan and Amundson, 1978).

The major difference between combustion and gasification from the point of view of the chemistry involved is that combustion takes place under oxidizing conditions, while gasification occurs under reducing conditions. In the gasification process, coal (in the presence of steam and oxygen at high temperature and moderate pressure) is converted to a mixture of product gases. The chemistry of coal gasification can be conveniently (and simply) represented by the following reaction:

$$C + O2 \rightarrow CO_2 \qquad \Delta Hr = -393.4\ MJ/kmol \tag{9.1}$$

$$C + ½\, O_2 \rightarrow CO \qquad \Delta Hr = -111.4\ MJ/kmol \tag{9.2}$$

$$C + H2O \rightarrow H2 + CO \qquad \Delta Hr = 130.5\ MJ/kmol \tag{9.3}$$

$$C + CO_2 \leftrightarrow 2CO \qquad \Delta Hr = 170.7\ MJ/kmol \tag{9.4}$$

$$CO + H_2O \leftrightarrow H_2 + CO_2 \qquad \Delta Hr = -40.2\ MJ/kmol \tag{9.5}$$

$$C + 2H_2 \rightarrow CH_4 \qquad \Delta Hr = -74.7\ MJ/kmol \tag{9.6}$$

Reactions (1) and (2) are exothermic oxidation reactions and provide most of the energy required by the endothermic gasification reactions (3) and (4). The oxidation reactions occur very rapidly, completely consuming all of the oxygen present in the gasifier, so that most of the gasifier operates under reducing conditions. Reaction (5) is the water-gas shift reaction, in water (steam) is converted to hydrogen – this reaction is used to alter the hydrogen/carbon monoxide ration when synthesis gas is the desired product, such as for use in Fischer-Tropsch processes. Reaction (6) is favored by high pressure and low temperature and is, thus, mainly important in lower temperature gasification systems. Methane formation is an exothermic reaction that does not consume oxygen and, therefore, increases the efficiency of the gasification process and the final heat content of the product gas. Overall, approximately 70% of the heating value of the product gas is associated with the carbon monoxide and hydrogen but this can be higher depending upon the gasifier type (Chadeesingh, 2011).

Thus, the thermal partial oxidation process (TPOX process) is a noncatalytic process in which the feed is partially combusted with a sub-stoichiometric amount of air, oxygen, or enriched air to obtain synthesis gas – a mixture of carbon monoxide (CO) and hydrogen (H_2) mixture – where the production of the synthesis gas depends on the oxygen-to-fuel ratio at an operating temperature range of 1200 to 1500°C (2190 to 2730°F). Feedstocks used for the process can be almost any carbonaceous material from natural gas, liquid feedstocks such as fuel oils, gas oils, coal and coal blends (including blends of coal with biomass and solid waste. A noncatalytic partial oxidation process was developed by Texaco and Shell which results in high yields of synthesis gas at high temperature and pressures. On the other hand, the catalytic partial oxidation process (CPOX process) uses a variety of catalysts to convert, for example, methane to synthesis gas. Typically, the catalysts used are various supported nickel catalysts. However, even if nickel is highly active, it suffers from carbon deposition and metal sintering.

Many other reactions, besides those presented above also occur. In the initial stages of gasification, the rising temperature of the feedstock initiates devolatilization of the feedstock and the breaking of weaker chemical bonds to yield tar, high-boiling oil, phenol, and hydrocarbon gases. These products generally react further to form hydrogen, carbon monoxide, and carbon dioxide. The fixed carbon that remains after devolatilization reacts with oxygen, steam, carbon dioxide, and hydrogen.

Depending on the gasifier technology employed and the operating conditions, significant quantities of water, carbon dioxide, and methane can be present in the product gas, as well as a number of minor and trace components. Under the reducing conditions in the gasifier, most of the sulfur in the fuel converts to hydrogen sulfide (H_2S), but 3 to 10% converts to carbonyl sulfide (COS). Organically bound nitrogen in the coal feedstock is generally converted to gaseous nitrogen (N_2), but some ammonia (NH_3) and a small amount of hydrogen cyanide (HCN) are also formed. Any chlorine in the coal is converted to hydrogen chloride (HCl) with some chlorine present in the particulate matter (fly ash). Trace elements, such as mercury and arsenic, are released during gasification and partition among the different phases, such as fly ash, bottom ash, slag, and product gas.

9.3.1 Influence of Coal Quality

The influence of physical process parameters and the effect of coal type on coal conversion is an important part of any process where coal is used as a feedstock, especially with respect to coal combustion (Chapters 7, 8) and coal gasification (Chapter 10). Thus, with respect to coal gasification, the most notable effects are those due to coal character, and often to the maceral content.

Variations in coal quality can have an impact on the heating value of the syngas produced by the gasification process. However, a desired throughput can be selected and then the size and number of gasifiers can be determined with the specific range of coal types taken into consideration. In fact, prior to gasification, some (or all) of the following processing steps will be required: (i) pretreatment of the feedstock, (ii) primary gasification, (iii) secondary gasification of the carbonaceous residue from the primary gasifier, (iv) removal of carbon dioxide, hydrogen sulfide, and other acid gases, (v) shift conversion for adjustment of the carbon monoxide/hydrogen mole ratio to the desired ratio, and (vi) catalytic methanation of the carbon monoxide/hydrogen mixture to form methane. If high heat-content (high-Btu) gas is desired, all of these processing steps are required since gasifiers (irrespective of the feedstock) do not typically yield methane in the concentrations required.

The reactivity of coal generally decreases with increase in rank (from lignite to subbituminous coal to bituminous coal anthracite). Furthermore, the smaller the particle size, the more contact area between the coal and the reaction gases causing faster reaction. For medium- and low-rank coals, reactivity increases with an increase in pore volume and surface area, but for coals having a carbon content greater than 85% w/w these factors have no effect on reactivity. In fact, in high-rank coals, pore sizes are so small that the reaction is diffusion controlled.

The volatile matter produced by the coal during thermal reactions varies widely for the four main coal ranks and is low for high-rank coals (such as anthracite) and higher for increasingly low-rank coals (such as lignite). The higher the volatile matter production, the more reactive a coal and the reactive coals can be more readily converted to gas while producing lower yields of char than a less reactive coal. Thus, for high-rank coals, the utilization of char within the gasifier is much more of an issue than for lower-rank coal. However, the ease with which they are gasified leads to high levels of tar in the gaseous products, which makes gas cleanup more difficult (Chapters 12, 14).

The mineral matter content of the coal does not have much impact on the composition of the produced syngas. Gasifiers may be designed to remove the produced ash in solid or liquid (slag) form. In fluidized- or fixed-bed gasifiers, the ash is typically removed as a solid, which limits operational temperatures in the gasifier to well below the ash melting point. In other designs, particularly slagging gasifiers, the operational temperatures are designed to be above the ash melting temperature. The selection of the most appropriate gasifier is often dependent on the melting temperature and/or the softening temperature of the ash and the coal which is to be used at the facility.

In fact, coals which display caking, or agglomerating, characteristics when heated (Chapter 6) are usually not amenable to treatment by gasification processes employing fluidized-bed or moving-bed reactors; in fact, caked coal is difficult to handle in fixed-bed reactors. The pretreatment involves a mild oxidation treatment which destroys the caking characteristics of coals and usually consists of low-temperature heating of the coal in the presence of air or oxygen.

High moisture content of the feedstock lowers internal gasifier temperatures through evaporation and the endothermic reaction of steam and char. Usually, a limit is set on the moisture content of coal supplied to the gasifier, which can be met by coal drying operations if necessary. For a typical fixed-bed gasifier and moderate rank and ash content of the coal, this moisture limit in the coal limit is on the order of 35% w/w. Fluidized-bed and entrained-bed gasifiers have a lower tolerance for moisture, limiting the moisture content to approximately 5 to 10% w/w a similar coal feedstock. Oxygen supplied to the gasifiers must be increased with an increase in mineral matter content (ash production) or moisture content in the coal.

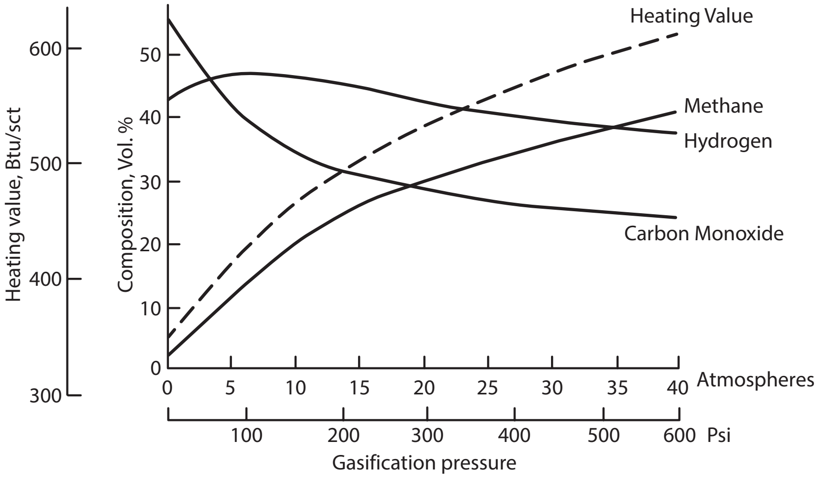

Figure 9.2 Variation of gas composition and heating value with pressure (Baughman, 1978).

In regard to the maceral content, differences have been noted between the different maceral groups with inertinite being the most reactive. In more general terms of the character of the coal, gasification technologies generally require some initial processing of the coal feedstock with the type and degree of pretreatment a function of the process and/or the type of coal. For example, the Lurgi process will accept *lump* coal [1 inch (25 mm) to 28 mesh], but it must be noncaking coal (Chapters 2, 6) with the fines removed. The caking, agglomerating coals tend to form a plastic mass in the bottom of a gasifier and subsequently plug up the system thereby markedly reducing process efficiency. Thus, some attempt to reduce caking tendencies is necessary and can involve preliminary partial oxidation of the coal thereby destroying the caking properties.

Depending on the type of coal being processed and the analysis of the gas product desired, pressure also plays a role in product definition (Figure 9.2). In fact, some (or all) of the following processing steps will be required: (i) pretreatment of the coal, if caking is a problem, (ii) primary gasification of the coal, (iii) secondary gasification of the carbonaceous residue from the primary gasifier, (iv) removal of carbon dioxide, hydrogen sulfide, and other acid gases, (v) shift conversion for adjustment of the carbon monoxide/hydrogen mole ratio to the desired ratio, and (vi) catalytic methanation of the carbon monoxide/hydrogen mixture to form methane. If high heat-content (high-Btu) gas is desired, all of these processing steps are required since coal gasifiers do not yield methane in the concentrations required (Mills, 1969; Graff *et al.*, 1976; Cusumano *et al.*, 1978).

9.3.2 Mechanism

The chemistry of gasification is quite complex and, only for discussion purposes, can the chemistry be viewed as consisting of a few major reactions which can progress to different extents depending on the gasification conditions (such as temperature and pressure) and the feedstock used (Figure 9.3). Combustion reactions take place in a gasification process, but, in comparison with conventional combustion which uses a stoichiometric excess of oxidant, gasification typically uses one-fifth to one-third of the theoretical oxidant.

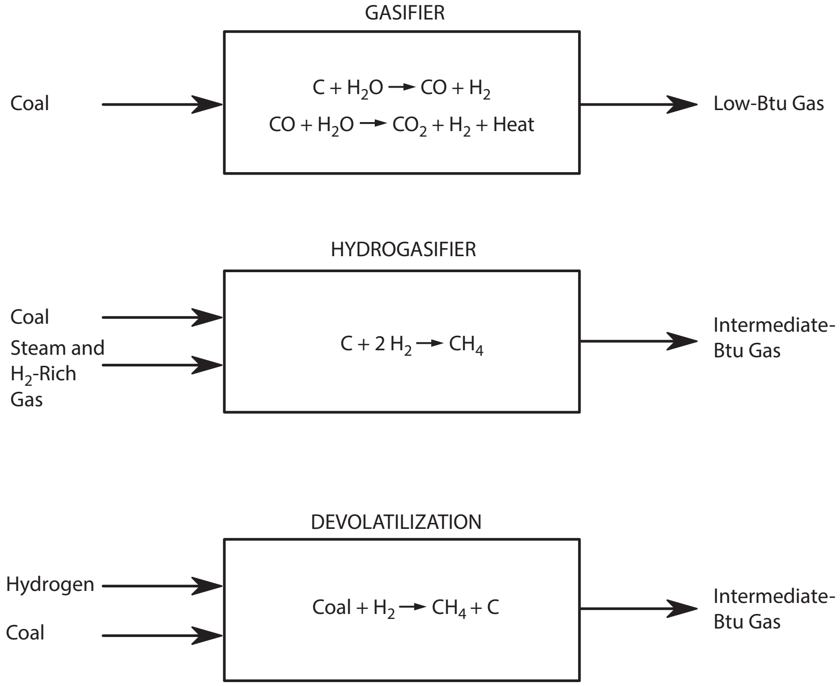

Figure 9.3 General chemistry of the various gasification systems.

This only partially oxidizes the carbon feedstock. As a *partial oxidation* process, the major combustible products of gasification are carbon monoxide (CO) and hydrogen, with only a minor portion of the carbon completely oxidized to carbon dioxide (CO_2). The heat produced by the partial oxidation provides most of the energy required to drive the endothermic gasification reactions.

Coal gasification involves the thermal decomposition of coal and the reaction of the coal carbon and other pyrolysis products with oxygen, water, and fuel gases such as methane (Table 9.1). Generally, the reaction rate (i.e., the rate of feedstock conversion) is higher at higher temperatures, whereas reaction equilibrium may be favored at either higher or lower temperatures depending on the specific type of gasification reaction. The effect of pressure on the rate also depends on the specific reaction. Thermodynamically, some gasification reactions such as the carbon-hydrogen reaction to produce methane are favored at high pressures (>1030 psi) and relatively lower temperatures (760 to 930°C; 1400 to 1705°F), whereas low pressures and high temperatures favor the production of synthesis gas (i.e., carbon monoxide and hydrogen) via the steam or carbon dioxide gasification reaction.

The reaction of carbonaceous feedstocks with carbon dioxide produces carbon monoxide (*Boudouard reaction*) and (like the steam gasification reaction) is also an endothermic reaction:

$$C(s) + CO_2(g) \rightarrow 2CO(g)$$

The reverse reaction results in carbon deposition (carbon fouling) on many surfaces including the catalysts and results in catalyst deactivation.

Table 9.1 Coal gasification reactions.

$2 C + O_2 \rightarrow 2 CO$
$C + O_2 \rightarrow CO_2$
$C + CO_2 \rightarrow 2 CO$
$CO + H_2O \rightarrow CO_2 + H_2$ (shift reaction)
$C + H_2O \rightarrow CO + H_2$ (water gas reaction)
$C + 2 H_2 \rightarrow CH_4$
$2 H_2 + O_2 \rightarrow 2 H_2O$
$CO + 2 H_2 \rightarrow CH_3OH$
$CO + 3 H_2 \rightarrow CH_4 + H_2O$ (methanation reaction)
$CO_2 + 4 H_2 \rightarrow CH_4 + 2 H_2O$
$C + 2 H_2O \rightarrow 2 H_2 + CO_2$
$2 C + H_2 \rightarrow C_2H_2$
$CH_4 + 2 H_2O \rightarrow CO_2 + 4 H_2$

This gasification reaction is thermodynamically favored at high temperatures (>680°C, >1255°F), which is also quite similar to the steam gasification. If carried out alone, the reaction requires high temperature (for fast reaction) and high pressure (for higher reactant concentrations) for significant conversion but as a separate reaction a variety of factors come into play: (i) low conversion, (ii) slow kinetic rate, and (iii) low thermal efficiency.

Also, the rate of the carbon dioxide gasification of a feedstock is different from the rate of the carbon dioxide gasification of carbon. Generally, the carbon-carbon dioxide reaction follows a reaction order based on the partial pressure of the carbon dioxide that is approximately 1.0 (or lower) whereas the feedstock-carbon dioxide reaction follows a reaction order based on the partial pressure of the carbon dioxide that is 1.0 (or higher). The observed higher reaction order for the feedstock reaction is also based on the relative reactivity of the feedstock in the gasification system.

The presence of oxygen, hydrogen, water vapor, carbon oxides, and other compounds in the reaction atmosphere during pyrolysis may either support or inhibit numerous reactions with coal and with the products evolved. The distribution of weight and chemical composition of the products are also influenced by the prevailing conditions (i.e., temperature, heating rate, pressure, residence time, etc.) and, last but not least, the nature of the feedstock (Wang and Mark, 1992).

If air is used for combustion, the product gas will have a heat content of ca. 150 to 300 Btu/ft^3 (depending on process design characteristics) and will contain undesirable constituents such as carbon dioxide, hydrogen sulfide, and nitrogen. The use of pure oxygen, although expensive, results in a product gas having a heat content of 300 to 400 Btu/ft^3 with carbon dioxide and hydrogen sulfide as by-products (both of which can be removed from low or medium heat-content low- or medium-Btu gas by any of several available processes).

If a high heat-content (high-Btu) gas (900 to 1000 Btu/ft^3) is required, efforts must be made to increase the methane content of the gas. The reactions which generate methane are all exothermic and have negative values but the reaction rates are relatively slow and catalysts may, therefore, be necessary to accelerate the reactions to acceptable commercial rates. Indeed, the overall reactivity of coal and char may be subject to catalytic effects. It is also possible that the mineral constituents of coal and char may modify the reactivity by a direct catalytic effect (Cusumano *et al.*, 1978; Wen, 1980; Davidson, 1983; Baker and Rodriguez, 1990; Mims, 1991; Martinez-Alonso and Tascon, 1991).

Gasification of coal/char in a carbon dioxide atmosphere can be divided into two stages, the first stage due to pyrolysis (removal of moisture content and devolatilization) which is comparatively at lower temperature and char gasification by different O2/CO2 mixtures at high temperature. In N2 and CO2 environments from room temperature to 1000°C, the mass loss rate of coal pyrolysis in N2 is lower than that of CO2 and may be due to the difference in properties of the bulk gases. The gasification process of pulverized coal in O2/CO2 environment is almost the same as compared with that in O2/N2 at the same oxygen concentration but this effect is little bit delayed at high temperature. This may be due to the lower rate of diffusion of oxygen through CO2 and the higher specific heat capacity of CO2. However, with the increase of O2 concentration the mass loss rate of coal also increases and hence it shortens the burn-out time of coal. The optimum value oxygen/carbon dioxide ratio for the reaction of oxygen with the functional group present in the coal sample was found to be approximately 8%. The combination of pyrolysis and gasification process can be a unique and fruitful technique as it can save the prior use of gasifying medium and the production of fresh char simultaneously in one process. With the increase of heating rate, coal particles are faster heated in a short period of time and burnt in a higher temperature region, but the increase in heating rate has almost no substantial effect on the combustion mechanism of coal. Also the increase of heating rate causes a decrease in activation energy value. Activation energy values were calculated by different well-known methods at different fractions from 90% to 15% of the original coal within the temperature range of approximately 400 to 600°C and it was found that Coats-Redfern approach showed the highest value of E and Freeman-Carroll method showed the least value of E at every fraction of converted coal (Irfan, 2009).

Relative to the chemical and thermodynamic understanding of the gasification process and data derived from thermodynamic studies (van der Burgt, 2008; Shabbar and Janajreh, 2013), the kinetic behavior of carbonaceous or hydrocarbonaceous feedstocks is more complex. Furthermore, while the basic thermodynamic cycles pertinent to the gasification process have long been established, novel combination and the use of alternative fluids to water/steam offer the prospect of higher process efficiency through use of thermodynamic studies.

Finally, a word of caution is advised when considering any kinetic information. The kinetics of the process are dependent on the process conditions *and* the nature of the feedstock, which can vary significantly with respect to composition, mineral impurities, and reactivity as well as the potential for certain impurities to exhibit catalytic activity on some of the gasification reactions.

9.3.3 Primary Gasification

Primary gasification involves thermal decomposition of the raw coal via various chemical processes (Table 9.1) and many schemes involve pressures ranging from atmospheric to 1000 psi. Air or oxygen may be admitted to support combustion to provide the necessary heat. The product is usually a low heat content (low-Btu) gas ranging from a carbon monoxide/hydrogen mixture to mixtures containing varying amounts of carbon monoxide, carbon dioxide, hydrogen, water, methane, hydrogen sulfide, nitrogen, and typical products of thermal decomposition such as tar (themselves being complex mixtures (see Dutcher *et al.*, 1983), hydrocarbon oils, and phenols.

A solid char product may also be produced, and may represent the bulk of the weight of the original coal. This type of coal being processed determines (to a large extent) the amount of char produced and the analysis of the gas product.

9.3.4 Secondary Gasification

Secondary gasification usually involves the gasification of char from the primary gasifier. This is usually done by reacting the hot char with water vapor to produce carbon monoxide and hydrogen:

$$C_{char} + H_2O \rightarrow CO + H_2$$

9.3.5 Shift Conversion

The gaseous product from a gasifier generally contains large amounts of carbon monoxide and hydrogen, plus lesser amounts of other gases. Carbon monoxide and hydrogen (if they are present in the mole ratio of 1:3) can be reacted in the presence of a catalyst to produce methane (Cusumano *et al.*, 1978).

However, some adjustment to the ideal (1:3) is usually required and, to accomplish this, all or part of the stream is treated according to the water gas shift (shift conversion) reaction. This involves reacting carbon monoxide with steam to produce a carbon dioxide and hydrogen whereby the desired 1:3 mole ratio of carbon monoxide to hydrogen may be obtained.

$$CO + H_2O \rightarrow CO_2 + H_2$$

9.3.6 Hydrogasification

Not all high heat-content (high-Btu) gasification technologies depend entirely on catalytic methanation and, in fact, a number of gasification processes use hydrogasification, that is, the direct addition of hydrogen to coal under pressure to form methane (Anthony and Howard, 1976).

$$C_{char} + 2H_2 \rightarrow CH_4$$

The hydrogen-rich gas for hydrogasification can be manufactured from steam by using the char that leaves the hydrogasifier. Appreciable quantities of methane are formed directly in the primary gasifier and the heat released by methane formation is at a sufficiently high temperature to be used in the steam-carbon reaction to produce hydrogen so that less oxygen is used to produce heat for the steam-carbon reaction. Hence, less heat is lost in the low-temperature methanation step, thereby leading to higher overall process efficiency.

The hydrogasification reaction is exothermic and is thermodynamically favored at low temperatures (<670°C, <1240°F), unlike the endothermic both steam gasification and carbon dioxide gasification reactions. However, at low temperatures, the reaction rate is inevitably too slow. Therefore, a high temperature is always required for kinetic reasons, which in turn requires high pressure of hydrogen, which is also preferred from equilibrium considerations. This reaction can be catalyzed by salts such as potassium carbonate (K_2CO_3), nickel chloride ($NiCl_2$), iron chloride ($FeCl_2$), and iron sulfate ($FeSO_4$). However, use of a catalyst in feedstock gasification suffers from difficulty in recovering and reusing the catalyst and the potential for the spent catalyst becoming an environmental issue.

In a hydrogen atmosphere at elevated pressure, additional yields of methane or other low molecular weight hydrocarbons can result during the initial feedstock gasification stage from direct hydrogenation of feedstock or semi-char because of active intermediate formed in the feedstock structure after pyrolysis. The direct hydrogenation can also increase the amount of feedstock carbon that is gasified as well as the hydrogenation of gaseous hydrocarbons, oil, and tar.

The kinetics of the rapid-rate reaction between gaseous hydrogen and the active intermediate depends on hydrogen partial pressure (P_{H2}). Greatly increased gaseous hydrocarbons produced during the initial feedstock gasification stage are extremely important in processes to convert feedstock into methane (SNG, synthetic natural gas).

9.3.7 Methanation

Several exothermic reactions may occur simultaneously within a methanation unit. A variety of metals have been used as catalysts for the methanation reaction; the most common, and to some extent the most effective methanation catalysts, appear to be nickel and ruthenium, with nickel being the most widely used (Cusumano *et al.*, 1978):

Ruthenium (Ru) > nickel (Ni) > cobalt (Co) > iron (Fe) > molybdenum (Mo).

Nearly all the commercially available catalysts used for this process are, however, very susceptible to sulfur poisoning and efforts must be taken to remove all hydrogen sulfide (H_2S) before the catalytic reaction starts. It is necessary to reduce the sulfur concentration in the feed gas to less than 0.5 ppm v/v in order to maintain adequate catalyst activity for a long period of time.

The synthesis gas must be desulfurized before the methanation step since sulfur compounds will rapidly deactivate (poison) the catalysts. A problem may arise when the concentration of carbon monoxide is excessive in the stream to be methanated since large amounts of heat must be removed from the system to prevent high temperatures and deactivation of the catalyst by sintering as well as the deposition of carbon. To eliminate this problem temperatures should be maintained below 400°C (750°F).

The methanation reaction is used to increase the methane content of the product gas, as needed for the production of high-Btu gas.

$$4H_2 + CO_2 \rightarrow CH_4 + 2H_2O$$

$$2CO \rightarrow C + CO_2$$

$$CO + H_2O \rightarrow CO_2 + H_2$$

Among these, the most dominant chemical reaction leading to methane is the first one. Therefore, if methanation is carried out over a catalyst with a synthesis gas mixture of hydrogen and carbon monoxide, the desired hydrogen-carbon monoxide ratio of the feed synthesis gas is around 3:1. The large amount of water (vapor) produced is removed by condensation and recirculated as process water or steam. During this process, most of the exothermic heat due to the methanation reaction is also recovered through a variety of energy integration processes.

Whereas all the reactions listed above are quite strongly exothermic except the forward water gas shift reaction, which is mildly exothermic, the heat release depends largely on the amount of carbon monoxide present in the feed synthesis gas. For each 1% v/v carbon monoxide in the feed synthesis gas, an adiabatic reaction will experience a 60°C (108°F) temperature rise, which may be termed as *adiabatic temperature rise*.

9.4 Catalytic Gasification

Catalysts are commonly used in the chemical and crude oil industries to increase reaction rates, sometimes making certain previously unachievable products possible (Speight, 2002; Hsu and Robinson, 2006; Speight, 2014). Acids, through donated protons (H^+), are common reaction catalysts, especially in the organic chemical industries. Catalysts can also be used to enhance the reactions involved in gasification. Many gasifiers must operate at high temperatures so that the gasification reactions will proceed at reasonable rates. Unfortunately, high temperatures can sometimes necessitate special gasifier materials and cause efficiency losses if heat cannot be reclaimed.

Thus, it is not surprising that catalysts can be used to enhance the reactions involved in coal gasification and use of appropriate catalysts not only reduces reaction temperature but also improves the gasification rates. In addition, catalysts also reduce tar formation (Shinnar *et al.*, 1982; McKee, 1981).

Alkali metal salts of weak acids (like potassium carbonate [K_2CO_3], sodium carbonate [Na_2CO_3], potassium sulfide [K_2S], and sodium sulfide [Na_2S]) can catalyze steam gasification of coal. In the early 1970s, research confirmed that 10-20% by weight K_2CO_3 could lower acceptable bituminous coal gasifier temperatures from 925°C to 700°C and that the catalyst could be introduced to the gasifier impregnated on coal or char. The field of catalysis (study of catalysts and their use) is large and this is just one example. Catalysts that have been used for years in petroleum refining have found use in gasification as well, again to lower operating temperatures.

Ruthenium-containing catalysts are used primarily in the production of ammonia. It has been shown that ruthenium catalysts provide five to 10 times higher reactivity rates than other catalysts. However, ruthenium quickly becomes inactive due to its necessary supporting material, such as activated carbon, which is used to achieve effective reactivity. However, during the process, the carbon is consumed, thereby reducing the effect of the ruthenium catalyst.

Catalysts can also be used to favor or suppress the formation of certain components in the syngas product. The primary constituents of syngas are hydrogen (H_2) and CO, but other products like methane are formed in small amounts. Catalytic gasification can be used to either promote methane formation (a form of which is steam hydrogasification), or suppress it.

The disadvantages of catalytic gasification include increased materials costs for the catalyst itself (often rare metals), as well as diminishing catalyst performance over time. Catalysts can be recycled, but their performance tends to diminish with age. The relative difficulty in reclaiming and recycling the catalyst can also be a disadvantage. For example, the K_2CO_3 catalyst described above can be recovered from spent char with a simple water wash, but some catalysts may not be so accommodating. In addition to age, catalysts can also be diminished by poisoning. Many catalysts are sensitive to particular chemical species which bond with the catalyst or alter it in such a way that it no longer functions. Sulfur, for example, can poison several types of catalysts including palladium and platinum.

9.5 Plasma Gasification

Plasma is a high-temperature, highly ionized (electrically charged) gas capable of conducting electrical current. Plasma technology has a long history of development and has evolved into a valuable tool for engineers and scientists who need to use high temperatures for new process applications (Kalinenko *et al.*, 1993; Messerle and Ustimenko, 2007). Man-made plasma is formed by passing an electrical discharge through a gas such as air or oxygen (O_2). The interaction of the gas with the electric arc dissociates the gas into electrons and ions, and causes its temperature to increase significantly, often (in theory) exceeding 6000°C (10,830°F).

A piece of equipment known as the *plasma torch* is used to generate plasma. The plasma torch can be fed with process gases of various chemical composition including air, oxygen, nitrogen (N_2), and argon, thereby allowing the process to be tailored to specific applications.

Serious efforts have been made, with some success, to apply plasma gasification technology to gasify coal and to treat industrial and municipal solid wastes (MSW) over the last two decades. It is believed that the technology can be used to gasify coal in an ambient pressure, plasma-fired reactor that can be retrofitted into existing power plants and/or installed as a new facility, with the following potential benefits over a pulverized coal power and/or conventional gasification plant: (i) greater feedstock flexibility enabling coal, coal fines, mining waste, lignite, and other opportunity fuels (such as biomass and municipal solid waste) to be used as fuel without the need for pulverizing, (ii) air blown and thus an oxygen plant is not required, (iii) high conversion (>99%) of carbonaceous matter to synthesis gas, (iv) absence of tar in the synthesis, (v) capable of producing high heating value synthesis gas suitable use in a combustion turbine operation, (vi) no char, ash or residual carbon, (vii) only producing a glassy slag with beneficial value, (viii) high thermal efficiency, and (ix) low carbon dioxide emissions.

In the process, the gasifier is heated by a plasma torch system located near the bottom of the reactor vessel. In the gasifier, the coal feedstock is charged into a vertical reactor vessel (refractory lined or water-cooled) at atmospheric pressure. A superheated blast of air, which may be enriched with oxygen, is provided to the bottom of the gasifier, at the stoichiometric amount required for gasification. The amount of air fed is such that the superficial velocity of the upward flowing gas is low, and that the pulverized feedstock can be fed directly into the reactor. Additional air and/or steam can be provided at different levels of the gasifier to assist with pyrolysis and gasification. The temperature of the syngas leaving the top of the gasifier is maintained above 1000°C (1830°F). At this temperature, tar formation is eliminated.

Gasification takes place at high temperatures, driven by the plasma torch system, which is located at the bottom of the gasifier vessel. The high operating temperatures break down the coal and/or all hazardous and toxic components into their elemental constituents, and dramatically increase the kinetics of the various reactions occurring in the gasification zone, converting all organic materials into hydrogen (H_2) and carbon monoxide (CO). Any residual materials of inorganics and heavy metals will be melted and produced as a vitrified slag which is highly resistant to leaching.

9.6 Gaseous Products

The products of coal gasification are varied insofar as the gas composition varies with the system employed. Furthermore, the gaseous product(s) must be first freed from any pollutants such as particulate matter and sulfur compounds before further use, particularly when the intended use is a water gas shift or methanation (Cusumano *et al.*, 1978; Probstein and Hicks, 1990; Speight, 2013, 2020).

If air is used for combustion, the product gas will have a heat content on the order of 150 to 300 Btu/ft^3 depending on process design characteristics and will contain undesirable constituents such as carbon dioxide, hydrogen sulfide, and nitrogen. The use of pure oxygen results in a product gas having a heat content of 300 to 400 Btu/ft^3 with carbon dioxide and hydrogen sulfide as by-products, both of which can be removed from low-heat content or medium heat-content – low-Btu or medium-Btu gas – by any of several available processes (Mokhatab *et al.*, 2006; Speight, 2013, 2014, 2020).

If high heat-content (high-Btu) gas (900 to 1000 Btu/ft^3) is required, efforts must be made to increase the methane content of the gas. The reactions which generate methane are all exothermic and have negative values, but the reaction rates are relatively slow and catalysts may therefore, be necessary to accelerate the reactions to acceptable commercial rates. Indeed, it is also possible that the mineral constituents of the feedstock and char may modify the reactivity by a direct catalytic mechanism. The presence of oxygen, hydrogen, water vapor, carbon oxides, and other compounds in the reaction atmosphere during pyrolysis may either support or inhibit numerous reactions with the feedstock and with the products evolved.

If high-Btu gas (high heat content gas; 900 to 1000 Btu/ft^3) is the desired product, efforts must be made to increase the methane content of the gas. The reactions which generate methane are all exothermic and have negative values (Lee, 2007), but the reaction rates are relatively slow and catalysts may, therefore, be necessary to accelerate the reactions to acceptable commercial rates.

9.6.1 Low-Btu Gas

Low-Btu gas (low heat-content gas) is also the usual product of *in situ* gasification of coal which is used essentially as a technique for obtaining energy from coal without the necessity of mining the coal. The process is, in essence, a technique for utilization of coal which cannot be mined by other techniques. This gas is the product when the oxygen is not separated from the air and, as a result, the gas product invariably has a low heat-content (ca. 150-300 Btu/ft^3).

Several important chemical reactions (Table 9.1), and a host of side reactions, are involved in the manufacture of low heat-content gas under the high temperature conditions employed. Low-Btu gas (low heat-content gas) contains several components (Table 9.2), four of which are always major components present at levels of at least several percent; a fifth component, methane, is marginally a major component.

The nitrogen content of low heat-content gas ranges from somewhat less than 33% v/v to slightly more than 50% v/v and cannot be removed by any reasonable means; the presence of nitrogen at these levels makes the product gas a low heat-content gas by definition. The nitrogen also strongly limits the applicability of the gas to chemical synthesis. Two other noncombustible components (water, H_2O, and carbon dioxide, CO) further lower the heating value of the gas; water can be removed by condensation and carbon dioxide by relatively straightforward chemical means.

The two major combustible components are hydrogen and carbon monoxide; the hydrogen/carbon monoxide ratio varies from approximately 2:3 to approximately 3:2. Methane may also make an appreciable contribution to the heat content of the gas. Of the minor components, hydrogen sulfide is the most significant and the amount produced is, in fact, proportional to the sulfur content of the feed coal. Any hydrogen sulfide present must be removed by one, or more, of several procedures (Chapters 12, 13, 14) (Speight, 2014, 2019).

9.6.2 Medium-Btu Gas

Medium-Btu gas (medium heat-content gas) has a heating value in the range 300 to 550 Btu/ft^3) and the composition is much like that of low heat-content gas, except that there is virtually no nitrogen. The primary combustible gases in medium heat-content gas are hydrogen and carbon monoxide (Kasem, 1979).

Table 9.2 Coal gasification products.

Product	Characteristics
Low-Btu gas (150–300 Btu/scf)	Around 50% nitrogen, with smaller quantities of combustible H_2 and CO, CO_2 and trace gases, such as methane
Medium-Btu gas (300–550 Btu/scf)	Predominantly CO and H_2, with some incombustible gases and sometimes methane
High-Btu gas (980–1080 Btu/scf)	Almost pure methane

Medium heat-content gas is considerably more versatile than low heat-content gas; like low heat-content gas, medium heat-content gas may be used directly as a fuel to raise steam, or used through a combined power cycle to drive a gas turbine, with the hot exhaust gases employed to raise steam, but medium heat-content gas is especially amenable to synthesize methane (by methanation), higher hydrocarbon derivatives (by Fischer-Tropsch synthesis), methanol, and a variety of synthetic chemicals (David and Occelli, 2010; Chadeesingh, 2011). The reactions used to produce medium heat-content gas are the same as those employed for low heat-content gas synthesis, the major difference being the application of a nitrogen barrier (such as the use of pure oxygen) to keep diluent nitrogen out of the system.

In medium heat-content gas, the H_2/CO ratio varies from 2:3 to ca. 3:1 and the increased heating value correlates with higher methane and hydrogen contents as well as with lower carbon dioxide contents. Furthermore, the very nature of the gasification process used to produce the medium heat-content gas has a marked effect upon the ease of subsequent processing. For example, the CO_2-acceptor product is quite amenable to use for methane production because it has (i) the desired H_2/CO ratio just exceeding 3:1, (ii) an initially high methane content, and (iii) relatively low water and carbon dioxide contents. Other gases may require appreciable shift reaction and removal of large quantities of water and carbon dioxide prior to methanation.

9.6.3 High-Btu Gas

High-Btu Gas (High heat-content gas) is essentially pure methane and often referred to as synthetic natural gas or substitute natural gas (SNG) (Kasem, 1979; Speight, 1990, 2013, 2020). However, to qualify as substitute natural gas, a product must contain at least 95% methane; the energy content of synthetic natural gas is 980 to 1080 Btu/ft^3. The commonly accepted approach to the synthesis of high heat content gas is the catalytic reaction of hydrogen and carbon monoxide.

$$3H_2 + CO \rightarrow CH_4 + H_2O$$

To avoid catalyst poisoning, the feed gases for this reaction must be quite pure and, therefore, impurities in the product are rare. The large quantities of water produced are removed by condensation and recirculated as very pure water through the gasification system. The hydrogen is usually present in slight excess to ensure that the toxic carbon monoxide is reacted; this small quantity of hydrogen will lower the heat content to a small degree.

The carbon monoxide/hydrogen reaction is somewhat inefficient as a means of producing methane because the reaction liberates large quantities of heat. In addition, the methanation catalyst is troublesome and prone to poisoning by sulfur compounds and the decomposition of metals can destroy the catalyst. Thus, hydrogasification may be employed to minimize the need for methanation.

$$C_{coal} + 2H_2 \rightarrow CH_4$$

The product of hydrogasification is far from pure methane and additional methanation is required after hydrogen sulfide and other impurities are removed.

9.6.4 Methane

Several exothermic reactions may occur simultaneously within a methanation unit (Seglin, 1975). A variety of metals have been used as catalysts for the methanation reaction; the most common, and to some extent the most effective methanation catalysts, appear to be nickel and ruthenium, with nickel being the most widely used (Seglin, 1975; Cusumano *et al.*, 1978; Tucci and Thompson, 1979; Watson, G.H. 1980). The synthesis gas must be desulfurized before the methanation step since sulfur compounds will rapidly deactivate (poison) the catalysts (Cusumano *et al.*, 1978). A problem may arise when the concentration of carbon monoxide is excessive in the stream to be methanated since large amounts of heat must be removed from the system to prevent high temperatures and deactivation of the catalyst by sintering as well as the deposition of carbon (Cusumano *et al.*, 1978). To eliminate this problem temperatures should be maintained below 400°C (750°F).

9.6.5 Hydrogen

Hydrogen is produced from coal by coal gasification. Although several gasifier types exist, entrained flow gasifiers are considered most appropriate for producing both hydrogen and electricity from coal since they operate at temperatures high enough (approximately 1500°C, 2730°F) to enable high carbon conversion and prevent downstream fouling from tars and other residuals. Of the three major commercial entrained flow gasifiers (Shell, GE, and E-Gas), the GE (formerly ChevronTexaco) gasifier is preferred for hydrogen production since the simple vessel design and slurry-feed allow for high operating pressures in the process.

In the process, the coal undergoes three processes in its conversion to syngas – the first two processes, pyrolysis, and combustion, occur very rapidly. In pyrolysis, char is produced as the coal heats up and volatiles are released. In the combustion process, the volatile products and some of the char reacts with oxygen to produce various products (primarily carbon dioxide and carbon monoxide) and the heat required for subsequent gasification reactions. Finally, in the gasification process, the coal char reacts with steam to produce hydrogen (H_2) and carbon monoxide (CO).

Combustion:

$$2C_{coal} + O_2 \rightarrow 2CO + H_2O$$

Gasification:

$$C_{coal} + H_2O \rightarrow H_2 + CO$$

$$CO + H_2O \rightarrow H_2 + CO_2$$

The resulting synthesis gas (syngas) is approximately 63% CO, 34% H_2, and 3% CO_2. At the gasifier temperature, the ash and other coal mineral matter liquefies and exits at the bottom of the gasifier as slag, a sand-like inert material that can be sold as a co-product to other industries (e.g., road building). The synthesis gas exits the gasifier at pressure and high temperature and must be cooled prior to the syngas cleaning stage.

Although processes that use the high temperature to raise high-pressure steam are more efficient for electricity production (Chapters 8, 10), full-quench cooling, by which the synthesis gas is cooled by the direct injection of water, is more appropriate for hydrogen production. Full-quench cooling provides the necessary steam to facilitate the water gas shift reaction, in which carbon monoxide is converted to hydrogen and carbon dioxide in the presence of a catalyst:

Water Gas Shift Reaction:

$$CO + H_2O \rightarrow CO_2 + H_2$$

This reaction maximizes the hydrogen content of the synthesis gas, which consists primarily of hydrogen and carbon dioxide at this stage. The synthesis gas is then scrubbed of particulate matter and sulfur is removed via physical absorption (Chapters 12, 13, 14). The carbon dioxide is captured by physical absorption or a membrane and either vented or sequestered.

Unlike pulverized coal combustion plants in which expensive emissions control technologies are required to scrub contaminants from large volumes of flue gas, smaller and less expensive emissions control technologies are appropriate for coal gasification plants since the clean-up occurs in the syngas. The synthesis gas is at high pressure and contains contaminants at high partial pressures, which facilitates clean-up. For this reason, emissions control is both more effective and less expensive in gasification facilities. Since the synthesis gas is at high pressure and has a high concentration of carbon dioxide, a physical solvent, can be used to capture carbon dioxide (Chapters 12, 13, 14), which is desorbed from the solvent by pressure reduction and the solvent is recycled into the system.

At this point, the hydrogen-rich synthesis gas is sufficiently pure for some stationary fuel cell applications and use in hydrogen internal combustion engines. However, for use in vehicles featuring proton exchange membrane fuel cells, the hydrogen must be purified to 99.999% using a pressure swing adsorption (PSA) unit. The high-purity hydrogen exits the pressure swing adsorption unit sufficiently compressed for pipeline transport to refueling stations. The purge gas from the pressure swing adsorption unit is compressed and directed to a combined cycle (gas and steam turbine) for co-production of electricity.

As with other processes, the characteristics of the coal feedstock (e.g., heating value and ash, moisture, and sulfur content) have a substantial impact on plant efficiency and emissions. As a result, the cost of producing hydrogen from coal gasification can vary substantially depending on the proximity to appropriate coal types.

One of the reasons that Powder River Basin (Wyoming) coals are widely used for pulverized coal combustion power plants (despite the relatively low heating value) is the low sulfur content. With the increased restrictions on sulfur dioxide emission regulations, coal combustion power plants looking to avoid expensive and efficiency-reducing flue gas desulfurization retrofits have switched to low-sulfur Powder River Basin coal. There is also the possibility that western coals can be combined with crude oil coke in order to increase the heating value and decrease the moisture content of the gasification feedstock.

Several technologies are being pursued to increase hydrogen conversion efficiency, improve plant reliability, and lower hydrogen costs. These technologies include high temperature syngas cleaning and carbon dioxide capture, improved hydrogen-rich syngas turbines and air separation units, co-capture of carbon dioxide and hydrogen sulfide (H_2S), solid oxide fuel cell topping cycles for co-production of electricity, and flexible gasification systems that can operate on a variety of available feedstocks (i.e., various coals, biomass, and waste).

Gasification is one of the critical technologies that enable hydrogen production from solid hydrocarbon derivatives such as coal and biomass (Speight, 2013, 2020). Gasifiers produce a syngas that has multiple applications and can be used for hydrogen production, electricity generation and chemical plants. Integrated gasification combined cycle (IGCC) plants utilize the syngas in a combined cycle power plant (gas turbine and steam turbine) to produce electricity (Chapters 8, 10).

With the increasing costs of crude oil, the gasification-based coal refinery is another concept for the production of fuels, electricity, and chemical products (Speight, 2011b). Coal gasification has also been used for production of liquid fuels (Fischer-Tropsch diesel and methanol) via a catalytic conversion of synthesis gas into liquid hydrocarbon derivatives (Chadeesingh, 2011; Speight, 2020).

9.6.6 Other Products

The major products produced by gasification of coal have been described above. However, there is a series of products that are called by older (even archaic) names that should also be mentioned here as clarification.

Producer gas is a low-Btu gas obtained from a coal gasifier (fixed-bed) upon introduction of air instead of oxygen into the fuel bed. The composition of the producer gas is approximately 28% v/v carbon monoxide, 55% v/v nitrogen, 12% v/v hydrogen, and 5% v/v methane with some carbon dioxide.

Water gas is a medium-Btu gas which is produced by the introduction of steam into the hot fuel bed of the gasifier. The composition of the gas is approximately 50% v/v hydrogen and 40% v/v carbon monoxide with small amounts of nitrogen and carbon dioxide.

Town gas is a medium-Btu gas that is produced in the coke ovens and has the approximate composition: 55% v/v hydrogen, 27% v/v methane, 6% v/v carbon monoxide, 10% v/v nitrogen, and 2% v/v carbon dioxide. Carbon monoxide can be removed from the gas by catalytic treatment with steam to produce carbon dioxide and hydrogen.

Synthetic natural gas (SNG) is methane obtained from the reaction of carbon monoxide or carbon with hydrogen. Depending on the methane concentration, the heating value can be in the range of high-Btu gases.

9.7 Underground Gasification

Underground coal gasification (UCG) is a technology which can exploit the energy in coal while avoiding the environmental problems at the surface associated with coal mining, disposal of mining waste and coal combustion. In the process, water/steam and air or oxygen are injected into a coal seam. The injected gases react with coal to form a combustible gas which is brought to the surface and cleaned prior to any utilization.

Underground coal gasification converts coal *in situ* into a gaseous product(s) through the same chemical reactions that occur in surface gasifiers. Gasification converts hydrocarbon derivatives into gas (such as synthesis gas or syngas) at elevated pressures and temperatures and can be used to create many products (such as chemical feedstock, liquid fuels, hydrogen, synthetic gas) and, in the current context, electric power. Gasification also provides numerous opportunities for pollution control, especially with respect to emissions of sulfur oxides, nitrogen oxides, and mercury.

In addition, with the increasing demand for coal-fired electric power, underground coal gasification could increase the coal resource available for utilization by gasifying otherwise non-mineable deep or thin coal seams under many different geological settings – a substantial (300 to 400%) increase in recoverable coal reserves in the United States is possible through use of underground coal gasification and the technology also may be of particular interest for developing countries undergoing rapid economic expansion, such as India and China (Burton *et al.*, 2007; Brown, 2012). In terms of the combustion process itself, both forward and reverse combustion are employed. Forward combustion is defined as movement of the combustion front in the same direction as the injected air whereas reverse combustion involves movement of the combustion front in the opposite direction to the injected air (Bodle and Huebler, 1981).

The concept of the gasification of coal in the ground is not new. In 1868, Siemens in Germany proposed that slack and waste be gasified in the mine without any effort being made to bring this waste material to the surface. However, it was left to Mendeleev (in 1888) to actually propose that coal be gasified in the undisturbed (*in situ*) state.

A further innovative suggestion followed in 1909 in England when Betts proposed that coal be gasified underground by ignition of the coal at the base of one shaft (or borehole) and that a supply of air and steam be made available to the burning coal and the product gases be led to the surface through a different borehole. The utility of such a concept was acknowledged in 1912 when it was suggested that coal be combusted in place to produce a mixture of carbon monoxide and steam which could then be used to drive gas engines at the mine site for the production of electricity.

A considerable volume of investigative work has since been performed on the *in situ* gasification of coal in the former USSR, but it is only in recent years that the concept has been revived in Russia, Western Europe, and North America as a means of gas (or even liquids) production (Elder, 1963; Gregg and Edgar, 1978; Thompson, 1978; King and Magee, 1979; Olness, 1981; Zvyaghintsev, 1981).

The aim of the underground (or *in situ*) gasification of coal is to convert the coal into combustible gases by combustion of a coal seam in the presence of air, oxygen, or oxygen and steam. Thus, not only could mining and the ever-present dangers (Chapter 3) be partially or fully eliminated, but the usable coal reserves would be increased because seams that were considered to be inaccessible, unworkable, or uneconomical to mine could be put to use. In addition, strip mining and the accompanying environmental impacts, the problems of spoil banks, acid mine drainage, and the problems associated with use of high-ash coal would be minimized or even eliminated.

The principles of underground gasification are similar to those involved in the above-ground gasification of coal. The concept involves the drilling and subsequent linking of two boreholes (Chapter 10) so that gas will pass between the two (King and Magee, 1979; Speight, 2013). Combustion is then initiated at the bottom of one bore-hole (injection well) and is maintained by the continuous injection of air. In the initial reaction zone (combustion zone), carbon dioxide is generated by the reaction of oxygen (air) with the coal after which the carbon dioxide reacts with coal (partially devolatilized) further along the seam (reduction zone) to produce carbon monoxide:

$$C_{coal} + O_2 \rightarrow CO_2$$

$$C_{coal} + CO_2 \rightarrow 2CO$$

In addition, at the high temperatures that can frequently occur, moisture injected with oxygen or even moisture inherent in the seam may also react with the coal to produce carbon monoxide and hydrogen.

$$C_{coal} + H_2O \rightarrow CO + H_2$$

The coal itself may also decompose (pyrolysis zone) by the ever-increasing temperature to produce hydrocarbon derivatives and tars which contribute to the product gas mix. The gas so produced varies in character and composition but usually falls into the low-heat (low-Btu) category ranging from (125 to 175 Btu/ft^3) (King and Magee, 1979).

Both shaft systems and shaftless systems (and combinations of these systems) constitute the methods for underground gasification. Selection of the method to be used depends on such parameters as the permeability of the seam, the geology of the deposit, the seam thickness, depth, inclination, and on the amount of mining desired. The shaft system involves driving large diameter openings into the seam and may therefore require some underground labor, whereas the shaftless system employs boreholes for gaining access to the coal and therefore does not require mining.

In summary, the United States must increasingly consider coal reserves as a means to end dependence on crude oil imports to fuel the economy. The United States is estimated to have approximately 27% w/w of the world supply of approximately 1,000 billion tons of recoverable coal resources (Chapter 1). At present rates of consumption, coal reserves can provide a secure domestic energy supply for up to 300 years (Burton *et al.*, 2007; Brown, 2012). Most coal in the United States is consumed for electricity production and while crude oil imports may be vulnerable to geopolitical uncertainties (Speight, 2011b, 2011c, 2013, 2014), domestic coal extraction and usage are limited primarily by environmental concerns.

Underground coal gasification does have advantages over conventional underground or strip mining and surface gasification, including: (i) conventional coal mining is eliminated with underground coal gasification, reducing surface damage and eliminating mine safety issues (Chapter 3), (ii) coal that cannot be mined (in deep, low grade, thin seams) is exploitable, thereby greatly increasing domestic resource availability, (iii) most of the produced ash in the coal stays underground, thereby avoiding the need for excessive gas clean-up, and the environmental issues associated with fly ash, and (iv) pollutant production is reduced in volume (Burton *et al.*, 2007; Brown, 2012).

Finally, gasification can be used to turn lower-priced feedstocks, such as petcoke and coal, into valuable products such as electricity, substitute natural gas, fuels, chemicals, and fertilizers. For example, a chemical plant can gasify crude oil coke or high-sulfur coal. In fact, gasification offers wider fuel flexibility – a gasification plant can vary the mix of solid feedstocks, thereby it has more freedom to adjust to the price and availability of its feedstocks.

Furthermore, if coal-based power plants will be required to capture and store carbon dioxide or participate in a carbon cap and trade market, electricity generation using gasification projects could have a cost advantage over conventional technologies. While carbon dioxide capture and sequestration will increase the cost of all forms of power generation, an IGCC plant has the potential to capture carbon dioxide at a fraction of the cost of a traditional pulverized coal plant.

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10

Gasification Systems

10.1 Introduction

In any text related to coal (but more specifically in any text that contains a chapter related to coal gasification), it is appropriate to include a listing of the types of processes available as well as a description of the different processes. Thus, it is the intent here to give selected examples of specific processes.

In contrast to liquefaction processes, gasification processes have been evolving since the early days of the 19th century when town gas became a common way of bringing illumination and heat not only to factories but also to the domestic consumer. But it must not be assumed that all processes included here have been successful in the move to commercialization. Some still remain conceptual but are included here because of their novelty and/or their promise for future generations of gasifiers.

The chemical conversion of coal to gaseous products was first used to produce gas for lighting and heat in the United Kingdom more than 200 years ago. The gasification of coal or a derivative (i.e., char produced from coal) is, essentially, the conversion of coal (by any one of a variety of processes) to produce combustible gases (Fryer and Speight, 1976; Radović *et al.*, 1983; Radović and Walker, 1984; Garcia and Radović, 1986; Calemma and Radović, 1991; Kristiansen, 1996; Speight, 2020a). With the rapid increase in the use of coal from the 15th century onwards (Nef, 1957; Taylor and Singer, 1957), it is not surprising the concept of using coal to produce a flammable gas became commonplace (Elton, 1958; Luque and Speight, 2015).

Depending on the type of gasifier (e.g., air-blown, enriched oxygen-blown) and the operating conditions (Chapter 9), gasification can be used to produce a fuel gas that is suitable for several applications. Coal gasification for electric power generation enables the use of a technology common in modern gas-fired power plants, the use of *combined cycle* technology to recover more of the energy released by burning the fuel. As a very general *rule of thumb*, optimum gas yields and gas quality are obtained at operating temperatures of approximately 595 to 650°C (1100 to 1200°F). A gaseous product with a higher heat content (BTU/ft.^{3}) can be obtained at lower system temperatures but the overall yield of gas (determined as the *fuel-to-gas ratio*) is reduced by the unburned char fraction.

There has been a general tendency to classify gasification processes by virtue of the heat content of the gas which is produced; it is also possible to classify gasification processes according to the type of reactor vessel and whether or not the system reacts under pressure. However, for the purposes of the present text gasification processes are segregated according to the bed types, which differ in their ability to accept (and use) various types of coal (Collot, 2002; Collot, 2006).

Thus, gasification processes can be generally divided into four categories based on reactor (bed) configuration: (i) fixed bed, (ii) fluidized bed, (iii) entrained bed, and (iv) molten salt (Table 10.1, Figure 10.1). Within each category there are several commonly known

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Table 10.1 Categories of gasification processes*.

Fixed-Bed Processes	
	Foster-Wheeler Stoic Process
	Lurgi Process
	Wellman-Galusha Process
	Woodall-Duckham Process
Fluidized-Bed Processes	
	Agglomerating Burner Process
	Carbon Dioxide Acceptor Process
	Coalcon Process
	COED/COGAS Process
	Exxon Catalytic Gasification Process
	Hydrane Process
	Hygas Process
	Pressurized Fluid-Bed Process
	Synthane Process
	U-Gas Process
	Winkler Process
Entrained-Bed Processes	
	Bi-Gas Process
	Combustion Engineering Process
	Koppers-Totzek Process
	Texaco Process
Molten Salt Processes	
	Atgas Process
	Pullman-Kellogg Process
	Rockgas Process
	Rummel Single-Shaft Process

*Listed alphabetically and not by any preference.

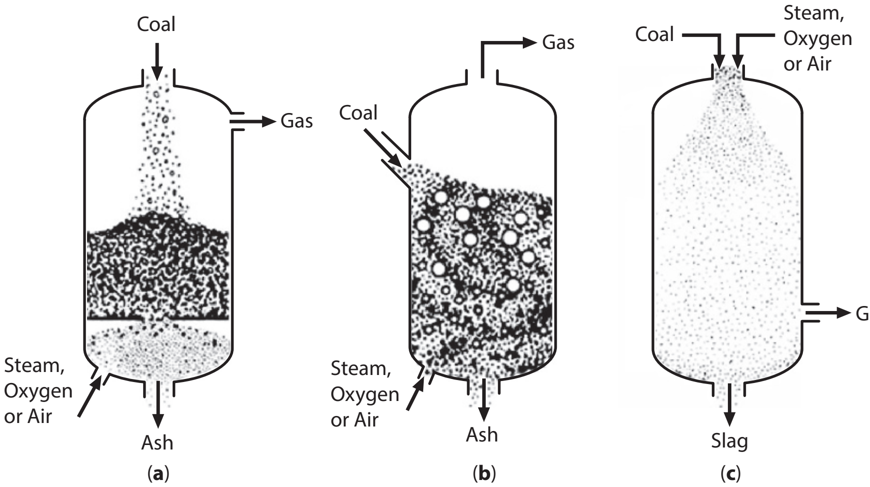

Figure 10.1 The principal types of gasifiers.

processes, some of which are in current use and some of which are in lesser use. These processes are presented alphabetically (in no order of preference) below.

However, on a general note, the main differences between the various gasifiers are as follows: (i) the method by which the feedstock is introduced into the gasifier and is moved around within it – the feedstock is either fed into the top of the gasifier, or into the side, and then is moved around either by gravity or air flows, (ii) the use of an oxidant such as oxygen, air or steam is used as an oxidant – using air dilutes the gas product with nitrogen, which adds to the cost of downstream processing while using oxygen avoids this, but is expensive, and so oxygen enriched air can also be used, (iii) the temperature range in which the gasifier is operated, (iv) the means by which the heat for the gasifier is provided by partially combusting some of the biomass in the gasifier (directly heated), or from an external source (indirectly heated), such as circulation of an inert material or steam (v) the pressure at which the gasifier is operated – above atmospheric pressure, which provides a higher throughput with larger maximum capacities, promotes hydrogen production and leads to smaller, cheaper downstream cleanup equipment; since no additional compression is required, the gas product temperature can be kept high for downstream operations and liquid fuels catalysis but at pressures in excess of 450 psi costs quickly increase, since gasifiers need to be more robustly engineered, and the required feeding mechanisms involve complex pressurizing steps.

Although there are many successful commercial gasifiers, the basic form and concept are available but details on the design and operation for the commercial coal gasifiers are closely guarded as proprietary information. In fact, the production of gas from carbonaceous feedstocks has been an expanding area of technology. As a result, several types of gasification reactors have arisen and there has been a general tendency to classify gasification processes by virtue of the heat content of the gas which is produced (Collot, 2002, 2006).

It is the purpose of this chapter to present the different categories of gasification reactors as they apply to various types of feedstocks (Speight, 2013, 2020b).

10.2 Gasifier Types

There has been a general tendency to classify gasification processes by virtue of the heat content of the gas which is produced; it is also possible to classify gasification processes according to the type of reactor vessel and whether or not the system reacts under pressure (Phillips, 2016). However, for the purposes of the present text gasification processes are segregated according to the bed types, which differ in their ability to accept (and use) caking coals (Table 10.1).

These gasifiers (Table 10.2) can be further subdivided into three reactor types: (i) a gasifier reactor, (ii) a devolatilizer, and (iii) a hydrogasifier (Chapter 9) with the choice of a particular design depending on the ultimate product gas desired.

Reactors may also be designed to operate either at atmospheric pressure or at high pressure. In the latter type of operation, the hydrogasification process is optimized and the quality of the product gas (in terms of heat, or Btu, content) is improved. In addition, the reactor size may be reduced and the need to pressurize the gas before it is introduced into a pipeline is eliminated (if a high heat-content gas is to be the ultimate product). However, high-pressure systems may have problems associated with the introduction of the coal into the reactor.

Contacting the solid coal with reactant gases to accomplish the required gasification is a second major mechanical problem. There are three types of contacting methods: (i) a moving bed of solids with up-flowing gas, also called a descending bed reactor, (ii) a fluidized bed of solids, and (iii) entrained flow of solids in which the coal feedstock flows into the reactor with the steam and oxygen/air (Figure 9.4).

However, each type of gasifier may be designed to operate either at atmospheric pressure or at high pressure. In the latter type of operation, hydrogasification of the feedstock (Chapter 2) is optimized and the quality of the product gas (in terms of heat, or Btu, content) is improved. In addition, the reactor size may be reduced and the need to pressurize the gas before it is introduced into a pipeline is eliminated (if a high heat-content gas is to be the ultimate product). High-pressure systems may have problems associated with the introduction of the feedstock into the reactor. Furthermore, low pressure or atmospheric

Table 10.2 Categories and characteristics of different gasifiers (Higman and Van der Burgt, 2003).

Gasifier type	Fixed bed	Fluidized bed	Entrained flow
Outlet temperature	425-600°C 800-1110°F	900-1050°C 1650-1920°F	1250-1600°C 2280-2030°F
Oxygen demand	Low	Moderate	High
Ash conditions	Dry ash, slagging	Dry ash, agglomerating	Slagging
Size of coal feed	6-50 mm	6-10 mm	<100 μm
Acceptability of fines	Limited	Good	Unlimited
Other characteristics	Tar and oil produced	Low carbon conversion	High carbon conversion

pressure gasification reactors are frequently designed with an accompanying fuel gas compressor after the synthesis gas (syngas) clean-up processes.

Furthermore some gasifiers are also categorized as *single-stage units* or *multi-stage units* and the multi-stage units are further sub-categorized into *single-line operation* or *double-line operation*.

In *single-stage* gasifiers, conversion takes place in a single reactor using steam, air, or oxygen. The common *single-stage* technologies are fixed-bed, fluidized-bed, and entrained-flow reactors. In fixed-bed gasifiers the fuel is fed from the top and the gasification medium is injected at the bottom. The fuel moves slowly down the reactor with the gas moving upwards in a countercurrent direction whereas in co-current designs the fuel and the gasification agent move in the same direction and the fuel must pass successively through the drying, pyrolysis, oxidation and reduction zones. The advantage of countercurrent designs are fewer restrictions on fuel moisture and particle size, no special fuel preparation required, and a wide range of fuels can be used. By comparison, co-current gasifiers produce a better-quality gas but place strict requirements on fuel properties. Fluid-bed gasifiers allow for more efficient gasification due to elimination of hot spots in the reactor. They are suitable for a wide range of feedstocks and can be scaled up to relatively large plants. They are more expensive to build and need better gas cleaning due to high particulate content in the product gas. Fluidized-bed gasifiers have no defined reaction zones and the conversion of fuel and secondary pyrolytic reactions take place in the same volume. Tar conversion can be supported by introducing catalytically active bed materials.

Multi-stage gasifiers consider the fuel conversion steps of drying, devolatilization, gasification and combustion zones to enhance process efficiency and product gas quality by influencing and optimizing the operating parameters. These concepts are categorized as *single-line operation* in which the feedstock stream is passed through reactors arranged in series or *double-line operation* in which the mass main stream is divided into at least two partial streams which pass through reactors which are arranged in parallel. Furthermore, in the *double-line* process, combustion and gasification reactors are separate and are only connected by heat transfer – a pyrolysis stage is used to split the fuel into char and gas and to provide the heat necessary for operation the char or part of the pyrolysis gas must be oxidized outside the pyrolysis reactor.

If chosen judiciously to accommodate the varying properties of the feedstock, the gasifier will operate satisfactorily with respect to gas quality, efficiency, and pressure variations within certain ranges of the fuel properties of which the most important are (i) feedstock reactivity, (ii) feedstock size and size distribution, (iii) bulk density of the feedstock, (iv) propensity of the feedstock for char formation, (v) feedstock energy content, (vi) feedstock moisture content, (vii) volatile matter production, (viii) mineral matter content, which is an indication of ash forming propensity, (ix) ash chemical composition, and (x) ash reactivity. However, before choosing a gasifier that is theoretically suitable to the fuel it is important to consider the opposing view insofar as the fuel meeting the requirements of the gasifier or, failing that, whether or not the fuel can be treated to meet the necessary gasifier requirements.

As an additional note, the use of two types of turbines – a combustion turbine and a steam turbine – in combination (known as a combined cycle) is one reason why gasification-based power systems can achieve high power generation efficiency. The higher efficiency means that less fuel is used to generate the rated power, resulting in better economics (which can mean lower costs to the user) and the formation of fewer greenhouse gases (a 60% efficient gasification power plant can cut the formation of carbon dioxide by 40% compared to a typical coal combustion plant).

10.2.1 Fixed-Bed Gasifier

The fixed-bed gasifier is often referred to as a descending-bed gasifier, moving-bed gasifier, or on occasion a countercurrent descending-bed gasifier (Figure 9.5) (Bodle and Huebler, 1981; Probstein and Hicks, 1990; Hobbs *et al.*, 1992). In a fixed-bed process the coal is supported by a grate and combustion gases (steam, air, oxygen, etc.) which pass through the supported coal whereupon the hot produced gases exit from the top of the reactor. Heat is supplied internally or from an outside source, but caking coals cannot be used in an unmodified fixed-bed reactor.

In the process, lumps of coal (approximately 1/8 to 1 inch diameter), often with fluxes, are laid down at the top of a refractory-lined vessel while reactant gases are introduced at the bottom of the vessel and flow at relatively low velocity upward through the interstices between the coal lumps. On moving downwards, the coal is gradually heated and contacted with an oxygen enriched gas flowing upwards countercurrently. Pyrolysis, char gasification, combustion and ash melting occur sequentially. The temperature at the top of the bed is typically 450°C (840°F), and at the bottom approximately 2000°C (3630°F). As the coal descends it is reacted first by devolatilization using the sensible heat from the rising gas, then hydrogenated by the hydrogen in the reactant gas, and finally burned to an ash. The reactions are, therefore, carried out in a countercurrent fashion. The mineral matter in the coal melts and is tapped as an inert slag. The characteristics of the melted (or melting) ash influence bed permeability, and fluxes may need to be added to modify slag flow characteristics.

Reaction zones are often used to describe the reactions occurring along the length of the gasifier: (i) the drying zone, (ii) carbonization zone, (iii) the gasification zone, and (iv) the combustion zone.

In the *drying zone* at the top of the gasifier, the entering coal is heated and dried by the countercurrent flow of synthesis gas, while simultaneously cooling the synthesis gas before it leaves the gasifier. The moisture content of the coal mainly controls the temperature of the discharge gas from the gasifier. Because of the countercurrent operation of this gasifier, hydrocarbon liquids can be found in the product gas which has been problematic for downstream operations. However, the hydrocarbon products can be recycled to the lower part of the gasifier.

As the coal continues down the bed, it enters the *carbonization zone* where the coal is further heated and devolatilized by higher temperature gas. This is followed by the *gasification zone* in which the devolatilized coal is converted to gas by reactions with steam and carbon dioxide. In the combustion zone near the bottom of the reactor, oxygen reacts with the remaining char to consume the remaining carbon and to generate the necessary heat for the *gasification zone*.

Depending upon the operation of the combustion zone, the gasifier can be made to operate in one of two distinct modes, i.e., dry ash or slagging. In the dry-ash version, the temperature is maintained below the ash slagging temperature by the endothermic reaction of the char with steam in the presence of excess steam. In addition, the ash below the combustion zone is cooled by the entering steam and oxidant. In the slagging version, much less steam is used so that the temperature of the ash in the combustion zone exceeds the ash fusion temperature of the coal and molten slag is formed.

The residence time of fixed-bed gasifiers is between 30 minutes and one hour, which places stringent restrictions on the physical and chemical properties of the coal feedstock. Coal size distribution must be controlled to ensure good bed permeability. Excess fines can be injected with oxygen at the tuyeres or briquetted to maintain stable operation. Long residence times mean that fixed-bed gasifiers have a low throughput and hence have limited application in large-scale IGCC plants. To ensure stable fluid-bed operation, gasification temperatures are kept below the AFT of the coal. Above this temperature, particles become sticky and excessive levels of agglomeration will occur, resulting in bed destabilization.

In summary, these types of gasifier have the following characteristics: (i) low oxidant requirements, (ii) relatively high methane content in the gas, (iii) production of liquid hydrocarbon derivatives, such as tar and oil, (iv) high thermal efficiency, when the heating value of the hydrocarbon liquids is included, and (v) a limited ability to handle fines.

10.2.2 Fluidized-Bed Gasifier

A fluidized-bed gasifier is a back-mixed or well-stirred reactor in which there is a consistent mixture of new coal particles mixed in with older, partially gasified and fully gasified particles. The mixing also promotes a uniform temperature throughout the bed. The flow of gas into the reactor (oxidant, steam, recycled synthesis gas) must be sufficient to float the coal particles within the bed but not so high as to entrain them out of the bed. However, as the particles are gasified, they decrease in size and density and lighter and will be entrained out of the reactor. It is also important that the temperatures within the bed are less than the initial ash fusion temperature of the coal to avoid particle agglomeration.

The fluidized-bed system uses finely sized coal particles and the bed exhibits liquid-like characteristics when a gas flows upward through the bed. Gas flowing through the coal produces turbulent lifting and separation of particles and the result is an expanded bed having greater coal surface area to promote the chemical reaction, but such systems have only a limited ability to handle caking coals.

The fluidized-bed gasifier requires coal to be ground to a low particle size or less (Figure 9.6) (see also Arnold *et al.*, 1992). The reactant gases are introduced through a perforated deck near the bottom of the vessel. The volume rate of gas flow is such that its velocity (1 to 2 ft/sec) is high enough to suspend the solids but not high enough to blow them out of the top of the vessel. The result is a violently "boiling" bed of solids having very intimate contact with the upward-flowing gas. This gives a very uniform temperature distribution. The solid flows rapidly and repeatedly from bottom to top and back again, while the gas flows rather uniformly upward. The reactor is said to be completely back-mixed and no countercurrent flow is possible. If a degree of countercurrent flow is desired, two or more fluid-bed stages are placed one above the other. Reaction rates are faster than in the moving bed because of the intimate contact between gas and solids and the increased solids surface area due to the smaller particle size.

During normal operation, the bed media is maintained at a temperature between 540 and 1000°C (1000 and 1830°F) depending on the feedstock and the desired outcome in terms of distribution and yield of gaseous products. When a fuel particle is introduced into this environment, its drying and pyrolyzing reactions proceed rapidly, driving off all gaseous portions of the fuel at relatively low temperatures. The remaining char is oxidized within the bed to provide the heat source for the drying and devolatilizing reactions to continue. In those systems using inert bed material, the feedstock particles may be subjected to an intense abrasion action if sand is the fluidizing – this abrasive action tends to remove any surface deposits (such as ash) from the particle and expose a clean reaction surface to the surrounding gases. As a result, the residence time of a particle in this system is on the order of only a few minutes, as opposed to hours in other types of gasifiers.

The high thermal capacity of inert bed material plus the intense mixing associated with the fluid bed enable this system to handle a much greater quantity and, normally, a much lower quality of fuel. Because the operating temperatures are lower in a fluid bed than other gasifiers the potential for slagging and ash fusion at high temperatures is reduced, thereby increasing the ability to utilize high slagging coal.

The low temperature operation limits the use of fluidized-bed gasifiers to reactive and predominantly low-rank coals. Most fluidized-bed gasifiers have a high level of entrained fines recycle to achieve 95 to 98% carbon conversion. To reduce the size of the fines recycle stream, it has been proposed that the gasifier is linked with a fluid-bed combustor (*air blown gasification cycle*) in which the coal is first gasified to 70 to 80% carbon conversion. The unreacted char is then fed to the combustor where generated heat is used for steam production. The gasifier-combustor combination enables the use of low reactivity, high ash fusion temperature coal in an IGCC system.

The unusual characteristic of fluidized-bed gasifiers is that the majority of the bed material is not coal but accumulated mineral matter and sorbent (if *in situ* desulfurization is an option). Operating with a high inventory of inert bed material does have advantages such as (i) the coal experiences high heat transfer rates on entry, and (ii) the gasifier can operate at variable load (high turndown flexibility).

Fluidized-bed gasifiers can also convert biomass waste products to a combustible gas that can be fired in a boiler, kiln, or other energy load. The gasifier can be installed as an add-on to a coal-fired power plant to provide a means to convert a portion of the fuel supply to clean, renewable biomass fuel.

In summary, a fluidized-bed gasifier can operate in a highly back-mixed mode, thoroughly mixing the coal feed particles with those particles already undergoing gasification. Because of the highly back-mixed operation, the gasifier operates under isothermal conditions at a temperature below the ash fusion temperature of the coal, thus avoiding clinker formation and possible collapse of the bed. The low temperature operation of this gasifier means that fluidized-bed gasifiers are best suited to relatively reactive feeds, such as low-rank coals and biomass, or to lower-quality feedstocks such as high mineral matter coal. This give the gasifier the following characteristics: (i) can accept a wide range of solid feedstocks, including high-mineral matter coal, wood, and solid waste, (ii) uniform, moderate temperature, (iii) moderate oxygen and steam requirements, and (iv) char recycling.

10.2.3 Entrained-Bed Gasifier

Entrained-flow gasification involves the pulverized coal and oxidizing gas flowing cocurrently. High reaction intensity is provided by a high pressure (20-30 atm), high temperature (>1400°C, >2550°F) environment. Turbulent flow causes the coal particles to engage in significant back-mixing, and residence times are measured in seconds. Entrained-flow gasification is specifically designed for low reactivity coals and high coal throughput – single pass carbon conversions generally fall into a range from 95 to 99%.

An entrained-bed system uses finely sized coal particles that are introduced into the gas steam prior to entry into the reactor and combustion occurs with the coal particles suspended in the gas phase; the entrained system is suitable for both caking and noncaking coals. The molten salt system employs a bath of molten salt to convert the charged coal (Cover *et al.*, 1973; Howard-Smith and Werner, 1976; Koh *et al.*, 1978).

The entrained-flow reactor (Figure 9.7) uses a still finer grind of coal (80% through 200 mesh) than the fluidized-bed gasifier and the coal must be fine enough that it can be conveyed pneumatically by the reactant gases. Velocity of the mixture must be approximately 20 ft/sec (6.1 m/sec) or higher depending upon the fineness of the coal. In this case, there is little or no mixing of the solids and gases, except when the gas initially meets the solids.

In addition, the extensive variety of gasification processes that are being developed are all influenced to a large extent by the mechanics of (i) feeding solid coal into reactors, often at high pressure, (ii) contacting the coal with reactant gases, (iii) removing solid or liquid ash, referred to as slag, and (iv) collecting of fine partially reacted dust that is carried out of the reactor with the gaseous products.

Thus, in entrained-flow gasifiers, fine coal particles react with steam and oxidant, generally pure oxygen, at temperatures well above the fusion temperature of the ash. The residence time of the coal in these gasifiers is short, and high temperatures are required to achieve high carbon conversion. Because of the high reaction temperatures required compared to the other gasifier types, oxygen consumption is higher because of the need to combust more of the feedstock to generate the required heat. To minimize oxygen consumption, these gasifiers are usually supplied with higher-quality feedstocks. Entrained-flow gasifiers can operate either in a down-flow or up-flow mode and have the following characteristics: (i) the ability to gasify all types of coal, regardless of rank, caking characteristics, or amount of fines, although feedstocks with lower mineral matter content are favored, (ii) uniform temperature, (iii) short feed residence time in the gasifier, (iv) the solid fuel must be very finely divided and homogeneous, (v) a relatively high oxygen (oxidant) requirement, (vi) a high amount of sensible heat in the raw gas, (vii) a high-temperature slagging operation, and (viii) entrainment of some of the ash or slag in the raw gas.

To experience smooth operation, the gasifier temperature must lie above the ash fusion temperature or fluxes, which lower the melting temperature of the coal mineral matter, must be used. A number of system constraints impose an economic limit on gasification temperature at 1400 to 1500°C (2550 to 2730°F) and are (i) extremely high temperatures shorten refractory life, (ii) there is a limit to the heat that can be recovered from the raw fuel gas, without water quench becoming necessary, (iii) the cost incurred in providing oxygen and coal to sustain the gasifier temperature. Consequently, it may be necessary to add fluxes or blend coal, which produces ash with a high fusion temperature, to achieve good slagging characteristics at economic gasifier temperatures.

10.2.4 Molten Salt Gasifier

The molten salt gasifier, as the name implies, use a molten medium of an inorganic salt to generate the heat to decompose the coal into products. Molten salts have also been studied since the early 1900s to gasify coal in a process called molten salt oxidation (MSO).

The molten salt used is usually sodium carbonate heated above its melting point of 851°C (1564°F) to approximately 900 to 1000°C (1650 to 1830°F) – in effect, the coal is flash pyrolyzed such that no tars or oils are produced.

In molten bath gasifiers, crushed coal, steam air and/or oxygen are injected into a bath of molten salt, iron, or coal ash. The coal appears to *dissolve* in the melt where the volatiles crack and are converted into carbon monoxide and hydrogen. The fixed carbon reacts with oxygen and steam to produce carbon monoxide and hydrogen. Unreacted carbon and ash float on the surface from which they are discharged. High temperatures, depending on the nature of the melt, are required to maintain the bath molten. Such temperature levels favor high reaction rates and throughputs and low residence times. Consequently, tars and oils are not produced in any great quantity, if at all.

Gasification may be enhanced by the catalytic properties of the melt used. Molten salts, which are generally less corrosive and have lower melting points than molten metals, can strongly catalyze the steam-coal reaction and lead to high conversion efficiencies.

10.3 Fixed-Bed Processes

In a fixed-bed process the coal is supported by a grate and combustion gases (steam, air, oxygen, etc.) pass through the supported coal whereupon the hot produced gases exit from the top of the reactor. Heat is supplied internally or from an outside source, but caking coals cannot be used in an unmodified fixed-bed reactor.

In the process, the fixed-bed gasifier (moving-bed gasifier) commonly operates at moderate pressures (375 to 450 psi). Feedstocks in the form of large coal particles and fluxes are loaded into the top of the refractory-lined gasifier vessel and move slowly downward through the bed, while reacting with high oxygen content gas introduced at the bottom of the gasifier that is flowing countercurrently upward in the gasifier. The basic configuration is the same as seen in the common blast furnace. The moving-bed gasifier (Figure 10.1a) operates in two different modes. In the dry-ash mode of operation (such as in the Lurgi dry-ash gasifier) the temperature is moderated to below the ash-slagging temperature by reaction of the char with excess steam. The ash below the combustion zone is cooled by the entering steam and oxidant (oxygen or air) and produced as a solid ash. In the slagging mode of operation (such as the British Gas/Lurgi gasifier), much less steam is used, and as the result, a much higher temperature is achieved in the combustion zone, melting the ash, and producing slag.

Typically, the feedstock is supported by a grate and combustion gases (such as steam, air, oxygen) pass through the supported feedstock after which the hot product gases exit from the top of the reactor. Heat is supplied internally or from an outside source, but some carbonaceous feedstocks (such as caking coal) cannot be used in an unmodified *fixed-bed reactor*. Because of the operation of the gasifier, the system may also be referred to as a *descending-bed reactor* and is also often referred to as a *moving-bed reactor* or, on occasion, a *countercurrent descending-bed reactor*. The descending-bed-of-solids system is often referred to as a moving or fixed bed or, on occasion, a countercurrent descending-bed reactor (Beenackers, 1999).

In the gasifier, the feedstock (approximately 1/8 to 1 in., 3 to 25 mm, diameter) is laid down at the top of a vessel while reactant gases are introduced at the bottom of the vessel and flow at relatively low velocity upward through the interstices between the coal lumps. As the feedstock descends it is reacted first by devolatilization using the sensible heat from the rising gas, then hydrogenated by the hydrogen in the reactant gas, and finally burned to an ash. The reactions are, therefore, carried out in a countercurrent fashion. The first reaction is *devolatilization* by the sensible heat from the rising gas, then *gasification* of the resulting hydrogen-deficient char (Speight, 2013, 2020a) (Chapter 9). Hydrogenation by the hydrogen in the reactant gas may also occur but, eventually, the feedstock is converted to gases and mineral ash.

Thus, the *countercurrent fixed-bed gasifier* (*updraft gasifier*, *counter-flow gasifier)* consists of a fixed bed of carbonaceous fuel through which the gasification agent (steam, oxygen and/or air) flows in counter-current configuration. The ash is either removed dry or as a slag. The *slagging gasifier* requires a higher ratio of steam and oxygen to carbon in order to reach temperatures higher than the ash fusion temperature. The nature of the gasifier means that the fuel must have high mechanical strength and must be non-caking so that it will form a permeable bed, although recent developments have reduced these restrictions to some extent. The throughput for this type of gasifier is relatively low but thermal efficiency is high as the gas exit temperatures are relatively low but, as a result, production of methane and tar is significant at typical operation temperatures.

The main advantage of this gasifier is the effective heat exchange in the reactor. The high temperature gas product, before it is led out of the gasifier, can be used to dry the feedstock (an important aspect of gasification of wet biomass) as it moves downwards in the reactor. By that heat exchange taken place, the raw gas product is cooled significantly on its way through the bed. The temperature of the synthesis at the reactor exit point is approximately 250°C (480°F – in a downdraft gasifier the exit gas temperature is on the order of 800°C, 1470°F). Since the gas product is exploited in order to dry the incoming feedstock, the system sensitivity to feedstock moisture content is less than in other gasification reactors. On the other hand, the countercurrent flow of feedstock and gas product results in higher tar content (10 to 20% w/w) in the raw gas product. Advantages of updraft gasification include: (i) relatively simple, low-cost process, (ii) equipped to process feedstocks (such as biomass) with a high moisture and high inorganic content, such as municipal solid waste, and (iii) proven technology (Chopra and Jain, 2007).

The *co-current fixed-bed* (*downdraft*) gasifier is similar to the countercurrent gasifier, but the gasification agent gas flows in co-current configuration with the fuel (downwards, hence the name down draft gasifier). Heat needs to be added to the upper part of the bed, either by combusting small amounts of the fuel or from external heat sources. The produced gas leaves the gasifier at a high temperature, and most of this heat is often transferred to the gasification agent added in the top of the bed, resulting in energy efficiency almost equivalent to the countercurrent gasifier. In this configuration, any produced tar must pass through a hot bed of char, thereby removing much of the tar from the product slate.

The co-current fixed-bed gasifier (downdraft gasifier) is easier to control than countercurrent fixed-bed gasifier but are more sensitive to the quality of the feedstock. For example, in the case of biomass feedstocks, while updraft gasifiers can process biomass with moisture content up to 50% w/w, in downdraft gasification a moisture content range between 10 and 25% w/w is required. The advantages of downdraft gasification are: (i) up to 99.9% w/w of the tar formed is consumed, requiring minimal or tar cleanup removal from the product gases, (ii) feedstock minerals remain with the char/ash, reducing the need for a cyclone,

(iii) relatively simple and low-cost process. However, the disadvantages of downdraft gasification are: (i) the feedstock should be dried to a low moisture content on the order of 20% w/w moisture, (ii) the gas product exiting the reactor is at high temperature, requiring a secondary heat recovery system, and (iii) approximately 4 to 7% w/w of the carbon may remain unconverted (Zainal *et al.*, 2002).

Due to the fact that the gaseous products from the pyrolysis step pass through the oxidation zone, the tar compounds concentration in the raw gas product is less than in the case of updraft gasifiers. These gasifiers are easier to control but are more sensitive to the quality of the feedstock. For example, in the case of biomass feedstocks, while updraft gasifiers can process biomass with moisture content up to 50% w/w, in downdraft gasification a moisture content range between 10 and 25% is required.

The advantages of downdraft gasification are: (i) up to 99.9% of the tar formed is consumed, requiring minimal or no tar cleanup, (ii) minerals remain with the char/ash, reducing the need for a cyclone, (iii) proven, simple and low-cost process. However, the disadvantages of downdraft gasification are: (i) the feed should be dried to a low moisture content (<20% w/w moisture), (ii) the gas product exiting the reactor is at high temperature, requiring a secondary heat recovery system, and (iii) 4 to 7% of the carbon remains unconverted.

Crossdraft gasification reactors – which operate well on dry air blast and dry fuel – do have advantages over updraft gasification reactors and downdraft gasifiers but the disadvantages – such as high exit gas temperature, poor carbon dioxide reduction and high gas velocity – which are the consequences of the design, outweigh the advantages.

Unlike downdraft and updraft gasifiers, the ash bin, fire, and reduction zone in crossdraft gasifiers are separated. This design characteristic limits the type of fuel for operation to low mineral matter fuels such as wood, charcoal, and coke. The load following ability of the crossdraft gasifier is quite good due to concentrated partial zones which operates at temperatures up to 2000°C (3600°F). The relatively higher temperature in crossdraft gasification reactor has an effect on gas composition – resulting in high carbon monoxide content and low hydrogen and methane content when dry fuel such as charcoal is used.

10.3.1 Foster-Wheeler Stoic Process

The Foster-Wheeler process involves the use of a two-stage gasifier (Figure 10.2) in which the upper stage is the distillation zone and the lower stage is the gasification zone (Probstein and Hicks, 1990). The coal is charged to the top of the unit and is reduced to coke by the time it reaches the bottom of the distillation zone. Ash is removed from the base of the gasifier through a water seal, and steam and air are introduced through a grate at the base of the coal bed.

The steam-air mixture is preheated by passage through the bed of hot ash and enters the fire zone, a narrow band 4 to 10 in. (100 to 250 mm) deep, operating at 980°C (1800°F). A partial oxidation reaction takes place in the fire zone and produces carbon monoxide, some carbon dioxide, and hydrogen as well as heat for the balance of the gasification reactions. The two stage operation of the gasifier is designed to heat the coal gradually with only part of the hot reducing gas and, thus, the oils and tars formed are sufficiently fluid to be handled easily. At temperatures in excess of 480°C (900°F), the plastic components resolidify and decompose to yield coke and a hydrogen-rich gas, some of which reacts with carbon to form a small additional amount of methane. The gas from the distillation zone contains

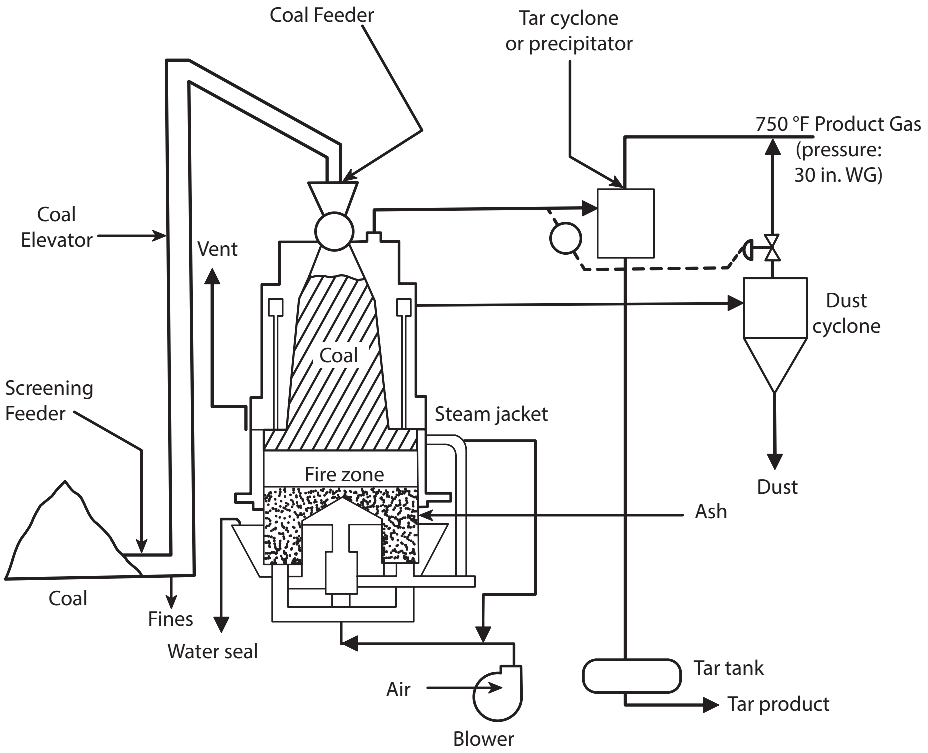

Figure 10.2 The Foster-Wheeler stoic gasifier.

almost all of the oil and tar and devolatilized methane as well as the residual water entering with the coal.

The coke is reduced to ash in the fire zone which then moves down onto the grate and out of the gasifier via the water seal. The bed of ash between the fire zone and the grate is cooled by the incoming blast of air and steam. Water jacketing is used in the gasification zone to cool the shell and, at the same time, to generate the steam required for the gasification reaction. The steam also helps to cool the fire zone so that the ash will not agglomerate, fuse, and form large clinkers that would block the flow out of the units.

10.3.2 Lurgi Process

The Lurgi process, which was developed in Germany before World War II, is a process that is adequately suited for large-scale commercial production of synthetic natural gas (Speight, 2013, 2020a, 2020b). The older Lurgi process is a dry-ash gasification process which differs significantly from the more recently developed slagging process (Baughman, 1978; Massey, 1979). The dry-ash Lurgi gasifier is a pressurized vertical kiln which accepts crushed (1/4 x 1-3/4 in.; 6 x 44 mm) noncaking coal and reacts the moving bed of coal with steam and either air or oxygen. The coal is gasified at 350 to 450 psi and devolatilization takes place in the temperature range 615 to 760°C (1140 to 1400°F); residence time in the reactor is approximately 1 hour.

Hydrogen is supplied by injected steam and the necessary heat is supplied by the combustion of a portion of the product char. The revolving grate, located at the bottom of the gasifier supports the bed of coal, removes the ash, and allows steam and oxygen (or air) to be introduced.

The Lurgi product gas has a high methane content relative to the products front non-pressurized gasifiers. With oxygen injection, the gas has a heat content of ca. 450 Btu/ft (16.8 MJ/m).

The crude gas which leaves the gasifier contains tar, oil, phenols, ammonia, coal fines, and ash particles. The steam is first quenched to remove the tar and oil and, prior to methanation, part of the gas passes through a shift converter and is then washed to remove naphtha and unsaturated hydrocarbon derivative. In a subsequent step the acid gases (such as carbon dioxide and hydrogen sulfide) are removed. The gas is then methanated to produce a high heat-content pipeline quality product.

Dry-ash Lurgi gasification is a highly advanced technology that, with the addition of a stirrer, can now process caking coals or those with low ash fusion temperatures. The agglomerated ash from such coals cannot be easily removed through the grate at the bottom of the gasifier. In addition, the low operating temperature encourages the production of by-product tars, oils, and phenols. A modification of the Lurgi process, known as the slagging Lurgi (Figure 10.3), is being developed to make it possible to process caking coals.

Thus, while minimizing wastewater treatment costs in a conventional Lurgi gasifier, the temperature is intentionally kept low (by injecting an excess amount of steam, usually 6-10 moles of steam per mole of oxygen) to minimize ash agglomeration. In a slagging Lurgi gasifier, the steam injection rate is reduced to 1-1.5 moles of steam per mole of oxygen and the higher operating temperature causes the coal ash to melt and run off as a slag. As in a conventional Lurgi unit, coal is fed to the gasifier through a lock hopper system and a distributor. As it passes down through the bed, the coal is preheated and devolatilized by the upward-flowing steam of hot product gas. The coal is then gasified with steam and oxygen which are injected near the bottom of the vessel. The entire bed rests on a hearth through which the molten ash, or slag, can pass through the slag tap hole. The slag is then quenched with water and is finally removed through a lock hopper.

The amount of unreacted steam passing through the bed is minimized in the slagging Lurgi process and, thus, the product gases can be removed from the unit faster with minimum fines carryover. This aspect of the process, together with the higher operating temperature, lead to higher output rates for slagging units than conventional dry ash units.

10.3.3 Wellman-Galusha Process

The Wellman-Galusha process has been in commercial use for more than 45 years (Howard-Smith and Werner, 1976). These are two types of gasifiers, the standard type (Figure 10.4) and the agitated type (Figure 10.5) and the rated capacity of an agitated unit may be 25% for more higher than that of a standard gasifier of the same size. In addition, an agitated gasifier is capable of treating volatile caking bituminous coals.

The gasifier is water-jacketed and, therefore, the inner wall of the vessel does not require a refractory lining. Agitated units include a varying speed revolving horizontal arm which also spirals vertically below the surface of the coal bed to minimize channeling and to provide a uniform bed for gasification. A rotating grate is located at the bottom of the gasifier

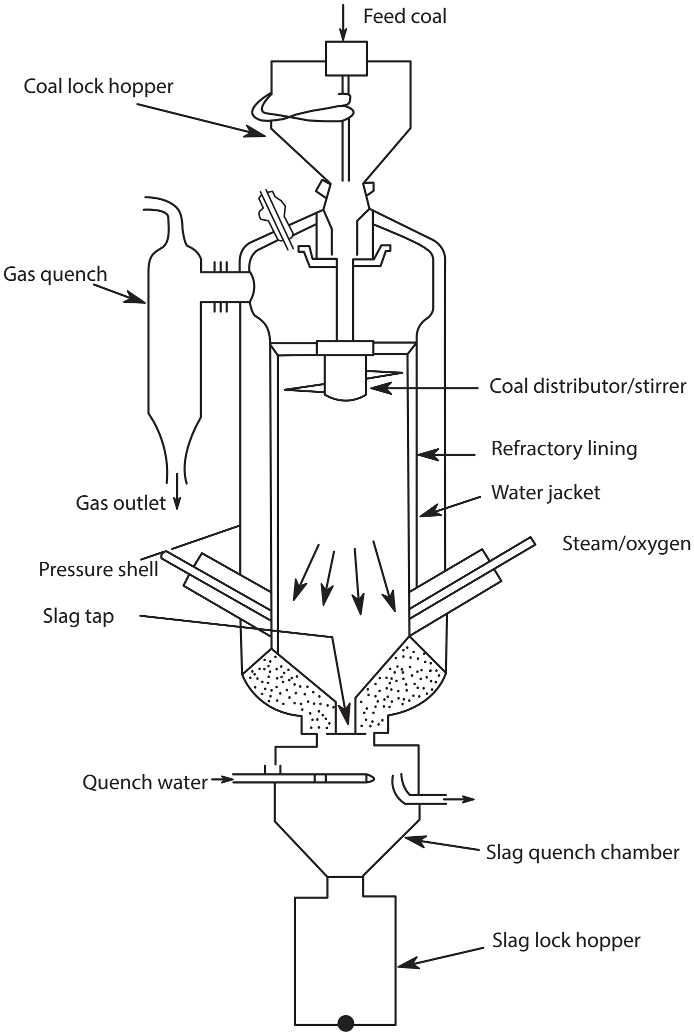

Figure 10.3 A slagging Lurgi gasifier.

to remove the ash from the bed uniformly. Steam and oxygen are injected at the bottom of the bed through tuyeres.

Crushed coal is fed to the gasifier through a lock hopper and vertical feed pipes. The fuel valves are operated so as to maintain a relatively constant flow of coal to the gasifier to assist in maintaining the stability of the bed and, therefore, the quality of the product gas. The air or oxygen which is injected into the gasifier passes over the top of the water jacket and thereby picks up the steam required for the process. The air-steam mix is introduced into the ash bin section underneath the grate and is then distributed through the grate into the bed, and passes upward through the ash, combustion, and gasification zones.

The product gas contains primarily carbon monoxide, carbon dioxide, hydrogen, and nitrogen (if air is injected) which, being hot, dries and preheats the incoming coal before leaving the gasifier. The product gas is passed through a cyclone, in which fine ash and

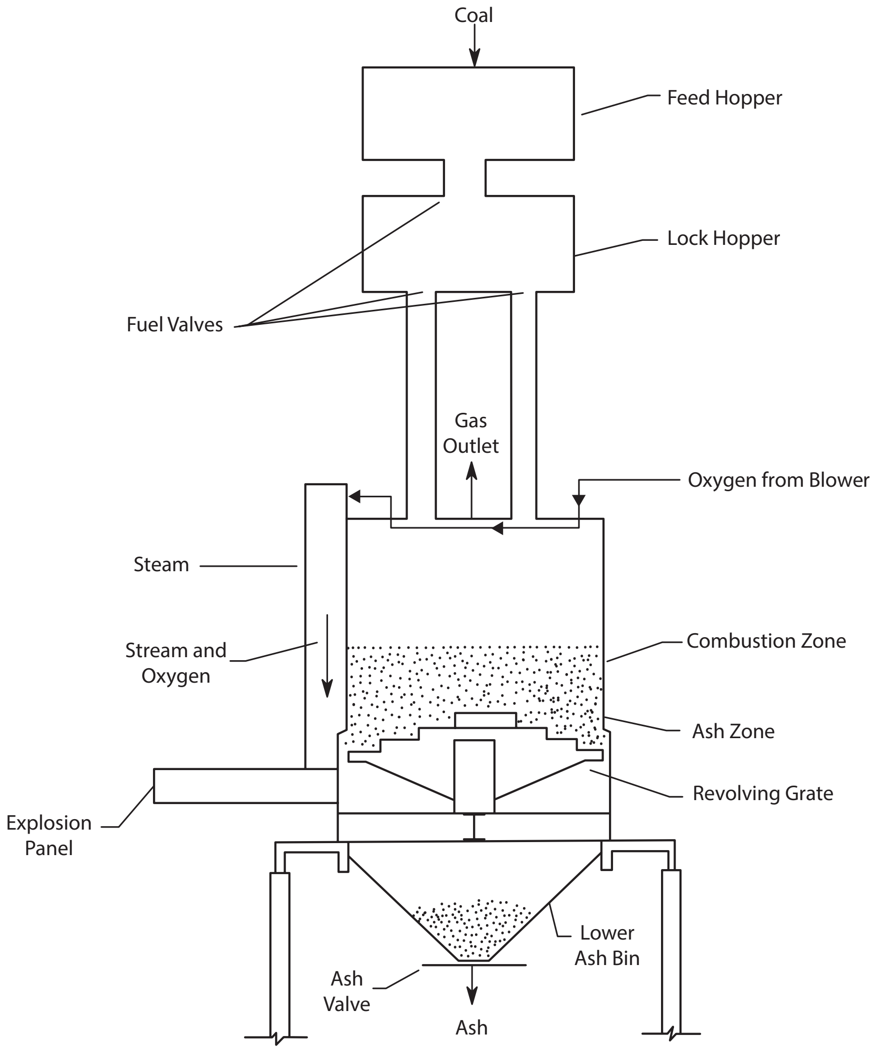

Figure 10.4 A Wellman-Galusha gasifier.

char particles are removed, and if the sulfur content of the gas is acceptable, it may be used directly. If, however, the sulfur content is too high, the gas can be scrubbed and cooled in a direct-contact countercurrent water cooler and then treated for sulfur removal. Use of air to support combustion will yield a low heat-content gas, but use of oxygen will yield a medium heat-content gas.

10.3.4 Woodall-Duckham Process

The Woodall-Duckham process employs a gasifier (Figure 10.6) which is a vertical cylindrical vessel having a rotating grate in the bottom for ash removal (Howard-Smith and Werner, 1976). There are three functional zones within the reactor: (i) a water-jacketed gasification zone, (ii) a refractory-lined distillation zone, and (iv) a refractory-lined drying zone.

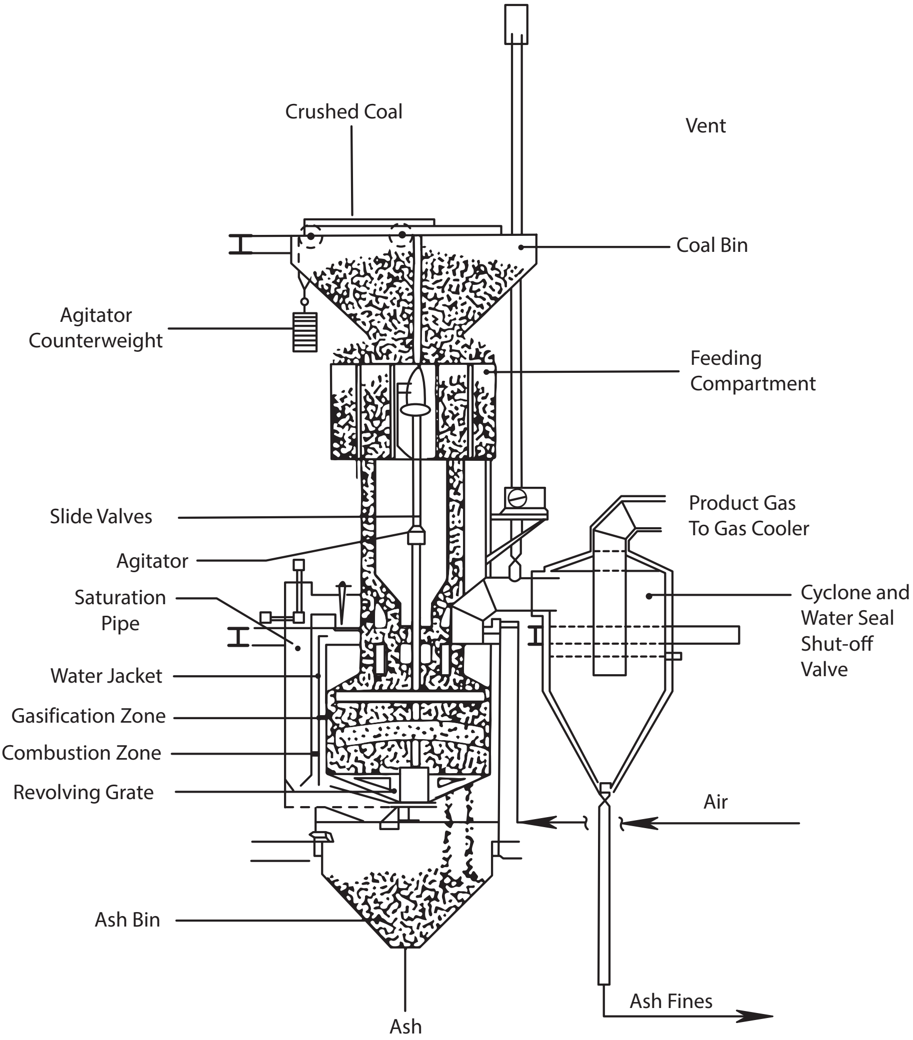

Figure 10.5 An agitated Wellman-Galusha gasifier.

Upon entering the gasifier, which operates at atmospheric pressure, the coal (0.25 to 1.5 in.; 6-38 mm) is contacted with upward-flowing hot gases from the gasification zone and any moisture present in the coal is driven off by the hot (120°C; 250°F) gases. The coal then falls into the distillation zone where the volatile matter present is driven off by the ascending hot gas, but since a relatively slow heating rate prevails, negligible cracking of the tar and oil occurs.

The devolatilized char (noncaking coals) or semicoke (caking coals) is further heated by the hot gases until the material passes into the gasification zone, where it is contacted countercurrently with steam and oxygen (or air) in a fixed bed whereupon the remaining carbon is mostly gasified. The temperature in the gasification zone may depend on the type of coal being processed but is usually of the order of 1205°C (2200°F).

In the lower portions of this zone, the descending ash is contacted with incoming steam and air, thereby effecting gas preheating and ash cooling. The ash is removed from the

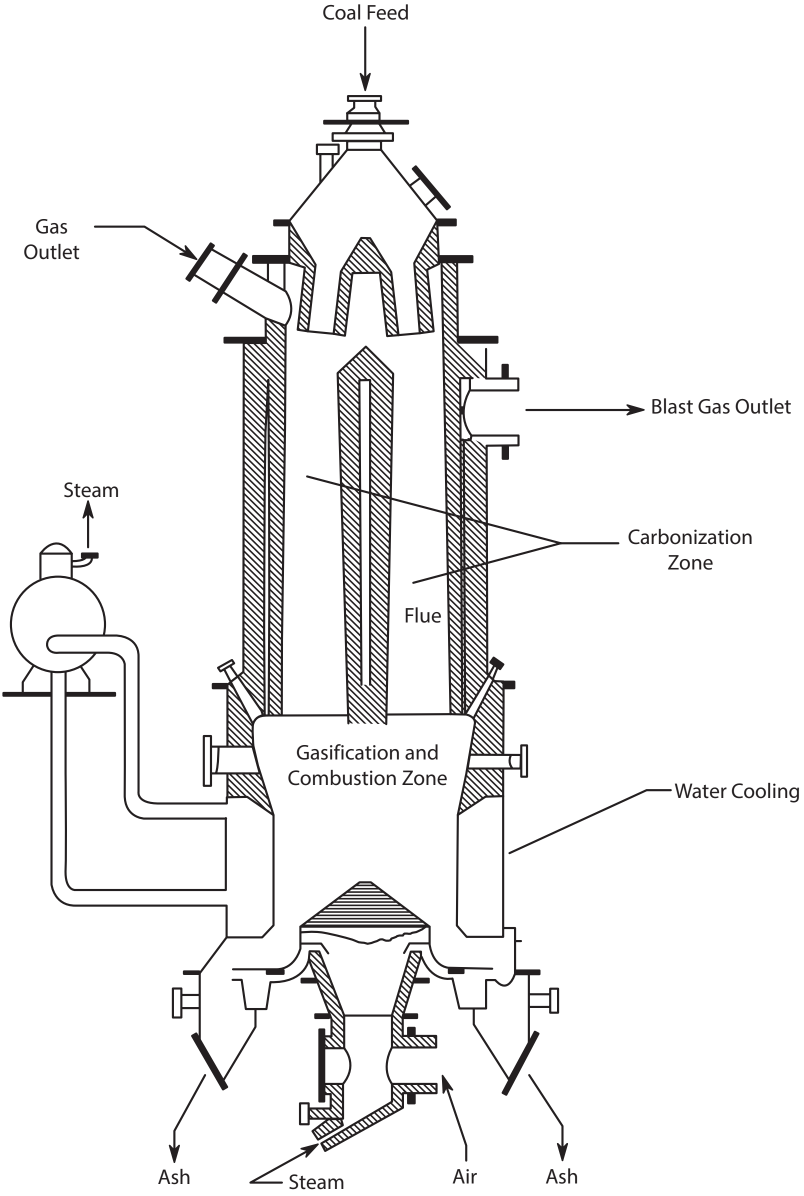

Figure 10.6 A Woodall-Duckham gasifier.

gasifier through a rotating grate, which also serves to distribute the air and steam evenly over the entire cross-section of the gasifier.

The product gas from the gasifier is withdrawn at two points in the vessel; the gas withdrawn between the distillation and drying zones is known as clear gas whereas the gas withdrawn near the top of the vessel is called top gas. Varying the portion of gas withdrawn through the lower tap affords a means of control of the temperature of the distillation zone. Thus, as the flow of clear gas is reduced, more hot gas is forced through the distillation zone, thus increasing the temperature.

10.4 Fluidized-Bed Processes

The fluidized-bed system uses finely sized coal particles and the bed exhibits liquid-like characteristics when a gas flows upward through the bed. Gas flowing through the coal produces turbulent lifting and separation of particles and the result is an expanded bed having greater coal surface area to promote the chemical reaction, but such systems have only a limited ability to handle caking coals.

In a fluid-bed gasifier (fluidized-bed gasifier) (Figure 10.1b), the feedstock particle are suspended feedstock particles in an oxygen-rich gas so the resulting bed within the gasifier acts as a fluid. These gasifiers employ back-mixing, and efficiently mix feed coal particles with coal particles already undergoing gasification. To sustain fluidization, or suspension of coal particles within the gasifier, coal of small particles sizes (<6 mm) is normally used. Coal enters at the side of the reactor, while steam and oxidant enter near the bottom with enough velocity to fully suspend or fluidize the reactor bed. Due to the thorough mixing within the gasifier, a constant temperature is sustained in the reactor bed. The gasifiers normally operate at moderately high temperature to achieve an acceptable carbon conversion rate (e.g., 90-95%) and to decompose most of the tar, oils, phenols, and other liquid by-products. However, the operating temperatures are usually less than the ash fusion temperature so as to avoid clinker formation and the possibility of de-fluidization of the bed. This, in turn means that fluidized-bed gasifiers are best suited to relatively reactive coal, low-rank coals, and other fuels such as biomass.

In the gasifier, the fuel is fluidized in oxygen (or air) and steam and the ash is removed dry or as high-density agglomerates. The temperatures are relatively low in dry ash gasifiers, so the fuel must be highly reactive. The fluidized-bed system uses finely sized feedstock particles and the bed exhibits liquid-like characteristics (in the form of fluid flow) when a gas flows upward through the bed. Gas flowing through the feedstock produces turbulent lifting and separation of particles and the result is an expanded bed having greater feedstock surface area to promote the chemical reaction.

The result is a bed of solids which simulates a boiling action ensuring intimate contact with the upward-flowing gas, leading to a uniform temperature distribution. The solid flows rapidly and repeatedly from bottom to top and back again, while the gas flows rather uniformly upward. As a result, reaction rates are faster than in the moving bed because of the intimate contact between gas and solids and the increased solids surface area due to the smaller particle size (Beenackers, 1999). Although no countercurrent flow is possible, a degree of countercurrent flow can be accomplished by placing two or more fluid-bed stages one above the other.

An aspect of *staged gasification* is to send the feedstock, such as biomass, to a pyrolysis reactor, where organic vapors are produced and sent to a gasifier to be reformed into a clean fuel gas (Leijenhorst and Van de Beld, 2009). In the top section of the gasifier, the vapors are mixed with (preheated) air to increase the temperature to 800 to 950°C (1470 to 1740°F). The bottom part can be filled with a reforming catalyst to convert remaining tar and ammonia. In the last stage the gas is cooled to ambient temperature. Feedstock throughput is higher than for the fixed bed, but not as high as for the entrained-flow gasifier (Figure 10.1c). The conversion efficiency is low and a recycle operation or subsequent combustion of solids is necessary to increase conversion. Fluidized-bed gasifiers are most useful for fuels that form highly corrosive ash (such as biomass) that would damage the walls of slagging gasifiers.

The fluidized-bed system requires the feedstock to be finely ground and the reactant gases are introduced through a perforated deck near the bottom of the vessel. The volume rate of gas flow is such that its velocity is sufficient to suspend the solids but not high enough to blow them out of the top of the vessel. The result is an active boiling bed of solids having very intimate contact with the upward-flowing gas, which gives a very uniform temperature distribution. The solid flows rapidly and repeatedly from bottom to top and back again, while the gas flows rather uniformly upward. The feedstock in the reactor is said to be completely back-mixed and no countercurrent flow is possible. If a degree of countercurrent flow is desired, two or more fluid-bed stages are placed one above the other. Reaction rates are faster than in the moving bed because of the intimate contact between gas and solids and the increased solids surface area due to the smaller size of the particles.

Compared with the fixed-bed gasifiers, the sequence of reactor processes (drying, pyrolysis, oxidation, and reduction) is not obvious at a certain point of the gasifier since they take place in the entire reactor thus resulting in a more homogeneous type of reaction. This means the existence of more constant and lower temperatures inside the reactor, where no *hot spots* are observed. Due to the lower operating temperatures, ash does not melt and it is more easily removed from the reactor. In addition, sulfur-containing constituents of the feedstock and chlorine-containing constituents of the feedstock can be absorbed in the inert bed material thus eliminating the fouling hazard and reducing the maintenance costs. Another significant difference is that fluidized-bed gasifiers are much less susceptible to biomass quality than fixed-bed systems, and they can even operate with feedstocks composed of mixed biomass types.

One critical advantage of a fluidized-bed gasification system (as opposed to a downdraft or fixed-bed system) is the use of multiple feedstocks without experiencing downtime (Capareda, 2011). Another important characteristic of the fluidized-bed system is the ability to operate at various throughputs without having to use a larger diameter unit. This is accomplished by changing the appropriate bed material. By using a larger bed material, more air flow rate is required for fluidization and thus more biomass may need to be fed at higher rates to maintain the same fuel to air ratio as before. The reactor free-board must then be high enough so that bed materials are not blown out of the system. Also, a fluidized-bed gasification reactor is also designed to be accompanied by a cyclone downstream of the gasifier to capture the larger particles that are entrained out of the reactor as a result of the fluidity of the bed and the velocity of the gas rising though the bed. These particles are recycled back into the reactor.. Overall, the residence time of coal particles in a fluidized-bed gasifier is shorter than that of a moving-bed indirect gasifier.

Uniform bed formation in a fluid-bed reactor is important for efficient bed utilization and consistent operation during gasification of the feedstock. In order to enhance the mixing and uniformity of a bubbling fluid bed, the feedstock is fed to the bed at multiple feed points around the circumference of the reactor vessel. In addition, the fluidization medium, whether air, oxygen, steam, or some combination of these substances, should be uniform in composition and should be introduced in multiple locations. Furthermore, depending on the inflow speed, the fluidized-bed gasifier can be characterized either as a *bubbling fluidized-bed* system or as a *circulating fluidized-bed* system – the circulating fluidized-bed system corresponds to a higher velocity of the gasification medium.

The *bubbling fluid-bed* design is generally more sensitive to bed utilization. The size of the feedstock particles greatly affects the rate of gasification and the ability of the biomass to migrate to the center of the bed in a bubbling fluid-bed design. With small particles, the gasification is very quick, and unburned material might not make it to the center of the bed, resulting in oxygen slip and a void center in the bubbling fluid bed reactor. If all or a majority of the feedstock quickly gasifies, there will be insufficient char to maintain a uniform bed. For this reason, more detail is required in designing the in-feed system with the proper number of in-feed points and controlling and/or monitoring the size particle distribution of the feedstock material. A bubbling fluid bed will generally require additional feed points that must be balanced for larger particle sizes.

The advantages of the bubbling fluidized-bed gasifier are: (i) yields a uniform product gas, (ii) exhibits a nearly uniform temperature distribution throughout the reactor, (iii) able to accept a wide range of fuel particle sizes, including fines, (iv) provides high rates of heat transfer between inert material, fuel and gas, and (v) high conversion possible with low tar and unconverted carbon. The disadvantages of bubbling fluidized-bed gasification are that a large bubble size may result in gas bypass through the bed.

If the gas flow of a bubbling fluidized bed is increased, the gas bubbles become larger forming large voids in the bed and entraining substantial amounts of solids. The bubbles basically disappear in a *circulating fluid bed* in which the turbulent bed solids are collected, separated from the gas, and returned to the bed, forming a solids circulation loop. A circulating fluid bed can be differentiated from a bubbling fluid bed in that there is no distinct separation between the dense solids zone and the dilute solids zone. Lower bed density can be achieved with increase in gas flow rates in excess of transport velocity of the fluidized-bed particles. The residence time of the solids in the circulating fluid bed is determined by the solids circulation rate, attrition of the solids, and the collection efficiency of the solids in the cyclones.

On the other hand, a *circulating fluid-bed* design, operates at a higher velocity and incorporates recycling of the char and bed material, resulting in complete mixing regardless of feedstock size. Generally, the circulating fluid-bed designs are more flexible but are still limited by the amount of fine material (small particle size) that can be processed.

The advantages of the circulating fluidized-bed gasifier are: (i) suitable for rapid reactions, (ii) high heat transport rates possible due to high heat capacity of bed material, and (iii) high conversion rates possible with low tar and unconverted carbon. The disadvantages of the circulating fluidized-bed gasifier are: (i) temperature gradients occur in direction of solid flow, (ii) the size of fuel particles determine minimum transport velocity – high velocities may result in equipment erosion, and (iii) heat exchange is less efficient than bubbling fluidized-bed (Babu, 2006).

A novel reactor design that is particularly appropriate for biomass is the *indirectly heated gasification* technology which utilizes a bed of hot particles (sand), which is fluidized using steam. Solids (sand and char) are separated from the gas product via a cyclone and then transported to a second fluidized-bed reactor. The second bed is air blown and acts as a char combustor, generating a flue gas exhaust stream and a stream of hot particles. The hot (sand) particles are separated from the flue gas and recirculated to the gasifier to provide the heat required for pyrolysis. This approach results in a product gas that is practically nitrogen free and has a heating value of approximately 400 Btu/ft^3) (Turn, 1999).

Another novel design is the new fluidized-bed gasifier with increased gas-solid interaction combining two circulating fluidized-bed reactors (Schmid *et al.*, 2011). The aim of the design is to generate a nitrogen-free product gas with low tar content and low fines (particulate matter) content. The system accomplishes this by division into an air/combustion and a fuel/gasification reactor – the two reactors are interconnected via loop seals to assure the global circulation of bed material.

The fuel/gasification reactor is a circulating fluidized bed but with the special characteristic of almost countercurrent flow conditions for gas phase and solids. The gas velocity and the geometrical properties in the fuel/gasification reactor are chosen in such a way that entrainment of coarse particles is low at the top. Due to the dispersed downward movement of the solids, volatile products are not produced occur in the upper part of the fuel reactor and the issues related to insufficient gas phase conversion and high tar content are avoided.

Finally, the design of fluidized-bed gasification reactor is extremely important (for all of the reasons given above) because both the axial and radial transport of solids within the bed influence gas-solid contact, the thermal gradient, and the heat transfer coefficient. Segregation in a fluidized bed is affected by the particle density, shape, size, superficial gas velocity, mixture composition, bed aspect ratio (the ratio of the static bed height divided by the dynamic or expanded bed height). Variations in the size, shape and density of the fuel particles can cause severe mixing problems which result in changes in temperature gradients within the reactor, increase tar formation and agglomeration, and decrease the conversion efficiency (Cranfield, 1978; Bilbao *et al.*, 1988; Vreugdenhil *et al.*, 2009). Effective mixing of fuels of various sizes is needed to maintain uniform temperature and a good mix depends on the relative concentrations of the solids in the bed and the velocity of the gas (Bilbao *et al.*, 1988; Ghaly *et al.*, 1989).

Some char particles may be entrained in the raw as its leaves the top of the gasifier, but are recovered and recycled back to the reactor via a cyclone. Ash particles, removed below the bed, give up heat to the incoming steam and recycle gas. At startup, the bed is heated externally before the feedstock is introduced.

10.4.1 Agglomerating Burner Process

In the Agglomerating Burner process (Figure 10.7), coal is crushed and separated into two sizes: -100 mesh and -8+100 mesh. Caking coal in the -8+100-mesh range is fed to a fluidized bed pre-treater, where it is mixed with gas and air at atmospheric pressure and 400°C (750°F) after which it is cooled, charged to the gasifier, and reacted with steam in the fluidized bed. The 100-mesh coal is burned with air in a fluidized-bed combustor in a manner allowing agglomeration of the ash at a temperature approaching the ash fusion point (1150°C; 2100°F).

The hot ash agglomerates are transferred continuously from burner to gasifier and coal is fed through lock hoppers and is conveyed by inert gas to the gasifier. Hot agglomerated ash flows downward and transfers a portion of its sensible heat to support the coal gasification reactions. Product gas from the gasifier is sent to the gas cleanup section. Most of the agglomerated ash is recycled to the burner for reheating, but ash equivalent to the ash content of the coal fed to the burner is removed from the system continuously to maintain a constant quantity of ash agglomerates in the cycle.

10.4.2 Carbon Dioxide Acceptor Process

In the Carbon Dioxide Acceptor process (Nowacki, 1980; Speight, 2013, 2020a, 2020b) (Figure 10.8), coal is first crushed to 8 x 100 mesh in hot-gas-swept impact mills in which the moisture content is reduced from ca. 38% w/w to ca. 16% w/w. The coal is further

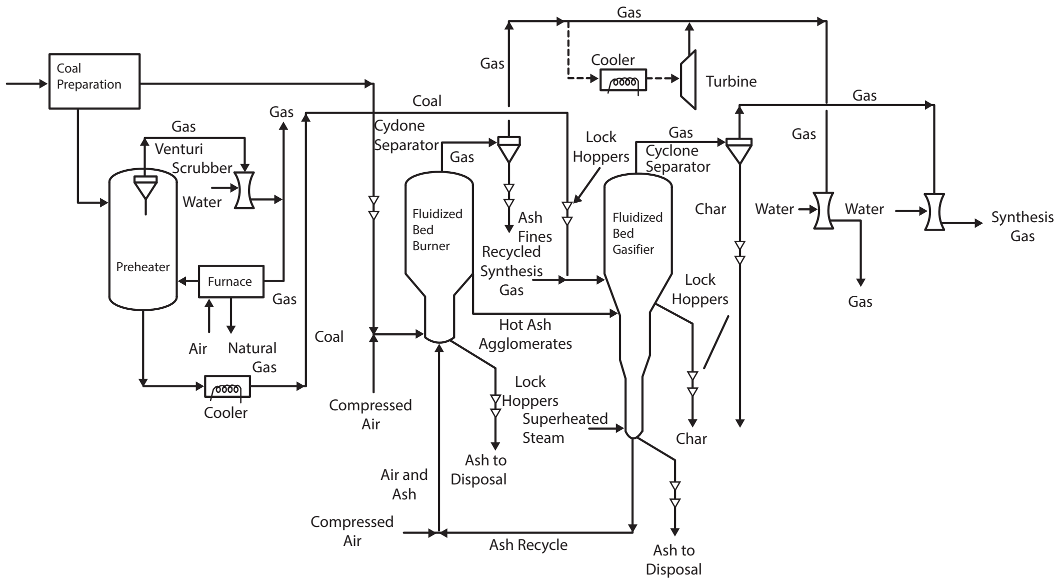

Figure 10.7 The agglomerating burner process.

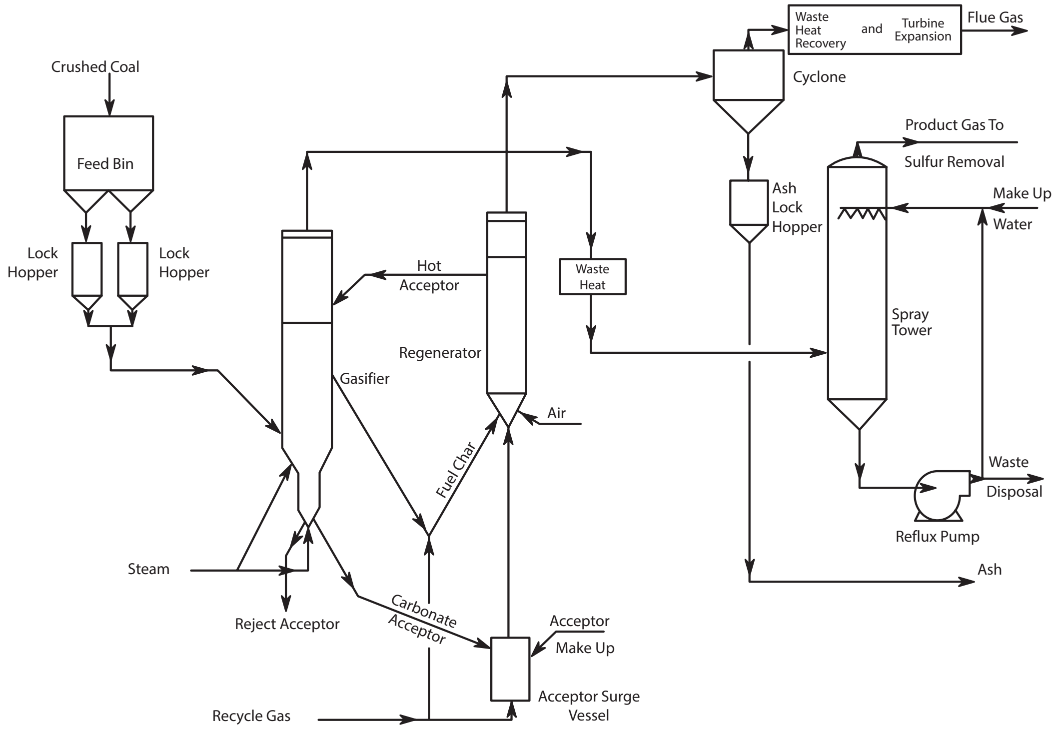

Figure 10.8 The carbon dioxide acceptor process.

dried to 0.5% w/w moisture in flash dryers and is then conveyed to fluidized-bed preheaters where the temperature is increased to approximately 260°C (500°F).

The coal is fed to the gasifier, entering near the bottom of a fluidized bed of char whereupon rapid devolatilization occurs, followed by the gasification of the fixed carbon with steam. The temperature in the gasifier ranges from 805 to 845°C (1480 to 1550°F). Heat for the gasification reactions is supplied by a circulating stream of lime-bearing material ("acceptor"), usually limestone or dolomite, which supplies the necessary heat through the exothermic carbon-dioxide acceptor reaction.

$$\mathrm{CaO} + \mathrm{CO_2} \rightarrow \mathrm{CaCO_3} + \text{heat}$$

This acceptor, having been crushed to 6 x 14 mesh, enters the gasifier above the fluidized char bed, showers through the bed, and is collected in the gasifier base. Steam for hydrogasification enters the gasifier through a distributor ring in the base. Product gas from the gasifier passes through a steam-generating heat exchanger and then passes to a gas cleanup section.

Spent acceptor leaving the gasifier is calcined in a regenerator vessel at approximately 1010°C (1850°F), at which temperature the carbon dioxide acceptor reaction is reversed; the calcined acceptor is then returned to the gasifier.

Both the product gas from the gasifier and the flue gas from the regenerator are quenched and purified. The flue gas is either recycled to the regenerator or flared whereas the product gas is sent to the methanation section.

The methanation facilities, which convert the low heat-content synthesis gas into a high heat-content product, include a shift converter, carbon dioxide absorber, hydrodesulfurizing unit, zinc oxide (ZnO) sulfur guard, and a packed-tube methanation unit.

10.4.3 Coalcon Process

In the Coalcon process (Hydrocarbonization process) (Figure 10.9) coal is first crushed, milled, and fed to the coal-preheating unit where the coal is entrained in a hot, oxygen-free flue gas which helps maintain the reactor heat efficiency and also drives off some volatiles and moisture. After heating to approximately 325°C (620°F), the coal is held in the coal feed hopper before it is pressurized to the operating pressure of the system (approximately 550 psi). The coal is then dropped from the lock hoppers into another coal holding vessel from whence it is fed into an injection vessel where it is fluidized with hydrogen at 560°C (1040°F) and 750 psi.

This mixture enters the reactor and the solids which are not gasified are removed from the reactor through the bottom of the reactor vessel. This char product may either be used to generate hydrogen or be burned to generate steam.

The gas passing upward through the reactor "carries" fines which are subsequently removed by two cyclones. The gas from the cyclones is then sent to a fractionator for cooling and separation. Four streams are produced by the fractionator for cooling and separation: (i) overhead gas (hydrogen, carbon monoxide, carbon dioxide, methane, (ii) low-boiling liquids, (iii) high-boiling liquids, and (iv) wastewater.

The high-boiling oil product is cooled to approximately 40°C (l05°F) and pumped to storage. The overhead product is condensed and fed to a decanter where the low-boiling fuel oil, overhead gas, and wastewater are separated. Some of the low-boiling fuel oil is sent

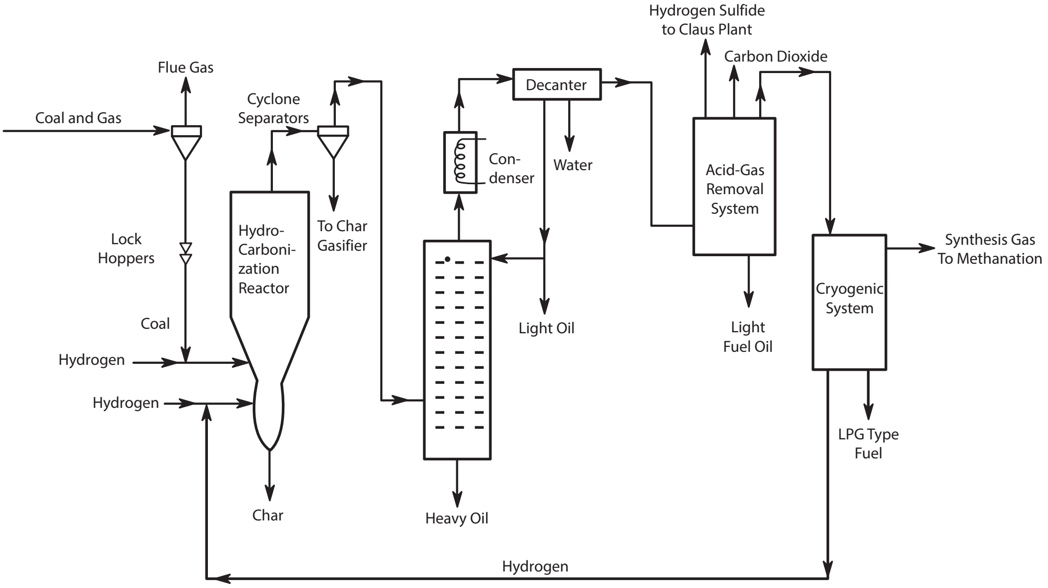

Figure 10.9 The Coalcon process.

to the fractionator as reflux and the remainder is sent to storage as product. The remaining gas is treated in a series of separation and purification systems which include ammonia removal and recovery, acid gas removal, and a cryogenic gas processing system; the latter system manufactures fuel gas, synthesis gas, and a hydrogen-rich gas stream. The hydrogen stream is recycled to the reactor while the synthesis gas is sent to a methanation reactor for upgrading to high heat-content pipeline gas.

10.4.4 The COED/COGAS Process

The COED/COGAS process (Figure 10.10) involves the flow of coal through four fluidized-bed pyrolysis stages, each operating at a higher temperature than the preceding unit, and the temperatures of the stages are selected to be just below the maximum temperature to which the particular feed coal can be heated without agglomerating.

The optimum stage temperatures (and even the number of stages) vary depending on the properties of the feed coal. Typical operating temperatures are 315 to 345°C (600 to 650°F) in the first stage, 425 to 455°C (800 to 850°F) in the second stage, 540°C (1000°F) in the third stage, and 870°C (1600°F) in the fourth stage.

Heat for the process is provided by burning a portion of the product char with oxygen in the presence of steam in the fourth stage. Hot gases from this stage flow countercurrent to the char and provide the hot fluidizing medium for the intermediate pyrolysis stages. The gases leaving both the first and second stages are passed to cyclones which remove the fines, but the vapors leaving the cyclones need to be quenched in a Venturi scrubber to condense the oil, and the gases and oil are separated in a decanter. The gas is desulfurized and then steam-reformed to yield hydrogen and fuel gas; the hydrogen is returned to the process.

The oil from the decanter is dehydrated, filtered, and hydrotreated to remove nitrogen, sulfur, and oxygen (forming ammonia, hydrogen sulfide, and water, respectively) to form a

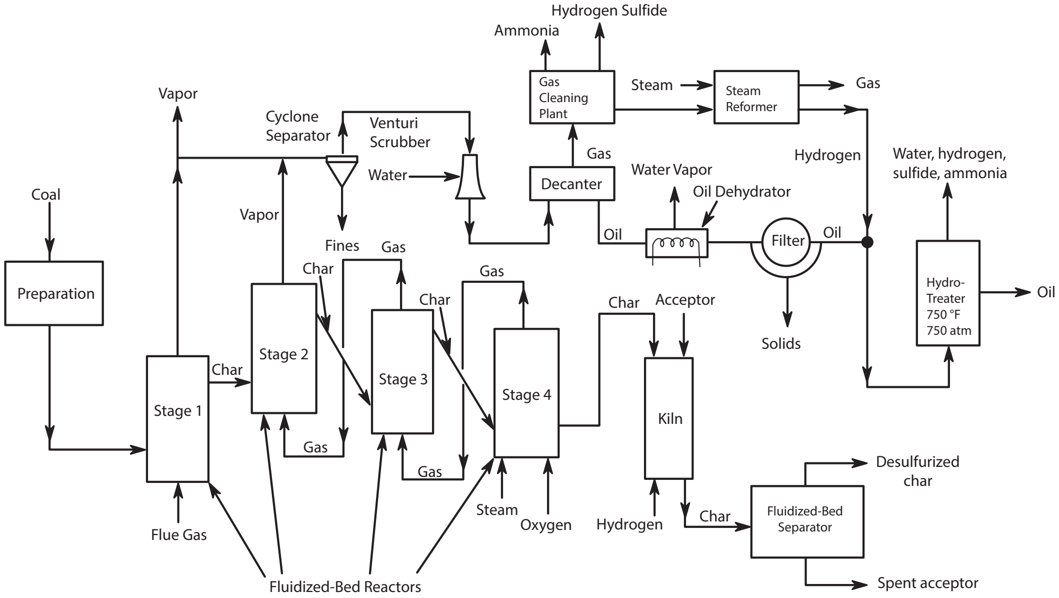

Figure 10.10 The COED/COGAS process.

high-boiling synthetic crude oil (ca. 25o API). The char produced by the process is desulfurized in a shift kiln, where hydrogen is treated with the char to produce hydrogen sulfide which is then absorbed by an acceptor, such as limestone or dolomite.

The COGAS process involves the gasification of the COED char to produce a synthesis gas composed of carbon monoxide and hydrogen. The heat for the char gasification reaction is provided by the combustion of part of the char.

10.4.5 Exxon Catalytic Gasification Process

The Exxon catalytic gasification process is based on the concept that alkali metal salts (such as potassium carbonate, sodium carbonate, potassium sulfide, sodium sulfide, and the like) will catalyze the steam gasification of coal. In addition, tests with potassium carbonate showed that this material also acts as a catalyst for the methanation reaction.

Thus, in this process (Figure 10.11), crushed (-8 mesh) coal is treated with an aqueous solution of the catalyst after which the feed is dried and charged (through a system of lock hoppers) to the fluidized-bed gasifier at 700°C (1300°F) and 500 psi.

The bed is fluidized by a mixture of steam and recycled carbon monoxide-hydrogen. Unreacted steam is condensed and the acid gases (carbon dioxide, hydrogen sulfide) are removed by conventional acid gas treatment. The product (methane) is separated from the carbon monoxide and hydrogen by a cryogenic process. The solid product (which is actually a mixture of char, coal minerals, and the catalyst) is removed on a continuous basis; the majority of the catalyst is recovered and recycled.

10.4.6 The Hydrane Process

In the Hydrane process, more than 90% of the methane produced is generated within the gasifier (Figure 10.12), thus minimizing the necessity for subsequent catalytic methanation

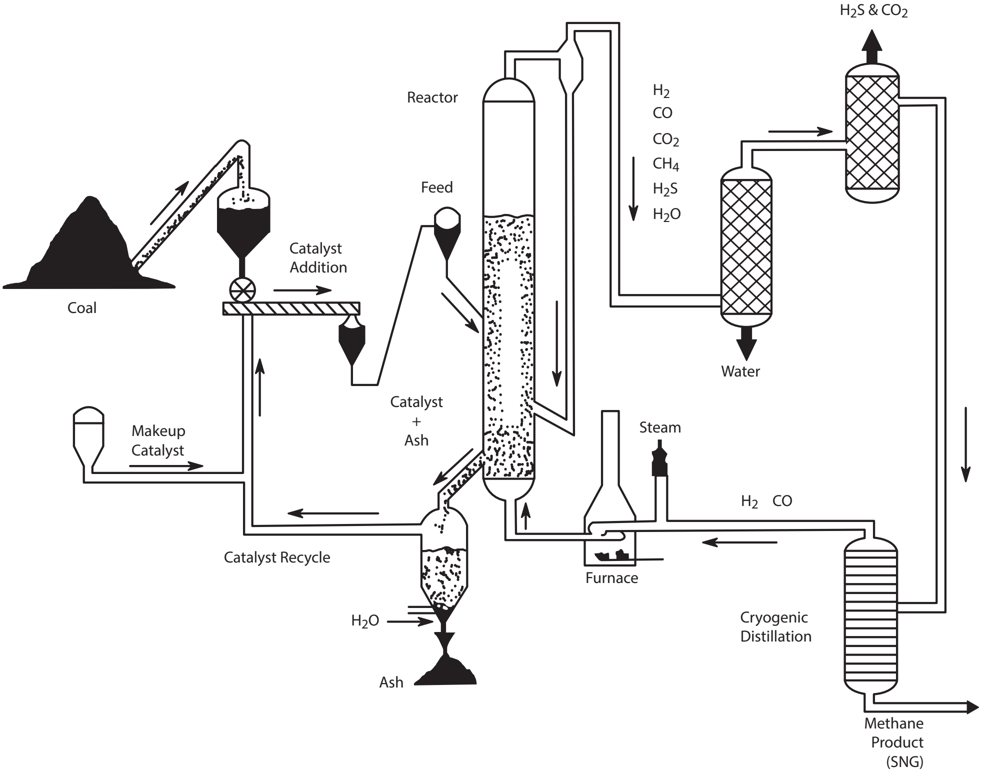

Figure 10.11 The Exxon Catalytic Gasification process.

processes (Howard-Smith and Werner, 1976). Coal enters the gasifier and falls through a countercurrently flowing stream of hot gases rising from the second stage fluidized bed, therefore allowing agglomerating coals to be hydrogasified (any agglomerating properties are usually destroyed during the free-fall preheating step). The preheated solids then enter the second zone (consisting of a bed fluidized by hydrogen) which permits maximum coal conversion without cracking the methane product to carbon.

The product gas requires purification and methanation so that the final product meets pipeline specifications. The char from the gasifier may be either completely consumed in synthesis gas production or it may be used for power production.

10.4.7 The Hygas Process

The Hygas process involves the direct hydrogasification of coal in the presence of pressurized hydrogen and steam in two stages (Nowacki, 1980). Crushed coal (minus 14 mesh) is slurried with an aromatic recycle oil to form a slurry which is pressurized to approximately 100 psi and injected into the top section of the gasifier (Figure 10.13) which contains a fluidized bed of hot coal particles. If the coal is a caking coal, it is pretreated in a fluidized bed at 400 to 455°C (750 to 810°F) and at atmospheric pressure to destroy the caking tendencies. The slurry oil is vaporized and removed together with the hot gases passing upward from the lower reactor stages; the vaporized oil is subsequently recovered for reuse.

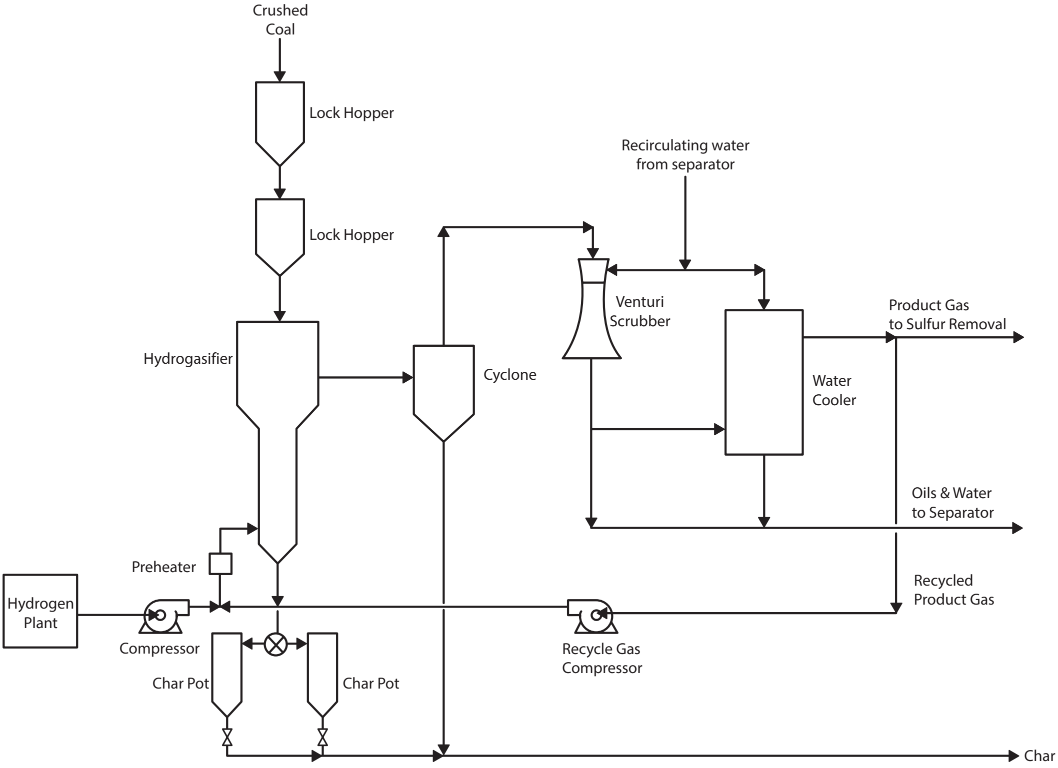

Figure 10.12 The Hydrane process.

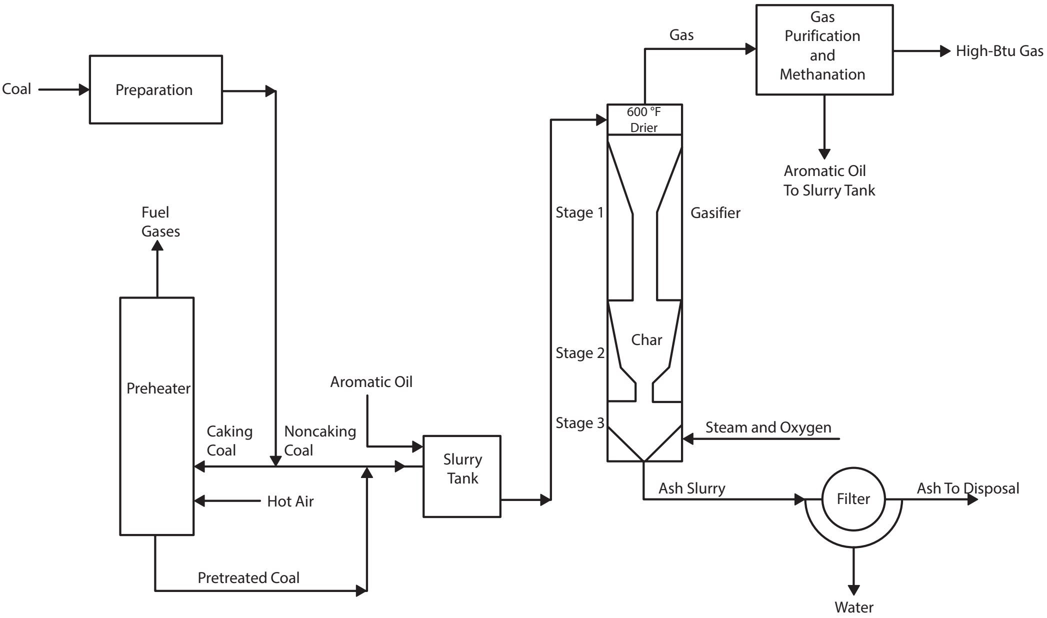

Figure 10.13 The Hygas process.

The dry coal particles flow into a lift pipe which serves as the first stage of hydrogasification. In the pipe, the coal is contacted with hot gas (methane, carbon oxides, hydrogen, and steam) from the lower sections of the reactor and the coal reacts with the hydrogen, forming additional methane (ca. 33% of the methane in the final product is produced in this section).

In the second stage, partially converted coal is contacted with hydrogen-rich gas at 760 to 925°C (1400 to 1700°F) where a further 33% of the methane in the final product is generated. The hot residual char is then transferred to the third stage where it reacts with steam and oxygen in a fluidized bed to yield a mixture of hydrogen-rich gases. The gaseous product from this stage passes upward through the reactor while Me ash is removed from the bottom of the steam-oxygen zone. The gas leaving the reactor is cooled and rinsed in a water quench before being purified, shifted, and methanated. Following methanation, the product gas has a heat content of ca. 930-950 Btu/ft (34.7-35.4 MJ/ft).

10.4.8 Pressurized Fluid-Bed Process

In the pressurized fluid-bed process (Figure 10.14), coal is crushed to -6+100 mesh, dried, and transported to a reactor vessel for devolatilization desulfurization and partial hydrogasification (Speight, 2013, 2020a, 2020b).

A central draft tube is used primarily for recirculating solids, and the dense, dry char collects in the fluidized bed at the top of the draft tube and is withdrawn at this point. Dolomite or calcium oxide (sorbent) is added to the fluidized bed to absorb the sulfur present as hydrogen sulfide in the fuel gas and spent sorbent is withdrawn from the bottom of the reactor and regenerated. The heat for devolatilization is supplied primarily by the high-temperature fuel gas produced in the gasifier combustor. After separation of fines and ash, product gas is cooled and scrubbed with water for final purification.

Final gasification occurs in a fluid-bed gasifier-combustor; char from the devolatilizer-desulfurizer is burned with air in the lower section of the gasifier at 1040 to 1095°C (1900 to 2000°F) to provide the heat for gasification. Heat is transported from the combustor to

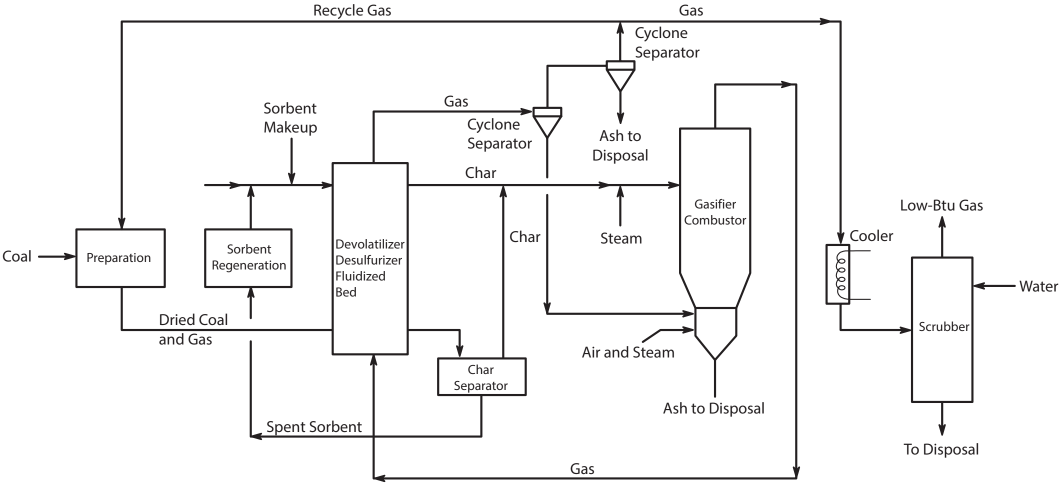

Figure 10.14 The Pressurized Fluid Bed.

the gasifier by combustion gases flowing upward and by fines that escape upward and are trapped and recycled to the space between the combustor and gasifier. Ash from the combustion of fines agglomerates on the ash from the char and segregates in the lower section for removal.

10.4.9 Synthane Process

The Synthane process (Figure 10.15) was developed as a result of investigations dealing with the pretreatment of caking coals when it was noted that the proper combination of (i) oxygen content of the fluidizing gas, (ii) temperature, and (iii) residence time made possible the pretreatment of caking coals. Additional work later showed that pretreatment, carbonization, and gasification were all possible within a single vessel (Speight, 2013, 2020a, 2020b).

The Synthane gasifier itself is a vertical, cylindrical, fluidized-bed reactor which operates at approximately 100 psi and up to 980°C (1800°F).

Coal (crushed to -20 mesh) is dried and then pressurized to approximately 1000 psi. Caking coals are then fed to a fluidized bed pre-treater by high-pressure steam and oxygen to provide a mild oxidation of the coal particles to minimize agglomeration in the gasifier. The coal then overflows from the top of the pre-treater into the top of the fluidized-bed gasifier and falls through the hot gases rising from the fluidized bed and is devolatilized. Steam and oxygen enter the gasifier just below the fluidizing gas distributor and gasification reaction occurs within the fluidized bed. Unreacted char flows downward into a bed fluidized

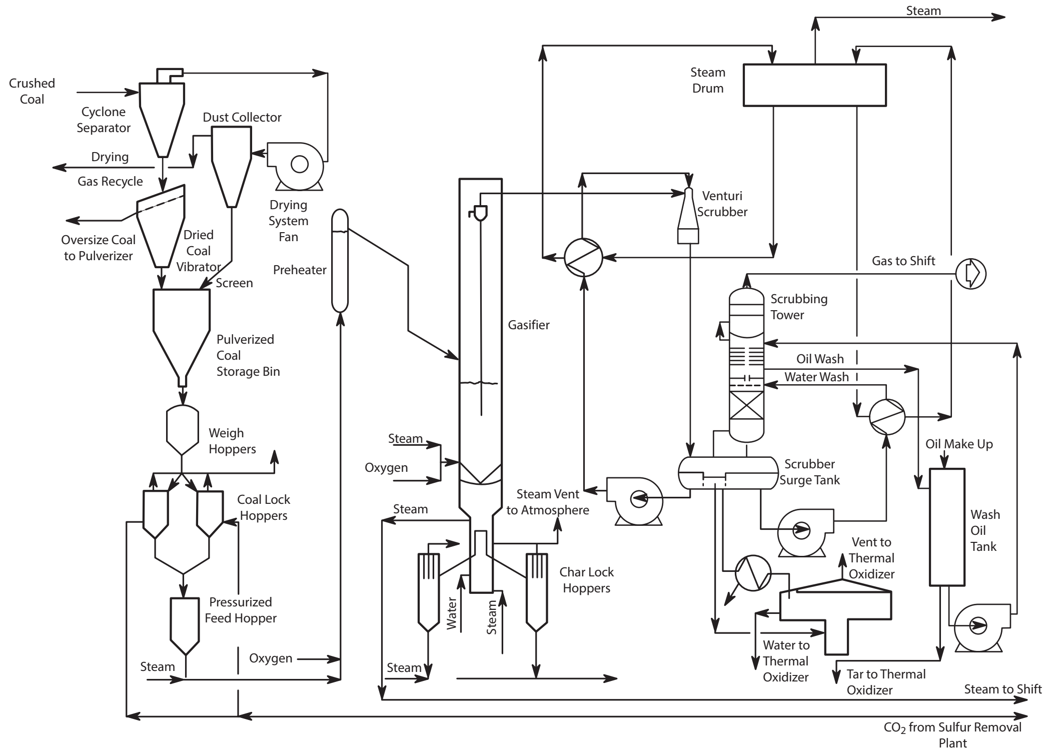

Figure 10.15 The Synthane process.

and cooled with steam and is removed through lock hoppers; the char can then be burned to produce process steam.

The product gas, containing methane, hydrogen, carbon monoxide, carbon dioxide, and ethane, is passed through a Venturi scrubber and a water scrubber to remove carryover ash, char, and tars. Acid gas impurities are absorbed in a hot potassium carbonate scrubber and any remaining traces of sulfur in the product gas are removed by passing the gas through activated charcoal.

10.4.10 The U-Gas Process

The U-Gas reactor (Figure 10.16) is a vertical vessel containing an internal cyclone for returning elutriated fines to the bed. A sloped grid at the bottom of the vessel serves as both an ash outlet and a steam/air distributor.

The feed coal is first crushed to -14 mesh and (lignite, or noncaking subbituminous coals) fed to the gasifier. However, caking coals must first be pretreated by contact with air in a fluidized-bed reactor operating at gasifier pressure and approximately 370 to 425°C (700 to

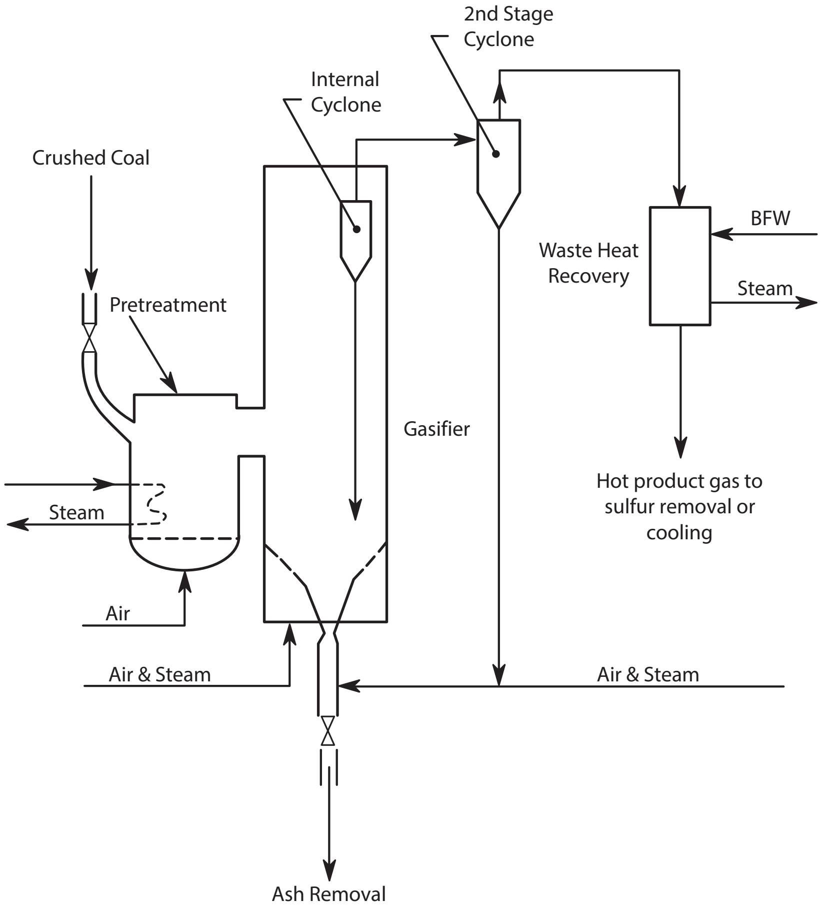

Figure 10.16 The U-Gas process.

800°F) to prevent agglomeration in the gasifier. The coal is then gasified with a mixture of air and steam in a single fluidized bed at 50 to 350 psi and 1040°C (1900°F).

The gases leaving the pre-treater and gasifier are passed through heat exchangers to recover the sensible heat and are treated to remove the sulfur compounds. With air-blown operation, the product gas typically has a heat content of ca. 155 Btu/ft whereas if the gasifier is oxygen-blown, the product gas may have a heat content of ca. 300 Btu/ft^3.

10.4.11 Winkler Process

In the Winkler process dried, crushed coal (-8 mesh) is fed to the fluidized-bed gasifier (Figure 10.17) through a variable-speed screw feeder whereupon the coal is contacted with steam and oxygen injected near the bottom of the vessel (Howard-Smith and Werner, 1976; Baughman, 1978). The upward flow of steam and oxygen maintains the bed in a fluidized state at a temperature of 815 to 980°C (1600 to 1800°F) with a pressure that is marginally higher than atmospheric. The high operating temperature reduces the amount of tars and other high-boiling hydrocarbon derivatives in the product (Nowacki, 1980).

Approximately 70% of the coal ash is carried over the gas flow and 30% is removed from the bottom of the vessel by screw conveyors. Unreacted carbon contained in the carryover ash is consumed by the injection of supplemental steam and oxygen in the space above the bed. To moderate the bed temperature and thereby minimize ash melting, a heat exchange

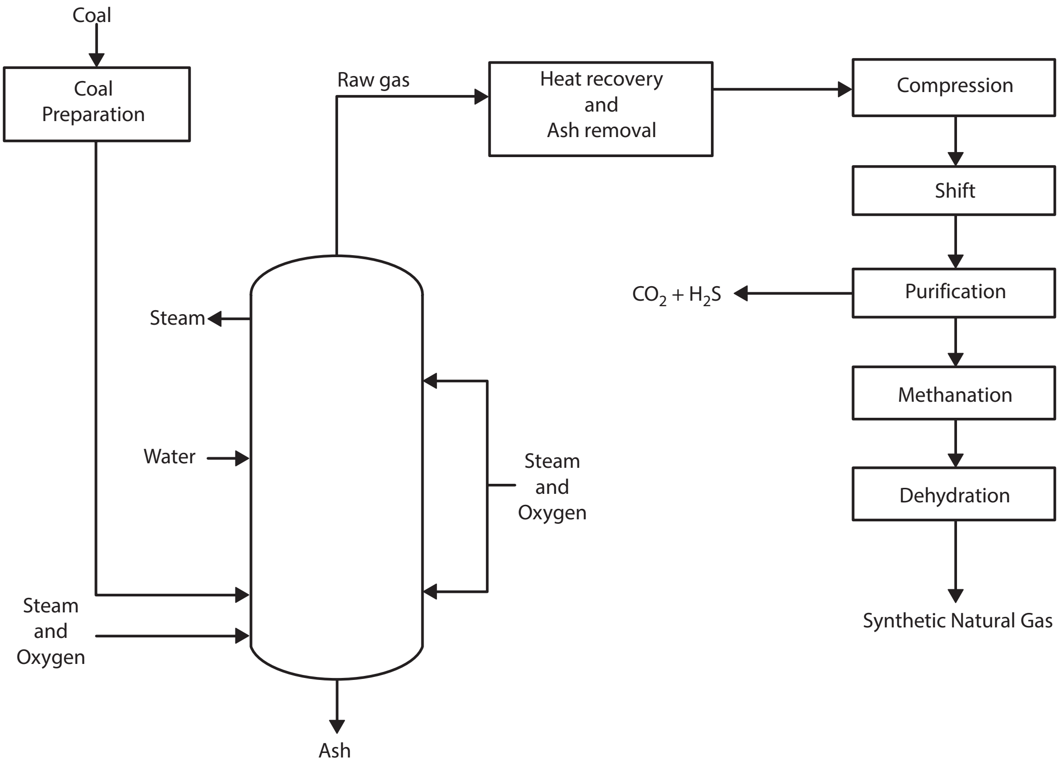

Figure 10.17 The Winkler process.

surface is provided in the dilute phase to remove heat and generate steam. The raw gas leaving the gasifier, rich in carbon monoxide and hydrogen, is cooled to approximately 705°C (1300°F) in a boiler and then passes through (i) a heat exchanger to superheat steam, (ii) a waste heat boiler, and (iii) a cyclone to remove entrained char. Further gas cleanup is effected by wet scrubbers, electrostatic precipitators, and sulfur removal equipment.

10.5 Entrained-Bed Processes

An entrained-bed system (entrained-flow system) uses finely sized feedstock particles blown into the gas steam prior to entry into the reactor and combustion occurs with the feedstock particles suspended in the gas phase (Figure 10.1c). The entrained system is suitable for both caking and noncaking coals.

In the process, the finely crushed and the oxidant (air or oxygen) and/or steam are fed co-currently to the gasifier. This results in the oxidant and steam surrounding or entraining the coal particles as they flow through the gasifier in a dense cloud. The feedstock can be fed to the gasifier in either a dry form or a slurry form. The former (dry form) uses a lock hopper system, while the latter (slurry form) relies on the use of high-pressure slurry pumps. The slurry feed is a simpler operation, but it introduces water into the reactor which needs to be evaporated. The result of this additional water is a product synthesis gas with higher hydrogen to carbon monoxide ratio, but with a lower gasifier thermal efficiency.

Entrained-flow gasifiers operate at high temperature and pressure (and extremely turbulent flow) which causes rapid conversion of the feedstock and allows a high throughput. The gasification reactions occur at a high rate (typical residence time is on the order of few seconds), with high carbon conversion efficiencies (98 to 99.5%). The tar, oil, phenols, and other liquids produced from devolatilization of coal inside the gasifier are decomposed into hydrogen (H_2), carbon monoxide (CO) and small amounts of light hydrocarbon gases. Entrained-bed gasifiers have the ability to handle practically any coal feedstock and produce a clean, tar-free synthesis gas. Given the high operating temperatures, gasifiers of this type melt the mineral matter (in the feedstock) ash into a vitreous inert slag.

In the *entrained-flow gasifier* (*entrained-bed gasifier*) a dry pulverized solid, an atomized liquid fuel or a fuel slurry is gasified with oxygen (much less frequent: air) in co-current flow and the gasification reactions take place in a dense cloud of fine particles. The high temperatures and pressures also mean that a higher throughput can be achieved; however, thermal efficiency is somewhat lower as the gas must be cooled before it can be cleaned with existing technology. The high temperatures also mean that tar and methane are not present in the product gas; however, the oxygen requirement is higher than for the other types of gasifiers.

The entrained-flow reactor requires a smaller particle size of the feedstock than the fluid-bed gasifier so that the feedstock can be conveyed pneumatically by the reactant gases. Velocity of the mixture must be approximately 20 ft/sec (6.1 m/sec) or higher depending upon the fineness of the feedstock. In this case, there is little or no mixing of the solids and gases, except when the gas initially meets the solids. Furthermore, apart from higher temperature, entrained-flow gasification usually takes place at elevated pressure (pressurized entrained-flow gasifiers) reaching operating pressures even up to 750 psi. The existence of such high temperatures and pressures requires more sophisticated reactor design and construction materials used.

The design of an entrained-flow reactor gives a residence time of the feedstock in the reaction zone to be on the order of seconds, or tens of seconds. This short residence time requires that entrained-flow gasifiers operate at high temperatures to achieve high carbon conversion. Consequently, most entrained-flow gasifiers are designed to use oxygen rather than air and also to operate above the slagging temperature of the feedstock mineral matter.

The entrained-flow reactor requires a smaller particle size of the feedstock than the fluid-bed gasifier so that the feedstock can be conveyed pneumatically by the reactant gases – typically the fuel must be pulverized. In this case, there is little or no mixing of the solids and gases, except when the gas initially meets the solids. Furthermore, apart from the higher temperature, entrained-flow gasification usually takes place at elevated pressure (pressurized entrained-flow gasifiers) reaching operating pressures even up to 750 psi. The existence of such high temperatures and pressures requires more sophisticated reactor design and construction materials used.

All entrained-flow gasifiers are designed to remove a major part of the ash as a slag as the operating temperature is well above the ash fusion temperature. A smaller fraction of the ash is produced either as a fine dry fly ash or as black colored fly ash slurry. Some fuels, in particular certain types of biomass, can form slag that is corrosive for ceramic inner walls that serve to protect the gasifier outer wall. However, some entrained-bed type of gasifiers do not possess a ceramic inner wall but have an inner water or steam cooled wall covered with partially solidified slag. For fuel that produces ash with a high ash fusion temperature, limestone can be mixed with the fuel prior to gasification in order to lower the ash fusion temperature. Typically, the fuel particles must be smaller than for other types of gasifier – the fuel must be pulverized.

10.5.1 Bi-Gas Process

The Bi-Gas process (Figure 10.18) is a two-stage, high-pressure, oxygen-blown slagging system using pulverized coal in an entrained flow (Speight, 2013, 2020a, 2020b). The coal is pulverized so that 70% passes through 200-mesh, is mixed with water, and is then fed to a cyclone where the solids are concentrated into a slurry. This slurry is concentrated in a thickener and centrifuged, re-pulped, and mixed with flux to produce the desired consistency. The blended slurry is transported at high pressure to a steam preheater where it is contacted with hot recycle gas in a spray drier which nearly instantaneously vaporizes the surface moisture. The coal is then conveyed to a cyclone at the top of the gasifier vessel by a stream of water vapor and inert recycle gas, as well as additional recycled gas from the methanator.

The coal is separated from the recycle gas in the cyclone and the coal flows by gravity into the gasifier through injector nozzles near the throat which separates the stages. Steam is injected through a separate annulus in the injector and the two streams combine at the injector tip and mix with hot synthesis gas (from stage l). A mixing temperature of approximately 1205°C (2200°F) is rapidly attained and the coal is decomposed to produce methane, synthesis gas, and char. The raw gas and char rise (through stage 2) and leave the vessel (at approximately 925°C; 1700°F) and are quenched to 425°C (800°F) by atomized water prior to separation in a cyclone.

The char is recycled to the gasifier and the synthesis gas passes through a scrubber for additional cooling and purification. The clean gas is then sent to a shift converter to adjust the ratio of carbon monoxide to hydrogen. After shift conversion, the gas is improved by (i) hydrogen sulfide removal, (ii) carbon dioxide removal, and (iii) methanation.

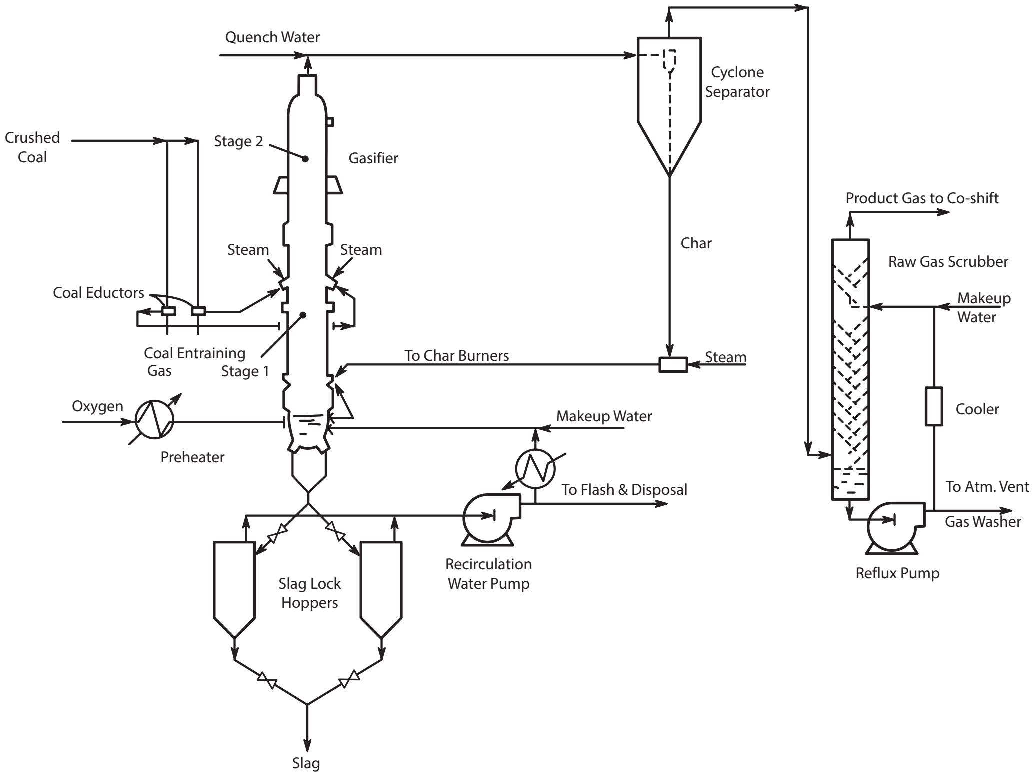

Figure 10.18 The Bi-Gas process.

10.5.2 Combustion Engineering Process

The combustion engineering process (Figure 10.19) is based on an air-blown, atmospheric pressure, entrained-bed slagging gasifier and in the process part of the coal char is charged to the combustion section of the gasifier to supply the heat necessary for the endothermic gasification reaction (Probstein and Hickes, 1990; Speight, 2013, 2020a, 2020b).

In the combustion section, substantially all of the ash in the system is converted to molten slag, which is removed via the bottom of the gasifier. The remainder of the coal is fed to the reaction section of the gasifier where it is contacted with hot gases entering the reaction zone from the combustor. The gasification process takes place in the entrainment section of the reactor where the coal is devolatilized and reacts with the hot gases to produce the desired product gas.

The gas contains solid particles and hydrogen sulfide; the former are removed and recycled to the combustor by means of a spray drier, cyclone separators, and Venturi scrubbers and the hydrogen sulfide is removed and elemental sulfur produced by the Stretford process.

10.5.3 Koppers-Totzek Process

The Koppers-Totzek process (Baughman, 1978; Speight, 2013, 2020a, 2020b) is an entrained-solids process which operates at atmospheric pressure. The reactor (Figure 10.20)

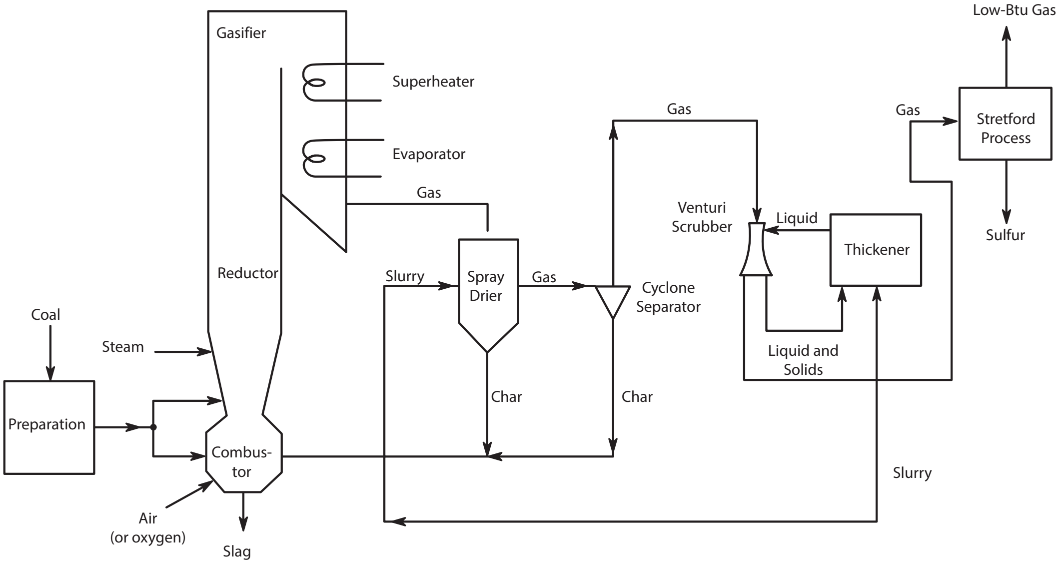

Figure 10.19 The Combustion Engineering process.

is a relatively small, cylindrical, refractory-lined coal "burner" into which coal, oxygen, and steam are charged through at least two burner heads.

The feed coal for the process is crushed (so that 70% will pass through a 200-mesh screen), mixed with oxygen and low-pressure steam, and injected into the gasifier through a burner head. The heads are spaced 180 or 90° apart (representing two-headed or four-headed opposed burner arrangements) and are designed such that steam envelopes the flame and protects the reactor walls from excessive heat.

The reactor typically operates at an exit temperature of approximately 1480°C (2700°F) and the pressure is maintained just slightly above atmospheric. Only approximately 85 to 90% w/w of the total carbon may be gasified in a single pass through the gasifier because carbon conversion is a function of the reactivity of the coal and approaches 100% for lignite.

The heat in the reactor causes the formation of slag from mineral ash and this is removed from the bottom of the gasifier through a water seal. Gases and vaporized hydrocarbon derivatives produced by the coal at medium temperatures immediately pass through a zone of very high temperature in which they decompose so rapidly that coal particles in the plastic stage do not agglomerate, and thus any type of coal can be gasified irrespective of caking tendencies, ash content, or ash fusion temperature.

In addition, the high operating temperature ensures that the gas product contains no ammonia, tars, phenols, or condensable hydrocarbon derivatives. The raw gas can be upgraded to synthesis gas by reacting all or part of the carbon monoxide content with steam to produce additional hydrogen plus carbon dioxide.

10.5.4 Texaco Process

Texaco process (Figure 10.21) gasifies coal under high pressure in an entrained bed by the injection of oxygen (or air) and steam with concurrent gas/solid flow (Probstein and Hicks, 1990). The coal is crushed in a two-stage system (the second step performed under an

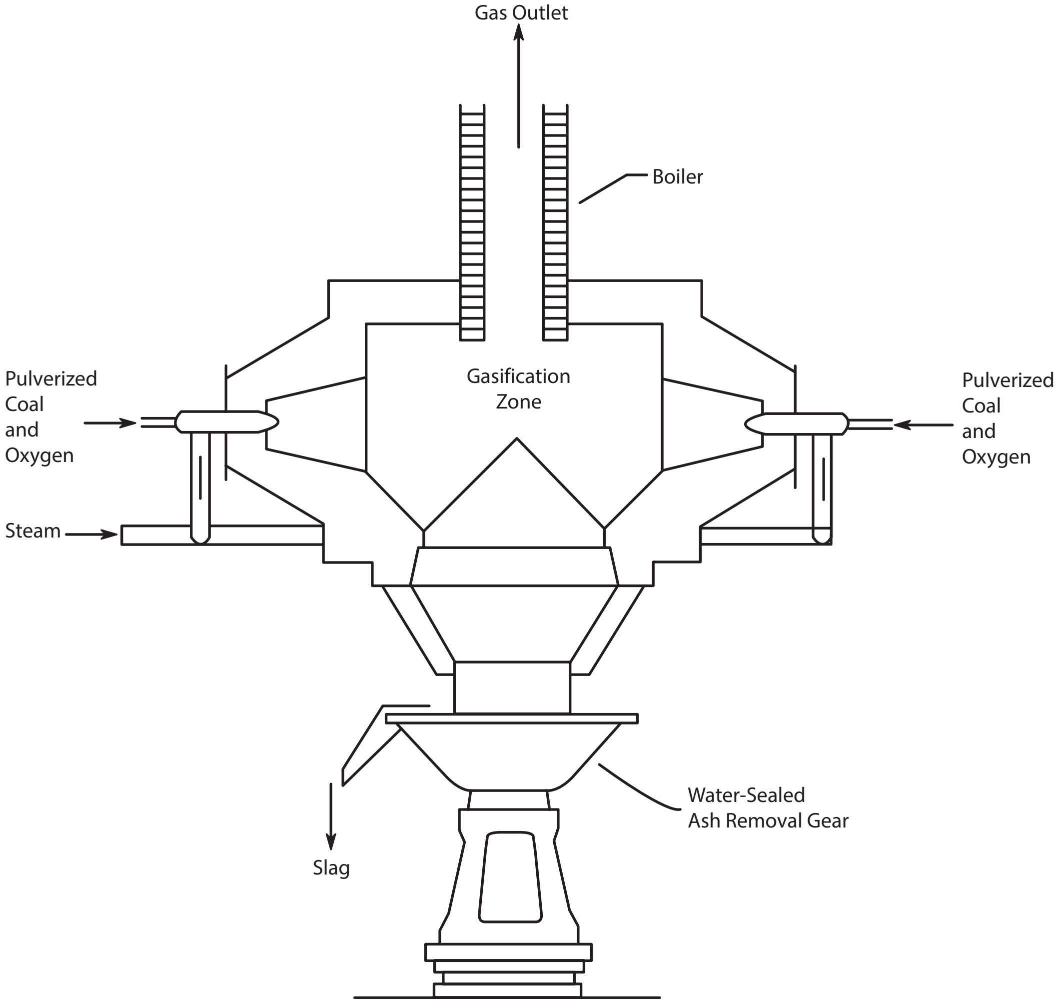

Figure 10.20 A Koppers-Totzek Gasifier.

inert atmosphere) and is then mixed with water or oil to form a pumpable slurry which is pumped under pressure into the gasifier vessel (a refractory-lined chamber inside a pressure vessel). In this unit, the slurry reacts with either air or oxygen at high temperature; the product gas from the reactor contains primarily carbon monoxide and hydrogen, but may contain appreciable quantities of nitrogen if the reactor is air-blown. Oils or tars are not usually produced by the process and methane is the only hydrocarbon gas generated.

The product gases and molten slag produced in the reaction zone pass downward through a water spray chamber and a slag quench bath and the cooled gas and slag are then removed for further treatment. In most cases the gas leaving the quench unit, once it is separated from the slag, is treated to remove the carbon fines and ash. The gas is then subsequently recycled to the slurry preparation system, treated for acid gas removal and elemental sulfur is recovered from the hydrogen sulfide-rich stream. Texaco has also modified the partial oxidation, which is used to gasify crude oil, to gasify coal; the effluent gas stream has little, or no, hydrocarbon content (Cornilis *et al.*, 1981).

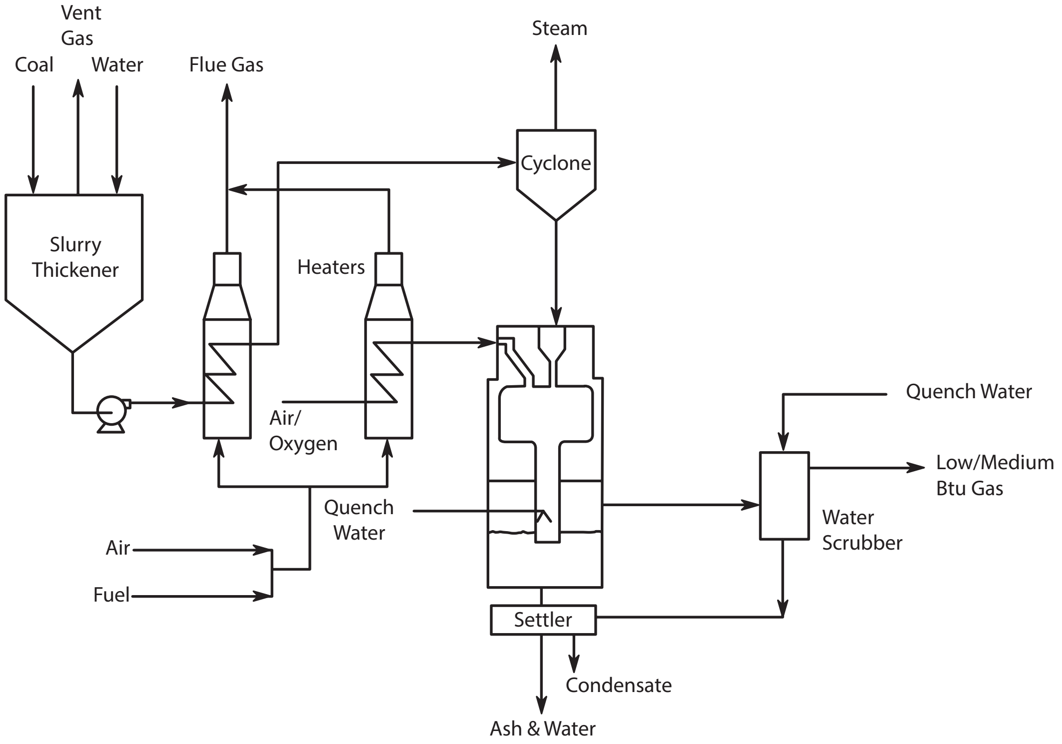

Figure 10.21 Texaco process.

10.6 Molten Salt Processes

The molten salt gasifier (molten metal gasifier) use, as the name implies, is a molten medium of an inorganic salt (or molten metal) to generate the heat to decompose the feedstock into products, and there are a number of applications of the molten bath gasification. A number of different designs have evolved through various stages of development but the basic concept is that instead of using a formed gasifying chamber where the reactions occur in suspension, the feedstocks are gasified in a molten bath of salt or metal. This type of design allows for more complete processing of the feedstock and also allows for a greater variety of feedstocks to be efficiently processed in the same gasifier.

High temperatures are required to maintain the bath molten – approximately 900°C, 1650°F and above, depending on the nature of the melt. Such temperature levels favor high reaction rates and throughputs and low residence times. Consequently, tar and volatile oil products are not produced in any great quantity, if at all. Gasification may be enhanced by the catalytic properties of the melt used. Molten salts, which are generally less corrosive and have lower melting points than molten metals, can strongly catalyze the steam-coal reaction and lead to high conversion efficiencies.

In molten bath gasifiers, crushed feedstock, steam air and/or oxygen are injected into a bath of molten salt, iron, or feedstock ash. The feedstock appears to *dissolve* in the melt where the volatiles crack and are converted into carbon monoxide and hydrogen. The feedstocks carbon reacts with oxygen and steam to produce carbon monoxide and hydrogen. Unreacted carbon and mineral ash float on the surface from which they are discharged.

In the process, the carbonaceous feedstock devolatilizes with some thermal cracking of the volatile constituents leaving the fixed carbon and sulfur to dissolve in the molten salt (such as an iron salt) whereupon carbon is oxidized to carbon monoxide by oxygen introduced through lances placed at a shallow depth in the bath. The sulfur migrates from the molten salt to the slag layer where it reacts with lime to produce calcium sulfide.

The product gas, which leaves the gasifier at approximately 1425°C (2600°F), is cooled, compressed, and fed to a shift converter where a portion of the carbon monoxide is reacted with steam to attain a carbon monoxide to hydrogen ratio of 1:3. The carbon dioxide so produced is removed and the gas is again cooled and enters a methanator where carbon monoxide and hydrogen react to form methane. Excess water is removed from the methane-rich product and, depending on the type of feedstock used and the extent of purification required – the final gas product may have a heat content of 920 Btu/ft^3.

In practice, the molten salt design allows for some of the catalysis process to take place within the gasifier instead of downstream. For example, if the reactor or process design allows the hydrogen and carbon monoxide to be produced in separate distinct streams, the need for post-process separation prior to catalyzing into synthetic fuels will be eliminated.

The molten salt/metal design also allows for a greater variety of co-products to be produced on site. All gasification methods allow for co-production of various chemicals and gases but the molten metal process adds various metals, such as vanadium and nickel as well as a variety of trace elements, to the mix. Most gasifier feedstocks contain trace metals which can then be extracted in the molten metal process, instead of being disposed of as slag. Also, the design and operation of molten metal reactors is such that the use of a fluxing material, such as lime or limestone, is required. When combined with the silica ash that is generated through normal gasification, the slag produced and removed from the molten metal reactor can be used directly as cement or formed into bricks for construction materials.

10.6.1 Atgas Process

The Atgas process (Figure 10.22) features the use of a molten iron bath (1550°C; 2820°F) into which coal, steam, and oxygen are injected (Speight, 2013, 2020a, 2020b). Coal and limestone are injected into the molten iron through tubes (lances) using steam as the carrier. The coal devolatilizes with some thermal cracking of the volatile constituents leaving the fixed carbon and sulfur to "dissolve" in the iron whereupon carbon is oxidized to carbon monoxide by oxygen introduced through lances placed at a shallow depth in the bath). The sulfur, both organic and pyritic, migrates from the molten iron to the slag layer where it reacts with lime to produce calcium sulfide.

The product gas, which leaves the gasifier at approximately 1425°C (2600°F), is cooled, compressed, and fed to a shift converter where a portion of the carbon monoxide is reacted with steam to attain a carbon monoxide to hydrogen ratio of 1:3. The carbon dioxide so produced is removed and the gas is again cooled and enters a methanator where carbon monoxide and hydrogen react to form methane. Excess water is removed from the methane-rich product and, depending on the type of coal used and the extent of purification desired, the final gas product may have a heat content of 920 Btu/ft (34.3 MJ/m).

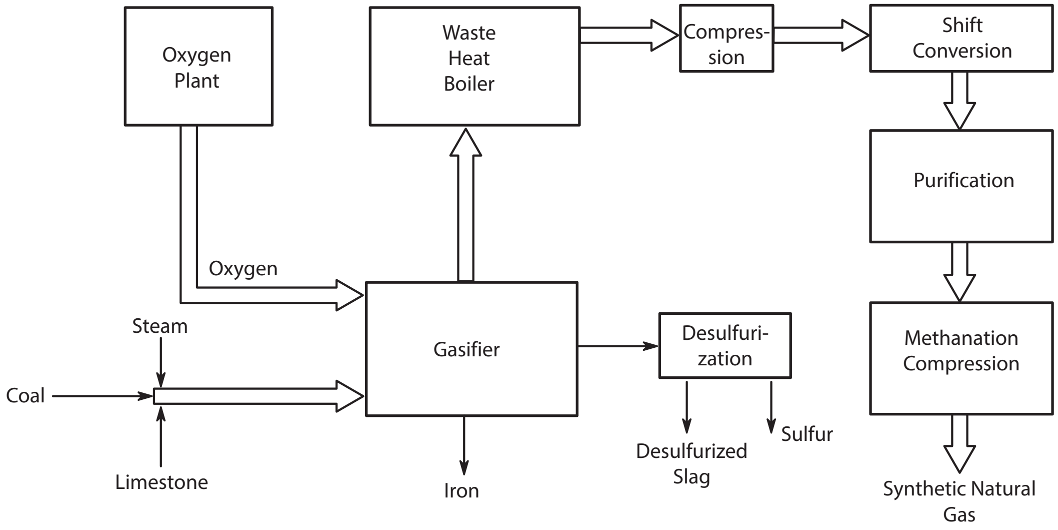

Figure 10.22 The Atgas process.

10.6.2 Pullman-Kellogg Process

The Pullman-Kellogg process involves contacting feedstock with a melt of an inorganic salt such as sodium carbonate to convert the feedstock (Speight, 2013, 2020a, 2020b).

In the process (Figure 10.23), air is bubbled into the bottom of the gasifier through multiple inlet nozzles and coal (sized to 1/4 in.; 6 mm) is fed beneath the surface of the molten salt bath using a central coal feed tube whereupon natural circulation and agitation of the melt disperses the coal. The main gasification reaction is a partial oxidation reaction and any volatile matter in the coal reacts to produce a fuel gas free of oils, tars, as well as ammonia. A water-gas shift equilibrium exists above the melt and, accordingly, in the reducing environment, carbon dioxide and water concentrations are minimal. Sulfur in the coal reacts with the melt to form sodium sulfide.

This process represents a unique approach to the problem of coal gasification insofar as the molten sodium carbonate system used for heat supply and catalysis in the provides the a strong catalytic action for the steam-carbon reaction and coal combustion reaction makes it possible to carry the overall gasification to essentially complete conversion of coal leaving very little fuel to be rejected with the ash. Heat can be supplied by air or oxygen combustion of coal or char from the molten salt, and, in the case of oxygen, it is possible to keep the combustion products separated from the synthesis gas. This has the advantage of keeping sulfur oxides out of the flue gas stream and, in addition, it eliminates carbon oxide dilution of the synthesis gas stream.

10.6.3 Rockgas Process

In the Rockgas (Rockwell International) molten salt gasification process (Figure 10.24), coal and sodium carbonate are first transported by compressed air at 150-300 psi) into the bottom of the melt bed (approximately 980°C/1800°F at 300 psi) in the gasifier. This melt bed is composed of sodium carbonate along with any sodium sulfide and sulfate formed during the process (Rosemary and Trilling, 1978).

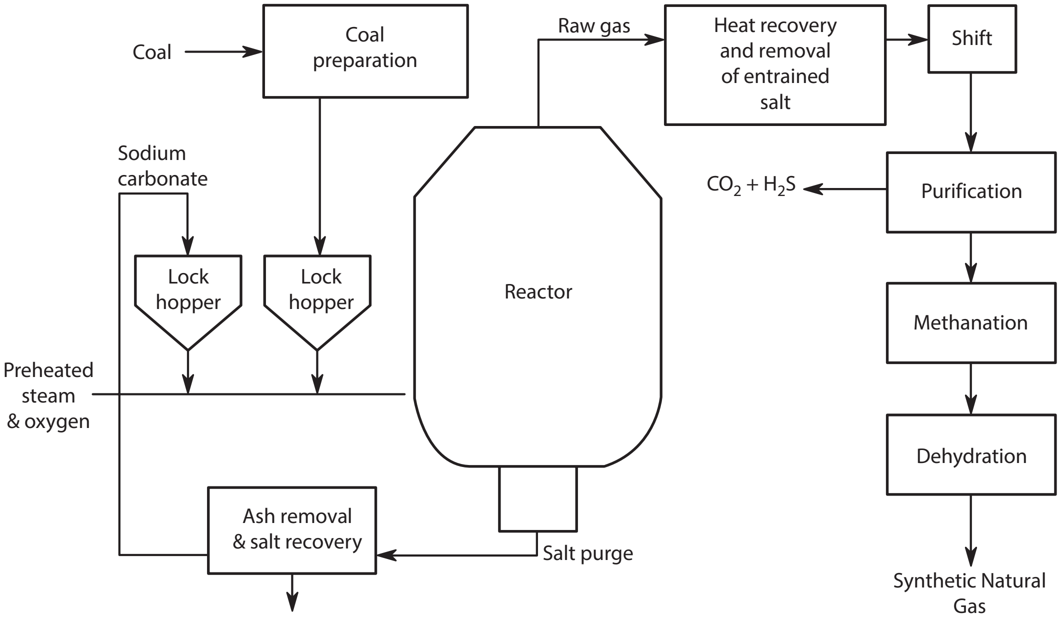

Figure 10.23 Pullman-Kellogg process.

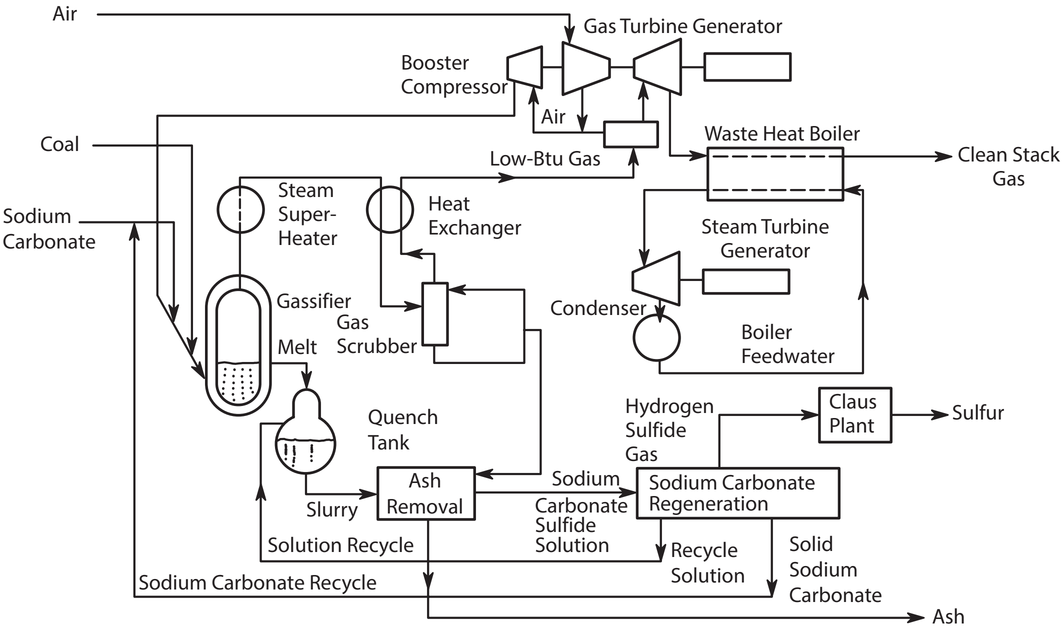

Figure 10.24 Rockgas process.

The fuel gas produced has a heat content of ca. 150 Btu/ft and is composed primarily of carbon monoxide, hydrogen, and nitrogen. The melt also contains ash and sulfur residue from the coal and hence part of the melt must be continuously withdrawn from the reactor for purification while additional fresh sodium carbonate is added.

10.6.4 Rummel Single-Shaft Process

The Rummel single-shaft gasifier is a tall, narrow water-cooled unit with the slag bath at the base that operates under atmospheric pressure (Rummel, 1959). Coal particles in suspension with the gasifying reactants are injected into the slag bath through the tangential nozzles. The coal is rapidly converted to gaseous products. The ash is converted to slag and the continuous overflow of the slag is quenched with water. The product gas is cooled at the top of the reactor.

10.7 Other Designs

In addition to the generic reactor designs of a gasification process, there are several other design options that a gasification process can have (Phillips, 2016). Each of these options can have important impacts on the downstream processes in an integrated combine cycle (IGCC) process. The various types of gasifiers involve differences in design and operational characteristics and offer methods for converting feedstocks such as coal, biomass, and waste streams into electricity and other useful products. The advantages of gasification in specific applications and conditions, particularly in clean generation of electricity from carbonaceous feedstocks (such as, in the current context, coal) may make it an increasingly important part of the world energy scenario. Other technologies also exist for the conversion of carbonaceous feedstocks into electricity and it is the purpose of this section to present an overview of the gasification technology that could well be involved in future power production.

For example, updraft and downdraft gasifiers are able to operate with slagging fuels if specially modified (continuously moving grates and/or external pyrolysis gas combustion). Cross-draft gasifiers, which work at high temperatures of 1500°C (2730°F) and above, need special safeguards with respect to the ash formation from the feedstock. Fluidized-bed reactors, because of their inherent capacity to control the operating temperature, suffer less from issues related to ash melting and ash fusion.

10.7.1 Moving-Grate Gasifier

The *moving-grate gasifier* is based on the system used for waste combustion in a waste-to-energy process. The constant-flow grate feeds the waste feedstock continuously to the incinerator furnace and provides movement of the waste bed and ash residue toward the discharge end of the grate. During the operation stoking and mixing of the burning material allows enhances distribution of the feedstocks and, hence, equalization of the feedstock composition in the gasifier. The thermal conversion takes place in two stages: (i) the primary chamber for gasification of the waste (typically at an equivalence ratio of 0.5) and (ii) the secondary chamber for high temperature oxidation of the gas product produced in the primary chamber (Grimshaw and Lago, 2010; Hankalin *et al.*, 2011).

10.7.2 Plasma Gasifier

Plasma is a high-temperature, highly ionized (electrically charged) gas capable of conducting electrical current. Plasma technology has a long history of development and has evolved into a valuable tool for engineers and scientists who need to use high temperatures for new process applications (Messerle and Ustimenko, 2007; Arena, 2012). Man-made plasma is formed by passing an electrical discharge through a gas such as air or oxygen (O_2). The interaction of the gas with the electric arc dissociates the gas into electrons and ions, and causes its temperature to increase significantly, often (in theory) exceeding 6000°C (10,830°F).

Serious efforts have been made, with some success, to apply plasma gasification technology to gasification technology and to treat industrial and municipal solid wastes (MSW) over the last two decades. It is believed that the technology can be used as a gasification reactor, thereby allowing: (i) greater feedstock flexibility enabling a variety of fuels such as coal, biomass, and municipal solid waste to be used as fuel without the need for pulverizing, (ii) air blowing and thus an oxygen plant is not required, (iii) high conversion (>99%) of carbonaceous matter to gas product, (iv) the absence of tar in the synthesis, (v) production of high heating value gas product suitable use in a combustion turbine operation, (vi) production of little or no char, ash or residual carbon, (vii) production of a glassy slag with beneficial value, (viii) high thermal efficiency, and (ix) low carbon dioxide emissions.

In the process, the gasifier is heated by a plasma torch system located near the bottom of the reactor vessel. In the gasifier, the feedstock is charged into a vertical reactor vessel (refractory lined or water-cooled) at atmospheric pressure. A superheated blast of air, which may be enriched with oxygen, is provided to the bottom of the gasifier, at the stoichiometric amount required for gasification. The amount of air fed is such that the superficial velocity of the upward flowing gas is low, and that the pulverized feedstock can be fed directly into the reactor. Additional air and/or steam can be provided at different levels of the gasifier to assist with pyrolysis and gasification. The temperature of the gas product leaving the top of the gasifier is maintained above 1000°C (1830°F). At this temperature, tar formation is eliminated.

There are two basic types of plasma torches, the *transferred torch,* and the *non-transferred torch*. The transferred torch creates an electric arc between the tip of the torch and a metal bath or the conductive lining of the reactor wall. In the non-transferred torch, the arc is produced within the torch itself. The plasma gas is fed into the torch and heated, and it then exits through the tip of the torch.

Plasma is used in two different ways in the gasification process: (i) as a heat source during gasification and (ii) for tar cracking after standard gasification. Primarily, plasma gasification is employed for the decomposition of toxic organic wastes, along with rubber and plastics, although the first reason and currently the main application for plasma gasification is the treatment of hazardous biomass waste. However, the technology has also gained interest for the production of gas product and electricity generation in recent years as the costs have entered into a commercially competitive range. Also, due to the high temperatures produced, the plasma process can be employed for toxic wastes, rubber, and treatment of plastic waste.

Gasification takes place at high temperatures, driven by the plasma torch system, which is located at the bottom of the gasifier vessel. The high operating temperatures break down the feedstock and/or all hazardous and toxic components into their respective elemental constituents, and dramatically increases the kinetics of the various reactions occurring in the gasification zone, converting all organic materials into hydrogen (H_2) and carbon monoxide (CO). Any residual materials from inorganic constituents of the feedstock (including heavy metals) will be melted and produced as a vitrified slag which is highly resistant to leaching.

Thus, in the plasma-based process, the gasifier is heated by a plasma torch system located near the bottom of the reactor vessel. In the gasifier, the feedstock is charged into a vertical reactor vessel (refractory lined or water-cooled) at atmospheric pressure. A superheated blast of air, which may be enriched with oxygen, is provided to the bottom of the gasifier, at the stoichiometric amount required for gasification. The amount of air fed is controlled so that a low velocity of the upward flowing gas is maintained and the pulverized (small-particle) feedstock can be fed directly into the reactor. Additional air and/or steam can be provided at different levels of the gasifier to assist with the pyrolysis and gasification components of the process. The temperature of the gas product leaving the top of the gasifier is maintained above 1000° (1830°F) – at this temperature, tar formation is eliminated.

The high operating temperatures decompose the feedstock (and/or all hazardous and toxic components) and dramatically increase the kinetics of the various reactions occurring in the gasification zone, converting all organic materials into hydrogen (H_2) and carbon monoxide (CO). Any residual materials from inorganic constituents and heavy metals will be melted and produced as a vitrified slag which is highly resistant to leaching. *Magmavication* or *vitrification* is the result of the interaction between plasma and inorganic materials, in presence of a coke bed or coke-like products in the cupola or reactor, a vitrified material is produced that can be used in the manufacture of architectural tiles and construction materials.

The main purported benefits of this process are (i) the yield of gas with a high content of hydrogen and a high content of carbon monoxide, (ii) improved heat content, (iii) low yield of carbon dioxide, and (iv) a low yield of tar. The process can be employed for wet biomass such as sewage sludge which are otherwise difficult to gasify.

10.7.3 Rotary Kiln Gasifier

The *rotary kiln gasifier* is used in several applications, varying from industrial waste to cement production; the reactor accomplishes two objectives simultaneously: (i) moving solids into and out of a high-temperature reaction zone and (ii) assuring thorough mixing of the solids during reaction. The kiln is typically comprised of a cylindrical steel shell lined with abrasion-resistant refractory – to prevent overheating of the metal – and is usually inclined slightly toward the discharge port. The movement of the solids being processed is controlled by the speed of rotation of the kiln.

10.7.4 Shell Coal Gasifier

The Shell coal gasifier was developed specifically to gasify solid feeds. The gasifier features a water-cooled membrane wall similar to the membrane walls used in conventional coal boilers. There are four feed injectors oriented horizontally in the mid-section of the gasifier vessel. Slag flows out of a slag tap at the bottom of the vessel where it falls into a water bath and synthesis gas flows out the top of the vessel. As the synthesis gas exits the gasifier it is quenched with cool, recycled synthesis gas to a temperature well below the ash melting point of the coal. The quenched synthesis gas is still quite warm (typically 900°C) and passes through a synthesis gas cooler and a dry solids filter before a portion of the gas is split off for recycle to the quench zone.

The coal is fed to the gasifier pneumatically using high pressure nitrogen as the transport medium. The coal must first be dried and finely ground in a roller mill where warm, inert gas flows through the mill to remove the coal's moisture. The dried coal is then pressurized via a system of lock hoppers. The gasifier can operate at pressures up to approximately 600 psi. The reason for flexibility of the gasifier is that the coal milling and drying process which eliminates the impact of moisture on the gasifier performance.

10.7.5 Conoco-Phillips Gasifier

The Conoco-Phillips gasifier (the Conoco-Phillips E-gas process) features a two-stage gasifier design in which the gasifier is refractory-lined and uses a coal-water slurry feedstock. The first stage of the gasifier has two opposed, horizontally oriented feed injectors. The synthesis gas exits the top of the first stage and slag flows out of the bottom into a water bath. The synthesis gas produced by the first stage enters the second stage at temperatures comparable to the exit temperatures of the entrained-flow gasifiers. Additional coal-water slurry is injected into this hot synthesis gas in the second gasifier stage, but no additional oxygen is injected.

Endothermic gasification reactions occur between the hot synthesis gas and the coal fed to the second stage which lowers the temperature of the synthesis gas and increases the cold gas efficiency of the process. Upon exiting the top of the second stage of the gasifier, the synthesis gas passes through a gas cooler, after which the cooled synthesis gas enters a rigid barrier filter where any unconverted char from the second stage is collected and recycled back to the first stage of the gasifier where the hotter temperatures ensure near complete carbon conversion.

10.7.6 Slagging Gasifier

A slagging gasifier has a lower ratio of steam to carbon, achieving temperatures higher than the ash fusion temperature. The nature of the gasifier means that the fuel must have high mechanical strength and must ideally be non-caking so that it will form a permeable bed, although recent developments have reduced these restrictions to some extent. The throughput for this type of gasifier is relatively low and the thermal efficiency is high as the temperatures in the gas exit are relatively low. However, this means that tar and methane production is significant at typical operation temperatures, so product gas must be extensively cleaned before use. The tar can be recycled to the reactor.

In the process, coal feedstock is introduced at the top of the gasifier via a lock hopper system and gradually descends through several process zones. Coal at the top of the bed is dried and devolatilized after which the descending coal is transformed into char, and then passes into the gasification (reaction) zone. Below this zone, any remaining carbon is oxidized, and the ash content of the coal is liquified, forming slag which is withdrawn from the slag pool by means of an opening in the hearth plate at the bottom of the gasifier vessel. The slag flows downward into a quench chamber and lock hopper in series. The pressure differential between the quench chamber and gasifier regulates the flow of slag between the two vessels.

Product gas exits the gasifier at approximately 565°C (1050°F through an opening near the top of the gasifier vessel and passes into a water quench vessel and a preheater for the boiler feed water that is designed to lower the temperature to approximately 150°C (300°F). Entrained solids and soluble compounds mixed with the exiting liquid are sent to a gas-liquor separation unit. Soluble hydrocarbon derivatives such as naphtha, high-boiling oil, and tar are recovered from the aqueous liquor and recycled to the top of the gasifier and/or reinjected at the tuyeres.

In many gasification processes most of the inorganic components of the input material, such as metals and minerals, are retained in the ash. In some gasification processes (slagging gasification) this ash has the form of a glassy solid with low leaching properties, but the net power production in slagging gasification is low (sometimes negative) and costs are higher. Regardless of the final fuel form, gasification itself and subsequent processing neither directly emits nor traps greenhouse gases. Power consumption in the gasification and gas product conversion processes may be significant though, and may indirectly cause carbon dioxide emissions; in slagging and plasma gasification, the electricity consumption may even exceed any power production from the gas product.

In general, no slagging is observed with fuels having ash production less than 6% w/w of the feedstock but severe slagging can be expected for feedstocks where the mineral matter content is higher than 12% w/w. For feedstocks with ash production from 6 to 12% w/w of the feedstock, the propensity for slagging depends on the ash melting temperature, which is influenced by the presence of trace elements giving rise to the formation of low melting point eutectic mixtures. For gasification purposes the melting behavior of the fuel ash should be determined in both oxidizing and reducing atmospheres.

10.7.7 Atmospheric and Pressurized Gasifiers

Gasifiers can operate at either atmospheric pressure or at pressures as high as 900 psi). Pressurized gasifiers are better suited for IGCC operation since the pressure of product synthesis gas will be sufficient to be fed directly into the fuel control system. Low-pressure or atmospheric-pressure gasifiers will require a fuel gas compressor after the synthesis gas clean-up by one or more of the available processes (Chapter 12).

High-pressure gasifiers also have a positive impact on the cost and performance of the synthesis gas clean-up section. Because the volumetric flow of the synthesis gas is much smaller than it would be for an atmospheric process, the size of the clean-up equipment is smaller. For example, mercury capture can be accomplished by passing the synthesis gas through a sulfur-impregnated, activated carbon bed. The size of the bed is dictated by the residence time of the synthesis gas in the bed. Therefore, a smaller volumetric flow of synthesis gas will result in a smaller carbon bed. For carbon dioxide capture, high-pressure gasifier operation will improve the performance of physical absorption processes that can remove carbon dioxide from the synthesis gas.

10.7.8 Dry Feed and Slurry Feed Gasifiers

In the gasification process, coal is typically fed into a pressurized gasifier either pneumatically as a dry solid or pumped as coal-water slurry. Slurry-fed systems have a lower capital cost, but result in less efficient conversion of coal to synthesis gas (referred to as the cold gas efficiency of the gasifier). This is because some of the synthesis gas must be burned in order to generate the heat needed to vaporize the water in the slurry. Consequently, the synthesis gas produced by a slurry-fed gasifier typically has a higher content of carbon dioxide in the synthesis gas from a dry-fed gasifier. This is not detrimental to the process operations because the carbon dioxide can act as an effective diluent for control of the nitrogen oxides. However, the higher content of carbon dioxide in the product gas stream does impact the design of the acid gas removal section of the process because the process must use a solvent which allows the carbon dioxide to pass through with the synthesis gas rather than being stripped out with the sulfur species (Chapter 12).

10.7.9 Air-Blown and Oxygen-Blown Gasifiers

The use of oxygen for the gasification reactions can be provided by either air or by high-purity oxygen produced by a cryogenic air separation unit (ASU) (Chapter 12). Air-blown gasifiers avoid the large capital cost of an air separation unit but produce a much lower calorific value synthesis gas than oxygen-blown gasifiers. The nitrogen in the air typically dilutes the synthesis gas by a factor of 3 compared to oxygen-blown gasification. Therefore, while a synthesis gas having a calorific value on the order of 300 Btu/scf might be typical from an oxygen-blown gasifier, an air-blown gasifier will typically produce synthesis gas with a calorific value on the order of 100 Btu/scf.

Because the nitrogen in air must be heated to the gasifier exit temperature by burning some of the synthesis gas, air-blown gasification is more favorable for gasifiers which operate at lower temperatures (such as the non-slagging gasifier).

Air-blown gasifiers also have a negative impact on carbon dioxide capture because of the dilution effect of the nitrogen, the partial pressure of the carbon dioxide in the synthesis gas will be lower than the partial pressure of the carbon dioxide in the synthesis gas to one-third of that from an oxygen-blown gasifier. This decreases the effectiveness of the CO2 removal equipment.

10.7.10 Quench versus Heat Recovery

A final design option involves the method for cooling the synthesis gas produced by the gasifier. Regardless of the type of gasifier, the exiting synthesis gas must be cooled down to approximately 100°C (212°F) in order to utilize conventional acid gas removal technology (Chapter 12). This can be accomplished either by passing the synthesis gas through a series of heat exchangers which recover the sensible heat for use or by directly contacting the synthesis gas with relatively cool water. This latter process results in some of the quench water being vaporized and mixed with the synthesis gas. The quenched synthesis gas is saturated with water and must pass through a series of condensing heat exchanges.

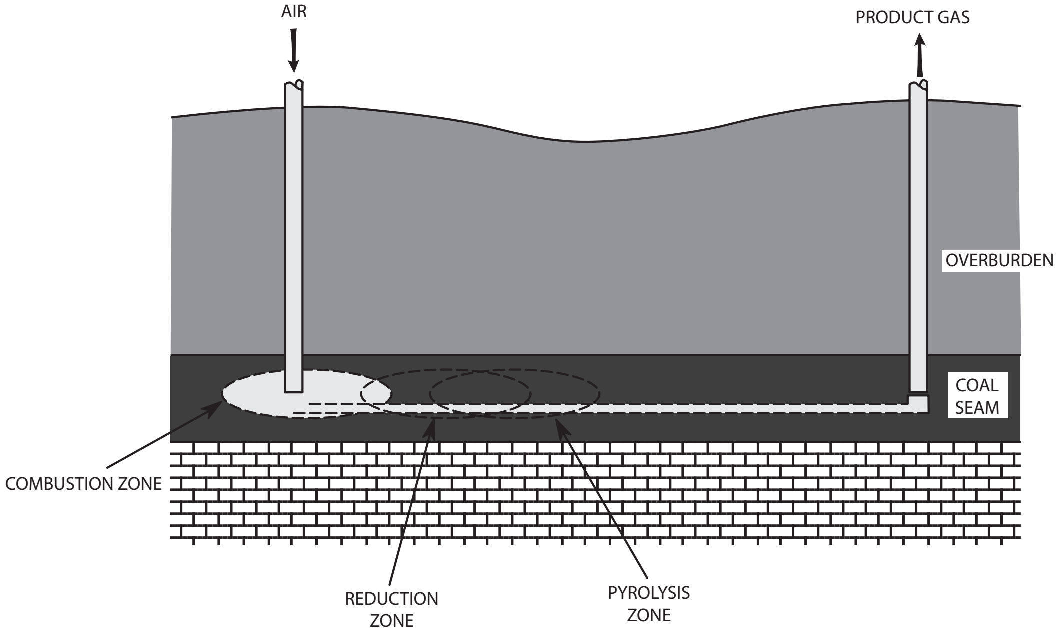

Figure 10.25 An Underground Coal Gasification system.

10.8 Gasifier-Feedstock Compatibility

All gasifier designs show relative advantages and disadvantages with respect to feedstock type, application, and simplicity of operation, and for this reason each gasifier-feedstock relationship will have specific technical and/or economic advantages in a particular set of circumstances. However, before selecting a feedstock for a gasifier it is important to ensure that the feedstock is compatible with the requirements of the gasifier or that it can be treated to meet these requirements. Furthermore, a series of test methods may need to be applied to the feedstock if the analysis is unknown or speculative and to determine the gasifier-feedstock compatibility. Thus, each type of gasifier will operate satisfactorily with respect to feedstock character, gas quality, process efficiency only within certain ranges of the feedstock properties, of which the most important are (i) feedstock reactivity, (ii) energy content, (iii) moisture content, (iv) production of volatile matter, (v) particle size and distribution, (vi) bulk density, (vii) propensity for char formation, (viii) mineral matter content, and (ix) ash yield.

10.8.1 Feedstock Reactivity

Feedstock reactivity is an important factor determining the rate of reduction of carbon dioxide to carbon monoxide in a gasifier. Reactivity influences the reactor design insofar as it dictates the height needed in the reduction zone – fluidized-bed gasifiers show great promise in gasifying a number of agricultural wastes. Furthermore, cogasification of various feedstocks (such as coal and biomass) may be advantageous from a chemical point of view; some practical problems have been associated with the process on upstream, gasification, and downstream processes. On the upstream side, the particle size of the feedstock is required to be uniform for optimum gasification. In addition, moisture content and pretreatment (torrefaction) are important during upstream processing.

In addition, most wood species have ash production yields than 2% w/w of the feedstock and are therefore suitable fixed-bed gasifiers. However, because of the high volatile content of wood, updraught systems produce a tar-containing gas suitable mainly for direct burning. Cleaning of the gas to make it suitable for engines is rather difficult and capital and labor intensive. Downdraught systems can be designed to deliver a virtually tar-free product gas in a certain capacity range when fueled by wood blocks or wood chips of low moisture content. However, most currently available downdraught gasifiers axe not suitable for non-pelletized sawdust. Problems encountered are related to (i) excessive tar production, (ii) inadmissible pressure drop, and (iii) lack of bunker flow. On the other hand, fluidized-bed gasifiers can accommodate small sawdust particles and produce burner quality gas.

In principle, many countries (especially developing countries) have a wide range of agricultural residues available for gasification but in practice, however, experience with most types of waste is extremely limited. Coconut shells and maize cobs are are the best documented and seem unlikely to create serious problems in fixed-bed gasifiers. Coconut husks can give rise to bridging problems in the bunker section, but the material can be gasified when mixed with a certain quantity of wood. Most cereal straws have ash contents above 10% and present slagging problems in downdraught gasifiers – in fact, rice husks can produce ash on the order of 20% w/w of the feedstock and, because of this, may be the most difficult feedstock for gasification.

It is possible to gasify most types of agricultural waste in updraught gasifiers. However, the capital, maintenance and labor costs, and the environmental consequences (disposal of tarry condensates) involved in cleaning the gas, prevent engine applications under most circumstances. Downdraught equipment is cheaper to install and operate and creates fewer environmental difficulties, but at present technology is inadequate to handle agricultural residues (with the possible exception of maize cobs and coconut shells) without installing expensive (and partly unproven) additional devices. In addition certain operational characteristics of the gasification system (load following response, restarting after temporary shutdown) are affected by the reactivity of the char produced in the gasifier. Reactivity is dependent on the type of feedstock – feedstocks such as wood, charcoal and peat are far more reactive than coal.

After the initial reaction in the gasifier, the reactivity of the char becomes important since there is a relation between reactivity and the number of active sites on the char surface, these being influenced by the morphological characteristics of the char and the feedstock from which the char was produced. The grain size and the porosity of the char produced in the reduction zone influence the surface available for reduction and, therefore, the rate of the reduction reactions. Another aspect of the properties of the char is the effect of various elements which act as catalysts on the rate of gasification of the feedstock. Small quantities of potassium, sodium and zinc can have a large effect on the reactivity of the fuel.

10.8.2 Energy Content

The choice of a fuel for gasification will in part be decided by its heating value. The method of measurement of the fuel energy content will influence the estimate of efficiency of a given gasification system. Reporting of fuel heating values is often confusing since at least three different bases are used: (i) fuel higher heating values as obtained in an adiabatic bomb calorimeter – these values include the heat of condensation of the water that is produced during combustion and because it is very difficult to recover the heat of condensation in actual gasification operations these values present a too optimistic view of the fuel energy content, (ii) fuel higher heating values on a moisture-free basis, which disregard the actual moisture content of the fuel and so provide even more optimistic estimates of energy content, (iii) fuel higher heating values on a moisture and ash free basis, which disregard the incombustible components and consequently provide estimates of energy content too high for a given weight of fuel, especially in the case of some agricultural residues (rice husks). The only realistic way therefore of presenting feedstock heating values for gasification purposes is to give lower heating values (excluding the heat of condensation of the water produced) on an ash inclusive basis and with specific reference to the actual moisture content of the fuel.

Plastics waste, being a potential energy source is another possible feedstock for fluid-bed gasifiers (Mastellone and Arena, 2007). Gasification of plastics can be subdivided into the following sequence of steps: (i) heating and melting of polymer particles, (ii) primary cracking of polymer chain with consequent formation of intermediate hydrocarbon fragments, and (iii) secondary cracking of intermediates with formation of methane, hydrogen, olefins, and oxidation/reduction reactions with the formation of carbon monoxide, carbon dioxide, and water. Ternary reactions can also occur with the subsequent formation of aromatic products and, in presence of metals, coke.

A suitable method to avoid or reduce tar formation during fluidized-bed gasification is the catalytic removal of tar precursors and intermediates. In particular, cycloparaffins, naphthenes, and aromatics, forming during ternary reactions of the intermediate species produced by primary cracking, can be decomposed to carbon and hydrogen by means of metal-based catalysts. These contain transition metals such as iron, cobalt, nickel, chromium, vanadium platinum, and magnesium, i.e., those metals typically used for the reforming of hydrocarbons (Wu and Williams, 2010).

10.8.3 Moisture Content

The heating value of the gas produced by any type of gasifier depends at least in part on the moisture content of the feedstock (Chapter 1). Moisture content can be determined on a dry basis as well as on a wet basis. In this chapter the moisture content on a dry basis will be used.

A high moisture content of the fuel reduces the thermal efficiency since heat is used to drive off the water and consequently this energy is not available for the reduction reactions and for converting thermal energy into chemical bound energy in the gas. Therefore high moisture contents result in low gas heating values. When the gas is used for direct combustion purposes, low heating values can be tolerated and the use of feedstocks with a moisture content (dry basis) of up to 40 to 50% w/w is feasible, especially when using updraught gasifiers.

In downdraught gasifiers high moisture contents give rise not only to low gas heating values, but also to low temperatures in the oxidation zone, and this can lead to insufficient tar converting capability if the gas is used for engine applications. Both because of the gas heating value and issues related to tar entrainment, downdraught gasifiers need reasonably dry fuels (less than 25% w/w moisture dry basis).

10.8.4 Production of Volatile Matter

The amount of volatile matter produced from the feedstock determines the necessity of special measures (either in design of the gasifier or in the layout of the gas cleanup train) in order to remove tars from the product gas in engine applications. In practice the only biomass fuel that does not need this special attention is good-quality charcoal.

The volatile matter produced by charcoal, however, is often underestimated and in practice may be anything from 3 to 30% w/w or more. As a general rule if the fuel has the ability to produce more than 10% w/w volatile matter it should be used in downdraught gas producers, but even in this case the method of charcoal production should be taken into account. Charcoal produced in large-scale retorts is fairly consistent in volatile matter content, but large differences can be observed in charcoal produced from small-scale open pits or portable metal kilos that are common in most developing countries.

10.8.5 Particle Size and Distribution

Many feedstocks require drying and size reduction before they can be fed into a gasifier. Size reduction is needed to obtain appropriate particle sizes; however, drying is required to achieve moisture content suitable for gasification operations. In addition, densification of biomass may be done to make pellets and improve density and material flow in the feeder areas.

Updraught and downdraught gasifiers are limited in the range of fuel size acceptable in the feed stock. Fine grained and/or fluffy feedstock may cause flow problems in the bunker section of the gasifier as well as an inadmissible pressure drop over the reduction zone and a high proportion of dust in the gas. Large pressure drops will lead to reduction of the gas load of downdraught equipment, resulting in low temperatures and tar production.

Excessively large sizes of particles or pieces give rise to a reduced reactivity of the fuel, resulting in startup problems and poor gas quality, and to transport problems through the equipment. A large range in size distribution of the feedstock will generally aggravate the above phenomena. The presence of large-sized particles can cause gas channeling, especially in updraught gasifiers.

Acceptable sizes of the feedstocks for gasification systems depend to a certain extent on the design of the units. In general, wood gasifiers operate on wood blocks and woodchips ranging from 8 x 4 x 4 cm. to 1 x 0.5 x 0.5 cm. Charcoal gasifiers are generally fuelled by charcoal lumps ranging between 1 x 1 x 1 cm. and 3 x 3 x 3 cm. Fluidized-bed gasifiers are normally able to handle fuels with particle diameters varying between 0.1 and 20 mm.

10.8.6 Bulk Density

The bulk density of a feedstock is the weight per unit volume of loosely packed feedstock, and feedstocks with a high bulk density are advantageous because they represent a high energy-for-volume value. Consequently these fuels need less bunker space for a given refueling time. Feedstocks with a low bulk density fuels can give rise to insufficient flow under gravity, resulting in low gas heating values and ultimately in burning of the char in the reduction zone – inadequate bulk densities can be improved by briquetting or pelletizing.

10.8.7 Propensity for Char Formation

The occurrence of physical and morphological difficulties with charcoal produced in the oxidation zone has been reported. Some feedstocks (especially softwoods) produce char that shows a tendency to disintegrate. In extreme cases this may lead to inadmissible pressure drop.

A number of tropical hardwoods (notably teak) are reported (38) to call for long residence times in the pyrolysis zone, leading to bunker flow problems, low gas quality and tar entrainment.

10.8.8 Mineral Matter Content

The presence of mineral matter in the coal-biomass feedstock is not appropriate for fluidized-bed gasification. Low melting point of ash present in woody biomass leads to agglomeration which causes defluidization of the ash and sintering, deposition as well as corrosion of the gasifier construction metal bed (Vélez *et al.*, 2009). Biomass containing alkali oxides and salts are likely to produce clinkering/slagging problems from ash formation (McKendry, 2002). It is imperative to be aware of the melting of biomass ash, its chemistry within the gasification bed (no bed, silica/sand, or calcium bed), and the fate of alkali metals when using fluidized-bed gasifiers.

Ash produced for the mineral matter in the feedstock can cause a variety of problems particularly in up or downdraught gasifiers. Slagging or clinker formation in the reactor, caused by melting and agglomeration of the ash, at the best will greatly add to the amount of labor required to operate the gasifier If no special measures are taken, slagging can lead to excessive tar formation and/or complete blocking of the reactor. A worst case is the possibility of air-channeling which can lead to a risk of explosion, especially in updraught gasifiers.

The occurrence of slagging in the gasifier occurs depends on (i) the ash produced from the fuel, (ii) the melting characteristics of the ash, and (iii) the temperature pattern in the gasifier. Local high temperatures in voids in the fuel bed in the oxidation zone, caused by bridging in the bed, may cause slagging even using fuels with a high ash melting temperature.

10.8.9 Ash Yield

In general, no slagging is observed with fuels having ash production less than 6% w/w of the feedstock but severe slagging can be expected for feedstocks where the mineral matter content is higher than 12% w/w. For feedstocks with ash production from 6 to 12% w/w of the feedstock, the propensity for slagging depends on the ash melting temperature, which is influenced by the presence of trace elements giving rise to the formation of low melting point eutectic mixtures. For gasification purposes the melting behavior of the fuel ash should be determined in both oxidizing and reducing atmospheres.

Updraught and downdraught gasifiers are able to operate with slagging fuels if specially modified (continuously moving grates and/or external pyrolysis gas combustion). Cross-draught gasifiers, which work at high temperatures on the order of 1500°C (2730°F) and above, need special safeguards with respect to the ash formation from the feedstock. Fluidized-bed reactors, because of their inherent capacity to control the operating temperature, suffer less from ash melting and fusion problems.

10.9 Energy Balance and Other Design Options

Fuels for gasification reactors differ significantly in chemical properties, physical properties, and morphological properties and, hence, require different reactor design and operation. It is for this reason that, during more than a century of gasification experience, a large number of different gasifiers has been developed – each reactor designed to accommodate the specific properties of a typical fuel or range of fuels. In short, the gasification reactor that is designed to accommodate all (or most) types of fuels does not exist.

However, before choosing a gasifier for any individual fuel it is important to ensure that the fuel meets the requirements of the gasifier or that it can be treated to meet these requirements. Practical tests are needed if the fuel has not previously been successfully gasified. In other words the fuel must match the gasifier and the gasifier must match the fuel.

The gasification reactor must be configured to accommodate the energy balance of the chemical reactions. During the gasification process, most of the energy bound up in the fuel is not released as heat. In fact, the fraction of the feedstock's chemical energy, or heating value, which remains in the product gases (especially the sun thesis gas) is an important measure of the efficiency of a gasification process (which is dependent upon the reactor configuration) and is known as the *cold gas efficiency*. Most commercial-scale gasification reactors have a cold gas efficiency on the order of 65% to 80%, or even higher.

Thus, it is important for the reactor to limit the amount of heat that is transferred out of the zone where the gasification reactions are occurring. If not, the temperature within the gasification zone could be too low to allow the reactions to proceed – as an example, a minimum temperature on the order of 1000°C (1830°F) is typically needed to gasify coal. As a result, a gasification reactor is typically refractory-lined with no water cooling to ensure as little heat loss as possible. Gasification reactors also typically operate at elevated pressure (often as high as 900 psia), which allows them to have very compact construction with minimum surface area and minimal heat loss.

In addition to being designed and selected for feedstock type, another design option for the gasification reactor involves the method for cooling the synthesis gas produced by the gasifier. Regardless of the type of gasifier, the exiting synthesis gas must be cooled down to approximately 100°C (212°F) in order to utilize conventional acid gas removal technology. This can be accomplished either by passing the synthesis gas through a series of heat exchangers which recover the sensible heat for use (for example, in the stem cycle an *integrated combined cycle unit*, IGCC unit) or by directly contacting the synthesis gas with relatively cool water (a *quench* operation). The quench operation results in some of the quench water being vaporized and mixed with the synthesis gas. The quenched synthesis gas is saturated with water and must pass through a series of condensing heat exchanges which remove the moisture from the synthesis gas (so it can be recycled to the quench zone).

Quench designs have a negative impact on the heating rate of related equipment (such as the IGCC unit) because the sensible heat of the high-temperature synthesis gas is converted to low-level process heat rather than high-pressure steam. However, quench designs have much lower capital costs and can be justified when low-cost feedstock (such as biomass or waste) is available. Quench designs also have an advantage if carbon dioxide capture is desired. The saturated synthesis gas exiting a quench section has near the optimum water/carbon monoxide ratio as the feedstock to a water-gas shift reactor which will convert the carbon monoxide to carbon dioxide. Non-quench designs that require carbon dioxide capture need to add steam to the synthesis gas before it is sent to a water-gas shift reactor.

10.10 Underground Gasification

Principle – leave "undesirable products" underground.

The present section outlines the methods available for the *in situ* gasification of coal. In terms of the combustion process itself, both forward and reverse combustion are employed.

In the process, a cavity is created as gasification proceeds and, as the cavity widens, the roof collapses. The caving process will depend on the mechanical properties of the rocks, geological and thermal stresses. By analogy with shortwall and longwall methods of mining, subsidence will depend largely on the geometry of the cavity and depth. In general, as extraction depth increases, surface subsidence decreases.

Waste residue, ashes, oxide, radioactive materials, and waste rock after gasification are left underground, which will eliminate the accumulation of waste on the surface and reduce the cavity space compared with mining. Surface subsidence per unit of energy produced will be less with underground coal gasification compared with conventional coal mining.

Both shaft systems and shaftless systems (and combinations of these systems) constitute the methods for underground gasification. Selection of the method to be used depends on such parameters as the permeability of the seam, the geology of the deposit, the seam thickness, depth, inclination, and on the amount of mining desired. The shaft system involves driving large diameter openings into the seam and may therefore require some underground labor, whereas the shaftless system employs boreholes for gaining access to the coal and therefore does not require mining.

The fuel gas produced by underground coal gasification is, invariably, laden with contaminants originating from the coal as a result of the high temperatures involved in the process. Tar, particulate matter, ammonia, hydrogen sulfide, hydrogen chloride and trace metal species (such as cadmium, mercury, lead, zinc, sodium, and potassium) will all be present in the gas, along with the usual major constituents (hydrogen, carbon monoxide, carbon dioxide, water, and methane). A major technical concern affecting the commercialization of the overall process is the need to ensure that these contaminants are removed in an environmentally friendly, cost-effective way so that gas turbine entry requirements are met.

The gas cools as it passes through the cavity (from which coal has already been consumed in the gasification process) and through the gas production well. During transit, a significant proportion of the contaminants will deposit or condense onto surrounding surfaces (including the production well pipework) and the gas-borne particulates. If the gas temperature leaving the production well cannot be maintained above the water dew point of the gas, condensed water vapor from the gas will collect at the base of the production well. This water and/or condensed tar from the gas have the potential to cause blockages in the well. In such circumstances, the collected water will become heavily polluted by the contaminants, leading to a significant potential for groundwater pollution.

Residual gas contaminants will pass up the well and will require cleaning from the gas prior to compression and use in the gas turbine. Where gas temperatures are maintained at higher levels, the mix of contaminants remaining in the gas will be different and the overall levels that need to be cleaned above ground will be much greater.

Thus, the key technical issues, which influence the development of underground coal gasification – specifically the use of gas turbines and related equipment for power generation – are (i) the availability of reliable gas composition/yield data over extended periods, (ii) the ability to maintain gasifier stability and caloric value (heat content) of the gas, (iii) the potential for groundwater pollution by condensed species from the gasification process.

10.10.1 Borehole Producer Method

In the borehole producer method (Figure 10.26), parallel galleries (used for air inlet and product gas withdrawal) are constructed in the coal bed. The boreholes are drilled from one gallery to another approximately 5 feet apart and are filled with valves at the inlet and with iron seatings at the outlet. Electric ignition of the coal in each borehole is achieved by remote control.

The borehole producer method was designed to gasify generally flat-lying seams and is usually constructed by driving three parallel galleries (ca. 490 ft; ca. 150 m apart) into the coal from an access road and then connecting them by approximately 4 in. (10 cm) diameter holes at 13 to 16 ft (4 to 5 m) intervals. Incoming air is directed to the operating panels by control valves placed at the drill hole inlets.

10.10.2 Chamber Method

In the chamber method (*warehouse method*) (Figure 10.27), coal panels are isolated with brick-work and underground galleries. This method relies on the natural porosity of coal for flow through the system. The panel is ignited at one side and any gas produced can be removed at the opposite end of the panel.

Typically, the gasification and combustion rates are low and the product gas may have a variable composition and oven contain unconsumed oxygen. Variations of this method consist of breaking the coal by hand or drilling several holes into the seam and charging them with dynamite in the hope that the coal will be crushed in advance of the reaction zone by a series of explosions.

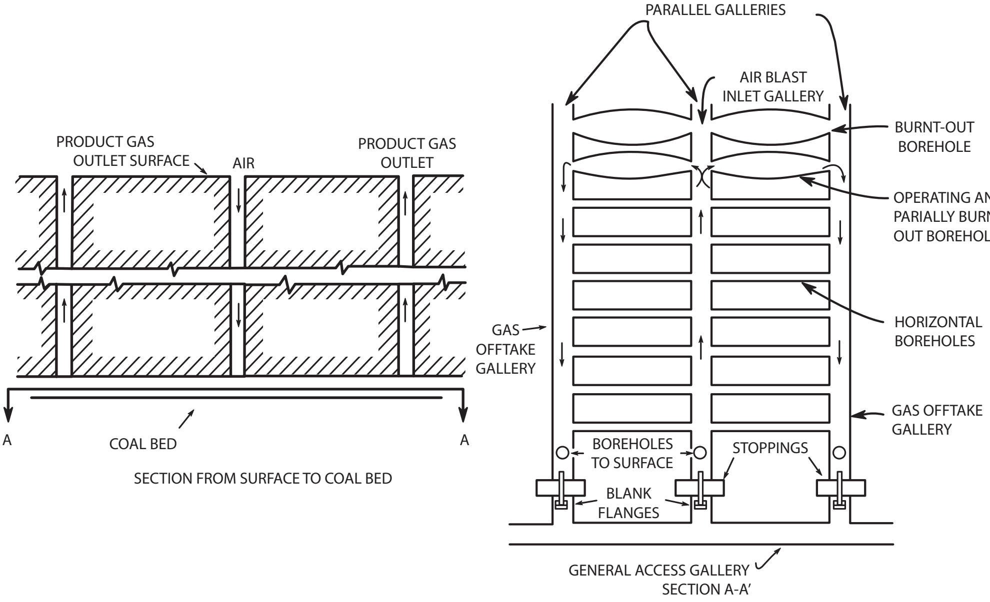

Figure 10.26 The Borehole Producer Method (Braunstein *et al.*, 1977).

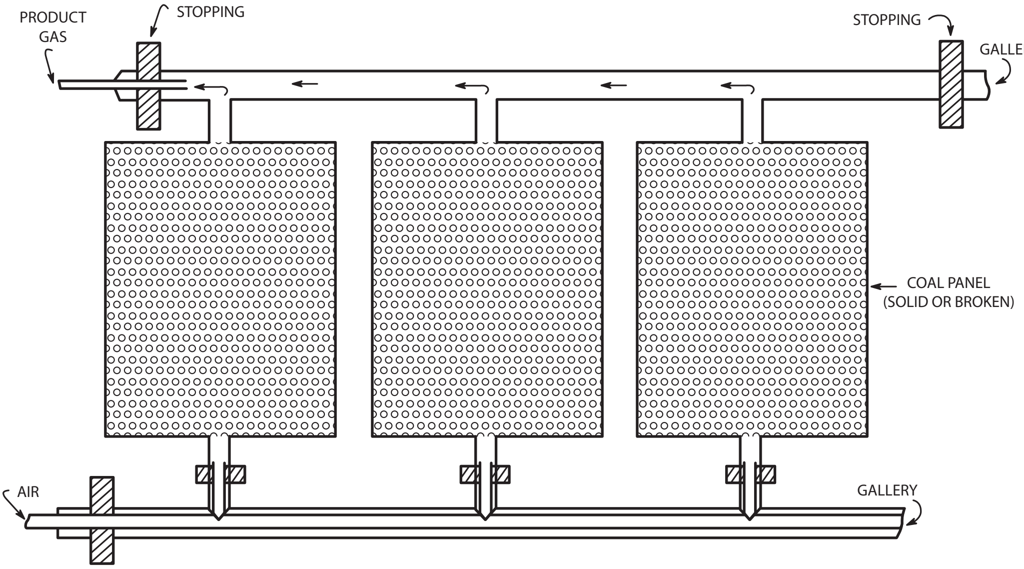

Figure 10.27 The Chamber Method (Braunstein *et al.*, 1977).

10.10.3 Shaftless Method

One example of a shaftless system for underground gasification of coal is the percolation or filtration method (Figure 10.28) in which two boreholes are drilled from the surface through the coal seam. The distance between boreholes depends on the seam permeability.

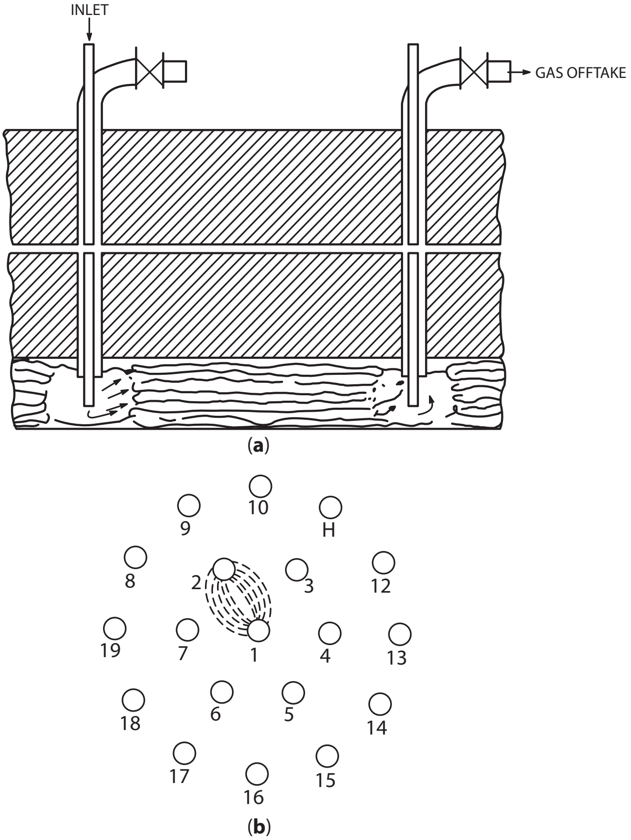

Figure 10.28 The Shaftless Method (Percolation Method) – (a) Section through Boreholes and (b) Plan of Boreholes (Braunstein *et al.*, 1977).

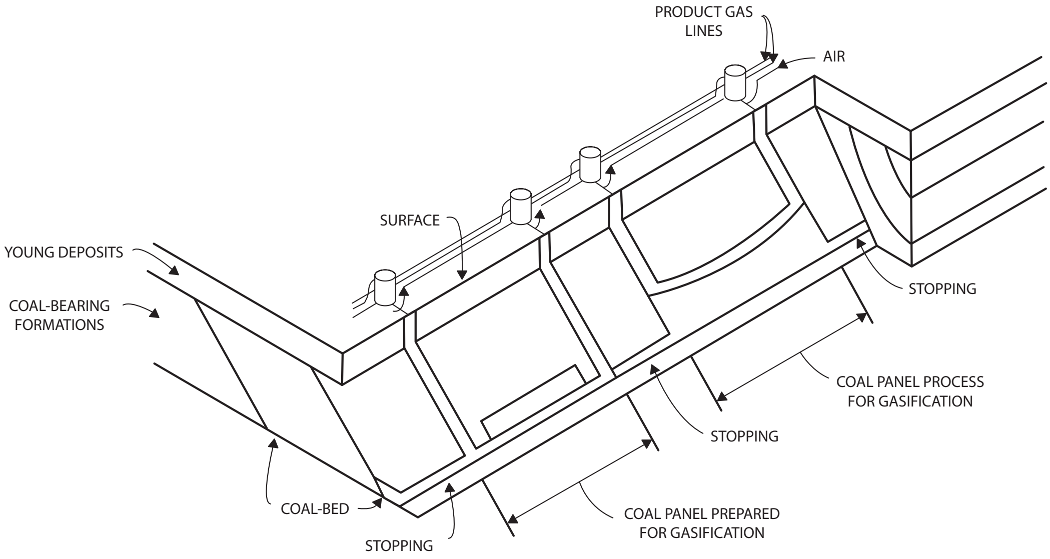

Figure 10.29 The Stream Method Gasification (Braunstein *et al.*, 1977).

Air or air and steam are blown through one hole, and gas is removed from the second; reverse combustion is permitted in this method. As the burning progresses, the permeability of the seam increases and compressed air blown through the seam also enlarges cracks in the seam. When combustion of a zone nears completion, the process is transferred to another pair of boreholes.

10.10.4 Stream Method

The stream method can be applied generally to steeply pitched coal beds; inclined galleries following the dip of the coal seam are constructed parallel to each other and are connected at the bottom by a horizontal gallery or *fire drift* (Figure 10.29).

A fire in the horizontal gallery starts the gasification, which proceeds upward with air coming down one inclined gallery and gas departing through the other. An advantage of this method is that the fire zone advances upward, and the ash, together with any roof that may fall, collects below the fire zone.

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11

Electric Power Generation

11.1 Introduction

Power generation (in this context, electricity generation) is the process of generating electric power from sources of primary energy, such as fossil fuels. Electricity must be produced from other forms of energy in power plants (also called power stations). Electricity is most often generated at a power plant by electromagnetic generators, primarily driven by heat engines fueled by combustion or nuclear fission but also by other means such as the kinetic energy of flowing water and wind. Other energy sources include solar photovoltaics and geothermal power.

Briefly, photovoltaics (often shortened as PV) gets its name from the process of converting light (photons) to electricity (voltage), often referred to as the *photovoltaic effect* in which a solar cell generates an electric current when exposed to sunlight. On the other hand, geothermal power is power that is generated by geothermal energy, i.e., heat derived from within the subsurface of the Earth. Water and/or steam carry the geothermal energy to the surface of the Earth. For electricity generation, high or medium temperature resources are needed, which are usually located close to tectonically active regions.

The production of electric power by the combustion of coal is a mature and well-established technology in the industrialized countries of the world (Figure 11.1) although other options are available (Table 11.1) (Speight, 2013). Put simply, coal-fired power plants produce electricity by burning coal in a boiler to produce steam which, under high pressure, flows into a turbine, which spins a generator to create electricity. The steam is then cooled, condensed back into water, and returned to the boiler to start the process over. Thus:

$$\text{Coal} \rightarrow \text{Boiler} \rightarrow \text{Turbine} \rightarrow \text{Generator} \rightarrow \text{Electricity} \rightarrow \text{User}$$

In fact, steam engines powered by coal boilers had been in use since the end of the 17th century. A century later, the Scottish inventor James Watt saw the potential in coal power. Watt took a simple pumping system intended to remove water from mines and adapted it to run machines in cotton, textile, paper, and lumber mills throughout England during the late 18th century. The invention turned the use of coal for heating of water in boilers into mechanical power that was far more efficient (at the time) than the wind, water, or animal power which had dominated industry until Watt's time. Following the initial design of Watt, Richard Trevithick placed the coal-powered boiler onto a modified mine cart and demonstrated that coal-fired boilers could act as a replacement for animals in transportation as well. In 1804, Trevithick applied his ideas to the manufacture of steel, and in the following year he extended it to water transportation when he placed the engine on a barge.

By the mid-19th century, most warships either relied upon steam power exclusively or used it in combination with wind power to provide propulsion. Steam power proved more

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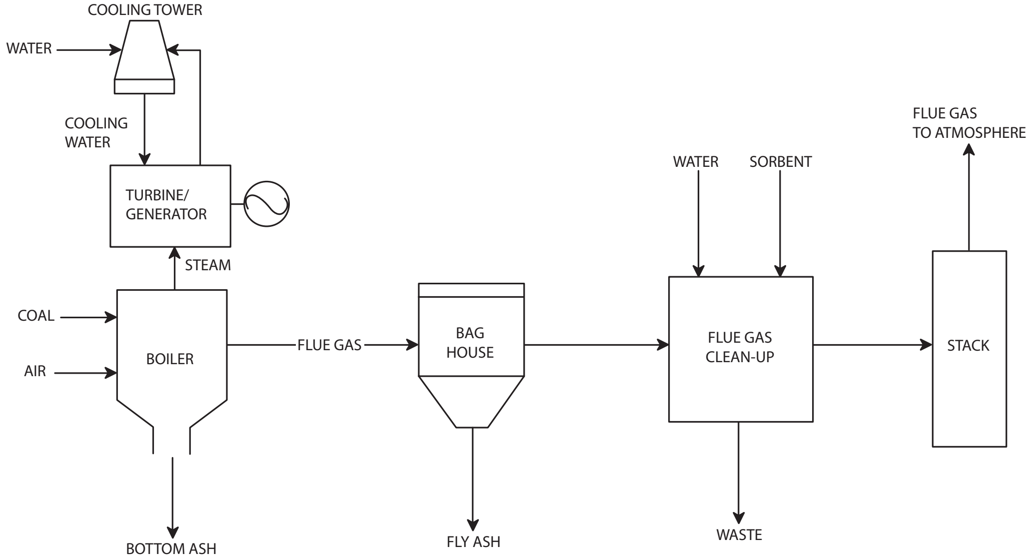

Figure 11.1 Schematic for a typical coal-fired power plant based on coal combustion.

Table 11.1 Options for power generation from coal.

Coal	Combustion
	Pulverized coal (PC)
	Fluidized-bed combustion
Gasification	Fluidized-bed gasifier (or other gasifier types)
	Integrated gasification combined cycle (IGCC)

reliable and faster than wind power, allowing ships to run against the wind at speed, thus outmaneuvering the mast-and-sail ships. In the United States, two of the most famous coal-boiler-powered ships of the 19th century were the *ironclads* – Monitor and Merrimack, which too heavy to rely on sails and thus needed steam power generated by coal boilers to move the ships. From that time to the present, coal-fired boilers have been applied to many aspects of industrial tasks and military tasks – in the present context the boilers proved to be excellent means of generating large amounts of electricity.

During the initial years of electricity generation and distribution the direct current method – as advocated by Thomas Edison – was the standard method of electricity supply for the United States (McNichol, 2006). However, the transformation efficiency of the early open-core bipolar transformers was low. Early alternating current systems used series-connected power distribution systems, with the inherent flaw that turning off a single lamp (or the disconnection of other electric device) affected the voltage supplied to all others on the same circuit. The direct current system did not have these drawbacks as of 1882, giving it significant advantages.

Finally, through the work of Nikola Tesla and others, including strong interest from George Westinghouse, and despite strong opposition from the supporters of the direct current method, the alternating current method prevailed because of the numerous advantages for power distribution that became evident. The direct current method for electricity generation and distribution had too many shortcomings for use in a growing consumer market and the method sank into the realms of history.

At that time, coal was determined to be the stable means (readily available and plenty of it) of steam generation to drive the turbines that would generate electricity. As a result, coal, with high reserves and a relatively low cost, has continued to be one of the most important energy sources for the United States and elsewhere. In the United States, coal accounts for approximately one-third of all carbon dioxide emissions arising from fossil fuel use (Blasing *et al.*, 2005). Worldwide, coal provides for approximately one-third of all electricity production, one-quarter of transportation use, and is projected to account for approximately one-quarter (or more) of all energy needs by 2030 (Michener and McMullan, 2008). Although alternative sources are being improved, it is likely that alternatives alone will not (in the near term) be sufficient to meet the entire energy demand (GAO, 2012).

Coal is one of the true measures of the energy strength of the United States. The use of electricity has been an essential part of the US economy (and of many industrialized countries and/or countries where electricity is in high demand and coal is readily available) since the beginning of the 20th century. Coal-derived power is an established electricity source that provides vast quantities of inexpensive and reliable sources of power and has become more important as supplies of crude oil and natural gas either (i) diminish, (ii) become harder and more expensive to produce, or (iii) are more susceptible to the phenomenon known as petro-politics (Speight, 2011). In addition, know coal reserves are expected to last for centuries at current rates of use.

Coal has played a major role in electrical production since the first power plants were built in the United States in the 1880s (Singer, 1981). The earliest power plants used hand fed wood or coal to heat a boiler and produce steam. This steam was used in reciprocating steam engines which turned generators to produce electricity. In 1884, the more efficient high-speed steam turbine was developed by British engineer Charles A. Parsons, and it replaced the use of steam engines to generate electricity. In the 1920s, the pulverized coal firing was developed. This process brought advantages that included a higher combustion temperature, improved thermal efficiency and a lower requirement for excess air for combustion. In the 1940s, the cyclone furnace was developed. This new technology allowed the combustion of poorer grade of coal with less ash production and greater overall efficiency (Yeh and Rubin, 2007).

In the process of using a coal to generate electricity, the chemical energy of the coal is converted to thermal energy and the heat is used to generate high-pressure steam that passes through a turbine to generate electricity. In a combined cycle, the coal is first combusted in a combustion turbine, using the heated exhaust gases to generate electricity. After these exhaust gases are recovered, they heat water in a boiler, creating steam to drive a second turbine. Apart from combustion, fossil fuels can also be gasified producing synthesis gas (syngas) – mixtures of carbon monoxide (CO) and hydrogen (H_2) – which can be directly used as a fuel for power generation. Alternatively, the hydrogen can be separated and used as a fuel in an open or combined cycle process.

The advent of stricter environmental controls on effluents from power plants, especially with respect to sulfur oxides, has required that new types of combustion/pollution control technology emerge. In fact, the increased utilization of coal in place of oil and gas for combustion applications in the United States is motivating near-term development and implementation of alternative technologies for electricity generation from coal.

11.2 Electricity from Coal

Coal-fired power generation has a number of advantages that make it a desirable source of electricity. It is a reliable, mature technology, and is well understood by the traditional producers of electricity. However, not all kinds of coal types are applicable to the coal-fired power plants. Hence, selection of applicable coal type is an important process.

Coal is characterized by many properties such as total calorific value, volatile portions, degree of coalification, and the chemical composition of the fly ash. These properties are available in advance by application of appropriate screening of the coal types by use of coal and fly ash properties (Speight, 2013, 2015).

Typically, coal properties such as total calorific value, inherent moisture, volatile matter, and chemical compositions are easily available with low cost. Screening of the coal types by using these coal and fly ash properties is preferable since many coal and fly ash properties affect the combustion state in a coal-fired power plant.

One-quarter of the coal reserves of the world are located within the United States, and the energy content of US coal resources exceeds that of the known recoverable crude oil reserves. Coal is also the workhorse of the US electric power industry and supplies approximately 50% of the electricity consumed within the United States (EIA, 2012).

However, much of the world is becoming increasingly electrified and, for the foreseeable future, coal (subject to some extremely strict – some observers would say unjust – environmental regulations) will continue to be the dominant fuel used for electric power production. The low cost and abundance of coal is one of the primary reasons why consumers in the United States benefit from some of the lowest electricity rates of any free-market economy.

11.2.1 Conventional Power Plant

A conventional coal-fired power plant produces electricity by burning coal in a steam generator, where it heats water to produce high-pressure and high-temperature steam. The steam flows through a series of steam turbines which spin an electrical generator to produce electricity. The exhaust steam from the turbines is cooled, condensed back into water, and returned to the steam generator to start the process over.

Conventional coal-fired power plants are complex and custom designed on a large scale for continuous operation 24 hours per day and 365 days per year. Such plants provide most of the electrical energy used in many countries.

Most plants built in the 1980s and early 1990s produce approximately 500 MW (500×10^6 watts) of power, while many of the modern plants produce approximately 1000 MW. Also the efficiency (ratio of electrical energy produced to energy released by the coal burned) of conventional coal-fired plants is increased from under 35% to close to 45%.

Furthermore, power plants for electricity generation are defined by functional type such as (i) base load, (ii) peak load, and (iii) combined cycle – each has advantages and disadvantages.

Base load power plants have the lowest operating cost and generate power most in any given year. There are several different types of base load power plants and the resources available typically determine the type of base load plant used to generate power. Coal and nuclear power plants are the primary types of base load power plants used in the midwestern United States.

Base load power plants are also subdivided into four types of base load power plants: (i) high-efficiency combined cycle plants fueled by natural gas, (ii) nuclear power plants, (iii) steam power plants fueled primarily by coal, and (iv) hydropower plants.

Peak load power plants are relatively simple cycle gas turbines that have the highest operating cost but are the cheapest to build. They are operated infrequently and are used to meet peak electricity demands in period of high use and are primarily fueled with natural gas or oil.

The key challenge is to remove the environmental objections to the use of coal in future power plants. New technologies being developed could virtually eliminate the sulfur, nitrogen, and mercury pollutants that are released when coal is burned. It may also be possible to capture greenhouse gases emitted from coal-fired power plants and prevent them from contributing to global warming concerns.

11.2.1.1 Coal Transport and Delivery

Coal is delivered by highway truck, rail, barge, or collier ship (Chapter 3). Some plants are even built near coal mines and the coal is delivered from the mines by conveyors or multi-hundred-ton trucks.

A large coal train (unit train) composed of 100 to 110 rail cars – each car containing 100 tons of coal – may be more than one mile long. A large plant under full load requires at least one coal delivery this size every day. Plants may get as many as three to five trains a day, especially in peak season, during the summer months when electrical energy consumption is high. A large coal-fired power plant will store several million tons of coal for winter use when delivery may be interrupted because of inclement weather or other disruptions.

Modern unloaders use rotary dump devices, which eliminate problems with coal freezing in bottom dump cars. The unloader includes a train positioner arm that pulls the entire train to position each car sequentially over a coal hopper. The dumper clamps an individual car against a platform that swivels the car upside down to dump the coal. Swiveling couplers enable the entire operation to occur while the cars are still coupled together. Unloading a unit train takes approximately three hours.

Shorter trains may use railcars with an *air dump*, which relies on air pressure from the engine plus a *hot shoe* on each car. The *hot shoe,* when it comes into contact with a *hot rail* at the unloading trestle, shoots an electric charge through the air dump apparatus and causes the doors on the bottom of the car to open, dumping the coal through the opening in the trestle. Unloading one of these trains takes anywhere from an hour to an hour and a half. Older unloaders may still use manually operated bottom-dump rail cars and a shaker attached to the cars to dump the coal.

A collier (a large, seaworthy, self-powered cargo ship carrying coal) may hold 40,000 tons of coal and takes several days to unload. For transporting coal in calmer waters, such as rivers and lakes, flat-bottomed vessels (barges) are pulled by tow boats.

Some power plants receive coal via a coal slurry pipeline between the power plant and a coal mine that may be 10 to 100 miles away. The coal is ground to approximately the size of coffee grounds and mixed with water to form the slurry. At the power plant the coal is either fed directly to the fuel preparation system or to a pond where the coal settles out and, at a later date, is re-slurried and then pumped to the fuel preparation system.

For startup or auxiliary purposes, a coal-fired power plant may use fuel oil, which can be delivered to plants by pipeline, tanker, tank car, or truck.

11.2.1.2 Fuel Preparation

For most coal-fired power plants, coal is prepared for use by first crushing the delivered coal into pieces to a size less than two inches (Chapter 3). The crushed coal is then transported from the storage yard to in-plant storage silos by rubberized conveyer belts.

In plants that burn pulverized coal, coal from the storage silos is fed into pulverizers that grind the crushed coal into the consistency of talcum powder and mix it with primary combustion air which transports the pulverized coal to the steam generator furnace. A 500 MW coal-fired power plant will have approximately six such pulverizers, five of which will supply the steam generator at full load with approximately 250 tons per hour.

In plants that do not burn pulverized coal, the crushed coal may be directly fed into cyclone burners, a specific kind of combustor that can efficiently burn larger pieces of coal. In plants fueled with slurried coal, the slurry is fed directly to the pulverizers and then mixed with air and fed to the steam generator. The slurry water is separated and removed during pulverizing of the coal.

The heart of a gasification-based system is the gasifier, which converts coal (or a coal-based feedstock such as a coal-biomass feedstock) into gaseous components by applying heat under pressure in the presence of steam.

Coal gasification (Chapters 9, 10) differs from coal combustion (Chapters 7, 8) in that the amount of air or oxygen available inside the gasifier is controlled so that only a relatively small portion of the fuel burns completely, which provides the heat. Most of the coal feedstock is chemically broken apart by the heat and pressure in the gasifier to produce synthesis gas – a mixture of carbon monoxide and hydrogen, but can include other gaseous constituents – which can have a variable composition depending upon the conditions in the gasifier and the coal type or feedstock type (Speight, 2020a).

Sulfur impurities in the feedstock are converted to hydrogen sulfide and carbonyl sulfide, from which sulfur can be easily extracted, typically as elemental sulfur or sulfuric acid, both valuable by-products. Nitrogen oxides, another potential pollutant, are not formed in the oxygen-deficient (reducing) environment of the gasifier; instead, ammonia is created by nitrogen-hydrogen reactions. The ammonia can be removed from the gas stream (Chapters 12, 13).

In Integrated Gasification Combined Cycle (IGCC) systems, the synthesis gas is cleaned of its hydrogen sulfide, ammonia and particulate matter and is burned as fuel in a combustion turbine (much like natural gas is burned in a turbine). The combustion turbine drives an electric generator. Exhaust heat from the combustion turbine is recovered and used to boil water, creating steam for the steam turbine-generator.

11.2.1.3 Feed-Water Heating and De-Aeration

The feed-water used in the steam generator consists of recirculated condensate water and makeup water. Because the metallic materials it contacts are subject to corrosion at high temperatures and pressures, the makeup water is highly purified in a system of water softeners and ion-exchange demineralizers. The makeup water in a 500 MW plant amounts to approximately 20 gallons per minute to offset the small losses from steam leaks in the system and blowdown from the steam drum.

The condensate and feed-water system begins with the water condensate being pumped out of the low pressure turbine exhaust steam condenser (commonly referred to as a surface condenser). The condensate water flow rate in a 500 MW coal-fired power plant is approximately 6,000 gallons per minute.

The feed-water plus makeup water flows through feed-water heaters heated with steam extracted from the steam turbines. Typically, the total feed-water also flows through a de-aerator that removes dissolved air from the water, further purifying and reducing its corrosivity.

Following the de-aeration, the water may be dosed with hydrazine to scavenge the remaining oxygen in the water to below 5 parts per billion (5 ppb). It is also dosed with pH control agents such as ammonia or morpholine to keep the residual acidity low and thus non-corrosive.

11.3 Steam Generation

In a steam turbine power plant, fuel is burned in a furnace and the hot gases flow through a boiler. Water is converted to steam in the boiler and additional heating stages may be included to superheat the steam. The steam is sent through controlling valves to a turbine and, as the steam expands and cools, the energy from the steam expansion is transferred to the turbine blades which turn a generator. The spent steam has a lower pressure and a lower energy content and is fed through a condenser, which removes heat from the steam. The condensed water is then pumped into the boiler to repeat the cycle. Emissions from the boiler include carbon dioxide, oxides of sulfur, and in the case of coal fly ash from non-combustible substances in the fuel. Waste heat from the condenser is transferred either to the air, or sometimes to a cooling pond, lake, or river.

More specifically, in the steam generation system, heat from combustion causes steam to form in the primary steam generation coils (Stultz and Kitto, 1992). The steam vapor rises into the steam drum, where it is accumulated. The steam then successively passes to the convective and radiant superheaters, which use combustion heat to further heat the steam well above its previous temperature. The steam next flows to the turbine, which has both high- and low-pressure stages.

High-temperature, high-pressure steam is generated in the boiler and then enters the steam turbine. At the other end of the steam turbine is the condenser, which is maintained at a low temperature and pressure. Steam rushing from the high-pressure boiler to the low-pressure condenser drives the turbine blades, which powers the electric generator. Steam expands as it works; hence, the turbine is wider at the exit end of the steam. The theoretical thermal efficiency of the unit is dependent on the high pressure and temperature in the boiler and the low temperature and pressure in condenser.

Steam turbines typically have a thermal efficiency of approximately 35% (i.e., 35% of the heat of content of the coal is transformed into electricity. The remaining 65% of the heat either goes up the stack (typically 10%) or is discharged with the condenser cooling water (typically 55%).

Low-pressure steam exiting the turbine enters the condenser shell and is condensed on the condenser tubes. The condenser tubes are maintained at a low temperature by the flow of cooling water. The condenser is necessary for efficient operation by providing a low-pressure sink for the exhausted steam. As the steam is cooled to condensate, the condensate is transported by the boiler feed-water system back to the boiler, where it is used again. Being a low-volume incompressible liquid, the condensate water can be efficiently pumped back into the high-pressure boiler.

A constant flow of low-temperature cooling water in the condenser tubes is required to keep the condenser shell (steam side) at proper pressure and to ensure efficient electricity generation. Through the condensing process, the cooling water is warmed. If the cooling system is an open or a once-through system, this warm water is released back to the source water body. In a closed system, the warm water is cooled by recirculation through cooling towers, lakes, or ponds, where the heat is released into the air through evaporation and/or sensible heat transfer. If a recirculating cooling system is used, only a small amount of makeup water is required to offset the cooling tower blowdown which must be discharged periodically to control the buildup of solids. Compared to a once-through system, a recirculated system uses approximately one twentieth of the volume of water (Elliot, 1989).

The feed-water used in the steam generator consists of recirculated *condensate* water and *makeup water*. Because the metallic materials it contacts are subject to corrosion at high temperatures and pressures, the makeup water is highly purified in a system of water softeners and ion exchange demineralizers. The makeup water in a 500 MW plant amounts to approximately 20 US gallons per minute and offsets any losses from steam leaks in the system and blowdown from the steam drum.

The condensate and feed-water system begins with the water condensate being pumped out of the low-pressure turbine exhaust steam condenser (commonly referred to as a *surface condenser*). The condensate water flow rate in a 500 MW coal-fired power plant is approximately 6,000 gallons per minute.

In a typical process (Figure 11.1), coal is first milled to a fine powder, which increases the surface area and allows it to burn more quickly. In these pulverized coal combustion (PCC) systems, the powdered coal is blown into the combustion chamber of a boiler where it is burnt at high temperature. The hot gases and heat energy produced converts water – in tubes lining the boiler – into steam.

The returning feed-water (condensed steam) requires a great deal of heat for vaporization to produce steam. Thus it is desirable to preheat the feed-water before returning it to the boiler by bleeding off a small amount of steam from successive turbine stages. Steam is bled from increasingly hotter stages as the feed-water gets hotter. Finally the feed-water is fed into the economizer, which is another set of tubes fairly far back in the convection section where the furnace temperature is lower. From here the feed-water returns to the boiler water drum and the primary steam generation coils.

The high-pressure steam is passed into a turbine (Figure 11.2) to drive the turbine blades and causing the turbine shaft to rotate at high speed. A generator is mounted at one end of the turbine shaft and consists of carefully wound wire coils. Electricity is generated when these are rapidly rotated in a strong magnetic field. After passing through the turbine, the steam is condensed and returned to the boiler to be heated once again.

The electricity generated is transformed into the higher voltages (up to 400,000 volts) used for economic, efficient transmission via power line grids. When it nears the point of consumption, such as our homes, the electricity is transformed down to the safer 100 to 250 volt systems used in the domestic market.

The generation of electrical generation using steam turbines involves three energy conversions: (i) extracting thermal energy from coal by combustion or by gasification and using it to raise steam in a boiler, (ii) converting the thermal energy of the steam into kinetic energy in the turbine, and (iii) using a generator to convert the mechanical energy of the turbine into electrical energy.

11.3.1 The Boiler

In the boiler (sometime referred to as the steam generator), which is typically a furnace with walls that are constructed of insulated steel with a web of high-pressure steel boiler tubes attached to the inner surface of the walls. The de-aerated boiler feed-water enters the economizer where it is preheated by the hot combustion flue gases and then flows into the boiler steam drum at the top of the furnace. Water from that drum circulates through the boiler tubes in the furnace walls using the density difference between water in the steam drum and the steam-water mixture in the boiler tubes.

Pulverized coal is air-blown into the furnace from fuel nozzles at the four corners and it rapidly burns, forming a large fireball at the center. The thermal radiation of the fireball heats the water that circulates through the boiler tubes mounted on the furnace walls. As the water circulates, it absorbs heat and partially changes into steam at approximately 360°C (680°F) and at a pressure of 2800 psi. In the boiler steam drum, the steam is separated

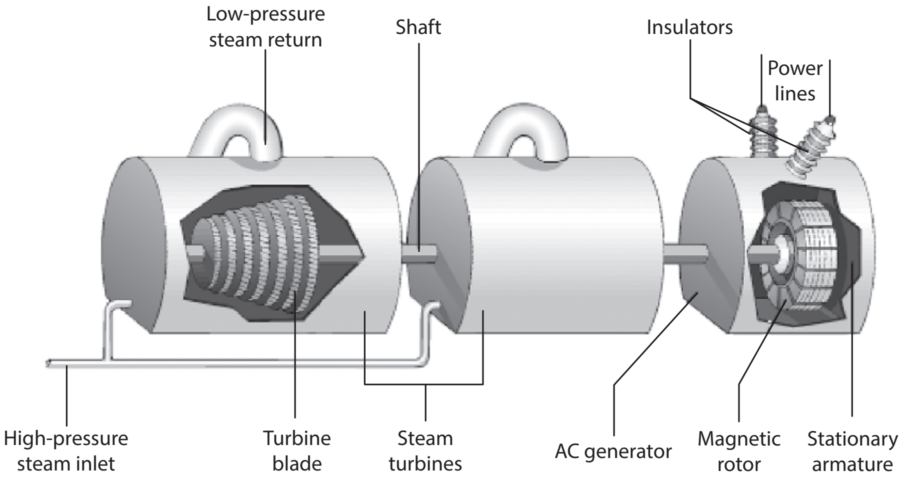

Figure 11.2 A steam turbine for electricity generation.

from the circulating water. The steam then flows through superheater tubes that hang in the hottest part of the combustion flue gases path as it exits the furnace. Here the steam is superheated to approximately 540°C (1005°F) before being routed into the high-pressure steam turbine.

11.3.1.1 Water Tube Boiler

In the water tube boiler, boiler feed water flows through the tubes and enters the boiler drum. The circulated water is heated by the combustion gases and converted into steam at the vapor space in the drum. These boilers are selected when the steam demand as well as steam pressure requirements are high as in the case of process cum power boiler/power boilers.

The features of water tube boilers are (i) forced, induced and balanced draft provisions help to improve combustion efficiency, and (ii) less tolerance for water quality often requires a water treatment plant.

11.3.1.2 Packaged Boiler

The packaged boiler is so called because it comes as a complete package. Once delivered to site, it requires only the steam, water pipe work, fuel supply and electrical connections to be made for it to become operational. Package boilers are generally of shell type with fire tube design so as to achieve high heat transfer rates by both radiation and convection. The features of package boilers are (i) small combustion space and high heat release rate resulting in faster evaporation, (ii) a large number of small-diameter tubes leading to good convective heat transfer, (iii) forced or induced draft systems resulting in good combustion efficiency, (iv) a number of passes resulting in better overall heat transfer, and (v) higher thermal efficiency levels compared with other boilers.

These boilers are classified based on the number of passes (i.e., the number of times the hot combustion gases pass through the boiler). The combustion chamber is taken, as the first pass after which there may be one, two or three sets of fire-tubes. The most common boiler of this class is a three-pass unit with two sets of fire-tubes and with the exhaust gases exiting through the rear of the boiler.

11.3.1.3 Fluidized-Bed Combustion Boiler

Fluidized-bed combustion (FBC) has emerged as a viable alternative and has significant advantages over conventional firing system and offers multiple benefits – compact boiler design, fuel flexibility, higher combustion efficiency and reduced emission of noxious pollutants such as SOx and NOx. The fuels burnt in these boilers include coal, washery rejects, rice husk, bagasse and other agricultural wastes.

When an evenly distributed air or gas is passed upward through a finely divided bed of solid particles such as sand supported on a fine mesh, the particles are undisturbed at low velocity. As air velocity is gradually increased, a stage is reached when the individual particles are suspended in the air stream – the bed is fluidized. With further increase in air velocity, there is bubble formation, vigorous turbulence, rapid mixing and formation of dense defined bed surface. The bed of solid particles exhibits the properties of a boiling liquid and assumes the appearance of a fluid – bubbling fluidized bed.

If sand particles in a fluidized state are heated to the ignition temperatures of coal, and coal is injected continuously into the bed, the coal will burn rapidly and the bed attains a uniform temperature. The fluidized-bed combustion (FBC) takes place at about 840 to 950°C (1540 to 1740°F) Since this temperature is much below the ash fusion temperature, melting of ash and associated problems are avoided.

The lower combustion temperature is achieved because of high coefficient of heat transfer due to rapid mixing in the fluidized bed and effective extraction of heat from the bed through in-bed heat transfer tubes and walls of the bed. The gas velocity is maintained between minimum fluidization velocity and particle entrainment velocity. This ensures stable operation of the bed and avoids particle entrainment in the gas stream.

11.3.1.4 Atmospheric Fluidized-Bed Combustion Boiler

Most operational boilers of this type are of the Atmospheric Fluidized-Bed Combustion (AFBC). This involves little more than adding a fluidized-bed combustor to a conventional shell boiler. Such systems have similarly being installed in conjunction with conventional water tube boiler.

In the process, coal is crushed to a size of 1 – 10 mm depending on the rank of coal, type of fuel fed to the combustion chamber. The atmospheric air, which acts as both the fluidization and combustion air, is delivered at a pressure, after being preheated by the exhaust fuel gases. The in-bed tubes carrying water generally act as the evaporator. The gaseous products of combustion pass over the super heater sections of the boiler flow past the economizer, the dust collectors and the air preheater before being exhausted to atmosphere.

11.3.1.5 Pressurized Fluidized-Bed Combustion Boiler

In the pressurized fluidized-bed combustion (PFBC) boiler, a compressor supplies the forced draft air and the combustor is a pressure vessel. The heat release rate in the bed is proportional to the bed pressure and hence a deep bed is used to extract a large amount of heat. This will improve the combustion efficiency and sulphur dioxide absorption in the bed. The steam is generated in the two tube bundles, one in the bed and one above it. Hot flue gases drive a power-generating gas turbine.

The system can be used for cogeneration (steam and electricity) or combined cycle power generation. The combined cycle operation (gas turbine & steam turbine) improves the overall conversion efficiency by 5 to 8%.

11.3.1.6 Atmospheric Circulating Fluidized-Bed Combustion Boiler

In a circulating system the bed parameters are so maintained as to promote solids elutriation from the bed. They are lifted in a relatively dilute phase in a solids riser, and a downcomer with a cyclone provides a return path for the solids. There are no steam generation tubes immersed in the bed. Generation and super heating of steam takes place in the convection section, water walls, at the exit of the riser.

Atmospheric circulating fluidized-bed combustion boilers are generally more economical than atmospheric fluidized-bed combustion boilers for industrial application requiring more than 75–100 T/hr of steam. For large units, the taller furnace characteristics of CFBC boilers offer better space utilization, greater fuel particle and sorbent residence time for efficient combustion and SO2 capture, and easier application of staged combustion techniques for NOx control than AFBC steam generators.

11.3.1.7 Stoker-Fired Boiler

Stokers are classified according to the method of feeding fuel to the furnace and by the type of grate. The main classifications are spreader stoker and chain-gate or traveling-gate stoker.

Spreader stokers utilize a combination of suspension burning and grate burning. The coal is continually fed into the furnace above a burning bed of coal. The coal fines are burned in suspension; the larger particles fall to the grate, where they are burned in a thin, fast-burning coal bed. This method of firing provides good flexibility to meet load fluctuations, since ignition is almost instantaneous when firing rate is increased. Due to this, the spreader stoker is favored over other types of stokers in many industrial applications.

In the chain-grate (or traveling-grate stoker) coal is fed onto one end of a moving steel grate. As grate moves along the length of the furnace, the coal burns before dropping off at the end as ash. The coal-feed hopper runs along the entire coal-feed end of the furnace. A coal gate is used to control the rate at which coal is fed into the furnace by controlling the thickness of the fuel bed. Coal must be uniform in size as large lumps will not burn out completely by the time they reach the end of the grate.

11.3.1.8 Pulverized Fuel Boiler

Most coal-fired power station boilers use pulverized coal, and many of the larger industrial water-tube boilers also use this pulverized fuel. This technology is well developed, and there are thousands of units around the world, accounting for well over 90% of coal-fired capacity.

The coal is ground (pulverized) to a fine powder, so that less than 2% is +300 micro meter (μm) and 70-75% is below 75 microns, for a bituminous coal. It should be noted that too fine a powder is wasteful of grinding mill power. On the other hand, too coarse a powder does not burn completely in the combustion chamber and results in higher unburnt losses. The pulverized coal is blown with part of the combustion air into the boiler plant through a series of burner nozzles. Secondary and tertiary air may also be added. Combustion takes place at temperatures from 1300 to 1700°C (2370 to 3090°F), depending largely on coal grade. Particle residence time in the boiler is typically 2 to 5 seconds, and the particles must be small enough for complete combustion to have taken place during this time.

This system has many advantages such as (i) ability to fire varying quality of coal, (ii) quick responses to changes in load, and (iii) use of high pre-heat air temperatures. One of the most popular systems for firing pulverized coal is the tangential firing using four burners corner to corner to create a fireball at the center of the furnace.

11.3.1.9 Waste Heat Boiler

Wherever the waste heat is available at medium or high temperatures, a waste heat boiler can be installed economically. Wherever the steam demand is more than the steam generated during waste heat, auxiliary fuel burners are also used. If there is no direct use of steam, the steam may be let down in a steam turbine-generator set and power produced from it. It is widely used in the heat recovery from exhaust gases from gas turbines and diesel engines.

11.3.2 The Steam Turbines and the Electrical Generator

The feed-water used in the steam boiler is a means of transferring heat energy from the coal feedstock to the mechanical energy of the spinning steam turbine. The total feed-water consists of recirculated *condensate* water and purified *makeup water*. Because the metallic materials it contacts are subject to corrosion at high temperatures and pressures, the makeup water is highly purified before use. A system of water softeners and ion exchange demineralizers produces water so pure that it coincidentally becomes an electrical.

The feed-water cycle begins with condensate water being pumped out of the condenser after traveling through the steam turbines. The water flows through a series of six or seven intermediate feed-water heaters – heated at each point with steam extracted from an appropriate duct on the turbines and gaining temperature at each stage.

Typically, the total feed-water also flows through a de-aerator that removes dissolved air from the water, further purifying and reducing the potential for corrosion. In the de-aerator following the de-aeration step, the water may be dosed with hydrazine to scavenge the remaining oxygen in the water to a level less than 5 ppb (5 parts per billion). The water is also dosed with pH control agents such as ammonia or morpholine to maintain a low level of acidity and, thus, reduce any potential for corrosion.

For the generation of electricity, high-pressure steam is fed to the turbine and passes along the machine axis through multiple rows of alternately fixed and moving blades. From the steam inlet port of the turbine towards the exhaust point, the blades and the turbine cavity are progressively larger to allow for the expansion of the steam.

The stationary blades act as nozzles in which the steam expands and emerges at an increased speed but lower pressure, which is based on the Bernoulli principle of the conservation of energy – i.e., the total amount of energy in an isolated system remains constant over time and, thus, as the kinetic energy increases as pressure energy falls. Thus, as the steam impacts on the moving blades it imparts some of its kinetic energy to the moving blades.

To maximize turbine efficiency the steam is expanded, doing work, in a number of stages. These stages are characterized by the means of extracting the energy. There are two basic steam turbine types: (i) the impulse turbine and (ii) the reaction turbine and the blades of the turbines are designed to control the speed, direction and pressure of the steam as is passes through the turbine.

Briefly, in the *impulse turbine*, the steam jets are directed at the bucket-shaped rotor blades of the turbine where the pressure exerted by the jets causes the rotor to rotate and the velocity of the steam to reduce as it imparts its kinetic energy to the blades. The blades change the direction of flow of the steam; however, its pressure remains constant as it passes through the rotor blades since the cross section of the chamber between the blades is constant. Impulse turbines are therefore also known as constant pressure turbines. The next series of fixed blades reverses the direction of the steam before it passes to the second row of moving blades.

In the *reaction turbine*, the rotor blades are shaped more like aero-foils, arranged such that the cross section of the chambers formed between the fixed blades diminishes from the inlet side towards the exhaust side of the blades. The chambers between the rotor blades form nozzles so that as the steam progresses through the chambers its velocity increases while at the same time its pressure decreases, just as in the nozzles formed by the fixed blades. Thus the pressure decreases in both the fixed and moving blades, and as the steam emerges in a jet from between the rotor blades, it creates a reactive force on the blades which in turn creates the turning moment on the turbine rotor, in agreement with the third law of thermodynamics as put forward by Isaac Newton: for every action there is an equal and opposite reaction.

Most steam turbines use a mixture of the reaction and impulse designs: each stage behaves as either one or the other, but the overall turbine uses both. Typically, higher-pressure sections are reaction type and lower-pressure stages are impulse type.

Typically, a staged series of steam turbines includes a high-pressure turbine, an intermediate pressure turbine and two low-pressure turbines. A common configuration is that the series of turbines are connected to each other and on a common shaft, with the electrical generator also being on that common shaft.

As steam moves through the system, it loses pressure and thermal energy and expands in volume, which requires increasing turbine diameter and longer turbine blades at each succeeding stage. The entire rotating mass may weigh over 180 tons and is on the order of 100 feet long. It is so heavy and the internal clearances are so close that it must be kept turning slowly at 3 rpm (using a turning gear mechanism) when shut down so that the shaft will not thermally bow even slightly and become bound.

Another essential system is the turbine lubricating oil system which supplies oil to all turbine bearings to prevent metal-to-metal contact between the turbine shaft and the shaft bearings. The turbine shaft literally floats on a film of oil at the bearing points. This is so important that it is one of the only major functions to be maintained by the emergency power batteries on site.

Superheated steam from the steam generator flows through a control valve into the high-pressure turbine. The control valve regulates the steam flow in accordance with the power output needed from the plant. The exhaust steam from the high-pressure turbine (reduced in pressure and in temperature) returns to the reheating tubes of the steam generator where the steam is reheated back to 540°C (1005°F) before it flows into the intermediate pressure turbine. The exhaust steam from the intermediate pressure turbine flows directly into the two low-pressure turbines and the exhaust steam from the low-pressure turbines flows into the surface condenser. A small fraction of steam from the turbines is used to heat the de-aerator and/or the boiler feed-water preheater(s).

The turbine-driven electrical generator, approximately 30 to 35 feet long and 12 to 15 feet in diameter, contains a stationary stator and a spinning rotor. In operation, it generates up to 21,000 amperes at 24,000 volts of three-phase alternating current (approximately 500 MW). A two-pole rotor would spin at 3000 rpm for a 50 Hz output or 3600 rpm for a 60 Hz output synchronized to the power grid frequency in Hz. If a four-pole rotor is used, it would spin at 1500 rpm for 50 Hz output or 1800 rpm for 60 Hz output.

The rotor spins in a sealed chamber cooled with hydrogen gas, selected because it has the highest known thermal conductivity of any gas and it has a low viscosity which reduces windage losses from friction between the generator rotor and the cooling gas. The system requires special handling during startup, with air in the chamber first displaced by carbon dioxide before filling with hydrogen. This ensures that a highly explosive hydrogen-oxygen environment is not created.

The electricity flows to a distribution yard where three-phase transformers step the voltage up to 115, 230, 500 or 765 kV as needed for transmission to its destination.

11.3.3 Steam Condensing and Cooling Towers

The exhaust steam from the low-pressure turbines is condensed into water in a water-cooled surface condenser. The condensed water is commonly referred to as condensate. The surface condenser operates at an absolute pressure of approximately 35 to 40 mm Hg (i.e., a vacuum of approximately 720 to 725 mm Hg) which maximizes the overall power plant efficiency.

The surface condenser is usually a shell and tube heat exchanger. Cooling water circulates through the tubes in the shell of the condenser and the low-pressure exhaust steam is cooled and condensed by flowing over the tubes as shown in the adjacent diagram. Typically the cooling water causes the steam to condense at a temperature of approximately 35°C (95°F). A lower condensing temperature results in a higher vacuum (i.e., a lower absolute temperature) at the exhaust of the low-pressure turbine and a higher overall plant efficiency. The limiting factor in providing a low condensing temperature is the temperature of the cooling water and that, in turn, is limited by the prevailing average climatic conditions at the location of the power plant. The condensate from the bottom of the surface condenser is pumped back to the de-aerator to be reused as feed-water.

The heat absorbed by the circulating cooling water in the condenser tubes must also be removed to maintain a constant cooling water supply temperature. This is done by pumping the warm water from the condenser through either natural draft, forced air or induced draft cooling towers that reduce the temperature of the water by approximately 11 to 17°C (20 to 31°F) and expel the low-temperature waste heat to the atmosphere. The circulation flow rate of the cooling water in a 500 MW unit is approximately 225,000 US gallons per minute) at full load.

Some older power plants use river water or lake water as cooling water. In these installations, the water is filtered to remove debris and aquatic life from the water before it passes through the condenser tubes.

The condenser tubes are often made of a copper alloy, stainless steel, or sometimes titanium to resist corrosion from either side. Nevertheless they may become internally fouled during operation by bacteria or algae in the cooling water or by mineral scaling, all of which inhibit heat transfer and reduce the condenser efficiency. In an enclosed system, the cooling water can be treated with biocidal chemicals to inhibit growth of bacteria and algae and with other chemicals to inhibit scaling. Many plants include an automatic cleaning system that circulates sponge rubber balls through the tubes to scrub them clean without the need to take the system off-line. Hot water flushes may also be used to thermally shock aquatic life buildup on the inner walls of the condenser tubes.

The cooling water used to condense the steam in the condenser returns to its source without having been changed other than having been warmed. If the water returns to a local water body (rather than a circulating cooling tower), it is mixed with cool raw water to lower its temperature and prevent thermal shock to aquatic biota when discharged into that body of water.

Another method sometimes utilized for condensing turbine exhaust steam is the use of an air-cooled condenser. Exhaust steam from the low-pressure steam turbines flows through the air-cooled condensing tubes which usually have metal fins on their external surface to increase their heat transfer capacity. Ambient air from a large fan is directed over the fins to cool the tubes and condense the low-pressure steam in the tubes. Air-cooled condensers typically operate at a higher temperature than water-cooled surface condensers. While reducing the amount of water used in a power plant, the higher condensing temperature results in a higher exhaust pressure for the low-pressure turbines which reduces the overall efficiency of the power plant.

As the combustion flue gas exits the steam generator, it flows through a heat exchange device (an incoming air preheater, APH) where it is cooled by exchanging heat with the incoming combustion air. The gas exiting the steam generator is laden with particulate matter (PM or fly ash), which consists of small ash particles. The flue gas contains nitrogen along with combustion products carbon dioxide (CO_2), sulfur dioxide (SO_2) and nitrogen oxides (NOx).

Various processes (known as De-NOx processes) are often used to reduce the amount of NOx in the flue gas before the flue gas exits the steam generator. After the exiting flue gas has been cooled by heat exchange with the incoming combustion air, the fly ash in the flue gas is removed by fabric bag filters or electrostatic precipitators. Finally, after removal of the fly ash, many coal-fired power plants use one of the available flue gas desulfurization (FGD) processes to reduce sulfur dioxide emissions. The flue gas then exits to the atmosphere via tall flue gas stacks. A typical flue gas stack may be approximately 500 to 800 feet tall to disperse the remaining flue gas components in the atmosphere.

11.3.3.1 Supercritical Steam Generators

Above the critical point for water of 375°C (705°F) and 3,200 psi, there is no phase transition from water to steam, but only a gradual decrease in density. Boiling does not occur and it is not possible to remove impurities via steam separation.

Supercritical steam generators operating at or above the critical point of water are referred to as once-through plants because boiler water does not circulate multiple times as in a conventional steam generator. Supercritical steam generators require additional water purification steps to ensure that any impurities picked up during the cycle are removed. This purification takes the form of high-pressure ion exchange units (condensate polishers) between the steam condenser and the feed-water heaters.

Conventional coal-fired power plants operate at subcritical conditions and typically achieve 34 to 36% thermal efficiency. Supercritical coal-fired power plants, operating at 565°C and 3,600 psi may have an efficiency on the order of 38 to 40%. New ultra-critical designs, operating at 700 to 720°C (1290 to 1330°F) and approximately 5500 psi are expected to achieve 44 to 46% efficiency.

11.4 Control of Emissions

Thermal power plants using coal as the fuel are a source of gases emissions and particulate matter. The major designated air pollutants emitted by coal-fired power plants are sulfur dioxide (SO_2), nitrogen oxides (NOx), particulate matter (PM), and mercury (Hg). Trace amounts of radioactive elements are also emitted (Speight, 2013, 2020b). Controlling the emissions by gas cleaning (Chapter 12) is an option that is a necessary part of modern coal-based power plants. Modern-day coal power plants produce lower levels of pollutants than the older designs due to the installation and careful operations of new emission control technologies.

Mitigation of the pollutants from coal-fired power plants is achieved by a series of processes whereby coal is chemically washed of minerals and impurities, sometimes gasified, burned, and the resulting flue gases treated with steam, with the purpose of removing sulfur dioxide (SO_2), and reburned so as to make the carbon dioxide in the flue gas economically recoverable, and storable underground (referred to as *carbon capture and storage*).

11.4.1 Carbon Dioxide Emissions

A major component of the combustion flue gases produced by burning coal is carbon dioxide (CO_2), which is not a pollutant in the traditional sense since it is essential to support photosynthesis for all plant life on Earth. However, carbon dioxide is a greenhouse gas considered to be a contributor to climate change.

The emissions from conventional coal-fired power plants include *carbon dioxide* (CO_2) which is the major component of the combustion flue gases produced by burning coal. As discussed above, carbon dioxide is not a pollutant in the traditional sense but it is considered to be a contributor to global warming. To better understand the discussion of carbon dioxide emissions from conventional coal-fired electricity generation plants.

Carbon dioxide emissions for conventional coal-fired power plants will vary significantly because the emissions are a function of the carbon content of the coal and the thermal efficiency of the power plant. The carbon content of the coal may range from approximately 50% w/w for lignite to 90% w/w for anthracite and the thermal efficiency of the power plants may vary from approximately 32 to 42%.

The leading technology for significantly reducing carbon dioxide emissions from coal-fired power plants is known as *carbon capture and sequestration* (CCS). It is currently regarded as the technology which could significantly reduce coal-fired power plant carbon dioxide emissions while also allowing the use of the abundant coal resources of the Earth to provide the increasing global need for energy.

It involves capturing the carbon dioxide produced by the combustion of coal and storing it in deep ocean areas or in underground geological formations for later use in enhanced oil recovery (Speight, 2014, 2016). The capture of the carbon dioxide from the coal combustion flue gases can be accomplished by using absorbents such as amines. The carbon dioxide is then recovered from the absorbent and compressed into a supercritical fluid at approximately 2200 psi, dehydrated and transported to the storage sites for injection into the underground or undersea reservoirs. Compressing the carbon dioxide into a supercritical fluid greatly increases its density which greatly reduces its volume as compared to transporting and storing the carbon dioxide as a gas.

11.4.2 Particulate Matter Emissions

Particulate matter, as a product of coal combustion, is (i) a function of (coal properties, (ii) coal properties, (iii) boiler firing configuration, (iv) boiler operation, and (v) pollution control equipment.

Particulate matter is often subdivided into two subcategories: (i) bottom ash and (ii) fly ash but, for the purposes of this text, particulate matter is considered to be the material that exits the boiler with the flue gases (fly ash) and is separated by the use of equipment such as electrostatic precipitators and the like.

The removal of *particulate matter* (often referred to as *fly ash*) from the combustion flue gas is typically accomplished with electrostatic precipitators (ESP) or fabric filters. Electrostatic precipitators (ESPs) or fabric filters are installed on all power plants in the United States that burn pulverized coal and routinely achieve 99% or greater fly ash removal.

Typical particulate emissions from modern power plants in the United States that burn pulverized coal are less than 15 mg per cubic meter of flue gas (referenced at 0 °C and 101,325 kPa). New units in Japan achieve 5 mg per cubic meter by using wet flue gas desulfurization units that also remove condensable particulate matter (Chapter 12) (Speight, 2013, 2020b).

11.4.3 Sulfur Dioxide Emissions

Partial flue gas desulfurization (FGD) can achieve approximately 50 to 70% removal of *sulfur dioxide emissions* by the injection of dry limestone just downstream of the air preheater. The resultant solids are recovered in the electrostatic precipitator along with the fly ash.

In power plants burning pulverized coal, wet flue gas desulfurization (FGD) that contacts the flue gases with lime slurries (in what are called wet lime scrubbers) can achieve 95% sulfur dioxide removal without additives and 99+% removal with additives. Wet flue gas desulfurization processes have the greatest share of the flue gas desulfurization processes in the United States and it is a commercially proven, well-established technology.

There are three technologies (known as De-NOx processes) available for reducing the emissions of *NOx emissions* from combustion sources:

The lowest cost combustion control technology for reducing NOx emissions is referred to as Lo-NOx and can achieve up to a 50% reduction in NOx emissions compared to uncontrolled combustion.

The most effective, but most expensive, NOx emission reduction technology is *selective catalytic reduction* (SCR). It can achieve 90% NOx reduction and is currently a technology of choice for achieving low levels of NOx emissions.

Selective non-catalytic reduction (SNCR) falls between Low-NOx and SCR in both cost and effectiveness.

11.4.4 Mercury Emissions

During combustion, the mercury (Hg) in coal is volatilized and converted to elemental mercury (zero valent, Hg^o) vapor in the high temperature regions of coal-fired boilers. As the flue gas is cooled, a series of complex reactions begin to convert mercury to ionic mercuric (Hg^{2+}) compounds and/or Hg compounds (Hg_p) that are in a solid-phase at flue gas cleaning temperatures or Hg that is adsorbed onto the surface of other particles. The presence of chlorine gas-phase equilibrium favors the formation of mercuric chloride ($HgCl_2$) at the temperatures used for flue gas cleaning (Lee *et al.,* 2006; Yang *et al.*, 2007; Wang *et al.*, 2008).

However, oxidation of zero-valent mercury is kinetically limited and, as a result, mercury enters the flue gas cleaning device(s) as a mixture of the zero-valent state and the mercuric state as well as solid-phase compounds. This partitioning of the various states of mercury (mercury speciation) can have considerable influence on selection of mercury control approaches. In general, the majority of gaseous mercury in bituminous coal-fired boilers is in the mercuric state (Hg^{2+}). On the other hand, the majority of gaseous mercury in subbituminous- and lignite-fired boilers is zero valent. Thus, mercury in flue gas exists as both elemental mercury and oxidized mercury vapor as well as mercury that has reacted with the fly ash as *solid phase mercury*.

Control of mercury emissions from coal-fired boilers is currently achieved via existing controls used to remove particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxides (NO_x). This includes capture of solid mercury emission in particulate matter control equipment and soluble mercuric compounds in wet flue gas desulfurization (FGD) systems. Available data also reflect that use of selective catalytic reduction (SCR) for NOx control enhances oxidation of zero valent mercury in flue gas and results in increased mercury removal in wet flue gas desulfurization systems.

In fact, the removal of the fly ash in an electrostatic precipitator or a fabric filter also removes the mercury that has reacted with the fly ash, resulting in 10 to 30% w/w removal for bituminous coal but less than 10% w/w removal for subbituminous coal and lignite. The oxidized mercury vapor left in the flue gas after the fly ash removal is effectively removed by wet flue gas desulfurization scrubbing, resulting in 40 to 60% w/w total mercury removal for bituminous coals and less than 30 to 40% w/w total mercury removal for subbituminous coals and lignite.

For low-sulfur subbituminous coals and particularly lignite, most of the mercury vapor is in the elemental form, which is not removed by wet flue gas desulfurization scrubbing. In bituminous coals, selective catalytic reduction (for NOx control) (Chapter 12) converted 85 to 95% w/w of the elemental mercury to the oxidized form, which is then effectively removed by wet flue gas desulfurization scrubbing. With subbituminous coals, the amount of mercury remained low even with addition of a selective catalytic reduction process.

Additional mercury removal can be achieved by powdered activate carbon injection (PAC) and an added fiber filter to collect the carbon. This can achieve up to 85-95% removal of the mercury. Removal rates are on the order of 90% w/w for bituminous coals but lower for subbituminous coals. For subbituminous coals, the injection of brominated, activated carbon is highly effective with a mercury removal efficiency of 90%.

No matter what governmental regulations are eventually adopted to mitigate the carbon dioxide emissions from coal-powered power plants (or other processes involving the combustion of substances containing carbon), there must be a successful, integrated large-scale demonstration of the technical, environmental and economic aspects of the major components of a carbon capture and sequestration system, namely carbon dioxide capture, transportation and storage. Such an integrated demonstration must also provide a definition of regulatory protocols for sequestration projects including site selection, injection operation, and eventual transfer of custody to public authorities after a period of successful operation.

11.5 Power Plant Efficiency

In terms of power plant efficiency, it is necessary that a valuable assessment of the coal feedstock be carried out. This involves the application of a series of test methods that commence with the coal in the seam which will assist the assist the plant operators to understand the nature of the feedstock and the available energy content of the coal at each step of the coal chain (Table 11.2).

Unfortunately, much of the energy content of the coal feedstock is wasted by inefficiencies the energy conversion and distribution processes and losses accumulate as follows: (i) approximately 10% of the energy content of the coal is lost in combustion and less than 90% of the calorific content is transferred to the steam, and (ii) the steam turbine efficiency in converting the energy content of the steam into mechanical energy is limited to approximately 40%.

Electric power plant efficiency is the ratio between the useful electricity output from the generating unit, in a specific time, and the energy value of the energy source supplied to the unit in the same time period. For electricity generation based on steam turbines, approximately 65% of all prime energy is wasted as heat. The efficiency may fall still further if fuels with lower energy content (such as biomass) are used to supply the power plant.

Briefly, the first stage of energy conversion is the combustion where the potential energy in coal is converted to heat energy. The efficiency of this conversion is approximately 90%. Due to practical limitations in heat transfer, all the heat produced by combustion is not transferred to the water; some is lost to the atmosphere as hot gases. In addition, the coal contains moisture (Chapter 5). Also coal contains a small percent of hydrogen, which may also be converted to moisture during combustion. In the furnace, moisture vaporizes taking latent heat from the combustion heat and exits the boiler along with the hot gases. Improper combustion of coal, hot ash discharged from the boiler and radiation are some of the other losses.

The second stage of conversion is the thermodynamic stage in which the heat from combustion is transferred to the water to produce steam. The energy of the steam is converted to mechanical rotation of the turbine after which the steam is condensed to water and pumped back into the boiler for reuse. This stage works on the principle of the Rankine cycle and for plants operating with steam at subcritical pressures (less than 3300 psi) and steam temperatures of 570°C (1060°F), the Rankine cycle efficiency is approximately 43%. For the state of the art plants running at greater than supercritical pressure and steam temperatures near to 600°C (1110°F), the efficiency is on the order of 47%. In addition, the steam is condensed for reuse and during this process the latent heat of condensation is lost to the cooling water, which is approximately 40% of the energy input. Losses in the turbine blades and exit losses at turbine end are some of the other losses.

Table 11.2 Examples of parameters for feedstock assessment in the coal chain.

Coal chain	Parameter
Coal seam database	ash fusion characteristics
	proximate analysis
	ultimate analysis
	mineral matter (ash-forming propensity)
	sulfur types
	toxic elements
Mine control database	free moisture (assessment for sticky coal*)
	size distribution
	sulfur content
	proximate analysis
	mineral matter (ash-forming constituents)
	hardness of the coal (Hardgrove Grindability Index)
Blending control database	size distribution
	mineral matter (ash-forming constituents)
	moisture consistency
	calorific value consistency
	sulfur consistency
Plant control database	moisture content
	sulfur content
	calorific value

*Sticky coal which arises from the fines and the moisture content; sticky coal hinders movement of the coal into and around the power plant.

The third stage converts the mechanical rotation to electricity in a generator in which copper, magnetic, and mechanical losses account for 5% in efficiency. More energy is lost in the step-up transformer which makes the power ready for transmission to the consumer. To operate the power plant it is required to run various auxiliary equipment – such as pulverizers, fans, pumps, and electrostatic precipitators. The power to operate these auxiliaries has to come from the power plant itself. For large power plants around 6% of the generator output is used for internal consumption.

Thus, there is the need to increase the fuel efficiency of coal-fueled power plants (DiPietro and Krulla, 2010). Currently, only one-third of the energy potential of coal is converted to electricity. Higher efficiencies mean even more affordable electricity and fewer greenhouse gases, and this is a worthwhile goal for the next decades. Among coals the higher-ranking coals enable higher efficiency because they contain less ash and less water. However, additional coal production is largely focused on the Powder River Basin (Wyoming) which is subbituminous.

While coal is the major fuel for electric power in the United States, natural gas is the fastest-growing fuel (Speight, 2014, 2019, 2020b) and the importance of coal to electricity generation worldwide is set to continue, with coal fueling 44% of global electricity in 2030. Natural gas is also likely to be a primary fuel for distributed power generators – mini-power plants that would be sited close to where the electricity is needed.

In the context of this text and electricity generation (power generation), coal plays a vital role worldwide. Coal-fired power plants currently fuel 41% of global electricity. In some countries, coal fuels a higher percentage of electricity.

The majority of the electricity currently generated in the United States is produced by facilities that employ steam turbine systems – other power generation systems employ a combination of the above, such as combined-cycle and cogeneration systems (Figure 11.1). The numbers of these systems being built are increasing as a result of the demands placed on the industry to provide economic and efficient systems.

Power plant efficiency is the amount of heat content in (Btu) per the amount of electric energy out (kWh), commonly called a heat rate (Btu/kWh).

For coal, the difference between gross calorific value (GCV) and net calorific value (NCV) (Chapter 5) stems from the assumptions made related to the availability of the energy present in the moisture in the combustion products. The gross calorific value measures all the heat released from fuel combustion, with the products being cooled back to the temperature of the original sample. In the net calorific value assessment, it is assumed that water in the combustion products is not condensed, so latent heat is not recovered. Using the net calorific value basis is questionable since a modern condensing boiler could potentially achieve a heating efficiency in excess of 100%, in violation of the first law of thermodynamics. Although some regions and industries prefer to use lower heating values in daily business, the true energy content of a fuel is its gross calorific value or higher heating value. Another complication, associated with fuel heating values, is the reference temperature used for their determination. Typically, calorific values are quoted based on a 25°C (77°F) reference temperature; however, 15°C (59°F) is also commonly used and other temperatures may be used after correction, if these differ from the temperature of the reactants and products at the start and end of the combustion test. Obviously, the use of values calculated on different reference temperature bases would result in different apparent heat input (IEA, 2010).

Nevertheless, assuming that the measurements of efficiency made in the past are commensurate and compatible with current measurements of efficiency, there have been improvements in power plant efficiency over time. However, these expected improvements mainly arise from the substitution of old plants with new plants that have better efficiency. Installation of environmental control systems will add internal energy requirements reducing the efficiency of the plant. Whether or not such changes will greatly increase the efficiency of a coal-fired power plant is subject to debate. Such changes typically, at best, only result in a few percentage point improvements to efficiency.

In addition, measuring coal-fired power plant efficiency consistently is particularly important at the global level, yet significant regional differences exist. Similarly, at the local level, the performance of individual generating units and power plants can only be compared if measured consistently. Although variations in efficiency may arise from differences in plant design and maintenance practices, the practical and operational constraints associated with different fuel sources, local ambient conditions and electricity dispatch all play significant roles. Misunderstanding these factors can result in the misinterpretation of efficiency data.

Thus, efficiency improvements can have broader impacts than simple monetary gains for the plant operator. Improvements can be viewed as a fuel supply – by increasing efficiency (i.e., decreasing the heat rate), less fuel is required to generate each kWh. In effect, more fuel supply is now available than would be otherwise. In large enough volumes, this could have market impacts on fuel costs. Likewise an increase in efficiency has an impact on the level of emissions a plant releases. Since less fuel is required to generate a given kWh, fewer emissions are released for that given kWh. Again, in large enough quantities this could impact emissions markets. However, the reasons for not adopting higher efficiency technologies are that they are not necessarily comparable to existing technology.

The efficiency of a power plant can be ascribed to two major parameters that are described in the following sections: (i) coal properties and (ii) combustion technology. Other parameters that can be added to this list are (i) the capacity factor, (ii) the availability factor, and (iii) the efficiency of the plant.

The net capacity factor of a power plant is the ratio of the actual output of a power plant over a period of time and its potential output if it had operated at full design over the entire time period. To calculate the capacity factor, the total amount of energy of the plant produced during a period of time is divided by the amount of energy the plant would have produced at full capacity. The capacity factor will vary considerably depending on the type of fuel that is used and the design of the plant. The capacity factor should not be confused with the availability factor or with the efficiency of the plant.

The *availability factor* of a coal-fired power plant is the amount of time that it is able to produce electricity over a specified time period divided by the amount of the time in the period. Occasions where only partial capacity is available may or may not be deducted. The availability factor should not be confused with the capacity factor. The availability of a power plant varies greatly depending on the type of fuel, the design of the plant and how the plant is operated. Typically a coal-fired power plant will have an availability factor on the order of 70% and 90%, and newer plants tend to have significantly higher availability factors, but preventive maintenance is as important as improvements in design and technology. Gas turbines have relatively high availability factors, ranging from 80% to 99% and are commonly used for peaking power plants, cogeneration plants, and the first stage of integrated gasification combined cycle (IGCC) power plants.

Finally, the efficiency of the power plant operations may be defined by using the *availability factor*, which is the amount of time that the power plant is able to produce electricity during a defined period of time divided by the amount of the time in the period. Occasions where only partial capacity is available may or may not be deducted.

The availability factor of a power plant varies greatly depending on (i) the type of fuel, (ii) the design of the plant, and (iii) the manner in which the plant is operated. Everything else being equal, plants that are run less frequently have higher availability factors because they require less maintenance. Most thermal power plants such as coal-fired power plants, geothermal plants, and nuclear power plants, have availability factors (typically between 70% and 90%). Newer plants tend to have significantly higher availability factors, but preventive maintenance is as important as improvements in design and technology. Gas turbines have relatively high availability factors, ranging from 80% to 99% and are commonly used for peak power plants, cogeneration plants, and combined cycle plants.

The availability factor of wind-powered plants and solar-powered plants depends on whether periods when the plant is operational, but there is no wind or sunlight, are counted as available, unavailable or disregarded. If these plants are counted as available during these times, photovoltaic plants have an availability factor approaching or equal to 100%. Modern wind turbines also have high availability factors on the order of 98%. However, solar-powered plants and wind-powered plants have relatively low capacity factors and the availability factors of such plants are much lower if the incidence of non-available wind and sunlight are taken into account.

11.6 Combined Cycle Generation

The use of these two types of turbines – a combustion turbine and a steam turbine in combination (combined cycle) is one reason why gasification-based power systems can achieve high power generation efficiency. Currently, commercially available gasification-based systems can operate at around 40% efficiencies; in the future, some IGCC systems may be able to achieve efficiencies approaching 60% with the deployment of advanced high pressure solid oxide fuel cells. A conventional coal-based boiler plant, by contrast, employs only a steam turbine-generator and is typically limited to 33 to 45% efficiencies. Higher efficiencies mean that less fuel is used to generate the rated power, resulting in better economics (which can mean lower costs to ratepayers) and the formation of fewer greenhouse gas emissions.

Thus, combined-cycle generation is a configuration using both gas turbines and steam generators. In a combined-cycle gas turbine (CCGT), the hot exhaust gases of a gas turbine are used to provide all, or a portion of, the heat source for the boiler, which produces steam for the steam generator turbine. This combination increases the thermal efficiency over a coal- or oil-fueled steam generator; the system has an efficiency of approximately 54%, and the fuel consumption is approximately 25% lower. Combined-cycle systems may have multiple gas turbines driving one steam turbine.

Another advantage of gasification-based energy systems is that when oxygen is used in the gasifier (rather than air), the carbon dioxide produced by the process is in a concentrated gas stream, making it easier and less expensive to separate and capture. Once the carbon dioxide is captured, it can be sequestered – prevented from escaping to the atmosphere, where it could otherwise potentially contribute to the commonly called *greenhouse effect*.

11.6.1 Cogeneration

Cogeneration is the simultaneous production of heat and power in a single thermodynamic process. Almost all cogeneration utilizes hot air and steam for the process fluid, although certain types of fuel cells also cogenerate. It is, in essence, the merging of a system designed to produce electric power and a system used for producing industrial heat and steam.

This system is a more efficient way of using energy inputs and allows the recovery of otherwise wasted thermal energy for use in an industrial process. Cogeneration technologies are classified as *topping cycle systems* and *bottoming cycle systems*, depending on whether electrical (topping cycle) or thermal (bottoming cycle) energy is derived first.

11.6.2 IGCC Technology

The integrated gasification combined cycle (IGCC) approach has been proposed to alleviate problems related to carbon dioxide emissions (Figure 11.3) (Van der Ploeg *et al.*, 2004).

IGCC allows the use of coal in a power plant that has the environmental benefits of a natural gas-fueled plant and the thermal performance of a combined cycle. In its simplest form, coal is gasified with either oxygen or air, and the resulting synthesis gas, or syngas, consisting primarily of hydrogen and carbon monoxide is cooled, cleaned, and fired in a gas turbine. The hot exhaust from the gas turbine passes through a heat recovery steam generator where it produces steam that drives a steam turbine. Power is produced from both the gas and steam turbine-generators. By removing the emission-forming constituents from the syngas under pressure prior to combustion in the power block, an IGCC power plant can meet extremely stringent emission standards.

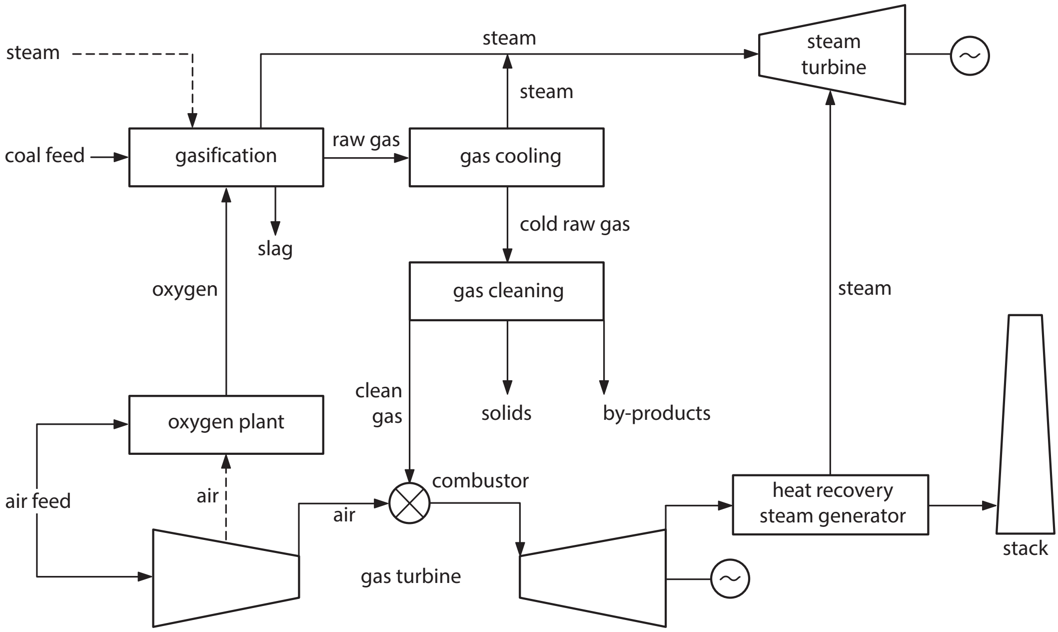

Figure 11.3 Schematic of an IGCC power plant.

Thus, IGCC systems involve gasification of coal, cleaning the gas, and combusting it in a gas turbine generator to produce electricity. Residual heat in the exhaust gas from the gas turbine is recovered in a heat recovery boiler as steam, which can be used to produce additional electricity in a steam turbine generator. IGCC systems are among the cleanest and most efficient of the emerging clean coal technologies. Sulfur, nitrogen compounds, and particulates are removed before the gas is burned in the gas turbine.

In the gasifier, the sulfur in the coal is released in the form of hydrogen sulfide (H_2S), which is readily removed by commercially available processes. By-products are salable sulfur or sulfuric acid. Sulfur removal exceeds 99.9%, and thermal efficiencies of over 50% can be achieved. High levels of nitrogen removal are also possible. Some of the nitrogen content of the coal is converted to ammonia (NH_3), which can be efficiently removed by established chemical processes (Mokhatab *et al.*, 2006; 2019). Nitrogen oxides are formed in the gas turbine can be held to well within allowable levels by staged combustion or by adding moisture to control flame temperature.

Thus, an IGCC power plant uses a coal gasification system to convert coal into a synthetic gas, which is then used as fuel in a combined cycle electric generation process. Coal is gasified by a process in which coal or coal/water slurry is reacted at high temperature and pressure with oxygen (or air) and steam to produce a combustible gas composed of a mixture of carbon monoxide (CO) and hydrogen (synthesis gas, syngas).

Gasification processes have been developed using a variety of designs including moving-bed, fluidized-bed, entrained-flow, and transport gasifiers (Chapter 10). Coal gasification processes are offered by a number of companies with varying degrees of existing commercial application. The hot syngas can then be processed to remove sulfur compounds, mercury, and particulate matter before it is used to fuel a combustion turbine generator to produce electricity. The heat in the exhaust gases from the combustion turbine is recovered to generate additional steam. This steam, along with the steam produced by the gasification process, then drives a steam turbine generator to produce additional electricity.

Historically, gasification has been used as industrial processes in the creation of chemicals, with power production as a secondary and subordinate process. In the last decade, the primary application of gasification to power production has become more common due to the demand for high efficiency and low environmental impact.

There are three types of gasifier classified by the configuration: entrained-flow gasifiers, fluidized-bed gasifiers and, moving-bed (also called fixed-bed) gasifiers (Speight, 2013, 2020b).

One of the advantages of the coal gasification technology is that it offers the polygeneration: co-production of liquid fuels, chemicals, hydrogen, and electricity from the syngas generated from gasification. Chemical gasification plants based on entrained flow and more especially on moving-bed technologies are at present operating all over the world with the biggest plants located in South Africa (Sasol) (Speight, 2013, 2020b). In addition, gasification is an important step of the indirect liquefaction of coal for production of liquid fuels (Speight, 2013, 2020b).

IGCC technology has advantages over pulverized coal combustion technology with respect to environmental benefits. After cleanup of the produced syngas, the sulfur in coal can be recovered to elemental form, the nitrogen oxide level will be low, and carbon dioxide can be more easily removed due to the high concentration, which would be the best selling point for IGCC power production. It is expected that IGCC may have a greater market penetration internationally due to the enforcement of carbon dioxide emission control. In addition, IGCC will consume less water than pulverized coal combustion units.

The efficiency of an IGCC power plant is comparable to the latest advanced pulverized coal-fired designs using supercritical boilers. The advantages of using IGCC technology can include greater fuel flexibility (e.g., capability to use a wider variety of coal ranks), potential improved control of particulate matter, sulfur oxide, emissions, and other air pollutants, with the need for fewer post-combustion control devices (e.g., almost all of the sulfur and ash in the coal can be removed once the fuel is gasified and prior to combustion), generation of less solid waste requiring disposal, and reduced water consumption. In addition, the IGCC technology provides several environmental benefits over pulverized coal-fired units. Since gasification operates in a low-oxygen environment (unlike pulverized coal-fired unit which is oxygen-rich for combustion), the sulfur in the fuel converts to hydrogen sulfide (H_2S), instead of Sulfur dioxide (SO_2). The hydrogen sulfide can be more easily captured and removed than sulfur dioxide. Removal rates of 99% and higher are common using technologies proven in the petrochemical industry (Speight, 2013, 2014, 2019, 2020b).

Disadvantages of using IGCC include additional plant complexity, higher construction costs, and poorer performance at high altitude locations when compared to an electricity generating unit using a supercritical boiler. However, IGCC power plants offer the potential for lower control costs of carbon dioxide emissions because the carbon dioxide in the syngas can be removed prior to combustion.

There are many variations on this basic IGCC scheme, especially in the degree of integration. It is the current general consensus among IGCC plant designers that the preferred design is one in which the air separation unit derives part of its air supply from the gas turbine compressor and part from a separate air compressor. Since prior studies have generally concluded that 25 to 50% air integration is an optimum range, this case study has been developed on that basis.

Three major types of gasification systems are used currently: (i) moving bed; (ii) fluidized bed, and (iii) entrained flow, although other options are also available (Chapter 10). Pressurized gasification is preferred to avoid large auxiliary power losses for compression of the syngas. Most gasification processes currently in use or planned for IGCC applications are oxygen-blown. High-pressure oxygen-blown gasification also provides advantages if carbon dioxide capture is considered at a later date.

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12

Gas Cleaning

12.1 Introduction

A major criticism of the use of coal for, in this context, power generation is the occurrence of process emissions. Flue gas and waste gases from power plants and other industrial operations where coal is used as a feedstock invariably contain constituents that are damaging to the climate or environment – these will be constituents such as carbon dioxide (CO_2), nitrogen oxides (NOx), sulfur oxides (SOx), dust and particles; and toxins such as dioxin and mercury. Yet, it is not often mentioned (to the point of being completely ignored) that gas cleaning is a major aspect of a power generation plant.

The processes that have been developed for gas cleaning vary from a simple once-through wash operation to complex multi-step systems with options for recycle of the gases (Mokhatab *et al.*, 2006; Speight, 2014, 2015, 2019, 2020). In some cases, process complexities arise because of the need for recovery of the materials used to remove the contaminants or even recovery of the contaminants in the original, or altered, form.

The purpose of preliminary cleaning of gases which arise from coal utilization is the removal of materials such as mechanically carried solid particles (either process products and/or dust) as well as liquid vapors (i.e., water, tars, and aromatics such as benzenes and/or naphthalenes); in some instances, preliminary cleaning might also include the removal of ammonia gas. For example, cleaning of a gas stream is the means to ensure that the stream is (i) free from tarry matter, including condensable aromatic derivatives such as naphthalene and (ii) the gas stream is purified by removal of materials such as hydrogen sulfide, other sulfur compounds, and any other unwanted components that will adversely affect the use of the gas (Mokhatab *et al.*, 2006; Speight, 2013, 2014, 2019).

12.2 General Aspects

Contrary to the general belief of some scientists and engineers, all gas cleaning systems are *not* alike and having a good understanding of the type of gaseous effluents from coal-based processes is necessary to implementing the appropriate solution.

The design of a gas cleaning system must always take into account the operation of the upstream installations since every process will have a specific set of requirements. In some cases, the application of a dry dusting removal unit may not be possible and thus requires a special process design of the wet gas cleaning plant. Thus, the gas cleaning process must always be of optimal design, one for both the upstream and downstream processes.

In more general terms, gas cleaning is divided into removal of particulate impurities and removal of gaseous impurities. For the purposes of this chapter, the latter operation

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includes the removal of hydrogen sulfide, carbon dioxide, sulfur dioxide, and the like. There is also need for subdivision of these two categories as dictated by needs and process capabilities such as (i) coarse cleaning whereby substantial amounts of unwanted impurities are removed in the simplest, most convenient, manner, (ii) fine cleaning for the removal of residual impurities to a degree sufficient for the majority of normal chemical plant operations, such as catalysis or preparation of normal commercial products; or cleaning to a degree sufficient to discharge an effluent gas to atmosphere through a chimney, and (iii) ultra-fine cleaning where the extra step (as well as the extra expense) is justified by the nature of the subsequent operations or the need to produce a particularly pure product.

To make matters even more complicated, a further subdivision of the processes, which applies particularly to removal of gaseous impurities, is by process character insofar as there are processes which rely upon chemical and physical properties/characteristics of the gas stream to enhance separation of the constituents. In addition, while conventional gas cleaning equipment – especially electrostatic precipitators or fabric filters for the removal of particulate matter, in many cases, flue gas desulfurization (FGD) units will still be needed for oxy-fuel power plants and will operate in an environment that is different from air-fired plants. These differences are characterized by higher concentrations of CO_2, SO_x, NO_x and H_2O as well as higher flue gas density and, depending on specific plant configurations, lower flue gas volume.

By way of explanation, oxy-fuel combustion is the process of burning a fuel using pure oxygen instead of air as the primary oxidant. Since the nitrogen component of air is not heated, fuel consumption is reduced, and higher flame temperatures are possible.

Since coal is a complex, heterogeneous material, there is a wide variety of constituents that are not required in a final product and must be removed during processing, and the oxy-fuel process may be more than sufficient for the removal of environmentally objectional constituents. Coal composition and characteristics vary significantly; there are varying amounts of sulfur, nitrogen, and trace-metal species which must be disposed of in an environmentally acceptable manner (Argonne, 1990). Thus whether the object of the power generating process is to produce a fuel gas or gas cleaning before ejection into the atmosphere, the stages required during this processing are numerous and can account for a major portion of a gas cleaning facility (Mokhatab *et al.,* 2006; Speight, 2013, 2014, 2019, 2020).

Thus, the oxy-fuel process offers an option for coal-fired power generation by use of an oxygen-enriched gas mix instead of air. Almost all of the nitrogen is removed from input air, yielding a stream that is approximately 95% v/v oxygen. Firing with pure oxygen would result in too high a flame temperature, so the mixture is diluted by mixing with recycled flue gas or staged combustion. The recycled flue gas can also be used to carry fuel into the boiler and ensure adequate convective heat transfer to all boiler areas. Oxy-fuel combustion produces approximately 75% v/v less flue gas than air fueled combustion and produces exhaust consisting primarily of carbon dioxide and water (vapor).

Generally, the majority of the sulfur that occurs naturally in the coal is driven into the product gas. Thermodynamically, the majority of the sulfur should exist as hydrogen sulfide, with smaller amounts of carbonyl sulfide (COS) and carbon disulfide (CS2). However, data from some operations (coke ovens) show higher than expected (from thermodynamic considerations) concentrations of carbonyl sulfide and carbon disulfide.

The existence of mercaptans, thiophenes, and other organic sulfur compounds in (gasifier) product gas will probably be a function of the degree of severity of the process, contacting schemes, and heat-up rate. Those processes that tend to produce tars and oils may also tend to drive off high molecular weight organic sulfur compounds into the raw product gas.

In general terms, the gaseous emissions from coal combustion and gasification facilities may be broadly classed as those originating from four processing steps: (i) pretreatment, (ii) conversion, and (iii) upgrading, as well as those from (iv) ancillary processes (Chapter 13). In conventional coal combustion power plants, pulverized coal is burned in a boiler, where the heat vaporizes water in steam tubes. The resulting steam turns the blades of a turbine, and the mechanical energy of the turbine is converted to electricity by a generator. Waste gases produced in the boiler during combustion, among them, sulfur dioxide, nitrogen oxide(s) and carbon dioxide, flow from the boiler to a particulate removal device and then to the stack and the air.

The sulfur dioxide, for example, that is produced during the combustion of coal or crude oil in power plants fuel will react with oxygen and water in the atmosphere to yield the environmentally detrimental sulfuric acid which is a contributor to acid rain.

$$S_{coal} + O_2 \rightarrow SO_2$$

$$2SO_2 + O_2 \rightarrow 2SO_3$$

$$SO_2 + H_2O \rightarrow H_2SO_3$$

$$2SO_2 + O_2 \rightarrow 2SO_3$$

$$SO_3 + H_2O \rightarrow H_2SO_4$$

Thus:

$$2SO_2 + O_2 + 2H_2O \rightarrow 2H_2SO_4$$

Using coal as an example, although the other two fossil fuels (natural gas and crude oil) are not necessarily free from blame even though there is the threat to *outlaw* coal in some countries (Coal & Synfuels Technology, 1992), the three major types of pollutants emitted by a coal-fired power plant are particulate matter, sulfur dioxide, and nitrogen oxides (NO). Particulate matter is generally the fine inorganic matter that is produced from mineral matter in the coal, although it may also be finely divided carbon which can also be produced during coal combustion or utilization. However, the material is mostly the finely divided inorganic matter and, for this reason, is referred to as *fly ash* which can be carried out of the stack with the hot exhaust gases (Chapters 13, 14). In fact, the practice of burning finely divided coal can contribute to fly ash emissions. Sulfur dioxide is produced by the oxidation of organic sulfur in the coal and is normally cited as the most troublesome of pollutants. From 10 to 50% of the nitrogen inherent in the organic coal structure is converted to nitric oxide during combustion.

$$N_{coal} + O_2 \rightarrow 2NO$$

$$2NO + O_2 \rightarrow 2NO_2$$

$$N_{coal} + O_2 \rightarrow NO_2$$

$$NO + H_2O \rightarrow H_2NO_3$$

$$NO_2 + H_2O \rightarrow HNO_3$$

Thus:

$$4NO_2 + O_2 + 2H_2O \rightarrow 4HNO_3$$

The hydrogen chloride, although not usually considered to be a major pollutant, is produced from mineral matter and other inorganic contaminants.

$$Cl_{coal\ minerals} + H_{coal} \rightarrow HCl$$

Hydrogen chloride quickly picks up water from the atmosphere to form droplets of hydrochloric acid and, like sulfur dioxide, is a contributor to acid rain. However, hydrogen chloride may exert severe local effects because, unlike sulfur dioxide, it does not need to participate in any further chemical reaction to become an acid. Under atmospheric conditions which favor a buildup of stack emissions in the area of a large power plant, the amount of hydrochloric acid in rain water could be quite high.

The nitrogen in the coal tends to gasify simultaneously with the carbon to form ammonia and cyanides (by reaction of ammonia with coal). High temperature processes, however, do not usually produce significant amounts of ammonia in the effluent gases, presumably because of the thermodynamic potential for ammonia to decompose to molecular nitrogen and hydrogen at high temperatures. On the other hand, in low-temperature gasifiers, the occurrence of high molecular weight nitrogenous compounds is anticipated because of the quantity of tar and high-boiling oil generated – these compounds include pyridine derivatives, pyrrole derivatives, azole derivatives, indole derivatives, quinoline derivatives, aniline derivatives, amine derivatives, and similar compounds. In addition, thiocyanate derivatives have been reported in the effluents (quench water) from gasifiers, to the exclusion of cyanide derivatives. However, the following reaction is not favored at the operating conditions:

$$H_2S + HCN \rightarrow HCNS + H_2$$

Conceivably, the reaction could occur by the action of hydrogen cyanide with sulfur

$$S_{coal} + HCN \rightarrow HCNS$$

The probability of quantitative reaction of hydrogen cyanide within the gasifier is small. There is also the possibility that the majority of the thiocyanates in gasifier effluents are due to the formation of thiocyanates by contact with air which is highly favored in aqueous media:

$$2H_2S + 2HCN + O_2 \rightarrow 2HCNS + 2H_2O$$

Other than a preliminary pyrolysis of the coal (to form a high-nitrogen coke), little if anything can be done during the pretreatment of coal to eliminate nitrogen since the nitrogen is part of the organic coal structure. The situation is less clear in the case of the sources of hydrogen chloride sources; both organic chlorine and inorganic chloride salts contribute to the formation of hydrogen chloride formation during combustion. Coal cleaning processes can reduce the mineral matter content but pretreatment processes do not remove organically bound chlorine, which is more likely to be the precursor to hydrogen chloride in a combustion process.

Pretreatment washing processes are also successful methods for removing inorganic sulfur but they do not affect the organic sulfur content. Thus, even before combustion begins, some of the sulfur can be removed from coal. For instance, commercially available processing methods crush the coal and separate the resulting particles on the basis of density, thereby removing up to approximately 30% w/w of the sulfur. But whilst pretreatment washing may remove up to 90% of the pyritic sulfur, up to 20% w/w of the combustible coal may also be removed and a balance must be struck between the value of the sulfur removed and coal lost to the cleaning process.

A wide range of metals occur in the coal in greater abundance than normally found in the crust of the Earth due to a concentration effect by the vegetation that initially formed the coal deposits. During coal processing (e.g., gasification) some of these elements may be present in the effluent either as vaporized metal or as a volatile compound.

The *average* (a most inaccurate term to say the least since it bears little relationship to the chemistry of the combustion of the different sulfur forms) sulfur content of coal burned to generate electricity is generally assumed to be on the order of 2.5% wt/wt. Many coals have a much higher sulfur content (Chapters 2, 5) (Berkowitz, 1979; Hessley *et al.,* 1986; Hessley, 1990) and, because of a variety of geographical, economic, as well as political issues, such coals are (or have to be) used for power generation.

Organic sulfur comprises 50 to 60% w/w of the total sulfur present in coal; it is an integral part of the coal structure and cannot he removed by mechanical means (Chapter 3). Pyritic sulfur accounts for most of the remaining sulfur in coal. Gravity separation techniques can readily remove pyritic sulfur from coal, if the pyrite particles in the coal are fairly large. The coal industry has used these techniques for many years. Many American coals permit the removal of approximately 50% w/w of the pyritic sulfur (FeS_2) in this way. The pyrite in some coals, however, is too fine to permit separation by these methods.

Gas processing, although generally simple in chemical and/or physical principles, is often confusing because of the frequent changes in terminology and, often, lack of cross-referencing (Mokhatab *et al.,* 2006; Speight, 2014, 2020). Although gas processing employs different process types there is always overlap between the various concepts. And, with the variety of possible constituents and process operating conditions, a "universal" purification system cannot be specified for economic application in all cases.

Nevertheless, the first step in gas cleaning is usually a device to remove large particles of coal and other solid materials (Mokhatab *et al.,* 2006; Speight, 2013, 2019, 2020). This is followed by cooling, quenching, or washing, to condense tars and oils and remove dust and water-soluble materials-phenols, chlorides, ammonia, hydrogen cyanide, thiocyanate, and perhaps some sulfur compounds from the gas stream. Water washing is desirable for simplicity in gas cleaning; however, the purification of this water is not simple.

Cleanup steps and their sequence can be affected by the type of gas produced and its end use (Mokhatab *et al.,* 2006; Speight, 2014, 2020). The minimum requirement in this respect would be the application of low heat-value (low-Btu) gas produced from low-sulfur anthracite coal as a fuel gas. The gas may pass directly from the gasifier to the burners and, in this case, the burners are the cleanup system. Many variations on this theme are possible and, in addition, the order of the cleanup stages may be varied.

The selection of a particular process-type for gas cleaning is not simple and several factors have to be considered, not the least of which is the constitution of the gas stream that requires treatment (Table 12.1). Indeed, process selectivity indicates the preference with which the process will remove one acid gas component relative to (or in preference to) another. For example, some processes remove both hydrogen sulfide and carbon dioxide whilst other processes are designed to remove hydrogen sulfide only (Table 12.2, Table 12.3).

Gas cleaning by absorption by a liquid or adsorption by use of a solid sorbent is one of the most widely applied operations in the chemical and process industries (Mokhatab *et al.,* 2006; Speight, 2013, 2014, 2019, 2020). Some processes have the potential for sorbent regeneration

Table 12.1 Summary of gas cleaning processes.

Sorbent	Nature of interaction	Regeneration	Examples
Liquid	Absorption + Chemical reaction	Yes	Many process for the removal of CO_2 and H2S from various gases, with solvents such as water + MEA, DEA, DIPA.
			Agents improving physical solubility may be added (Sulfinol process); H_2S may be recovered as such or oxidized to S.
Liquid + solid	Absorption + chemical reaction	Varies	Some slurry wash processes for flue gas desulfurization.
Liquid	Physical adsorption	Yes	CO_2 and H_2S from hydrocarbon gases; and solvents: N-methyl pyrrolidone, propylene carbonate, methanol.
Solid	Physical adsorption	Yes	Purification of natural gas (H_2S, CO_2) with molecular sieves.
		Yes	Gas drying operations (cyclic regenerative), molecular sieves.
		Varies	Odor removal from waste gases (active carbon).
Solid	Chemical reaction	No	H_2S from process gases, with ZnO.
		Yes	SO_2 from flue gases, with CuO/Al_2O_3

Table 12.2 Processes for hydrogen sulfide and carbon dioxide removal from gas streams.

Process	**Sorbent**	**Removes**
Amine	Monethanolamine, 15% in water	CO_2, H_2S
Economine	Diglycolamine, 50–70% in water	CO_2, H_2S
Alkazid	Solution M or DIK (potassium salt of dimethylamine acetic acid), 25% in water	H_2S, small amount of CO_2
Benfield, Catacarb	Hot potassium carbonate, 20–30% in water (also contains catalyst)	CO_2, H_2S; selective to H_2S
Purisol (Lurgi)	*N*-Methyl-2-pyrrolidone	H_2S, CO_2
Fluor	Propylene carbonate	H_2S, CO_2
Selexol (Allied)	Dimethyl ether polyethylene glycol	H_2S, CO_2
Rectisol (Lurgi)	Methanol	H_2S, CO_2
Sulfinol (Shell)	Tetrahydrothiophene dioxide (sulfolane) plus diisopropanolamine	H_2S, CO_2; selective to H_2S
Giammarco-Vetrocoke	K_3AsO_3 activated with arsenic	H_2S
Stretford	Water solution of Na_2CO_3 and anthraquinone disulfonic acid with activator	H_2S
Activated carbon	Carbon	H_2S
Iron sponge	Iron oxide	H_2S
Adip	Alkanolamine solution	H_2S; some COS, CO_2, and mercaptans
SNPA-DEA	Diethanolamine solution	H_2S, CO_2
Takahax	Sodium 1,4-naphthoquinone 2-sulfonate	H_2S

Table 12.3 Flue gas desulfurization systems in common use.

Wet	**Dry**
Limestone Forced Oxidation	Lime spray drying
Limestone Forced Oxidation/Organic Acid	Duct sorbent injection
Lime Dual-Alkali Process	Furnace sorbent injection
Magnesium-Promoted Lime	Circulating fluidized bed
Seawater Processes	
Sodium Scrubbing	
Ammonia Scrubbing	

Table 12.4 Simple classification system for acid gas removal processes.

Chemical absorption (chemical solvent processes)	**Physical absorption (physical solvent processes)**
Alkanolamines	
MEA	Selexol
SNPA:DEA (DEA)	Rectisol
UCAP (TEA)	Sulfinol[a]
Selectamine (MDEA)	
Econamine (DGA)	
ADIP (DIPA)	
Alkaline salt solutions	
Hot potassium carbonate	
Catacarb	
Benfield	
Giammarco-Vetrocoke	
Nonregenerable	
Caustic	

[a] A combined physical/chemical solvent process.

but, in a few cases, the process is applied in a non-regenerative manner. The interaction between sorbate and sorbent may either be physical in nature or consist of physical sorption followed by chemical reaction. Other gas stream treatments use the principle of chemical conversion of the contaminants with the production of benign (non-contaminant) products or to substances which can be removed much more readily than the impurities from which they are derived (Mokhatab *et al.,* 2006; Speight, 2014, 2020).

There are many variables in gas cleaning and the precise area of application of a given process is difficult to define although there are several factors that need to be considered such as (i) the types and concentrations of contaminants in the gas, (ii) the degree of contaminant removal desired, (iii) the selectivity of acid gas removal required, (iv) the temperature, pressure, volume, and composition of the gas to be processed, (v) the carbon dioxide to hydrogen sulfide ratio in the gas, and (vi) the desirability of sulfur recovery due to process economics or environmental issues.

Any gases, such as hydrogen sulfide and/or carbon dioxide, that are the products of coal processing can be removed by application of an amine washing procedure.

$$2RNH_2 + H_2S \rightarrow (RNH_3)_2S$$

$$(RNH_3)_2S + H_2S \rightarrow 2RNH_3HS$$

$$2RNH_2 + CO_2 + H_2O \rightarrow (RNH_3)_2CO_3$$

$$(RNH_3)_2CO_3 + H_2O \rightarrow 2RNH_3HCO_3$$

There are also *solvent extraction* methods for producing low-sulfur and low-mineral matter coal but hydrotreatment of the coal extract is also required. In these methods, the organic material is extracted from the inorganic material in coal. A study has indicated that solvent-refined coal will probably not penetrate the power generation industry on a large scale for several years to come.

In addition to hydrogen sulfide and carbon dioxide, gas streams may contain other contaminants such as sulfur dioxide, mercaptans and carbonyl sulfide.

The presence of these impurities may eliminate some of the sweetening processes since some processes will remove large amounts of acid gas but not to a sufficiently low concentration. On the other hand, there are those processes that are not designed to remove (or are incapable of removing) large amounts of acid gases whereas they are capable of removing the acid gas impurities to low levels when the acid gases are there in low-to-medium concentrations in the gas stream.

Many different methods have been developed for carbon dioxide and hydrogen sulfide removal, some of which are briefly discussed below. Concentrates of hydrogen sulfide obtained as by-products of gas desulfurization, are often converted by partial oxidation to elemental sulfur (Claus process).

For large gas volumes containing high concentrations of carbon dioxide mixed with hydrogen sulfide, a likely but by no means unique sequence of treatments is possible (Probstein and Hicks, 1990). Most of the carbon dioxide and hydrogen sulfide are removed in a regenerable liquid absorbent which is continuously circulated and the final traces of hydrogen sulfide which, for example in a refining scenario, might poison processing catalysts are removed in a solid adsorbent which can be regenerated or discarded. Off-gas from the solvent-section of the process may be treated in a Claus unit for recovery of sulfur. The final cleanup of the Claus plant off-gas, usually referred to as "tail gas," can be by a direct conversion process.

12.3 Air Pollution Control Devices

The processes that have been developed for gas cleaning (Mokhatab *et al.,* 2006; Speight, 2013, 2014, 2019, 2020) vary from a simple once-through wash operation to complex multistep systems with options for recycle of the gases (Mokhatab *et al.,* 2006). In some cases, process complexities arise because of the need for recovery of the materials used to remove the contaminants or even recovery of the contaminants in the original, or altered, form.

The environmental impact of coal-based power plants has drawn increasing attention, not only for controlling pollutants like sulfur dioxide (SO_2), oxides of nitrogen (NOx), particulates (PM), but also for controlling the emission of carbon dioxide (CO2), as there is there is an increasing need to reduce the emissions of carbon dioxide to the atmosphere to alleviate the global warming effect. It induces significant challenges to generate electricity efficiently together with near-zero carbon dioxide emissions.

In the process, carbon dioxide, hydrogen, and other coal by-products are captured so they can be used for useful purposes. Evolving technologies are also making coal at existing plants cleaner – refined coal technologies remove many of the impurities contained in existing coal.

On this note, mercury is present in coal in trace amounts (0.01 to 0.5 mg/kg) (Speight, 2013, 2015) and at the high temperatures in combustion zone of boilers, combustion releases the Hg in coal into the exhaust gas as elemental mercury (Hg^0). This vapor may then be oxidized by hydrogen chloride and sulfur dioxide by thermo-chemical processes. Oxidized mercury (Hg^{2+}) is soluble and has a tendency to associate with the particles in flue gas to form particulate-bound mercury. Therefore, emissions of oxidized mercury (i.e., Hg^{2+}), may be efficiently controlled by typical air pollution control devices such as electrostatic precipitators (ESP), fabric filter (FF), and flue gas desulfurization (FGD) systems. In fact, new techniques are helping remove mercury and harmful gases while unlocking more energy potential (Wang *et al.,* 2010).

12.3.1 Nitrogen Oxide Emissions

The provisions of the Clean Air Act Amendments have also affected nitrogen oxide (NOx) emissions and their controls for the electric utility industry. The process for reducing nitrogen oxide emissions through combustion control technologies has generally increased the amount of unburned carbon content and the relative coarseness of fly ash at many locations. In particular, post-combustion control technologies for nitrogen oxide emissions such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) both utilize ammonia injection into the boiler exhaust gas stream to reduce nitrogen oxide emissions. As a result, the potential for ammonia contamination of the fly ash due to excessive ammonia slip from SCR/SNCR operation is an additional concern.

12.3.2 Sulfur Oxide Emissions

The methods for controlling sulfur oxides from coal which in turn impact the combustion system design can be classified into three types: (i) sulfur removal after combustion, (ii) sulfur removal during combustion, and (iii) sulfur removal before combustion.

The first approach (i.e., sulfur removal after combustion) is currently receiving the most attention in many industrialized countries because it does not represent a significant departure from existing coal-fired power plant technology. Ordinarily a wet scrubber can be used to remove sulfur oxides from the flue gas. However, currently available sulfur oxide control technology has proven to be expensive, is subject to operational difficulties, and produces a liquid or dry waste product which must be disposed. It is, however, the approach which is now generally accepted by the utility industry.

The second sulfur removal technology (i.e., sulfur removal during combustion) primarily involves the use of fluidizedbed coal combustion. In this type of process, a desulfurization chemical (such as solid limestone) is injected into the burning coal bed where it reacts with sulfur dioxide. The resulting calcium sulfate compound is then removed from the bed in solid form with the coal ash.

The final type of sulfur removal technology is best illustrated by use of physical methods of coal cleaning (Chapter 3), although sufficiently high sulfur removal efficiencies are not always possible. Another option that falls into this category is the conversion of coal to low-sulfur products, such as by liquefaction or gasification (Speight, 2013). The greatest obstacle to implementation of this technology is the excessive costs of converting the coal to a clean fuel.

Partial flue gas desulfurization (FGD) can achieve approximately 50 to 70% removal of sulfur dioxide by the injection of dry limestone downstream of the air preheater (Figure 12.1). The resultant solids are recovered in the electrostatic precipitators along with the fly ash. In power plants burning pulverized coal, wet flue gas desulfurization (FGD) that contacts the flue gases with lime slurries (in what are called wet lime scrubbers) (Figure 12.2) can achieve 95% sulfur dioxide removal without additives and in excess of 99% removal with additives. Wet flue gas desulfurization has the greatest share of the flue gas desulfurization usage in the United States and it is commercially proven, well-established technology. The typical older flue gas desulfurization units in power plants burning pulverized coal in the United States achieve sulfur dioxide emission levels, which meets the level to which those units were permitted.

Wet flue gas desulfurization systems frequently utilize calcium-based sorbents and produce either wet flue gas desulfurization material (sludge or unoxidized wet flue gas desulfurization material) or flue gas desulfurization gypsum (from forced-oxidation systems).

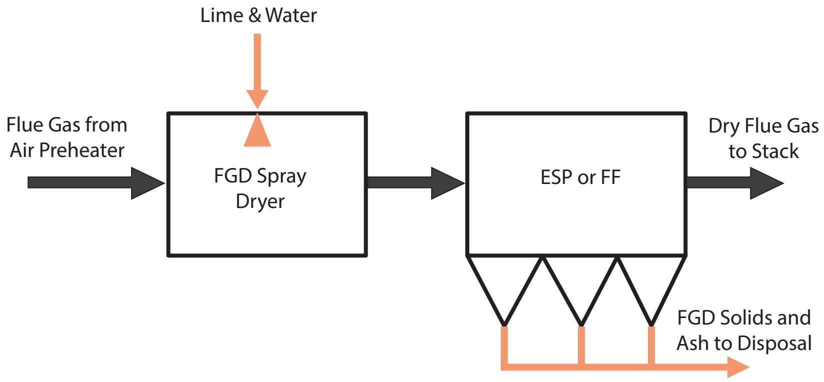

Figure 12.1 A dry process for flue gas desulfurization (key: ESP – electrostatic precipitator; FF – fabric filter).

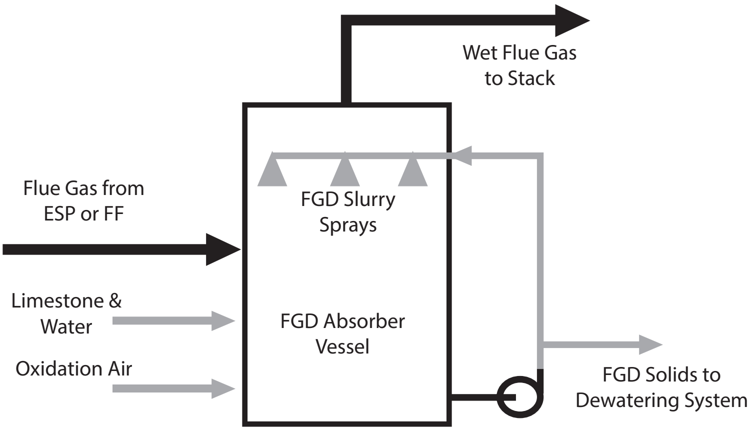

Figure 12.2 A wet process for flue gas desulfurization (key: ESP – electrostatic precipitator; FF – fabric filter).

These materials have similar bulk chemical compositions, but have different mineralogical compositions. The chemical composition of wet flue gas desulfurization material depends largely on the sorbent used for desulfurization and the proportion of fly ash collected with the flue gas desulfurization residues. Wet flue gas desulfurization material is composed primarily of calcium sulfite hemihydrate (hannebachite, $CaSO_3.½H_2O$). Both wet flue gas desulfurization material and flue gas desulfurization gypsum are primarily crystalline in their morphology. The purity of flue gas desulfurization gypsum ranges from 96 to 99% w/w. The physical properties of wet flue gas desulfurization materials vary significantly depending on the relative proportions of sulfate ($CaSO_4$) and sulfite ($CaSO_3$) from each system.

Like wet flue gas desulfurization materials, the chemical composition of spray dryer material residues depends on the sorbent used for desulfurization and the proportion of fly ash collected with the flue gas desulfurization residues. The fly ash in dry flue gas desulfurization materials has similar particle size, particle density, and morphology to those of conventional fly ash, but flue gas desulfurization materials have lower bulk densities. The difference in bulk density is due to variations in the chemical and mineralogical characteristics of the reacted and unreacted sorbent. Dry flue gas desulfurization materials contain higher concentrations of calcium and sulfur and lower concentrations of silicon, aluminum, and iron than fly ash.

Both wet and dry materials are produced wet in the scrubbers and are then thickened and dried for handling and/or recycling. The complexity of the dewatering process is determined by the chemical composition and crystalline formation of the spent sorbent and whether the end product is to be utilized or disposed of. Sometimes when commercial-quality gypsum is made, a pelletization process is used.

Regulations to reduce sulfur dioxide emissions result in the introduction of wet scrubber flue gas desulfurization (FGD) systems which can produce gypsum as a by-product. In 1990, overall annual sulfur dioxide (SO_2) emissions from electric utility companies had fallen 46%. In 1990, the Clean Air Act Amendments were enacted, requiring electric utility companies nationwide to reduce their collective sulfur dioxide emissions.

Many coals of the western United States (and some eastern US coals) are naturally low in sulfur and can be used to meet the SO2 compliance requirements. Blending coals of different sulfur contents to achieve a mix that is in compliance with applicable regulation is also common. Wet flue gas desulfurization (FGD) systems are currently installed on at least one-quarter of the coal-fired utility generating capacity in the United States.

Thus, many governments currently have emissions standards for coal and other power generating facilities. Each coal facility must meet air quality standards in order to operate. IGCC, or integrated gasification combined cycle generation, is one of the most widely discussed clean coal technologies. During this process, coal reacts with steam under high pressure and heat to form a hydrogen gas, which powers a gas turbine. Exhaust from the gas turbine is hot enough to power a conventional steam turbine as well, increasing efficiency.

Air pollution control devices (gas cleaning devices) found in fossil fuel-fired systems (particularly steam electric power facilities) include particulate removal equipment, sulfur oxide (SO_x) removal equipment, and nitrogen oxide (NO_x) removal equipment.

Particulate removal equipment includes electrostatic precipitators, fabric filters, or mechanical particulate collectors, such as cyclones. Sulfur dioxide removal equipment includes sorbent injection technologies as well as wet and dry scrubbers. Both types of scrubbers result in the formation of calcium sulfate and sulfite as waste products.

The state of the art of the implemented systems for reduction of sulfur dioxide and nitrogen oxides in the current pulverized coal combustion plants are flue gas desulfurization (FGD), low NOx burner, and selective catalytic reduction (SCR) of NOx. A typical modern coal-fired boiler system eliminates up to 97% of the combined sulfur dioxide (SO2) and nitrogen oxides (NOx) emissions.

A novel process is proposed that replaces the combustion step with solid oxide fuel cells (SOFC) (Adams and Barton, 2010). A solid oxide fuel cell oxidizes hydrogen electrochemically, producing electricity without the thermodynamic limitations of heat engines. The solid oxide fuel cell is designed to have separate anode (fuel) and cathode (air) sections, so air can be used for oxidation without diluting the fuel stream with nitrogen. This permits easy separation of the anode exhaust (water and carbon dioxide) with a low energy penalty and no solvent recovery step. The spent air stream, being heated by the solid oxide fuel cell, can provide additional power through the Brayton cycle. Together, these innovations provide higher plant efficiency, significantly reduce the energy penalty of carbon dioxide capture, and facilitate recycle of water in the process.

12.4 Particulate Matter Removal

Gas cleaning and process systems characterized by high content of particulate matter that can occur (as a result of coal combustion) present a unique challenge in the treatment of gas streams. These systems can develop severe deposition and/or corrosion problems in a short period of time. The deposits are often of an unusual composition, which can vary widely throughout a single system. The deposit and corrosion problems can cause sudden losses of production time, increased labor costs, and frequent equipment replacement. Moreover, particulate emissions from coal-fired boilers are considered to be abrasive and can cause erosion within the mechanical collector. Such erosion reduces the efficiency of particulate matter collection over time unless corrective maintenance procedures are employed.

Furthermore, the detrimental effects of particulate matter on the atmosphere have been of some concern for several decades. In fact, the total output of particulate matter into the atmosphere has increased in Europe since medieval times (Brimblecombe, 1976) and, although the sources are various, there is special concern because of the issue of particulate matter from fossil fuel use (Cawse, 1982). Species such as mercury, selenium, and vanadium which can be ejected into the atmosphere from fossil fuel combustion (Kothny, 1973; Lakin, 1973; Zoller *et al.,* 1973) are particularly harmful to the flora and fauna mercury. Thus, there is the need to remove such materials from gas streams that are generated during fossil fuel processing. The following processes are typical processes for the treatment of gas streams with a high content of particulate matter: (i) wet scrubbers, and (ii) wet electrostatic precipitators.

In addition, mercury can also occur in the flue gas in the elemental form (Hg^o) and in the oxidized form (Hg^{2+}), both in the vapor, and as mercury that has reacted with the fly ash. This third form of mercury is removed with the fly ash, resulting in 10 to 30% w/w removal for bituminous coal but less than 10% w/w removal for subbituminous coal and lignite. The oxidized form of mercury is effectively removed by wet flue gas desulfurization scrubbing, resulting in 40 to 60% w/w total mercury removal for bituminous coal and less than 30 to 40% w/w total mercury removal for subbituminous coal and lignite. For low-sulfur subbituminous coal and particularly lignite, most of the mercury is in the elemental form, which is not removed by wet flue gas desulfurization scrubbing. In bituminous coal, selective catalytic reduction (SCR), for NOx control converts 85 to 95% of the elemental mercury to the oxidized form, which is then removed by flue gas desulfurization. With subbituminous coal, the amount of oxidized mercury remained low even with addition of a selective catalytic reduction process. Additional mercury removal can be achieved by activated carbon injection and an added fiber filter to collect the carbon, which can achieve up to 85 to 95% w/w removal of the mercury.

There are many types of particulate collection devices in use and they involve a number of different principles for removal of particles from gas streams (Licht, 1988). However, the selection of an appropriate particle removal device must be based upon equipment performance as anticipated/predicted under the process conditions. To enter into a detailed description of the various devices available for particulate removal is well beyond the scope of this text. However, it is essential for the reader to be aware of the equipment available for particulate removal and the means by which this might be accomplished.

12.4.1 Electrostatic Precipitators

Electrostatic precipitators (Parker and Calvert, 1977; White, 1977) are efficient collectors of fine particulates matter and are capable of reducing the amount of submicron particles by 90%, or more; they have the capability of collecting liquid mists as well as dust.

The basic components of a precipitator are the discharge (or corona) electrode, the collection electrode (plates), and the precipitator shell. Other components are the dust hopper, high-voltage equipment, and gas distributors. Suspended particles are charged by collisions with the negative ions passing through the zone between the corona and the collection electrode. Movement of the particles to the collection electrode is governed by the interaction of the electric field and charged particles in the moving gas stream.

Thus, particulate collection in an electrostatic precipitator occurs in three steps: (i) suspended particles are given an electrical charge, (ii) the charged particles migrate to a collecting electrode of opposite polarity while subjected to a diverging electric field, and (iii) the collected particulate matter is dislodged from the collecting electrodes.

Removal of the collected particulate matter is accomplished mechanically by rapping or vibrating the collecting electrodes. When applied to anthracite coal-fired boilers, electrostatic precipitators may have a low efficiency on the order of 90 to 97% due to the characteristically high resistivity of the low-sulfur anthracite fly ash. Higher efficiency can be achieved using larger electrostatic precipitators with prior flue gas conditioning.

When applied to coal-fired boilers, electrostatic precipitators are often used downstream of mechanical collector pre-cleaners which remove larger-sized particles. When applied to anthracite coal-fired boilers, electrostatic precipitators typically are only 90 to 97% efficient, because of the characteristic high resistivity of low-sulfur anthracite fly ash. Higher efficiencies can be achieved using larger precipitators and flue gas conditioning.

The operation of an electrostatic precipitator can be affected by the sulfur content of the coal. Sulfur in the coal is oxidized to form mainly sulfur dioxide. However, a small amount of the sulfur dioxide is oxidized further to form sulfur trioxide, which will form sulfuric acid in the presence of water vapor. Sulfuric acid condenses on the surface of the fly ash particles if the temperature of the particles is below the dew point of the acid. The amount of condensed sulfuric acid depends on the sulfur content of the coal. This *conditioning* produces an electrically conductive film that improves the collection efficiency of the electrostatic precipitator. However, this conditioning will only occur if the temperature of the particles is below the acid dew point temperature.

The coal properties which have the most impact on electrostatic precipitator performance are (i) mineral matter content, reflected as the yield of the ash after combustion, (ii) the composition of the ash, and (iii) the particle size distribution in the ash. These factors impact on the dust loading, collection efficiency and residual emissions to the atmosphere – if the latter is higher than regulations allow, plant output would need to be reduced. Also, the moisture content of the coal feedstock is an important aspect of the process because increased moisture levels in the gas from the combustor (the flue gas) will generally have a beneficial effect on electrostatic precipitator collection efficiency.

12.4.2 Fabric Filters

Fabric filters (*baghouses*) use the principle of filtration in which particulate-laden dust is passed through a set of filters mounted inside the collector housing. Dust particles in the inlet air are retained on the filters by inertial impaction, diffusion, direct interception, and sieving. The first three processes prevail only briefly during the first few minutes of filtration with new or recently cleaned filters, while the sieving action of the dust layer accumulating on the fabric surface soon predominates. The sieving mechanism leads to high efficiency particulate matter collection unless defects such as pinhole leaks or cracks appear in the filter cake. The particulate matter collection efficiencies for fabric filters operating on coal-fired are on the order of 99%+.

Cleaning of the bag filters typically occurs in one of three ways. In shaker cleaning, the bags are oscillated by a small electric motor. The oscillation shakes most of the collected dust into a hopper. In reverse air cleaning, backwash air is introduced to the bags to collapse them and fracture the dust cake. Both shaker cleaning and reverse air cleaning require a sectionalized baghouse to permit cleaning of one section while other sections are functioning normally. The third cleaning method, pulse jet cleaning, does not require sectionalizing. A short pulse of compressed air is introduced through venturi nozzles and directed from the top to the bottom of each bag. The primary pulse of air aspirates secondary air as it passes through the nozzles. The resulting air mass expands the bag and fractures the cake.

12.4.3 Granular-Bed Filters

Granular-bed filters comprise a class of filtration equipment that is distinguished by a bed of separate, closely packed granules which serve as the filter medium and have the ability to collect particulates at high temperature and pressure. Although eminently suitable for low-temperature cleanup of gas streams, an attractive feature of granular-bed filters is the potential for high-temperature cleanup of process gas. It is also conceivable that these filters can be used for simultaneous control of particulates and hydrogen sulfide (by adsorption) at high temperature because of their ability to use almost any material as the filter medium.

Granular-bed filters are classified according to the method used to remove collected dust from the filter medium continuously moving, intermittently moving, or fixed-bed filters. Cleaning is required to prevent interstitial plugging, which can cause pressure drop. This requirement distinguishes granular-bed filters from fluidized-bed systems, which utilize the product gas to keep the granules in motion and prevent plugging.

Continuously moving systems may be arranged in a cross-flow configuration in which the gas passes horizontally through the granular layer while the granules and collected dust move continuously downward and are collected at the bottom. The dust and granules are then separated and the cleaned granules returned to the bed. In the intermittently moving-bed concept, the bed is stationary during filtration. Accumulated dust and the surface layer of granules are removed from the panel by a backwash pulse and replaced by fresh granules from the overhead hoppers. Fixed-bed systems use either backwash air and/or mechanical agitation to remove collected dust.

12.4.4 Scrubber Systems

Scrubber systems are methods used to clean flue gas and remove toxic or smelling compounds. In the flue gas scrubber, the gas gets in close contact with an adsorbent in a co-current or countercurrent flow. A scrubber system can also be combined with other flue gas cleaning methods. Gases can be first cleaned by a washer, then treated by a thermal reactor, and then treated again by a scrubber.

Currently, the two most common scrubber technology used are (i) wet systems or (ii) dry systems (Table 12.3). A third system, the semi-dry system – often considered to be a hybrid of the wet and dry systems – is also in used in some gas cleaning operations.

12.4.4.1 Wet Systems

A wet scrubber is a collection device which uses an aqueous stream or slurry to remove particulate and/or gaseous pollutants.

Wet flue desulfurization systems frequently utilize calcium-based sorbents and produce either wet flue desulfurization material (sludge or unoxidized wet flue desulfurization material) or flue desulfurization gypsum (from forced-oxidation systems). These materials have similar bulk chemical compositions, but have different mineralogical compositions. The chemical composition of wet flue desulfurization material depends largely on the sorbent used for desulfurization and the proportion of fly ash collected with the flue desulfurization residues. Wet flue desulfurization material is composed primarily of calcium sulfite hemihydrate (hannebachite, $2CaSO_3.H_2O$). Both wet flue desulfurization material and flue desulfurization gypsum are primarily crystalline in their morphology. The purity of flue desulfurization gypsum ranges from 96% to 99%. The physical properties of wet flue desulfurization materials vary significantly depending on the relative proportions of sulfate and sulfite from each system (Clarke, 1993).

However, the bulk physical properties of dry desulfurization materials are similar to fly ash; therefore, the material must be handled similarly. Although the physical properties of these materials are similar, dry flue gas desulfurization material is primarily crystalline in its morphology, and fly ash is primarily glassy or amorphous. As a result, flow characteristics of dry FGD material may vary significantly from fly ash.

Wet flue gas desulfurization systems introduce a spray of alkaline sorbent consisting of lime or limestone (primarily limestone) into the exhaust gas. The alkali reacts with the sulfur dioxide to form calcium sulfite ($CaSO_3$) or calcium sulfate ($CaSO_4$) that is collected in a liquid slurry form. The calcium sulfite or sulfate is allowed to settle out and the majority of the water is recycled. The settled material (*flue gas desulfurization scrubber material* or *scrubber sludge*) is an off-white slurry with a solids content in the range of 5 to 10% w/w. Because coal-fired power plants typically have both a flue gas desulfurization systems and a fly ash removal system, fly ash is sometimes incorporated into the flue gas desulfurization material.

There are three basic mechanisms involved with collecting particulate matter in wet scrubbers: (i) interception, (ii) inertial impaction, and (iii) diffusion of particles on droplets. The interception and inertial impaction effects dominate at large particle diameters; the diffusion effects dominate at small particle diameter.

Wet scrubbers are usually classified by energy consumption (in terms of gas-phase pressure drop). Low-energy scrubbers, represented by spray chambers and towers, have low pressure drop. Medium-energy scrubbers such as impingement scrubbers have greater pressure drop and high-energy scrubbers such as high-pressure drop venturi scrubbers have exhibit higher removal levels of particulate matter.

Wet scrubbers have particulate matter collection efficiencies on the order of 90% or greater. However, operational problems can occur with wet scrubbers due to logged spray nozzles, sludge deposits, dirty recirculation water, improper water levels, and unusually low-pressure drops.

In a wet scrubber system, flue gas is ducted to a spray tower where an aqueous slurry of sorbent is injected into the flue gas. To provide good contact between the waste gas and sorbent, the nozzles and injection locations are designed to optimize the size and density of slurry droplets formed by the system.

A portion of the water in the slurry is evaporated and the waste gas stream becomes saturated with water vapor. Sulfur dioxide dissolves into the slurry droplets where it reacts with the alkaline particulates. The slurry falls to the bottom of the absorber where it is collected. Treated flue gas passes through a mist eliminator before exiting the absorber which removes any entrained slurry droplets. The absorber effluent is sent to a reaction tank where the sulfur dioxide-alkali reaction is completed forming a neutral salt. In a regenerable system, the spent slurry is recycled back to the absorber. Once-through systems dewater the spent slurry for disposal or use as a by-product.

Typical sorbent material is limestone, or lime. Limestone is very inexpensive but control efficiencies for limestone systems are limited to approximately 90%. Lime is easier to manage on-site and has control efficiencies up to 95% but is significantly more costly (Cooper, 2002). Proprietary sorbents with reactivity-enhancing additives provide control efficiencies greater than 95% but are very costly. Electrical utilities store large volumes of limestone or lime on-site and prepare the sorbent for injection, but this is generally not cost effective for smaller industrial applications.

The volume ratio of reagent slurry to waste gas is referred to as the liquid to gas ratio. The liquid to gas ratio determines the amount of reagent available for reaction with sulfur dioxide. Higher liquid to gas ratio ratios result in higher control efficiencies. Higher liquid to gas ratios also increase oxidation of the sulfur dioxide, which results in a decrease of the formation of scale in the absorber.

Oxidation of the slurry sorbent causes gypsum (calcium sulfate) scale to form in the absorber. Limestone forced oxidation (LSFO) is a newer process based on wet limestone scrubbing which reduces scale. In the limestone forced oxidation process, air is added to the reaction tank which oxidizes the spent slurry to gypsum. The gypsum is removed from the reaction tank prior to the slurry being recycled to the absorber. The recycle slurry has a lower concentration of gypsum and scale formation in the absorber is significantly reduced. In addition to scale control, the larger size gypsum crystals formed in limestone forced oxidation settle and dewater_more efficiently, reducing the size of the by-product handling equipment (EPA, 2002). However, limestone forced oxidation requires additional blowers which increase the capital and annual costs of the system.

Wet limestone scrubbing has high capital and operating cost due to the handling of liquid reagent and waste. Nonetheless, it is the preferred process for coal-fired electric utility power plants burning coal due to the low cost of limestone and sulfur oxide control efficiencies from 90% up to 98% (Schnelle, 2002).

By dissolving water-soluble components, the water or washing liquid will be contaminated in many cases. The dissolved components are frequently acid or basic chemicals (such as hydrogen chloride, nitrogen oxides, and sulfur oxides. An optional neutralization unit, installed in the wet scrubber, is often required to keep the pH value of the washing liquid and the waste water at a neutral level. Furthermore absorption of acid components is improved by using basic washing liquid and removal of basic chemicals is more effective by using acid washing liquid.

When hot raw gas is to be cooled directly or if it has already been cooled in a waste-heat recovery system, it will normally be treated in a wet scrubber. Wet scrubbers are devices that utilize gas/liquid contacting to cool the gas stream, condense high-boiling hydrocarbon derivatives, dissolve some constituents, and separate particles from gas streams. There are many different wet scrubber designs, but all utilize similar mechanisms. For wet scrubbers, typical inlet gas temperatures are 150 to 370°C (300 to 700°F).

Wet scrubbers have reported particulate matter collection efficiencies of 90% or greater. Gaseous emissions such as sulfur dioxide, nitrogen oxides, carbon monoxide, and organic emissions may also be absorbed to a significant extent in a wet scrubber. Operational problems can occur with wet scrubbers due to clogged spray nozzles, sludge deposits, dirty recirculation water, improper water levels, and unusually low pressure drops.

Mechanical collectors, or cyclones, use centrifugal separation to remove particulate matter from flue gas streams. At the entrance of the cyclone, a spin is imparted to the particle-laden gas – the spin creates a centrifugal force which causes the PM to move away from the axis of rotation and toward the walls of the cyclone. Particles which contact the walls of the cyclone tube are directed to a dust collection hopper where they are deposited. Mechanical collectors typically have particulate matter collection efficiencies up to 80%.

A type of wet scrubber that has been widely applied to coal-generated gas is the venturi scrubber (Figure 12.3); gas streams are passed through a tube to contact with water, which is added at the throat. The throat promotes intimate mixing of the gas and liquid. The liquid, which forms droplets ranging in size from 100 to 1000 micron, collects particulates mainly by inertial impaction.

Venturi scrubbers are the most widely used wet scrubbers for anthracite coal-fired boilers. In a typical venturi scrubber, the particle-laden gas first contacts the liquor stream in the core and throat of the venturi section. The gas and liquid streams then pass through the annular

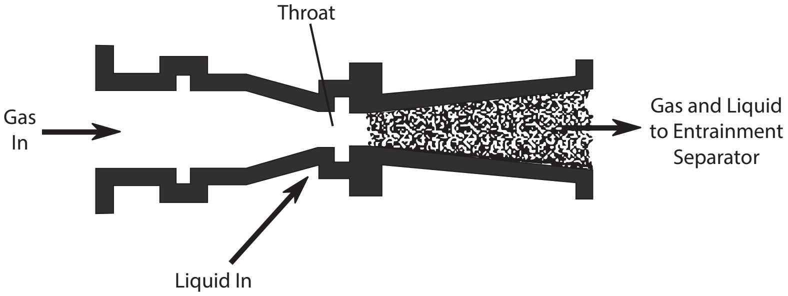

Figure 12.3 A Venturi scrubber.

orifice formed by the core and throat, atomizing the liquid into droplets which are impacted by particles in the gas stream. Impaction results mainly from the high differential velocity between the gas stream and the atomized droplets. The droplets are then removed from the gas stream by centrifugal action in a cyclone separator and (if present) a mist eliminator section.

Other wet scrubber designs that might be applied to coal gas are plate scrubbers (sieves, bubble caps, and impingement plates), massive packing (rings, saddles), fibrous packing plastic, spun glass, fiber glass, steel wool), centrifugal (cyclone), and directional baffles (louvers, zigzags, disk, and donut) (Sundberg, 1974; Semrau, 1977; Strauss, 1977).

Although made up of many technologies, the majority (approximately 85%) of the flue gas desulfurization systems in the United States are categorized as wet systems, with the remaining systems being considered dry systems, with some semi-dry units (US EPA 2003). The major difference in the flue gas desulfurization material produced from these two systems is the relative proportion of calcium sulfite and calcium sulfate. Calcium sulfite to sulfate proportion affects physical properties of flue gas desulfurization material, and with the many available flue gas desulfurization technologies there is a large variability in the characteristics of flue gas desulfurization material (Bigham *et al.,* 2005).

Depending on the type of process and sorbent used, 20 to 90% w/w of the available sulfur can be converted to calcium sulfite with the remaining portion being calcium sulfate. Flue gas desulfurization material with high concentrations of sulfite pose dewatering problem. Sulfite sludge settles and filters poorly and is thixotropic (a material that appears to be a solid but liquefies when vibrated or agitated). High-sulfite flue gas desulfurization material is typically not suitable for either use or disposal without treatment. Treatment can include forced oxidation, dewatering, and/or fixation or stabilization.

12.4.4.2 Dry Systems

Dry sorbent injection systems pneumatically inject powdered sorbent directly into the furnace, the economizer, or downstream ductwork. The dry waste product is removed using particulate control equipment such as a baghouse or electrostatic precipitator (ESP). The flue gas is generally cooled prior to entering the particulate matter control device. Water can be injected upstream of the absorber to enhance sulfur dioxide removal (Srivastava, 2001).

Dry flue gas desulfurization systems use less water than wet systems and produce a dry by-product. The most common dry flue gas desulfurization system sprays slaked lime slurry into the flue gas. The main product of dry flue gas desulfurization systems is calcium sulfite with minor amounts of calcium sulfate.

Furnace injection requires flue gas temperatures between 950°C to 1000°C (1740°F to 1830°F) in order to decompose the sorbent into porous solids with high surface area (Srivastava, 2001). Injection into the economizer requires temperatures of 500°C to 570°C (930°F to 1060°F) (Srivastava, 2001). Duct injection requires the dispersion of a fine sorbent spray into the flue gas downstream of the air preheater. The injection must occur at flue gas temperatures between 150°C to 180°C (300°F to 350°F) (Joseph, 1998).

Dry sorbent systems typically use calcium and sodium based alkaline reagents. A typical injection system uses several injection lances protruding from the furnace or duct walls. Injection of water downstream of the sorbent injection increases sulfur dioxide removal by the sorbent.

Two factors are critical for high rate of sulfur dioxide removal: (i) even distribution of sorbent across the reactor and (ii) adequate residence time at the appropriate temperature (Srivastava, 2001). Flue gas must be kept 10 to 15°C (50 to 59°F) below saturation temperature to minimize deposits on the absorber and downstream equipment.

Dry scrubbers have significantly lower capital and annual costs than wet systems because they are simpler, demand less water and waste disposal is less complex. Dry injection systems install easily and use less space and, therefore, are good candidates for retrofit applications. Sulfur dioxide removal efficiency of a dry system is significantly lower than a wet system, between 50% and 60% for calcium based sorbents. Sodium-based dry sorbent injection into the duct can achieve up to 80% control efficiencies (Srivastava, 2001). Dry sorbent injection is viewed as an emerging sulfur dioxide control technology for medium to small coal-fired boilers – application of dry sorbent injection on small coal-fired boilers have are reported to have achieved sulfur dioxide control efficiency than 90%.

12.4.4.3 Semi-Dry Systems

Semi-dry systems, or spray dryers, inject an aqueous sorbent slurry similar to a wet system; however, the slurry has a higher sorbent concentration. As the hot flue gas mixes with the slurry solution, water from the slurry is evaporated. The water that remains on the solid sorbent enhances the reaction with sulfur dioxide. The process forms a dry waste product which is collected with a standard particulate matter (PM) collection device such as a bag house or electrostatic precipitator (ESP). The waste product can be disposed, sold as a by-product or recycled to the slurry.

Various calcium and sodium-based reagents can be utilized as sorbent. Spray dry scrubbers typically inject lime since it is more reactive than limestone and less expensive than sodium-based reagents. The reagent slurry is injected through rotary atomizers or dual-fluid nozzles to create a finer droplet spray than wet scrubber systems (Srivastava, 2000).

The performance of a lime spray dry scrubber is more sensitive to operating conditions. Close-to-adiabatic saturation temperature is required to maximize the removal of sulfur dioxide. However, excess moisture causes the wet solids to deposit on the absorber and downstream equipment. The optimum temperature is 10°C to 15°C (50°F to 59°F) below saturation temperature (Srivastava, 2000).

Lower liquid-to-gas ratios (approximately 1:3) must be utilized do to the limitation on flue gas moisture (Schnelle, 2002). Flue gas with a high concentration of sulfur dioxide or having high temperature reduces the performance of the scrubber (Schnelle, 2002).

The control efficiency for sulfur dioxide control in spray dry scrubbers is slightly lower than wet systems, between 80% and 90% due to its lower reactivity and liquid-to-gas ratios.

12.4.5 Cyclones

Cyclones are low-cost particle collectors that have many potential applications in coal gasification systems; however, they have low efficiency for collecting particles smaller than 10 micron but above this size collection efficiency can be at least 90%. Conventional applications for cyclones include use as pre-cleaners, entrainment separators, and for controlling dust emissions from coal grinding and pulverizing (Chapters 3, 13).

Cyclone collectors utilize the principle of centrifugal force to separate particulates from a gas stream; vortex flow is induced by the design of the gas inlet duct (Figure 12.4). The main

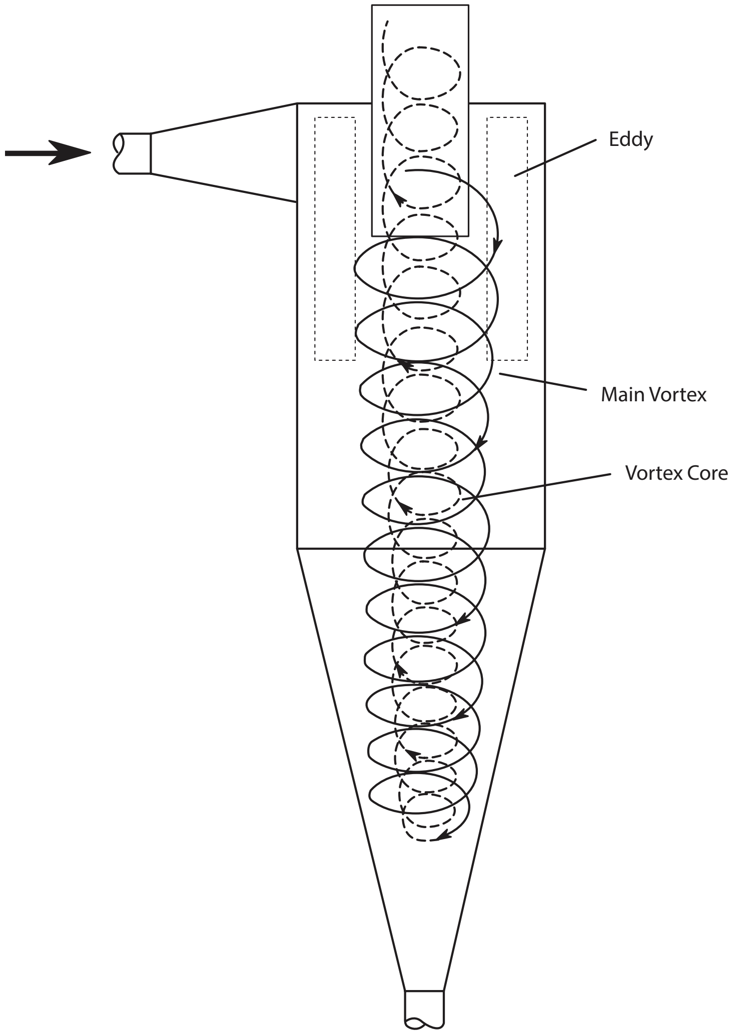

Figure 12.4 Vortex and Eddy flows in a cyclone.

vortex is characterized by axial flow away from the gas inlet and radial flow outward from the ads of the cyclone body. The central core has the same rotary direction, but the axial and radial velocity components are in the opposite direction to that of the main vortex.

The major requirements of the dust discharge are that upward gas flow into the cyclone body should be minimal while continuous discharge of the dust is maintained. This is often accomplished by the inclusion of baffles or straightening vanes at the discharge to suppress the vortex at this point, thus minimizing upflow.

At the entrance of the cyclone, a spin is imparted to the particle-laden gas. This spin creates a centrifugal force which causes the particulate matter to move away from the axis of rotation and towards the walls of the cyclone. Particles which contact the walls of the cyclone tube are directed to a dust collection hopper where they are deposited.

In a typical single cyclone, the gas enters tangentially to initiate the spinning motion. In a multi-tube cyclone (often referred to as a *multiclone* or *multi-clone*), the gas approaches the entrance axially and has the spin imparted by a stationary spin vane that is in its path. This allows the use of many small, higher efficiency cyclone tubes operating parallel to the gas flow stream, with a common inlet and outlet header. One variation of the multi-tube cyclone is to place two similar mechanical collectors in series. This system is often referred to as a dual or double mechanical collector. The first collector removes the bulk of the dust and the second removes smaller particles. Single mechanical collectors have been reported to have collection of particulate matter 80% efficiency.

Some high solids gas streams are designed to use hydrocyclones to improve suspended solids removal. A side stream is taken from the primary process stream, sent to the hydrocyclone for solids reduction, and returned to the system. Theoretically, this process is similar to side stream filtration in a cooling system. Hydrocyclones are designed to perform a gross separation of solids by density – the process uses centrifugal force to separate and remove large particles from the incoming stream.

12.5 Acid Gas Removal

A variety of processes are commercially available for removal of acid gas from gas streams and the processes generally fall into one of two categories: (i) chemical absorption processes and (ii) physical absorption processes (Figure 12.5). The features of the individual process may vary (Table 12.5) (van den Berg and de Jong, 1980; Bodle and Huebler, 1981; Probstein and Hicks, 1991; Mokhatab *et al.,* 2006; Speight, 2013, 2014, 2019, 2020). In addition, there are several factors that control the choice of an acid gas removal process and these include but are not limited to the following: (i) gas flow rate, (ii) concentration of acid gases in the gas stream, and (iii) the necessity to remove carbon dioxide as well as hydrogen sulfide.

In more general process terms, acid gas removal is considered to be hydrogen sulfide and carbon dioxide removal; the removal of sulfur oxides and nitrogen oxides is often achieved by contact of the gas with an alkaline solution as used in various processes which offer variations in the relative selectivity for hydrogen sulfide, carbon dioxide, and hydrocarbon derivatives (Bodle and Huebler, 1981; Wesch, 1992; Mokhatab *et al.,* 2006; Speight, 2014, 2019, 2020).

Most of the treating agents rely upon physical absorption and chemical reaction. When only carbon dioxide is to be removed in large quantities, or when only partial removal is

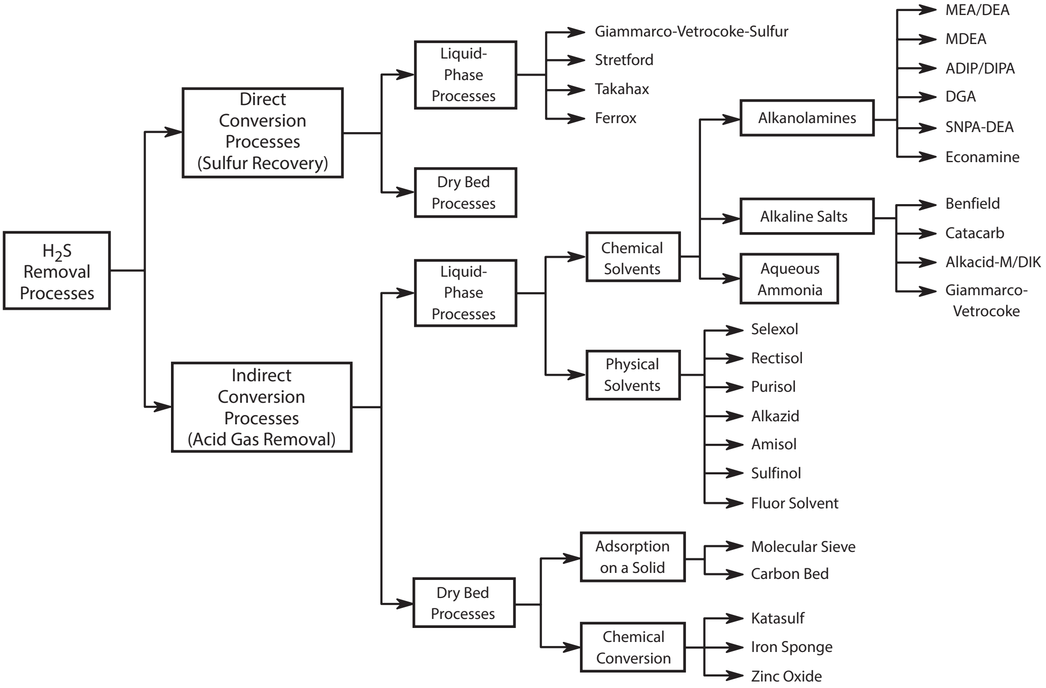

Figure 12.5 Processes for hydrogen sulfide removal.

necessary, a hot carbonate solution or one of the physical solvents is the most economical selection. The Sulfinol solvent (a mixture of an aqueous amine, chemical solvent, with sulfolane, physical solvent), is reported to be particularly advantageous (Taylor *et al.,* 1991). Hydrogen sulfide may be removed solely by the use of several processes (Grosick and Kovacic, 1981; Mokhatab *et al.,* 2006; Speight, 2013, 2014, 2019, 2020).

Most sulfur removal processes concentrate on removing the hydrogen sulfide because over the years it has been considered the greatest health hazard and also because it is corrosive, particularly when water is present. With increasing emphasis on eliminating or minimizing sulfur discharge to the atmosphere, attention in the newer and more effective processes is turning to removal of other sulfur compounds from gas. Generally, specifications dictate a low hydrogen sulfide content to be transmitted by pipeline.

A number of processes are available for the removal of hydrogen sulfide from gas streams. These processes can be categorized as those based on physical absorption, adsorption by a solid, or chemical reaction.

Physical absorption processes suffer from the fact that they frequently encounter difficulty in reaching the low concentrations of hydrogen sulfide required in the sweetened gas stream. However, there are processes which, with proper attention and care to regeneration cycles, can meet this specification.

Solid bed adsorption processes suffer from that fact that they are generally restricted to low concentrations of hydrogen sulfide in the entering sour gas stream. The development of a short-cycle adsorption unit for hydrogen sulfide removal might help remove part of this low-concentration restriction for the solid bed absorption processes.

Table 12.5 Summary of the various acid gas removal processes.

Chemical adsorption			
Feature	**Amine processes**	**Carbonate processes**	**Physical absorption**
Absorbents	MEA, DEA, DGA, MDEA	K_2CO_3, K_2CO_3 + MEA K_2CO_3 + DEA, K_2CO_3 + arsenic trioxide	Selexol, Purisol, Rectisol
Operating pressure, psi	Insensitive to pressure	>200	250–1000
Operating temp, °F	100–400	200–250	Ambient temperature
Recovery of absorbents	Reboiled stripping	Stripping	Flashing, reboiled, or steam stripping
Utility cost	High	Medium	Low–medium
Selectivity, H_2S, CO_2	Selective for some amines (MDEA)	May be selective	Selective for H_2S
Effect of O_2 in the feed	Formation of degradation products	None	Sulfur precipitation at low temperature
CO_S and CS_2 removal	MEA not removed; DEA slightly removed; DGA removed	Converted to CO_2 and H_2S and removed	Removed
Operating problems	Solutions degradation; foaming; corrosion	Column instability; erosion; corrosion	Absorption of heavy hydrocarbons

In general, chemical processes are able to meet the regulated hydrogen sulfide levels with little difficulty. However, they suffer from the fact that, in general, a material that will react satisfactorily with hydrogen sulfide will also react with carbon dioxide.

The most well-known hydrogen sulfide removal process is based on the reaction of hydrogen sulfide with iron oxide (often also called the Iron Sponge process or the Dry Box method) in which the gas is passed through a bed of wood chips impregnated with iron oxide after which the bed is regenerated by passage of air through the bed.

$$Fe_2O_3 + 3H_2S \rightarrow Fe_2S_3 + 3H_2O$$

$$2Fe_2S_3 + 3O_2 \rightarrow 2Fe_2O_3 + 6S$$

The bed is maintained in a moist state by circulation of water or a solution of soda ash.

The method is suitable only for small-to-moderate quantities of hydrogen sulfide. Approximately 90% of the hydrogen sulfide can be removed per bed but bed clogging by elemental sulfur occurs and the bed must be discarded and the use of several beds in series is not usually economical.

Removal of larger amounts of hydrogen sulfide from gas streams requires continuous processes, such as the Ferrox process or the Stretford process (Mokhatab *et al.*, 2006; Speight, 2013, 2014, 2019, 2020). The Ferrox process is based on the same chemistry as the iron oxide process except that it is fluid and continuous. The Stretford process employs a solution containing vanadium salts and anthraquinone disulfonic acid (Maddox, 1974).

Most hydrogen sulfide removal processes involve fairly simple paper chemistry (Table 12.6) with the potential for regeneration and recovery of the hydrogen sulfide. However, if the quantity involved does not justify installation of a sulfur recovery plant, usually a Claus plant, it is will be necessary to select a process which produces elemental sulfur directly.

$$3H_2S + 3O_2 \rightarrow 2SO_2 + 2H_2O$$

$$2H_2S + SO_2 \rightarrow 3S + 2H_2O$$

The conversion can be achieved by reaction of the hydrogen sulfide gas directly with air in a burner reactor if the gas can be burned with a stable flame.

Other equilibria which should be taken into account are the formation of sulfur dimer, hexamer, and octamer as well as the dissociation of hydrogen sulfide.

$$2H_2S + O_2 \rightarrow 2S + 2H_2O$$

$$H_2S \rightarrow S + H_2$$

Table 12.6 Chemistry of hydrogen sulfide removal from gas streams.

Name	Reaction	Regeneration
Caustic soda	$2\ NaOH + H_2S \rightarrow NaS + 2\ H_2O$	None
Lime	$Ca(OH)_2 + H_2S \rightarrow CaS + 2\ H_2O$	None
Iron oxide	$Fe_2O_3 + 3\ H_2S \rightarrow Fe_2S_3 + 3\ H_2O$	Partly by air
Seaboard	$Na_2CO_3 + H_2S \rightleftharpoons NaHCO_3 + NaHS$	Air blowing
Thylox	$Na_4As_2S_5O_2 + H_2S \rightarrow Na_4As_2S_4O + H_2O$	Air blowing
	$Na_4As_2S_4O + ½O_2 \rightarrow Na_4As_2S_5O_2 + S$	
Girbotol	$2RNH_2 + H_2S \rightleftharpoons (RNH_3)_2S$	Steaming
Phosphate	$K_3PO_4 + H_2S \rightleftharpoons KHS + K_2HPO_4$	Steaming
Phenolate	$NaOC_6H_5 + H_2S \rightleftharpoons NaHS + C_6H_5OH$	Steaming
Carbonate	$Na_2CO_3 + H_2S \rightleftharpoons NaHCO_3 + NaHS$	Steaming

Carbonyl sulfide and carbon disulfide may be formed, especially when the gas is burned with less than the stoichiometric amount of air in the presence of hydrocarbon impurities or large amounts of carbon dioxide.

Equilibrium data on the reaction between hydrogen sulfide and sulfur dioxide indicate that the equilibrium conversion is almost complete (100%) at relatively low temperatures and diminishes at first at higher temperatures, in accordance with the exothermic nature of the reaction. A further rise in temperature causes the equilibrium conversion to increase again. This is a consequence of the dissociation of the polymeric sulfur into monatomic sulfur.

Catalysis by alumina is necessary to obtain good equilibrium conversions: the thermal Claus reaction is fast only above 500°C (930°F) (Dowling *et al.,* 1990; Chou *et al.,* 1991). There is also a lower temperature limit which is not caused by low rates but by sulfur condensation in the catalyst pores and consequent deactivation of the catalyst. The lower limit at which satisfactory operation is still possible depends on the pore size and size distribution of the catalyst; with alumina-based catalysts having wide pores, the conversion proceeds satisfactorily at ca. 200°C (390°F) (Lagas *et al.,* 1989; Luinstra and d'Haene, 1989).

In all Claus process configurations several conversion steps in adiabatic, i.e., cheap, reactors are used, with intermittent and final condensation of the sulfur produced. There are three main process forms, depending on the concentration of hydrogen sulfide and other sulfur compounds in the gas to be converted, i.e., the straight-through, the split-flow oxidation process.

The straight-through process is applicable when the gas stream contains more than 50% v/v hydrogen sulfide. Feed gases of this type can be burnt with the stoichiometric amount of air to give sulfur. The combustion reactor is followed by a combined waste heat boiler and sulfur condenser from which liquid sulfur and steam are obtained. The gases are then reheated by in-line fuel combustion to the temperature of the first catalytic convertor, which is usually kept at approximately 350°C (660°F) to decompose any carbonyl sulfide and any carbon disulfide formed in the combustion step. A second catalytic convertor, operating at as low a temperature as possible, is also employed to obtain high final conversions.

Caution is necessary to avoid condensation of an aqueous phase in the system because of the extreme corrosive nature of the liquid phase. Another operating issue concerns mist formation, a phenomenon which occurs very readily when condensing sulfur and a series of demisters are necessary to prevent this. Residual sulfur is converted to sulfur dioxide by incineration of the tail gas from the process to prevent emission of other sulfur compounds and to dilute the effluent to reduce ground level sulfur dioxide concentrations.

Molecular sieves and membranes have been undergoing development for the removal of hydrogen sulfide and carbon dioxide from gas streams, especially when the amount of the acid gas(es) is low (Benson, 1981; Chiu, 1990; Winnick, 1991; Mokhatab *et al.,* 2006; Speight, 2013, 2014, 2019, 2020). The most appropriate use of the sieves and the membranes would be use of the sieve to selectively remove hydrogen sulfide, without removing much of the carbon dioxide, and/or use of membranes permeable to hydrogen sulfide but not to carbon dioxide.

12.6 Removal of Sulfur-Containing Gases

Since the time when members of the English monarchy recognized that the burning of coal could produce noxious fumes (Speight, 2013 and references cited therein), there has been a series of attempts (not always continuous) to mitigate the amounts of noxious gases entering the atmosphere, the least of which have been attempts to reduce the amount of sulfur oxide(s) (particularly sulfur dioxide) released to the environment.

Historically, the first method for removing sulfur dioxide from flue gases consisted of simple water scrubbing of the flue gas to absorb sulfur dioxide into solution (Plumley, 1971) and the method was first used in London during the 1930s. Since then, various regulatory organizations in many countries have set standards for sulfur dioxide emissions which must be met immediately, or in the very near future.

Sulfur dioxide represents a high percentage of the sulfur oxide pollutants generated in combustion. The removal of the sulfur dioxide from the combustion gases before they are released to the stack is essential and a considerable number of procedures exist for flue gas desulfurization (FGD). These procedures may be classified as wet or dry (Mokhatab *et al.,* 2006; Speight, 20013, 2014, 2019, 2020) depending on whether a water mixture is used to absorb the sulfur dioxide or whether the acceptor is dry.

Methods to control sulfur dioxide emissions from coal-fired power plants include switching to a lower sulfur fuel, cleaning the coal to remove the sulfur-bearing components such as pyrite, or installing flue gas desulfurization systems. In the past, building tall stacks to disperse the pollutants was a control method; however, this practice is no longer an alternative – tall stacks do not remove the pollutants but only serve to dilute the concentrations and reduce the ground-level emissions to acceptable levels.

Fuel switching includes using natural gas, liquefied natural gas, low-sulfur fuel oils, or low-sulfur coals in place of high-sulfur coals. In coal-fired boilers, switching from a high-sulfur coal to lower-sulfur non-coal fuels may make sense from both an economic and technological standpoint for smaller-sized industrial and utility boilers; however, the practice of switching power generation units from coal to natural gas is a questionable one. While this option may make good business sense (at least at the time), it is neither good energy policy nor advisable energy security to use a premium fuel for power generation.

When fuel switching or coal cleaning is not an option, flue gas desulfurization (FGD) is selected to control sulfur dioxide emissions from coal-fired power plants, except for fluidized-bed systems (Chapters 8, 10). Flue gas desulfurization has been in commercial use for several decades (in the gas cleaning and crude oil processing industries) and has become the most widely used technique to control sulfur dioxide emissions next to the firing of low-sulfur coal. Many flue gas desulfurization systems are currently in use and others are under development (Mokhatab *et al.,* 2006; Speight, 2013, 2015, 2019, 2020).

Flue gas desulfurization processes are generally classified as wet scrubbers or dry scrubbers but can also be categorized as follows: (i) wet scrubbers, (ii) spray dryers, (iii) sorbent (dry) injection processes, (iv) regenerable processes, (v), circulating fluid-bed and moving-bed scrubbers, and (vi) combined sulfur dioxide-nitrogen oxide removal systems (Mokhatab *et al.,* 2006; Speight, 2013, 2019). Based on the nature of the waste/by-product generated, a commercially available throwaway flue gas desulfurization technology may be categorized as wet or dry. A wet flue gas desulfurization process produces a slurry waste or a salable slurry by-product. A dry flue gas desulfurization process application results in a solid waste, the transport and disposal of which is easier than transport and disposal of the waste/by-product from wet flue gas desulfurization applications (Chapter 13). Regenerable flue gas desulfurization processes produce a concentrated sulfur dioxide by-product usually elemental sulfur or sulfuric acid (Mokhatab *et al.,* 2006).

There is a variety of processes which are designed for sulfur dioxide removal from stack gas but scrubbing process utilizing limestone (CaCO3) or lime [Ca(OH)2] slurries have received more attention than other stack gas scrubbing processes. Attempts have been made to use dry limestone or dolomite (CaCO3.MgCO3) within the combustor as an *in situ* method for sulfur dioxide removal, thereby eliminating the wet sludge from wet processes. This involves injection of dry carbonate mineral with the coal followed by recovery of the calcined product along with sulfite and sulfate salts.

$$S_{coal} + O_2 \rightarrow SO_2$$

$$2SO_2 + O_2 \rightarrow 2SO_3$$

$$2CaCO_3 + SO_2 + SO_3 \rightarrow CaSO_3 + CaSO_4 + 2CO_2$$

The majority of the stack gas scrubbing processes is designed to remove sulfur dioxide from the gas streams; some processes show the potential for removal of nitrogen oxide(s). However, there is the current line of thinking that pursues the options which enable sulfur oxides and nitrogen oxide(s) to be controlled, at least as far as possible, by modification of the combustion process. Sulfur (as already noted) can be removed by injecting limestone, with the coal into a boiler whilst modifications of the combustion chamber, as well as methods of flame temperature regulation and techniques that lower combustion temperatures, such as injection of steam into the combustion region are claimed to reduce emissions of nitrogen oxide(s).

The procedures can be classified further as regenerative or non-regenerative depending upon whether the chemical used to remove the sulfur dioxide can be regenerated and used again or whether the chemical passes to disposal. In the wet regenerative processes either elemental sulfur or sulfuric acid is recovered. In the wet non-regenerative lime and/or limestone procedures, calcium sulfite sludge or calcium sulfate sludge is produced that is disposed. Wet scrubbing processes contact the flue gas with a solution or slurry for sulfur dioxide removal.

In a wet limestone process, the flue gas contacts a limestone slurry in a scrubber.

$$CaCO_3 + SO_2 \rightarrow CaSO_3 + CO_2$$

$$2CaCO_3 + O_2 \rightarrow 2CaSO_4$$

Both the sulfite and the sulfate absorb water of hydration to form the sulfite/sulfate sludge.

In a wet lime process, a gas stream containing the sulfur dioxide is reacted with wet lime slurry to form the sulfite with subsequent conversion, by oxidation, to the sulfate.

$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 + H_2O$$

$$2CaSO_3 + O_2 \rightarrow 2CaSO_4$$

In the double alkali non-regenerative procedure, flue gas is scrubbed with a soluble alkali such as sodium sulfite which is subsequently regenerated with lime to form insoluble calcium sulfite after which disposal of the calcium sulfite slurry occurs and the spent absorbent, sodium bisulfite, is regenerated by thermal means.

$$Na_2SO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3$$

$$2NaHSO_3 + Ca(OH)_2 \rightarrow Na_2SO_3 + 2H_2O + CaSO_3$$

$$2NaHSO_3 + \rightarrow Na_2SO_3 + SO_2 + H_2O$$

In all of these procedures, water exits the system as vapor in the flue gas.

In either the lime/limestone or sodium sulfite/lime scrubbing processes the hydrated calcium sulfite and calcium sulfate can be of some environmental concern when the issue of disposal arises. This has, more than anything else, promoted efforts to develop alternate dry scrubbing procedures for the removal of sulfur dioxide. And the dry systems have the additional advantage of reducing the pumping requirements necessary for the wet systems.

Thus, the tendency is to advocate the use of dry lime scrubbing systems thereby producing a waste stream that can be handled by conventional fly ash removal procedures. There are also dry processes, such as the metal oxide processes, in which sulfur dioxide can be removed from gas streams by reaction with a metal oxide. These processes, which are able to operate at high temperatures (approximately 400°C, 750°F) are suitable for hot gas desulfurization and do not require an additional cooling stage. The metal oxides can usually be regenerated by aerial oxidation to convert any metal sulfide(s) back to the oxide(s) or by use of a mixture of hydrogen and steam.

In the dry desulfurization process, metal oxides are reduced by coal gasification gas, and the reduced metal oxides remove sulfur compounds from the gas, and are then converted to sulfides. This method can be used more than once by letting the sulfides react with oxygen to release the sulfur contents as SO2 to return them to metal oxides.

Membranes have found increasing industrial use in the past two decades (Porter, 1990; Hsieh, 1991; Ho and Sirkar, 1992) and have also been suggested as being appropriate for the separation of hydrogen sulfide and sulfur dioxide, and they are applicable to higher temperature conditions (McKee *et al.,* 1991; Shaver *et al.,* 1991; Winnick, 1991). The removal of carbonyl sulfide from gas streams, especially those that are destined for the manufacture of synthesis gas, has also been investigated using the principle of hydrogenation.

$$COS + H_2 \rightarrow CO + H_2S$$

$$COS + H_2O \rightarrow CO_2 + H_2S$$

12.7 Removal of Nitrogen-Containing Gases

The occurrence of nitrogen in natural gas can be a major issue if the quantity is sufficient to lower the heating value. Thus, several plants for the removal of nitrogen from the natural gas have been built but it must be recognized that nitrogen removal requires liquefaction and fractionation of the entire gas stream which may affect process economics. In many cases, the nitrogen-containing natural gas is blended with a gas having a higher heating value and sold at a reduced price depending upon the thermal value (Btu/ft; kJ/m).

Of equal interest is the occurrence of nitrogen compounds in gases produced by coal combustion. These compounds, the oxides, originate from the organically bound nitrogen in the coal.

$$2N_{coal} + O_2 \rightarrow 2NO$$

$$2NO + O_2 \rightarrow 2NO_2$$

Nitrogen oxides are formed during burning by oxidation, at the high temperatures, of the nitrogen in the fuel and in the air. This has given rise to the terminology *thermal-NOx* and *fuel-NOx* as a means of distinguishing between the two sources of nitrogen oxides. But, be that as it may, nitrogen oxides from whatever the sources are pollutants that must be removed from gas streams.

Indeed, many coal-fired boilers are being built with burners designed to reduce nitrogen oxide formation by delaying fuel/air mixing, or distributed fuel addition, thereby establishing fuel-rich combustion zones within the burner whereby the reduced oxygen level maintains a low level of nitrogen oxides production (Slack, 1981; Wendt and Mereb, 1990). Other procedures employ ammonia to reduce the nitrogen oxides by injection of ammonia and oxygen into the post combustion zone.

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

Vanadium oxide/aluminum oxide and iron/chromium, as well as the systems based on iron oxide itself, have also been reported to be successful for the removal of nitrogen oxides from gas streams.

Nitrogen compounds must be absorbed in several chemical and related processes, the most important of which is the absorption of nitrogen peroxide in water for the manufacture of nitric acid. Absorption of nitrous gases also takes place in the lead-chamber process used for the production of sulfuric acid, in the metallurgical industries where metals are treated with nitric acid, and in the purification of several tail gases.

It is also worth, at this point, giving some consideration to the production of nitric acid from nitric oxide (using simple chemistry), as might be envisaged in the formation of nitrous and nitric acids in an industrial setting or even in the atmosphere; this latter phenomenon would result in the deposition of acid rain. Thus, nitric oxide is oxidized to nitrogen peroxide and dimerization of nitrogen peroxide gives nitrogen tetroxide after which combination of nitrogen peroxide and nitric oxide gives nitrogen trioxide. In the presence of water vapor nitrogen trioxide can be hydrated to nitrous acid. In the liquid phase the gross reaction equation of the formation of nitric acid is:

$$2NO + O_2 \rightarrow 2NO_2$$

$$NO + NO_2 \rightarrow N_2O_3$$

$$N_2O_3 + H_2O \rightarrow HNO_2$$

Thus:

$$3NO_2 + H_2O \rightarrow 2HNO_3 + NO$$

These same reactions occur in the atmosphere leading to the formation and deposition of acid rain.

12.8 Environmental Legislation

The environmental aspects of coal use have been a major factor in the various processes, and the see-sawing movement of the fossil fuel base between crude oil, natural gas, and coal increased the need for pollutant control for large, coal-fired power plants. These power plants emit pollutants which, by atmospheric chemical transformations, may become even more harmful secondary pollutants (Moran *et al.,* 1986).

It has been recognized for some time that gaseous pollutants, especially sulfur dioxide, aggravate existing respiratory disease in humans and contribute to its development (e.g., Houghson, 1966). Sulfur dioxide gas by itself can irritate the upper respiratory tract. It can also be carried deep into the respiratory tract by airborne adsorbents and can cause near-irreversible damage in the lungs. There is also the belief that sulfur dioxide is a contributor to increased respiratory disease death rates. Sulfur dioxide also contributes to the various types of smog that occur in many industrialized areas of the world. Indeed, sulfur dioxide is also harmful to a variety of flora including forage, forest, fiber, and cereal crops as well as many vegetable crops. Vegetation just cannot grow, let alone flourish, in an atmosphere polluted by sulfur dioxide. Indeed, the occurrence of zones of dead vegetation were a common sight at points downwind of sulfide ore smelters.

Thus, it has become very apparent over the last three decades that abatement of air pollution needs to be mandatory now and in the future. Four main avenues of action are open to decrease the amount of sulfur dioxide emitted from stacks of power generating plants: (i) burn low-sulfur fuels, (ii) desulfurize available fuels, (iii) remove sulfur oxides from flue gases, or (iv) generate power by nuclear reactors.

Low-sulfur fuels are expensive and not readily available in many areas where population density is the greatest. Desulfurization of fuels is also expensive, and the technology for desulfurizing coal is still in the development stage. Safety and health concerns related to the operation of nuclear facilities make it unlikely that there will be an outburst of building such facilities for some years to come.

The use of coal involves, at some stage by deliberate means or by accidental means, the generation of gaseous mixtures that can be quite obnoxious in terms of environmental contamination. Coal combustion and gasification produce hydrogen sulfide as a by-product of the primary process. Thereafter, the usual practice is to utilize a Claus sulfur recovery unit to convert the hydrogen sulfide to elemental sulfur (Speight, 1990, 2000). Whilst the problem, in the former heavy industrialized centers, may be seemingly less acute than it was decades ago, predominantly because of an increased environmental consciousness, the generation of such noxious materials is still an issue. Industry continues to march forward but the increased need to maintain a clean, livable, environment is more evident now than at any time in the past.

In the past, a certain amount of pollution was recognized as being almost inevitable, perhaps even fashionable! But now this is not the case. Any industry found guilty of emitting noxious materials can suffer heavy fines. And there is also the possibility of a jail term for the offending executives! Pollution of the environment will not be tolerated.

Thus, whilst industry marches on using many of the same processes that were in use in the early days of the century, more stringent methods for clean-up are necessary before any product/by-product can be released to the atmosphere. And this is where gas processing becomes an important aspect of industrial life. Furthermore, gas-cleaning processes are now required to be more efficient than ever before.

In terms of current legislation (i.e., active legislation at the time of writing, November 2012), Section 112 of the Clean Air Act (CAA) requires the United States Environmental Protection Agency (EPA) to establish National Emissions Standards for Hazardous Air Pollutants (NESHAPS) for major (and area) sources of hazardous air pollutants (HAPS) that are subject to regulation. A major source is defined as a stationary source that emits or has the potential to emit 10 tons per year or more of any single hazardous air pollutant or 25 tons per year or more of any combination of the 187 hazardous air pollutants subject to regulation. Hazardous air pollutants are different from other types of air pollutants (e.g., sulfur dioxide, nitrogen dioxide, and particulate matter) that are regulated under other provisions of the Clean Air Act.

Section 112(n)(1), however, provides that steam generating electric power plants shall not be subject to regulation under Section 122 unless the EPA determines that *such regulation is appropriate and necessary* on the basis of a hazard to public health of such plants. On December 20, 2000, the EPA issued a determination that it was appropriate and necessary to include coal- and oil-fired power plants among hazardous air pollutant sources subject to regulation. On March 29, 2005, the EPA reversed course and decided to *de-list* those power plants from regulation under the statute (the De-listing Rule).

On May 18, 2005, the EPA issued a final rule on mercury emissions from new and existing coal-fired power plants. The so-called Clean Air Mercury Rule (CAMR) set new source performance standards (NSPS) for new coal-fired power plants under Section 111 of the Clean Air Act, and established a national mercury cap and trade program for electric generating units, allocating a mercury emission budget to each state. The Clean Air Mercury Rule was designed to reduce mercury emissions from electric generating plants by 70% by 2018. The Clean Air Mercury Rule was appealed, along with the Delisting Rule, and the United States Court of Appeals for the District of Columbia Circuit, on February 8, 2008, remanded the Clean Air Mercury Rule based on failure by the EPA to properly de-list electric generation units pursuant to Section 112(c)(9) of the Clean Air Act.

On February 16, 2012, EPA issued its final National Emissions Standards for Hazardous Air Pollutants (NESHAPS) rule under Section 112 for new and existing coal- and oil-fired electric power plants. The rule would limit emission of heavy metals, including mercury (Hg), arsenic (As), chromium (Cr), and nickel (Ni), and acid gases, including hydrogen chloride (HCl) and hydrogen fluoride (HF). The rule also includes revised NSPS for new oil- and coal-fired power plants under Section 111 of the NESHAPS rule. The revised new source performance standards would limit emissions of particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxides (NOx). If authorized into law, the rule would allow three years for electric power plants to meet the standards, with the possibility of an additional year upon a demonstration that additional time is needed in order to complete construction.

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13

Clean Coal Technologies for Power Generation

13.1 Introduction

Coal is one of the many vital commodities that contributes on a large scale to energy supply and, unfortunately to environmental pollution, including acid rain, the greenhouse effect, and *allegedly* global warming (global climate change) but there are other effects that need to be considered before global climate change is laid upon the shoulders of coal (Speight, 2020a). There are some effects due to the use of coal and whatever these effects, the risks attached to the coal fuel cycle could be minimized by the introduction of new clean coal technologies, remembering that there is no single substitute for coal fuel in the generation of energy.

Of late, coal has been scandalized as the so-called *bad boy* of fossil fuels but coal is recognized as an essential element in providing the United States with energy and economic stability and security to its citizens. Coal, which accounts for over 94% of the proven fossil energy reserves in the United States, supplies approximately 50% of the electricity vital to the economy of the nation as well as competitiveness on the global scale. To support continued domestic economic growth, in addition to the use of coal increasing by several orders of magnitude since the early decades of the 20th century, the demand for electricity is projected to increase by approximately 40% by 2030. In addition, coal is projected to account for at least 50% of the new generating capacity additions through 2030. Moreover, coal is envisioned as an economically stable source of environmentally friendly fuels such as hydrogen, as well as strategically important chemicals. The expanded use of coal is dependent on developing technological capabilities that eliminate environmental concerns associated with coal use at a cost and efficiency that support economic growth (Miller, 2005; United States Department of Energy, 2008; Speight, 2020b).

The expansion of the industrialized system which requires the generation and use of vast amounts of electrical energy as well as the increased use of automobiles, to mention only two examples, has been the major driving force behind the expansion of fossil fuel usage. But, in concert with this increased usage, there has also followed the onset of detrimental side effects. Emissions of non-indigenous chemicals into the environment or the ejection into the environment of chemicals that are indigenous but in quantities that exceed their natural occurrence are major issues. Thus, the expansion and evolution of industry in the service of man is, perhaps, an excellent example of medicine almost killing the patient.

Emissions resulting from the use of the various fossil fuels have had deleterious effects on the environment and promise further detriment unless adequate curbs are taken to control not only the nature but also the amount of gaseous products being released into the

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atmosphere. In this respect, coal is often considered to be a *dirty* fuel and is usually cited as the most environmentally obnoxious of the fossil fuels. However, coal is not necessarily dirty fuel; perhaps coal is no dirtier than the so-called clean nuclear fuels which have a habit of being really dirty when nuclear plants go awry. In fact, it is quite possible that nuclear power will only be chosen as a viable energy option if the demand for electricity accelerates, nuclear costs (including the potential for accidents) are contained, and if global warming concerns escalate (Ahearne, 1993). Thus, it is more appropriate to consider the way in which we use coal as being detrimental to the environment! Such a change in thinking opens new avenues for coal use.

Fossil fuel use is a necessary part of the modern world and the need for stringent controls over the amounts and types of emissions from the use of, in the present context, coal is real. The necessity for the cleanup of process gases is real but to intimate that coal is the major cause of all our environmental concerns is unjust. Gaseous products and by-products are produced from a variety of industries (Austin, 1984; Probstein and Hicks, 1990; Speight, 2014, 2020b). These gaseous products all contain quantities of noxious materials that are a severe detriment to the environment.

Coal is an abundant energy source and forms a major part of the fossil fuel resources of the Earth (Speight, 2013, 2020b), the amount available being subject to the method of estimation and to the definition of the resources (Chapter 1) (EIA, 1988, 1989, 1991a, 1991b, 1992). In general, but in terms of the measurable reserves, coal constitutes ca. 33% of the fossil fuel supplies of the world (Speight, 2013, 2020b). In terms of the energy content, coal (68%) and natural gas (13%) are the major energy-containing fossil fuels, crude oil (19%) making up the remainder (EIA, 1989, 1991a, 1991b, 1992).

Coal is the most familiar of the fossil fuels not necessarily because of its use throughout the preceding centuries (Galloway, 1882) but more because of its common use during the 19th century. Coal was largely responsible not only for the onset but also for the continuation of the Industrial Revolution. Coal occurs in various forms defined in a variety by rank or type (Chapter 2) and is not only a solid hydrocarbonaceous material with the potential to produce considerable quantities of carbon dioxide as a result of combustion, but many coals also contain considerable quantities of sulfur (Chapters 2, 5). Sulfur content varies between the ranks of coal but, nevertheless, opens up not only the possibility but also the reality of sulfur dioxide production (Manowitz and Lipfert, 1990; Tomas-Alonso, 2005; Speight, 2013).

Most coal-fired power generating units in the United States burn either bituminous coal or subbituminous coal. Approximately one-half of the tonnage of coals delivered to US electric power generation facilities is subbituminous coal (49.5%), and another 44% is bituminous coal – the reminder often being lignite. Some coal-fired power generating units burn multiple coal ranks. At many of these facilities, the coals are blended together before firing. However, some facilities may switch between coal ranks because of site-specific considerations. The largest sources of bituminous coals burned in power generating units are mines in regions along the Appalachian Mountains, in southern Illinois, and in Indiana. Additional bituminous coals are supplied from mines in Utah and Colorado. The vast majority of subbituminous coals are supplied from mines in Wyoming and Montana, and many power generating units burn subbituminous coals from the Powder River Basin (PRB) region in Wyoming.

In general, the burning of lignite or anthracite by electric utilities is limited to those power generating units that are located near the mines supplying the coal. Lignite accounted for approximately 7% of the total tonnage of coal delivered to electric utility power plants. All of those facilities were located near the coal deposits from which the lignite was mined in Texas, Louisiana, Mississippi, Montana, or North Dakota. Similarly, anthracite use was limited to a power plants located close to the anthracite mines in eastern Pennsylvania. The coal-fired power generating units at those facilities primarily burn anthracite that has been reclaimed from coal refuse piles of previous mining operations.

In general, *coal refuse* means any by-product of coal mining or coal cleaning operations with a mineral matter content (determined as mineral ash, approximately greater than 50% w/w and a heating value less than 6,000 Btu per pound (Btu/lb) on a dry basis. Coal refuse piles from previous mining operations are primarily located in Pennsylvania and West Virginia. Current mining operations generate less coal refuse than older ones.

It is predictable that coal will be the primary source of energy for the next several decades, well into the next century, and therefore the message is clear: until other energy sources supplant coal, the challenge is to develop technological concepts that will provide the maximum, and environmentally efficient, recovery of energy from coal (Dryden, 1975; Fulkerson *et al.,* 1990). There are a number of processes that are being used in coal-fired power stations that improve the efficiency and environmental acceptability of coal extraction, preparation, and use, and many more are under development (Bris *et al.,* 2008). These processes are collectively known as *clean coal technologies*.

Designation of a technology as a *clean coal technology* does not imply that it reduces emissions to zero or near zero. For this reason, the term has been criticized as being misleading; it might be more appropriate to refer to *cleaner coal technologies* (Balat, 2008a, 2008b; Nordstrand *et al.,* 2008; Franco and Diaz, 2009).

The Clean Coal Technology of the United States was created to mitigate some of the environmental issues of coal use described in the above paragraphs to pursue two major strategies: (i) capturing and storing greenhouse gases; and (ii) improving the efficiency and footprint of fossil energy systems. The first strategy aims to remove emissions of greenhouse gases from fossil fueled energy systems. The second strategy seeks to improve the fuel-to-energy efficiencies of these systems, thus reducing pollutant emissions, water usage, and carbon emissions on a per unit of energy basis. Collectively, these two strategies constitute the approach to ensure that current and future fossil energy plants can contribute to a safe and secure clean energy future.

In summary, the program has been used to reduce emissions of several pollutants, reduce waste, and increase the amount of energy gained from each ton of coal (Nordstrand *et al.,* 2008; Franco and Diaz, 2009). This includes various chemical and physical treatments applied in the pre-combustion or post-combustion stages and may be broadly divided into processes relating either to (i) combustion efficiency or to (ii) pollution control.

An example is gasification of coal in which the coal is reacted with a calculated amount of oxygen to produce a cleaner gaseous fuel known as *synthesis gas* (often referred to as *syngas*, a mixture mainly of hydrogen and carbon monoxide) (Chapters 9, 10), which is comparable in its combustion efficiency to natural gas. This reduces the emissions of sulfur, nitrogen oxides, and mercury, resulting in a much cleaner fuel (Nordstrand *et al.,* 2008; Lee *et al.,* 2006; Sondreal *et al.,* 2004, 2006; Yang *et al.,* 2007; Wang *et al.,* 2008). The resulting hydrogen gas can be used for electricity generation or as a transport fuel. The gasification process also facilitates capture of carbon dioxide emissions from the combustion effluent (see discussion of carbon capture and storage below).

Integrated gasification combined cycle (IGCC) systems combine gasification with a heat recovery system that feeds a secondary steam-powered generator, thereby increasing the power generated from a given amount of coal. These systems are currently being employed in many new coal-fired power plants worldwide.

Furthermore, IGCC power plants have been reported to achieve the lowest levels of criteria pollutant air emissions (NOx, SOx, CO, PM_{10}) of any coal-fueled power plants worldwide (Ratafia-Brown *et al.,* 2002). Emissions of trace hazardous air pollutants are extremely low, comparable with those from direct-fired combustion plants that use advanced emission control technologies. Discharge of solid by-products and wastewater is reduced by approximately 50% when compared to other coal-fired power plants, and the by-products generated (e.g., slag and sulfur) are environmentally benign and can potentially be sold as valuable products. Another significant environmental benefit is the reduction of carbon dioxide emissions, by at least 10% per equivalent net production of electricity, due to a higher operating efficiency compared to conventional pulverized coal-fired power plants (Ratafia-Brown *et al.,* 2002).

Thus, gasification-based energy conversion systems, such as IGCC, have the likelihood to provide energy production with minimal environmental impact. The systems can meet strict air pollution emission standards, produce water effluent within environmental limits, produce an environmentally benign slag, with good potential as a salable by-product, and recover a valuable sulfur commodity by-product. Furthermore, the environmental performance of IGCC technology makes it an excellent technology for the clean production of electricity as well as the flexibility to produce of a wide range of products including (in addition to electricity): fuels, chemicals, hydrogen, and steam, while utilizing widely available feedstocks. Coal-based gasification systems (Chapters 9, 10) provide an energy production alternative that is more efficient and environmentally friendly than competing coal-fired technologies (Ratafia-Brown *et al.,* 2002).

Carbon capture and storage (CCS) is a technology under development that offers much higher prospects of emissions reductions than other clean coal technologies. Carbon capture and storage involves capture of carbon dioxide either before or after combustion of the fuel; transport of the captured carbon dioxide to the site of storage; and injection of the carbon dioxide in deep underground reservoirs for long-term storage (*geosequestration*). Carbon capture and storage is proposed as a means of reducing to near-zero the greenhouse gas emissions of fossil fuel burning in power generation and carbon dioxide production from other industrial processes such as cement manufacturing and purification of natural gas. Many clean coal technologies are being developed with carbon capture and storage in mind, for example concentrating carbon dioxide in the combustion exhaust to ease the separation and capture of carbon dioxide. The majority of the carbon capture and storage effort is being invested in incorporating carbon capture and storage into new power generation plant designs – current data indicate that it is cheaper to build a new IGCC plant that produces a pure carbon dioxide exhaust stream than retrofit an existing plant with post-combustion carbon dioxide-capture technology (Clarke, 1991).

Many coal-fired electricity-generating plants are of a conventional design, with typical efficiencies of approximately 33 to 35% – only approximately 35% of the usable energy in the coal is actually converted into electricity and the rest appears as waste heat. Plants with greater energy conversion efficiency (up to approximately 42 to 45%) are possible with combined cycles that recycle heat using high temperature steam. Even higher efficiencies are expected from plants that utilize additional heat-capturing cycles, technological developments in turbine efficiencies, and higher process temperatures.

Clean coal technologies seek to reduce harsh environmental effects by using multiple technologies to clean coal and contain its emissions.

When coal burns, it releases carbon dioxide and other emissions in *flue gas*. Some clean coal technologies purify the coal before it burns. One type of coal preparation, *coal washing*, removes unwanted minerals by mixing crushed coal with a liquid and allowing the impurities to separate and settle (Luttrell *et al.,* 2005).

However, mineral matter may be thoroughly intermixed into the coal structure and hence coal washing using physical methods is difficult, although it might be necessary for industrial use. The high yield also leads to technical difficulties for utilizing the coal, as well as lower efficiency and higher costs for power plants. Some specific problems with the high ash content include high ash disposal requirements, corrosion of boiler walls and fouling of economizers, and high fly ash emissions. A high silica and alumina content in coal ash is another problem, as it increases ash resistivity, which reduces the collection efficiency of electrostatic precipitators and increases emissions.

Other systems control the coal burn to minimize emissions of sulfur dioxide, nitrogen oxides and particulates (Darcovkic *et al.,* 1997; Bhanarkar *et al.,* 2008). *Wet scrubbers*, or flue gas desulfurization systems (Table 13.1), remove sulfur dioxide, a major cause of *acid rain*, by spraying flue gas with limestone and water. The mixture reacts with the sulfur dioxide to form synthetic gypsum, a component of drywall.

Low-NOx (nitrogen oxide) burners (Table 13.2) reduce the creation of nitrogen oxides, a cause of ground-level ozone, by restricting oxygen and manipulating the combustion process (Bris *et al.,* 2007). *Electrostatic precipitators* remove particulates that aggravate asthma and cause respiratory ailments by charging particles with an electrical field and then capturing them on collection plates.

Gasification avoids burning coal altogether. With integrated gasification combined cycle (IGCC) systems, steam and hot pressurized air or oxygen combine with coal. The resulting *synthesis gas* is then cleaned and burned in a gas turbine to make electricity. The heat energy from the gas turbine also powers a steam turbine. Since integrated gasification combined cycle power plants create two forms of energy, they have the potential to reach a fuel efficiency of 50%.

The clean coal technology field is moving in the direction of coal gasification with a second stage so as to produce a concentrated and pressurized carbon dioxide stream followed by its separation and geological storage. This technology has the potential to provide what may be called *zero emissions* – but which, in reality, is extremely low emissions of the conventional coal pollutants, and as low-as-engineered carbon dioxide emissions.

This has been a result of the realization that efficiency improvements, together with the use of natural gas and renewables such as wind will not provide the deep cuts in greenhouse gas emissions necessary to meet future national targets (Omer, 2008; United States Department of Energy, 2008).

Finally, upgrading coal quality enhances power plant efficiency and reduces emissions per kW of electricity produced. Upgrading technologies include coal drying and ash removal methods to significantly increase coal energy density. The challenge in coal drying and ash removal is (i) to realize a net energy benefit in using the upgraded product, and (ii) for processes that export the product, a significant challenge resides in maintaining stability (preventing spontaneous combustion) of the product after removing *in situ* water.

Table 13.1 Flue gas desulfurization (FGD) technologies (Kohl and Nielsen, 1997; IEA, 2003; Miller, 2005; Mokhatab *et al.,* 2006; Suarez-Ruiz and Ward, 2008; Speight, 2013; Breeze, 2014; Speight, 2014, 2019).

1. Wet Processes: Limestone-gypsum It is the most common flue gas desulfurization process – the flue gas is treated with limestone slurry for the sulfur dioxide removal. Approximately 95% of the SO2 from the flue gas can be eliminated. The method can be used for medium-to high-sulfur coals. A slurry waste or a saleable slurry by-product is obtained.
2. Sea-water washing Flue gas is treated with sea water to neutralize the sulfur dioxide – up to 98% of the sulfur dioxide can be removed using this method. The process also removes almost 100% of HCl in the flue gas. Treatment of the waste water with air is required to reduce its chemical oxygen demand and acidity before discharging back to the sea.
3. Ammonia scrubbing The ammonia/ammonium sulfate is employed as scrubbing agent in this process. Approximately 93% v/v of the sulfur dioxide from the flue gas can be eliminated at the commercial scale. Ammonium sulfate is obtained as a saleable product.
4. Wellman-Lord process The process uses sodium sulfite solution for scrubbing sulfur dioxide from flue gas – the removal rate of sulfur dioxide is up to 98%. The method includes reagent regeneration stage in the process scheme which reduces sorbent consumption. Depending on the plant design, different saleable byproducts (elemental sulfur, sulfuric acid, or liquid sulfur dioxide) can be produced.
5. Semi-dry Processes: Circulating Fluidized bed (CFB) Hydrated lime is used to remove the sulfur dioxide, sulfur trioxide, and hydrogen chloride from the flue gas in this method. Water is injected into the bed to obtain an operation close to the adiabatic saturation temperature. More than 95% sulfur dioxide removal efficiency can be achieved by using this process. The final product is a dry powdered mixture of calcium compounds requiring disposal operations.
6. Spray-dry process Lime or calcium oxide is usually employed as sorbent in this process in which the flue gas is given into a reactor vessel and the lime slurry is atomized into the same vessel. The water in the slurry is completely evaporated in the spray dry absorber. It is possible to remove 85-90% of the sulfur dioxide for moderately high sulfur fuels. A solid by-product needing disposal operation is produced.
7. The duct spray dry process This process is similar to the conventional spray-drying. However, the slaked lime slurry is directly fed into the ductwork. A moderate degree of desulfurization (50-75%) is possible by using this method. A dry powdered mixture of calcium compounds is produced as the final product.

(*Continued*)

Table 13.1 Flue gas desulfurization (FGD) technologies (Kohl and Nielsen, 1997; IEA, 2003; Miller, 2005; Mokhatab *et al.,* 2006; Suarez-Ruiz and Ward, 2008; Speight, 2013; Breeze, 2014; Speight, 2014, 2019). (*Continued*)

8. Dry Processes Furnace Sorbent Injection The process considers the injection of lime into wall and tangentially fired boilers for the sulfur dioxide absorption. This process removes between as little as 30% and as much as 90% of the sulfur in the flue gas – inefficient use of the absorbent and the costs of by-product disposal (a mixture of ash and calcium compounds) add to operation expenses.
9. The sodium bicarbonate injection process The dry soda sorbents are injected as dry powders into the flue gas duct downstream of the air heater to react with acidic compounds such as sulfur dioxide, sulfur trioxide, and hydrogen chloride. It is possible to remove up to 70% of the sulfur dioxide and approximately 90% of the hydrogen chloride. The final product is a dry powdered mixture of sodium compounds and fly ash.

Table 13.2 NOx control technologies in electricity generation (Miller, 2005; Breeze, 2005; Graus and Worrell, 2007; Suarez-Ruiz, 2008; Franco and Diaz, 2009).

1. Low NOx burners This technology relies on the principle of staging the combustion air within the burner to reduce NOx formation. Unburned carbon levels are higher in low-NOx firing systems. A 35 to 55 % NOx reduction is possible.
2. Furnace air staging This process involves staging the combustion by diverting 5 to 20% of combustion air from the burners and injecting above the main combustion zone and can reduce the NOx emissions by 20% to 60% depending on the initial nitrogen oxide levels in the boiler, fuel combustion equipment design, and fuel type. The amount of unburned carbon is on the order of 35 to 50%.
3. Fuel staging (Reburning) In this technology, the burners in the primary combustion zone are worked with low excess air. Up to 30% of the total fuel heat input is given above the main combustion zone to create a fuel-rich zone during combustion. Reburning of coal takes relatively longer residence time, approximately 50% of NOx reduction can be achieved.
4. Selective non-catalytic reduction This process involves the injection of a reagent such as ammonia (NH_3) or urea (H_2NCONH_2) into the hot flue gas stream to reduce the NOx to nitrogen and water. Using this technology, 30 to 60% NOx reductions can be achieved.
5. Selective catalytic reduction The process considers ammonia (NH_3) injection into the flue gas which is then passed through the layers of a catalyst made from a base metal, a zeolite, or a precious metal. This technology can achieve NOx reductions on the order of 85 to 95% v/v. It is most suitable for low-sulfur coals (up to 1.5% w/w sulfur) due to the corrosive effects of sulfuric acid formed during the operation.

Conversion of coal to clean liquid fuels, chemicals, or hydrogen enhances energy security and supports global climate change and hydrogen fuel initiatives. Technologies include coal liquefaction, which involves converting coal gasification-derived synthesis gas into zero-sulfur, aromatic-free transportation fuels using the Fischer-Tropsch process and hydrogen-from-coal processing techniques.

13.2 Historical Perspectives

Coal has been the principal source of fuel and energy for many hundreds of years; perhaps even millennia, even though its use is documented somewhat less completely than the use of crude oil and its derivatives (Speight, 2014). Nevertheless, coal has been the principal source of solid and gaseous fuels during this and the last century. In fact, each town of any size had a plant for the gasification of coal (hence, the use of the term *town gas*). Most of the natural gas produced at the crude oil fields was vented to the air or burned in a flare stack. Only a small amount of the natural gas from the crude oil fields was pipelined to industrial areas for commercial use. It was only in the years after World War II that natural gas became a popular fuel commodity leading to the recognition that it has at the present time. Coal has probably been known and used for an equal length of time but the records are somewhat less than complete.

There are frequent references to coal in the Bible (Cruden, 1930) but all in all, the recorded use of coal in antiquity is very sketchy. However, there are excellent examples of coal mining in Britain from AD 1200 which marked, perhaps, the first documented use of mined coal in England (Galloway, 1882). On another historical note, and it is worthy of repetition here, that a singular environmentally significant event occurred in England in 1257 which threatened the very existence of coal use and its future as a fuel (Speight, 2013).

Thus, Eleanor, Queen of Henry III of England, was obliged to leave the town of Nottingham where she had been staying during the absence of the king on an expedition into Wales. The queen was unable to remain in Nottingham due to the troublesome smoke from the coal being used for heating and cooking. Over the next several decades, a variety of proclamations were issued by Henry and by his son, Edward I, which threatened the population with the loss of various liberties, perhaps even the loss of significant part(s) of the anatomy of the miscreant and even loss of life, if the consumption of coal was not seriously decreased and, in some cases, halted (Galloway, 1882).

By the late 1500s, an increasing shortage of wood in Europe resulted in the search for another form of combustible energy and coal became even more popular with the English, French, Germans, and Belgians being very willing to exploit the resource. In the mid-to-late 1700s, the use of coal increased dramatically in Britain with the successful development of coke smelters and the ensuing use of coal to produce steam power. By the 1800s, with the Industrial Revolution well under way, coal was supplying most of the energy requirements of Britain. By this time, the use of gas from coal (*town gas*) for lighting has become established.

In contrast, in the United States, where the population density was much lower than in Europe, wood was more plentiful and many colonial fires were fueled by this resource; any coal (often in limited quantities or for specific uses such as in smelters) required for energy was imported from Britain and/or Nova Scotia. But after the Revolutionary War, coal entered the picture as an increasingly popular source of energy. As an example, the state of Virginia supplied coal to New York City. However, attempts to open the market to accept coal as a fuel were generally ineffective in the United States and progress was slow, if not extremely slow. It was not until the period from 1850 to 1885 that coal use in the United States increased, spurred by the emerging railroad industry as a fuel for the locomotives as well as for the manufacture of steel rails. At last, coal seemed to undergo a transformation as a fuel on both sides of the Atlantic Ocean.

13.3 Modern Perspectives

The increased use and popularity of coal is due, no doubt, to the relative ease of accessibility which has remained virtually unchanged over the centuries. On the other hand, crude oil is now an occasional exception because of a variety of physical and political reasons.

The relatively simple means by which coal can be used has also been a major factor in determining its popularity. In addition, coal can be interchanged to the three fuel types insofar as one form can be readily converted to another:

$$\text{Gas} \rightarrow \text{Liquid} \rightarrow \text{Solid}.$$

Indeed, the conversion of coal to fuel products and to chemicals as evidenced by the birth and evolution of the coal chemicals industry in the 19th century served to increase the popularity of coal.

The prognosis for the continued use of coal is good. Projections that the era of fossil fuels (natural gas, crude oil, and coal) will be almost over when the cumulative production of the fossil resources reaches 85% of their initial total reserves (Hubbert, 1973) may or may not have some merit. In fact, the relative scarcity (compared to a few decades ago) of crude oil is real but it seems that the remaining reserves coal, and perhaps natural gas, make it likely that there will be an adequate supply of energy for several decades but the environmental issues are very real and need close attention (Martin, 1985; Bending *et al.*, 1987; Speight and Lee, 2000; Speight, 2013, 2014).

The use of coal in an environmentally detrimental manner is to be deplored. The use of coal in an environmentally acceptable manner is to be applauded. Technologies which ameliorate the effects of coal combustion on acid rain deposition, urban air pollution, and global warming must be pursued vigorously (Vallero, 2008). There is a challenge that must not be ignored and the effects of acid rain in soil and water leave no doubt related to the need to control the causes of the acid rain. Indeed, recognition of the need to address these issues is the driving force behind recent energy strategies as well as a variety of research and development programs (United States Department of Energy, 1990; United States General Accounting Office, 1990).

As new technology is developed, emissions will be reduced (if not mitigated) by repowering in which aging equipment is replaced by more advanced and efficient substitutes. Such repowering might, for example, involve an exchange in which an aging unit is exchanged for a newer combustion chamber, such as the atmospheric fluidized-bed combustor (AFBC) or the pressurized fluidized-bed combustor (PFBC) (Chapters 8, 9).

In the pressurized fluid-bed combustor, pressure is maintained in the boiler, often an order of magnitude greater than in the atmospheric combustor, and additional efficiency is achieved by judicious use of the hot gases in the combustion chamber (combined cycle). Both the atmospheric and pressurized fluid-bed combustors burn coal with limestone or dolomite in a fluid bed which allows, with recent modifications to the system, allows the limestone sorbent to take up approximately 90% of the sulfur that would normally be emitted as sulfur dioxide. In addition, boiler reconfiguration can allow combustion to be achieved more efficiently than in a conventional combustor, thereby reducing the formation of nitrogen oxide(s) (Baldwin *et al.,* 1992).

An important repowering approach attracting great interest is the integrated coal-gasification combined cycle (IGCC) system (Notestein, 1990; Takematsu and Maude, 1991) (Chapters 9, 10, 11). The major innovation introduced with the IGCC technology is the conversion of coal into synthesis gas, a mixture of mainly hydrogen (H2) and carbon monoxide (CO) with lesser quantities of methane (CH4), carbon dioxide (CO2), and hydrogen sulfide (H2S). Up to 99% of the hydrogen sulfide can be removed by commercially available processes (Chapter 12) before the gas is burned. The synthesis gas then powers a combined cycle in which the hot gases are burned in a combustion chamber to power a gas turbine and the exhaust gases from the turbine generate steam to drive a steam turbine.

The carbon oxides (carbon monoxide, CO, and carbon dioxide, CO2) are also of importance insofar as coal can produce either or both of these gases during use; and both gases have the potential for harm to the environment. Reduction in the emission of these gases, particularly carbon dioxide, which is the final combustion product of coal, can be achieved by trapping the carbon dioxide at the time of coal usage.

However, it is not only the production of carbon dioxide from coal that needs to be decreased. The production of pollutants such as sulfur dioxide (SO2) and oxides of nitrogen (NOx, where x = 1 or 2) also needs attention. These gases react with the water in the atmosphere and the result is an acid:

$$SO_2 + H_2O \rightarrow H_2SO_4 \text{ (sulfurous acid)}$$
$$2SO_2 + O_2 \rightarrow 2SO_3$$
$$SO_3 + H_2O \rightarrow H_2SO_4 \text{ (sulfuric acid)}$$
$$2NO + H_2O \rightarrow HNO_2 + HNO_3 \text{ (nitrous acid + nitric acid)}$$
$$2NO + O_2 \rightarrow 2NO_2$$
$$NO_2 + H_2O \rightarrow HNO_3 \text{ (nitric acid)}$$

Indeed, the careless combustion of coal can account for the large majority of the sulfur oxides and nitrogen oxides released to the atmosphere. Whichever technologies succeed in reducing the amounts of these gases in the atmosphere should also succeed in reducing the amounts of urban smog, those notorious brown and grey clouds that are easily recognizable at some considerable distances from urban areas, not only by their appearance but also by their odor.

Current awareness of these issues by a variety of levels of government has resulted, in the United States, of the institution of the Clean Coal Program to facilitate the development of pollution abatement technologies. And it has led to successful partnerships between government and industry (United States Department of Energy, 1993). In addition, there is the potential that new laws, such as the passage in 1990 of the Clean Air Act Amendments (United States Congress, 1990; Stensvaag, 1991) will be a positive factor and supportive of the controlled clean use of coal.

Indeed, recognition of the production of these atmospheric pollutants in considerable quantities every year has led to the institution of national emission standards for many pollutants. Using sulfur dioxide as the example, the various standards are not only specific (Kyte, 1991) but will become more stringent with the passage of time (IEA Coal Research, 1991). Atmospheric pollution is being taken very seriously and there is also the threat, or promise, of heavy fines and/or jail terms for any pollution-minded miscreants who seek to flaunt the laws (Vallero, 2008). Be that as it may, a trend to the increased use of coal will require more stringent approaches to environmental protection issues than we have ever known at any time in the past. The need to protect the environment is strong. One example is the passage of amendments to the Clean Air Act which attests to this fact.

Thus, as the alternatives in energy vacillate from coal to oil to gas and back again to be followed, presumably, by the eras of nuclear fuels and solar energy, there is an even greater need to ensure that emissions from coal use are clean. It is time to move away from the uncontrolled and irresponsible use of coal and to show that coal can be used in an environmentally safe manner.

13.4 Clean Coal Technology

Coal, the fuel that helped initiate and maintain the Industrial Revolution, remains the primary fuel for electricity generation worldwide as well as in the United States. In fact, according to various industry estimates, if coal production remains constant, there are enough coal reserves in the United States alone to power coal boilers for the next 200 years. However, coal also releases the greenhouse gas carbon dioxide, as well as other pollutants. It is these pollutants that cause concern among environmentalists and the general public. Methods are being devised, and some have already been implemented, that make coal-burning boilers more efficient and less polluting.

In recent years, issues related to global climate change has attained political prominence thereby potentially limiting the role of coal can play under various scenarios of greenhouse gas regulations. There are, however, serious, and meaningful questions related to the facts relating to climate change and whether or not the evidence on which these so-called facts are based is believable (Bell, 2011).

There is no one technology that will serve as a panacea to halt pollution. The idea of *clean coal* may be better understood as a collection of different technologies, each with its own benefits and drawbacks that are typically limited by the character of the coal being employed for the generation of energy.

The focus of the United States Clean Coal Program is to seek methods by which coal can be used cleanly and efficiently in a variety of industrial operations. The capacity of the environment to absorb the effluents and the impacts of energy technologies is not unlimited as some would have us believe. The environment should be considered to be an extremely limited resource, and discharge of chemicals into it should be subject to severe constraints. Indeed, the declining quality of raw materials, especially fossil fuels that produce the energy for industrial and domestic use, gives rise to a variety of emissions (gaseous, liquid, and solid) and dictates that more material must be processed to provide the needed energy. And the growing magnitude of the effluents from fossil fuel processes has moved above the line where the environment has the capability to absorb such (gaseous) effluents without disruption.

In a more general perspective, coal and its companion fossil fuels are not the only feedstocks which produce emissions that are of harm to the environment. In fact, process operators must make serious attempts to ensure that natural resources such as air, land, and water remain as unpolluted as possible and the environmental aspects of such an operation are carefully addressed. In addition, there must always be reason in the minds of the regulators. It may not always be physically and economically possible or necessary to clean up every last molecule of pollutant. But such rationale must not be used as a free license to pollute nor should the law be so restrictive that industry cannot survive. Rational thought must prevail.

Although the focus of this chapter is on the cleanup of potentially harmful gaseous emissions from coal plants, there is also the need to recognize that gas processing operations, as a consequence of the chemicals employed (Mokhatab *et al.,* 2006; Speight, 2014, 2019) can also cause other environmental damage. For example, the spill of an acid solution or any solution that might be used in gas washing operations can cause severe damage to the flora and fauna as well as to the aquatic life in the region. Thus, caution is advised from all environmental aspects and not just that most closely related to the process operation.

Indeed, any of the products from a gas cleaning plant can contain contaminants. The very nature of the gas cleaning plant dictates that this is so but there are many options available to assist in the cleanup of the plant products. However, it is very necessary, in view of the scale of such plants, that controls be placed on the release of materials to the environment to minimize the potential damage to the immediate environment; damage to the environment must be avoided.

Coal combustion releases substantial quantities of carbon dioxide (CO_2) to the atmosphere which can participate in one or more of the various cycles that exist in the biosphere and atmosphere (Graedel and Crutzen, 1989; Maurits la Rivière, 1989; Speight and Lee, 2000) and have dominated the global environmental system for millennia. In addition, other coal plant emissions such as sulfur dioxide (SO_2) and nitrogen oxides (NO) are major contributors to acid rain (Manowitz and Lipfert, 1990).

The major waste streams leaving many coal plants might be water vapor and carbon dioxide. The former has little effect on the environment whilst the effect of the latter on the environment, while being considered proven, is still open to considerable debate, speculation, and often violent scientific and emotional disagreement. Nevertheless, as common sense alone must tell us, it must be assumed that the effects of releasing of unlimited amounts of carbon dioxide to the atmosphere will, and most probably does, cause adverse, if not severe, perturbations to the environment. However, it is all a matter of degree. The discharge of liquid water, because the potential for dissolved contaminants is real, is a different issue. Water may not be water may not be water.

If it can be assumed that water used for cooling purposes in a coal utility plant is the predominantly the type that passes through cooling towers, the gaseous emissions from such a plant will be carbon dioxide (CO_2), sulfur oxides (SO_X, where x = 2 or 3), nitrogen oxides (NO_X, where x = 1 or 2), as well as sundry other sulfur compounds of which hydrogen sulfide (H_2S), carbonyl sulfide (COS), carbon disulfide (CS_2), and mercaptans (RSH) are examples.

Nevertheless, coal use can give rise to pollution and the polluting effects of coal mining and combustion on the air, water and soil remain as significant a challenge, with coal providing such a large fraction of global primary energy, as they did during the early ages of coal use. With both US and worldwide supplies of coal in relative abundance compared to oil and gas, a number of concepts have been proposed to continue taking advantage of this inexpensive and comparatively widespread resource while minimizing the environmental impacts associated with its use.

The term *clean coal technology* refers to a new generation of advanced coal utilization technologies that are environmentally cleaner and in many cases more efficient and less costly than the older, and more *conventional* coal-using processes (United States Department of Energy, 1992). Clean coal technologies offer the potential for a more clean use of coal thereby having a direct effect on the environment and contributing to the resolution of issues relating to acid rain and global climate change.

There are a number of technological concepts that fall under the umbrella of *clean coal*, including installation of air pollution control equipment, and more innovative ideas such as carbon capture and gasification of coal for use in combined cycle plants similar in design to natural gas-fired power plants. There is also the potential for producing synthetic liquid fuels from coal as means of offsetting crude oil depletion (Speight, 2013, 2020b). In each case, there are economic and environmental benefits of each option, as well as the disadvantages and obstacles to their implementation.

While some of these concepts are technically viable, there is no single technology or combination of technologies that is capable of addressing all of the environmental or economic challenges likely to arise from continued dependence on coal as a major source of energy in the coming decades, underscoring the need to assemble and prove viable alternatives to address these challenges over the long term.

Moreover, viable clean coal technologies also promote the continued use of coal, thereby offering some degree of energy security to those countries that are net oil importers but having plentiful supplies of coal. Clean coal combustion technologies can reduce emissions of sulfur oxides (SO), nitrogen oxides (NO), and other pollutants at various points of coal use from a mine to a power plant or factory.

Clean combustion refers to optimizing the process of burning coal, or other fuels, to release more useful heat and generate fewer harmful pollutants from the outset, prior to the effects of any pollution control exhaust post-treatment. While the combustion process itself has little effect on the release of certain pollutants intrinsic to the physical material of coal on a per-unit-combusted basis, such as mercury, arsenic, lead or antimony present in coal ash, it can have a significant impact on the formation of pollutants that form due to combustion itself, such as smog-forming nitrogen oxides (NOx) as well as carbon monoxide (CO) and other incomplete combustion by-products such as volatile organic compounds (VOCs) and black carbon (soot).

One of the challenges of designing an optimized combustion system is that soot, volatile organic compound, and carbon monoxide emissions tend to form due to insufficient oxygen supply or insufficient mixing of fuel and air in the combustion chamber and are primarily eliminated through a more complete combustion, whereas NOx tends to form due to an overabundance of oxygen and forms preferentially at higher temperatures typically associated with more complete combustion.

Combustion system improvements must therefore balance nitrogen oxide control with formation of pollutants resulting from incomplete burning like carbon monoxide or, in the case of waste combustors, dioxins and furans. The preferred method is to promote more complete combustion to avoid the formation of a wide range of organic pollutants, then to reduce nitrogen oxide emissions through a combination of effective control over combustion temperature and exhaust post-treatment with ammonia or other chemicals to dissociate nitrogen oxide particles into benign atmospheric nitrogen and oxygen.

Thus, there is (i) precombustion cleaning, (ii) cleaning during combustion, (iii) post-combustion cleaning, and (iv) cleaning by conversion.

13.4.1 Precombustion Cleaning

Application of coal cleaning/upgrading methods before combustion process can improve the economic value of coal and makes it more environmentally friendly. There are a number of different applications to be used for this purpose such as physical, chemical, biological cleaning methods, drying, briquetting, and blending (IEA, 2003; Breeze, 2005; Miller, 2005). Physical cleaning methods are most effective for removing the ash content, pyritic sulfur and trace elements associated with major inorganic elements such as mercury (Xu *et al.,* 2003; Lee *et al.,* 2006; Sondreal *et al.,* 2004, 2006; Yang *et al.,* 2007; Wand *et al.,* 2008).

Precombustion cleaning involves the removal of any, or at least of a part, of pollution-generating impurities from coal by physical, chemical, or biological means. A substantial amount of the coal used in utility boilers does receive some form of cleaning before it is burned. The major objective of many of the precombustion cleaning processes is the reduction of the sulfur content (usually pyritic, FeS_2, sulfur). The wider use of conventional coal-cleaning processes will allow the sulfur dioxide emissions to be reduced markedly.

Coal cleaning processes could achieve trace element rejections of 50 to 80% (Luttrell, *et al.,* 2000; Xu *et al.,* 2003). Drying removes the excess moisture and reduces the weight and volume of the coal, rendering it more economical to transport and increaseing the heating value. Solar drying is the simplest option; it involves leaving the coal in an open storage area before transporting it. Drying coal can also be realized by applying heat to remove the moisture. This is most often carried out at the power station by utilizing surplus energy in the plant flue gases. Blending of coals of different types at power plants is also effective for saving the costs, meeting the quality requirements, and improving the combustion behavior of the fuel (Breeze, 2005). Briquetting of coal using the appropriate binders could provide reduction in sulfur dioxide emissions and fixation of some toxic elements.

Low-quality coals can be upgraded by using physical (coal washing plants), chemical (leaching) and biotechnological (microorganisms) processes before the combustion process. However, the most promising solution for this purpose is the use of coal washing plants. In general, gravity-based separation techniques are used for the removal of mineral matter from coal. Dense media separators such as heavy media separators, heavy media cyclones and jigs are used worldwide for coal upgrading.

Enhanced gravity separators, selective agglomeration, and froth flotation are the effective alternative coal cleaning methods for the mineral matter and pyrite removal. The ash content of coal could be reduced by over 50% by using these devices (WCI, 2005). Sometimes the properties of the coal may not suitable for the wet washing or wet washing plants may not be considered as feasible by the power plant operators due to its additional capital and operational costs. Under these circumstances dry cleaning methods such as air-heavy medium devices, air tables, and air jigs can be used for the cleaning of coals (Cicek, 2008).

The removal of mineral matter content including the pyritic sulfur improves the efficiency of power plant; it could provide a reduction of up to 40% in SO2 emissions and approximately 5% in carbon dioxide emissions (Breeze, 2005; IEA, 2008c).

Traditionally, research to improve precombustion cleaning has been concentrated on two major categories of cleaning technology: physical cleaning and chemical cleaning (Wheelock, 1977). A new category of coal cleaning, biological cleaning, has recently attracted much interest as advances have been made in microbial and enzymatic techniques for liberating sulfur and ash from coal (Dugan *et al.,* 1989; Beier, 1990; Couch, 1987, 1991).

13.4.1.1 Physical Cleaning

Generally, precombustion coal cleaning is achieved by the use of physical techniques, some of which have been used for more than a century. Physical cleaning methods typically separate undesirable matter from coal by relying on differences in densities or variations in surface properties.

Physical cleaning can remove only matter that is physically distinct from the coal, such as small dirt particles, rocks, and pyrite. Physical cleaning methods cannot remove sulfur that is chemically combined with the coal (organic sulfur), nor can they remove nitrogen from the coal. Currently, physical cleaning can remove 30-50% of the pyritic sulfur and approximately 60% of the ash-forming minerals in coal.

Advanced physical cleaning techniques are expected to be more effective than older techniques (Feibus *et al.,* 1986). And increased efficiency can be achieved by grinding the coal to a much smaller size consistency, whereupon the coal will release more of the pyrite and other mineral matter. Thermal treatment can be used to reduce moisture and modify surface characteristics to prevent reabsorption. New coal-cleaning processes can remove more than 90% of the pyritic sulfur and undesirable minerals from the coal.

13.4.1.2 Chemical/Biological Cleaning

Removing organic sulfur that is chemically bound to the coal is a more difficult task than removing pyritic sulfur through physical means (Wheelock, 1977). Currently, chemical, and biological processes are being used to remove organic sulfur.

One chemical technique that has shown promise is molten caustic leaching. This technique exposes coal to a hot sodium- or potassium-based chemical which leaches sulfur and mineral matter from the coal. Biological cleaning represents some of the most exotic techniques in coal cleaning insofar as bacteria are *cultured* (*developed*) to consume the organic sulfur in coal. Other approaches involve using fungi and the injection of sulfur-digesting enzymes directly into the coal.

Chemical or biological coal cleaning appears to be capable of removing as much as 90% of the total sulfur (pyritic and organic) in coal. Some chemical techniques also can remove 99% of the ash.

13.4.1.3 Fuel Switching

Fuel switching is the substitution of one type of fuel for another, especially the use of a more environmentally friendly fuel as a source of energy in place of a less environmentally friendly fuel.

Thus, fuel switching is an emission control measure that involves the exchange of a less pure fuel to a cleaner fuel. The environmental impact of the fuel switching methods is a potential reduction of greenhouse gases or other element that give negative impact to the environment. The common potential reductions include lower emissions of carbon dioxide, sulfur dioxide, and nitrogen oxides.

The capability to use substitute energy sources means that the combustors (for example, boilers, furnaces, ovens, and blast furnaces) of a facility had the machinery or equipment either in place or available for installation so that substitutions could actually have been introduced within a specific time period without extensive modifications.

Fuel-switching capability does not depend on the relative prices of energy sources; it depends only on the characteristics of the equipment, environmental issues, and legal constraints.

13.4.2 Cleaning During Combustion

Cleaning during combustion can involve modification of the manner in which coal is burned or, alternately, the use of pollutant absorbing substances which can be injected into the combustion chamber.

Clean combustion consists of removing the pollutants from coal as it is burned. This can be accomplished by controlling the combustion parameters (fuel, air/oxygen, and temperature) to minimize the formation of pollutants and/or by injecting pollutant-absorbing substances into the combustion chamber to capture the pollutants as they are formed (Martin *et al.,* 1986).

13.4.2.1 Advanced Combustion

Advanced combustion systems control or remove sulfur dioxide (SO2), nitrogen oxides (NO), and/or particulate matter from coal combustion gases before they enter a steam generator or heater. Pollutants are controlled by the combustion parameters and/or sorbents used during the combustion process. Nitrogen oxides can be controlled through staged combustion, coal reburning, or by a method of controlling combustion flame temperature. On the other hand, sulfur dioxide is controlled by means of a sorbent injected in the combustion chamber. Ash can be controlled by operating at high temperatures and converting it into molten slag, but such high temperatures may not be conducive to removal of sulfur dioxide and of and nitrogen oxides.

Advanced NOx control technologies include (i) low-NOx burners and reburning systems that limit NOx formation by staging the introduction of air in the combustion process, otherwise known as combustion modification, (ii) selective catalytic reduction, SCR, (iii) selective non-catalytic reduction, SNCR, and (iv) other chemical processes that act upon and reduce NOx already formed (post-combustion processes), and oxygen-enhanced combustion that displaces a portion of the air with oxygen in low-NOx burners (United States Department of Energy, 2008).

In terms of low-NOx burners, (i) the amount of air available is limited in the initial stages of combustion when fuel-bound nitrogen is volatilized, (ii) the flames are lengthened to avoid hot spots, (3) the burner is typically integrated with over-fire air to complete combustion in a cooler zone, and (iv) the burner can be used with neural network controls for optimum load-following performances. Reburning systems inject fuel into flue gas to strip oxygen away from the NOx and introduce over-fire air to complete combustion. Selective catalytic reduction and selective non-catalytic reduction use ammonia/urea to transform NOx into nitrogen and water. Selective catalytic reduction typically requires an array of catalysts in a reactor vessel to operate at relatively low post-boiler application temperatures, whereas selective non-catalytic reduction simply involves ammonia/urea injection in the boiler where temperatures are high. Oxygen-enhanced combustion reduces available nitrogen and enables deeper staging through increased combustion efficiency (United States Department of Energy, 2008).

Some advanced combustion systems are designed to reduce only nitrogen oxide emissions while others are designed to reduce or capture several pollutants (sulfur dioxide, nitrogen oxides, and ash). Depending on the specific technology, these systems are capable of reducing nitrogen oxide emissions by 50 to 70%, sulfur dioxide emissions by 50 to 95%, and ash by 50 to 90%, relative to present conventional technology.

Efficiency improvements of conventional solid coal combustion plants can take a number of forms, and each reduces the environmental footprint of the output of a power plant by using rather than wasting more of the energy contained in chemical bonds in the coal and released when it is burned. Technical improvements that fall into this category include improved furnace and boiler design to keep heat inside the power generation cycle rather than releasing it through ash quenching and condensing of steam, reductions in parasitic load demand from pumps, induced draft fans, and other plant components, and improved efficiency of the steam turbines used to transform heat energy into electricity.

The steam temperature can be raised to levels as high as 580 to 600°C (930 to 1110°F) and pressure over 4500 psi. Under these conditions, water enters a *supercritical* phase with properties in between those of liquid and gas. This supercritical water can dissolve a variety of organic compounds and gases, and when hydrogen per-oxide and liquid oxygen are added, combustion is triggered. Turbines based on this principle (*supercritical turbines*) offer outputs of over 500 MW.

The supercritical turbines can burn low-grade fossil fuels and can completely stop nitrogen oxide emissions and keep emissions of sulfur dioxide to a minimum. For example, lignite or brown coal has a high water content and is not normally used for power generation but when lignite is added to water that has been heated to 600°C (1110°F) at a pressure of 4500 psi, it will completely burn up in one minute while emitting no nitrogen oxides and only 1% of its original sulfur content as sulfur dioxide. This also eliminates the need for desulfurization and denitrogenation equipment and soot collectors. Although large amounts of energy are required to create supercritical water, operating costs could be significantly different from existing power generating facilities because there would be no need to control gas emissions. The demand for cooling water is also reduced, almost proportionally to an increase in the efficiency.

Currently, supercritical power plants reach thermal efficiencies of just over 40%, although a few of the more plants have attained high efficiency up to 45%. A number of steam generator and turbine manufacturers around the world now claim that steam temperatures up to 700°C (1290°F) (*ultra-supercritical conditions*) are possible which might raise plant efficiencies to over 50%, but require the use of expensive nickel-based alloys for reaction equipment and power generators because of the corrosive properties of supercritical.

The main competition to supercritical system is from new gas turbine combined cycle plants which are now expedited to achieve an overall efficiency of 60%, making a huge difference in generating and life-cycle costs. However, the new gas turbines will release exhaust into waste heat recovery steam generator at temperatures above 600°C (1110°F), thus necessitating the use of the high chromium steel and nickel alloys as used in the supercritical coal-fired plants.

The advancements that have been achieved in conventional coal plant performance demonstrate significant promise and room for further improvements; however, they also demonstrate the limitations of existing technology, as coal combustion and turbine design have been continually improving for many years, yet power generation from this source still generates considerable pollution. Potential areas of further improvement are being exhausted. *Conventional clean coal* offers promise for the future, perhaps more so than any other form of coal power, but it is still far from unproblematic. Analogous and in some cases greater improvements are likely to occur in alternative energy sources as well, as has certainly been the case with wind power and other renewable energy sources over the past decade (Omer, 2008), and coal may not remain the winner in pure economic terms that has been with many of the changes listed above as fuel prices and capital costs of new plants and retrofits continue to increase.

13.4.2.2 Fluidized-Bed Combustion

Fluidized-bed combustion has the ability to reduce emissions by controlling combustion parameters and by injecting a sorbent, or a pollutant absorbent (such as crushed limestone), into the combustion chamber along with the coal (Martin *et al.,* 1986). In the process, pulverized coal mixed with crushed limestone is suspended on jets of air (or fluidized) in the combustion chamber. As the coal burns, sulfur is released, and the limestone captures the sulfur before it can escape from the boiler. The sulfur combines with the limestone to form a mixture of calcium sulfite (CaSO3) and calcium sulfate (CaSO4).

The temperature in the fluidized-bed combustor is on the order of 800 to 900°C (1470 to 1650°F) compared with 1300 to 1500°C (2370 to 2730°F) in *pulverized coal combustion* systems (PCC). Low temperature helps minimize the production of nitrogen oxides and, with the addition of a sorbent (typically limestone) into the fluidized bed, much of the sulfur dioxide formed can be captured. The other advantages of fluidized-bed combustors are compactness, ability to burn low calorific values and the production of ash of low corrosivity.

Fluidized-bed combustors are essentially of two types: (i) bubbling bed, and (ii) circulating bed. While bubbling beds have low fluidization velocities to prevent solids from being elutriated, circulating beds employ high velocities to actually promote elutriation. Both of these technologies operate at atmospheric pressure. The circulating bed can remove 90 to 95% of the sulfur content from the coal while the bubbling bed can achieve 70 to 90% sulfur removal.

The fluidized mixing of fuel and sorbent enhances both the coal-burning and sulfur-capturing processes and allows for reduced combustion temperatures of 760 to 870°C (1400 to 1600°F), or almost half the temperature of a conventional boiler. This temperature range is below the threshold where most of the nitrogen oxides form and, thus, fluidized-bed combustors have the potential to reduce the emission of both sulfur dioxide and nitrogen oxides.

Fluidized-bed combustors can be either atmospheric or pressurized. The atmospheric of combustor type operates at normal atmospheric pressure while the pressurized type of combustor operates at pressures 6-16 times higher than normal atmospheric pressure. The pressurized fluid-bed boiler offers a higher efficiency and less waste products than the atmospheric fluid-bed boiler. There is also a circulating (entrained) bed combustor which allows for finer coal feed, better fuel mixing, and higher efficiency, as well as an increased sulfur dioxide capture.

Unlike conventional pulverized-coal combustor, the circulating fluidized-bed combustor is capable of burning fuel with volatile content as low as 8 to 9% w/w (such as anthracite coke and crude oil with minimal carbon loss). Fuels with low ash-melting temperature such as wood, and bio-mass have been proved to be feedstocks in circulating fluidized-bed combustors due to the low operating temperature of 850 to 900°C (1560 to 1650°F). The circulating fluidized-bed combustor boiler is not bound by the tight restrictions on ash content either and can effectively burn fuels with mineral matter content up to 70% w/w.

The circulating fluidized-bed combustor can successfully burn agricultural wastes, urban waste, wood, and other form of bio-mass which are the low melting temperature as fuels. The low furnace temperature precludes the production of *thermal NOx* which appears above a temperature of 1200 to 1300°C (2190 to 2370°F). Besides, in a circulating fluidized-bed combustor boiler, the lower bed is operated at near substoichiometric conditions to minimize the oxidation of *fuel-bound nitrogen*. The remainder of the combustion air is added higher up in the furnace to complete the combustion. With the staged-combustion, approximately 90% w/w of fuel-bound nitrogen is converted to elemental nitrogen as the main product.

The *pressurized bed* was developed in the late 1980s to further improve the efficiency levels in coal-fired plants. In this concept, the conventional combustion chamber of the gas turbine is replaced by a pressurized fluidized-bed combustor. The products of combustion pass through a hot gas cleaning system before entering the turbine. The heat of the exhaust gas from the gas turbine is utilized in the downstream steam turbine. This technology is called pressurized fluidized-bed combustion combined cycle (PFBC).

The bed is operated at a pressure of between 75 and 300 psi. Operating the plant at such low pressures allows some additional energy to be captured by venting the exhaust gases through a gas turbine which is then combined with the normal steam turbine to achieve plant efficiency levels of up to 50%. The steam turbine is the major source of power in a pressurized fluidized-bed combustor (PFBC), contributing approximately 80% of the total power output – the remaining 20% is produced in gas turbines.

The *pulsed atmospheric fluidized-bed combustor* (PAFBC) is a bubbling fluidized-bed coal combustor combined with a pulse combustor (Pence and Beasley, 1995; Muller, 1996). Fluidized-bed combustors allow the use of high-sulfur coal, performing extremely well environmentally with particularly low nitrogen oxide and sulfur dioxide emissions. However, they have the disadvantage of requiring coarse coal with no fines. Adding the pulse combustor to the fluidized bed allows the use of fine coal. The pulsing stabilizes the hydrodynamic and thermodynamic characteristics while minimizing particulate carry-over.

The pulse combustor is a combustion chamber with no moving parts operating on either gas or fine coal. The chamber and exit tube are designed in a manner which results in a self-sustaining, periodic combustion process. The frequency of the resonance varies with chamber size and exit tube length. The exit tube of the pulse combustor is immersed in the fluidized bed. The raw coal is pneumatically separated with the coal fines carried to the pulse combustor and the coarse coal to the fluidized-bed combustor via a screw feeder.

13.4.3 Post-Combustion Cleaning

Post-combustion cleaning involves the use of processes which remove pollutants from the flue gases exiting the boiler (Kuhr *et al.,* 1988; Frazier *et al.,* 1991). Finally, cleaning by coal conversion (which is a departure from traditional coal-burning methods) involves the conversion of coal into a gas or liquid that can be cleaned and then used as fuel.

The use of coal in electricity production plants inevitably generates some pollutants such as sulfur oxides (SOx), nitrogen oxides (NOx), coal combustion products (CCPs) and trace elements. Several technologies are utilized alone or together throughout the coal combustion to eliminate these pollutant emissions (Kuhr *et al.,* 1988; Frazier *et al.,* 1991; Xu *et al.,* 2003).

13.4.3.1 Sulfur Oxide Emissions

The sulfur presents in both inorganic and organic forms in coal. The inorganic sulfur occurs as sulfide minerals (pyritic sulfur, FeS_2) and/or a range of sulfate compounds (sulfate sulfur). Pyritic and organically bound sulfur constitute the majority of sulfur content and sulfates are at low concentrations in coal. Approximately 95% of sulfur content is converted to sulfur dioxide (SO_2) during the combustion process and a small amount of sulfur trioxide (SO_3) is also formed. Sulfur dioxide is a major contributor to acid rain formation and harmful to the plants and soil (IEA, 2003; Miller, 2005; Breeze, 2005; Graus and Worrell, 2007; Suarez-Ruiz and Ward, 2008; Franco and Diaz, 2009).

The sulfur gas produced by burning coal can be partially removed with scrubbers or filters. In conventional coal plants, the most common form of sulfur dioxide control is through the use of scrubbers. To remove the SO_2, the exhaust from a coal-fired power plant is passed through a mixture of lime or limestone and water, which absorbs the SO_2 before the exhaust gas is released through the smokestack. Scrubbers can reduce sulfur emissions by up to 90%, but smaller particulates are less likely to be absorbed by the limestone and can pass out the smokestack into the atmosphere. In addition, scrubbers require more energy to operate, thus increasing the amount of coal that must be burned to power their operation.

Other coal plants use *fluidized-bed combustion* (Chapters 8, 10, 11) instead of a standard furnace. Fluidized-bed technology was developed in an effort to find a combustion process that could limit emissions without the need for external emission controls such as scrubbers. A fluidized bed consists of small particles of ash, limestone, and other non-flammable materials, which are suspended in an upward flow of hot air.

Powdered coal and limestone are blown into the bed at high temperature to create a tumbling action, which spurs more effective chemical reactions and heat transfer. During this burning process, the limestone binds with sulfur released from the coal and prevents it from being released into the atmosphere. Fluidized-bed combustion plants generate lower sulfur emissions than standard coal plants, but they are also more complex and expensive to maintain. According to the Union of Concerned Scientists, sulfur emissions decreased by 33% between 1975 and 1990 through the use of scrubbers and fluidized-bed combustors, as well as switching to low-sulfur coal.

Conventional technology (wet scrubbers) uses limestone or lime (and in some cases other alkaline agents to remove sulfur pollutants from the flue gas before it exits the stack (Chapter 12) (Slack, 1986; Mokhatab *et al.,* 2006; Speight, 2013, 2014, 2019). Such processes can be plagued by corrosion and plugging and also produce a wet waste product (sludge) which has high disposal costs. However, the reliability of wet scrubbers has improved significantly, and they have demonstrated the ability to remove more than 90% of the sulfur dioxide (Slack, 1986).

Flue gas purification (*air pollution control*, APC), refers to technologies used to condition the emissions from a power plant after the combustion of fuel but before the release of gaseous and suspended particulate combustion by-products into the atmosphere. Each device or system corresponds to a given pollutant or category of pollutants to be removed from the flue gas stream. Reducing chemicals such as ammonia or urea, along with catalysts in the case of selective catalytic reduction (SCR) systems, are used to treat the exhaust to remove nitrogen oxides.

Slaked or slurried lime is used to neutralize acid gases such as sulfur dioxide. Packed beds or spray injection of activated carbon, with its high surface area to volume ratio, are used to adsorb heavy metals and other particulate fly ash. Electrostatic precipitators and fabric filters remove adsorbed and residual particulates entrained in the flue gases as well as reagents from other air pollution control processes. Most air pollution control devices are applied on the *cold side* of the heat exchangers once the heat used to do work has been transferred to the boiler fluid. The main exception is in control of nitrogen oxides, wherein the reducing agents ammonia and its precursor urea are typically added on the hot side to eliminate nitrogen oxides in order to meet the temperature range requirements for the reduction reaction.

13.4.3.2 Nitrogen Oxide Emissions

The principal atmospheric oxides of nitrogen include nitric oxide (NO), nitrogen dioxide (NO_2) and nitrous oxide (N_2O). Collectively, nitric oxide and nitrogen dioxide are commonly referred to as NOx, which are generated by the reaction of the nitrogenous compounds of the coal and nitrogen in the air with the oxygen used during the combustion process (Miller, 2005; Suarez-Ruiz and Ward, 2008; Franco and Diaz, 2009). The majority of nitrogen oxide emissions are in the form of nitric oxide (NO). A small fraction of nitrogen dioxide (NO_2) and nitrous oxide (N_2O) can also be formed.

Three primary sources of nitrogen oxide formation are documented: (i) thermal NOx, which is generated by the high-temperature – above 1600°C / 2910°F) – reaction of oxygen and nitrogen from the combustion air, (ii) prompt NOx, which is the fixation of atmospheric (molecular) nitrogen by hydrocarbon fragments in the reducing atmosphere in the flame zone, and (iii) fuel NOx, which originates from the nitrogen in the coal. Nitrogen oxides are being considered responsible for the formation of acid rain (atmospheric NOx eventually forms nitric acid and contributes to acid rain), as well as contributing to the formation of urban smog which is known as ozone pollution (Miller, 2005; Bris *et al.,* 2007; Suarez-Ruiz and Ward, 2008; Franco and Diaz, 2009).

NOx pollutants do not form in significant amounts at temperatures below 2800 degrees Fahrenheit. Initially the focus of NOx controls was on finding ways to burn fuel in stages. *Low-NOx* burners use a staged combustion process, which uses a lower flame temperature during some phases of combustion to reduce the amount of NOx that forms. These burners also limit the amount of air in the initial stages of combustion, when the nitrogen naturally occurring in the coal is released, so that there is less oxygen present to bond with the nitrogen. These burners can reduce nitrogen oxide emissions by 40% or more. In the case of fluidized-bed technology, combustion occurs at temperatures of 760 to 930°C (1400 to 1700°F), lower than the threshold at which nitrogen oxide pollutants form.

In 2005, the EPA passed the Clean Air Interstate Rule, which requires a 61% cut in nitrogen oxide emissions from power plants by 2015. This level of emissions reduction requires a different technology. Selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) both convert NOx into water (H_2O) and nitrogen (N_2). Selective catalytic reduction is capable of reducing NOx emissions by approximately 90%. Selective non-catalytic reduction is a simpler and less expensive technology than selective catalytic reduction, but it also provides a lower level of the reduction of the oxides of nitrogen.

In general, control technologies for nitrogen oxides can be divided into two main groups: (i) the first group of control technologies for nitrogen oxides considers the reduction of nitrogen oxides produced in the primary combustion zone and (ii) the other involves the reduction of nitrogen oxides existing in the flue gas (Miller, 2005). There are also multi-pollutant control technologies to eliminate nitrogen oxides emissions together with the other pollutants such as sulfur dioxide (SO_2), mercury (Hg), particulate matter (PM), and/or air toxics. Several control technologies for nitrogen oxides such as low-nitrogen oxides burners, furnace air staging, fuel staging (reburning), selective catalytic reduction, selective non-catalytic reduction, flue gas recirculation, co-firing and flue gas treatment are applied at the power plants. Sometimes, these nitrogen oxide control technologies can be used together to increase the control efficiency. Recently, hybrid nitrogen oxide control systems incorporating both a redesigned selective non-catalytic reduction system and a compact induct selective catalytic reduction system have been introduced for more effective emission control.

13.4.3.3 Fly Ash Emissions

Combustion of coal produces various forms of coal combustion products (CCPs) due to the mineral impurities in coal body. Fly ash is one of the most important coal combustion products requiring efficient control during coal combustion (Akar *et al.,* 2009). Especially, the fine particulates (PM_{10}) in the fly ash may pass through the dust collection devices and be released to the atmosphere.

The fly ash particles can be a potential source of contamination because of the high concentration and surface associations of some trace elements in their composition (hence, trace element emissions). Coal contains various trace elements originating from different minerals and macerals in its body (Pavlish *et al.,* 2003; Balat, 2008b; Xu *et al.,* 2003). These elements show different behavior during coal combustion (Suarez-Ruiz and Ward, 2008).

During the combustion process, the low volatile trace elements tend to stay in the bottom ash or to be distributed between the bottom and fly ash. The more volatile trace elements (volatile and especially highly volatile trace elements) are vaporized in the furnace and they may be incorporated with any fouling/slagging deposits or mostly condense onto the existing fine fly ash or totally emitted in vapor phase (Xu *et al.,* 2003; Suarez-Ruiz and Ward, 2008; Vejahati *et al.,* 2009).

There are several methods of removing fine particulate matter before it can be released from the smokestack. Wet scrubbers remove dust pollutants by capturing them in liquid droplets and then collecting the liquid for disposal. Electrostatic precipitators add electrical charges to particles in the flue gas and collect the particles on plates to remove them from the air stream. Wet electrostatic precipitators combine the functions of a standard dry electrostatic precipitator with a wet scrubber and spray moisture to the air flow to help collect extremely fine particulate matter ($PM_{2.5}$), making the process more effective. Fabric filter baghouses are another means of controlling particulate matter emissions. As dust enters the baghouse compartment, larger particles fall out of the system, while smaller dust particles are collected onto cloth filters.

Particulate emissions generated in coal combustion are categorized in three main groups, namely PM_{10}, $PM_{2.5}$ and PM_1.

The ultra-fine fractions of these particulates (PM_1 and $PM_{2.5}$) may remain air-suspended for a long time and have deleterious impacts on the environment and human health (Miller, 2005; Breeze, 2005; Suarez-Ruiz and Crelling, 2008; Bhanarkar *et al.,* 2008). The finest fraction of the particulates (<1 micron in size) are mostly originated from the ash-forming species vaporized during combustion. The remaining particles are referred as the residual ash; they are larger than 1 micron and are generally formed by the mineral impurities in coal (Senior *et al.,* 2000a; Ohlstrom *et al.,* 2006).

Emissions of primary ash particles can be controlled efficiently (up to 99.99%) by the combination of an efficient electrostatic precipitator or baghouse and wet flue gas desulfurization system (Tables 13.1, 13.3). Most of trace metals, except for volatile elements such as mercury and selenium, are captured with the primary particles (Sondreal *et al.,* 2004, 2006; Yang *et al.,* 2007; Wang *et al.,* 2008).

The fine particulates (<2.5 microns, $<PM_{2.5}$) have minor impact on the control efficiency due to their small size and small proportion in the total particulate mass; however, they are the most dangerous particulates in terms of human health. Considering that it is crucial to capture these particles with high collection efficiencies using improved technologies (Table 13.3) (Ohlstrom *et al.,* 2006).

13.4.3.4 Mercury

Mercury is identified as the toxic of greatest concern in all the air toxics emitted from power plants due to its persistence and bioaccumulation in the foods and environment (Senior *et al.,* 2000b).

Mercury generally occurs in coal in association with sulfide minerals (FeS_2 and HgS) and may also be organically bound to the organic structure of coal (Chapter 5) (Pavlish *et al.,* 2003; Sondreal *et al.,* 2004; Kolker *et al.,* 2006). Mercury concentration in coal is (depending on the coal) on the order of 0.1 to 0.15 g/ton and it passes to the flue gas during the combustion process as a mixture of different chemical states or species at varying percentages; namely, elemental mercury (Hg^0), oxidized mercury (Hg^{2+}), and particulate-bound mercury (Hg_p) (Chapter 7) (Madsen *et al.,* 2004; Lee *et al.,* 2006; Yang *et al.,* 2007; Wang *et al.,* 2008).

Elemental mercury (Hg) is highly volatile and insoluble; therefore it is hard to capture by emission controlling equipment. It is almost completely released to the atmosphere and can be transported over long distances (Wang *et al.,* 2008; Pavlish *et al.,* 2003). The long lifetime in the atmosphere and long-distance atmospheric transport of elemental mercury make it a global environmental threat (Sondreal *et al.,* 2004). The oxidized form of mercury (generally considered to be mercuric chloride) is soluble and tends to form surface associations with particulate matter. The oxidized mercury and particulate-bound mercury have a short

Table 13.3 Particulate control technologies for coal combustion (Miller, 2005; Mokhatab *et al.*, 2006).

1. Electrostatic Precipitation Uses electrical forces to capture the particles from the flue gas and collect them onto a grounded plate within an electrical field. The process has a somewhat lower performance for the particle sizes between 0.1 to 1 micron (90-95 %). Overall efficiency of these devices is over 99%. They work with low pressure drops which minimizes the fan costs.
2. Cyclone/multicyclones Inertial collectors use centrifugal force to separate the particles from the flue gas stream. The inlet flue gas is forced to follow a circular or conical path at high velocity in a cyclone. The particles are forced to move against the walls by the centrifugal force and settle down into hoppers. These devices separate the particles in the size range of 1.0 to 100 microns with 50 to 90% efficiency.
3. Fabric filter (baghouses) Flue gas is forced to pass through a filter and the dust particles are collected on the surface of the permeable fabric. These systems have high collection efficiencies (on the order of 99.9%) for both coarse and fine particles (0.01 to 100 microns). The fabric needs replacement at every 2 to 4 years. Hot gases must be cooled, the system generally operates in the temperature range of 120 to 180°C (250 to 355°F).
4. Wet Scrubbers This technology involves contacting a flue gas stream with a scrubbing liquid by applying different methods. There are different scrubber designs such as spray tower, dynamic scrubber, collision scrubber and venturi scrubber which render the removal of gaseous and particle emissions at the same time and neutralize corrosive gases with a removal efficiency from 90 to 99.9% for particles in the size range of 0.5 to 100 microns. The efficiency is somewhat lower for fine particles (less than 1 micron size). There can be corrosion problems and freezing in cold climates.

lifetime (a few days) in the atmosphere. If they released from the power plant, they tend to be deposited near the source of emission (Pavlish *et al.,* 2003). Efficient control of oxidized mercury and particulate-bound mercury is possible by using conventional emission control equipment (Wang *et al.,* 2008; Senior *et al.,* 2000b; Pavlish *et al.,* 2003; Sondreal *et al.,* 2004).

In combustion systems, mercury is oxidized by kinetically controlled reactions. Chlorine species promotes homogeneous oxidation of mercury (Pavlish *et al.,* 2003). Calcium likely reacts with chlorine during combustion and its high concentrations may have a reducing effect on the positive influence of chlorine in mercury oxidation (Yang *et al.,* 2007). The presence of fly ash and sorbents promote heterogeneous oxidation of mercury.

Hydrogen chloride (HCl), nitric oxide (NO), and nitrogen dioxide (NO_2) affect mercury oxidation and capture process positively, whereas the interaction of sulfur dioxide (SO_2) with nitrogen dioxide in the flue gas greatly reduces the capture of elemental mercury by the fly ash and sorbents (Senior *et al.,* 2000b, Pavlish *et al.,* 2003; Sondreal *et al.,* 2004). Currently there is no mature single-best technology for mercury reduction. Combination of the existing pollution control devices can provide some degree of mercury removal from the flue gas. The rate of mercury reduction strongly depends on the type of coal, mercury speciation in the flue gas and the configuration of the existing pollution control devices (Yang *et al.,* 2007).

Mercury controls address EPA regulations regarding mercury emissions from coal-fired power generation, which represents approximately one-third of mercury emissions in the United States (US EPA, 2004). In addition, a number of states have adopted, or are moving to adopt, more restrictive limits on mercury emissions.

Mercury control technologies include (i) sorbents and oxidizing agents to transform mercury into a solid to be removed along with fly ash in electrostatic precipitators (ESP) or fabric filter dust collectors (FFDCs), also referred to as baghouses, (ii) oxidizing agents in conjunction with wet flue gas desulfurization (FGD) scrubbers to capture mercury in sulfate by-products, and (iii) real-time measurement of mercury species and total mercury, for process control and validation.

Controlling mercury emission by the use of solid adsorbents such as activated carbon has received and continues to receive much attention (Madsen *et al.,* 2004; US EPA, 2004).

In the case of activated carbon, injection of the adsorbent has the potential to achieve moderate to high levels of mercury control (Monroe *et al.,* 2004; Nelson *et al.,* 2004; Sjostrom *et al.,* 2004). The performance of activated carbon is related to the physical and chemical characteristics of the carbon such as surface area, pore size distribution, and particle size distribution. The capacity for mercury capture generally increases with increasing surface area and pore volume. The ability of mercury to penetrate into the interior of a particle is related to pore size distribution and the pore systems of the carbon sorbent must be large enough to provide free access to internal surface area by zero-valent mercury (Hg^o) and by mercuric ions (Hg^{2+}) while avoiding excessive blockage of the pore mouths by previously adsorbed reactants. As particle sizes decrease, access to the internal surface area of particle increases along with potential adsorption rates.

In addition, the sorbent capacity of the activated carbon (or, for that matter, any sorbent) is dependent on (i) the temperature, (ii) the concentration of mercury in the flue gas, and (iii) the flue gas composition. In general, the capacity for adsorbing mercuric ions will be different than that for zero-valent mercury. Thus, selection of an adsorbent for a given application would take into consideration (i) the total concentration of mercury species, (ii) the relative amounts of zero-valent mercury (Hg°) and mercuric ions (Hg^{2+}), (iii) the flue gas composition, and (iv) the method of capture – electrostatic precipitator fabric filter (baghouse), or dry flue gas desulfurization scrubber.

Electrostatic precipitator, fabric filter baghouse and wet flue gas desulfurization systems can remove some particulate-bound and oxidized forms of mercury from the flue gas (McDonald *et al.,* 2003). The efficiency of the mercury removal by these devices can range from 0% to 90%. However, elemental mercury cannot be controlled effectively by conventional air pollution control equipment (Pavlish *et al.,* 2003; Yang *et al.,* 2007; Wang *et al.,* 2008; Pavlish *et al.,* 2009). The scrubber systems have moderate–high costs and need additional equipment and installation area (Pavlish *et al.,* 2003). The highest reduction rate can be achieved by the use of fabric filters. Cold-side electrostatic precipitators are much more effective than hot-side electrostatic precipitators. The cost of these systems is moderate–high, and additional equipment and laydown space may be needed (Pavlish *et al.,* 2003). In general, higher removal efficiencies can be achieved for the combustion bituminous coals by using these air pollution control equipment. They are less effective for subbituminous coal combustion and almost useless in lignite coal combustion (Pavlish *et al.,* 2003; Kolker *et al.,* 2006).

Sorbent injection technology seems to have the highest potential to remove both elemental and oxidized mercury from the flue gas (Yang *et al.,* 2007). Different sorbents such as activated carbon, chemically treated sorbents and coal additives, calcium-based sorbents, crude oil coke, zeolites, fly ash, other chemically treated carbons or carbon substitutes are injected into the upstream of either an ESP or fabric filter baghouses to control mercury emissions (Pavlish *et al.,* 2003; Yang *et al.,* 2007). The cost of this process is low-to-moderate and separate injection systems may be required (Pavlish *et al.,* 2003).

Oxidizing agents or mechanisms convert vapor-state elemental mercury to a solid-state mercury oxide that can be captured in electrostatic precipitators or fabric filter dust collectors or wet flue gas desulfurization units. For plants equipped with wet flue gas desulfurization units, the oxidizing agent can be incorporated with the scrubber slurry used for sulfur capture. The mercury captured in the by-product (gypsum, often used in wallboard) of the flue gas desulfurization units is chemically bound and precluded from re-release. Mercury instrumentation and controls measure both the mercury species (elemental and oxidized) entering the control device, and the total mercury entering the stack.

13.4.3.5 Particulate Matter

The control of particulate matter (PM), including PM equal to or less than 2.5 microns in size ($PM_{2.5}$), responds to EPA regulations. The objective of the particulate matter control program is to develop technology for coal-based sources that will result in substantial reductions in primary particulate matter, its secondary precursors (sulfur dioxide and nitrogen oxides), and problematic acid gases that can cause localized plume opacity and visibility impairment, and have been linked to human health impacts (United States Department of Energy, 2008).

Control technologies include (i) electrostatic precipitator-fabric filter dust collector hybrids to incorporate the optimal features of both sulfur dioxide and sulfur nitrogen oxide removal, (ii) flue gas preconditioning to enhance electrostatic precipitator performance, (iii) concentration of particulate matter at electrostatic precipitator outlets for recycle, (iv) alkaline injection for sulfur trioxide (SO_3) acid aerosol precursor control, and (v) continuous sulfur trioxide analyzers for process control and validation (United States Department of Energy, 2008).

Electrostatic precipitators electrically charge particulate matter for capture on collection plates. Fabric filter dust collectors use fabric filter bags that receive and collect particulate matter on the outside surface, and then are pulsed internally with jets of air to disengage the collected particulate. Preconditioning agents either lower resistivity or induce agglomeration of incoming particulate matter. Alkaline injection converts sulfur dioxide and sulfur trioxide acid precursors into readily captured sulfate particulates, and neutralizes other acid gases such as hydrochloric acid (HCl) and hydrofluoric acid (HF). Sulfur trioxide analyzers also measure input and output levels for control validation (United States Department of Energy, 2008).

13.4.3.6 Advanced Post-Combustion Cleaning

Advanced post-combustion cleaning technologies encompass two approaches: (i) using the existing flue gas ductwork to inject a sorbent, and (ii) inserting one or more separate vessels into the downstream ductwork where pollutant absorbents are added. These advanced technologies offer several advantages over conventional technologies: (i) regeneration of the sulfur-absorbing chemical, (ii) increased residence time with the sulfur absorbent, (iii) reduced physical size requirements, and (iv) a dry, environmentally benign, waste product that may have commercial value.

In-duct sorbent cleaning occurs, as the name indicates, inside the ductwork leading from the boiler to the smokestack. Sulfur dioxide absorbers (e.g., hydrated lime) are sprayed into the center of the duct. By controlling the humidity of the flue gas and the spray pattern of the sorbent, 50-70% of the sulfur dioxide can be removed and the reaction produces dry particles that can be collected downstream. In-duct sorbent injection is an attractive option for retrofitting smaller, older plants where space requirements are limited.

When separate vessels are used, one or more process chambers are inserted in the flue gas ductwork, and various sorbents are injected to remove the pollutants. The separate vessels provide a longer residence time for the absorbent to react with the gas, and pollutant capture is greater. This approach, at some increase in cost over the in-duct injection procedure, has the potential of capturing more than 90% of the pollutants. Technologies such as the spray dryer and selective catalytic reduction represent approaches that use separate vessels.

13.4.4 Conversion and Added-Value Products

Techniques that convert coal into another form of fuel bypass the conventional *coal fuel path* of combustion. The most common system is that in which coal is converted into a gaseous fuel. In other techniques, liquid products are the result whilst in others, a combination of gases, liquids, and solids is produced.

13.4.4.1 Integrated Gasification Combined-Cycle Systems

Integrated Gasification-Combined Cycle (IGCC) is another approach to reducing the environmental footprint of coal power. IGCC systems are distinct from the carbon capture and storage systems, although there is the potential to combine the two in order to achieve greater environmental benefits than either method alone, albeit at great expense.

Gasification, or incomplete combustion in an oxygen-poor environment, produces an intermediate gaseous fuel known as synthesis gas. Coal gasification was used to produce the gas burned to light the streets of Paris and a number of other cities beginning in the late 1800s, as well as in the first step of the Fischer-Tropsch process used to produce substitute liquid fuels in Germany when the World War II effort strained the energy supplies of the country to the breaking point. The usual combustion by-products of water and carbon dioxide ultimately form when synthesis gas is burned as well.

Combined cycle power generation, as the name suggests, uses a multi-stage process to generate electricity. The first stage involves the recovery of energy released by a gas as it burns and expands inside a combustion turbine using the Brayton cycle; the second stage involves the transfer of heat from flue gases to a working fluid, typically water in a boiler, used to turn a steam turbine as in a conventional power plant using the Rankine cycle. Because the first cycle takes place at extremely high temperatures needed to rapidly expand gas to do work in the combustion turbine, the flue gas still contains enough heat at the end of the cycle to make additional energy recovery feasible using heat exchangers. The net power output from the two power generating cycles is combined and fed into the grid. The most obvious disadvantage of generating power this way is the far higher capital cost of constructing an integrated gasification combined cycle plant compared to conventional generation facilities.

The integrated gasification combined-cycle process basically has four steps: (i) combustion gases are formed by reacting coal with high-temperature steam and oxygen or air, (ii) the gases are purified, (iii) the clean gases are burned and the hot exhaust gas is passed through a gas turbine to generate electricity, and (iv) the residual heat in the exhaust is used to boil water for a conventional steam turbine generator to produce additional electricity.

This combination of gas and steam turbines accounts for the name combined cycle. Gasification combined-cycle systems are among the cleanest and most efficient of the emerging clean coal technologies. Sulfur species, nitrogen species, and particulate matter are removed before the fuel is burned in the gas turbine. Thus, there is a much lower volume of gas to be treated than in a post-combustion scrubber.

The gas stream must have extremely low levels of impurities not only to avoid pollution but to protect turbine components from chipping or corroding. As in the case of clean combustion, much of the sulfur-containing gas can be captured by a sorbent injected into the gasifier.

Many coal gasifiers release fuel gas at temperatures well in excess of 1095°C (2000°F). Loss of efficiency often occurred when the gas had to be cooled before cleaning, although perhaps the simplest of all gas cleaning processes, namely the iron oxide process (Mokhatab *et al.,* 2006; Speight, 2013, 2014), was often eminently suitable for the task of hot gas cleaning; zinc oxide was also used on occasion in place of the iron oxide. A more efficient chemical is zinc ferrite ($ZnFeO_2$) and passage of the hot gas through a bed of zinc ferrite particles will cause removal of sulfur contaminants at temperatures in excess of 540°C (1000°F). The zinc ferrite can be regenerated and reused with little loss of effectiveness. During the regeneration stage, salable sulfur is produced and the method is capable of removing more than 99% of the sulfur in coal.

High levels of nitrogen removal are also possible. Some of the coal-nitrogen is converted to ammonia which can be almost totally removed by commercially available processes. Nitrogen oxides formation can be held to allowable levels by staging the combustion process at the turbine or by adding moisture to hold down flame temperature.

The theoretical advantage an integrated gasification combined cycle plant has over a conventional coal plant is in the higher system efficiency of the *combined cycle*, a concept originally developed for natural gas-fired plants and used in many such plants to meet intermediate and peak loads.

While the overall combined cycle is more efficient than conventional pulverized coal plants, energy losses do occur in the transformation of coal into a gaseous fuel, mostly due to the heat input needed for gasification. As a result of the added gasification process needed for combined cycle systems using coal, the integrated gasification combined cycle process is less efficient than the same combined power generation cycle run on a fuel that does not require pretreatment such as natural gas or fuel oils.

As a result, most estimates place the efficiency of full-size integrated gasification combined cycle plants at around 45% of the total energy released from burning coal converted into usable electric power, an improvement over the 30 to 40% efficiencies achievable in conventional plants but still considerably lower than the 60% electric efficiency achievable in modern advanced combined cycle plants.

Additionally, the use of a gasification process generates additional environmental problems distinct from those of conventional coal-fired generation. One of the challenges of designing integrated gasification combined cycle plants is management of slag, the semi-liquid by-product that forms from trace elements in coal that do not gasify such as silicon, aluminum, and other metals.

Slag, like combustion ash, contains a high proportion of heavy metals and other contaminants, but in the more potentially hazardous form of wastewater rather than relatively inert solids, and the limited field experience with integrated gasification combined cycle plants because of the potential for creating water quality problems. When taking into account the added challenges of managing these unique by-products from the gasification reaction, as well as the dramatically increased capital costs of integrated gasification combined cycle plants relative to conventional coal plants, the theoretical environmental benefits that could be gained by achieving a higher plant efficiency and thereby conserving a still relatively inexpensive fuel appear less attractive.

As might be expected, coal properties were found to influence a number of facets of Integrated Gasification Combined Cycle plant performance and to potentially have a significant impact on the overall coal utilization cost. These facets include the overall cycle efficiency, oxygen usage and flux requirements. Assessment of coal impact on plant performance requires determination and assessment of desirable coal properties which include (i) low moisture content, (ii) low mineral matter content, hence low ash production, (iii) low sulfur content of the coal, (iv) high rank, (v) low fusion temperature of the ash, (vi) high reactivity of the char, and (vii) high Hardgrove grindability index.

13.4.4.2 Mild Gasification

Mild gasification is a modification of the conventional coal gasification (Speight, 2013) and produces gaseous, liquid, and solid products by heating coal in an oxygen-free reactor. In fact, the process is less a gasification process and more a pyrolysis process insofar as the goal is to remove condensable volatile hydrocarbon derivatives and leaving a carbonaceous char/residue, in lieu of converting the entire charge of coal. The char can be upgraded further to remove both ash and pyritic sulfur, mixed back with coal-derived liquids, and burned in both coal- and oil-fired boilers.

A slurry of coal-derived fuel and upgraded char has the potential of being a very versatile fuel that can be burned in both coal- and oil-fired boilers. If the char is upgraded to a high degree, even feedstock coal with a high sulfur content can be used without alternating heat rates or capacity factors.

13.4.4.3 Coal Liquefaction

Two primary methods exist for converting coal into liquid fuels: (i) direct liquefaction and (ii) indirect liquefaction using the Fischer-Tropsch process (Speight, 2013, 2020b).

Direct liquefaction is the conversion of coal directly to liquid products. In general chemical terms, coal liquefaction involves addition of hydrogen to the coal by various techniques so that the ratio of hydrogen to carbon in the product is increased to a level comparable to crude oil-based fuels. *Indirect liquefaction* is coal gasification followed by conversion of the synthesis gas (a carbon monoxide, CO, hydrogen, mixture) to liquid fuels.

While the use of coal as a feedstock to produce liquids to replace crude oil-derived fuels does not technically fall under the same *clean coal* umbrella as carbon capture and storage or integrated gasification combined cycle, it is similar enough to these concepts as an alternative use of coal and ties into related concerns of oil and gas supply problems enough that the possibility of doing so merits some discussion here. A number of processes have been proposed to produce liquid fuels from coal, most of which are claimed to become cost-competitive at sustained oil prices over $35 per barrel, and almost all of which are very similar to the gasification stage of integrated gasification combined cycle plants (when the product of incomplete combustion is a liquid rather than a gas, the process is called *pyrolysis* rather than *gasification*).

As production of oil and gas, more versatile and energy-dense resources than coal, peaks and then declines, increased dependence on relatively more abundant but lower-quality solid fuels appears likely in the absence of greenhouse gas emission constraints. While coal, oil and gas are all viable fuels for electricity generation, many other energy-using technologies such as internal combustion engines require higher quality liquid or gaseous fuels and cannot run on coal in its native form. Since it is a solid fuel and has a lower energy content than oil or gas, coal cannot serve as a direct replacement for the myriad uses of liquid fuel without first being converted into a liquid itself, and it is difficult to envision a scenario in which such large-scale substitution could take place without creating a major source of pollution and wasting large quantities of energy, exacerbating regional and possibly even global coal shortages in the future.

Coprocessing, a recent development for coal liquefaction technology, involves the production of liquids from a mixture of coal and heavy crude oil residue, with the residual oil providing all or most of the hydrogen needed for the conversion process (Speight, 2013). Once produced, the coal-derived liquid can be refined by sulfur mineral matter (ash) removal before use.

13.4.4.4 Biomass Cofiring

One of the most effective ways of reducing pollution associated with burning coal for electricity is to directly replace it with a renewable fuel of similar quality, usually wood.

Within the family of fossil fuels, coal contains the highest ash (inorganic) content and produces the most climate-altering greenhouse gases, nitrogen oxides, carbon monoxide, sulfur dioxide, heavy metal emissions, and waste to be disposed. Coal also produces more of these pollutants than wood, a relatively similar solid fuel with physical and chemical properties that make it a suitable replacement for coal in generating base load power, at least up to a point (Omer, 2008). While wood is less energy dense than higher-quality coals, it is also renewable, produces lower quantities of most air emissions, avoids waste and damage to the landscape associated with mining coal, and is carbon neutral, assuming the sources of biomass are sustainably managed (Beer, 2007). Since wood is physically similar to coal and is comparable to lower-quality coals such as lignite in energy density, the two fuels can burn in the same furnaces at the same time so long as certain constraints are met.

Pollutant formation during biomass cofiring exhibits all the complexities of pollutant formation during coal combustion. Sulfur dioxide production decreases in proportion to the sulfur in the fuel, which is low for many (but not all) biomass fuels. NOx may increase, decrease, or remain the same, depending on fuel, firing conditions, and operating conditions. However, the NOx chemistry of biomass shows the same, complex but conceptually well understood behavior as NOx chemistry during coal combustion with the exception that biomass appears to produce much higher ammonia content and lower hydrogen cyanide (HCN) content as a nitrogen-laden product gas compared to coal. Some of the commercially most mature biomass fuels, notably wood, contain relatively little fuel nitrogen and cofiring with such fuels tends to decrease total NOx.

While direct cofiring of biomass with coal can be effective as a way of reducing harmful emissions, there are limitations to this practice as well. The lower energy content of wood compared to most coal used in electricity generation renders long-distance transport an inconvenient step. To maintain positive net energy and avoid exorbitant costs, wood-fired plants, including plants where it is cofired with coal, must be located within a certain radius of sources of harvestable wood, determined by the growth rate and the energy content of the fuel. This limitation places a practical size limit on direct-fired biomass power plants, typically 50-150 megawatts of electric power. This size is much smaller than the larger multi-gigawatt size typical of coal-fired power stations.

There is also a limit to how much wood can be practically burned in a coal furnace due to the differing requirements of the fuel and emissions control. For example, wood produces fewer total particulates, but they tend to be of a larger size than coal particulate emissions, resulting in a greater overall mass of particulate emissions. Wood also has different ash handling requirements, since it primarily generates bottom ash that remains in the furnace, while coal ash is lighter, higher in metal content, and is more likely to be entrained in flue gases exiting the furnace. While wood can make a useful substitute for some of the coal used in power generation, the physical properties of the fuel prevent it from being a fully acceptable replacement for all uses.

While wood and other biomass can substitute for some quantity of coal-fired generation, physical differences in the two fuels as well as insufficient total energy resources in sustainably managed biomass make it an insufficient replacement to match the raw power and infrastructure in place for coal-fired utility generation.

Typically, biomass produces a non-friable, fibrous material during comminution. It is generally unfeasible (and unnecessary) to reduce biomass to the same size or shape as coal. In many demonstration plants, biomass firing occurs with particles that pass through a ¼” (6.4 mm) mesh, which measurements indicate results in a size distribution dominantly less than approximately 3 mm. Depending on the type of biomass and preparation technique, average aspect ratios of these particles range from three to seven, with many particles commonly having much higher aspect ratios. Such particles have low packing densities and create challenges when pneumatically or otherwise transporting biomass fuels.

Although the mineral matter content of biomass (such as wood) is significantly lower than those of most power station coals, the ash chemistry and mineralogy are different. In general terms, biomass ashes have relatively low ash fusion temperatures, with deformation temperatures commonly in the range of 750 to 1000°C (1380 to 1830°F), compared to values in excess of 1000°C (1830°F) for most coal ash. Even at modest cofiring ratios, the cofiring of biomass materials can have a major impact on the ash fusion behavior. The rate and extent of coal ash slag formation on surfaces in the boiler furnace tends to increase, due principally to the decrease in the fusion temperatures of the mixed biomass-coal ashes, since fused or partially fused slag deposits tend to be more receptive to oncoming particles and grow more rapidly. The impact of cofiring on slag deposition depends largely on the chemistry and the fusion behavior of the coal ash and the cofiring ratio.

A simple index has been developed (Miles *et al.,* 1995), which can be used to assess the fouling propensity of a fuel or mixed fuel ash. The index is based on the mass in kg of alkali metal oxides ($K_2O + Na_2O$) introduced into the system per unit of heat input to the furnace. At high index values, significant/severe fouling of the boiler convective section is probable, even anticipated.

Thus, cofiring biomass with coal in traditional coal-fired boilers represents one combination of renewable and fossil energy utilization that derives the greatest benefit from both fuel types. It capitalizes on the large investment and infrastructure associated with the existing fossil-fuel-based power systems (e.g., fuel shipment and storage facilities as well as flue gas cleaning installations). In cases where additional capacity is anticipated, capital costs for cofiring are much higher when, for example, induced draft fans and other common capacity limiting subsystems must be replaced or upgraded.

In general, there are compelling reasons to pursue this option as reviewed in the introduction. However, there are many issues that, if not carefully managed, could compromise the boiler or downstream processes. Results to date indicate that these are all manageable but that they require careful consideration of fuels, boiler operating conditions, and boiler design.

In fact, mitigating *global climate change* through emission control of carbon dioxide is likely to enhance the move to more cost competitiveness of feedstocks such as woody biomass (as a co-feedstock with coal) for electricity production. Logging residues would become a competitive fuel source for electricity production (Gan and Smith, 2006).

13.5 Managing Wastes from Coal Use

Burning coal, such as for power generation, gives rise to a variety of wastes which must be controlled or at least accounted for. Thus coal plants, in addition to gaseous and liquid wastes, also produce solid wastes which either must be removed or serious attempts made to mitigate the problem (Saroff and Robey, 1992). Some of this solid waste is removed with the bed ash through the bottom of the boiler. Small ash particles, or fly ash, that escapes the boiler is captured with dust collectors (cyclones and baghouses). More than 90% of the sulfur released from coal can be captured in this manner.

While it is possible to control some of the toxic emissions released by coal-fired power plants, the resulting waste creates more problems for the environment. The pollution controls used to capture harmful emissions concentrate toxins and heavy metals such as mercury into coal ash and sludge. Toxic substances in ash and sludge include arsenic, mercury, chromium, and cadmium.

The *clean coal technologies* are a variety of evolving responses to the environmental concerns of the late 20th century and early 21st century, including that of global warming due to carbon dioxide releases to the atmosphere (Speight, 2020a). However, many of the elements have in fact been applied for many years, and they will be only briefly mentioned here:

- Coal cleaning by washing has been standard practice in developed countries for some time. The washing process reduces the production of ash and sulfur dioxide when the coal is burned.

- Electrostatic precipitators and fabric filters can remove 99% of the fly ash from the flue gases – these technologies are in widespread use.
- Flue gas desulfurization reduces the output of sulfur dioxide to the atmosphere by up to 97%, the task depending on the level of sulfur in the coal and the extent of the reduction. It is widely used where needed in developed countries.
- Low-NOx burners allow coal-fired plants to reduce nitrogen oxide emissions by up to 40%. Coupled with reburning techniques NOx can be reduced 70% and selective catalytic reduction can clean up 90% of NOx emissions.
- Increased efficiency of plant – up to 46% thermal efficiency now (and 50% expected in future) means that newer plants create fewer emissions per kWh than older ones.
- Advanced technologies such as Integrated Gasification Combined Cycle (IGCC) and Pressurized fluidized-bed combustion (PFBC) will enable higher thermal efficiencies still – up to 50% in the future.
- Ultra-clean coal (UCC) from new processing technologies which reduce ash below 0.25% and sulfur to low levels mean that pulverized coal might be used as fuel for large marine engines, in place of heavy fuel oil. There are at least two UCC technologies under development. Wastes from UCC are likely to be a problem.
- Gasification, including underground coal gasification (UCG) *in situ*, uses steam and oxygen to turn the coal into carbon monoxide and hydrogen.
- Sequestration refers to disposal of liquid carbon dioxide, once captured, into deep geological strata.

Briefly, underground coal gasification converts coal to gas *in situ* by injecting oxygen and water into coal seams, thereby converting the coal into a low-energy synthetic gas, in a process similar to surface coal gasification. The produced synthesis gas can then be burned in a combined-cycle gas turbine, or used for other purposes. There are significant environmental advantages of underground coal gasification: (i) the process eliminates coal mining and its attendant environmental damages, (ii) much of the produced ash remains underground, and (iii) the process produces little, if any, sulfur oxides (SOx) and nitrogen oxides (NOx) (Speight, 2013, 2020b).

Furthermore, the commercial use of deeper coal seams would significantly increase the amount of coal usable for energy purposes in the country, although better assessment of deeper coal resources is necessary before undertaking underground coal gasification – although seemingly ready, the technology is barely ready for full commercial-scale operation.

Carbon dioxide from burning coal is the main focus of attention since it is implicated in global warming, and the Kyoto Protocol requires that emissions decline, notwithstanding increasing energy demand.

Carbon capture and storage (CCS) technologies are in the forefront of measures to enjoy *clean coal*. Carbon capture and storage involves two distinct aspects: (i) capture of the carbon dioxide, and (ii) storage of carbon dioxide.

13.6 Carbon Dioxide Capture and Sequestration

Major reductions in coal-fired carbon dioxide CO2 emissions require either pre-combustion, combustion modification, or post-combustion devices to capture the carbon dioxide rather than allow release of this gas into the atmosphere. Post-combustion capture of carbon dioxide involves treating the burner exhaust gases immediately before they enter the stack. The advantage of this approach is that it would allow retrofit at existing facilities that can accommodate the necessary capturing hardware and ancillary equipment. In this sense, it is like retrofitting post-combustion sulfur dioxide (SO_2), nitrogen oxides (NO_x), or particulate control on an existing facility. Post-combustion processes capture the carbon dioxide from the exhaust gas through the use of distillation, membranes, or absorption (physical or chemical) (Chapter 12).

The most commonly used process for post-combustion carbon dioxide capture involves the use of amine (olamine: for example ethanolamine $H_2NCH_2CH_2OH$, often referred to as monoethanolamine or MEA) washing technology in which a carbon dioxide-rich gas stream, such as a power flue gas from the plant, is passed through an olamine (amine) solution. The carbon dioxide forms a bond with the amine as it passes through the solution while other gases continue up through to the flue. The carbon dioxide in the resulting carbon dioxide-saturated amine solution is then removed from the amines, captured, and is ready for carbon storage. The amine solution can be recycled and reused. The olamine washing technology is in wide commercial use in the crude oil and natural gas industries.

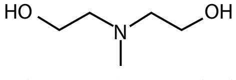
The use of monoethanolamine to capture the carbon dioxide is the most proven and tested capture process available. The basic design (common to most solvent-based processes) involves passing the exhaust gases through the ethanolamine whereupon a chemical reaction occurs to fix the carbon dioxide:

$$2(HOCH_2CH_2NH_2) + CO_2 \rightarrow HOCH_2CH_2NHCOOH_3NCH_2CH_2OH$$

The ethanolamine can be recovered in a post-capture regeneration process in which the reverse reaction occurs by a change in the temperature of the system. Thus:

$$HOCH_2CH_2NHCOOH_3NCH_2CH_2OH \rightarrow 2(HOCH_2CH_2NH_2) + CO_2$$

Carbon dioxide capture in some facilities is achieved before combustion, under pressure using a physical solvent (such as Selexol process or the Rectisol process), or a chemical solvent (such as methyl diethanolamine, MDEA).



Methyl diethanolamine (N-methyl-diethanolamine)

Because the gases are under substantial pressure with a high content of carbon dioxide, a physical solvent can separate out the carbon dioxide. The advantage of a physical solvent is that the carbon dioxide can be freed and the solvent regenerated by reducing the pressure – a process that is substantially less energy intensive than having to beat the gas as in a monoethanolamine stripper. From the capture process, the carbon dioxide is further compressed for transportation or storage, and the hydrogen is directed through gas and steam cycles to produce electricity.

Carbon capture and sequestration (carbon capture and storage, CCS), is the *clean coal* concept being promoted the most prominently. If successful, the concept would offer a way to continue burning coal for electricity while avoiding major costs expected under greenhouse gas emission regulations. Such regulations appear likely over the long run, whether they take the form of energy and climate legislation passed by Congress or by the Environmental Protection Agency, which is authorized to regulate the emissions under its Clean Air Act authority. The concept in any plant with *carbon capture and storage* is to pump the carbon dioxide emissions that are the chief by-product of coal combustion underground or into some other permanent or semi-permanent reservoir rather than directly into the atmosphere.

The reduction of carbon dioxide emissions to near-zero level imposes more economic restriction than technical restriction for coal-based power generation, as current state of the art can provide several technologies to capture and store carbon dioxide.

Addressing the challenge of climate change, while meeting the need for affordable energy, will require access to and deployment of the full range of energy-efficient and low-carbon technologies.

Capturing carbon dioxide that would otherwise be emitted to the atmosphere and injecting it to be stored in deep geological formations (CCS) is the only technology currently available to make deep cuts in greenhouse gas emissions from fossil fuel use while allowing energy needs to be met securely and affordably.

Carbon capture and storage is not a replacement for taking actions which increase energy efficiency or maximizing the use of renewables or other less carbon-intensive forms of energy. A portfolio approach taking every opportunity to reduce emissions will be required to meet the challenge of climate change. All of the elements of carbon capture and storage have been separately proven and deployed in various fields of commercial activity. In fact, approximately 32 million tons of carbon dioxide is already stored worldwide and this number continues to increase.

The vital next stage is the successful application of a fully integrated, large-scale carbon capture and storage systems fitted to commercial-scale power stations. Failure to deploy carbon capture and storage may hamper international efforts to address climate change. The Intergovernmental Panel on Climate Change (IPCC) has identified carbon capture and storage as a critical technology to stabilize atmospheric greenhouse gas concentrations in an economically efficient manner. The IPCC has concluded that by 2100, carbon capture and storage technologies could contribute up to 55% of the cumulative mitigation effort whilst reducing the costs of stabilization to society by 30% or more.

While carbon dioxide capture technologies are new to the power industry, they have been deployed for the past 60 years by the oil, gas, and chemical industries. They are an integral component of natural gas processing and of many coal gasification processes used for the production of synthesis gas from which chemicals and liquid fuels are produced. There are three main carbon dioxide capture processes for power generation: (i) post-combustion, (ii) pre-combustion, and (iii) oxy-fuel.

Post-combustion capture involves separating the carbon dioxide from other exhaust gases after combustion of the fossil fuel. Post-combustion capture systems are similar to those that already remove pollutants such as particulates, sulfur oxides and nitrogen oxides from many power plants.

Pre-combustion capture involves separating the carbon dioxide as part of the combustion or before the coal is burned. The coal is first gasified with a controlled amount of oxygen to produce two gases, hydrogen (H_2) and carbon monoxide (CO). The carbon monoxide is converted to carbon dioxide and removed, leaving pure hydrogen to be burned to produce electricity or used for another purpose. The carbon dioxide is then compressed into a supercritical fluid for transport and geological storage. The hydrogen can be used to generate power in an advanced gas turbine and steam cycle or in fuels cells – or a combination of both.

Oxy-fuel combustion (also called *oxyfiring*) involves the combustion of coal in pure oxygen, rather than air, to fuel a conventional steam generator (Chapter 8). By avoiding the introduction of nitrogen into the combustion chamber, the amount of carbon dioxide in the power station exhaust stream is greatly concentrated, making it easier to capture and compress. However, removing nitrogen from the gas mix has both benefits and challenges. The benefit is a higher concentration of oxygen that burns better. On the other hand, the challenge is that burning with pure oxygen results in a high flame temperature in the boiler. This is important because conventional boilers are not designed to handle extremely high temperatures.

Each of these capture options has its particular benefits. Post-combustion capture and the oxy-fuel process have the potential to be retrofitted to existing coal-fired power stations and new plants constructed over the next 10 to 20 years. Pre-combustion capture utilizing IGCC is potentially more flexible, opening up a wider range of possibilities for coal, including a major role in a future hydrogen economy.

Oxy-fuel combustion has significant advantages over traditional air-fired combustion, partly because of increased emphasis being placed on carbon sequestration. Carbon sequestration is the process of capturing carbon emissions, primarily in the form of carbon dioxide (CO_2), from power plants and storing it in a permanent location so it is not released into the atmosphere. Oxy-fuel combustion produces approximately 75% less flue gas, by volume, than conventional air-fueled combustion and consists primarily of carbon dioxide (CO_2) and water (H_2O).

Along with the carbon sequestration benefits, another benefit is that the mass and volume of the flu gas is reduced in oxy-fuel combustion; when the volume is reduced, the amount of heat lost in the flue gas is reduced, increasing efficiency and requiring less treatment equipment to process the gas. Finally, as the process removes all nitrogen from the air before it is injected into the boiler, the production of nitrogen oxide is reduced, substantially. However, even with all the positives of oxy-fuel combustion, there are still challenges for the technology. The greatest challenge facing oxy-fuel combustion is the cost to produce and supply pure oxygen to the burner in the combustion process. Because of the energy and economic costs to produce the oxygen, the oxy-fuel process is less efficient than the air-fired plant.

All the options for capturing carbon dioxide from power generation have higher capital and operating costs as well as lower efficiencies then conventional power plants without capture. Capture is typically the most expensive part of the carbon capture and storage chain. Costs are higher than for plants without carbon capture and storage because more equipment must be built and operated. Around 10 to 40% more energy is required with carbon capture and storage than without. Energy is required mostly to separate carbon dioxide from the other gases and to compress it, but some is also used to transport the carbon dioxide to the injection site and inject it underground.

As carbon capture and storage and power generation technology become more efficient and better integrated, the increased energy use is likely to fall significantly below early levels. Much of the work on capture is focused on lowering costs and improving efficiency as well as improving the integration of the capture and power generation components.

The technology for carbon dioxide transportation and its environmental safety are well established. Carbon dioxide is largely inert and easily handled and is already transported in high-pressure pipelines. In the United States, carbon dioxide is already transported by pipeline for use in *enhanced oil recovery* (EOR) (Speight, 2014, 2016).

The means of transport depends on the quantity of carbon dioxide to be transported, the terrain and the distance between the capture plant and storage site. In general, pipelines are used for large volumes over shorter distances. In some situations or locations, transportation of carbon dioxide by ship may be more economical, particularly when the carbon dioxide has to be moved over large distances or overseas.

A number of means exist to capture carbon dioxide from gas streams, but they have not yet been optimized for the scale required in coal-burning power plants. The focus has often been on obtaining pure carbon dioxide for industrial purposes rather than reducing carbon dioxide levels in power plant emissions.

Where there is carbon dioxide mixed with methane from natural gas wells, its separation is well proven. Several processes are used, including hot potassium carbonate which is energy-intensive and requires a large plant, an olamine process which yields high-purity carbon dioxide, amine scrubbing, and membrane processes (Mokhatab *et al.,* 2006; Speight, 2013, 2014, 2019).

Capture of carbon dioxide from flue gas streams following combustion in air is much more difficult and expensive, as the carbon dioxide concentration is only approximately 14% at best. As flue gases are passed through an amine-derivative solution (olamine – for example, mono-ethanolamine $HOCH_2CH_2NH_2$) whereupon the carbon dioxide is absorbed and can be released by heating the solution. This amine scrubbing process is also used for taking carbon dioxide out of natural gas (Mokhatab *et al.,* 2006; Speight, 2014, 2020b). For new power plants, carbon dioxide removal by this means may cost as much as 20 to 25% of plant output, due both to reduced plant efficiency and the energy requirements of the actual process.

The chemistry of the removal of carbon dioxide removal; process is often represented simply as:

For primary olamine derivatives:

$$CO_2 + 2R_1NH_2 \rightarrow R_1NH_3^+ + R_1NHCOO^-$$

For secondary olamine derivatives:

$$CO_2 + 2R_1R_2NH \rightarrow R_1R_2NH_2^+ + R_1R_2NCOO^-$$

In these cases, the carbon dioxide reacts with the amine to form a carbamate derivative and a protonated olamine, limiting the theoretical capacity to 0.5 mole carbon dioxide per mole of olamine. Reactions of carbon dioxide with primary olamine and secondary olamine derivatives are generally rapid reactions, which is an important benefit that will reduce gas/liquid contactor sizes and reduce investment costs.

Reaction pathways without the formation of a carbamate result in the formation of a bicarbonate derivative:

For tertiary olamine derivatives:

$$CO_2 + R_1R_2R_3N + H_2O \rightarrow R_1R_2R_3NH+ + HCO_3^-$$

For sterically hindered primary olamine derivatives:

$$CO_2 + R_1NH_2 + H_2O \rightarrow R_1NH_3^+ + HCO_3^-$$

For sterically hindered secondary olamine derivatives:

$$CO_2 + R_1R_2NH + H_2O \rightarrow R_1R_2NH_2^+ + HCO_3^-$$

In these cases, carbon dioxide reacts with the olamine to form bicarbonate and a protonated amine, allowing a theoretical capacity of 1 mole carbon dioxide per mole of olamine. These reaction paths are generally much slower than the previous pathways, but the energy requirement for thermal regeneration is usually much lower.

As an end-of-pipe technology, processes such as carbon dioxide absorption provides added flexibility insofar as the carbon dioxide capture plant can be switched off if necessary to allow for a larger output of the power plant at times when electricity demand and market prices are high. This is a beneficial feature in a highly competitive electricity market, allowing the technology to adapt to market requirements. Furthermore, a partial retrofit of the technology is also possible.

Liquid absorbent-based technology also allows for easy incorporation of technological improvements. As the performance of liquid absorbents improves, liquid absorbents in existing equipment will be replaced – such practice is widely used in other commercial applications. Improved performance can be used to increase output or overall efficiency and, as such, the technology is applicable in new and retrofit applications, thus providing a broad pathway toward reduction of carbon dioxide emissions from coal-fired power stations.

Oxy-fuel recycle combustion process (oxygen/carbon dioxide recycle combustion) (Figure 13.1) is a highly interesting option for coal-based power generation with carbon dioxide capture, due to the possibility to use advanced steam technology, reduce the boiler size and cost and to design a zero-emission power plant. This technology, however, also poses engineering challenges in the areas of combustion and heat transfer, boiler design, boiler materials, energy-efficient oxygen production and flue gas processing. The overall challenge is to design a robust plant that has a sufficiently low total cost of electricity so that it is interesting to build, but it must also have a sufficiently low variable cost of electricity so that it will be put in operation as a base load plant once it is built.

Oxy-fuel combustion is one of the most promising technical options for carbon dioxide capture from coal-fired power generation (Buhre *et al.*, 2005). The possibility to use

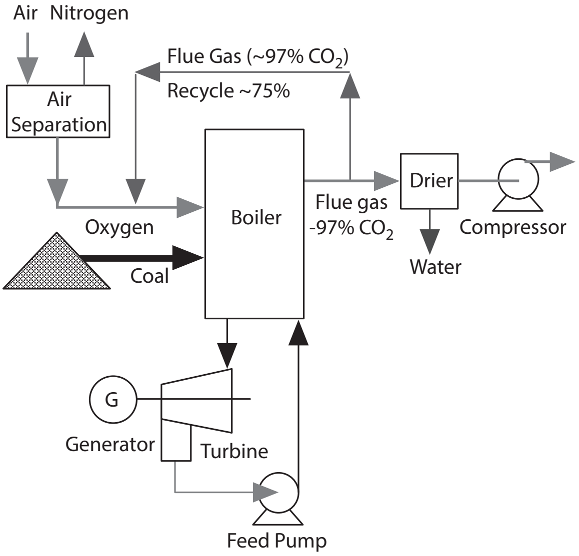


Figure 13.1 The oxy-fuel process.

advanced steam technology and simplified flue gas processing has brought it into an economically competitive position. Theoretically, a relatively simple flue gas cleaning system is preferable for CO2 capture, which is essential to achieve a low-cost capture technology. The conceptual development of the flue gas cleaning system focuses on a full understanding of the characteristics of flue gas produced under coal-fired oxy-fuel combustion conditions and the differences in the design criteria/requirements in comparison to that of conventional coal-fired power generation (Anheden *et al.,* 2004; Jordal *et al.,* 2004). The relations between the flue gas cleaning and other processes associated with the oxy-fuel combustion, such as CO2 capture, transport and storage, and plant emissions are also evaluated in order to optimize the flue gas cleaning system within the carbon dioxide capture chain.

The Integrated gasification combined cycle (IGCC) plant is a means of using coal and steam to produce hydrogen and carbon monoxide (CO) from the coal and these are then burned in a gas turbine with secondary steam turbine (i.e., combined cycle) to produce electricity. If the IGCC gasifier is fed with oxygen rather than air, the flue gas contains highly concentrated CO2 which can readily be captured post-combustion as above.

Further development of this oxygen-fed IGCC process will add a shift reactor to oxidize the carbon monoxide with water so that the gas stream is basically just hydrogen and carbon dioxide. The carbon dioxide with some hydrogen sulfide and mercury impurities are separated before combustion (with approximately 85% carbon dioxide recovery) and the hydrogen alone becomes the fuel for electricity generation (or other uses) while the concentrated pressurized carbon dioxide is readily disposed of – the hydrogen sulfide is oxidized to water and sulfur, which is saleable). No commercial-scale power plants are operating with this process yet. Currently IGCC plants typically have a 45% thermal efficiency.

Capture of carbon dioxide from coal gasification is already achieved at low marginal cost in some plants. One (albeit where the high capital cost has been largely written off) is the Great Plains Synfuels Plant in North Dakota, where 6 million tons of lignite is gasified each year to produce clean synthetic natural gas.

Oxy-fuel technology has potential for retrofit to existing pulverized coal plants, which are the backbone of electricity generation in many countries. The captured carbon dioxide gas can be put to good use, even on a commercial basis, for enhanced oil recovery. This is well demonstrated in West Texas, and in excess of 3,500 miles of pipelines connect oilfields to a number of carbon dioxide sources in the United States. Geological storage is an obvious method for sequestration of carbon dioxide. The geological features being considered for carbon dioxide storage fall into three categories: (i) deep saline formations, (ii) depleted oil and gas fields, and (iii) unmineable coal seams.

As carbon dioxide is pumped deep underground, it is compressed by the higher pressures and becomes essentially a liquid. There are a number of different types of geological trapping mechanisms (depending on the physical and chemical characteristics of the rocks and fluids) which can be utilized for carbon dioxide storage: (i) deep saline formations, (ii) depleted oil and gas fields, and (iii) coal seam storage – providing the formations are of the correct geological character (Table 13.4).

Deep saline formations are underground formations of permeable reservoir rock, such as sandstones, that are saturated with very salty water (which would never be used as drinking water) and covered by a layer of impermeable cap rock (e.g., shale or clay) which acts as a seal. In the case of gas and oilfields, it was this cap rock that trapped the oil and gas underground for millions of years. Carbon dioxide injected into the formation is contained beneath the cap rock and in the groundwater flow and, in time, dissolves into the saline water in the reservoir. Carbon dioxide storage in deep saline formations is expected to

Table 13.4 Geological formations suitable for carbon dioxide storage.

Structural Storage	When the carbon dioxide is pumped deep underground, it is initially more buoyant than water and will rise up through the porous rocks until it reaches the top of the formation where it can become trapped by an impermeable layer of cap-rock, such as shale. The wells that were drilled to place the carbon dioxide in storage can be sealed with plugs made of steel and cement.
Residual Storage	Reservoir rocks act like a tight, rigid sponge. Air in a sponge is residually trapped and the sponge usually has to be squeezed several times to replace the air with water. When liquid carbon dioxide is pumped into a rock formation, much of it becomes stuck within the pore spaces of the rock and does not move.
Dissolution Storage	Carbon dioxide dissolves in salty water, just like sugar dissolves in tea. The water with carbon dioxide dissolved in it is then heavier than the water around it (without carbon dioxide) and so sinks to the bottom of the rock formation.
Mineral Storage	Carbon dioxide dissolved in salt water is weakly acidic and can react with the minerals in the surrounding rocks, forming new minerals, as a coating on the rock (much like shellfish use calcium and carbon from seawater to form their shells). This process can be rapid or slow (depending on the chemistry of the rocks and water) and it effectively binds the carbon dioxide to the rocks.

take place at depths below 2,500 feet (800 meters). Saline aquifers have the largest storage potential globally but are the least well-explored and researched of the geological options. However, a number of storage projects are now using saline formations and have proven their viability and potential.

Depleted oil and gas fields are well-explored and geologically well-defined and have a proven ability to store hydrocarbon derivatives over geological time spans of millions of years. Carbon dioxide is already widely used in the oil industry for enhanced oil recovery (EOR) from mature oilfields (Speight, 2014, 2016). When carbon dioxide is injected into an oilfield it can mix with the crude oil causing it to swell and thereby reducing its viscosity, helping to maintain or increase the pressure in the reservoir. The combination of these processes allows more of the crude oil to flow to the production wells. In other situations, the carbon dioxide is not soluble in the oil and injection of carbon dioxide raises the pressure in the reservoir, helping to sweep the oil towards the production well (Speight, 2014, 2016).

Coal seam storage involves another form of trapping in which the injected carbon dioxide is adsorbed onto (accumulates on) the surface of the *in situ* coal in preference to other gases (such as methane) which are displaced. The effectiveness of the technique depends on the permeability of the coal seam. It is generally accepted that coal seam storage is most likely to be feasible when undertaken in conjunction with enhanced coalbed methane recovery (ECBM) in which the commercial production of coal seam methane is assisted by the displacement effect of the carbon dioxide.

Such storage projects are carefully tracked through measurement, monitoring and verification procedures both during and after the period when the carbon dioxide is being injected. These procedures address the effectiveness and safety of storage activities and the behavior of the injected carbon dioxide underground.

Measurement, monitoring, and verification procedures are used to measure the amount of carbon dioxide stored at a specific geological storage site, to ensure that the carbon dioxide is behaving as expected. The techniques used for measurement, monitoring and verification procedure are largely new applications of existing technologies. These technologies now monitor oil and gas fields and waste storage sites. They measure injection rates and pressures, subsurface distributions of carbon dioxide, injection well integrity, and local environmental impacts.

Injecting carbon dioxide into deep, unmineable coal seams where it is adsorbed to displace methane (effectively: natural gas) is another potential use or disposal strategy. Currently the economics of enhanced coal bed methane extraction are not as favorable as enhanced oil recovery, but the potential is large. While the scale of envisaged need for carbon dioxide disposal far exceeds uses, they do demonstrate the practicality. Safety and permanence of disposition are key considerations in sequestration.

Research on geosequestration is ongoing in several parts of the world. The main potential appears to be deep saline aquifers and depleted oil and gas fields. In both, the CO_2 is expected to remain as a supercritical gas for thousands of years, with some dissolving.

Large-scale storage of CO_2 from power generation will require an extensive pipeline network in densely populated areas. This has safety implications.

Given that rock strata have held CO_2 and methane for millions of years there seems no reason that carefully chosen ones cannot hold sequestered CO_2. However, the eruption of a million tons of CO_2 from Lake Nyos in Cameroon in 1986 asphyxiated 1,700 people, so the consequences of major releases of heavier-than-air gas are potentially serious.

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14

Environmental Issues

14.1 Introduction

Concerns about the impacts of coal on the environment and human health are not new; they may date from the first use of coal as a fuel in China in about 1100 BC. In the 13th century the concern about the *sulfurous air* (Galloway, 1882).

Until industrialization, the amounts of coal being used were minuscule and the environmental and health problems were local. However, during the past 200 years, increasingly large amounts of coal have been required to satisfy the ever-growing demand for global energy. Moreover, it is estimated that global coal resources can last more than 100 years at current consumption rates and considering that the United States has the largest coal reserves in the world (Chapter 1), producing fuels from coal would improve the energy security of the United States by reducing dependence on imported transportation fuels.

Despite these benefits, the use of coal also presents several serious environmental challenges, including significant air quality, climate change, and mining impacts. However, coal gasification technologies have been demonstrated that provide order-of-magnitude reductions in criteria pollutant emissions and, when coupled with carbon capture and sequestration (CCS), the potential for significant reductions in carbon dioxide emissions. Therefore, although coal is a finite non-renewable resource, coal-derived hydrogen with carbon capture and storage can increase domestic energy independence, provide near-term carbon dioxide and criteria pollutant reduction benefits, and facilitate the transition to a more sustainable hydrogen-based transportation system. Carbon capture and storage is one of the critical enabling technologies that could lead to coal-based hydrogen production for use as a transportation fuel. However, there are other risks to the environment that need to be addressed.

Coal is one of the many vital commodities that contribute on a large scale to energy supply and, historically, coal combustion has been a significant source of emissions of the acidifying air pollutants sulfur dioxide (SO_2) as well as nitrogen oxides (NOx), and other air pollutants (such as particulate matter, carbon monoxide, and volatile organic compounds) that potentially impact human health and the environment (Shindell and Faluvegi, 2009). These emissions lead to the formation of contaminants with such effects as acid rain formation, the greenhouse effect, and *allegedly* global warming (global climate change) (EEA, 2008; Bell, 2011). Whatever the effects, the risks attached to the coal fuel cycle could be minimized by the introduction of new clean coal technologies for coal-based power generation (Chapter 13), remembering that there is no single substitute for coal fuel in the generation of energy.

Because coal plays such a significant role in the generation of electricity in the United States, understanding the impact the by-products (such as bottom ash, fly ash, and flue gas

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cleaning wastes) have on the environment is an important part of understanding energy and environmental issues in general. In fact, as a result of environmental concerns, various technologies have been developed that capture potentially harmful elements and compounds before they can be emitted to the atmosphere.

Coal produces approximately 40% of the electricity consumed in the world and approximately 50% of the electricity consumed in the United States. Furthermore, many of the existing coal-fired plants are dated relative to air quality control design and many are less efficient than the modern designs that have become available in the past three decades. In addition, despite the continued need for coal as a source of electricity, there is a focus on greenhouse gas reductions which is a challenge to coal-fired plants. As a result, modern coal-fired power plants can help meet the increasing electricity demand, with significantly reduced impacts on the environment.

Coal-fired power plants influence climate via both the emissions of long-lived carbon dioxide (CO_2) and short-lived ozone and aerosol precursors. However, concerns related to the impacts of coal on the environment and human health are not new and are recorded throughout documented history (Galloway, 1882; Speight, 2013). Until industrialization, the amounts of coal being used were minuscule and the environmental and health problems were localized. However, during the past 200 years, coinciding with the onset and continuation of the Industrial Revolution, increasingly large amounts of coal have been required to satisfy the ever-growing demand for global energy.

Coal itself is harmless and presents no risk when it is *in situ* where it has remained since coalification occurred millions of years· ago. When involved in coal-related activities, however, the environmental impacts can be deleterious if the coal is utilized in the wrong place at the wrong time and in the wrong amounts. From the earliest days of coal extraction, potential hazardous situations were created by the coal-mining and coal-use technologies of the time. The consequences of past irresponsible practices have been inherited in current power production (from coal) scenarios. Recent industrial expansion and the population explosion worldwide are contributing further to the pollution caused by the use of coal.

A balance must be struck between industrial development and the energy required in order to build self-contained national economies. At one time, oil-fuel and then nuclear power were considered to be the answer to the world energy demands. These assumptions were to be proved inadequate because of (i) the unrest and armed conflicts in many crude oil-producing countries which affect oil supplies and (ii) the catastrophic nuclear accidents in various parts of the world, which have (justifiably or unjustifiably) posed serious questions about the viability and safety of the nuclear industry. However, it is not the purpose of this text to decide on the viability of energy from nuclear sources.

By comparison, coal offers substantial opportunities for diversification of energy supply. Reserves are abundant and it is well dispersed geographically which makes coal an invaluable source of energy and fundamental raw material for the generation of electrical power. However, the use of coal does pose serious environmental questions, some of which have been answered with satisfaction and others which have not been answered to the satisfaction of everyone.

Coal mining has always been regarded as a dangerous industry and to a certain degree it will always be so, but the new technologies offer the prospect of safer working conditions and improved productivity while at the same time meeting the new environmental standards required by legislative regulations. Criticism and judgment by the general public and environmental action groups on the coal industry are often based on emotion rather than facts. In scientific circles, the reasons for and effects of certain kinds of pollution are still causes of speculation. It is generally accepted that the proper application of modern technologies to mining and coal utilization can substantially limit its adverse environmental impacts and enure that the value of coal and use in industry will continue to some extent into the foreseeable future.

In the 1970s a legacy of abandoned mined areas and red-stained streams (somewhat reminiscent of the River Nile at the beginning of the ten plagues) from acid mine drainage of mines and preparation areas in the United States spurred public concern related to the environmental impacts of mining (Costello, 2003). These concerns led to federal regulations to guide reclamation and limit off-site impacts to the environment. Most industrialized countries regulate modern mining practices, but in those countries with a long mining history, it will take time to mitigate the legacy of past mining. This legacy includes physical disturbances to the landscape, subsidence, and settlement above abandoned underground mines, flooding and increased sedimentation, polluted ground and surface-waters, unstable slopes, long-burning fires, the safety of the miners, as well as public safety and land disturbance issues. In countries where such regulations do not exist, these issues are a continued concern.

This chapter focuses on the various environmental issues related to coal utilization for electricity generation. Emphasis is placed on those activities that are related to a power plant: (i) coal preparation, (ii) coal transportation, (iii) storage, and (iv) the emission-related environmental issues from combustion of coal in the power plant. Issues related to coal mining will not be covered here and have been dealt with elsewhere (Speight, 2013).

14.2 Coal Preparation

Coal preparation can occur immediately after mining or prior to use in the power plant. For the purposes of this chapter it is assumed that coal preparation occurs immediately after the mining operation (Chapter 3). Thus, run-of-mine coal is sent directly to the coal washing section or preparation plants where beneficiation and removal of certain impurities associated with coal substance take place.

Coal preparation has a substantial impact on the environment and refuse (unwanted mine spoil) disposal forms a major part of this multi-faceted problem (Argonne, 1990). In itself, the disposal of waste material from coal cleaning operations presents a two-part problem and (i) unless return of the coal wastes to the mine is possible, large areas of land are required, (ii) a fixed and mobile materials handling plant must be provided, and (iii) land sterilization and spoil-heap drainage can present serious problems related to environmental control.

In addition, the danger of spontaneous ignition and spontaneous combustion of coal is a constant threat in coal stockpiles and in coal refuse piles (Chapter 4) (Schmeling *et al.*, 1978; Chakravorty, 1984; Chakravorty and Kar, 1986). The danger of combustion in refuse piles arises when the coal wastes contain sufficient carbonaceous material and where spoil heaps are constructed by methods that allow ingress of sufficient air to support combustion. Refuse disposal requires the handling of wet granular material and sludge. The latter present severe difficulties during handling because of the ultrafine nature of the constituents and if mixed into main spoil heaps can lead to pile stability problems. On the other hand, if the sludge is disposed of separately, the pile usually require additional treatment, including chemical dosing, to achieve acceptable stability.

Washing and beneficiation processes produce large quantities of liquid and solid wastes. Liquid residues, so-called slurries, contain 95% of water mixed with very fine coal particles. Environmental and health risks arising from the possible leaching of such wastes could lead to the deterioration of surface water and groundwater. Piles (often referred to as mine tipple) formed from the dumping of solid waste from preparation plants become unstable after prolonged wetting, particularly if the slopes contain fine coal particles.

Spontaneous ignition and the ensuing combustion may develop due to the heating of coal particles and slow combustion (Chapter 4). Moreover, toxic material may be released with the oxidation of compounds present in the waste material. Runoff, with minimal iron pyrites content, from the tip surface, promotes hazards and the acid compounds may leach into domestic water supplies.

14.2.1 Water Treatment

Cleaning plants may require up to 2,000 gallons of water per ton of feed coal, although volumes much less than this quantity are now required by the latest jig designs, which are the units in a coal cleaning plant that require the greatest quantities of water (Couch, 1991). If water treatment and water recycling are not practiced, this volume represents a net demand for fresh water, which like tar sand processing (Speight, 2014, 2020) can be a major issue in coal producing regions that lie in semi-arid areas. To combat the need for water, the installation of recycle water systems has become a major aim, one advantage being that the water requirement reduces to that necessary for replacing water lost in the products so that water consumption shows a dramatic decrease.

Unless the coal being washed contains appreciable quantities of soluble salts, cleaning processes do not materially alter water composition. However, difficulties may be encountered when iron carbonate ($FeCO_3$) and pyrite (FeS_2) are present, particularly if the coal passes through stockpiles which allow some oxidation of the iron salts. The contamination is usually indicated by a substantial lowering of pH, from a typical range on the order of 6 to 7.5 (slightly acid to slightly alkaline) to values of 3 or even less (highly acidic), which may necessitate addition of alkali (caustic soda or lime) to restore near-neutral conditions. This type of problem is not often encountered and the usual type of water treatment involves clarification to remove suspended salts (*slime*) after which the water may be recirculated.

Clarification may be partially achieved using batteries of small-diameter hydrocyclones (see above) to remove particles down to approximately 50 micron (Couch, 1991). Complete water clarification requires settling in cones and static thickeners, in conjunction with chemical dosing to promote flocculation and rapid settling.

14.2.2 Dust Control

The presence of dust can cause serious problems in many dry cleaning plants and in the pretreatment sections of wet cleaning plants. In addition, dust containment is an integral part of all thermal drying units. The need for dust collection arises because of air pollution control, safety-hazard, and health-hazard elimination, and reduction of equipment maintenance costs. Coal dust can present serious explosion hazards. Certain bituminous coals and anthracites also continue to release measurable quantities of methane gas for days, and sometimes weeks, after they have been mined, which increases the possibility of explosion. Provision of efficient ventilation and restriction of electrical or thermal sources of ignition are required by regulation.

The main sources of dust emissions are crushers, breakers, de-dusters, dry screens, and transfer points between the units in coal pretreatment operations. The size of the coal particles that become airborne generally falls into the range 1 to 100 micron (1 to 100 x 10^{-6} meter) and particles larger than this usually deposit close to the point of origin. It is the usual practice to extract the dust clouds from the various sources through ducts that exhaust to a central air cleaning unit, although some equipment may include integral dust suppression devices. Dust collection equipment used at cleaning plants includes (i) dry units such as cyclones, dynamic collectors, and baghouses (fabric filters), and (ii) wet units such as dynamic, impingement, or centrifugal devices; or gravity, disintegrator, or venturi scrubber systems (King, 1968).

Other sources of dust are coal stockpiles and from railcars during loading and transportation. Various chemical treatments are available for stockpile sealing and are being used for spraying the tops of railcars; active stockpiles present an almost insurmountable problem.

14.2.3 Noise Control

Coal preparation plants invariably contain various types of active machinery, in addition to large throughput tonnages of free-falling solids, and have long been recognized as presenting a serious noise problem. Most of the noise control measures may be classified broadly into two measures: (i) noise generation and suppression or (ii) the provision of noise containment measures. Examples of the former include the installation of mufflers on air pumps and of rubber screen cloths and resilient screen decks and chute liners. Noise containment requires erection of barriers, either walls or curtains.

14.3 Transportation and Storage

Like all fuels, coal must be transported to an end user and often stored in stockpiles before it can be used. Specific transportation and storage needs vary – some coals are transported over very short distances to mine-mouth power plants while other coals are typically transported over somewhat longer distances from mine to market. For example, coal mined in the Powder River Basin (Wyoming) may travel distances ranging from less than 100 miles to more than 1,500 miles before it reaches the user in, say, Texas. In terms of coal storage, coal is a material which can be stored in large quantities because of some necessities. Although stacking is generally done in open areas, there are also covered stack areas or completely closed coal silos.

This section presents the various aspects (the environmental advantages and disadvantages) of coal transportation and storage and the cautions that must be applied to each of these aspects of coal use.

14.3.1 Transportation

If the washing and upgrading facilities are not on the same site as the power plant, the coal is transported to the plant either by rail, truck, barge, ship, or slurry pipeline (Chapter 3)

(Speight, 2013). Generally, the manner of coal handling is substantially affected by particle size, particle size distribution, moisture content and local weather conditions. Environmental impacts also occur during loading, en route, or during unloading and affect natural systems, man-made buildings and installations, and people (e.g., due to injuries or deaths) (Chadwick *et al.*, 1987).

The choice of the mode of transportation may be instrumental in dealing with pollution hazards. Bulk movement of coal by methods other than road is advantageous from both the economic and environmental standpoint. Transportation by road tends to create dust, increase traffic noise and congestion, and raises the risk of accidents and injuries. For example, the major adverse environmental impacts resulting from truck coal hauling are coal dust particle releases during coal loading or unloading, and coal dust entrainment during transport. Some coal will escape from the trucks during transport because the loads are normally uncovered. The coal dust tends to wash off roadways during rainstorms, causing aesthetic unsightliness and contamination of runoff waters. The air pollutant emissions from diesel fuel combustion add to the emissions.

All forms of coal transportation have certain common environmental impacts, which include use of land, structural damage to facilities such as buildings or highways, air pollution from engines that power the transportation systems, and injuries and deaths related to accidents involving workers and the general public (e.g., railway crossing accidents). In addition, fugitive dust emissions are experienced with all forms of coal transport, although precautionary measures are increasingly being taken (Chadwick *et al.*, 1987). It has been estimated that 0.02% of the coal loaded is lost as fugitive dust with a similar percentage lost when unloading. Coal losses during transit are estimated to range from 0.05 to 1.0%. The amount is dependent upon mode of transportation and length of trip but can be a sizeable amount, especially for unit train coal transit across the United States.

In many instances, conventional railroads are preferred for the handling of coal since the large capacity wagons can be covered, sprayed by water, and wind guards and chemical binders can be used. In the future, slurry pipelines may prove to be the most economic method of moving huge volumes of coal over long distances. However, land requirement, the use of large quantities of water which are difficult to dispose of and lack of eminent domain rights are the main drawbacks in establishing a nationwide network system.

Coal stockpiled near the mine-head or in close proximity to an industrial site is a potential source of dust and surface water runoff. Regular inspection is required to monitor the rate of spontaneous combustion which causes the emission of local scale toxic gases. Moreover, stockpiling on a large scale or over a long period arouses adverse reaction from the general public regarding its unsightliness and puts constraints on coal handling. These problems can, to a certain degree, be overcome by storing coal in abandoned pits or silos constructed for the purpose, but authorities still need to look into alternative optional proposals to deal with the environmental matters.

14.3.2 Storage

Storage of coal at a coal-fired power plant is essential if the plant is to maintain operations during situations or events that disrupt coal delivery (Chapter 4). Typically, a power plant may have coal stored that is sufficient for continued operation of the plant over a two-to-several day period, if coal deliveries are interrupted.

The active principles in the disadvantages of coal storage at power plants are (i) fugitive dust and (ii) runoff control after rain or snow. In fact, in some areas, local environmental regulations may rule out open storage, but it should be considered at least initially, because it can be less expensive from a total cost standpoint, even with environmental controls.

On the other hand, utility coal yards at power plants often need to store coal so that in anticipation of disruption in coal delivery for the plant (such as a train derailment) often means that the plants may require several days of backup. An efficient method that has been and still is used where environmental regulations permit such actions for storing large quantities of coal is ground placement, where stocks of 30 to 90 days' consumption may be required.

However, in such cases where open storage is allowed, rain and snow runoff can become contaminated by chemical and bacteriological action on pyritic materials contained in the coal. Chemically, this occurs by the same series of reactions that are known to produce acid coal mine drainage and the amount of runoff is dependent upon (i) the configuration of the stockpile, (ii) the particle size of the coal, (iii) the moisture content of the coal, (iv) the amount of precipitation in the form of rain or snow, and (v) the intensity of the rain (shower or downpour). Studies indicate runoff ranges from 50 to 95% of the rainfall on the pile; the remainder evaporates or is held in the pile. Constructing coal storage piles so as to encourage runoff and inhibit the amount of water percolating through the piles can minimize the energy wasted in driving off moisture prior to the in-plant combustion (Chapter 4) (Cox *et al*., 1977; Ripp, 1984).

In many countries (including the United States), regulations require mine operators to comply with specific limitations relating to effluents. In order to meet these requirements, the following treatments are typically employed: (i) the addition of alkaline material, such as lime – CaO – or sodium hydroxide NaOH, (ii) natural or mechanical aeration, and (iii) settling of the coal in the pile. When the pH is raised to 7 (neutral) or 8 (slightly alkaline) and settling has occurred, most drainage waters will meet the standards for iron content and suspended solids (Watzlaf, 1988).

In drainage waters, a pH value as high as 10 (sternly alkaline water) may be sometimes required to reduce manganese to effluent limits. Thus, the reduction of manganese to the regulated standard may require discharging water with pH higher than the upper limit, which action requires the operator to obtain a variance.

14.4 Combustion

Emissions from coal combustion depend on coal type and composition, the design type and capacity of the boiler, the firing conditions, load, the type of control devices, and the level of equipment maintenance. Emissions from anthracite coal firing primarily include particulate matter (PM), sulfur oxides (SOx), nitrogen oxides (NOx), and carbon monoxide (CO); and trace amounts of organic compounds and trace elements.

Thus, coal utilization for power generation (Chapter 11) is of growing environmental concern, due mainly to emissions of carbon dioxide associated with the combustion process. Although coal is only one of many sources represented by this anthropogenic carbon dioxide, the coal industry is searching for and developing technological options to mitigate its contribution to the problem.

Previously, coal was used extensively as a fuel for energy production and as a raw material in the chemical, gas, and metallurgical industries. However, the principal uses of coal are in the utility, industrial, and residential sectors. In countries with planned economies, 70 to 90% of the total quantity of coal consumed is burnt in the utility sector (Chadwick *et al.*, 1987; Speight, 2013, 2020).

The principal chemical constituents of coal are carbon, hydrogen, oxygen, nitrogen, sulfur, moisture, and incombustible mineral matter (which forms mineral ash as a result of combustion or gasification processes) (Chapters 2, 5, 8, 10). When coal is burned or subject to gasification processes, the carbon and hydrogen are oxidized to form the ultimate products of coal decomposition under the prevalent conditions – carbon dioxide and water. Other combustion products such as nitrogen oxides, sulfur oxides, carbon monoxide, and particulate matter are produced in varying amounts depending upon the conditions in the reactor.

Formation of nitrous oxide (N_2O) during the combustion process results from a complex series of reactions and its formation is dependent upon many factors. However, the formation of nitrous oxide is minimized when combustion temperatures are kept high and excess air is kept to a minimum. However, pulverized coal-fired electricity generating units are typically operated under conditions that are not significant sources of nitrous oxide emissions. On the other hand, fluidized-bed combustor electricity generating units can have measurable nitrous oxide emissions, resulting from the lower combustion temperatures and the use of selective non-catalytic reduction to reduce NOx emissions. Operating factors impacting nitrous oxide formation include combustion temperature, excess air, and sorbent feed rate. The nitrous oxide formation resulting from selective non-catalytic reduction depends upon (i) the reagent used, (ii) the amount of reagent injected, and (iii) the injection temperature (Yang, 2007).

During the combustion of coal, the mineral matter is transformed into ash, part of which is fly ash discharged to the atmosphere as particles suspended in the flue gases and part of which is bottom ash removed from the base of the furnace. Furthermore, scrubber sludge is formed where sulfur dioxide scrubber facilities are employed (Chapter 12). The quantity, particle size distribution and properties of fly ash are directly related to the combustion technique applied and the constitution of the coal.

Of the various methods of conventional combustion techniques, pulverized coal-fired furnaces are preferred for power stations and larger industrial facilities. Combustion processes create very fine effluents of which 70 to 90% is carried to the air fly ash and 10 to 30% remains as bottom ash. Difficulties in disposing fly ash stem from the enormous quantities collected (Scanlon and Dugan, 1979).

14.4.1 Effect of Coal Type

The amount of carbon dioxide that potentially can be emitted from a coal-fired electricity generating unit varies depending on the type of coal used as the feedstock. The lower heating value of lower-rank coals (Chapter 2) means that more coal must be burned to produce one unit of electricity compared to higher-rank (e.g., bituminous) coals. Just as the amount of sulfur in a coal can be translated into amount of sulfur dioxide per unit of energy produced, on the basis of the heating value, the abundance of hazardous air pollutants and similar elements may also need to be expressed in energy terms. In general anthracite emits the largest amount of carbon dioxide per million Btu (MMBtu), followed by lignite, subbituminous coal, and bituminous coal. However, for a given coal rank there is variation in the carbon dioxide emission factor depending on the coal bed from which the coal is mined.

In addition to the lower carbon dioxide emissions rate per unit of heat input (lbs CO_2/MMBtu), due to the inherent moisture in subbituminous and lignite coals, all else being equal a bituminous coal-fired boiler is more efficient than a corresponding boiler burning subbituminous or lignite coal. Therefore, switching from a low- to a high-rank coal will tend to lower greenhouse gas emissions from the utility stack. Overall greenhouse gas emissions might not be lowered by switching to bituminous coal. All coal mining operations release coal bed methane to the atmosphere during the mining process. Some bituminous coal reserves release significant amounts of methane, which could, in theory, offset greenhouse gas savings.

14.4.2 Gaseous Effluents

Emissions to air from coal-fired power plants may be categorized as (i) fugitive emissions, and (ii) point source emissions (Speight and Lee, 2000).

Fugitive emissions are emissions that are not released from a point source such as a stack. Examples of fugitive emissions include dust from stockpiles, volatilization of vapor from open vessels, and material handling. Emissions emanating from ridgeline roof-vents, louvers, and open doors of a building, as well as equipment leaks, and leaks from valves and flanges are also examples of fugitive emissions. With appropriate management, these emission sources are generally minor for power stations. *Point source emissions* are emissions that are exhausted into a stack or vent, and emitted through a single point source into the atmosphere. An air emission control device, such as an electrostatic precipitator or a fabric filter (baghouse), can be incorporated into the exhaust system to the stack prior to the atmospheric release.

The air emission sources related to fossil fuel electricity generation include (i) the products of fuel combustion emanating from the smoke stacks), (ii) the fugitive dust from coal stockpiles and handling equipment, (iii) the fugitive dust from ash storage, and (iv) particulate emissions from a wet cooling tower drift.

In a cooling tower, water pumped from the tower basin is routed through the process coolers and condensers. The cool water absorbs heat from the hot process streams which need to be cooled or condensed, and the absorbed heat warms the circulating water. The warm water returns to the top of the cooling tower and trickles downward over the fill material inside the tower. As the water trickles down the tower, it contacts ambient air rising up through the tower either by natural draft or by forced draft using large fans in the tower. That contact causes a small amount of the water to be lost as windage or drift and some of the water to evaporate.

The products of the complete combustion of coal are carbon dioxide and water. However, in the exhaust gases from any coal combustor there will also be carbon monoxide, sulfur oxides (SOx), nitrogen oxides (NOx), unburned hydrocarbon derivatives, and solid particulate matter as well as small amounts of hydrogen chloride and polycyclic organic matter. Of these pollutants, concern has largely been focused on sulfur dioxide and nitrogen oxides because of their apparent importance on long-term environmental effects.

The coal properties which have the most impact on gaseous emissions are (i) the nitrogen content of the coal – the level of nitrogen oxide (NO_x) emissions is governed by the distribution of nitrogen between the volatiles and the char, and (2) the sulfur content of the coal – emissions of sulfur dioxide (SO_2) are directly related to coal sulfur content, with only a small portion being incorporated in the ash for most bituminous coal feedstocks.

14.4.2.1 Carbon Emissions

Carbon emissions include emissions of carbon monoxide, carbon dioxide, and total organic compounds. Emissions of carbon monoxide (CO) and total organic compound (TOC) are dependent on combustion efficiency – generally the emission rates of these species (the mass of emissions per unit of heat input) decrease with increasing boiler size. The emissions of total organic compounds are expected to be lower for pulverized coal-fired units and higher for underfeed and overfeed stokers as a result of relative combustion efficiency levels.

Carbon monoxide (CO) is generally formed by the partial combustion of carbonaceous material in a limited supply of air. Small quantities of carbon monoxide are produced by the combustion of coal and from spontaneous combustion. In the atmosphere the carbon monoxide is eventually converted to carbon dioxide.

As the carbon dioxide from a combustor is discharged into the air increases, the temperature of the lower atmosphere also increases – the carbon dioxide absorbs thermal radiation and reflects back a proportion of the infrared radiations. These processes contribute to the so-called greenhouse effect or global warming of the atmosphere. Scientific opinions differ on the possible consequences, but man may be the cause of further significant global climate change and imbalance in world ecology.

14.4.2.2 Sulfur Oxides

Acid gases (such as sulfur oxides) emitted into the atmosphere provide the essential components in the formation of acid rain. Sulfur is present in coal as both an organic and inorganic compound. Sulfur oxide emissions are directly proportional to the sulfur content of the coal, although minor variations will occur from unit to unit, however, due to (i) ash partitioning between fly ash and bottom ash, and (ii) the sodium content of the coal, which tends to react with and bind coal sulfur in the bottom ash as sodium sulfite or sodium sulfate. For fluidized-bed combustion boilers, sulfur oxide emissions are inversely proportional, in general, to the molar ratio of calcium (in the limestone) to sulfur (in the fuel) added to the bed.

During coal combustion, most of the sulfur is converted to sulfur dioxide with a small proportion remaining in the ash as sulfite:

$$S_{coal} + O_2 \rightarrow SO_2$$

At flame temperatures in the presence of excess air, some sulfur trioxide is also formed:

$$2SO_2 + O_2 \rightarrow 2SO_3$$

$$SO_3 + H_2O \rightarrow H_2SO_4$$

Only a small amount of sulfur trioxide can have an adverse effect as it brings related the condensation of sulfuric acid and causes severe corrosion. Although diminution of the excess air reduces sulfur trioxide formation considerably, other considerations, such as soot formation, dictate that the excess air level cannot be lowered sufficiently to eliminate sulfur trioxide entirely.

14.4.2.3 Nitrogen Oxides

From 10 to 50% of the nitrogen inherent in the organic coal structure is converted to nitrogen oxides during combustion which also produce acidic products thereby contributing to the acid rain:

$$2N_{coal} + O_2 \rightarrow 2NO$$

$$NO + H_2O \rightarrow \underset{\text{Nitrous acid}}{HNO_3}$$

$$2NO + O_2 \rightarrow 2NO_2$$

$$NO_2 + H_2O \rightarrow \underset{\text{Nitric acid}}{HNO_3}$$

Nitrogen in the coal itself also contributes significantly to the formation of gases. Of the nitrogen oxides emitted in power station flue gas, 95% is nitric oxide (NO), which oxidizes rapidly in the atmosphere to form nitrogen dioxide (NO_2). Fluidized-bed combustion generates little, if any, thermal nitrogen oxides despite the long residence times since the bed temperatures are usually too low; any residual nitrogen oxide is often derived from the fuel nitrogen rather than from the conversion of aerial nitrogen.

Little, if anything, can be done as part of the coal pretreatment operation(s) (Chapter 3) to eliminate nitrogen because this element is an integral part of the organic structure of coal (Chapters 2, 5). The situation is less clear in the case of hydrogen chloride sources in coal; both organically bound chlorine and inorganic chloride salts (although it is not known that these contribute appreciably to hydrogen chloride formation during combustion) but these processes do not remove organically bound chlorine, which is a more likely precursor to hydrogen chloride in a combustion process.

However, the management of volatile matter evolution patterns also is of significance in controlling nitrogen oxide emissions (Baxter *et al.*, 1996). Nitrogen evolving rapidly, frequently under reducing conditions, does not oxidize but converts to nitrogen. Nitrogen volatiles that evolve more slowly can exist in an oxidizing environment and formation of nitrogen oxides from these is more likely than from fuel nitrogen sources.

This principle is one of the principles behind staged combustion as well as oxygen-enhanced combustion approaches where the oxygen is injected at the root of the flame, increasing volatile nitrogen evolution; however, the quantity of oxygen used is insufficient to convert the reducing environment at the base of the flame to an oxidizing environment.

Nitrogen oxide emissions (NOx emissions) are typically lower in traveling-grate and underfeed stokers compared to pulverized coal-fired boilers. Underfeed and traveling-grate stokers have large furnace areas and consequently lower volumetric- and surface area-based heat release rates. Lower heat release rates reduce peak combustion temperatures and, hence, contribute to lower emissions of nitrogen oxides. In addition, the partially staged combustion that naturally occurs in all stokers due to the use of under-fire and over-fire air contributes to reduced emissions of nitrogen oxides relative to emissions from pulverized coal-fired units. The low operating temperatures which characterize fluidized-bed boilers firing culm also favor relatively low emissions of nitrogen oxides. Reducing boiler load tends to decrease combustion intensity which, in turn, leads to decreased nitrogen oxide emissions for all boiler types.

Thus, control of nitrogen oxides has traditionally been achieved with staged combustion and with catalytic conversion processes using ammonia or urea. Catalytic processes using ammonia or urea have proven to be quite effective, but they are very expensive to implement and operate. Staged combustion has provided some control of nitrogen oxides formed from the volatiles, but it has had little effect on the formation of nitrogen oxides formed from the char.

Recently, advanced staging processes, known as low-NOx burners, have been developed. These burners are designed on the basis that volatile nitrogen may be converted to nitrogen rather than nitrogen oxides under locally fuel-rich conditions with sufficient residence time at appropriate temperatures. The amount and chemical form of nitrogen released during devolatilization greatly influences the amount of nitrogen oxide reduction achieved using this strategy. Since the nitrogen in the char is released by heterogeneous oxidation, these burner design modifications have no effect on NOX formed from the char nitrogen.

Low-NOx burners alter the near-burner aerodynamics of the combustor. This alteration influences the devolatilization process and therefore influences the amount and chemical form of nitrogen released during devolatilization (Blair *et al.*, 1977; Chen *et al.*, 1982; Solomon and Fletcher, 1994). Low-NOX burners provide a less expensive emission control strategy and are often the method of choice to limit the amount of nitrogen oxides formed during combustion.

Most stack gas scrubbing processes are designed for sulfur dioxide removal; nitrogen oxides are controlled as far as possible by modification of combustion design and flame temperature regulation. However, processes for the removal of sulfur dioxide usually do remove some nitrogen oxides; particulate matter can be removed efficiently by commercially well-established electrostatic precipitators.

There are several processes for the removal of sulfur dioxide from stack gas (Chapter 12) (Mokhatab *et al.*, 2006; Speight, 2013, 2014, 2019, 2020) but (generally) scrubbing process utilizing limestone ($CaCO_3$) or lime [$Ca(OH)_2$] slurries have received more attention than other stack gas scrubbing processes. Attempts have been made to use dry limestone or dolomite ($CaCO_3.MgCO_3$) within the combustor as an *in situ* method for sulfur dioxide removal, thus eliminating the wet sludge from wet processes. This involves injection of dry carbonate mineral with the coal followed by recovery of the calcined product along with sulfite and sulfate salts:

$$CaCO_3 + SO_2 \rightarrow CaSO_3 + CO_2$$

$$CaCO_3 + SO_3 \rightarrow CaSO_4 + CO_2$$

The various solid products are removed by standard means, including cyclone separators and electrostatic precipitators.

Some of the sulfur and nitrogen oxides will fall to the ground quite quickly as dry deposition. Both are in the form of dry gases or are adsorbed on other aerosols like fly ash or soot (Park, 1987). These particles may not be in the acidic state while in the air but will become so on contact with moisture. The remaining oxides will be carried up into the atmosphere with the help of tall chimney stacks. Sulfur and nitrogen oxides are immediately absorbed by water droplets in clouds to form acidic species. Subsequent dissolution causes sulfuric and nitric acids to dissociate into a solution of positively charged hydrogen cations and negatively charged sulfate and nitrate anions, which eventually return to earth as acid rain. This is termed wet deposition. Furthermore, nitrogen oxide absorbs ultraviolet light from the sun and triggers off photochemical reactions that produce smog, of which ozone is a part.

Besides the adverse consequences of acid rain, many green plants are damaged by exposure to low concentrations of sulfur and nitrogen oxides (Clark *et al*., 1977). These gases can also severely impair respiratory functions and change the metabolic rates of humans. Sulfur oxides, moreover, affect metals and building materials causing corrosion. On the whole, it is apparent that oxides of sulfur and nitrogen pose a direct threat to the balance of nature devastating both terrestrial and aquatic ecosystems alike.

The scale of these environmental problems can be minimized, if not eliminated, by the use of proper processes invented for the purpose. Control of sulfur dioxide emissions could be accomplished by using low-sulfur content coal, blending high-sulfur coal with low, and treating coal before combustion to remove some of the sulfur. Coal washing, although mainly applied for reducing the mineral content of coal, removes up to 70% of inorganic sulfur and 40% of total sulfur. Another alternative would be to switch from coal to natural gas or crude oil or a crude oil-derived oil fuel (Speight, 2020).

Environmental concerns and strict pollution legislation prompted action in the construction of up-to-date coal-fired boilers and adaptation of existing plants. At the present time, flue gas desulfurization is the only conventional method employed on a commercial scale for reducing sulfur emissions after coal combustion. Over 90% reduction of sulfur dioxide in flue gases can be achieved by this process. Combustion control techniques of the flames will effectively reduce oxides of nitrogen emissions into the atmosphere.

Flue gas denitrification by selective catalytic reduction has limited application with acceptable results in reducing the effluent nitrogen oxides emissions from power stations. Future technology includes fluidized-bed combustion where sulfur removal can be achieved during the combustion of coal with a subsequent reduction of sulfur dioxide emissions of 35 to 50% (Burdett *et al*., 1985). Furthermore, coal can be converted to liquid or gaseous products, so-called synthetic fuels, with sulfur and other impurities largely removed. Coal-oil and coal-water mixtures with a low ash and sulfur content are seriously being considered as alternative replacement fuels for oil in utility and industrial boilers.

Although not generally considered to be a major pollutant, hydrogen chloride from inorganic contaminants is gaining increasing recognition as a pollutant arising from the combustion of coal. Hydrogen chloride quickly picks up water from the atmosphere to form droplets of hydrochloric acid and, like sulfur dioxide, is a contributor to acid rain. However, hydrogen chloride may exert severe local effects because it does not have to undergo any chemical change to become an acid and, therefore, under atmospheric conditions involving a buildup of stack emissions in the area of a large power plant, the concentration of hydrochloric acid in rain droplets could be quite high.

14.5 Gasification

Gasifiers require flares for start-up, shutdown and fault conditions as the gas, inherently toxic before the combustion stage, cannot be simply vented. Although flares are standard items on oil refineries they could be a source of difficulties for gasification power plant. They have to be sized for the full gas production rate and hence have a large potential thermal output. In addition the gas from gasifiers has very different radiative properties to natural gas combustion in flares. Visual effects of flare operation and heat fluxes to surrounding equipment and buildings can be significant. The potential for ignition of stored fuel needs particular assessment. Flares may appear to be a simple component of a gasification power plant but they have caused considerable problems on many gasification power plant designs and have often had to be redesigned or relocated.

The increasing costs of conventional waste management and disposal options, and the desire, in most developed countries, to divert an increasing proportion of mixed organic waste materials from landfill disposal, for environmental reasons, will render the investment in energy from waste projects increasingly attractive. Most new projects involving the recovery of energy from municipal waste materials will involve the installation of new purpose-designed incineration plant with heat recovery and power generation. However, advanced thermal processes for municipal solid waste which are based on pyrolysis or gasification processes are also being introduced. These processes offer significant environmental and other attractions and will likely have an increasing role to play, but the rate of increase of use is difficult to predict.

In addition to the product gas, coal gasification plants produce other effluent streams that must be disposed of in an economically and environmentally acceptable manner (Argonne, 1990; Speight, 2013). Some of the streams contain valuable by-products such as hydrocarbon oils, sulfur, ammonia, as well as valuable elements in (and properties of) the ash (Braunstein *et al.*, 1977; Probstein and Hicks, 1990).

The gas from any gasification process is inherently toxic, because of essential components such as carbon monoxide and unwanted components. However, this inherent toxicity is not the reason for gas cleaning because the gas should never be released to the atmosphere directly.

Gas cleaning (Chapter 12) is usually required to prevent damage to the electricity generating system using the gas and to prevent unwanted emissions from the combustion process using this gas. The relatively small volume and the reactive nature of species to be removed is a major advantage in gas cleaning from large pressurized oxygen-blown coal gasifiers when compared with conventional coal combustion plants.

The relatively small volume throughput advantages of gasifiers (compared with combustion processes) are to a great extent lost when gasifiers are used at smaller scales, atmospheric pressure and are air-blown.

The effect of nitrogen is more than would be expected from simple nitrogen dilution by bringing four volumes of nitrogen into the system with every one volume of oxygen. The effect is not always fully appreciated so some explanation may be helpful for readers new to the observation. The nitrogen needs sensible heat to raise it to the gasification reaction temperature. It retains some of this heat on reaching the gas cleaning stage. It increases the number of oxygen molecules needed for gasification reactions if air is used instead of oxygen. This further reduces the ratio of chemical energy to sensible heat in the gas and hence increases the volume of gas to be cleaned than what would be expected from the simple dilution calculation.

The major gas emissions are carbon dioxide and water vapor. Wood and refuse inherently emit more carbon dioxide than coal during an electricity generation process, whatever technology is used. Carbon dioxide emission reporting and trading is not always sophisticated enough to distinguish between emission of carbon dioxide for which the carbon was in the atmosphere only a few years ago and that for which the carbon was last in the atmosphere millions of years ago.

All of the major operations associated with low-, medium- and high-Btu gasification technology (coal pretreatment, gasification, raw gas cleaning, and gas beneficiation) can produce potentially hazardous air emissions. Auxiliary operations, such as sulfur recovery and combustion of fuel for electricity and steam generation, could account for a major portion of the emissions from a gasification plant.

Dust emissions from coal storage, handling, and crushing/sizing can be controlled with available techniques. Controlling air emissions from coal drying, briquetting, and partial oxidation processes is more difficult because of the volatile organics and possible trace metals liberated as the coal is heated.

The coal gasification process itself appears to be the most serious potential source of air emissions. The feeding of coal and the withdrawal of ash release emissions of coal or ash dust and organic and inorganic gases that are potentially toxic and carcinogenic. Because of their reduced production of tars and condensable organics, slagging gasifiers pose less severe emission problems at the coal inlet and ash outlet.

Gasifiers and associated equipment also will be sources of potentially hazardous fugitive leaks. These leaks may be more severe from pressurized gasifiers and/or gasifiers operating at high temperatures.

Depending on subsequent processing and final use, various products and by-products must be removed from the low and medium heat-content products that are produced in the gasifier (Chapters 9, 10). In all cases hydrogen sulfide and other sulfur compounds must be removed because (in addition to the environmental aspects of gas use) they can poison catalysts in subsequent processing. This may be essentially all of the cleanup that is necessary for low heat-content gas destined for combustion whereas gas that is to be methanated requires virtually complete removal of essentially all components except hydrogen and carbon monoxide.

Sulfur compounds generally result in sulfur dioxide emissions. Sulfur removal from coal gas is a relatively straightforward process. Co-gasification of coal with a low sulfur substance such as biomass or waste reduces the hydrogen sulfide partial pressure and hence requires a larger gas cleaning system. The tar from wood gasification and the hydrochloric acid from waste gasification further complicate the issue. Objective assessment of potentially toxic emissions probably regards liquid products from gas cleaning as the greatest concern.

Acid gas removal refers to the removal of carbon dioxide, hydrogen sulfide, and other gases with acidic qualities and may be achieved in several ways (Chapter 12) (Speight, 2013, 2014, 2019, 2020). The first of these is absorption by a solvent, including hot carbonate solutions, amines, or methanol.

On the other hand, absorption onto a solid surface may be employed and solids employed for this purpose include activated carbon, charcoal, and iron sponge. Finally, acid gases may be chemically converted by reactants such as ferric oxide, zinc oxide, calcium oxide, and vanadium pentoxide. Some of these processes remove both carbon dioxide and hydrogen sulfide, whereas others selectively remove hydrogen sulfide (Mokhatab *et al*., 2006; Speight, 2014).

These processes require regeneration of the sorbent by release of hydrogen sulfide which is subsequently reacted with sulfur dioxide to produce elemental sulfur (Claus reaction):

$$2H_2S + SO_2 \rightarrow 2H_2O + 3S$$

The Stretford process for acid gas treatment allows for direct recovery of sulfur without going through a Claus reaction i.e., Claus reaction

$$2H_2S + O_2 \rightarrow 2H_2O + 2S$$

The absorbent is an aqueous solution of sodium carbonate, sodium metavanadate, and anthraquinone disulfonic acid.

$$H_2S + Na_2CO_3 \rightarrow NaHS + NaHCO_3$$

$$HS^- + 2VS^{5+} \rightarrow S + 2V^{4+} + H^+$$

The vanadium (IV) product reacts with the anthraquinone disulfonic acid to regenerate vanadium (V); oxygen is provided by air blowing.

Most processes for ammonia removal from gas streams involve absorption of the ammonia in water and steam may be used to strip a concentrated stream of ammonia from the scrubber water. The moist ammonia from the steam stripping may be condensed to yield a fairly concentrated ammonia solution. Alternatively, the stripped ammonia may be absorbed in a solvent such as phosphoric acid to yield a solution that is subsequently treated to recover anhydrous ammonia.

Particulate matter may be removed from gas products by a number of means such as (i) water scrubbing or (ii) a cyclone separator. Part of the ash from a conversion operation occurs as fly ash and is removed with particulate matter. Some gasifiers produce a melted bottom ash (slag) which is quenched in water while other processes produce a "self-agglomerating" ash consisting of softened particles.

Wastewater streams are generated in many coal gasification processes from the quenching and water washing of the raw gas, which removes water-soluble impurities such as ammonia, hydrogen sulfide, and phenols. The nature of the contaminants depends, to a large extent, on the composition of the feedstock coal as well as on the gasifier operation, and the techniques that are used for quenching and washing the raw gas. Hence, wastewater management has to be an integral part of any gasification plant (Luthy and Walters, 1979).

Liquid/liquid extraction processes are used to remove high concentrations of phenols from industrial wastewaters. For water that contains dissolved ammonia and hydrogen sulfide, most designs place the phenol extraction process before water stripping to prevent phenol-initiated problems in the stripper and ammonia-recovery steps. The extent of phenol removal depends on the types of phenols in the feed as well as other organic compounds.

Water stripping is a form of distillation in which trace amounts of relatively volatile materials, such as dissolved gases, are removed from a large volume of wastewater. The stripping is affected by either indirect reboiling of the feed-water by steam or by direct injection of steam into the bottom of a column. This technique is used extensively for sour-water strippers in almost all refinery installations. For coal gasification processes, dissolved base ionization may complicate the design procedures. For example, acidifying the feed will fix the ammonia in solution to allow selective removal of hydrogen sulfide. Unless cations, such as ammonia and sodium, are present to fix the hydrogen sulfide, removals greater than 98% are commonly reported.

The stripped water can be sent to a biological wastewater treatment plant for further processing. The gases require further treatment, such as ammonia recovery, sulfur removal recovery, or incineration/combustion.

Insoluble entrained organic compounds can be removed from wastewater by physical separators; the principal contaminant removed is free oil. If suspended solids are present in the wastewater, these solids will also settle in the basin.

In addition to the various water-treating systems, a variety of treatments may be considered depending upon the particular circumstances of contaminants and degree of final water purity required. These treatment systems include (i) clarification, (ii) filtration, (iii) air flotation, (iv) carbon adsorption, (v) vapor compression distillation, and (vi) biological treatment. In the last case, i.e., biological treatment, techniques such as trickle filtration, sludge activation, and digestion processes are used. Such treatments are worthy of detailed consideration as they generally offer attractive options that are acceptable to a variety of environmental regulators.

Additional changes to gas cleaning strategies for cofiring coal (even coal blends) with other feedstocks such as biomass (Chapters 7, 9) compared with a single coal feedstock are required. Co-combustion and co-gasification of coal with biomass and waste results in a higher tar content of the gas and often a higher hydrochloric acid content of the gas as well as more potentially toxic and carcinogenic organic compounds compared with coal alone. Waste may require additional removal of toxic compounds, particularly mercury and heavy metals. Sulfur compound removal is much more important in coal gasification gas-cleaning but may be unnecessary in biomass and some waste gasification situations. It is clear that gas cleaning associated with co-combustion and co-gasification may not be the same as gas cleaning for other single coal feedstock combustors and/or gasifiers. The differences may even be enough for separate gasifiers and gas cleaning streams for coal, biomass and waste to be preferred to a single larger co-gasification and gas cleaning system, even if all the systems feed gas to the same electricity generation unit.

Biomass firing and probably waste firing will require tar removal. Catalytic cracking or thermal cracking, if they prove reliable, are generally regarded as the best processes as they retain much of the chemical energy of tars in the gas phase. However, experience to date on the reliability of tar cracking processes has been at best variable. Condensation and/or wet scrubbing are better proven than tar cracking processes. However, the collected tars are often toxic, carcinogenic or difficult to break down even in combustion or oxygen gasification processes. Oxygen-blown entrained gasifiers are particularly good at breakdown of the most difficult tars but it is likely to be rare to find such a gasifier conveniently close to a smaller co-gasification unit.

The issue then arises as to what advantages, technical or economic, are offered by the co-utilization of waste materials with coal. There is no simple answer to this question.

The partial replacement of coal with waste and biomass materials can be a way of introducing renewable energy. In a number of countries, this is regarded as being of significant environmental benefit, and government subsidies and other inducements are available to encourage these activities. The coal can be regarded as being beneficial because the security of supply of a number of the waste and biomass materials is uncertain, and the quality of the delivered fuel is subject to only limited control. These are significant risk areas in most waste/biomass energy conversion projects, and the co-utilization of coal can be regarded as providing a means of reducing these risks, in that the supply of coal to a prescribed quality specification is assured in most industrial countries.

The co-utilization of refuse-derived fuel materials with coal in gasification and pyrolysis plant will also be of increasing relevance in the medium to longer-term future, even though there are relatively few plant currently in operation. Apart from the limited extent of demonstration of the technologies and the lack of a turnkey supplier for plant, electricity market economics are a major hurdle to the introduction of co-gasification.

The difficulties of co-gasification of very different fuels in small gasifiers outweigh the benefits of combining fuels for economies of scale, at least at the gasification and gas cleaning stages. For oxygen-blown gasifiers the situation is more likely to be dictated by considerations of fuel pretreatment and conclusions will be specific to each gasifier technology.

Co-gasification adds additional complexity to the gas cleaning system as the different products from coal, waste and biomass all have to be addressed. There will be wastes from gas cleaning, including some form of chlorides, sulfur compounds and potentially very toxic and carcinogenic tars and organic compounds. It may or may not be possible to use these tars by recycling to the gasifier.

Biomass growth specifically for power generation can be an excellent environmental option, particularly if the crop is managed with environmental care. There are many benefits over current set-aside arrangements for arable land.

Waste is an area of considerable public concern. The waste industry has had a bad public image, not always based on logical or scientific evaluation of the facts. However, whatever the facts, public concern is a major issue in the use of waste by any technology. Any link with waste or traffic is an area of particular concern for brand image. Major issues are therefore local planning consents, the environmental permits and the support of the local population.

The technology of co-gasification of waste/biomass with coal can result in very clean power plant using a range of fuels. In addition, the use of coal allows economies of scale and reliability of fuel supply. There are also considerable economic and permitting challenges in producing a financially attractive project.

14.6 Power Plant Waste

Coal combustion for electric generation produces four main types of large volume waste materials: (i) fly ash, which consists of the fine particles of silica glass that are removed from the plant exhaust gases by air emission control devices, (ii) bottom ash, which consists of the ash particles that are too large to be carried in the flue gases and collect on the furnace walls or fall through open grates to an ash hopper, (iii) boiler slag, which is the molten bottom ash collected at the base of slag tap and cyclone type furnaces that is quenched with water and consists of hard, black, angular particles that have a smooth, glassy appearance, and (iv) flue gas desulfurization materials such as gypsum, which is the sludge or powdered sulfate and sulfite – $CaSO_4$ and $CaSO_3$, respectively – that is produced through a process used to reduce sulfur dioxide emissions from the exhaust gas system of a coal-fired boiler.

The use of coal has a long history of emitting a variety of waste products (typically referred to as *pollutants*) into the environment which has contributed to several known health episodes. Although regulations on coal usage date back to medieval times (Speight, 2013), it was not until major incidents in the 1940s and 1950s in England and the United States, which had severe impacts on human health, that the impetus for legislation in these two countries took hold in order to protect the health of the general public. In the United States, the major development of legislative and regulatory acts occurred from 1955 to 1970.

Coal-based processes involved in combustion and conversion facilities release waste gaseous effluents, waste liquid effluents, and waste solid effluents, all of which are deleterious to the environment and human health. The preference can be made from the following alternatives: (i) removal of the pollutant from the process effluent by passing polluted air through a series of dust collectors which filter the fine particulates, (ii) removal of the pollutant from the process input by desulfurization of the feed coal, (iii) control of the process by lowering the combustion temperature to minimize the generation of the oxides of nitrogen, (iv) replacement of the process with an alternate process that does not generate pollutants or will minimize the formation of the pollutants, such as the pressurized fluidized-bed combustion instead of pulverized coal burning, and (v) selection of a type of coal or an alternate fuel mix that eliminates or minimizes the pollutant, such as the use of low-sulfur coal or a blend of coals that has an overall low sulfur content (Clark *et al.*, 1977).

The regulations are continually changing, as more information on the effect of emissions on health and the environment is obtained, new control technologies are developed, and the demands for a safe living environment are heard and acted upon by various levels of government. Indeed, the use of coal for power generation is a highly regulated industry with regulations being developed and implemented on a regular basis.

In the early days of the power generation industry, coal combustion products (CCPs) were considered to be a waste material. The properties of these materials were not evaluated seriously for other uses and nearly all of the coal combustion products were landfilled. In the course of time, the cementitious and pozzolanic properties of fly ash were recognized. The products were tested to understand their physical properties, chemical properties and suitability as a construction material. During the last few decades these waste materials have seen a transformation to the status of *by-products* and more recently *products* that are sought for construction and other applications (Speight, 2013).

Power plant wastes (or combustion wastes, in the current context) are waste materials that are produced from the burning of coal. This includes all ash, slag, and particulates removed from flue gas. These wastes are categorized by EPA as a *special waste* and have been exempted from federal hazardous waste regulations under Subtitle C of the Resource Conservation and Recovery Act (RCRA). In addressing the regulatory status of fossil fuel combustion wastes, EPA divided the wastes into two categories: (i) large-volume coal combustion wastes generated at electric utility and independent power producing facilities that are managed separately, and (ii) all remaining fossil fuel combustion wastes, including those pertaining to coal use in power plants, such as large-volume coal combustion waste generated at electric utility and independent power producing facilities that are co-managed with certain other coal combustion wastes (referred to as *co-managed wastes*) and coal combustion wastes generated at facilities with fluidized-bed combustion technology as well as waste from the combustion of mixtures of coal and other fuels.

In two separate regulatory determinations, EPA determined that coal combustion wastes (CCWs) that are disposed in landfills and surface impoundments should be regulated under Subtitle D of RCRA (i.e., the solid waste regulations), whereas coal combustion waste used to fill surface mines or underground mines (*mine fill*) should be regulated under authority of Subtitle D of RCRA, the Surface Mining Control and Reclamation Act (SMCRA), or a combination of these authorities.

As a result of the waste produced by coal-fired power plants, efforts are continuously underway to address utilization of the vast amount of solid residue that is the by-product of coal cleaning and combustion – coal utilization by-products (CUBs). There are two primary targets (i) abandoned coal waste piles from old mining operations, and (ii) ash produced from existing coal-fired plants.

Thus, for the purposes of this text, power plant waste is material not covered in the above section. For example, the non-volatile inorganic constituents of the fuel (e.g., sodium, potassium) are left as ash and contribute to the formation of corrosive deposits (Reid, 1981; Argonne, 1990; Speight, 2013). When pulverized coal is used, a large proportion of the mineral ash is carried out of the combustion chamber with the exhaust gas stream and has to be removed as completely as possible, usually by use of electrostatic precipitators.

On completion of the coal cycle, a number of solid wastes are formed from the combustion and conversion of coal. The disposal of the solid waste necessitated stringent regulations and legislation. Thus, solid waste and dewatered sludge are generally tipped onto selected sites above ground, thrown into mine cavities or dumped in landfill sites, which is a serious cause for environmental pollution and protection.

During the disposal activities, a large quantity of dust is created which not only spoils the air opacity, but pollutes the soil fertility when it is deposited on the surface of the Earth. Contaminated soil can affect human health through the food chain. In transportation, approximately 10% water is added to the waste material to dampen the surface and so minimize the rate of dusting. If a dry disposal scheme is in use, like landfill, the bottom ash is generally dewatered in bins, whereas in wet disposal the ash is deposited into a pond or lagoon. In order to prevent the leaching of undesirable toxic solutions into groundwater, discharging in safe areas, compaction and sound management design are essential precautionary steps. Use of solid ash in industry is an alternative which is advantageous, both commercially and for the environment.

Because of its organic origin and its intimate co-mixture with mineral formations, coal contains a large number of elements in minor or trace quantities (Speight, 2013). Of the known non-transuranic elements, only a minority have not yet been found. In regard to the behavior of trace elements in coal-fired power plants, the elements have been divided into two groups, those appearing mainly in the bottom ash (elements or oxides having lower volatility) and those appearing mainly in the fly ash (elements or oxides having higher volatility).

Coal combustion products (often referred to as *CCPs*) are the inorganic residues that remain after pulverized coal is burned. Fine particles (*fly ash*) is removed from the flue gas by electrostatic precipitators or other gas-scrubbing systems whereas coarse particles (*bottom ash* and *boiler slag*) settle to the bottom of the combustion chamber (Speight, 2013).

The largest use of coal combustion products (mostly fly ash) is in cement and concrete. The coal combustion products displace Portland cement and significantly reduce emissions of carbon dioxide (CO_2). Portland cement manufacture requires the burning of fossil fuels and decomposition of carbonates, which release large amounts of carbon dioxide into the atmosphere.

Coal combustion products have many economic and environmentally safe uses (Speight, 2013). For example, in construction, a metric ton of fly ash used in cement and concrete can save the equivalent of a barrel of oil and can reduce carbon dioxide releases that may affect global warming. The use of coal combustion products saves landfill space and can replace clay, sand, limestone, gravel, and natural gypsum.

14.6.1 Coal Ash

The greatest single issue in operation of coal-fired units is the accumulation of *coal ash* on boiler heat transfer surfaces.

The mineral content of coal determines the amount and type of ash that will be produced during combustion when it is burned, and the fusion temperature (melting point) of the ash dictates the design of furnaces and boilers. In general, if the fusion temperature of the ash is relatively low, then the molten ash is collected at the bottom of the furnace as bottom ash, requiring one design. If, however, the fusion temperature of the ash is relatively high, then the part of the ash that does not melt easily (fly ash) is blown through the furnace or boiler with the flue gas and is collected in giant filter bags, or electrostatic precipitators, at the bottom of the flue stack, requiring a different design.

Coal that is relatively rich in iron-bearing minerals (such as pyrite or siderite) has low fusion temperatures, whereas coals relatively rich in aluminum-bearing minerals (such as kaolinite or illite) tend to have high fusion temperatures. If an electricity-generating or heating plant is designed to burn one type of coal, then it must continue to be supplied with a similar coal or undergo an extensive and costly redesign in order to adapt to a different type of coal. Similarly, furnaces designed to use coal that produces high amounts of heat will suffer severe losses in efficiency if they must accept coal that burns with substantially less heat.

Coal ash causes three main problems in large furnaces: (i) the buildup of ash on furnace wall tubes, (ii) the accumulation of small, sticky, molten particles of ash on superheater and reheater tube banks; and (iii) corrosion of the equipment. Two types of ash are generated during combustion of fossil fuels: bottom ash and fly ash. Some estimates place bottom ash forming up to 25% w/w of the total ash and the fly ash (isolated in the electrostatic precipitator) constitutes the remaining 75% w/w of the ash (Goodarzi, 2009).

Ash disposal can be a major issue for a coal-fired power plant. The coal properties affecting ash disposal are (i) the reactivity of the coal, which influences the residual carbon in ash where fly ash is sold to the cement industry, and this level of carbon in ash must be less than prescribed limits (usually approximately 5%w/w – if the carbon in the ash is above this limit, then disposal by other means will be required, at increased cost, (ii) mineral matter content of the coal, which affect the quality of ash to be disposed, and (iii) the levels of trace elements in the coal which may lead to a breach of environmental regulations.

Ash that collects at the bottom of the boiler is called *bottom ash* and/or *slag*. *Fly ash* is a finer ash material that is borne by the flue gas from the furnace to the end of the boiler. Bottom ashes are collected and discharged from the boiler, economizer, air heaters, electrostatic precipitator, and fabric filters. However, *boiler slag* may be somewhat different in character and properties to *bottom ash*.

There are two types of wet-bottom boilers that produce boiler slag: slag-tap and cyclone. The slag-tap boiler burns pulverized coal while the cyclone boiler burns crushed coal. Wet-bottom boiler slag is a term that describes the molten condition of the ash being drawn from the bottom of the furnaces. Both boiler types have a solid base with an orifice that can be opened to permit molten ash to flow into a hopper below. The hopper in wet-bottom furnaces contains quenching water. When the molten slag comes in contact with the quenching water, the ash fractures instantly, crystallizes, and forms pellets. High-pressure water jets wash the boiler slag from the hopper into a sluiceway which then conveys the ash to collection basins for dewatering, possible crushing or screening, and stockpiling. The resulting boiler slag is a coarse, angular, glassy, black material – somewhat different in appearance and properties to bottom ash.

When pulverized coal is burned in a slag-tap furnace, as much as 50% of the ash is retained in the furnace as boiler slag. In a cyclone furnace, which burns crushed coal, 70 to 85% w/w of the ash is retained as boiler slag.

Furthermore, it is important to distinguish fly ash, bottom ash, and other coal combustion products from incinerator ash (Speight, 2013). Coal combustion products result from the burning of coal under controlled conditions and are non-hazardous. On the other hand, *incinerator ash* is the ash obtained as a result of burning municipal wastes, medical waste, paper, wood, etc., and is sometimes classified as hazardous waste. The mineralogical composition of fly ash and incinerator ash consequently is very different. The composition of fly ash from a single source is very consistent and uniform, unlike the composition of incinerator ash, which varies tremendously because of the wide variety of waste materials burned.

Ash differs in characteristics depending upon the content of the fuel burned. For coal, the chemical composition of ash is a function of the type of coal that is burned, the extent to which the coal is prepared before it is burned, and the operating conditions of the boiler. These factors are very power plant-specific and coal-specific.

Generally, however, more than 95% w/w of ash is made up of silicon, aluminum, iron, and calcium in their oxide forms, with magnesium, potassium, sodium, and titanium representing the remaining major constituents. Ash may also contain a wide range of trace constituents in highly variable concentrations. Potential trace constituents include antimony, arsenic, barium, cadmium, chromium, lead, mercury, selenium, strontium, zinc, and other metals.

When ash melts in a pulverized-coal flame, the droplets coalesce to form larger drops of *molten slag*. Some of these drops reach the wall tubes of the furnace and adhere to the metal surface, eventually forming a solid layer of slag. Coal-ash slag does not conduct heat readily and thus decreases the amount of heat reaching the wall tubes, lowering the quantity of steam produced at this point. During load changes, there is a differential expansion between the wall tubes and the slag layer, causing huge sheets of slag to peel off the walls.

Slag is controlled more effectively via retractable wall blowers, which use high-velocity jets of air, steam, or water to dislodge the slag and clean the furnace walls – analogous to de-coking the delayed coker drums in a crude oil refinery. Each wall blower has an effective range of approximately 8 feet, so more than 100 blowers may be required in a typical installation. Occasionally, slag accumulations may get so large that manual cleaning is required, because large pieces of slag may fall to the bottom of the furnace. Since these pieces cannot be removed without manual breaking, a furnace shutdown may be required.

Fouling of heat transfer surfaces also occurs when very small particles of ash are carried to the bundles of tubing in the superheaters and reheaters. These fly ash particles collect on the tube surfaces, insulating the metal so that not enough heat is transferred to raise the steam temperature to design levels. These accumulations of ash can plug the normal gas passages. Soot blowers can be employed to remove such ash deposits periodically, but some coal ash may form dense, adherent layers, which are very difficult to remove except by manual cleaning.

Fuel and air nozzles can be adjusted to compensate for changes in heat absorption due to fouling. As furnace walls become coated with ash deposits, the burners are tilted downward and combustion is completed lower in the furnace. This exposes more furnace wall surface to the flame and restores the furnace exit gas temperature and steam temperature to satisfactory levels.

Ash-handling equipment and disposal facilities, if improperly designed, can also limit boiler capacity. The hopper section of the furnace typically slopes at 55° and generally covers a distance of 12 to 30 feet in a tangentially-fired furnace. High fractions of calcium oxide can combine with moisture and other elements to harden the fly ash as it cools in the hoppers. This ash packs and resists flowing and may require prodding.

The ash from most low-rank coals differs from that of higher-rank coals in that the percentage of alkaline earth metals (e.g., calcium and magnesium as the oxides CaO and MgO) exceeds the iron content. In many cases, the sodium content may be in excess of 5%. A higher percentage of basic metals may result in lower ash-fusion temperatures. While a lignite-type ash is generally classified as non-slagging, the presence of the alkaline earth metals (sodium and calcium rather than aluminum and silica) increases the tendency for rapid deposit build-up on superheater and reheater tube banks in the form of calcium and/or sodium sulfates. This property requires wider spacing in tube banks, especially for power plants utilizing western subbituminous coal and lignite.

The measurement of ash fusibility has long been recognized as an index for evaluating performance with regard to slagging and deposit build-up. If the ash is at a temperature above its softening temperature, it probably will settle out as a dust and, as such, is comparatively simple to remove. If, however, the ash is near its softening temperature, the resulting deposit is apt to be porous in structure.

Depending on the strength of the bond, the deposit may fall off due to its own weight or may readily be removed by soot blowing. However, if the deposit is permitted to build up in a zone of high gas temperature, its surface fuses more thoroughly and may exceed the melting temperature with resulting runoff as slag.

The fusibility characteristics of coal ash will vary with its chemical constituents. Most low-rank coals produce an ash high in basic metals and low in iron content. Therefore, they have a higher softening temperature, and consequently, are less susceptible to slagging. The behavior of ash is extremely complex, and while some constituents melt below 1040°C (1900°F), as the calcium and sodium content of the ash increases, the rate of deposition increases on tube surfaces. The sodium oxide content, in particular, can have a catalytic effect on the rate of deposition, and investigations have shown that ash with a sodium content above 5% fouls at an accelerated rate. However, prediction of fouling behavior based on sodium alone can be misleading. Many factors must be considered when predicting ash deposition, e.g., original mineral composition, furnace design, and utility operating practice.

A typical ash deposit structure for a low-rank coal (from the United States) may consist of three distinct layers which differ in physical character but are quite similar chemically.

The first thin *white layer* of very fine powdery ash is deposited all around the tube. This layer, which is usually enriched in sodium sulfate, is always observed during the early period of operation after boiler cleanup.

Next, an inner *sinter layer* a few millimeters thick begins to form by initial impaction on the upstream face of the boiler tube. Particles in this deposit are bonded together by surface stickiness. As this layer grows, its outer edge is insulated from the relatively cool boiler tube, thus causing the temperature of the surface of the deposit to increase and approach the temperature of the flue gas. Given a sufficiently high gas temperature and the presence of sufficient sodium (not all sodium in the ash is "active") to flux the remainder of the fly ash material, a melt phase will begin to form at the leading edge of the deposit. This melt material collects particles that impact on the deposit and binds them together into a strong bulk deposit which is designated the outer sinter layer. Sodium compounds provide the continuous melt phase that binds the deposit, while a deficiency in sodium yields a discontinuous melt and weaker bonding (which can be broken up).

Corrosion is generally caused by oxides of sulfur (which become sulfuric acid in the presence of moisture), but another important corrosion source is buildup of tube deposits that destroy the protective surface oxide coating, due to attack by sulfates of sodium, aluminum, iron, and potassium. Since the dew point can be as high as 120 to 150°C (250 to 300°F), cooler surfaces are subjected to acid attack.

Originally, coal-ash corrosion was believed to be confined to boilers burning high alkali coals. However, combustors burning medium to low alkali coals also encounter the same problem. In cases where there was no corrosion, either the complex sulfates were absent or the tube wall temperatures were below 595°C (1100°F).

Generally, sufficient sulfur and alkali are present in all bituminous coals to produce corrosive ash deposits on superheater and reheater tubes. In addition, coal containing more than 3.5% w/w sulfur and 0.25% w/w chlorine can be exceptionally difficult to handle and the rate of corrosion is greatly affected by the deposit temperature and metal skin temperature.

14.6.1.1 Fly Ash

Fly ash (often referred to as *particulate matter*) is a fine powder that is collected from the combustion gases of coal-fired power plants with electrostatic precipitators and/or baghouses. Fly ash particles are very fine, mostly spherical and vary in diameter but the typical particle size is considered to be on the order of 10 microns but can vary from <1 micron to over 150 microns.

Typically, fly ash is a heterogeneous material, especially upon the micrometer scale and this heterogeneity is reflected in variability of the bulk physical and chemical properties. Such heterogeneity needs to be taken into account when considering options for utilization options or the likely environmental impact of ash disposal. The variability of fly ash is controlled by the following factors: (i) the nature of the coal feedstock – rank mineral matter chemistry and mineralogy, (ii) the design of the furnace, (iii) the operation of the furnace, (iv) the method of control of particulate matter emissions – such as electrostatic precipitator or bag filters, and (v) the control technologies for sulfur oxide and nitrogen oxide emissions. Of the physical properties particle size is one of the most important characteristics especially for utilization in the cement and concrete industry in which particle size determines the ability of the fly ash to fill voids and the workability of the resultant mix.

With respect to the chemical properties of fly ash, loss on ignition is one of the most significant parameters due to the deleterious effect of high loss on ignition levels (assuming that loss on ignition is a reflection of the level of unburned carbon present in the ash). Although maximum permissible levels may be set for the major elements it is often difficult to relate the values to performance apart from those chemical species (such as alkali and sulfite) known to have an adverse effect and it appears that the major chemical analysis of significance is the free lime content for fly ashes destined for cement use.

Coal-fired facilities generate the largest quantity of ash; gas facilities generate so little that separate ash management facilities are not necessary. Fly ash and bottom ash may be managed separately or together in landfills or in wet surface impoundments.

Coal combustion and coal gasification processes release fly ash (which contains toxic metal species) into the atmosphere (Chapters 7, 8, 9, 10) (Adriano *et al.*, 1980; Fisher and Natusch, 1979; Reid, 1981; Speight, 2013). In the current context, the United States Clean Air Act requires that fly ash be removed from combustion and gasification coal emissions and, as a result, antipollution devices such as air baghouses and electrostatic precipitators are used to trap these pollutants.

The removal of fly ash from combustion effluent streams is as important to the environment as the removal of sulfur oxides and nitrogen oxides (Senapati, 2011). If not removed, the inorganic constituents and the organic constituents of the ash can cause serious environmental consequences, in addition to the solid particles acting as condensation nuclei and (catalytic) surfaces for the conversion of sulfur dioxide to the trioxide.

Emission of particulate matter emissions from coal-fired boilers depend primarily on the mineral matter content of the fuel as well as the mineral type, firing mechanism, and boiler load. Stokers generally have lower emissions of particulate matter than pulverized coal systems because the coal is burned on a bed, which leads to less entrainment of particulate matter than occurs in suspension firing. Small natural draft units have lower emissions of particulate matter due to relatively lower flow rates of the under-fire air rates whereas larger units equipped with forced draft fans can (and often do) produce high rates of particulate emissions, especially when operating at or near rated capacity.

Firing coals with higher ash-producing propensity generally results in higher emissions of particulate matter emissions. Particulate emissions from stoker units will also be higher if fly ash collected by mechanical collectors is reinjected into the furnace; emissions from all stokers will increase during soot-blowing operations.

Coals with higher ash fusion temperatures, such as anthracite, are generally fired in dry-bottom units which emit higher levels of particulate matter than do wet-bottom boilers. The emission levels of particulate matter from coal-fired boilers also depend on boiler load. Traveling grate stokers emit coarser particles than do underfeed stokers and pulverized coal-fired units. Hence, emissions of particulate matter less than 10 microns (PM_{10}) will also be lower for the former unit relative to the latter units.

Using anthracite as an example, fly ash emissions (particulate matter emissions) from the combustion of anthracite are a function of furnace firing configuration, firing practices (such as boiler load, quantity and location of under-fire air, soot blowing, and fly ash reinjection), and the ash content of the coal. Pulverized coal-fired units (Chapter 8) or coal gasification reactors (Chapter 10) tend to emit the highest quantity of particulate matter per unit of coal fuel because such combustors convert the coal in suspension, which results in a high percentage of ash carryover into exhaust gases. On the other hand, in terms of combustion reactors, traveling-grate stokers (Chapter 8) produce less particulate matter per unit of fuel fired, and coarser particulates, because combustion takes place in a quiescent fuel bed without significant ash carryover into the exhaust gases. In general, particulate emissions from traveling-grate stokers will increase during soot blowing and fly ash reinjection and with higher fuel bed underfeed air flow rates.

Baghouses simulate the operation of a vacuum cleaner by drawing coal emissions through large fabric bags that trap the fly ash inside. *Electrostatic precipitators* use discharge electrodes (electrically charged parts of an electric circuit) to trap ash particles. In an electrostatic precipitator the electrodes are located between long, positively charged collection plates. As the fly ash passes between the collector plates, the discharge electrodes give each particle a negative charge and the negatively charged particles are then attracted to, and held by, the positively charged collection plates.

The *furnace sorbent injection process* removes acid gas from coal emissions at less cost than expensive scrubbers (Speight, 2013). In this process a highly absorbent material (such as powdered limestone, $CaCO_3$) is injected into the boilers, where the limestone reacts with the acid gases emitted the combustion process. The used powder is siphoned away through the boiler outtake and is captured (with fly ash) in a baghouse or electrostatic precipitator.

The *advanced flue-gas desulfurization* process also removes acid gas from burning coal without expensive scrubbers (Speight, 2013). Emissions from burning coal are piped into an *absorber*, where the acid gases react with an absorbing solution (such as a mixture of lime, water, and oxygen). This reaction forms gypsum ($CaSO_4$), a soft white mineral valuable as an ingredient in cement.

Fly ash effluents escaping from power plants and being emitted into the atmosphere are further contaminated with trace elements suspended on the fly ash particles. The degree of contamination is relative to the variety of elements present in the coal substance derived from transformation processes which occurred before, during, and after coalification (Chapters 1, 2) and then during the high temperature processes in the combustor or gasifier (Chapters 8, 10) (Chadwick *et al.*, 1987; Speight, 2013).

Pollution control techniques are well established in order to efficiently collect effluent particulates. These include mechanical cyclone collectors, electrostatic precipitators and fabric filters or baghouses, and wet scrubbers. Only electrostatic precipitators and fabric filters are able to carry out the collection of particles with an overall efficiency of 99.5% or more, so meeting the strict emission standards economically. Effluent particles are valuable in certain sectors of industry – they can be used as a lightweight engineering fill material to stabilize soil and as a road sub-base. When appropriately added to concrete mix, fly ash yields a stronger and more durable concrete than that produced by regular Portland cement.

Controls on anthracite-fired boilers have mainly have been applied to reduce emissions of particulate matter. The most efficient particulate controls – fabric filters (baghouses), electrostatic precipitators, and scrubbers – have been installed on large pulverized anthracite-fired boilers. In fabric filters, particulate-laden dust passes through a set of filters mounted inside the collector housing. Dust particles in the inlet gas are collected on the filters by inertial impaction, diffusion, direct interception, and sieving. The collection efficiency of a fabric filter unit for a coal-fired boiler is typically in excess of 99%.

The properties of fly ash vary with the type of coal used, grinding equipment, the furnace and the combustion process itself. Fly ash is classified into two categories – Class F and Class C fly ash (ASTM C618). Combustion of bituminous or anthracite usually produces

Class F (low calcium) fly ash and combustion of lignite or subbituminous coal normally produces Class C (high calcium) fly ash.

Although the standard test method (ASTM C618) does not differentiate fly ash by CaO content, Class C fly ash generally contains more than 15% w/w calcium oxide (CaO), and Class F fly ash normally contains less than 5% w/w (CaO). In addition to Class F and Class C fly ash, a third class of mineral admixture is defined (ASTM C618) – Class N. Class N mineral admixtures are raw or natural pozzolans such as diatomaceous earths, opaline chert and shale, volcanic ash or pumicite, and various other materials that require calcination to induce pozzolanic or cementitious properties, such as some shale and clay minerals.

Class C fly ash has been widely used for soil stabilization. It can be incorporated into the soil by disking or mixing. Fly ash can increase the subgrade support capacity for pavements and increase the shear strength of soils in embankment sections when proportioned, disked and compacted properly.

All fly ash is pozzolanic and Class C fly ash is also cementitious – it reacts with calcium hydroxide produced by the hydration of cement in the presence of water to form additional cementitious compounds. Class C fly ash has been successfully utilized in reconstructing and/or upgrading existing pavements. In this process, commonly known as cold-in-place recycling (CIR) or full depth reclamation (FDR), existing asphalt pavement is pulverized with its base, and the pulverized mixture is stabilized by the addition of fly ash and water. The cementitious and pozzolanic properties of fly ash enhance the stability of the section. Fly ash recycled pavement sections have structural capacities substantially higher than crushed stone aggregate base. A new asphaltic concrete wearing surface is then installed above the stabilized section.

Cements blended with fly ash are becoming more common. Building material applications range from grouts and masonry products to cellular concrete and roofing tiles. Many asphaltic concrete pavements contain fly ash. Geotechnical applications include soil stabilization, road base, structural fill, embankments and mine reclamation. Fly ash also serves as filler in wood and plastic products, paints and metal castings.

14.6.1.2 Bottom Ash

The coal combustion process also generates bottom ash, which is second in volume to the fly ash. In fact, the most common type of coal-burning furnace in the electric utility industry is the dry bottom pulverized coal boiler. When pulverized coal is burned in a dry, bottom boiler, approximately 80% w/w of the unburned material or ash is entrained in the flue gas and is captured and recovered as *fly ash*. The remaining 20% of the ash is dry *bottom ash*, which is collected in a water-filled hopper at the bottom of the furnace. When a sufficient amount of bottom ash drops into the hopper, it is removed by means of high-pressure water jets and conveyed by sluiceways either to a disposal pond or to a decant basin for dewatering, crushing, and stockpiling for disposal or use.

Bottom ash is a dark gray black or brown granular, porous, predominantly sand size material, predominantly sand size minus 12.7mm (0.5 inch) material. The characteristics of the bottom ash depend on the type of furnace used to burn the coal, the variety of coal, the transport system (wet or dry), and whether the bottom ash is ground prior to transport and storage.

The most common type of coal-fired furnace in the electric utility industry is the dry bottom pulverized coal boiler. When pulverized coal is burned in a dry bottom boiler, approximately

80% of the unburned material or ash is entrained in the flue gas and is captured and recovered as fly ash. The remaining 20% of the unburned material is dry bottom ash, a porous, glassy, dark gray material with a grain size similar to that of sand or gravelly sand.

Although similar to natural fine aggregate, bottom ash is lighter and more brittle and has a greater resemblance to cement clinker. Bottom ash is collected at the bottom of the combustion chamber (Chapter 8) or gasification reactor (Chapter 10) in a water-filled hopper and is removed by means of high-pressure water jets and conveyed by sluiceways to a decanting basin for dewatering followed by stockpiling and possibly crushing.

Bottom ash is agglomerated ash particles, formed in pulverized coal furnaces that are too large to be carried in the flue gases and impinge on the furnace walls or fall through open grates to an ash hopper at the bottom of the furnace. Physically, bottom ash is typically grey to black in color, is quite angular, and has a porous surface structure.

Bottom ash is coarse, with grain sizes spanning from fine sand to fine gravel. Bottom ash can be used as a replacement for aggregate and is usually sufficiently well-graded in size to avoid the need for blending with other fine aggregates. The porous surface structure of bottom ash particles make this material less durable than conventional aggregates and better suited for use in base course and shoulder mixtures or in cold mix applications, as opposed to wearing surface mixtures. This porous surface structure also makes this material lighter than conventional aggregate and useful in lightweight concrete applications.

Bottom ash has low concentrations of volatile elements, such as mercury, compared to electrostatic precipitator fly ash. It may also contain some unburned coal and/or char fragments. In general, for the pulverized coal-fired power plants the elemental concentrations in bottom ash are lower than that in electrostatic precipitator fly ash for most of the elements. Mineralogy of most bottom ash consists of silicates, with unburned carbon/char contributing only a small fraction (Goodarzi, 2009).

For coal-fired power plants using dry particulate collection devices, such as electrostatic precipitators, it was believed that the most volatile elements (such as mercury and selenium) could actually escape in the elemental state with the flue gas. Wet scrubbers, however, were believed capable of removing most of the elements from the gas streams and transferring them to the liquid effluent.

The material from *flue gas desulfurization* units is the product of a process typically used for reducing sulfur dioxide emissions from the exhaust gas system of a coal-fired boiler. The physical nature of these materials varies from a wet sludge to a dry powdered material depending on the process. The wet sludge from a lime-based reagent wet scrubbing process is predominantly calcium sulfite. The wet product from limestone-based reagent wet scrubbing processes is predominantly calcium sulfate. The dry material from dry scrubbers that is captured in a baghouse consists of a mixture of sulfites and sulfates. This powdered material is referred to as dry flue gas desulfurization ash, dry flue gas desulfurization material, or lime spray dryer ash. Flue gas desulfurization gypsum consists of small, fine particles.

Calcium sulfite flue gas desulfurization material can be used as an embankment and road base material. Calcium sulfate flue gas desulfurization material, once it has been dewatered, can be used in wallboard manufacturing and in place of gypsum for the production of cement. The largest single market for flue gas desulfurization material is in wallboard manufacturing.

Essentially no particulates from coal combustion should be ejected into the atmosphere; all particulate streams should be collected and either returned to the combustors, where they melt and are removed as slag, or are removed as fly ash. Any eventual dispersion of the elements present depends on the possibility of leaching. The concern, therefore, is to identify elements that may be occurring in the gaseous state.

Among the trace elements present in coal with recognized toxic properties, high-volatility elements (beryllium. mercury, and lead) do not form gaseous-hydrides, will condense on cooling and likely will be almost completely removed by the aqueous condensates formed on gas cooling and/or purification. Arsenic, antimony, and selenium have lower volatility but can form gaseous hydrides, (covalent) hydrides: arsine (AsH_3), stibine (SbH_3), and hydrogen selenide (H_2Se). These however, have stability characteristics which preclude their formation at the temperature and pressure prevailing in the oil/gas plant gasifiers.

Coal waste represents both a groundwater contamination threat and a potential source of energy. Coal ash, which represents a relatively untapped resource for construction materials, is, to a large extent, disposed of in landfills that are in increasingly short supply. By-product use technologies include (i) coal waste reuse in power production to support reclamation of abandoned coal waste piles, and (ii) conversion of coal ash to cement substitutes or additives and construction grade aggregates (United States Department of Energy, 2008).

Bottom ash particles are much coarser than fly ash. The grain size typically ranges from fine sand to gravel in size. The chemical composition of bottom ash is similar to that of fly ash but typically contains greater quantities of carbon. Bottom ash tends to be relatively more inert because the particles are larger and more fused than fly ash. Since these particles are highly fused, they tend to show less pozzolanic activity and are less suited as a binder constituent in cement or concrete products. However, bottom ash can be used as a concrete aggregate or for several other civil engineering applications where sand, gravel and crushed stone are used.

Thus, unlike fly ash, the primary application of bottom ash is as an alternative for aggregates in applications such as sub-base and base courses under rigid and flexible pavements. It has also been used as a coarse aggregate for hot mix asphalt and as an aggregate in masonry products. In these applications, the chemical properties are generally not a critical factor in utilizing bottom ash.

The gradation of bottom ash can vary widely based on the coal pulverization and burning process in the power plant, the variety of coal burned, and the bottom ash handling equipment.

14.6.1.3 Bottom Slag

Bottom slag (also referred to as boiler slag) is often included in the product known as bottom ash. As might be anticipated, the physical and chemical properties of coal gasification slags are found to be related to the composition of the coal feedstock, the method of recovering the molten ash from the gasifier, and the proportion of devolatilized carbon particles (char) discharged with the slag. The rapid water-quench method of cooling the molten slag inhibits recrystallization, and results in the formation of a granular, amorphous material. Differences in the properties of the slag samples that can be attributed to the specific design and operating conditions prevailing in the gasifiers.

There are two types of wet-bottom boilers: (i) the slag-tap boiler and (ii) the cyclone boiler. The slag-tap boiler burns pulverized coal and the cyclone boiler burns crushed coal.

In each type, the bottom ash is kept in a molten state and tapped off as a liquid. Both boiler types have a solid base with an orifice that can be opened to permit the molten ash that has collected at the base to flow into the ash hopper below. The ash hopper in wet-bottom furnaces contains quenching water. When the molten slag comes in contact with the quenching water, it fractures instantly, crystallizes, and forms pellets. The resulting boiler slag (often referred to as *black beauty*) is a coarse, hard, black, angular, glassy material.

When pulverized coal is burned in a slag-tap furnace, as much as 50% of the ash is retained in the furnace as boiler slag. In a cyclone furnace, which burns crushed coal, some 70 to 80% w/w of the ash is retained as boiler slag, with only 20 to 30% w/w leaving the furnace in the form of fly ash.

Wet-bottom boiler slag is a term that describes the molten condition of the ash as it is drawn from the bottom of the slag-tap or cyclone furnaces. At intervals, high-pressure water jets wash the boiler slag from the hopper pit into a sluiceway which then conveys it to a collection basin for dewatering, possible crushing or screening, and either disposal or reuse.

Boiler slag is predominantly single-sized and within a range of 0.2 to 0.02 inch 0.5 to 5.0 mm). Generally, boiler slag particles have a smooth texture, but if gases are trapped in the slag as it is tapped from the furnace, the quenched slag will become somewhat vesicular or porous. Boiler slag from the combustion of lignite or subbituminous coal tends to be more porous than boiler slag from the combustion of that of bituminous coal. Compared to natural granular materials, the maximum dry density values of boiler slag are from 10 to 25% lower; while the optimum moisture content values are higher. The chemical composition of boiler slag is similar to that of bottom ash, although the production process for boiler slag and for bottom ash are relatively different. Generally, the elemental composition of the slag with respect to both major and trace elements is similar to that of the gasifier feed coal ash. The major constituents of most coal ashes are silica, alumina, calcium, and iron. Slag fluxing agents, when used to control molten ash viscosity inside the gasifier, can result in an enrichment of calcium in the slag.

Boiler slag has been frequently used in hot mix asphalt because of its hard durable particles and resistance to surface wear. It can also be used as asphalt wearing surface mixtures because of its affinity for asphalt and its dust-free surface, increasing the asphalt adhesion and anti-stripping characteristics. Since boiler slag has a uniform particle size, it is usually mixed with other size aggregates to achieve the target gradation used in hot mix asphalt. Boiler slag has also been used very successfully as a seal coat aggregate for bituminous surface treatments to enhance skid resistance.

The physical characteristics of bottom ash and boiler slag lend themselves as replacements for aggregate in flowable fill and in concrete masonry products. Boiler slag is also used for roofing granules and as blasting grit.

Discarded bottom ash and boiler slag are either landfilled or sluiced to storage lagoons. When sluiced to storage lagoons, the bottom ash or boiler slag is usually combined with fly ash. This blended fly ash and bottom ash or boiler slag are referred to as ponded ash. Approximately 30% w/w of all coal ash is handled wet and disposed of as ponded ash.

Ponded ash is potentially useable, but variable in its characteristics because of its manner of disposal. Because of differences in the unit weight of fly ash and bottom ash or boiler slag, the coarser bottom ash or boiler slag particles settle first and the finer fly ash remains in suspension longer. Ponded ash can be reclaimed and stockpiled, during which time it can be dewatered. Under favorable drying conditions, ponded ash may be dewatered into a range of moisture that will be within the vicinity of its optimum moisture content. The higher the percentage of bottom ash or boiler slag there is in ponded ash, the easier it is to dewater and the greater the potential for water reuse. Reclaimed ponded ash has been used in stabilized base or sub-base mixes and in embankment construction, and can also be used as fine aggregate or filler material in flowable fill.

14.6.1.4 Properties and Uses of Ash and Slag

Bottom ash is typically composed of angular particles with a very porous surface texture. Bottom ash particles range in size from fine gravel to fine sand and have a low percentage of silt-clay sized particles. The ash is usually a well-graded material, although variations in particle size distribution may be encountered in ash samples taken from the same power plant at different times. Bottom ash is predominantly sand-sized, usually with 50 to 90% passing a 4.75 mm (No. 4) sieve, 10 to 60% passing a 0.42 mm (No. 40) sieve, 0 to 10% passing a 0.075 mm (No. 200) sieve, and a top size usually ranging from 0.75 inch (19 mm to 1.5 inches (38.1 mm).

Boiler slag is predominantly single-sized and within a range of 5.0 to 0.5 mm (No. 4 to No. 40 sieve). Ordinarily, boiler slags have a smooth surface texture, but if gases are trapped in the slag as it is tapped from the furnace, the quenched slag will become somewhat vesicular or porous. Boiler slag from the burning of lignite or subbituminous coal tends to be more porous than that of the eastern bituminous coal. Boiler slag is essentially a coarse to medium sand with 90 to 100% passing a 4.75 mm (No. 4) sieve, 40 to 60% passing a 2.0 mm (No. 10) sieve, 10% or less passing a 0.42 mm (No. 40) sieve, and 5% or less passing a 0.075 mm (No. 200) sieve. The specific gravity of the dry bottom ash is a function of chemical composition, with higher carbon content resulting in lower specific gravity. Bottom ash with a low specific gravity has a porous or vesicular texture, a characteristic of popcorn particles that readily degrade under loading or compaction.

Bottom ash and boiler slag are composed principally of silica, alumina, and iron, with smaller percentages of calcium, magnesium, sulfates, and other compounds. The composition of the bottom ash or boiler slag particles is controlled primarily by the source of the coal and not by the type of furnace.

Bottom ash or boiler slag derived from lignite or subbituminous coals has a higher percentage of calcium than the bottom ash or boiler slag from anthracite or bituminous coals. The sulfate content is very low (less than 1.0% w/w), unless pyrites have not been removed from the bottom ash or boiler slag.

Due to the salt content and, in some cases, the low pH of bottom ash and boiler slag, these materials could exhibit corrosive properties. When using bottom ash or boiler slag in an embankment, backfill, sub-base, or even possibly in a base course, the potential for corrosion of metal structures that may come in contact with the material is of concern and should be investigated prior to use.

Tests to evaluate the corrosive nature of bottom ash or boiler slag are pH, electrical resistivity, soluble chloride content, and soluble sulfate content. Materials are judged to be noncorrosive if the pH exceeds 5.5, the electrical resistivity is greater than 1,500 ohm-centimeters, the soluble chloride content is less than 200 parts per million (ppm), or the soluble sulfate content is less than 1,000 parts per million (ppm).

The maximum dry density values of bottom ash and boiler slag are usually from 10 to 25% lower than that of naturally occurring granular materials. The optimum moisture content values of bottom ash and boiler slag are both higher than those of naturally occurring granular materials, with bottom ash being considerably higher in optimum moisture content than boiler slag.

Boiler slag usually exhibits less abrasion loss and soundness loss than bottom ash because of its glassy surface texture and lower porosity. In some power plants, coal pyrites are disposed of with the bottom ash or boiler slag. In such cases, some pyrite or soluble sulfate is contained in the bottom ash or boiler slag, which may be reflected in higher sodium sulfate soundness loss values.

Most electric utility companies do not handle, dispose of, or sell the ash that is produced in the coal-fired units. Instead, management of bottom ash or boiler slag is contracted out to ash marketing firms or to local hauling contractors. In addition to commercial ash marketing organizations, certain coal-burning electric utility companies have a formal ash marketing program of their own. Most coal-burning electric utility companies currently employ an ash marketing specialist, who is responsible for monitoring ash generation, quality, use or disposal, and for interfacing with the ash marketers or brokers who are under contract to the utility companies.

Both bottom ash and boiler slag have been used as fine aggregate substitute in hot mix asphalt wearing surfaces and base courses, and emulsified asphalt cold mix wearing surfaces and base courses. Because of the low durability nature of some bottom ash particles, bottom ash has been used more frequently in base courses than wearing surfaces. Boiler slag has been used in wearing surfaces, base courses and asphalt surface treatment or seal coat applications.

Screening of oversized particles and blending with other aggregates will typically be required to use bottom ash and boiler slag in paving applications. Pyrite, which may be present in the bottom ash should also be removed (with electromagnets) prior to use. Pyrites (iron sulfide) are volumetrically unstable, expansive, and produce a reddish stain when exposed to water over an extended time period.

Both bottom ash and boiler slag have occasionally been used as unbound aggregate or granular base material for pavement construction. Bottom ash and boiler slag are considered fine aggregates in this use. To meet required specifications, the bottom ash or slag may need to be blended with other natural aggregates prior to its use as a base or sub-base material. Screening or grinding may also be necessary prior to use, particularly for the bottom ash, where large particle sizes, typically greater than 19 mm (0.75 inch), are present in the ash.

Bottom ash and boiler slag have been used in stabilized base applications. Stabilized base or sub-base mixtures contain a blend of aggregate and cementitious materials that bind the aggregates, providing the mixture with greater bearing strength. Types of cementitious materials typically used include Portland cement, cement kiln dust, or pozzolans with activators, such as lime, cement kiln dusts, and lime kiln dusts. When constructing a stabilized base using either bottom ash or boiler slag, moisture control and proper sizing are required and deleterious materials such as pyrite should also be removed.

Bottom ash and ponded ash have been used as structural fill materials for the construction of highway embankments and/or the backfilling of abutments, retaining walls, or trenches. These materials may also be used as pipe bedding in lieu of sand or pea gravel.

To be suitable for these applications, the bottom ash or ponded ash must be at or reasonably close to its optimum moisture content, free of pyrites and/or honeycomb-type clinker, and must be non-corrosive. Reclaimed ponded ash must be stockpiled and adequately dewatered prior to use. Bottom ash may require screening or grinding to remove or reduce oversize materials (>0.75 inch, >19 mm in size).

Bottom ash has been used as an aggregate material in flowable fill mixes. Ponded ash also has the potential for being reclaimed and used in flowable fill. Since most flowable fill mixes involve the development of comparatively low compressive strength (in order to be able to be excavated at a later time, if necessary), no advance processing of bottom ash or ponded ash is needed. Neither bottom ash nor ponded ash needs to be at any particular moisture content to be used in flowable fill mixes because the amount of water in the mix can be adjusted in order to provide the desired flow characteristics.

14.6.2 Flue Gas Desulfurization Waste

Briefly, flue gas desulfurization (FGD) is a chemical process to remove sulfur oxides from the flue gas at coal-burning power plants (Speight, 2013). Many methods have been developed to varying stages of applicability and the goal of these processes is to chemically combine the sulfur gases released in coal combustion by reacting them with a sorbent, such as limestone (calcium carbonate, $CaCO_3$), lime (calcium oxide, CaO), or ammonia (NH_3) (Speight, 2013).

In the process, the flue gas emerges from the combustor/boiler and is contacted with the slurry of calcium salts, sulfur dioxide (SO_2) reacts with the calcium to form hydrous calcium sulfate (gypsum, $CaSO_4.2H_2O$).

Another flue gas desulfurization method uses ammonia (NH_3) as the sorbent; the flue gas desulfurization product is ammonium sulfate [$(NH_4)_2SO_4$)]. Sulfate is the preferred form of sulfur readily assimilated by crops, and ammonium sulfate is the ideal sulfate compound for soil supplements because it also provides nitrogen from the ammonium. The use of ammonium sulfate in large-scale fertilizer formulations has been growing gradually. This growth provides a market for flue gas desulfurization products and could make flue gas desulfurization processes based on ammonia attractive alternatives to the processes based on lime and limestone (Mokhatab *et al.*, 2006; Speight, 2013, 2014).

Flue gas desulfurization material is the solid material resulting from the removal of sulfur dioxide gas from the utility boiler stack gases in the flue gas desulfurization process. The material is produced in the flue gas scrubbers by reacting slurried limestone ($CaCO_3.H_2O$) or lime (CaO) with the gaseous sulfur dioxide to produce calcium sulfite ($CaSO_3$), which can be further oxidized to synthetic gypsum (calcium sulfate, $CaSO_4$). The dewatering system removes water from the calcium sulfate or synthetic gypsum slurry leaving the flue gas desulfurization absorber modules using centrifuges or belt filter presses. A belt conveyor system transports the dewatered materials from the dewatering building to an adjacent storage shed.

The wet lime/limestone scrubbers produce a slurry of ash, unreacted lime, calcium sulfate, and calcium sulfite. Dry scrubber systems produce a mixture of unreacted sorbent (e.g., lime, limestone, sodium carbonates, calcium carbonates), sulfur salts, and fly ash. Furthermore, depending on the type of process and sorbent used, 20 to 90% w/w of the available sulfur can be calcium sulfite with the remaining portion being calcium sulfate.

Flue gas desulfurization material with high concentrations of sulfite pose a dewatering problem. Sulfite sludge settles poorly and filters poorly and is thixotropic – a thixotropic material appears as a solid, but will liquefy when vibrated or agitated. High sulfite flue gas desulfurization material is generally not suitable for either use or disposal without treatment. Treatment can include forced oxidation, dewatering, and/or fixation or stabilization.

In IGCC facilities (Chapters 8, 9, 14), the sulfur-containing gases from the acid gas removal system are converted to elemental sulfur or sulfuric acid (H_2SO_4). Sulfur dioxide combines with oxygen and water to form sulfuric acid; the reaction of hydrogen sulfide and sulfur dioxide forms water and elemental sulfur. Either elemental sulfur or sulfuric acid would be suitable for sale to other industries for various process uses. If elemental sulfur is produced, a storage tank would be provided to hold molten sulfur until it could be transferred to railcars for shipment off-site.

Sulfur can be used in bituminous mixtures, sulfur-concrete, and in the manufacture of fertilizer, paper, etc. If sulfuric acid is produced, above-ground storage tanks are constructed to temporarily hold the acid until it is transported off site by specially designed rail cars or trucks for commercial use, such as wastewater treatment or the production of phosphate fertilizer.

Sludge is typically stabilized with fly ash and sludge produced in a wet scrubber may be disposed of in impoundments or below-grade landfills, or may be stabilized and disposed of in landfills. Dry scrubber sludge may be managed dry or wet.

14.6.3 Waste Heat

The electrical efficiency of a coal-fired power plant is the ratio between the input and output energy – it is typically only 30% and waste hear is heat that is lost to the environment which may otherwise have been used to advantage.

All thermal power plants produce waste heat energy as a by-product of the useful electrical energy produced. The amount of waste heat energy equals or exceeds the amount of electrical energy produced. Gas-fired power plants can achieve 50% conversion efficiency while coal and oil plants achieve around 30 to 45%. The waste heat produces a temperature rise in the atmosphere which is small compared to that of greenhouse-gas emissions from the same power plant.

Wherever the waste heat is available at medium or high temperatures, a waste heat boiler can be installed economically. Wherever the steam demand is more than the steam generated during waste heat, auxiliary fuel burners are also used. If there is no direct use of steam, the steam may be let down in a steam turbine-generator set and power produced from it. It is widely used in the heat recovery from exhaust gases from gas turbines and diesel engines.

Natural draft wet cooling towers at many coal power plants use large hyperbolic chimney-like structures that release the waste heat to the ambient atmosphere by the evaporation of water. However, the mechanical induced-draft or forced-draft wet cooling towers in many large thermal power plants use fans to provide air movement upward through down-coming water and are not hyperbolic chimney-like structures. The induced or forced-draft cooling towers are typically rectangular, box-like structures filled with a material that enhances the contacting of the up-flowing air and the down-flowing water.

In areas with restricted water use a dry cooling tower or radiator, directly air cooled, may be necessary, since the cost or environmental consequences of obtaining makeup water for evaporative cooling would be prohibitive. These have lower efficiency and higher energy consumption in fans than a wet, evaporative cooling tower.

Where it is economically and environmentally possible, electric companies prefer to use cooling water from the ocean, or a lake or river, or a cooling pond, instead of a cooling tower. This type of cooling can save the cost of a cooling tower and may have lower energy costs for pumping cooling water through heat exchangers. However, the waste heat can cause the temperature of the water to rise detectably. Power plants using natural bodies of water for cooling must be designed to prevent intake of organisms into the cooling cycle. A further environmental impact would be organisms that adapt to the warmer plant water and may be injured if the plant shuts down in cold weather.

14.7 The Future

Coal combustion produces large amounts of residual material (waste material) and there is a strong impetus to use these waste materials for bulk utilization applications such as agricultural amendments, in construction of roads, and in the manufacture of bricks. To achieve the maximum utilization of coal combustion residues in diverse applications it is necessary to know as much information as possible related to the various properties of coal. An insight into physical properties of coal combustion residues is necessary in order to apply the waste materials (for example, fly ash) in a variety of construction and geotechnical applications (Ferraiolo *et al.*, 1990; Mishra, 2004).

In terms of health effects, despite the best efforts at prevention, electricity production by coal-fired power plants can cause the production of particulate matter (PM) as well as gases that undergo chemical reactions to form fine particles in the atmosphere, such as sulfur oxides (SOx) and nitrogen oxides (NOx) (Chapter 12). If allowed to escape into the atmosphere, as is often the case in less-developed countries, these emissions increase the increased incidence of related cardiopulmonary diseases, lung cancer, and numerous other respiratory illnesses (Cohen *et al.*, 2005; Pope, 2000; Pope *et al.*, 2002; Penney *et al.*, 2009).

As a result, most new power plants are equipped with pollution controls, such as electrostatic precipitators (ESPs), fabric filters, and flue-gas desulfurization (FGD) (Chapter 12), although such equipment may be relatively rare in the less-developed countries. When utilized on plants that otherwise do not remove large amounts of sulfur from their emissions (e.g., through coal fluidized-bed techniques), flue gas desulfurization technologies can reduce sulfur dioxide emissions by 90%, resulting in substantial human health risk reductions.

In addition, there is a wide scope for improvement of the technologies used for coal-fired power generation – more specifically for improving conversion efficiency – since any gains would translate into substantial reduction in carbon dioxide emissions as well as coal savings. For example, and very generally, each percentage point efficiency increase is equivalent to approximately 2.5% v/v reduction of carbon dioxide emissions. Power plant efficiency is therefore a major factor that could be used to reduce global emissions of carbon dioxide.

The technologies used to generate electricity from coal can be categorized based on the type of coal used, the technology of conversion of the chemical energy of the coal thermal energy (conventional thermal/fluidized bed/internal combustion or gasification), the type of turbine used (gas turbine or steam turbine) and the generated steam conditions. The heat is used to generate high-pressure steam that passes through a turbine to generate electricity. In the gas turbine the produced hot exhaust gases pass through the turbine to generate electricity. More advanced systems include a combination of both – in a combined cycle system the coal is first combusted in a combustion turbine, using the heated exhaust gases to generate electricity. After these exhaust gases are recovered, they heat water in a boiler, creating steam to drive a second turbine. Apart from combustion, coal can also be gasified to produce synthesis gas, which can be directly used as a fuel for power generation. Alternatively, the hydrogen can be separated and used as a fuel in an open or combined cycle process.

The main fossil coal-fired electricity generation technology is combustion of pulverized coal combustion and the majority of these plants are decades old and operate with sub-critical steam. Upgrading low-efficiency coal plants should be a high priority in the future. Supercritical plants with steam conditions typically of 540°C (1005°F) and 3500 psi have been in commercial operation for a number of years. However, it is estimated that advanced supercritical plants with steam conditions up to 600°C (1110°F) and 4400 psi are making it possible to reach higher efficiency. Reaching these steam conditions demands successive reheating cycles and stronger and more corrosion resistant (and higher cost) steel. The overall efficiency could offset the additional cost and on-site energy consumption (Bugge *et al.*, 2006; Beer, 2007).

For combustion, fuel flexibility (i.e., using different types of coal and coal mixed with biomass and/or refuse) seems to be best achieved using fluidized-bed systems which offer at least 45% efficiency, with very low NOx emissions and easy in-bed capture of sulfur. High temperature entrained flow gasification increases the gasification rate, allowing better matching with high-capacity gas turbines that achieve high efficiency by avoiding the potential problems that can arise from the formation of tarry products and. Further into the future, IGCC with hybrid fuel cells, gas turbines and steam turbines could conceivably reach 60% efficiency with zero emissions.

In pre-combustion and post-combustion capture, it is the carbon dioxide that is removed from a mixture of gases.

However, post-combustion scrubbing is less efficient, but it allows the plant to operate as a conventional facility if there are technical difficulties with the CO2 scrubbers. The oxy-fuel process (Chapter 12) facilitates post-combustion carbon dioxide scrubbing by enriching the oxygen content of the combustion air, reducing the volume that must be scrubbed per unit volume (or unit weight) of carbon dioxide. Pre-combustion scrubbing typically involves combining carbon dioxide capture with the gasification process in an IGCC plant (Chapter 12), which is more efficient but makes the functioning of the plant dependent on the reliability of carbon dioxide capture equipment.

In particular, IGCC could become a dominant technology in the power industry because of the following advantages: (i) the ability to handle almost any carbonaceous feedstock, (ii) the ability to efficiently clean up product gas to achieve near-zero emissions of criteria pollutants, particulates, and mercury at substantially higher efficiency, (iii) the flexibility to divert some synthesis gas to uses other than turbine fuel for load following applications, (iv) the high efficiency because of the use of both gas turbine and steam turbine cycles, (v) the ability to cost-effectively recover carbon dioxide for sequestration, if required, (vi) the ability to produce pure hydrogen if desired, (vii) a substantial (>50%) reduction in the production of solid by-products, and (viii) a substantial reduction in water usage and consumption.

In the oxy-fuel case (Chapter 12), on the other hand, it is water and non-condensable gases that are removed from the carbon dioxide-rich stream. Fractions of carbon dioxide may be dissolved in the water as it is condensed out from the carbon dioxide-rich exhaust, and some more carbon dioxide may be lost during the process of removal of non-condensable gases. Nevertheless, almost all of the carbon dioxide will be captured, and if deemed desirable, there may be a possibility for co-capture of other pollutants, mainly sulfur dioxide. Should co-capture not be possible, the absence of bulk nitrogen in the flue gas results in a smaller gas volume and the equipment for flue-gas desulphurization (FGD) and nitrogen oxide removal (deNOx) (Chapter 12) will not be required to the same extent as for an air-fired power plant.

Furthermore, water-soluble acidic pollutants will be dissolved in the water condensed from the process and not emitted to the atmosphere, which may very well be the case in atmospheric coal-fired boilers. The cleaning of the condensed water can be done with methods already commercially available. Also the particles that remain in the flue gas after the particle removal unit will to a large part be removed with the flue gas condensation. Altogether, with careful design, the oxygen/carbon dioxide recycle combustion power plant may offer a possibility for zero-emission or close-to-zero-emission not only of carbon dioxide but also of other harmful substances.

Fuel flexibility is becoming increasingly important as fuel resources are depleted and costs can fluctuate significantly over the life of a power plant. Substantial efforts have been made to use alternative fuels in pulverized coal power plants. In recent years this has been driven mainly by the need to increase power generation from renewables and so biomass has been widely used in amounts typically up to 5% energy input. Markets for trade in biomass for cofiring are not yet mature and as a consequence feedstock costs can vary widely in a relatively short space of time. The impact of biomass cofiring on power generation efficiency is very small within the low range of inputs of biomass currently used. There is an additional cost for preparation of the biomass (milling) for injection into pulverized coal plants (direct cofiring). Indirect cofiring via a pre-gasification step followed by injection of a product gas (rich in carbon monoxide and hydrogen) into the coal boiler is not yet commercial, although there have been large-scale demonstrations.

The main technology challenge by far on the immediate horizon is the introduction of carbon capture and sequestration (Adams, 2009). In the near future, the plants that have to comply with emissions trading systems may consider implementing carbon dioxide capture and storage technologies, but at a cost. Retrofitting existing coal-fired power plants to capture carbon dioxide is an important greenhouse gas mitigation option for the United States. Also, retrofitting utilizes the base power plant and related infrastructure and so the cost and level of disruption could be less than other greenhouse gas mitigation options (United States Department of Energy, 2011).

In summary, improved combustion and air quality control technologies are enhancing the environmental acceptability of coal though technology know-how which enables plant operators to navigate the complex development and construction hurdles inherent to coal projects.

Finally, the beneficial use of coal combustion products involves the use of or substitution of coal combustion products for another product based on performance criteria (Seshadri *et al.*, 2010). Using coal combustion products can generate significant environmental, economic benefits. Beneficial use include raw feed for cement clinker, concrete, grout, flowable fill, structural fill, road base/sub-base, soil-modification, mineral filler, snow and ice traction control, blasting grit and abrasives, roofing granules, mining applications, wallboard, waste stabilization/solidification, soil amendment, and agriculture.

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PART III

ALTERNATE FEEDSTOCKS AND ENERGY SECURITY

15

Alternate Feedstocks

15.1 Introduction

Coal has been the mainstay of electricity generation for over a century and has seen decades of near-uninterrupted growth. However, although there is considerable coal use in developed countries, including the United States, the European Union, and South Korea, current trends could signal the beginning of the end of the industry. Reduction in use due to environmental issues is likely to continue for some time and the decline in coal use suggests that coal plants will take a significant blow to revenues. Coal also faces competition from renewable energy, where costs have plunged in recent years. Hydroelectricity is the most-used electricity generation source in six states, including Washington and Oregon.

In addition, the end of the widespread production of liquid fuels and other products within the current refinery infrastructure will occur, according to some observers, during the present century, even as early as the next five decades but, as with all projections, this is very dependent upon the remaining reserves and petro-politics (Speight, 2011a; Speight and Islam, 2016). During this time, fossil fuels (including natural gas and crude oil from tight formations) will be the mainstay of the energy scenarios of many countries.

Furthermore, for the right reasons or for the wrong reasons and without much justification but with much speculation, the combustion of fossil fuels is considered as the largest source of anthropogenic emissions of carbon dioxide (CO_2), which is largely blamed for global warming and climate change (Zanganeh and Shafeen, 2007; Speight, 2020a). Although other sources – such as natural sources – play a role in climate change they are often ignored (Speight, 2020b). Nevertheless, having been identified as one of the causative agents of climate change, it is necessary to attempt to mitigate the emissions of carbon dioxide from fossil fuel combustion and to offset the depletion of fossil fuels such as the commonly used natural gas, and crude oil, and coal (Ragland *et al.*, 1991). Coal is the current bad boy of the fossil fuel world but still offers many options for energy production, providing the process gases are cleaned rather than vented to the atmosphere (Speight, 2013a). On the other hand, oil shale has been of lesser importance having received on-again and off-again popularity as a source of fuels but has never really been recognized as a major source of fuels (Scouten, 1990; Lee, 1991, 1996; US DOE, 2004a, 2004b, 2004c).

The most popular energy resources (natural gas and the various members of the crude oil family) are currently on a depletion curve with estimates of the longevity of these resources varying up to 50 years (Speight and Islam, 2016). However, seeking alternate sources of energy is of critical importance for long-term security and continued economic growth. Supplementing crude oil consumption with renewable biomass resources is a first step towards this goal. The realignment of the chemical industry from one of crude oil refining to a refinery solely devoted to providing fuels and chemicals from biomass (frequently

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referred to as a biorefinery), has, in fact, given time and feasibility, become a national goal of many countries that currently rely on imports of crude oil to sustain their energy needs. However, clearly defined goals are necessary for increasing the use of biomass-derived feedstocks for fuel production and for the production of chemicals and it is important to keep the goal in perspective. In this context, the increased use of feedstocks and the production of fuels therefrom should be viewed as one of a range of possible measures for achieving self-sufficiency in energy, rather than a panacea (Demirbaş, 2008, 2009; Speight, 2019a).

As the refining industry evolves even further and, in many cases away from natural gas and crude oil as the major feedstocks, a variety of biomass and waste-derived feedstocks will be used as feedstocks fuels production and this may be no more evident than the use of biofeedstocks for gasifier units. Moreover, gasification is (i) a well-established technology, (ii) has broad flexibility of feedstocks and operation, and (iii) is the most environmentally friendly route for handling these feedstocks for power production. A wide variety of biofeedstocks such as wood pellets, and wood chips, waste wood, plastics, municipal solid waste (MSW), refuse-derived fuel (RDF), agricultural and industrial wastes, sewage sludge, switch grass, discarded seed corn, corn stover and other crop residues will all be used as gasifier feedstocks. In fact, wood is the oldest known biofuel. Burning wood rather than fossil fuels can reduce the carbon dioxide emissions responsible for global climate change. Wood fuel is carbon dioxide (CO_2) neutral. It gives off only as much carbon dioxide when burned as it stores during its lifetime. In addition, wood fuel has low levels of sulphur, a chemical that contributes to acid rain.

This chapter presents an overview of the production of the potential of fuels production and chemicals production from alternate sources (non-fossil fuel sources) in order for the reader to understand the chemical and physical parameters that are involved in the production of alternate fuels. For the purpose of this chapter, the alternate sources of energy are presented: (i) biomass, which includes agricultural crops and wood, and (iii) waste, which includes waste from domestic and industrial sources.

15.2 Viscous Feedstocks

Viscous feedstocks are hydrocarbonaceous materials such as crude oil residua, heavy crude oils, extra heavy oil, tar sand bitumen, and crude oil coke that have low volatility. Thus, by definition, viscous feedstocks are the carbonaceous materials that flow with difficulty under ambient conditions and require heating (typically above 100°C, 212°F) to flow down an inclined (30°) plane. These feedstocks can be found in refineries as non-volatile fraction of crude oil from the distillation section of the refinery or as the non-volatile fraction from various reactors.

15.2.1 Crude Oil Residua

Residua (sing. *residuum*, also shortened to *resid*, pl. *resids*) are the non-volatile residues obtained from crude oil after non-destructive distillation has removed all the volatile materials (Figure 15.1). *Residua* are black, viscous materials that may be liquid or semi-solid at room temperature (generally atmospheric residua) or near-solid or solid (generally vacuum residua) depending upon the nature of the crude oil (Speight, 2014, 2017).

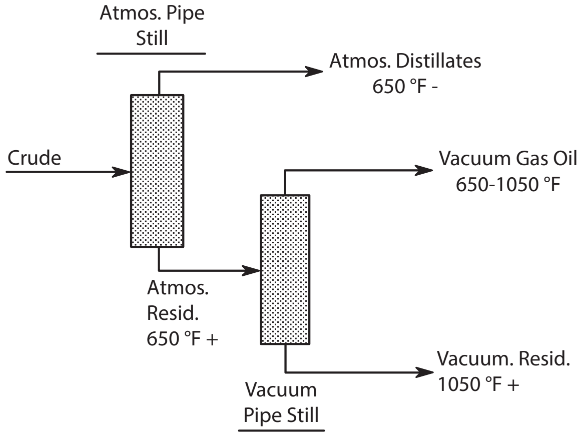


Figure 15.1 Simplified crude oil distillation scheme. Key: pipe still – distillation column.

However, residua can be produced in various types from crude oil (i) the atmospheric residua, typically this fraction is the collection of the constituents of crude oil that boil above 345°C/650°F, and (ii) the vacuum residua, typically this fraction is the collection of the constituents of crude oil that boil above 565°C/1050°F. However, the cut point for both the atmospheric residuum and the vacuum residuum are refinery (and crude oil) dependent. Put simply, the resids contain the majority of the nitrogen-containing, the sulfur-contain constituents, and the metal-containing constituents of the original crude oil which occur predominantly in the higher molecular weight constituents and in ring systems (Speight, 2014, 2017). Also, the atmospheric residua and the vacuum residua from the same crude oil are dissimilar in composition with the vacuum resids continuing higher proportions of the heteroatoms – the difference being in the removal (by distillation under vacuum) (Figure 15.1) of the predominantly hydrocarbon vacuum gas oil (Tables 15.1, 15.2).

In the distillation process, the temperature of the distillation is usually maintained below 350°C (660°F) since the rate of thermal decomposition of crude oil constituents is minimal below this temperature but the rate of thermal decomposition of crude oil constituents is substantial above 350°C (660°F) (Speight, 2014). If the temperature of the distillation unit rises above 350°C (660°F) as happens in certain units where temperatures up to 395°C (740°F) are known to occur, cracking can be controlled by adjustment of the residence time. When a residuum is obtained from crude oil and thermal decomposition has commenced, it is more usual to refer to this product as *pitch*. The differences between conventional crude oil and the related residua are due to the relative amounts of various constituents present, which are removed or remain by virtue of their relative volatility.

The chemical composition of a residuum is complex. Physical methods of fractionation usually indicate high proportions of asphaltenes and resins, even in amounts up to 50% (or higher) of the residuum. In addition, the presence of ash-forming metallic constituents, including such organometallic compounds as those of vanadium and nickel, is also a distinguishing feature of residua and the heavier oils. Furthermore, the deeper the *cut* into the crude oil, the greater is the concentration of sulfur and metals in the residuum and the greater the deterioration in physical properties.

Table 15.1 Properties of various atmospheric (>345°C, >650°F) residua.

Feedstock	**Gravity °API**	**Sulfur wt. %**	**Nitrogen wt. %**	**Nickel ppm**	**Vanadium ppm**	**Asphaltenes* wt. %**	**Carbon residue** wt. %**
Arabian Light (Saudi Arabia)	17.7	3.0	0.2	10.0	26.0	1.8	7.5
Arabian Heavy (Saudi Arabia)	11.9	4.4	0.3	27.0	103.0	8.0	14.0
Alaska, North Slope	15.2	1.6	0.4	18.0	30.0	2.0	8.5
Lloydminster (Canada), >650 F	10.3	4.1	0.3	65.0	141.0	14.0	12.1
Kuwait	13.9	4.4	0.3	14.0	50.0	2.4	12.2
Tia Juana (Venezuela)	17.3	1.8	0.3	25.0	185.0		9.3
Daqing (China)	27.3	0.2	0.2	5.0	1.0	4.4	3.8
Maya (Mexico)	10.5	4.4	0.5	70.0	370.0	16.0	15.0

*Heptane insoluble fraction (ASTM D6560)

**Conradson carbon residue (ASTM D189)

Table 15.2 Properties of various vacuum (>565°C, >1050°F) residua.

Feedstock	Gravity API	Sulfur wt. %	Nitrogen wt. %	Nickel ppm	Vanadium ppm	Asphaltenes (heptane) wt. %	Carbon residue (Conradson) wt. %
Arabian Light (Saudi Arabia)	8.5	4.4	0.5	24.0	66.0	4.3	14.2
Arabian Heavy (Saudi Arabia)	7.3	5.1	0.3	40.0	174.0	10.0	19.0
Alaska, North Slope	8.2	2.2	0.6	47.0	82.0	4.0	18.0
Lloydminster (Canada)	8.5	4.4	0.6	115.0	252.0	18.0	21.4
Kuwait	5.5	5.5	0.4	32.0	102.0	7.1	23.1
Tia Juana (Venezuela)	7.1	2.6	0.6	64.0	450.0		21.6
Daqing (China)	21.5	0.3	0.4	9.0	2.0	7.6	7.9

15.2.2 Extra Heavy Oil and Tar Sand Bitumen

In addition to conventional crude oil and heavy crude oil, there are even more viscous material that offers some relief to the potential shortfalls in supply (Speight, 2014). These resources are often referred to as (i) extra heavy crude oil and (ii) tar sand bitumen.

15.2.2.1 Extra Heavy Oil

The term *extra heavy oil* is a recent addtion to the fossil fuel lexicon and is used to describe materials that occur in the solid or near-solid state in the deposit or reservoir and are generally incapable of free flow under ambient conditions. Whether or not such a material exists in the near-solid or solid state in the reservoir can be determined from the pour point and the reservoir temperature. Extra heavy oil is a nondescript term (related to viscosity) of little scientific meaning that is usually applied to tar sand bitumen-like material. The general difference is that extra heavy oil, which may have properties similar to tar sand bitumen in the laboratory but, unlike immobile tar sand bitumen in the deposit, has some degree of mobility in the reservoir or deposit such as the Zuata material (Venezuela) (Tables 15.3, 15.4) (Delbianco and Montanari, 2009; Speight, 2013b, 2014).

Table 15.3 Examples of the properties of bitumen from different california tar sand deposits.

Deposit/Field	API	Viscosity cP reservoir conditions	Viscosity cP 80°F	Viscosity Cp 87°F	Viscosity cP 100°F	Viscosity Cp 200°F	Sulfur % w/w
Arroyo Grande	8				15,000		3 to 5
Basal Foxen	9.5		47,000				4 to 5
Cat Canyon	0 to 12						
Brooks Sand	0 to 12	15,000					
S Sand		12,000 to 1,000,000					
Casmalia							
Oxnard (Vaca)					500,000	2,000	6 to 7
Paris Valley							1.5
Upper Lobe				227,000			
Lower Lobe				23,000			
Midway-Sunset							
Webster Sands	14				1,650		

Table 15.4 Comparison of selected properties of Athabasca tar sand bitumen (Alberta, Canada) and Zuata extra heavy oil (Orinoco, Venezuela).

		Athabasca bitumen	***Zuata extra heavy oil***
Whole oil	API gravity	8	8
	Sulfur, % w/w	4.8	4.2
Resid (>650°F)	% v/v	85	86
	Sulfur, % w/w	5.4	4.6
	Ni + V, ppm	420	600
	CCR*, % w/w*	14	15

*Conradson carbon residue

Thus, extra heavy oil is a material that occurs in the solid or near-solid state and is generally has mobility under reservoir conditions. However, he term *extra heavy oil* is a recently evolved term (related to viscosity) of little scientific meaning. While this type of oil may resemble tar sand bitumen and does not flow easily, extra heavy oil is generally recognized as having mobility in the reservoir compared to tar sand bitumen, which is typically incapable of mobility (free flow) under reservoir conditions. For example, the tar sand bitumen located in Alberta, Canada, is not mobile in the deposit and requires extreme methods of recovery to recover the bitumen. On the other hand, much of the extra heavy oil located in the Orinoco basin of Venezuela requires recovery methods that are less extreme because of the mobility of the material in the reservoir. Whether the mobility of extra heavy oil is due to a high reservoir temperature (that is higher than the pour point of the extra heavy oil) or due to other factors is variable and subject to localized conditions in the reservoir. This may also be reflected in the choice of suitable extra heavy oil or bitumen conversion processes in the refinery.

15.2.2.2 Tar Sand Bitumen

Tar sand bitumen is the *bitumen* found in *tar sand* (*oil sand*) deposits. However, many of these reserves are only available with some difficulty and optional refinery scenarios will be necessary for conversion of these materials to liquid products (Speight, 2000, 2014) because of the substantial differences in character between conventional crude oil and tar sand bitumen (Speight, 2014, 2017). *Tar sands*, also variously called *oil sands* or *bituminous sands*, are a loose-to-consolidated sandstone or a porous carbonate rock, impregnated with bitumen, a heavy asphaltic crude oil with an extremely high viscosity under reservoir conditions. Tar sand bitumen is a high-boiling material with little, if any, material boiling below 350°C (660°F) and the boiling range approximates the boiling range of an atmospheric residuum.

The most appropriate definition of *tar sands* is by the US government, viz. (United States Congress, 1976):

> *Tar sands are the several rock types that contain an extremely viscous hydrocarbon which is not recoverable in its natural state by conventional oil well production methods including*

> *currently used enhanced recovery techniques. The hydrocarbon-bearing rocks are variously known as bitumen-rocks oil, impregnated rocks, oil sands, and rock asphalt.*

This definition speaks to the character of the bitumen through the method of recovery. Thus, the bitumen found in tar sand deposits is an extremely viscous material that is *immobile under reservoir conditions* and cannot be recovered through a well by the application of secondary or enhanced recovery techniques. By inference and by omission, conventional crude oil and heavy oil are also included in this definition. Crude oil is the material that can be recovered by conventional oil well production methods whereas heavy oil is the material that can be recovered by enhanced recovery methods. Tar sand is currently recovered by a mining process followed by separation of the bitumen by the hot water process. The bitumen is then used to produce hydrocarbon derivatives by a conversion process.

The term *tar sand*, also known as *oil sand* (in Canada), or bituminous sand, commonly describes sandstones or friable sand (quartz) impregnated with a viscous organic material known as *bitumen* (a hydrocarbonaceous material that is soluble in carbon disulfide). Tar sand deposits occur throughout the world; the largest occur in Alberta, Canada (the Athabasca, Wabasca, Cold Lake, and Peace River areas), and in Venezuela. Smaller deposits occur in the United States, with the larger individual deposits in Utah, California, New Mexico, and Kentucky.

The bitumen makes up the desirable fraction of the tar sand deposits from which liquid fuels can be derived. Typically, the bitumen is not amenable to refining by conventional crude oil refinery processes (Speight, 2013b, 2014, 2016, 2017, 2020a).

15.2.3 Other Feedstocks

For decades coal has been the primary feedstock for gasification processes and as advancements in the technology have evolved and the more stringent regulations relating to the environment have ben enacted, the gasification processes have been developed and evolved to accept a wide range of feedstocks. Gasifiers have been developed to suit all different ranks of coal as well as coke from crude oil refining processes along with biomass (including agricultural waste) as well as industrial and municipal solid waste. The flexibility stems from the ability of gasification to take any carbonaceous feedstock which is thermochemically decomposed to a variety of gaseous products which can then be processed into several marketable products.

In the context of the refinery, there are several types of potential feedstock for combustion or gasification in a refinery (Table 15.5), the most prominent of which have been coke from refining processes and the various types of residua (Parkash, 2003; Gary *et al.*, 2007; Speight, 2014; Hsu and Robinson, 2017; Speight, 2017). The key to this development has been the adaptability of gasification technology for any carbonaceous feedstock as well as advances in preprocessing feedstocks and gasifier design.

A number of factors have increased the interest in gasification applications in petroleum refinery operations: (i) coking capacity has increased with the shift to heavier, more sour crude oils being supplied to the refiners, (ii) disposal of hazardous waste has become a major issue for refiners, (iii) the need to reduce the emissions of criteria pollutants and greenhouse gases is increasing, (iv) the requirements to produce ultra-low sulfur fuels are increasing the hydrogen needs of the refineries.

Table 15.5 Examples of the types of refinery feedstocks available for on-site combustion or gasification (see also Table 15.1 and Table 15.2).

Ultimate analysis	Tar sand bitumen	Visbreaker bottoms	Deasphalter bottoms	Delayed coke
Carbon, % w/w	83.0	83.1	85.9	88.6
Hydrogen, % w/w	10.6	10.4	9.5	2.8
Nitrogen, % w/w	0.5	0.6	1.4	1.1
Sulfur, % w/w*	4.9	2.4	2.4	7.3
Oxygen, % w/w	0.9	0.5	0.5	0.0
Mineral matter, % w/w	<0.5	<0.5	<0.5	<1.0
Specific Gravity	1.03	1.008	1.036	0.863
API Gravity	5.8	8.9	5.1	

Thus, gasification in the refinery can provide high-purity hydrogen for a variety of uses within the refinery (Speight, 2014, 2017, 2019a). Hydrogen is used in the refinery to remove sulfur, nitrogen, and other impurities from intermediate to finished product streams and in hydrocracking operations for the conversion of heavy distillates and oils into light products, naphtha, kerosene and diesel. Hydrocracking and severe hydrotreating require hydrogen which is at least 99% v/v pure, while less severe hydrotreating can use 90% v/v pure hydrogen (Speight, 2016).

In the current context, electric power and high-pressure steam can be generated by the gasification of petcoke and residuals to drive mostly small and intermittent loads such as compressors, blowers, and pumps. Steam can also be used for process heating, steam tracing, partial pressure reduction in fractionation systems, and stripping low-boiling components to stabilize process streams.

This section presents an introduction to the feedstocks other than coal that can be used in gasification processes. However, the gasification of refinery bottoms or refinery waste streams while offering the refiner with (for example) synthesis gas that can be used in several ways (Speight, 2014, 20176, 2019a), is not the end of the story. Like all refinery gases, the gas from any gasification process must be cleaned and contaminants removed before any further processing or actions are attempted, just as the contaminants must be removed from any product gas from the gasification of coal because of the potential issues that can arise (Chapters 12, 14). And contrary to any other thoughts and ideas, the gaseous products produced when biomass is the feedstock (Chapters 16, 17) are not immune to the need for contaminant removal and protection of the environment.

15.2.3.1 Refinery Coke

Coke is the residue left by the destructive distillation (thermal cracking) of crude oil residua (Parkash, 2003; Gary *et al.*, 2007; Speight, 2014; Hsu and Robinson, 2017; Speight, 2017). That formed in catalytic cracking operations is usually non-recoverable, as it is often irreversibly adsorbed on to the catalyst and is employed as fuel for the process when it is burned from the catalyst. The composition of crude oil coke varies with the source of the crude oil, but in general, large amounts of high-molecular-weight complex hydrocarbon derivatives (rich in carbon but correspondingly poor in hydrogen) make up a high proportion. The solubility of crude oil *coke* in carbon disulfide has been reported to be as high as 50 to 80%, but this is in fact a misnomer, since the coke is the insoluble, honeycomb material that is the end product of thermal processes.

Typically, the composition of refinery coke is on the order of (green coke): carbon 89.5 to 92% w/w, hydrogen 3.7 to 5.0% w/w, oxygen 1.3 to 2.0% w/w, nitrogen 0.9 to 1.5% w/w, and sulfur 1.2 to 4.0% w/w. On the other hand, calcined coke has the approximate composition: carbon 98.5% w/w, hydrogen 0.1 – 0.2 % w/w, oxygen <0.05% w/w, nitrogen 0.5% w/w, and sulfur 1.2% w/w.

By way of description, green coke (raw coke) is the primary solid refinery that is produced from crude oil and high boiling crude oil fractions obtained at temperatures below 650°C (1200°F). This type of coke contains a fraction of non-coke material that can be released as volatiles during subsequent heat treatment at temperatures up to approximately 1325°C (2420°F). This mass fraction referred to as volatile matter) is in the case of green coke between 4 and 15% w/w, but the amount of volatile matter also depends on the heating rate. On the other hand, calcined coke is created by placing green coke into rotary kilns, where it is heated to temperatures between 1200 to 1350°C (2190 to 2460°F).

Crude oil coke is employed for a number of purposes, but its chief use is in the manufacture of carbon electrodes for aluminum refining, which requires a high-purity carbon – low in ash and sulfur free; the volatile matter must be removed by calcining. In addition to its use as a metallurgical reducing agent, crude oil coke is employed in the manufacture of carbon brushes, silicon carbide abrasives, and structural carbon (e.g., pipes and Rashig rings), as well as calcium carbide manufacture from which acetylene is produced:

$$\text{Coke} \rightarrow \text{CaC}_2$$

$$\text{CaC}_2 + \text{H}_2\text{O} \rightarrow \text{HC}{\equiv}\text{CH}$$

However, with the progressive increase in the amount of coke produced from the heavier (more viscous) refinery feedstocks, there is a renewed interest the utilization of coke as a feedstock for a gasification process. This is one of the attractive options and is gaining increasing attention to convert the petcoke to value-added products. The process offers the refiners a variety of product slates mainly via the production of synthesis gas. The products include steam, hydrogen, electricity, chemicals (such as methanol, CH_3OH, and ammonia, NH_3), and liquid fuels by way of the Fischer–Tropsch synthesis (Speight, 2013, 2014, 2017).

15.2.3.2 Solvent Deasphalter Bottoms

The deasphalting unit (deasphalter) is a unit in a crude oil refinery for residuum upgrading that separates an asphalt-like product from crude oil, heavy crude oil, extra heavy oil, or tar sand bitumen. The deasphalter unit is usually placed after the vacuum distillation tower where, by the use of a low-boiling liquid hydrocarbon solvent (such as propane or butane under pressure), the insoluble asphalt-like product (*deasphalter bottoms*) is separated from the feedstock – the other output from the deasphalter is deasphalted oil (DAO) (Parkash, 2003; Gary *et al.*, 2007; Speight, 2014; Hsu and Robinson, 2017; Speight, 2017).

The solvent deasphalting process has been employed for more than six decades to separate high molecular weight fractions of crude oil boiling beyond the range of economical commercial distillation. The earliest commercial applications of solvent deasphalting used liquid propane as the solvent to extract high-quality lubricating oil bright stock from vacuum residue. The process has been extended to the preparation of catalytic cracking feeds, hydrocracking feeds, hydrodesulfurization feedstocks, and asphalts. The latter product (asphalt, also called *deasphalter bottoms*) is used for (i) road asphalt manufacture, (ii) refinery fuel, or (iii) gasification feedstock for hydrogen production.

In fact, the combination of ROSE solvent deasphalting and gasification has been commercially proven at the ERG Petroli refinery (Bernetti *et al.*, 2000). The combination is very synergistic and offers a number of advantages including a low-cost feedstock to the gasifier, thus enhancing the refinery economics, and converts low-value feedstock to high-value products such as power, steam, hydrogen, and chemical feedstock. The process also improves the economics of the refinery by eliminating/reducing the production of low-value fuel oil and maximizing the production of transportation fuel.

15.2.3.3 Asphalt, Tar, and Pitch

Asphalt does not occur naturally but is manufactured from crude oil and is a black or brown material that has a consistency varying from a viscous liquid to a glassy solid (Parkash, 2003; Gary *et al.*, 2007; Speight, 2014, 2015; Hsu and Robinson, 2017; Speight, 2017).

To a point, asphalt can resemble tar sand bitumen (isolated form tar sand formation), hence the tendency to refer to bitumen (incorrectly) as *native asphalt*. It is recommended that there be differentiation between asphalt (manufactured) and bitumen (naturally occurring) other than by use of the qualifying terms *crude oil* and *native* since the origins of the materials may be reflected in the resulting physicochemical properties of the two types of materials. It is also necessary to distinguish between the asphalt which originates from crude oil by refining and the product in which the source of the asphalt is a material other than crude oil, e.g., *Wurtzilite asphalt* (Speight, 2014). In the absence of a qualifying word, it should be assumed that the word *asphalt* (with or without qualifiers such as *cutback*, *solvent*, and *blown*, which indicate the process used to produce the asphalt) refers to the product manufactured from crude oil.

When the asphalt is produced simply by distillation of an asphaltic crude oil, the product can be referred to as *residual asphalt* or *straight-run asphalt*. For example, if the asphalt is prepared by *solvent* extraction of residua or by low-boiling hydrocarbon (propane) precipitation, or if *blown* or otherwise treated, the term should be modified accordingly to qualify the product (e.g., *solvent asphalt*, *propane asphalt*, *blown asphalt*).

Asphalt softens when heated and is elastic under certain conditions and has many uses. For example, the mechanical properties of asphalt are of particular significance when it is used as a binder or adhesive. The principal application of asphalt is in road surfacing, which may be done in a variety of ways. Low-boiling oil *dust layer* treatments may be built up by repetition to form a hard surface, or a granular aggregate may be added to an asphalt coat, or earth materials from the road surface itself may be mixed with the asphalt. Other important applications of asphalt include canal and reservoir linings, dam facings, and sea works. The asphalt so used may be a thin, sprayed membrane, covered with earth for protection against weathering and mechanical damage, or thicker surfaces, often including riprap (crushed rock). Asphalt is also used for roofs, coatings, floor tiles, soundproofing, waterproofing, and other building-construction elements and in a number of industrial products, such as batteries. For certain applications, an asphaltic emulsion is prepared, in which fine globules of asphalt are suspended in water.

Tar is a product of the destructive distillation of many bituminous or other organic materials and is a brown to black, oily, viscous liquid to semi-solid material. However, *tar* is most commonly produced from *bituminous coal* and is generally understood to refer to the product from coal, although it is advisable to specify *coal tar* if there is the possibility of ambiguity. The most important factor in determining the yield and character of the coal tar is the carbonizing temperature. Three general temperature ranges are recognized, and the products have acquired the designations: *low-temperature tar* (approximately 450 to 700°C; 540 to 1290°F); *mid-temperature tar* (approximately 700 to 900°C; 1290 to 1650°F); and *high-temperature tar* (approximately 900 to 1200°C; 1650 to 2190°F). Tar released during the early stages of the decomposition of the organic material is called *primary tar* since it represents a product that has been recovered without the secondary alteration that results from prolonged residence of the vapor in the heated zone.

Treatment of the distillate (boiling up to 250°C, 480°F) of the tar with caustic soda causes separation of a fraction known as *tar acids*; acid treatment of the distillate produces a variety of organic nitrogen compounds known as *tar bases*. The residue left following removal of the high-boiling oil, or distillate, is *pitch*, a black, hard, and highly ductile material.

In the chemical-process industries, pitch is the black or dark brown residue obtained by distilling coal tar, wood tar, fats, fatty acids, or fatty oils. The pitch produced in a refinery, like coal tar pitch is a soft to hard and brittle substance containing chiefly aromatic resinous compounds along with aromatic and other hydrocarbon derivatives and their derivatives; it is used chiefly as road tar, in waterproofing roofs and other structures, and to make electrodes. *Wood tar pitch* is a bright, lustrous substance containing resin acids; it is used chiefly in the manufacture of plastics and insulating materials and in caulking seams. *Pitch* derived from fats, fatty acids, or fatty oils by distillation are usually soft substances containing polymers and decomposition products; they are used chiefly in varnishes and paints and in floor coverings.

Any of the above derivatives can be used as a combustion feedstock or as a gasification feedstock. The properties of asphalt change markedly during the aging process (oxidation in service) to the point where the asphalt fails to perform the task for which it was designed. In some cases, the asphalt is recovered and reprocessed for additional use or it may be sent to a gasifier.

15.2.3.4 Black Liquor

Another waste that is not often recognized as a source of energy – in the current context a potential source of synthesis gas – is the waste from pulping processes. As an example, black liquor is the spent liquor from the Kraft process in which pulpwood is converted into paper pulp by removing lignin and hemicellulose constituents as well as other extractable materials from wood to free the cellulose fibers. The equivalent spent cooking liquor in the sulfite process is usually called *brown liquor*, but the terms *red liquor*, *thick liquor*, and *sulfite liquor* are also used (Biermann, 1993).

Black liquor is the spent liquor from the Kraft process in which pulpwood is converted into paper pulp by removing lignin and hemicellulose constituents as well as other extractable materials from wood to free the cellulose fibers. The present-day chemical pulping process uses a complex combustion system called a recovery boiler to generate process heat and electricity as well as to recover the processing chemicals in an almost closed cycle. The recovery boiler is actually operated as a gasifier-combustor. After evaporation of the majority of the water, the high-solids black liquor is sprayed onto a mass of char in the bottom of the boiler. Black liquor comprises an aqueous solution of lignin residues, hemicellulose, and the inorganic chemical used in the process and 15% w/w solids of which 10% w/w are inorganic and 5% w/w are organic. Typically, the organic constituents in black liquor are 40 to 45% w/w soaps, 35 to 45% w/w lignin, and 10 to 15% w/w other (miscellaneous) organic materials.

The organic constituents in the black liquor are made up of water/alkali soluble degradation components from the wood. Lignin is partially degraded to shorter fragments with sulfur contents in the order of 1 to 2% w/w and sodium content at approximately 6% w/w of the dry solids. Cellulose (and hemicellulose) is degraded to aliphatic carboxylic acid soaps and hemicellulose fragments. The extractable constituents yield *tall oil soap* and crude turpentine. The tall oil soap may contain up to 20% w/w sodium. Residual lignin components currently serve for hydrolytic or pyrolytic conversion or combustion. Alternative, hemicellulose constituents may be used in fermentation processes.

Gasification of black liquor has the potential to achieve higher overall energy efficiency as compared to those of conventional recovery boilers, while generating an energy-rich synthesis gas. The synthesis gas can then be burned in a gas turbine combined cycle system (*BLGCC* – black liquor gasification combined cycle – and similar to *IGCC*, integrated gasification combined cycle) to produce electricity or converted (through catalytic processes) into chemicals or fuels (e.g., methanol, dimethyl ether, Fischer-Tropsch hydrocarbon derivatives and diesel fuel).

The organic constituents in the black liquor are made up of water/alkali soluble degradation components from the wood. Lignin is partially degraded to shorter fragments with sulfur contents in the order of 1 to 2% w/w and sodium content at approximately 6% w/w of the dry solids. Cellulose (and hemicellulose) is degraded to aliphatic carboxylic acid soaps and hemicellulose fragments. The extractable constituents yield *tall oil soap* and crude turpentine. The tall oil soap may contain up to 20% w/w sodium. Lignin components currently serve for hydrolytic or pyrolytic conversion or combustion. Alternative, hemicellulose constituents may be used in fermentation processes.

In another aspect. lignin pyrolysis produces reducing gases and char which react with the spent pulping chemicals to produce sodium carbonate (Na_2CO_3) and sodium sulfide (Na_2S). Other minerals in the feedstock appear as non-usable chemical ash and have to be removed from the cycle. The gas product from the char bed passes to an oxidizing zone in the furnace where the gas is combusted to produce process steam (and electricity) as well as provide radiant heat back to the char bed for the reduction chemistry to take place. The product chemicals are molten, drained from the char bed to collectors, and then poured into water to produce green liquor.

Thus, the pulp and paper industry offers unique opportunities for the production of synthesis gas insofar as an important part of many pulp and paper plants is the chemicals recovery cycle where black liquor is combusted in boilers. Substituting the boiler by a gasification plant with additional biofuel and electricity production is attractive, especially when the old boiler has to be replaced. The equivalent spent cooking liquor in the sulfite process is usually called *brown liquor*, but the terms *red liquor*, *thick liquor*, and *sulfite liquor* are also used. Approximately seven units of black liquor are produced in the manufacture of one unit of pulp (Biermann, 1993).

15.2.3.5 Used Motor Oil

Used motor oil (also known as used lubricating oil and *waste oil* without further qualification) is any lubricating oil, whether refined from crude or synthetic components, which has been contaminated by physical or chemical impurities as a result of use. The oil loses its effectiveness during operation due to the presence of certain types of contaminants which can be classed as (i) extraneous contaminants and (ii) products of oil deterioration (Speight and Exall, 2014).

Extraneous contaminants are introduced from the surrounding air and by metallic particles from the engine. Contaminants from the air are dust, dirt, and moisture – in fact, air itself may be considered as a contaminant since it can cause foaming of the oil. The contaminants from the engine are (i) metallic particles resulting from wear of the engine, (ii) carbonaceous particles due to incomplete fuel combustion, (iii) metallic oxides present as corrosion products of metals, (iv) water from leakage of the cooling system, (v) water as a product of fuel combustion, and (vi) fuel or fuel additives or their by-products, which might enter the crankcase of engines.

In terms of the products of oil deterioration, many products are formed during oil deterioration. Some of these important products are (i) sludge: a mixture of oil, water, dust, dirt, and carbon particles that results from the incomplete combustion of the fuels. sludge may deposit on various parts of the engine or remain in colloidal dispersion in the oil, (ii) lacquer: a hard or gummy substance that deposits on engine parts as a result of subjecting sludge in the oil to high temperature operation, and (iii) oil-soluble products: the result of oil oxidation products that remain in the oil and cannot be filtered out and deposit on the engine parts. The quantity and distribution of engine deposits vary widely depending on the conditions at which the engine is operated. At low temperatures, carbonaceous deposits originate mainly from incomplete combustion products of the fuel and not from the lubricating oil. At high temperature, the increase in lacquer and sludge deposits may be caused by the lubricating oil.

Typically the used oil is sent to a refinery or plant that specialized in re-refining the oil to product a clean lubricating oil-type product. If the oil is sent to a combustion plant or gasification plant, the real and potential contaminant must be taken into account and appropriate contaminant removal methods applied. The used oil should not be blended into fuel oil for used in domestic or industrial furnace as fuel oil. The standard definitions and specification for fuel oils are well defined (ASTM D396) and the fuel oil should not contain any blended material that does not meet the specification for a fuel oil (Table 15.6). In this respect, used motor oil may be suitable as a bend stock for congestion and/or gasification processes (Chapters 16, 17), subject to cleanup pf the gaseous product and suitable disposable method for any ash that is formed.

Table 15.6 Types of fuel oil.

Fuel oil	Description
Number 1 fuel oil	A volatile distillate oil intended for vaporizing pot-type burners. It is the kerosene; former names include coal oil, stove oil, and range oil.
Number 2 fuel oil	A distillate home heating oil, sometime known as Bunker A fuel oil; trucks and some cars use similar diesel fuel with a cetane number limit describing the ignition quality of the fuel.
Number 3 fuel oil	A distillate oil for burners requiring low-viscosity fuel; the term has been rarely used since the mid-20th century.
Number 4 fuel oil	A commercial heating oil for burner installations not equipped with preheaters; may be obtained from the heavy gas oil fraction.
Number 5 fuel oil	A residual-type industrial heating oil requiring preheating to 77 to 104°C (171 to 219°F) for proper atomization at the burners; sometimes known as Bunker B fuel oil; may be obtained from the heavy gas oil fraction or it may be a blend of residual oil with enough number 2 oil to adjust viscosity until it can be pumped without preheating.
Number 6 fuel oil	A high-viscosity residual oil requiring preheating to 104 to 127°C (219 to 261°F); this fuel oil may be known as residual fuel oil (RFO), by the Navy specification of Bunker C fuel oil.

15.3 Biomass

Biomass is a term used to describe any material of recent biological origin, including plant materials such as trees, grasses, agricultural crops, and even animal manure. Thus, biomass (also referred to as bio-feedstock) refers to living and recently dead biological material which can be used as fuel or for industrial production of chemicals (Lee, 1996; Wright *et al.*, 2006; Lorenzini *et al.*, 2010; Nersesian, 2010; Speight, 2020).

In terms of the chemical composition, biomass is a mixture of complex organic compounds that contain, for the most part, carbon, hydrogen, and oxygen, with small amounts of nitrogen and sulfur, as well as with traces of other elements including metals. In most cases, the biomass composition is approximately carbon 47 to 53% w/w, hydrogen 5.9 to 6.1% w/w, and oxygen 41 to 45% w/w – which is a higher oxygen content than coal (Figure 15.2). The presence of a large amount of oxygen in biomass makes a significant difference with fossil-derived hydrocarbon derivatives. When used as fuel this is less efficient, but more suited for getting higher-value chemicals and bioproducts containing functional entities within the constituent molecules.

The biomass used as industrial feedstock can be supplied by agriculture, forestry, and aquaculture, as well as resulting from various waste materials. The biomass can be classified as follows: (i) agricultural feedstocks, such as sugarcane, sugar-beet, and cassava, (ii) starch feedstocks, such as wheat, maize, and potatoes, (iii) oil feedstocks, such as rapeseed, and soy, (iv) dedicated energy crops, such as short rotation coppice which includes poplar, willow, and eucalyptus, (v) high-yield perennial grass, such as miscanthus, and switchgrass, (vi) non-edible oil plants, such as jatropha, camellia, sorghum, and (vii) lignocellulosic

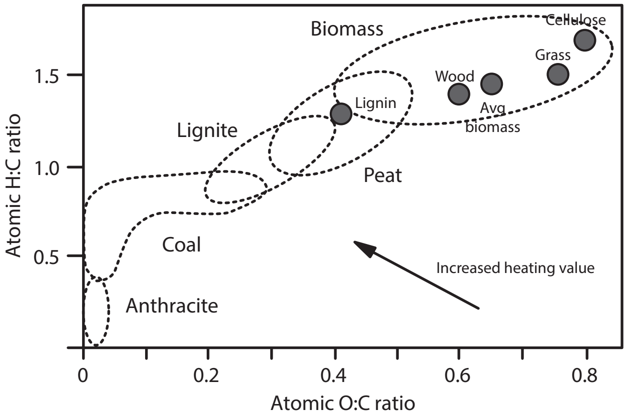


Figure 15.2 Relative oxygen content of coal and biomass.

waste material, which includes forestry wood, straw, corn stover, bagasse, paper-pulp, and algal crops from land farming (Table 15.7).

The utilization of biomass through the adoption of the conventional crude oil refinery systems and infrastructure to produce substitutes for fuels and other chemicals currently derived from conventional fuels (coal, oil, natural gas) is one of the most favored methods to combat fossil fuel depletion as the 21st century matures. In a biorefinery, a solid biomass feedstock is converted, through either a thermochemical process (such as gasification, pyrolysis) or a biochemical process (such as hydrolysis, fermentation) into a mixture of organic (such as hydrocarbon derivatives, alcohol derivatives, and ester derivatives) and inorganic compounds (such as carbon monoxide and hydrogen) that are can be upgraded through catalytic reactions to high-value fuels or chemicals (Speight, 2011a, 2014, 2017, 2019a).

In this manner, reducing the national dependence of any country on imported crude oil for long-term security and continued economic growth by supplementing crude oil consumption with renewable biomass resources becomes a first step towards energy

Table 15.7 Examples of the types of agricultural biomass.

Crop residues - Corn Stover - Corn cobs - Straw - oats, wheat, barley
Dedicated ('purpose-grown') energy crops: - Grasses - switchgrass, canary grass, alfalfa stems - Sorghum - Miscanthus - Willow/poplar plantations
Grain milling and distilling residues - Oat hulls - Wheat shorts - Dried distillers grains (ethanol production)
Manure

self-sufficiency. The realignment of the chemical industry from one of crude oil refining to a biomass refining concept is, given time, feasible and is a worthy goal of many oil-importing countries (Speight and Islam, 2016; Speight and El-Gendy, 2018; Speight, 2019a). However, clearly defined goals are necessary for increasing the use of biomass-derived feedstocks in industrial chemical production and it is important to keep the goal in perspective. In this context, the increased use of biofuels should be viewed as one of a range of possible measures for achieving self-sufficiency in energy, rather than the sole panacea (Crocker and Crofcheck, 2006; Langeveld *et al.*, 2010), although there are arguments against the rush to the large-scale production of biofuels (Giampietro and Mayumi, 2009).

Biomass is carbonaceous feedstock that is composed of a variety of organic constituents that contain carbon, hydrogen, oxygen, often nitrogen and also small quantities of other atoms, including alkali metals, alkaline earth metals, and heavy metals.

Briefly, the alkali metals consist of the chemical elements lithium (li), sodium (Na), potassium (K), rubidium (Rb), cesium (Cs), and francium (Fr). Together with hydrogen they make up Group I of the Periodic Table (Figure 15.3). On the other hand, the alkaline earth metals are the six chemical elements in Group 2 of the Periodic Table: beryllium (be), magnesium (Mg), calcium (Ca), strontium (Sr)barium (Ba), and radium (Ra). These elements have similar properties – they are shiny, silvery-white, and are somewhat reactive at standard temperature and pressure. Finally, the heavy metals are less easy to define but are generally recognized as metals with relatively high density, atomic weight, or atomic number. The common transition metals such as copper (Cu), lead (Pb), and zinc (Zn) are often classed as heavy metals but the criteria used for the definition and whether metalloids (types of chemical elements which have properties in between, or that are a mixture of, those of metals and nonmetals) are included, vary depending on the context. These metals

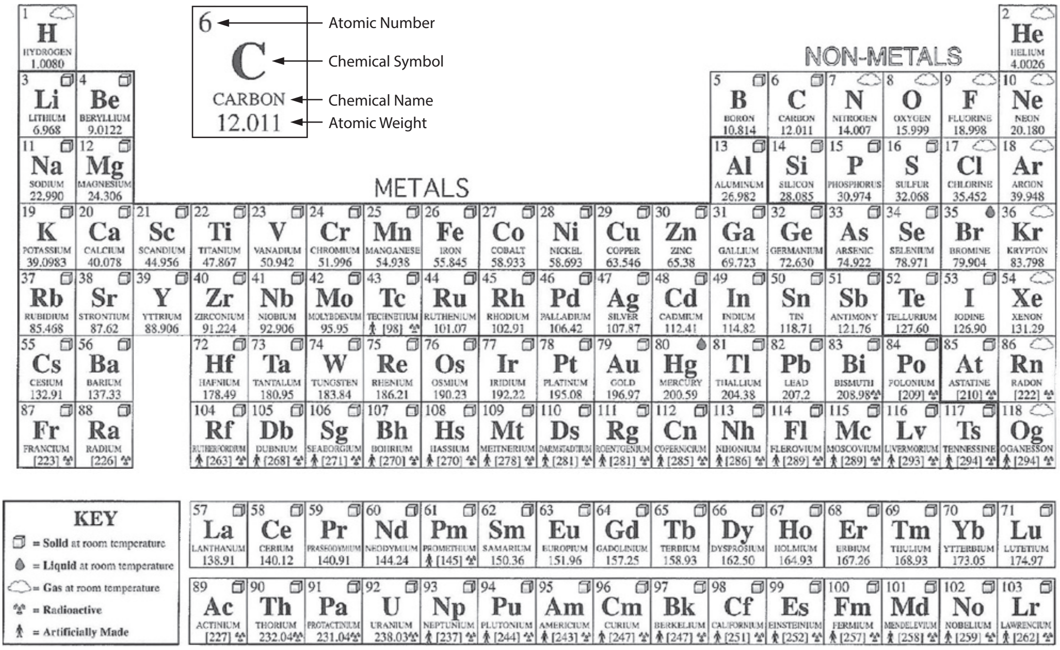


Figure 15.3 The periodic table of the elements.

are often found in functional molecules such as the porphyrin molecules which include chlorophyll and which contains magnesium.

Biomass is the oldest form of energy used by humans and traditionally, biomass has been utilized through direct combustion, and this process is still widely used in many parts of the world (Ragland *et al.*, 1991). Since the energy crises of the 1970s, many countries have become interested in biomass as a fuel source to expand the development of domestic and renewable energy sources and reduce the environmental impacts of energy production. Energy from biomass energy (frequently referred to as bioenergy) can be an important alternative in a future and more sustainable energy supply. Biomass is material that is derived from plants and there are many types of biomass resources currently used and potentially available. Biomass energy has the potential to be produced and used efficiently and cost competitively, generally in the more convenient forms of gases, liquids, or electricity (Larson and Kartha, 2000).

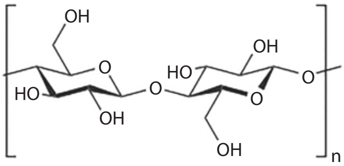
Biomass feedstocks and fuels exhibit a wide range of physical, chemical, and agricultural/process engineering properties and are subdivided into three different grades (or types) and the feedstock origin determines the so-called biomass generation (Table 15.8). In some cases, the third-generation biomass may also include high-yield algal crops which can be fed directly with concentrated carbon dioxide streams resulting from industrial processes, as from coal power plants and from fermentation of sugars – algal cultures can produce various hydrocarbon derivatives as well as various volatile olefins derivatives (Dimian, 2015).

Chemically, the forms of biomass include: (i) cellulose and related compounds which can be used for the production of paper and/or bioethanol, and (ii) long-chain lipid derivatives which can be used in cosmetics or for other specialty chemicals.

Cellulose is an important structural component of the primary cell wall of green plants. Chemically, cellulose is an organic compound with the empirical formula ($C_6H_{10}O_5$) and is a polysaccharide consisting of a linear chain of several hundred to many thousands of linked glucose.

Table 15.8 Different grades of biomass.

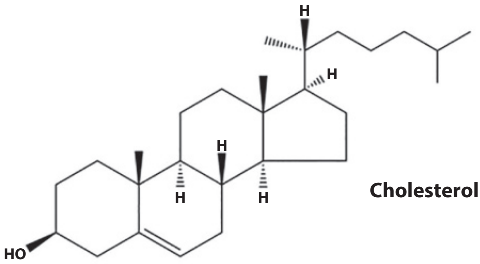
Grade	Description
Primary biomass	Produced directly by photosynthesis and includes all terrestrial plants now used for food, feed, fiber, and fuel wood.
Secondary biomass	Differs from primary biomass feedstocks in that the secondary feedstocks are a by-product of processing of the primary feedstocks in which there has been a substantial physical or chemical breakdown of the primary biomass and production of by-products; processors may be factories or animals. Specific examples of secondary biomass include: (i) sawdust from sawmills, (ii) black liquor, which is a byproduct of paper making, (iii) cheese whey, which is a by-product of cheese making processes, (iv) manure from concentrated animal feeding operations, and (v) vegetable oils used for biodiesel that are derived directly from the processing of oilseeds for various uses.
Tertiary biomass	Includes post-consumer residues and wastes, such as fats, greases, oils, construction and demolition wood debris, other waste wood from the urban environments, as well as packaging wastes, municipal solid wastes, and landfill gases.



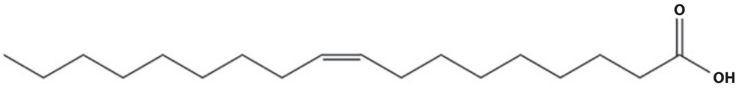
Cellulose

On the other hand, lipid derivatives are diverse in both their respective structures and functions. These diverse compounds that make up the lipid family are so grouped because they are insoluble in water (hydrophobic). They are also soluble in other organic solvents such as ether, acetone, and other lipids. Lipids serve a variety of important functions in living organisms and also act as chemical messengers, serve as valuable energy sources, provide insulation, and are the main components of membranes. Major lipid derivatives include the phospholipids derivatives (Figure 15.4).

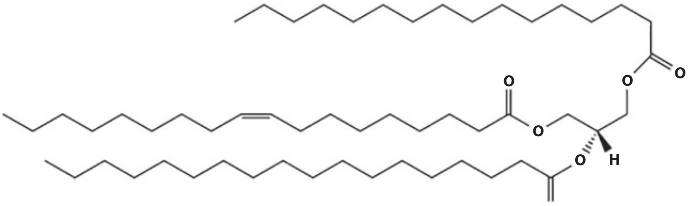
Briefly, the phospholipids are a class of lipids that are a major component of all cell membranes. They can form lipid bilayers because of their amphiphilic characteristic. The



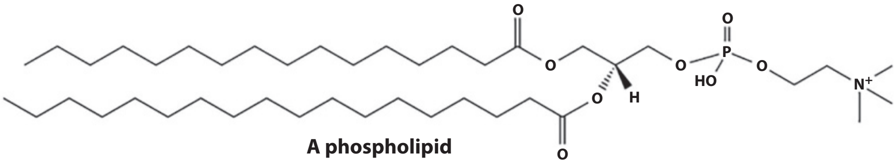
Cholesterol



A free fatty acid



A triglyceride



A phospholipid

Figure 15.4 Examples of lipid derivatives.

structure of the phospholipid molecule generally consists of two hydrophobic fatty acid tails and a hydrophilic head consisting of a phosphate group. The two components are usually joined together by a glycerol ($HOCH_2CHOHCH_2OH$) molecule. The free fatty acid derivatives are variable but commonly include the naturally occurring stearic acid, palmitic acid oleic acid, and linoleic acid (Figure 15.5).

Other biomass components, which are generally present in minor amounts, include triglycerides, sterols, alkaloids, resins, terpenes, terpenoids and waxes. This includes everything from primary sources of crops and residues harvested/collected directly from the land to secondary sources such as sawmill residuals, to tertiary sources of post-consumer residuals that often end up in landfills. A fourth source, although not usually categorized as such, includes the gases that result from anaerobic digestion of animal manures or organic materials in landfills (Wright *et al.*, 2006; Speight, 2019b).

Examples of modern biomass use are ethanol production from sugarcane, combined heat, and power (often referred to by the acronym CHP) district heating programs, and the co-combustion of biomass in conventional coal-based power plants (Hoogwijk *et al.*, 2005). In industrialized countries, the main biomass processes used in the future are expected to be direct combustion of residues and wastes for electricity generation, bio-ethanol and biodiesel as liquid fuels, and combined heat and power production from energy crops. In fact, biomass can be considered as the best option and has the largest potential, which meets these requirements and could ensure fuel supply in the future (Demirbas, 2008, 2009).

Other biomass components, which are generally present in minor amounts, include (i) diglyceride derivatives that are based on the glycol structure, $HOCH_2CHOHCH_2OH$, (ii) triglyceride derivatives that are based on the glycerol structure, $HOCH_2CH_2OH$, (iii) sterol derivatives which are also known as steroid alcohols, are a subgroup of the steroids, (iv) alkaloid derivatives that are based on any of a class of naturally occurring organic nitrogen-containing bases, (v) terpene derivatives and terpenoid derivatives which are generally rationalized as derivatives of isoprene – 2-methyl-1,3-butadiene – but isoprene is not involved in the biosynthesis, and (vi) waxes which are a diverse class of organic compounds that are lipophilic solids near ambient temperatures and include higher alkane derivatives and lipid derivatives.

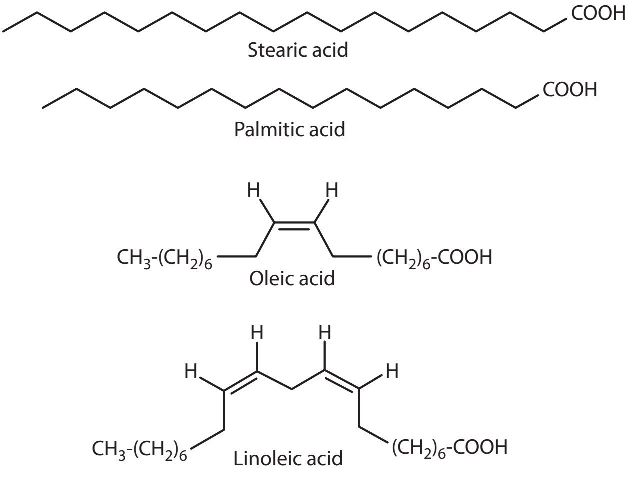
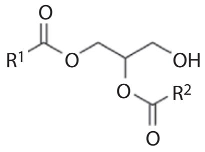
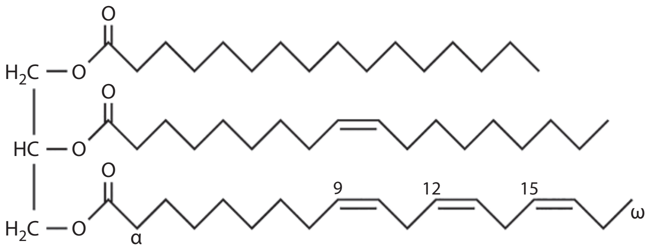


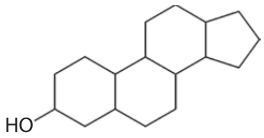
Figure 15.5 Examples of fatty acids.



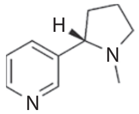
Example of a diglyceride



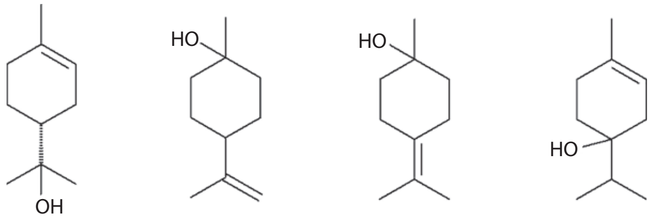
Example of a triglyceride



Sterol

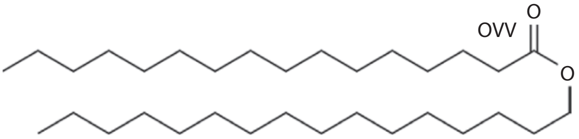


An alkaloid (nicotine)



α *β* *γ* 4-

Terpineol derivatives



Cetyl palmitate – a wax ester

More generally, biomass feedstocks are recognized (or classified) by the specific plant content of the feedstock or the manner in which the feedstocks are produced. For example, primary biomass feedstocks are thus primary biomass that is harvested or collected from the field or forest where it is grown. Examples of primary biomass feedstocks currently being used for bioenergy include grains and oilseed crops used for transportation fuel production, plus some crop residues (such as orchard trimmings and nut hulls) and some residues from logging and forest operations that are currently used for heat and power production.

Secondary biomass feedstocks differ from primary biomass feedstocks in that the secondary feedstocks are a by-product of processing of the primary feedstocks. By processing it is meant that there is substantial physical or chemical breakdown of the primary biomass and production of by-products; processors may be factories or animals. Field processes such as harvesting, bundling, chipping, or pressing do not cause a biomass resource that was produced by photosynthesis (e.g., tree tops and limbs) to be classified as secondary biomass. Specific examples of secondary biomass includes sawdust from sawmills, black liquor (which is a by-product of paper making), and cheese whey (which is a by-product of cheese-making processes). Manure from concentrated animal feeding operations are collectable secondary biomass resources. Vegetable oils used for biodiesel that are derived directly from the processing of oilseeds for various uses are also a secondary biomass resource.

Tertiary biomass feedstock includes post-consumer residues and wastes, such as fats, greases, oils, construction and demolition wood debris, other waste wood from the urban environments, as well as packaging wastes, municipal solid wastes, and landfill gases. Another category of wood waste from the urban environment includes trimmings from urban trees, which technically fits the definition of primary biomass. However, because this material is normally handled as a waste stream along with other post-consumer wastes from urban environments (and included in those statistics), it makes the most sense to consider it to be part of the tertiary biomass stream. Tertiary biomass often includes fats and greases, which are by-products of the reduction of animal biomass into component parts, since most fats and greases, and some oils, are not available for bioenergy use until after they become a post-consumer waste stream. Vegetable oils derived from processing of plant components and used directly for bioenergy (e.g., soybean oil used in biodiesel) would be a secondary biomass resource, though amounts being used for bioenergy are most likely to be tracked together with fats, greases, and waste oils.

One aspect of designing a refinery for any feedstocks is the composition of the feedstocks. For example, a heavy oil refinery would differ somewhat from a conventional refinery and a refinery for tar sand bitumen would be significantly different from both (Speight, 2014, 2017, 2020). Furthermore, the composition of biomass is variable (Speight, 2020) which is reflected in the range of heat value (heat content, calorific value) of biomass, which is somewhat less than for coal and much lower than the heat value for crude oil, generally falling in the range 6,000 to 8,500 Btu/lb (Table 15.9). Moisture content is probably the most important determinant of heating value. Air-dried biomass typically has approximately 15 to 20% moisture, whereas the moisture content for oven-dried biomass is around 0%. Moisture content is also an important characteristic of coals, varying in the range of 2 to 30%. However, the bulk density (and hence energy density) of most biomass feedstocks is generally low, even after densification, approximately 10 and 40% of the bulk density of most fossil fuels.

Plants offer a unique and diverse feedstock for chemicals (Table 15.10) and the production of biofuels from biomass requires some knowledge of the chemistry of biomass, the

Table 15.9 Heating value of selected fuels.

Fuel	Btu/lb
Natural gas	23,000
Gasoline	20,000
Crude oil	18,000
Heavy oil	16,000
Coal (anthracite)	14,000
Coal (bituminous)	11,000
Wood (farmed trees, dry)	8,400
Coal (lignite)	8,000
Biomass (herbaceous, dry)	7,400
Biomass (corn stover, dry)	7,000
Wood (forest residue, dry)	6,600
Bagasse (sugar cane)	6,500
Wood	6,000

Table 15.10 Typical plants used as a source of energy.

Type of biomass	Plant species	Predominant use
Wood	Butea monosperma, Casurina equisetifolia, Eucalyptus globulus, Leucaena leucocephala, Melia azadirachta, Tamarix dioica	Firewood
Starch	Cereals, millets, root and tuber crops, e.g., potato	Bioethanol
Sugar	Sugarcane, sugar beet	Bioethanol
Hydrocarbons	Euphorbia lathyris, Aslepia speciosa, Copaifera multijuga, algae	Biodiesel
Wastes	Crop residues, animal/human refuge, sewage	Biogas

chemistry of the individual constituents of biomass, and the chemical means by which the biomass can be converted to fuel. It is widely recognized that further significant production of plant-based chemicals will only be economically viable in highly integrated and efficient production complexes producing a diverse range of chemical products. This biorefinery concept is analogous to conventional oil refineries and petrochemical complexes that have evolved over many years to maximize process synergies, energy integration and feedstock utilization to drive down production costs.

In addition, the specific components of plants such as (i) carbohydrates, (ii) vegetable oils, (iii) plant fibers, and (iv) complex organic molecules known as primary and secondary metabolites can be utilized to produce a range of valuable monomers, chemical intermediates, pharmaceuticals, and materials.

15.3.1 Carbohydrates

Plants capture solar energy as fixed carbon during which carbon dioxide is converted to water and sugars $(CH_2O)_x$:

$$CO_2 + H_2O \rightarrow (CH_2O)_x + O_2.$$

The sugars produced are stored in three types of polymeric macromolecules: (i) starch, (ii) cellulose, and (iii) hemicellulose.

In general sugar polymers such as cellulose (Figure 15.6) and starch can be readily broken down to their constituent monomers by hydrolysis, preparatory to conversion to ethanol or other chemicals. In contrast, lignin is an unknown complex structure containing aromatic groups that is totally hypothetical (Figure 15.7) and is less readily degraded than starch or cellulose.

Although lignocellulose is one of the cheapest and most abundant forms of biomass, it is difficult to convert this relatively unreactive material into sugars. Among other factors, the walls of lignocellulose are composed of lignin, which must be broken down in order to render the cellulose and hemicellulose accessible to acid hydrolysis. For this reason, many efforts focused on ethanol production from biomass are based almost entirely on the fermentation of sugars derived from the starch in corn grain.

Carbohydrates (starch, cellulose, sugars): starch readily obtained from wheat and potato, whilst cellulose is obtained from wood pulp. The structures of these polysaccharides can be readily manipulated to produce a range of biodegradable polymers with properties similar to those of conventional plastics such as polystyrene foams and polyethylene film. In addition, these polysaccharides can be hydrolyzed, catalytically or enzymatically to produce sugars, a valuable fermentation feedstock for the production of ethanol, citric acid, lactic acid, and dibasic acids such as succinic acid.

15.3.2 Vegetable Oils

Vegetable oils (sometimes referred to as vegetable fats) are oils extracted from seeds, or less often, from other parts of fruits. Like animal fats, vegetable fats are mixtures of triglycerides. Soybean oil and rapeseed oil are examples of fats from seeds while olive oil and palm oil are examples of fats from other parts of fruits. In common usage, vegetable oil may

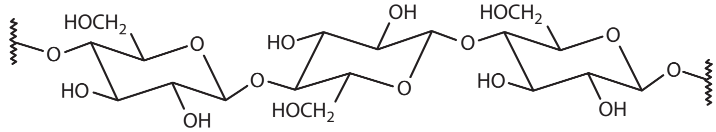


Figure 15.6 Generalized structure of cellulose.

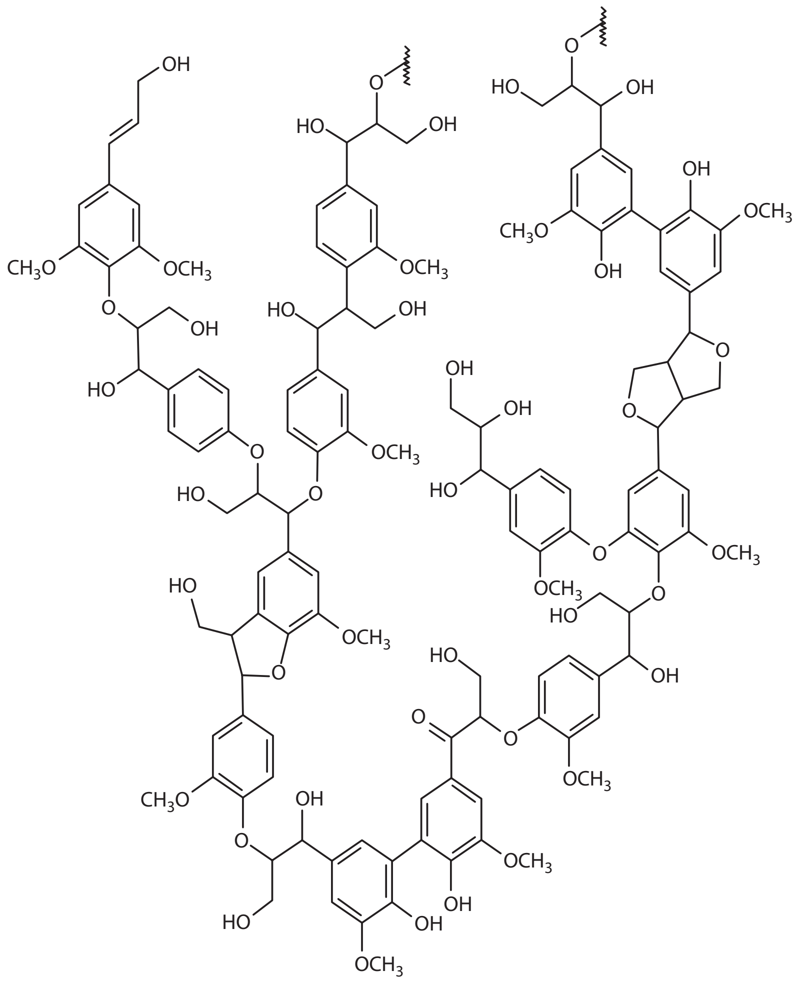


Figure 15.7 Hypothetical structure of lignin to illustrate the complexity of the molecule.

refer exclusively to vegetable fats which are liquid at room temperature. Vegetable oils are usually edible; non-edible oils derived mainly from crude oil are termed mineral oils. The predominant source of vegetable oils in many countries is rapeseed oil. Vegetable oils are a major feedstock for the oleo-chemicals industry (surfactants, dispersants, and personal care products) and are now successfully entering new markets such as diesel fuel, lubricants, polyurethane monomers, functional polymer additives and solvents.

However, most natural oils have only a limited application in their original form, as a consequence of their specific chemical composition. They therefore often undergo a chemical or physical modification. Due to the continuous technological developments, a whole variety of products normally processed by solvent or detergent fractionation can now be obtained with a high degree of selectivity by dry fractionation (Gibon *et al.*, 2009).

Unsaturated vegetable oils can be transformed through partial or complete hydrogenation into oils of higher melting point. The hydrogenation process involves sparging the oil at high temperature and pressure with hydrgoen in the presence of a catalyst, typically a nickel compound. As each carbon-carbon double-bond is chemically reduced to a single bond, two hydrogen atoms each form single bonds with the two carbon atoms. An oil may be hydrogenated to increase resistance to oxidation (which can turn the oil rancid) or to change its physical characteristics. As the degree of saturation increases, the viscosity, and the melting point of the oil increase.

Vegetable oils are used as an ingredient or component in many manufactured products. They are used to make soaps, skin products, candles, perfumes and other personal care and cosmetic products. Some oils are particularly suitable as drying oils, and are used in making paints and other wood treatment products. Vegetable oils are increasingly being used in the electrical industry as insulators since vegetable oils are bridgeable if spilled and are not toxic to the environment – they also have high flash and fire points. However, vegetable oils are less stable chemically, so they are generally used in systems where they are not exposed to oxygen and they are more expensive than crude oil distillate. More important in the present context, vegetable oils are also used as the starting material for biodiesel, which can be used like conventional diesel. Some vegetable oils are used in unmodified vehicles but straight vegetable oil – also known as pure plant oil – needs specially prepared vehicles which have a method of heating the oil to reduce the viscosity.

15.3.3 Plant Fibers

Lignocellulosic fibers extracted from plants such as hemp and flax can replace cotton and polyester fibers in textile materials and glass fibers in insulation products. Lignin is a complex chemical compound that is most commonly derived from wood and is an integral part of the cell walls of plants, especially in tracheids, xylem fibers and sclereids. The chemical structure of lignin is unknown and, at best, can only be represented by hypothetical formulas.

Lignin is one of most abundant organic compounds on earth after cellulose and chitin. By way of clarification, chitin $(C_{8H13O5N})_n$ is a long-chain polymeric polysaccharide of beta-glucose that forms a hard, semitransparent material found throughout the natural world. Chitin is the main component of the cell walls of fungi and is also a major component of the exoskeletons of arthropods, such as the crustaceans (e.g., crab, lobster, and shrimp), and the insects (e.g., ants, beetles, and butterflies), and of the beaks of cephalopods (e.g., squids and octopuses).

Lignin makes up approximately one-quarter to one-third of the dry mass of wood and is generally considered to be a large, cross-linked hydrophobic, aromatic macromolecule with molecular mass that is estimated to be in excess of 10,000. Degradation studies indicate that the molecule consists of various types of substructures which appear to repeat in random manner.

Lignin fills the spaces in the cell wall between cellulose, hemicellulose and pectin components and is covalently linked to hemicellulose. Lignin also forms covalent bonds to polysaccharides which enables cross-linking to different plant polysaccharides. Lignin confers mechanical strength to the cell wall (stabilizing the mature cell wall) and therefore the entire plant.

15.3.4 Energy Crops

Biomass currently provides varying proportions (depending upon the country) of the primary energy supply but, as a word of caution, the production of energy crops may compete with traditional agricultural and forestry uses of land. It is essential to create integrated biomass production systems that landowners can use to help meet the growing energy demands of any nation. For example, the production of fast-growing short rotation woody crops on agricultural lands is one such approach that shows considerable promise. In addition to using woody biomass for energy for power and heat generation by means of cofiring and gasification, woody crops with their high hemicellulose and cellulose content are well suited for biorefining to yield liquid (Speight, 2019a).

Crops are the annual or seasonal yield of any plant that is grown to be harvested as food, as livestock fodder, fuel, or for any other economic purpose in significant quantities. This category includes crop species as well as agricultural techniques related to cropping. The products from crops are not only as primary source of human foods and animal feed, but also as source of timber, fibers, and biomass energy. In addition, crops have also an essential function to maintain ecological systems and natural environment. Most of crop production is used as foods but in the 20th century crops were also cultivated for non-food use – examples are pharmaceutical and nutritional products, chemical derivative products such as adhesive, paints, polymer, plastics, and industrial oils in forms of bio diesel, transmission fluids, and lubricants.

Thus, by definition, energy crops are plants grown specifically for use as a fuel. Although growing crops for fuel dates from medieval times, in their modern form energy crops are the most recent and innovative renewable energy option. Energy crops are important as a renewable energy technology because their use will produce a variety of economic, environmental and energy benefits. Commercial energy crops are typically densely planted, high-yielding crop species where the energy crops will be burnt to generate power. Woody crops such as willow and poplar are widely utilized, as well as tropical grasses such as miscanthus and elephant grass (Pennisetum purpureum).

Grasses are usually herbaceous plants with narrow leaves growing from the base. They include the true grasses of the Poaceae (or Gramineae) family, as well as the sedges (Cyperaceae) and the rushes (Juncaceae). The true grasses include cereals, bamboo, and the grasses of lawns (turf) and grassland. Sedges include many wild marsh and grassland plants, and some cultivated ones such as water chestnut (Eleocharis dulcis) and papyrus sedge (Cyperus papyrus). Most of the interest in grass biomass tends to focus on economics, but there is a list of traits that should be considered and valued when evaluating a potential solid biomass energy source. These traits are beneficial to society in general, or impact the suitability of biomass for a farm operation.

If the carbohydrate content is desired for the production of biogas, whole-crops such as maize, Sudan grass, millet, white sweet clover, and many others, can be made into silage after which they can converted into biogas. On the other hand, crop residues are the residues remaining after crops have been harvested. Crop residues typically contain 40% w/w of the nitrogen (N), 80% w/w of the potassium (K), and 10% w/w of the phosphorus (P) applied to the soil in the form of fertilizer. If these residues are subjected to direct combustion for energy, only a small percentage of the nutrients is left in the ash.

The valuable portion of sugar and starch crops (in terms of biofuel production) is the stalks and leaves, which are composed mainly of cellulose. The individual six-carbon sugar units in cellulose are linked together in extremely long chains by a stronger chemical bond than exists in starch. In starch crops, most of the six-carbon sugar units are linked together in long, branched chains (starch). Yeast cannot use these chains to produce ethanol. The starch chains must be broken down into individual six-carbon units or groups of two units. The starch conversion process is relatively simple because the bonds in the starch chain can be broken in an inexpensive manner by the use of heat and enzymes, or by a mild acid solution.

Sugar crops include a variety of plants such as fodder beets, fruit crops, Jerusalem artichokes, sugar beets, sugar cane, and sweet sorghum. Interest in ethanol production from such agricultural crops has prompted the development of sugar crops that have not been cultivated on a widespread commercial basis in many countries. Preparation is basically a crushing and extraction of the sugars which the yeast can immediately use. But sugar crops must be dealt with fairly quickly before their high sugar and water content causes spoilage. Because of the danger of such spoilage, the storage of sugar crops is not practical.

As with starch, cellulose must be broken down into sugar units before it can be used by yeast to make ethanol. However, the breaking of the cellulose bonds is much more complex and costly than the breaking of the starch bonds. Breaking the cellulose into individual sugar units is complicated by the presence of lignin, a complex compound surrounding cellulose, which is even more resistant than cellulose to enzymatic or acidic pretreatment (Hwang and Obst, 2003). Because of the high cost of converting liquefied cellulose into fermentable sugars, agricultural residues (as well as other crops having a high percentage of cellulose) are not yet a practical feedstock source for small ethanol plants.

Crop residues (cobs, stems, leaves, in particularly straw and other plant matter) left in agricultural fields after harvest could potentially be used for solid biofuels production. Due to high energy content, straw is one of the best crop residues for solid biofuels. However, straw has several disadvantages – it has a higher ash content, which results in lower calorific value. In order to improve its bulk density, the straw is generally baled before transportation. Straw burning requires a specific technology. There are four basic types of straw burners: those that accept shredded, loose straw; burners that use densified straw products such as pellets, briquettes or cubes and straw logs; small, square bale burners and round bale burners. To be suitable for heat and electricity production straw should not have a large content of moisture, preferably not more than 20% as the moisture reduces the boiler efficiency. Also straw color as well as straw chemistry should be considered before burning as it indicates the quality of the straw. Most crop residues are returned to the soil, and the humus resulting from their decomposition helps maintain soil nutrients, soil porosity, water infiltration and storage, as well as reducing soil erosion.

Regularly coppiced plantations will actually absorb more carbon dioxide than mature trees, since carbon dioxide absorption slows once a tree has grown. Growing crops for fuel, particularly wood coppice, offers very promising developments for the future. Short rotation arable coppicing, using fast-growing willows, is currently seen as an important source of fuel for electricity generation. The overall process involves several stages – growing over two or three years, cutting, and converting to wood chip, storage and drying, transport to a power plant for combustion. And the combustion process can be very efficient, given the development of advanced co-generation techniques.

Energy crop fuel contains almost no sulfur and has significantly less nitrogen than fossil fuels; therefore reductions in pollutants causing acid rain (SO_2) and smog (NOx) may be realized. For example, the use of energy crops will greatly reduce greenhouse gas emissions. Burning fossil fuels removes carbon that is stored underground and transfers it to the atmosphere. Burning energy crops, on the other hand, releases carbon dioxide but as their growth requires carbon dioxide there is no net release of carbon into the atmosphere, i.e., it creates a closed carbon cycle. Furthermore, where energy crops are gasified there is a net reduction of carbon dioxide. In addition, substantial quantities of carbon can be captured in the soil through energy crop root structures, creating a net carbon sink.

An additional environmental benefit is in water quality, as energy crop fuel contains less mercury than coal. Also, energy crop farms using environmentally pro-active designs will create water quality filtration zones as well as the uptake and sequestering pollutants such as phosphorus from soils that leach into water bodies. Also, growing energy crops on agricultural land that might otherwise be converted to residential or industrial use will reduce erosion/chemical runoff and enhance wildlife habitat. Thus energy producers and consumers will have available a renewable energy option with uniquely desirable characteristics. For example, energy crops differ from other sources of renewable energy in virtue of the fact that they can be grown to meet the needs of the market whereas other renewable resources (for example, wind and wave power) must be harnessed where and when they occur.

In the biochemical process, bacteria, yeasts, and enzymes also break down carbohydrates. For example, the fermentation process used to make wine, changes biomass liquids into alcohol, a combustible fuel. A similar process is used to turn corn into ethanol, which is mixed with gasoline to make gasohol. Also, when bacteria break down biomass, methane and carbon dioxide are produced. This methane can be captured, in sewage treatment plants and landfills, for example, and burned for heat and power (Speight, 2019b). Also, biomass oils, such as soybean oil and canola oil, can be chemically converted into a liquid fuel similar to diesel fuel, and into gasoline additives. Used cooking oil has been used as a source to make biodiesel.

In the thermochemical process, the plant mater is broken down into gaseous products, liquid products, and a carbonaceous solid (commonly referred to as char). These products can then be processed further and refined into useful fuels such as methane and alcohol. Another approach is to take these fuels and run them through fuel cells, converting the hydrogen-rich fuels into electricity and water, with few or no emissions. However, the direct conversion thermal processes, such as combustion, may encounter the same problems as those encountered when coal is the feedstock (Speight, 2013a). The conversion of biomass into other useful forms such as gaseous fuels or liquid fuels is considered as an alternative way to make use of biomass energy. Perennial crops that regenerate annually from buds at the base of the plant offer the greatest potential for energy-efficient production These include (i) cordgrass and switchgrass, (ii) Jerusalem artichoke, (iii) Miscanthus, (iv) reed plants, (v) residual herbaceous biomass, (vi) short rotation coppice, and (vii) sorghum.

15.3.4.1 Cordgrass and Switchgrass

Cordgrass (genus *Spartina*), also called marsh grass or salt grass, is a genus of 16 species of perennial grasses in the family Poaceae which is found on the marshes and tidal mud flats of North America, Europe, and Africa and often forms dense colonies. Some species are planted as soil binders to prevent erosion and a few are considered invasive species in areas outside their native range. Prairie cordgrass (*Spartina pectinata*) and gulf cordgrass (*S. spartinae*) are the most widely distributed North American species.

Cordgrasses are erect, tough, long-leaved plants that range from 1 to 10 feet in height. Most species grow in clumps, with short flower spikes alternating along and often adherent to the upper portion of the stems. Many spread though rhizomes (underground stems) that send up new plants. One of the variations of cordgrass – referred to as smooth cordgrass – has smooth, blade-like leaves that taper to a point. The leaves grow 12 to 20 inches in length and one-half an inch wide and has round, hollow stems, and a strong, interconnected root system. Smooth cordgrass grows in two forms: a short form that grows to 2 feet tall, and a tall form that can reach 7 feet tall.

Switchgrass (Panicum virgatum) is a perennial sod-forming grass with thick, strong stems. It is a perennial warm season bunchgrass that is native to North America, where it occurs naturally from Canada southwards into the United States and Mexico. Switchgrass is one of the dominant species of the central North American tallgrass prairie and can be found in prairie remnants (grassland areas in the western and midwestern United States and Canada that remain, to some extent, undisturbed), in native grass pastures, and naturalized along roadsides.

The advantages of switchgrass as an energy crop are that it is fast-growing, remarkably adaptable, and high-yielding. Further advantages of switchgrass are that it can be harvested, using conventional equipment, either annually or semi-annually for 10 years or more before replanting is needed and that it is able to reach deep into the soil for water and use water very efficiently.

Besides showing great promise as an energy crop for energy production, switchgrass also restores vital organic nutrients to farmed-out soils and with its extensive network of stems and roots (the plants extend nearly as far below ground as above), it is also a valuable soil stabilization plant.

Switchgrass has the potential to be a versatile bioenergy feedstock since the energy content is comparable to that of wood with significantly lower initial moisture content. Switchgrass is very suitable substrate and produces high ethanol yield using current simultaneous saccharification and fermentation technology. Extensive analysis of ash and alkali content of switchgrass indicates that it typically has relatively low alkali content and should have low slagging potential in coal-fired combustion systems. As an agro-fiber source for pulping, switchgrass has a relatively high cellulose content, low ash content, and good fiber length to width ratios. Switchgrass reaches its full yield potential after the third year planted, producing approximately 6 to 8 tons per acre; that is 500 gallons of ethanol per acre.

The utilization of energy crops such as switchgrass (Panicum virgatum, L., Poaceae) is a concept with great relevance to current ecological and economic issues on a global scale. Development of a significant national capacity to utilize perennial forage crops, such as switchgrass as biofuels could provide an important new source of energy from perennial cropping systems, which are compatible with conventional farming practices, would help reduce degradation of agricultural soils, lower national dependence on foreign oil.

15.3.4.2 Jerusalem Artichoke

The Jerusalem artichoke (Helianthus tuberosus, also called sunroot, sunchoke, or earth apple) is a species of sunflower native to central North America. It is a herbaceous perennial plant that grows up to 5 to 10 feet tall with opposite leaves on the upper part of the stem but alternate below. The leaves have a rough, hairy texture. Larger leaves on the lower stem are broad-ovoid-acute and can be up to 12 inches long while the leaves higher on the stem are smaller and narrower.

The tubers are often elongated and uneven, typically 3 to 4 inches long and 1 to 2 2 inches thick with a crisp and crunchy texture when raw. They vary in color from pale brown to white, red, or purple.

The Jerusalem artichoke has shown excellent potential as an alternative sugar crop. A member of the sunflower family, this crop is native to North America and well-adapted to northern climates. Like the sugar beet, the Jerusalem artichoke produces sugar in the top growth and stores it in the roots and tuber. It can grow in a variety of soils, and it is not demanding of soil fertility. The Jerusalem artichoke is a perennial; small tubers left in the field will produce a crop for the next season, so no ploughing or seeding is necessary. The high-fructose syrups that can be derived from the tubers produced by the Jerusalem artichoke may be used for the production of ethanol and other industrial raw materials. Jerusalem artichokes also produce a large amount of top growth which may also prove to be a useful source of biomass for energy purposes.

15.3.4.3 Miscanthus

Miscanthus (also called silvergrass) is a hardy perennial grass that produces a crop of bamboo-like cane up to 15 feet tall. Miscanthus is high in lignin and lignocellulose fiber. Lignocellulose is the term used to describe the three-dimensional polymeric composites formed by plants as structural material. It consists of variable amounts of cellulose, hemicellulose, and lignin.

Briefly, lignocellulosic feedstocks are composed primarily of carbohydrate polymers (cellulose and hemicellulose) and phenolic polymers (lignin). Lower concentrations of various other compounds, such as proteins, acids, salts, and minerals, are also present. Cellulose and hemicellulose, which typically make up two-thirds of cell wall dry matter (dry matter: the portion of biomass that is not water), are polysaccharides that can be hydrolyzed to sugars and then fermented to ethanol. Process performance, in this case ethanol yield from biomass, is related to cellulose, hemicellulose, and individual sugar concentration in the feedstock. Lignin cannot be used in fermentation processes; however, it may be useful for other purposes.

Miscanthus can be grown in a cool climate and on many types of arable land. Miscanthus does not require a big input of fertilizers due to its capability to recycle large amounts of nutrients. Miscanthus has a similar calorific value per unit weight as wood and therefore could possibly be used in the same power plant or those designed for agricultural residues.

Miscanthus is well equipped for high productivity under relatively cool temperatures and may require substantial amounts of water for maximal growth. (Its growth could therefore also have valuable environmental benefits by acting as absorbing disposal areas for waste water and some industrial effluents.) Furthermore, Miscanthus seems to grow well in most soil conditions (bar thin droughty soils) but appears to thrive within areas which are currently best-suited to maize production. The advantages of Miscanthus as an energy crop are that it multiplies very rapidly, has a high yield which is relatively dry and can be harvested annually (from its second season onwards) compared with every 2 to 4 years for short rotation coppice. Further advantages are that Miscanthus can be grown and harvested with existing farm machinery, it requires little or no pesticide/fertilizer input after establishment and the harvest can use the same infrastructure for storage and transport as short rotation coppice. Finally, Miscanthus has a similar calorific value per unit weight as wood and therefore could possibly be used in the same power plant or those designed for agricultural residues.

15.3.4.4 Reed Plants

Reed is a common name for several tall, grass-like plants that are commonly found in wetlands. Reed plants are a potentially prolific producer of biomass, capable of yielding 20 to

25 tons per hectare (2.47 acres) of dry matter annually for a number of years. They can grow up to 6 m, are spread by means of stout rhizomes (continuously growing horizontal underground stems, which puts out lateral shoots and adventitious roots at intervals) and stolons (also known as runners, which are horizontal connections between organisms), and are commonly found in swampy ground and shallow water throughout temperate and subtropical areas.

Reed canary grass is a robust perennial grass, widely distributed across temperate regions of Europe, Asia and also North America. It occurs in wet places, along the margins of rivers, streams, lakes, and pools. The species spreads naturally by creeping rhizomes, but plants can also be raised from seed. The advantages of Reed canary grass as an energy crop are its good adaptation to cool temperate climates and poor wet soil conditions and, conversely, its ability to withstand drought. Crucially, for the purposes of biomass production, reed canary grass is also able to attain high dry matter content earlier than Miscanthus. The crop responds well to nitrogen and phosphate and it may be used in a bed system to remove nutrients from wastewater, as well as to stabilize areas at risk of soil erosion.

15.3.4.5 Residual Herbaceous Biomass

Residual herbaceous biomass (straw) is the main residual herbaceous material for energy application. As it is a residual product, its availability for energy purposes is driven by the cereals market and does not have autonomous market behavior. In addition, farms consume significant quantities of straw internally – as bed material for livestock, grain drying, etc. Some straw is also chaffed and returned back to the field as soil ameliorator. The net straw yield per hectare for energy application also depends on the crop, the grain yield per hectare, climate, and cultivation conditions, etc. Nevertheless, one can roughly estimate that the average straw yield per hectare is approximately 50 to 65% of the grain yield per hectare from cereals and oilseeds.

Similar to herbaceous crops, straw usually has lower moisture content than woody biomass. Conversely, it has a lower calorific value, bulk density, ash melting point and higher content of ash, problematic inorganic component such as chlorine, potassium, and sulfur, which cause corrosion and pollution. The last two drawbacks can be relatively easily overcome by leaving straw on the field for a while. In such a way rainfall provides a natural leaching process and separates a large part of the potassium and the chlorine. Alternatively, fresh straw can be directly shipped to the gasification plant, where it is washed by dedicated facilities at moderate temperatures (50 to 60°C; 120 to 140°F). Due to washing, the initially low moisture content of straw becomes higher in both cases and hence a mandatory drying is applied afterwards. In both cases also the content of corrosive components is reduced, but not completely taken out. In order to decrease handling costs, straw and dedicated herbaceous energy crops are usually baled before being shipped to the gasification plant. The weight and the size of bales depend on the baling equipment and on the requirements of the gasification plant (Luque and Speight, 2015).

The simplest form of agricultural biomass energy use involves direct combustion of cellulosic crops or residues, such as hay, straw, or corn fodder, to heat space or produce steam. Such fuels are useful for heating farm buildings and small commercial buildings in rural areas and for drying crops. Ideally, energy crops should be produced on land not needed for food production. This use should not increase the erosion hazard or cause other environmental damage. On the other hand, a variety of crops can be grown specifically to provide sources of energy and once established, a stand of perennial biomass/energy crop is expected to remain productive for a period of 6 years or more.

15.3.4.6 Short Rotation Coppice

Short rotation woody crops (short rotation coppice or SRC) refers to fast-growing deciduous trees which are grown as energy crops, such as willow and poplar trees. The species of short rotation coppice that are most suitable, and therefore most popular, for use as energy crops are poplar and willow (and possibly also birch) because they both require deep, moisture-retentive soils for proper growth. Willow, in particular, is able to endure periods of waterlogging and is therefore better suited to wetter soils.

Short rotation coppice is harvested during winter when the dry matter percentage of the coppice is at its highest and it is then bundled or immediately chipped. It may then be stored for a few weeks in order to reduce its moisture content to a satisfactory level for use in energy production. Dry short rotation coppice can then be burnt under controlled conditions to produce other fuels, gas, or liquid, which are then used for electricity generation.

15.3.4.7 Sorghum

Sorghum is an annual tropical grass with large genetic variation that is a crop with the potential for energy production. It is a genus of flowering plants in the grass family Poaceae. Seventeen of the 25 species are native to Australia with the range of some extending to Africa, Asia, and Central America as well as to islands in the Indian Ocean and the Pacific Ocean. One species is grown for grain, while many others are used as fodder plants, either cultivated in warm climates throughout the world or naturalized, in pasture lands.

Sweet sorghum has been selected for its sugar content and is normally grown for molasses production. Forage sorghum has been selected for high yields of reasonably good-quality animal feed. Sorghum varieties producing tall plants with large stems make the best candidates for biomass production. Both sweet and forage sorghum have a high potential for lodging. Lodging can result in harvest problems with ensuing loss of yield from both initial and ratoon crops.

Sweet sorghum is a name given to varieties of a species of sorghum. This crop has been cultivated on a small scale in the past for production of table syrup, but other varieties can be grown for production of sugar. The most common types of sorghum species are those used for production of grain. Sweet sorghum can be considered as an energy crop, because it can be grown in all continents, in tropical, sub-tropical, temperate regions as well as in poor-quality soils. Sweet sorghum is a warm-season crop that matures earlier under high temperatures and short days. Sweet sorghum is an extraordinarily promising multifunctional crop not only for its high economic value but also for its capacity to provide a very wide range of renewable energy products, industrial commodities, food, and animal feed products. Sweet sorghum biomass is rich in readily fermentable sugars and thus it can be considered as an excellent raw material for fermentative hydrogen production – hydrgoen is an important commodity for the refining industry and new sources are continually sought.

Sweet sorghum crops produce sugar syrups which could form the basis of fermentation processes for methane or ethanol production and some of the forage types of the plant may be suitable for biomass production.

15.3.5 Wood

Wood is a porous and fibrous structural tissue found in the stems and roots of trees and oth er woody plants. It is a natural composite of cellulose fibers that are strong in tension and embedded in a matrix of lignin that resists compression. Wood is sometimes defined as only the secondary xylem in the stems of trees, or it is defined more broadly to include the same type of tissue elsewhere such as in the roots of trees or shrubs. In a living tree it performs a support function, enabling woody plants to grow large or to stand up by themselves. Wood also conveys water and nutrients between the leaves, other growing tissues, and the roots. As a result of this structure, wood has lent itself to a variety of uses throughout recorded history.

The amount and types of wood fuel used vary considerably between regions, mainly due to different local situations and conditions. The quality of wood fuels is determined for fuel types by choosing for each delivery batch the limit values for the energy density, moisture content and particle size of the fuel as received from the quality. However, some of the use of wood is derived from the use of black liquor from the pulp and paper industries.

Composition of Black Liquor	
Element	% w/w
Carbon	35.7
Hydrogen	3.7
Nitrogen	≥0.1
Oxygen	35.8
Sulfur	4.4
Chlorine	0.3
Potassium	1.1
Sodium	19.0

Source: Kavalov and Peteves, 2005.

The components of wood include cellulose, hemicellulose, lignin, extractives, lipids, proteins, simple sugars, starches, water, hydrocarbon derivatives, ash, and other compounds. The proportion of these wood constituents varies between species, and there are distinct differences between hardwoods and softwoods.

15.3.5.1 *Types of Wood*

Hardwood, as the name suggests, is generally harder than softwood but there are significant exceptions. In both groups (hardwood and softwood) there is an enormous variation in actual wood hardness, with the range in density in hardwoods completely including that of softwoods; some hardwoods (such as balsa) are softer than most softwoods, while yew is an example of a hard softwood. Trees grown in tropical climates are generally hardwood. Hardwood grows faster than softwood but has shorter fibers compared to softwood. Hardwoods or deciduous woods have a higher proportion of cellulose, hemicelluloses, and extractives than softwoods, but softwoods have a higher proportion of lignin (Table 15.11). Generally, hardwoods which provide long-burning fires contain the greatest total heating value per unit of volume.

Hardwoods have a more complex structure than softwoods and are often much slower growing as a result. The dominant feature separating hardwoods from softwoods is the presence of pores, or vessels. The vessels may show considerable variation in size, shape of perforation plates (simple, scalariform, reticulate, foraminate), and structure of cell wall, such as spiral thickenings.

Hardwoods are employed in a large range of applications, including fuel, tools, construction, and the manufacture of charcoal. Solid hardwood joinery tends to be expensive compared to softwood. In the past, tropical hardwoods were easily available, but the supply of some species, such as teak and mahogany is now becoming scarce due to over-exploitation. Hardwoods may be used in a variety of objects, but are most frequently seen in furniture or musical instruments because of their density, which adds to durability, appearance, and performance. Different species of hardwood lend themselves to different end uses or construction processes due to the variety of characteristics apparent in different timbers, including density, grain, pore size, growth and fiber pattern, flexibility, and ability to be steam bent.

Softwood is usually wood from gymnosperm trees such as pine trees and spruce trees which often reproduce using cones and occasionally nuts. The trees classified as softwoods have needle-like or scale-like leaves that, with a few exceptions, remain on the tree all through the year. Hence softwood trees are sometimes called evergreens. Botanically, they are known as gymnosperms and instead of bearing seeds from flowers, gymnosperms have exposed seeds in cones.

Within the softwood and hardwood groups there is a considerable variation in actual wood hardness, the range of density in hardwoods completely including that of softwoods. Some hardwoods (such as balsa) are softer than most softwoods, while the hardest hardwoods are much harder than any softwood. In short, the terms softwood and hardwood are archaic with questionable meaning and often belie the properties of the wood.

Table 15.11 Composition of different biomass types (% w/w, dry basis).

Type	Cellulose	Hemicellulose	Lignin	Others	Ash
Soft wood	41	24	28	2	0.4
Hard wood	39	35	20	3	0.3
Pine bark	34	16	34	14	2
Straw (wheat)	40	28	17	11	7
Rice husks	30	25	12	18	16
Peat	10	32	44	11	6

Source: Prakash and Karunanithi, 2008.

Softwoods are generally most used by the construction industry and are also used to produce paper pulp, and card products. In many of these applications, there is a constant need for density and thickness monitoring and gamma-ray sensors have shown good performance in this case. Certain species of softwood are more resistant to insect attack from woodworm, as certain insects prefer damp hardwood. Softwoods which give a fast-burning, cracking blaze are less dense and contain less total heating value per unit of volume.

15.3.5.2 Composition and Properties

Wood is the hard, fibrous substance found beneath bark in the stems and branches of trees and shrubs. Practically all commercial wood, however, comes from trees. It is plentiful and replaceable. Since a new tree can be grown where one has been cut, wood has been called the only renewable natural resource in the world. Wood consists of cellulose ($C_6H_{19}O_5$), resins, lignin, various inorganic salts, and water, which is reflected in the ultimate analysis of wood (Table 15.12). The quantity of water present has great effect on the heating value and ranges from 25 to 50% w/w in green wood, and from 10 to 20% w/w in air-dried wood (Table 15.13).

Wood cut in the spring and summer contains more water than that cut in the early part of the winter. A cord (8 feet long by 4 feet wide by 4 feet high) of hardwood, such as ash or maple, is approximately equal in heating value to one ton of bituminous coal; soft woods, such as pine and poplar, have less than half this amount. Wood burns with a long flame and is kindled, the fire quickly reaches its maximum intensity, and a relatively small quantity of ash is formed. Wood is too expensive for industrial use, except in a few special cases, where freedom from dirt and smoke is necessary. Of other cellulose materials, shavings, sawdust, and straw are used for fuel in some places. They are bulky and difficult to handle, while their heat value, which depends on the amount of moisture they contain, is seldom more than from one-third to one-half that of good coal. Such waste matter as spent tan-bark and bagasse (crushed sugar cane), and the pulp from sugar beets is sometimes used for fuel for evaporation for steam, but owing to the large amount of moisture they contain, the heat value is low.

15.3.5.3 Chemical Composition

The chemical composition of wood varies from species to species, but is approximately 50% w/w carbon, 42% w/w oxygen, 6% w/w hydrogen, 1% w/w nitrogen, and 1% w/w other elements (mainly calcium, potassium, sodium, magnesium, iron, and manganese).

Table 15.12 Ultimate analysis of wood (% w/w, dry-ash-free).

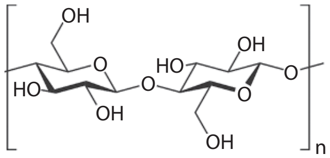
Element	Average of 11 hardwoods[a]	Average of 9 softwoods[a]	Oak bark[b]	Pine bark[b]
C	50•2	52•7	52•6	54•9
H	6•2	6•3	5•7	5•8
O	43•5	40•8	41•5	39•0
N	0•1	0•2	0•1	0•2
S	—	0•0	0•1	0•1

Table 15.13 Properties of various woody feedstocks compared to coal and natural gas.

	Bituminous coal	**Natural gas**	**Wood**	**Bark**	**Willow**	**Forest residues**
Ash, % w/w	8.5-10.9	0	0.4-0.5	3.5-8	1.1-4.0	1-3
Moisture, % w/w	5-10	0	5-60	45-65	50-60	50-60
Volatile matter, % w/w	25-40	•100	>70	70-77	>70	>70
Ash melting point, °C	1100-1400		1400-1700	1300-1700	n.a.	n.a."
C,% w/w	76-87	75	46-52	46-52	47-51	48-52
H, % w/w	3.5-5	24	6.2-604	4.6-6.8	5.8-6.7	6.0-6.2
N, % w/w	0.8-1.5	0.9	0.1-0.5	0.3-0.8	0.2-0.8	0.3-0.5
O % w/w	2.8-11.3	0.9	36-42	24.3-42.4	40-46	40-44
S, % w/w	0.5-3.1	0	<0.05	<0.05	0.02-0.10	<0.05
Cl, % w/w	<0.1		0.01-0.03	0.01-0.03	0.02-0.05	0.01-0.04
K, % w/w	0.003	-	0.02-0.05	0.1-0.4	0.2-0.5	0.1-004
Ca, % w/w	4-12		0.1-1.5	0.02-0.08	0.2-0.7	0.2-0.9

15.3.5.3.1 Cellulose

Cellulose, the major chemical constituent of wood, is in many respects the most important. It is also the most easily defined and described. Wood cellulose is chemically defined as $(C_6H_{10}O_5)_n$. Cellulose is a high molecular weight, stereoregular, and linear polymer of repeating beta-D-glucopyranose units. Simply speaking it is the chief structural element and major constituents of the cell wall of trees and plants. The empirical formula for cellulose is $(C_6H_{10}O_5)$n where *n* is the degree of polymerization (DP).

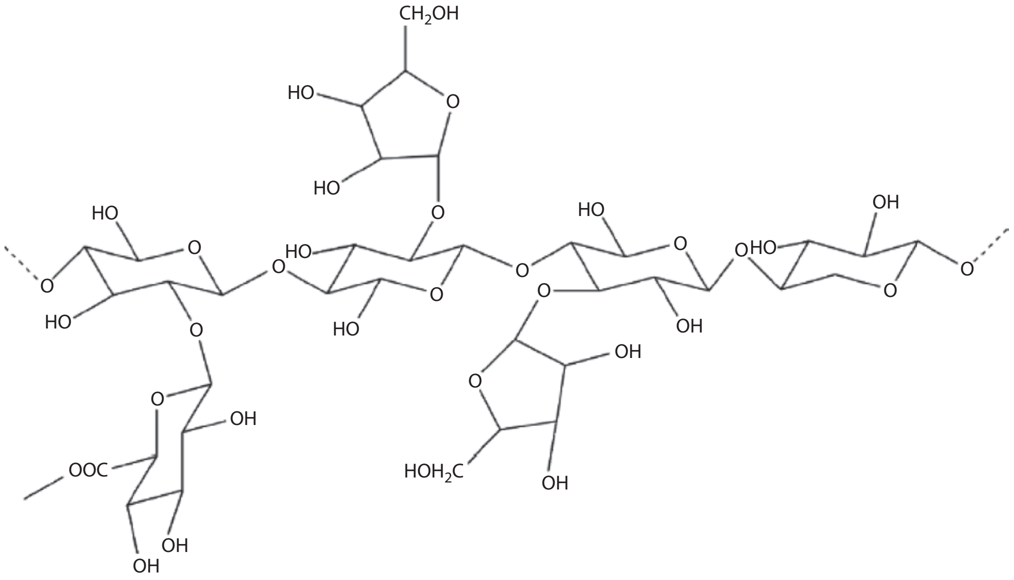


Generalized structure of cellulose

15.3.5.3.2 Hemicellulose

Hemicellulose derivatives, which make up 20 to 35% of the dry weight of wood, are the second important constituent of wood, and are also sugar polymers and unlike cellulose, which is made only from glucose, hemicelluloses consist of glucose and several other water-soluble sugar derivatives that are produced during photosynthesis. In the hemicellulose family, the degree of polymerization is lower than in cellulose and is composed of shorter molecular chains than are found in cellulose. There are many varieties of hemicelluloses and they markedly differ in composition in softwoods and hardwoods – generally, hemicellulose derivatives are in a relatively greater proportion in hardwoods than in softwoods.

Hemicellulose (hemi-cellulose) is a constituent of woods that is, like cellulose, a polysaccharide, but less complex and easily hydrolysable. Hemicellulose derivatives are polysaccharides that are often associated with cellulose, but have different composition.



Generalized structure of hemicellulose

Unlike cellulose, hemicellulose consists of 50 to 3,000 sugar units as opposed to 7,000 to 15,000 glucose molecules per polymer in cellulose. Hemicelluloses are classified according to the main sugar residue in the backbone as xylan derivatives, mannan derivatives, and glucan derivatives. Depending on the plant species, developmental stage, and tissue type, various subclasses of hemicellulose may exist which may be grouped into two general categories based on the hydration of the fibers. Low hydration polysaccharide derivatives function primarily to stabilize the cell wall through hydrogen-bonding interactions with cellulose and covalent interaction with lignin. They are water soluble due to their branched structure. The second type is hemicellulose derivatives composed mainly of hydrocolloids (often called gums, which are hydrophilic polymers, of vegetable, animal, microbial or synthetic origin, that generally contain many hydroxyl groups and may be polyelectrolytes) which function primarily as an extracellular energy and raw materials storage system and as a water-retention mechanism in seeds.

Hemicellulose derivatives contain many different sugar monomers, while cellulose only contains anhydrous glucose. For example, in addition to glucose, the sugar monomers in hemicellulose derivatives can include the five-carbon sugars xylose and arabinose, the six-carbon sugars mannose and galactose, and the six-carbon deoxy-sugar rhamnose.

Xylose is, in most cases, the sugar monomer present in the largest amount, although in softwoods mannose can be the most abundant sugar, leading to the production of ethanol

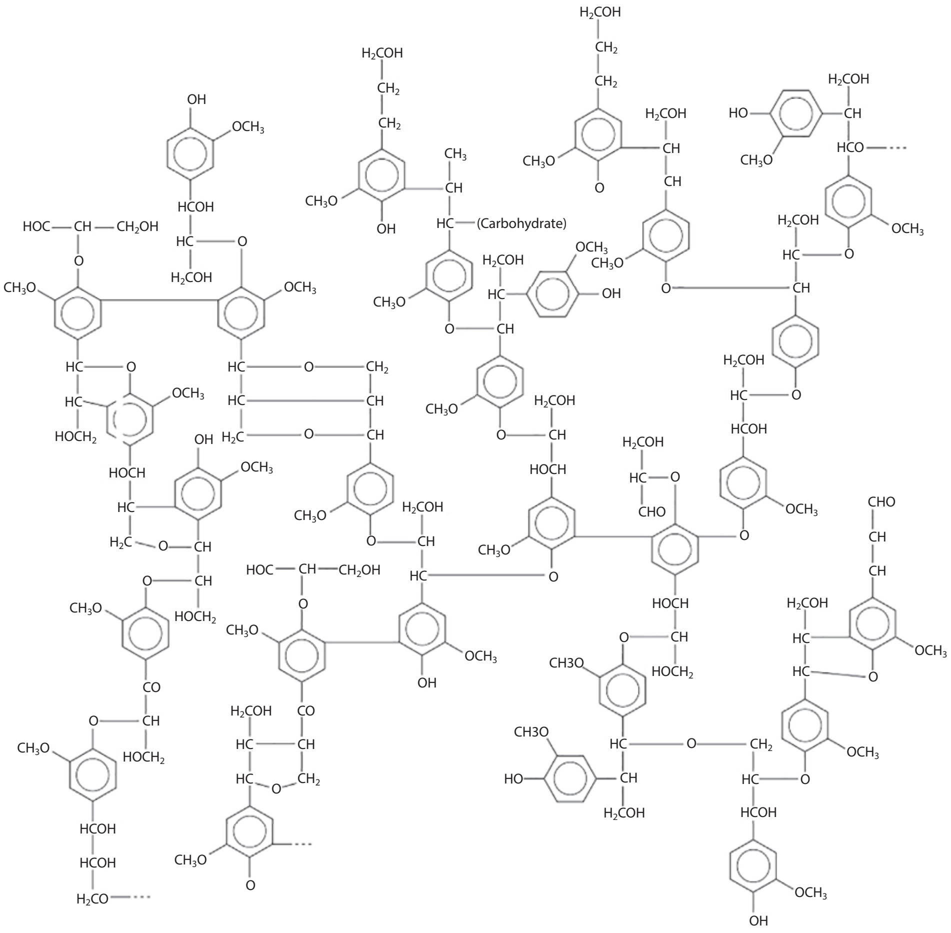
(Keller, 1996; Galbe and Zacchi, 2002). Not only regular sugars can be found in hemicellulose, but also their acidified form, for instance glucuronic acid and galacturonic acid can be present.

15.3.5.3.3 Lignin

Lignin is a complex constituent of the wood that cement the cellulose fibers together and is largely responsible for the strength and rigidity of plants. Lignin is a class of complex organic polymers that form key structural plants. As a biopolymer, lignin is unusual because of the heterogeneity and lack of a defined primary structure. Its most commonly noted function is the support through strengthening of wood.

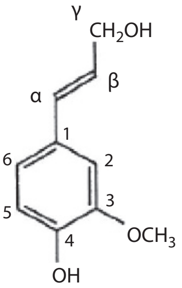
Structurally, lignin is a cross-linked polymer with a molecular mass in excess of 10,000. It is relatively hydrophobic and rich in aromatic subunits. The actual degree of polymerization is difficult to measure since the material is heterogeneous. Lignin is particularly important in the formation of cell walls, especially in wood and bark, because it does not rot easily.

Chemically, lignins are cross-linked phenolic polymers but the composition does vary from species to species – as example of composition from an aspen sample is carbon 63.4% w/w, hydrogen 5.9%, and oxygen 30% (by difference), mineral as 0.7% ash which corresponds to the approximate formula $(C_{31}H_{34}O_{11})_n$.

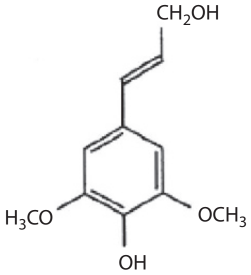


Hypothetical structure of lignin

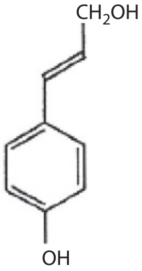
The lignol derivatives that cross-link are of three main types, all derived from phenylpropane: 4-hydroxy-3-methoxy phenylpropane, 3,5-dimethoxy-4-hydroxy phenylpropane, and 4-hydroxy phenylpropane. Thus, different types of lignin have been described depending on the means of isolation. The three common monolignols presented below are (i) trans-coniferyl alcohol, (ii) trans-sinapyl alcohol, and (iii) trans-p-coumaryl alcohol



trans-Coniferyl alcohol



trans-Sinapyl alcohol

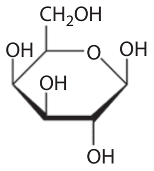


trans-p-Coumaryl alcohol

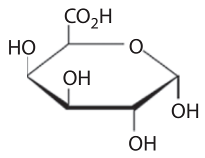
Thus, lignin can be defined as a polyphenolic material arising primarily from enzymic dehydrogenative polymerization of three phenylpropanoid units (p-hydroxy-cinnamyl alcohols). The proportions of the precursors in lignins vary with their botanical origin. The typical structural elements of softwood lignins are derived principally from trans-coniferyl alcohol (90%) with the remainder of the structure consisting predominantly of trans-p-coumaryl alcohol. In contrast, the lignin derivatives in hardwood are composed predominantly of trans-coniferyl alcohol and trans-sinapyl alcohol in varying ratios (approximately 50% for each alcohol).

Structural and other chemical issues aside, lignin fills the spaces in the cell wall between cellulose, hemicellulose, and pectin components (structural acidic heteropolysaccharide derivatives contained in the primary cell walls of terrestrial plants), especially in vascular and support tissues. It is covalently linked to hemicellulose and therefore cross-links different plant polysaccharides, conferring mechanical strength to the cell wall and, by inference, to the whole plant.

By way of explanation, pectin is a structural acidic heteropolysaccharide contained in the primary cell walls of terrestrial plants. The main component is galacturonic, a sugar acid derived from galactose.



Galactose



Galacturonic acid

Lignin plays a crucial part in conducting water in plant stems – the polysaccharide constituents of the plant cell are hydrophilic and thus permeable to water, whereas lignin is more hydrophobic and less permeable to water. The cross-linking of polysaccharides by lignin is an obstacle for water absorption to the cell wall and, thus, the presence of lignin makes it possible for the vascular tissue of the plant to conduct water efficiently.

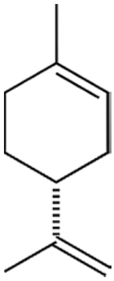
15.3.5.3.4 Solvent Extractable Materials

The structure created by hydrogen bonds results in the typical material properties of the chemical constituents of wood confers insolubility in most solvents. For isolation of, for example, cellulose from wood, a direct nitration of wood yields undegraded cellulose trinitrate, which is soluble in organic solvents. On the other hand, the glycosidic linkages are easily cleaved by strong mineral acids and therefore cellulose can be hydrolyzed to simple sugars. However, for a complete hydrolysis of cellulose, concentrated acid solutions must be used in order to achieve the necessary swelling and at least a partial destroying of the ordered regions. Furthermore, although native lignin derivatives behave as an insoluble and three-dimensional network, the isolated lignin derivatives exhibit maximum solubility in a variety of solvents including dioxane, acetone, methyl cellosolve, tetrahydrofuran, dimethylformamide, and dimethyl sulfoxide.

More generally, the soluble materials or extractives in wood consist of those components that are soluble in neutral organic solvents. The di-chloromethane extractable content of wood is a measure of such substances as waxes, fats, resins, phyto-sterols, and non-volatile hydrocarbon derivatives. The amount of extractives is highly dependent on seasoning or drying of wood. The ethanol-benzene extractable content of the wood consists of certain other di-chloromethane insoluble components such as low molecular weight carbohydrates, salts, and other water soluble substances. Most water soluble and volatile compounds are removed during pulping. The extractives reduce pulp yield, increase pulping and bleaching chemical consumption and create problems such as foaming during papermaking if not removed.

For isolation of the solvent extractable constituents from wood, the different methods can be used. Volatile extractives are represented by high-volatile compounds which can be separated by water distillation. They are mainly composed of monoterpene derivatives and other volatile terpene derivatives, terpenoid derivatives as well as of many different low molecular compounds. Resin is the name as a collective name for the lipophilic extractives (with the exception of phenolic substances). Resin extractives can be extracted with organic solvents. Water-soluble compounds consist of various phenol derivatives, carbohydrates, glycoside derivatives, and soluble salts, which can be extracted by cold or hot water.

Most plant resins are composed of terpenes. Specific components include alpha-pinene, beta-pinene as well as the monocyclic terpenes limonene and terpinolene, with and smaller amounts of the tricyclic sesquiterpene derivatives.



Limonene

Some wood resins also contain a high proportion of resin acid derivative. On the other hand, rosins are less volatile and consist, inter alia, of diterpane derivatives. In addtion, wood resins are divided into free acids, e.g., resin acid and fatty acid, and neutral compounds (such as fats and waxes). The resin fraction is soluble in organic solvents but insoluble in water, and therefore it can be extracted with organic solvents, such as hexane, dichloromethane, diethyl ether, acetone, or ethanol. Different non-polar and polar solvents can be selected for isolation of the different types of the soluble extractable constituents of wood.

15.3.6 Chemistry and Uses

The utilization of biomass to produce valuable products by thermal processes is an important aspect of biomass technology (Speight, 2011b, 2020). Biomass pyrolysis gives usually rise to three phases: (i) gases, (ii) condensable liquids, and (iii) char/coke (Figure 15.8). However, there are various types of related kinetic pathways ranging from simple paths to more complex paths and all usually include several elementary processes occurring in series or in competition. As anticipated, the kinetic paths are different for cellulose, lignin, and hemicelluloses (biomass main basic components) and also for usual biomasses according to their origin, composition, and inorganic contents.

The main biomass constituents – hemicellulose, cellulose, and lignin – can be selectively devolatilized into value-added chemicals. This thermal breakdown is guided by the order of thermochemical stability of the biomass constituents that ranges from hemicellulose (as the least stable constituent) to the more stable – lignin exhibits an intermediate thermal degradation behavior. Thus, wood constituents are decomposed in the order of hemicellulose-cellulose-lignin, with a restricted decomposition of the lignin at relatively low temperatures. With prolonged heating, condensation of the lignin takes place, whereby thermally largely stable macromolecules develop. Whereas both hemicellulose and cellulose exhibit a relatively high devolatilization rate over a relatively narrow temperature range, thermal degradation of lignin is a slow-rate process that commences at a lower temperature when compared to cellulose.

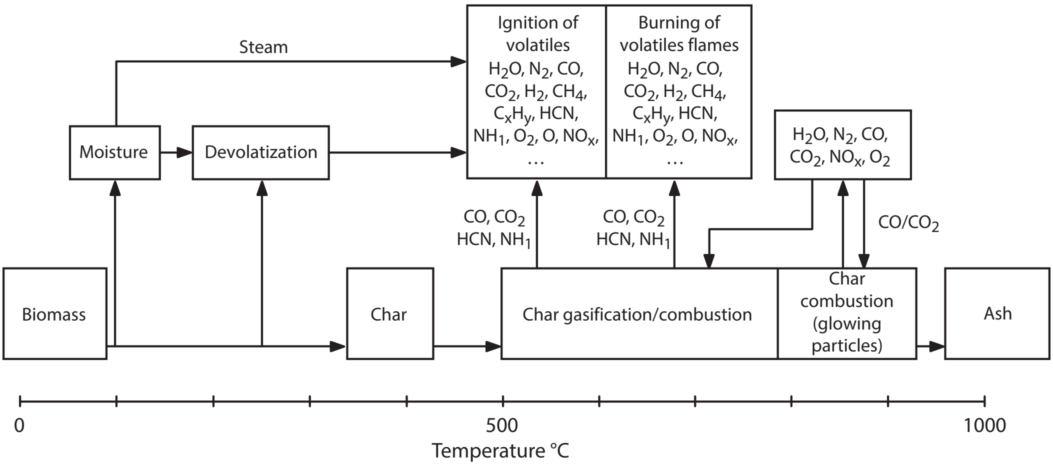


Figure 15.8 Products from biomass pyrolysis.

Thus, biomass, unlike natural gas or crude oil, offers a wide variety of compositions. In addition, the specific components of plants such as carbohydrates, vegetable oils, plant fiber and complex organic molecules known as primary and secondary metabolites can be utilized to produce a range of valuable monomers, chemical intermediates, pharmaceuticals and materials: (i) carbohydrates, (ii) vegetable oils, (iii) plant fibers, and (iv) specialty chemicals.

Carbohydrates (starch, cellulose, sugars): starch readily obtained from wheat and potato, whilst cellulose is obtained from wood pulp. Polysaccharides can be hydrolyzed, catalytically or enzymatically to produce sugars, a valuable fermentation feedstock for the production of ethanol, citric acid, lactic acid, and dibasic acids such as succinic acid. Vegetable oils: vegetable oils are obtained from seed oil plants such as palm, sunflower and soya. The predominant source of vegetable oils in many countries is rapeseed oil. Plant fibers, such as lignocellulosic fibers, can be extracted from plants such as hemp and flax and can replace cotton and polyester fibers in textile materials and glass fibers in insulation products.

More generally, biomass feedstocks are recognized by the specific chemical content of the feedstock or the manner in which the feedstocks is produced. However, the chemical composition of biomass varies considerably. Predictably, the chemical and molecular composition of biomass impacts its subsequent decomposition. The rate of decomposition is an early facet of the dynamic process for converting biomass and is dependent on biomass quality (chemical composition and molecular composition) as well as other factors, such as process parameters.

The main bio-feedstock constituents hemicellulose, cellulose and lignin can be selectively devolatilized into value-added chemicals – this thermal breakdown is guided by the order of thermochemical stability of the biomass constituents that ranges from hemicellulose (fast degassing/decomposition from 200 to 300°C, 390 to 570°F) as the least stable natural product to the more stable cellulose (fast degassing/decomposition from 300 to 400°C, 570 to 750°F). Lignin exhibits an intermediate thermal degradation behavior (gradual degassing/decomposition from 250 to 500°C, 480 to 930°F).

The chemical components of wood are decomposed in the order of hemicellulose-cellulose-lignin, with a restricted decomposition of the lignin at relatively low temperatures. In the further course of heating, a re-condensation of the lignin takes place, whereby thermally largely stable macromolecules develop. Whereas both hemicellulose and cellulose exhibit a relatively high devolatilization rate over a relatively narrow temperature range, thermal degradation of lignin is a slow-rate process that commences at a lower temperature when compared to cellulose (Bajus, 2010).

The past abundance of biomass, particularly word, and the dispersion of the industry have worked against advances in technology for the efficient production, conversion, and use of wood products. Fortunately, and despite its relatively recent origin as a recognized field of study, wood science has had an appreciable effect on wood technology as well as science in general. The study of wood chemistry has contributed to our understanding of the principal components of wood – cellulose and lignin – and their reactions. Early research on hydrolysis of cellulose was prompted by fuel needs in World War I, but contributed much to our knowledge of this form of chemical reaction.

The Madison Process as it was described in the 1940s was developed to hydrolyze softwood species, which is particularly valuable for the production of fuels such as ethanol (Keller, 1996; Galbe and Zacchi, 2002). The hemicellulose sugars were recovered in the form of furfural, and only one stage was required. If hardwood species are used, a two-stage process is more desirable to maximize the recovery of both the hemicellulose and cellulose. High yields of hemicellulose products can be obtained at the milder pre-hydrolysis conditions compared to the higher temperature required to maximize glucose yields from the cellulose in the second stage.

The several acid hydrolysis processes now being promoted to produce ethanol from wood do it in different types of equipment at slightly different acid-temperature-time conditions. The stake process uses a horizontal screw reactor. The Iotech process uses a high-pressure, short-time hydrolysis followed by rapid release of pressure. The twin-screw extruder process developed by New York University uses a high-pressure, special reactor design. The plug-flow reactor under study at Dartmouth and another developed by American Can use different methods to pump the wood and acid into the reactor. The New Zealand process under license to Ultra Systems is probably a modern version of Madison Process.

After the hydrolysis of the cellulose, the processes could be identical if the same products were to be recovered. Some of the two-stage processes differ in that the residue from the first stage is delignified with a lignin solvent. This dissolves the lignin to leave only cellulose to be hydrolyzed in the second stage. The lignin is then recovered by distilling off the solvent. This is in contrast to hydrolyzing the first-stage residue to solubilize the cellulose and leave the lignin.

Wood is bulky, has less than half the heat of combustion of fuel oil, and in its green state is heavy to ship. Furthermore the cost of a wood-burning system may be three to four times that of a gas-burning installation because of fuel storage, handling, and air quality control systems. These drawbacks have kindled interest in production of liquid and gaseous fuels from wood. Much research is devoted to improving existing technology and devising new approaches, but such fuels are still expensive compared with crude oil-based fuels.

Finally, closely related to the conversion of wood to liquid or gaseous fuel is the use of the chemical storehouse that is wood to produce a wide range of silvichemicals. Many processes of these types already form the basis of chemical production on a commercial scale. But the potential to use wood as a chemical feedstock is much greater than has so far been realized. Whole wood can be gasified, liquefied, or pyrolyzed in ways comparable with those used for coal to yield a wide variety of chemicals. Cellulose, as a glucose polymer, can be hydrolyzed to the glucose monomer by acid or enzymes, and the glucose then fermented to ethanol. The ethanol can be used as a fuel or as a source of other important chemicals such as ethylene or butadiene.

Lignin can be pyrolyzed, hydrogenated, and hydrolyzed to yield phenols, which can be further processed to benzene. Once the technology and economics are feasible, future plants will manufacture a variety of these significant chemicals from wood, now derived from crude oil or other resources.

Charcoal continues to be used as an important industrial source of energy. For example, in Brazil, some 6 million tonnes of charcoal are produced every year for use in heavy industry, such as steel and alloy production. The industrial demand for charcoal in the last few years has led to new, more efficient, and large-scale technologies, mainly aimed at improving charcoal yield and quality. Furthermore, although fuel wood is mainly a local source of energy, there are signs of an international trade in wood fuel developing between European and North American countries.

The dynamics of wood fuel flow are complex and very site-specific. The development of sustainable wood energy systems remains one of the most critical issues to be addressed by policy makers and community planners. With society giving increasing attention to sustainability issues, in the case of wood energy in both developing and developed countries, economic, environmental, and social issues deserve particular attention.

15.4 Waste

Waste (often referred to as refuse) is the result of human activities or the by-product from a process (or processes) for which no use is planned or foreseen. Thus, waste in the context of this book is actually a by-product of the human chemical, physical, and economic system. The words domestic and industrial are qualifiers of the source of the waste and, to some extent, are also descriptive of the contents of the waste. Once a material has been designated as waste, it remains waste until it has been fully recovered and no longer poses a potential threat to the environment or a use is found for the waste. However, in nature (which is typically a balanced system unless disturbed by human activities) there is no waste. Since the Industrial Revolution, human society has developed economies that are largely unrelated to nature and the natural order of events and generate considerable quantities of waste – domestic and industrial.

Waste (refuse) comes in a variety of forms and must be dealt with on a day-to-day basis. Industry produces huge amounts of industrial waste and domestic waste makes a large contribution to the general waste problem. In spite of the recognition, many insidious waste products escape (inadvertently or deliberately) into the surrounding environment. Thus, there are numerous pollution incidents. On the other hand, there are technologies available for the treatment of most of the waste we produce. The level of treatment is largely a matter of cost but conversion of waste to new products is a concept that has long been ready to hatch.

Domestic waste (also known as rubbish, garbage, trash, or junk) is unwanted or undesired material (Table 15.14). Waste is the general term; though the other terms are used loosely as synonyms, they have more specific meanings. Thus: (i) rubbish or trash are mixed household waste including paper and packaging; (ii) food waste or garbage (North America) is kitchen and table waste, and (iii) junk or scrap is metallic or industrial material. There are other categories of waste as well: sewage, ash, manure, and plant materials from garden operations, including grass cuttings, fallen leaves, and pruned branches. On the other hand, industrial waste is waste produced by industrial operations such as factories, mills, and mines and has existed since the onset of the Industrial Revolution. Chemical waste and toxic waste are two additional (but specific) designations of industrial waste (Table 15.15).

Municipal solid waste (MSW) is a waste type that includes predominantly household waste (domestic waste) with sometimes the addition of commercial wastes collected by a municipality within a given area. They are in either solid or semisolid form and generally exclude industrial hazardous waste. The term residual waste relates to waste left from household sources containing materials that have not been separated out or sent for reprocessing.

Relevant to the disposal of waste, streams such as chemical waste, medical waste, paper waste, plastic waste, and textile waste, as well as many other types of carbonaceous waste

Table 15.14 Major sources of waste.

Dredging and irrigation	Waste consists of soil and sediments removed from waterways, harbours, estuaries, and irrigation canals. The quantities may be considerable and contain hazardous materials discharged from industrial and farming activities. It is not suited for energy production.
Farming, livestock rearing, dairy activities	Waste composed largely of spoilt food, manure, crop waste, waste from chemical or pesticide use. Not all of the agricultural waste generated can be put to energy production; some of this waste is returned to the land as part of good agricultural practice.
Industrial	Some of the major industrial sources of waste are construction and demolition, fabrication, light and heavy manufacturing, refineries, chemical plants, and non-nuclear power plants. Some large industrial facilities have their own recycling initiatives and operate their own landfills; it is difficult to determine the amount of waste discarded.
Mining and quarrying	Waste consists of mine tailings (silts, fine sands, or other aggregate materials) and may pose problems to the environment due to large quantities of waste produced and, in some cases, its hazardous nature. Not suited for energy production
Nuclear power and nuclear defence	The civilian nuclear power industry, defence facilities and nuclear research projects generate dangerous radioactive waste. The toxicity due to exposure and concerns over long-range health and environmental effects make nuclear waste extraordinarily difficult to dispose of safely.
Residential, commercial, and institutional	Homes, commercial or institutional businesses, construction and demolition activities, municipal services, and treatment plants (inclusive of waste incinerators) are major contributors to waste streams.

which may form part of industrial and domestic waste are usable as feedstocks for various processes such as (i) gasification processes, (ii) pyrolysis processes, or (iii) incineration processes. However, although waste is a very general category, it must be remembered that as is the case for the feedstocks for any process, these raw materials require different processes for optimal operation.

There are five broad categories of municipal solid waste: (i) biodegradable waste, such as food and kitchen waste and green waste, (ii) recyclable material such as paper, glass, cans metals, and certain types of plastic, (iii) inert waste such as construction and demolition waste, dirt, rocks, debris, (iv) composite waste which includes waste clothing, and waste plastics, and (v) domestic hazardous waste (also called household hazardous waste) and toxic waste such as discarded medications, paints, chemicals, light bulbs, fluorescent tubes, spray cans, fertilizer containers, pesticide containers, batteries, and shoe polish.

Table 15.15 Amounts (% w/w) of cellulose, hemicellulose and lignin common agricultural residues and wastes.

Agricultural residue	Cellulose	Hemicellulose	Lignin
Bamboo	41-49	24-28	24-26
Coastal Bermuda grass	25	35.7	6.4
Corn cobs	45	35	15
Corn stover	35	28	16-21
Cotton seed hairs	80-90	5-20	0
Grasses	25-40	35-50	10-30
Hardwood stem	40-50	24-40	18-25
Leaves	15-20	80-85	0
Newspaper	40-55	25-40	18-30
Nut shells	25-30	25-30	30-40
Paper	85-99	0	0-15
Primary wastewater solids	8-15	NA	24-29
Rice straw	40	18	5.5
Softwood stem	45-50	25-35	25-35
Solid cattle manure	1.6-4.7	1.4-3.3	2.7-5.7
Sorted refuse	50-60	10-20	15-20
Sugar cane bagasse	32-48	19-24	23-32
Sweet sorghum	27	25	11
Swine waste	6.0	28	-
Switch grass	30-51	10-50	5-20
Waste papers from chemical pulps	60-70	10-20	5-10
Wheat straw	33-40	20-25	15-20

Some components of waste – such as plastic bottles, metals, glass, or paper – can be recycled once recovered from the waste stream. The biodegradable components of wastes (such as paper and food waste), including agricultural waste (Tables 15.14, 15.15). Biomass is carbon based and is composed of a mixture of organic molecules containing hydrogen, usually including atoms of oxygen, often nitrogen and also small quantities of other atoms, including alkali metals, alkaline earth metals, and heavy metals. These metals are often found in functional molecules such as the porphyrin molecules which include chlorophyll which contains magnesium. Also, if biomass not used in a sustainable manner biodegradable waste can contribute to greenhouse gas emissions and, by implication, climate change.

On the other hand, there is also electronic waste which is a waste consisting of any broken or unwanted electrical or electronic appliance. While there is no generally accepted definition of electronic waste, in most cases it consists of electronic products that were used for data processing, telecommunications, or entertainment in private households and businesses that are now considered obsolete, broken, irreparable, or of no further use due to planned obsolescence. Despite its common classification as a waste, disposed electronics are a considerable category of secondary resource due to their significant suitability for direct reuse (for example, many fully functional computers and components are discarded during upgrades), refurbishing, and material recycling of its constituents. It is a point of concern considering that many components of such equipment are considered toxic and are not biodegradable but they are not precursors to fuels and other than recognition though the above paragraph will not be considered in the context of the present text.

15.4.1 Domestic and Industrial Waste

Much of what human society discards contains usable material, much of it in the form of recoverable energy. Paper, wood, cloth, food waste, and plastics are the main potential energy sources in waste. The remainder of the waste consists of glass, metals, and miscellaneous rubble. Domestic waste is typically disposed of by tipping it into large holes in the ground – landfill sites. Sometimes the waste is incinerated first and only the remaining ash and non-combustible material is sent to a landfill. Increasingly, a proportion of the waste is being separated for recycling at some stage along the way.

Domestic waste could also provide feedstock for a number of other conversion systems, all of which could recover useful energy while reducing the requirement for landfill sites. However, whatever the energy technology, domestic waste is a low-grade fuel. Its consistency is variable and not well suited to mechanical handling systems; the proportions of the various constituents will vary from load to load; the moisture content and heating value will vary; and the proportion of non-combustible material will keep the heating value low. All of this can lead to inefficient combustion if the process is not well controlled, making it more difficult to control toxic emissions from plastics and other materials. There is also a potential conflict between the recycling of materials and the recovery of energy from those materials. The main benefit of domestic waste as a fuel source is that, as with most other waste streams, energy technology can reduce the waste disposal problem.

15.4.2 Effects of Waste

Wastes generated from domestic and industrial sources increase continuously with rising population. In general, the lack of facilities for disposal of waste led to overuse of landfill sites, resulting in hazards for the environment and for public health. These effects include (i) air pollution, (ii) pollution of surface waters, (iii) changes in soil fertility, and (iv) changes in the landscape and visual discomfort. The historic approach to solid waste has been to bury it in landfill. This is becoming increasingly problematic because the diminishing availability of suitable landfill sites, and the increasingly stringent conditions being applied to landfill, mean that charges have increased and will continue to increase. Major problems associated with landfills are the leachate containing toxic heavy metals and the methane gas that is produced.

Indeed, the challenge for waste disposal arises from the joint storage of hazardous materials (including toxic sludge, oil products, dyeing residues, metallurgical slag) and solid domestic waste. This situation is likely to generate inflammable, explosive, or corrosive mixtures and combinations thereof. On the other hand, the presence of easily degradable household waste may facilitate the decomposition of complex hazardous components, and thus diminish environmental pollution.

Another negative aspect is the fact that several recyclable and useful materials are stored in the same place as materials that cannot be recycled; consequently, these materials blend together and become chemically and biologically contaminated, which renders their retrieval rather difficult.

Thus, the problems faced by waste management activities may be summarized as follows: (i) storage in open grounds is the most used method to remove waste ultimately, (ii) existing landfills may be located in sensitive places, which are those places in close proximity to lodgings, surface or groundwater, leisure areas), (iii) existing waste landfills may be improperly designed from an environmental protection point of view, thus allowing for water and soil pollution in those areas, (iv) currently waste landfills may require a review of waste handling practices insofar as waste layers are not compacted and there is no strict control of the quality and quantity of waste that is dumped on the landfill leading to the potential for fire and/or the emanation of unpleasant odors.

All of the above lead to the conclusion that specific measures need to be taken with regard to waste management, which would be adequate in each phase of the waste dumping process. Environmental monitoring activities should comprise the observance of these measures. However, one answer to these issues is to convert the waste to usable products either through (i) the production of gaseous fuels, or (ii) the production of liquid fuels, or (iii) the production of solid fuels. Such efforts may not only solve the depletion of fuels from fossil sources but also assist in the disposal of waste materials and the ensuing environmental issues. However, before entering upon the process descriptions for waste conversion, it is necessary to understand the composition of domestic and industrial waste.

Generating waste at current levels is incompatible with a sustainable future. While the problem of waste is serious, a variety of initiatives are being taken to address the various threats. These include moves toward waste minimization, waste segregation and recycling, cleaner production with regular waste audits, green chemistry, renewable energy, and energy efficiency, and developing the concept of industrial ecosystems. The issues involved are much more than technical problems.

This is a major issue because of the variability of industrial solid, liquid, and gaseous wastes, and the capacity of modern processing industries to produce huge quantities of waste. Fortunately, regulatory processes are now such that the numerous disasters caused previously should not be repeated. However there are remaining problem sites that constitute long-term hazards.

Thus, in order to reduce the amount of landfill, the amount of waste must be reduced. This involves either (i) cutting back on the use of many materials or (ii) use of the waste by conversion to useful products. Either option would reduce the amount of waste sent to landfill sites. The first option certainly reduces the amount of landfill material but is often more difficult to achieve. However, the second option offers the attractive proposition of the production of fuel products. Thus, waste conversion becomes an attractive option to landfill disposal and the result is the generation of a usable product in the form of a gaseous, liquid, or solid fuel. However, ancillary of the second option is the heterogeneity of waste material. In fact, it is obvious that many waste streams are not subject to direct processing and will require special measures in the form of specific pretreatment of the waste prior to processing.

One form of pretreatment is separation and recycling of waste components, thereby removing a portion of the waste stream for recycling and other uses. The result of this separation at the source is the remaining residual waste (i.e., the waste stream from which recyclable materials have been removed) that is not destined for any use other than landfill is sent to the conversion reactor.

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16

Combustion of Alternate Feedstocks

16.1 Introduction

Combustion is the reaction of a fuel with oxygen in air to release heat or to generate steam (Chapters 7, 8). Chemically, combustion is a complex interaction of physical and chemical processes. The most appropriate fuels for combustion are materials rich in hydrogen and carbon and such fuels include natural gas, crude oil (or fractions thereof), coal, wood, agricultural residues, and municipal solid waste. Ideally, in the process all of the hydrogen and carbon in the fuel would combine with the oxygen in the air to create water vapor, carbon dioxide and heat. Thus: Below is the generalized formula for a combustion reaction of a carbonaceous fuel, typically a fossil fuel:

$$\text{Hydrocarbon fuel} + \text{oxygen} \rightarrow \text{carbon dioxide} + \text{water vapor}$$

The complete combustion of a carbonaceous fuel – a fuel containing carbon and hydrogen (sometimes referred to as a hydrocarbonaceous fuel) as well as other elements such as nitrogen and sulfur and metals – can be represented as:

$$\text{Carbonaceous fuel}_{(\text{nitrogen, sulfur})} + \text{oxygen} \rightarrow \text{carbon dioxide} + \text{water vapor} + \\ \text{nitrogen oxides} + \text{sulfur oxides, metal oxides (ash)}$$

Since the alternate fuels that are presented here are primarily composed of carbon, hydrogen and oxygen, the main products from burning such fuels are carbon dioxide and water. Flame temperatures can exceed 2000°C (3630°F), depending on the heating value and moisture content of the fuel, the amount of air used to burn the fuel and the construction of the furnace. Thus, the complete combustion of an alternate fuel requires a certain amount of air and since air consists of 21% v/v oxygen and approximately 79% v/v nitrogen, the product of the combustion of an alternate fuel air will include carbon dioxide and water vapor, excluding the nitrogen oxides formed from the nitrogen in the air. This reaction will generate heat and some observers represent the combustion of biomass (and solid waste) using this equation:

$$\text{Alternate fuel} + \text{air} \rightarrow \text{carbon dioxide} + \text{water vapor}$$

However, this is not the complete equation since biomass also contains constituents that are potential contaminants. In other words, biomass (and in this context) solid waste can

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cause serious damage to the environment when combusted. Thus a more appropriate equation for the combustion of these two alternate fuels (biomass and solid waste) is:

Alternate fuel + air → carbon dioxide + water vapor + nitrogen oxides _ sulfur oxides + metal oxides (ash)

Thus, like coal, in order for an alternate fuel to be converted into useful heat energy, it has to undergo combustion and a variety of contaminant can be present in the product gas. Although there are many different combustion systems available, the principle of biomass combustion is essentially the same for each. There are three main stages to the combustion process: (i) drying, (ii) pyrolysis, and (iii) oxidation. It is worth bearing in mind that while the three stages have been described as separate stages, all the above stages can occur simultaneously within the combustion zone.

In terms of the drying stage, most alternate fuels (especially biomass) contain moisture, and this moisture has to be driven off before combustion can take place. The heat for drying is supplied by radiation from flames and from the stored heat in the body of the combustion unit. After this – the pyrolysis stage – when the temperature of the dry fuel reaches between 200 and 350°C (390 and 660°F), gases and other volatile products are released. The products include carbon monoxide (CO), carbon dioxide (CO_2), methane (CH_4), and high molecular weight compounds (tar) that condense to a liquid if cooled. The gases mix with oxygen from the air and burn producing a yellow flame. This process is self-sustaining as the heat from the burning gases is used to dry the fresh fuel and release further volatile gases. Oxygen has to be provided to sustain this part of the combustion process. Char is the remaining material after all the volatiles have been burned off.

The final stage of the process – the oxidation stage – occurs at approximately is 800°C (1470°F) when the char – the carbonaceous residue – oxidizes or burns. Again oxygen is required, both at the fire bed for the oxidation of the carbon and, secondly, above the fire bed where it mixes with carbon monoxide to form carbon dioxide that is given off to the atmosphere. Long residence time for fuel in a combustor allows the fuel to be completely consumed.

Combustion is complete when 100% of the energy in the fuel has been extracted. It is important to achieve complete combustion to maximize the use of the fuel and to improve the efficiency of the combustion process. There must be enough air in the combustion chamber for complete combustion to occur. In addition. the addition of excess air greatly lowers the formation of carbon monoxide (CO) by allowing the carbon monoxide to react with the oxygen thereby resulting in the maximum effect of the process. More complete combustion will result in less carbon monoxide in the product gas:

$$2CO + O2 \rightarrow 2CO2$$

Complete combustion will occur when the correct amounts of fuel and air (fuel-to-air ratio) are mixed for the correct amount of time under appropriate conditions of turbulence and temperature. Theoretically, stoichiometric combustion provides the perfect fuel-to-air ratio, which lowers losses and extracts all of the energy from the fuel. However, when dealing with fuels such as the alternate fuels (described below), stoichiometric combustion is unattainable due to many factors, thereby rendering the maximum efficiency (100% efficiency) difficult (if not impossible) to attain. In practice, in order to achieve complete combustion, it is necessary to increase the amount of air to the combustion process to ensure the burning of all of the fuel. The amount of air (the excess air) that is required for various combustion systems is in the range of 5 to 50% v/v of the stoichiometric amount – assuming the stoichiometry is based on the pure hydrocarbon – depending on the fuel characteristics and the system configuration.

This chapter focuses on the alternate fuels that can be used into combustion systems, i.e., (i) viscous feedstocks, such as crude oil residua, heavy crude oil, (ii) extra heavy crude oil and tar sand bitumen, as well as (iii) crude oil coke, solvent deasphalter bottoms, asphalt, tar, and pitch, and (iv) biomass, (v) solid waste, and (vi) black liquor. Each of these feedstocks has its own peculiarities (i.e., compositional differences, properties, and behavior) and should be treated as such when a combustion system is considered for the process.

16.2 Viscous Feedstocks

In the current context, the refining industry is no stranger to the combustion and gasification resids which are typically combusted or gasified to produce gaseous fuels (Wolff and Vliegenthart, 2011, Speight, 2014a, 2017). In fact, for the refining industry, replacing coal with viscous feedstocks for power generation offers a continuation of the current power generation.

The physical and chemical properties of the viscous feedstocks are extremely complex, comprising a wide range of hydrocarbon derivaitves some of which contain elevated levels of sulfur, nitrogen, and metals as well as considerable variations in the properties and behavior (Tables 16.1, 16.2) (Speight, 2014a, 2017). These factors alone may result in more emissions from a power plant and require (like coal-fired plants) strict emission control and cleaning standards. Simply, the viscous feedstock can be represented by the formula ($C_aH_bN_cO_dS_eM_f$, where N, O, S, and M represent nitrogen, oxygen, sulfur, and metals, respectively and the subscript letters represent the number of atoms of the element in the feedstock).

Using crude oil residua as the example, combustion causes an increased amount of nitrogen oxides (NO_x), along with sulfur dioxide (SO_2) – which reacts with oxygen in the atmosphere to produce sulfur trioxide). These gases combine with water in the atmosphere to create acid rain (Chapter 7):

$$SO_2 + H_2O \rightarrow H_2SO_3$$

$$2SO_2 + O_2 \rightarrow 2SO_3$$

$$SO_3 + H_2O \rightarrow H_2SO_4$$

Thus:

$$2SO_2 + O_2 + 2H_2O \rightarrow 2H_2SO_4$$

Nitrogen oxides also contribute to the formation and occurrence of acid rain, in similar manner to the production of acids from the sulfur oxides, yielding nitrous and nitric acids.

Table 16.1 Simplified differentiation between conventional crude oil, tight oil, heavy crude oil, extra heavy crude oil, and tar sand bitumen*.

Conventional Crude Oil
Mobile in the reservoir; API gravity: >25°
High-permeability reservoir
Primary recovery
Secondary recovery
Tight Oil
Similar properties to the properties of conventional crude oil; API gravity: >25°
Immobile in the reservoir
Low-permeability reservoir
Horizontal drilling into reservoir
Fracturing (typically multi-fracturing) to release fluids/gases
Resids
API gravity (typically) <20°
Low mobility to no mobility
Contain the majority of the heteroatoms (N, S) originally in the crude oil
Atmospheric resid: boiling range >510°C (>650°F)
Vacuum resid: boiling range or >565 °C (>1050°F)
Also includes deasphalter bottoms, refinery coke, asphalt, tar, pitch, and the non-refinery black liquor
Heavy Crude Oil
More viscous than conventional crude oil; API gravity: 10-20°
Mobile in the reservoir
High-permeability reservoir
Secondary recovery
Tertiary recovery (enhanced oil recovery – EOR, e.g., steam stimulation)
Extra Heavy Crude Oil
Similar properties to the properties of tar sand bitumen; API gravity: <10°
Mobile in the reservoir
High-permeability reservoir

(*Continued*)

Table 16.1 Simplified differentiation between conventional crude oil, tight oil, heavy crude oil, extra heavy crude oil, and tar sand bitumen*. (*Continued*)

Secondary recovery
Tertiary recovery (enhanced oil recovery – EOR, e.g., steam stimulation)
Tar Sand Bitumen
Immobile in the deposit; API gravity: <10°
High-permeability reservoir
Mining (often preceded by explosive fracturing)
Steam assisted gravity draining (SAGD)
Solvent methods (VAPEX)
Extreme heating methods
Innovative methods**

*This list is not intended for use as a means of classification.
**Innovative methods excludes tertiary recovery methods and methods such as steam assisted gravity drainage (SAGD) and vapor assisted extraction (VAPEX) methods but does include variants or hybrids thereof (Speight, 2016).

Table 16.2 Comparison of selected properties of athabasca tar sand bitumen (Alberta, Canada) and zuata extra heavy oil (Orinoco, Venezuela).

		Athabasca bitumen	***Zuata extra heavy oil***
Whole oil	API gravity	8	8
	Sulfur, % w/w	4.8	4.2
Resid (>650°F)	% v/v	85	86
	Sulfur, % w/w	5.4	4.6
	Ni + V, ppm	420	600
	CCR*, % w/w*	14	15

*Conradson carbon residue.

$$NO + H_2O \rightarrow H_2NO_3$$

$$2NO + O_2 \rightarrow 2NO_2$$

$$NO_2 + H_2O \rightarrow HNO_3$$

Thus:

$$4NO_2 + O_2 + 2H_2O \rightarrow 4HNO_3$$

The increased concentrations of acidic species in the atmosphere have significant effects on the acidity (pH <7) of the rainfall. The acid rain has adverse impacts on the larger ecosystem. For example, acid rain can kill trees, and can kill fish by acidifying lakes.

In addition, the products of the combustion of residua are also carbon dioxide (CO_2), water (H_2O), and the metals (mercury, Hg, is the exception) passing into the combustion ash. As for coal, emission control is a necessity and can be achieved as follows. Thus, emissions from the combustion of a viscous feedstock depend on the feedstock type and composition, the design type and capacity of the boiler, the firing conditions, load, and the type of control devices, and the level of equipment maintenance. Emissions from viscous feedstocks primarily include particulate matter (PM), sulfur oxides (SOx), nitrogen oxides (NOx), and carbon monoxide (CO), as well as trace amounts of volatile organic compounds and trace elements (Chapter 15).

The organic emissions include volatile, semi-volatile, and condensable organic compounds either present in the feedstock or formed as a product of incomplete combustion (PIC). Organic emissions are primarily characterized by the criteria pollutant class of unburned vapor-phase hydrocarbon derivatives. These emissions include alkanes, alkenes, aldehydes, alcohols, and substituted benzene derivatives (such as benzene, toluene, xylene isomers, and ethyl benzene).

Waste oil (used motor oil) is often cited as a useful fuel but there are hazards involved and caution is advised (Speight and Exall, 2014). Waste oil can be disposed of in different ways, including sending the used oil off-site (some facilities are permitted to handle the used oil, such as a local garage and a local waste disposal facility), burning used oil as a fuel (some used oil is not regulated by burner standards, but others that are off-specification used oil can only be burned in either industrial furnaces certain boilers, and permitted hazardous waste incinerators), and marketing the used oil. (Claims are made that the used oil is to be burned for energy recovery, and then it is shipped to a used oil burner who burns the used oil in an approved industrial furnace or boiler.) Oils that are off-specification typically contain arsenic 5 ppm, cadmium 2 ppm, chromium 10 ppm, lead 100 ppm, flash point 38°C (100°F minimum (i.e., the flash point must be greater than 38°C), total halogens >4,000 ppm.

In addtion, the metal content has interesting effects on the pyrolysis and char combustion behavior: when the sample is heated up under mildly oxidizing atmospheres (i.e., when the oxygen concentration is in excess of 1% v/v), the metals promote the uptake of oxygen in parallel with char formation and affect the degree of graphitization of the carbon structure The composition of the pyrolysis gas is strongly affected by the presence of even low concentration of oxygen.

Controls on various types of boilers have been applied to reduce the various emissions (Chapter 12). As an example, the emission of particulate matter is controlled by efficient control systems, such as fabric filters, electrostatic precipitators (ESP), and scrubbers. In the fabric filters (also referred to as baghouses), particulate-laden vapors passes through a set of filters mounted inside the collector housing. Particulate matter in the inlet gas are collected on the filters by inertial impaction, diffusion, direct interception, and sieving. The collection efficiencies of fabric filters can exceed 99%. The collection of particulate matter in an electrostatic precipitator occurs in three steps: (i) suspended particles are given an electrical charge, (ii) the charged particles migrate to a collecting electrode of opposite polarity while subjected to a diverging electric field; and (iii) the collected particulate matter is dislodged from the collecting electrodes. In some cases electrostatic precipitators have an efficiency on the order of 90 to 97% efficient, because of the characteristic high resistivity of low-sulfur fly ash. Higher efficiencies can be achieved using larger electrostatic precipitators combined with other forms of flue gas conditioning (Chapter 12).

The most widely used wet scrubbers for fossil fuel-fired boilers are venturi scrubbers. In a typical venturi scrubber, the particle-laden gas first contacts the liquor stream in the core and throat of the venturi section. The gas and liquid streams then pass through the annular orifice formed by the core and throat, atomizing the liquid into droplets which are impacted by particles in the gas stream. Impaction results mainly from the high differential velocity between the gas stream and the atomized droplets which are then removed from the gas stream by centrifugal action in a cyclone separator and (if present) a mist eliminator section. Wet scrubbers have a particular matter collection efficiencies of on the order of 90% or greater.

Gaseous emissions such as sulfur dioxide, nitrogen oxides, carbon monoxide and organics may also be absorbed to a significant extent in a wet scrubber. Operational problems can occur with wet scrubbers due to clogged spray nozzles, sludge deposits, dirty recirculation water, improper water levels, and unusually low pressure drop. Mechanical collectors, or cyclones, use centrifugal separation to remove particulate matter from flue gas streams. At the entrance of the cyclone, a spin is imparted to the particle-laden gas. This spin creates a centrifugal force which causes the particulate matter to move away from the axis of rotation and toward the walls of the cyclone. Particles which contact the walls of the cyclone tube are directed to an ash collection hopper where they are deposited. Mechanical collectors typically have a collection efficiency for particulate matter on the order of 70 to 80%.

16.3 Biomass

The term biomass encompasses diverse fuels derived from timber, agriculture, and food processing wastes or from fuel crops that are specifically grown or reserved for electricity generation. Biomass fuel can also include sewage sludge and animal manure. Some biomass fuels are derived from trees. Given the capacity of trees to regenerate, these fuels are considered renewable. Burning crop residues, sewage, or manure – all wastes that are continually generated by society -- to generate electricity may offer environmental benefits in the form of preserving precious landfill space or may be grown and harvested in ways that cause environmental harm.

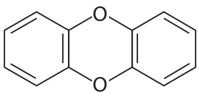
Biomass is the single most abundantly available renewable energy source that can be used on demand (Suri and Horio, 2010). Wood combustion/gasification can thus play a significant role not just on an industrial scale, but also in domestic electricity supply by following load changes. Moreover, small- to mid-scale biomass thermal power stations can be installed that can help reduce transmission losses and also serve as district heating and for regional hot water supply lines, thus reducing the double conversion such as in the case of using electricity for heating. Besides the industrial and domestic use of biomass combustion, waste incineration is another major sector where solid biomass combustion technology is widely applied. So far, biomass residues have been either land filled or incinerated together with other municipal wastes, and only a small amount of their energy has been utilized. This is because the main concern has been waste disposal and/or volume reduction. However, efficient thermal recycling of solid wastes has now become important to reduce fossil fuel consumption. Since woody biomass can be first utilized as material, say for buildings, and after decades as an energy source, waste biomass combustion is also a major area of biomass utilization.

To utilize the energy efficiently a range of advanced combustion concepts and technologies have been developed during recent decades, and continue to be developed, such as: direct combustion boilers, co-combustion in a pulverized coal furnace (PCF), fire grid combustion boilers, fluidized-bed combustion (FBC), pressurized fluidized-bed combustion (PFBC), circulating fluidized-bed combustion (CFBC), gasification–combustion boilers/in combination with Sterling engines, wood pellet boilers/heaters, small-scale automated biomass combustion devices, and so on. As long as a proper fuel strategy is adopted, as discussed later, solid biomass combustion technologies can be a technically efficient, economically viable, and environmentally sustainable option for biomass utilization (Suri and Horio, 2010).

At present, most biomass power plants burn lumber, agricultural or construction/demolition wood wastes. Direct combustion power plants burn the biomass fuel directly in boilers that supply steam for the same kind of steam-electric generators used to burn fossil fuels. With biomass gasification, biomass is converted into a gas – methane – that can then fuel steam generators, combustion turbines, combined cycle technologies or fuel cells. The primary benefit of biomass gasification, compared to direct combustion, is that extracted gases can be used in a variety of power plant configurations.

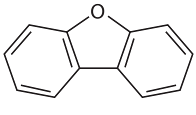
In the current context, there are two basic technologies for an initial thermochemical conversion of biomass to energy: (i) combustion, and (ii) gasification, of which combustion is the most proven technology for heat and power production (Suri and Horio, 2010). Gasification is of interest for future applications due to two advantages: (i) higher electric efficiencies are possible by gasification, especially if the producer gas is used for combined cycle applications, and (ii) the gasification process allows an application with low airborne emissions. Emissions of particulate matter can be significantly reduced in comparison to conventional combustion, since highly efficient particle removal in the raw gas needs to be applied to protect the gas turbine and/or the turbo charger. Furthermore, an almost complete combustion of the producer gas in the gas turbine combustion chamber is reached, thus resulting in negligible organic emissions such as volatile organic compounds and the volatile organic constituents that are condensable.

However, the combustion of biomass is often related to significant pollutant formation and needs to be improved. Pollutant formation occurs due to three reasons: (i) incomplete combustion can lead to high emissions of non-combustible pollutants such as carbon monoxide soot, tar, and polycyclic aromatic hydrocarbon derivatives, (ii) pollutants such as sulfur oxides, nitrogen oxides, and particulate matter are formed as a result of natural fuel constituents such as potassium, calcium, sodium, magnesium and phosphorus, and (iii) biomass feedstocks can be carriers of additional contaminants such as heavy metals or chlorine, which can lead to high emissions of heavy metals, hydrogen chloride (HCl), and potentially highly toxic polychlorinated dibenzo-p-dioxin derivatives and furan derivatives.



Dibenzo-p-dioxin

Dibenzo-1,4-dioxin



Dibenzofuran

Biomass combustion exhibits relatively high emissions of NOX and submicron particles. Air staging and fuel staging can be applied as primary measures for NOX reduction that offer a potential of 50% to 80% reduction. For further reduction, secondary measures such as selective catalytic and selective non-catalytic reduction (SCR, SNCR) can be applied. However, the selective non-catalytic reduction process can lead to significant undesired side-products that need to be carefully avoided. Moreover, in order to develop measures for emission reduction, the specific fuel properties need to be considered.

The use of biomass as a fuel is considered to be *carbon neutral* because plants and trees remove carbon dioxide (CO_2) from the atmosphere and store it while they grow. In fact, the simplest, cheapest and most common method of obtaining energy from biomass is direct combustion. Any organic material, with a water content low enough to allow for sustained combustion, can be burned to produce energy. The heat of combustion can be used to provide space or process heat, water heating or, through the use of a steam turbine, electricity. In the developing world, many types of biomass such as dung and agricultural wastes are burned for cooking and heating.

The combustion process results in a residue after the primary use has been fulfilled. The organic residue can be used for energy production through direct combustion. Most crop residues are returned to the soil, and the humus resulting from their decomposition helps maintain soil nutrients, soil porosity, water infiltration and storage, as well as reducing soil erosion. Crop residues typically contain 40% of the nitrogen (N), 80% of the potassium (K) and 10% of the phosphorous (P) applied to the soil in the form of fertilizer. If these residues are subjected to direct combustion for energy, only a small percentage of the nutrients is left in the ash. Similarly, soil erosion will increase.

The combustion of biomass produces carbon dioxide which is a part of the so-called net zero carbon dioxide cycle. This *net-zero* or *carbon neutral* cycle can be repeated indefinitely, as long as biomass is regrown in the next management cycle and harvested for use. *The sustainable management of the biomass source is thus critical* to ensuring that the carbon cycle is not interrupted. However, although the sequestered carbon dioxide (in the biomass) is introduced (released) into atmosphere, new plant or tree growth keeps the carbon cycle of the atmosphere in balance by recapturing carbon dioxide. In contrast to biomass, fossil fuels such as gas, oil and coal are not regarded as carbon neutral because they release carbon dioxide which has been stored for millions of years, and do not have any storage or sequestration capacity.

16.3.1 Properties and Combustion

Biomass properties that affect its utilization for energy, biofuels, and materials include the chemical composition, the polymeric composition, and the physical traits such as density and strength. The traditional biomass used in energy applications has been fuelwood, which is a fiber that is composed of lignin, cellulose, and hemicellulose, and wood is a lignocellulosic material resource. Cellulose, hemicellulose, and lignin are carbon hydrogen oxygen polymers that serve different structural purposes in the construction of the cell walls of woody plants. Lignocellulosics include trees, most woody plants, the straw, and stalks of cereal crops, and are the most important biomass materials and energy resource as they represent much more than half of the above-ground biomass produced by photosynthesis. In addition to the lignocellulosic component, there are more complex polymers such as proteins (that can contain sulfur in addition to nitrogen), extractives, and inorganic materials. The inorganic materials range from anions such as chlorine, sulfate, and nitrates, and cations such as potassium, sodium, calcium and magnesium as major constituents and there are also many trace elements including manganese and iron, which are the metallic elements in key enzyme pathways involved in cell wall construction.

Since biomass fuels are primarily composed of carbon, hydrogen and oxygen, the main products from burning biomass are carbon dioxide and water. Flame temperatures can exceed 2000°C (3630°F), depending on the heating value and moisture content of the fuel, the amount of air used to burn the fuel and the construction of the furnace.

Combustion has three requirements: (i) fuel, (ii) air, and (iii) heat. If any of these three are removed, burning stops. When all three are available in the correct proportion, combustion is self-sustaining, because the fuel releases excess heat to initiate further burning. Complete combustion of biomass requires a certain amount of air, which consists of 21% v/v oxygen and approximately 79% v/v nitrogen. Therefore, the product of a stoichiometric combustion of biomass in air will include carbon dioxide, water vapor and nitrogen. This reaction will generate heat.

For solid biomass to be converted into useful heat energy, it has to undergo combustion. Although there are many different combustion systems available, the principle of biomass combustion is essentially the same for each.

The preparation, storage, and handling properties of biomass impact are different from coal. Biomass has low bulk energy density, is generally moist and strongly hydrophilic, and is non-friable. Biomass heating values generally are slightly over half that of coal, particle densities are approximately half that of coal, and bulk densities are approximately one-fifth that of coal. This results in an overall fuel density roughly one-tenth that of coal. Consequently, cofiring biomass at a 10% heat input rate results in volumetric coal and biomass flow rates of comparable magnitudes. Consequently, biomass demands shipping, storage, and on-site fuel handling technologies disproportionately high compared to its heat contribution.

Biomass produces a non-friable, fibrous material during comminution. It is generally unfeasible (and unnecessary) to reduce biomass to the same size or shape as coal. In many demonstration plants, biomass firing occurs with particles that pass through a ¼" (6.4 mm) mesh, which measurements indicate results in a size distribution dominantly less than approximately 3 mm. Depending on the type of biomass and preparation technique, average aspect ratios of these particles range from three to seven, with many particles commonly having much higher aspect ratios. Such particles have low packing densities and create challenges when pneumatically or otherwise transporting biomass fuels.

16.3.2 Combustors

Biomass, such as wood, crop residues and animal manure, is burned in various types of combustion reactors. What is left is a number of gases, fragments of partially oxidized hydrocarbon derivatives and water vapor.

Wood chip and pellet furnaces, fed from a hopper or by a small auger, are very efficient, and the firing rate can be controlled to match the heating load. Woodchip furnaces are generally restricted to commercial applications, as chips are not readily available in most areas and must be stored under cover. Outdoor wood-fired furnaces keep the dirt and ash outside the home. The unit is usually located within 200 feet of the house, where fuel can be easily supplied and where the heat can be piped to the home.

The furnace of the boiler is where the fuel and air are introduced to combust; fuel/air mixtures are normally introduced into the furnace by using burners, where the flames are formed. The resulting hot gases travel through a series of heat exchangers, where heat is transferred to the water flowing through them. The combustion gases are finally released to the atmosphere via the exhaust section of the boiler. The boiler is an enclosed vessel in which water is heated and circulated, either as hot water, steam or superheated steam for the purpose of heating, powering and/or generating electricity.

Three of the most common types of industrial combustion systems are downdraft combustion, updraft combustion and fluidized-bed combustion systems. Downdraft combustion is where flames are drawn into the combustion chamber and combustion occurs inside the reactor, while updraft combustion is where the combustion occurs outside and above the reactor. In fluidized-bed combustion, solid fuels are suspended on upward-blowing jets of air during the combustion process. This mixes the gas and solids in a turbulent regime. Fluidized-bed combustors provide an effective environment for chemical reactions and heat transfer.

16.3.3 Biomass for Electricity Generation

Biomass is used for facility heating, electric power generation, and combined heat and power. The term biomass encompasses a large variety of materials, including wood from various sources, agricultural residues, and animal and human waste. Biomass can be converted into electric power through several methods. The most common is direct combustion of biomass material, such as agricultural waste or woody materials. Other options include gasification, pyrolysis, and anaerobic digestion. Gasification produces a synthesis gas with usable energy content by heating the biomass with less oxygen than needed for complete combustion. Pyrolysis yields bio-oil by rapidly heating the biomass in the absence of oxygen. Anaerobic digestion produces a renewable natural gas when organic matter is decomposed by bacteria in the absence of oxygen.

Electricity generation from biomass is a diverse collection of organic feedstocks including wood and wood waste solids, black liquor, municipal solid waste, and landfill gas. Wood solids were the largest feedstock electricity generation from biomass. Wood solids primarily consist of residues from forestry, lumber production and manufacturing, paper mills, and other allied industries and are used to produce heat and electricity in the electric power and industrial sectors.

Black liquor, a by-product of making wood pulp, accounted for 28% of biomass and waste electricity generation in 2018, second only to wood solids. Black liquor has a high heat content, making it desirable as a boiler fuel, and contributes 56% of total electric generation at papermaking plants. Production of black liquor depends on the demand for wood pulp by the papermaking industry. Although paper production has grown over the past decade, recycled paper replaced wood pulp as the principal feedstock for much of the increase in paper production.

Different methods work best with different types of biomass. Typically, woody biomass such as wood chips, pellets, and sawdust are combusted or gasified to generate electricity. Corn stover and wheat straw residues are baled for combustion or converted into a gas using an anaerobic digester. Very wet wastes, like animal and human wastes, are converted into a medium-energy content gas in an anaerobic digester. In addition, most other types of biomass can be converted into bio-oil through pyrolysis, which can then be used in boilers and furnaces. Although the ash contents of both wood and straw materials are significantly lower than those of most power station coals, the ash chemistry and mineralogy are different.

In general terms, biomass ash has a relatively low ash fusion temperature, with the ash deformation temperature commonly in the range of 750 to 1000°C, (1380 to 1830°F) compared to values in excess of 1000°C (1830°F) for coal ash. Even at modest cofiring ratios, the cofiring of biomass materials can have a major impact on the ash fusion behavior. The rate and extent of coal ash slag formation on surfaces in the boiler furnace tends to increase, due principally to the decrease in the fusion temperatures of the mixed biomass-coal ashes, since fused or partially fused slag deposits tend to be more receptive to oncoming particles and grow more rapidly. The impact of cofiring on slag deposition depends largely on the chemistry and the fusion behavior of the coal ash and the cofiring ratio.

A simple biomass electric generation system is made up of several key components. For a steam cycle, this includes some combination of the following items: (i) fuel storage and handling equipment, (ii) combustor/furnace, (iii) boiler, (iv) steam turbine, (v) generator, (vi) condenser, (vii) cooling tower, and (viii) exhaust/emissions controls.

Direct combustion systems feed a biomass feedstock into a combustor or furnace, where the biomass is burned with excess air to heat water in a boiler to create steam. Instead of direct combustion, some developing technologies gasify the biomass to produce a combustible gas, and others produce pyrolysis oils that can be used to replace liquid fuels and boiler, fuel can include wood chips, pellets, sawdust, or bio-oil. Steam from the boiler is then expanded through a steam turbine, which spins to run a generator and produce electricity.

In general, all biomass systems require fuel storage space and some type of fuel handling equipment and controls. A system using wood chips, sawdust, or pellets typically use a bunker or silo for short-term storage and an outside fuel yard for larger storage. An automated control system conveys the fuel from the outside storage area using some combination of cranes, stackers, reclaimers, front-end loaders, belts, augers, and pneumatic transport. Manual equipment, like front loaders, can be used to transfer biomass from the piles to the bunkers, but this method will incur significant cost in labor and equipment operations and maintenance. A less labor-intensive option is to use automated stackers to build the piles and reclaimers to move chips from the piles to the chip bunker or silo.

Wood chip-fired electric power systems typically use one dry ton per megawatt-hour of electricity production. This approximation is typical of wet wood systems and is useful for a first approximation of fuel use and storage requirements but the actual value will vary with system efficiency. For comparison, this is equivalent to 20% HHV efficiency with 17 MMBtu/ton wood.

Most wood chips produced from green lumber will have a moisture content of 40% to 55%, wet basis, which means that a ton of green fuel will contain 800 to 1,100 pounds of water. This water will reduce the recoverable energy content of the material, and reduce the efficiency of the boiler, as the water must be evaporated in the first stages of combustion.

16.3.4 Combustion Systems

There are a number of ways for converting biomass into electricity. The simplest approach is to burn the biomass in a furnace, exploiting the heat generated to produce steam in a boiler, which is then used to drive a steam turbine. This approach, often called direct firing, is the most widespread means of deriving heat and electricity from biomass. It is also generally rather inefficient, though new technologies will be able to improve efficiency significantly.

A simple, direct-fired biomass power plant can either produce electricity alone or it can operate as a combined heat and power unit, producing both electricity and heat. This latter is common in the textile, food processing, chemical and paper industries where the heat is used in the processing plant. The electricity generated is used by the plant too, with any surplus exported to the grid. Simplicity is the key feature of direct firing type of application.

A more advanced approach is biomass gasification. This employs a partial combustion process to convert biomass into a combustible gas. The gas has a lower energy content than natural gas but, nevertheless, it can be used in the same way as natural gas. In particular it can provide fuel for gas turbines and fuel cells. Biomass gasification is still in the development stage but it promises high efficiency and may offer the best option for future biomass-based generation.

An intermediate option for exploiting biomass is to mix it with coal and burn it in a coal-fired power station. In the short term this may offer the cheapest and most efficient means of exploiting biomass. Finally there are number of specialized methods of turning biomass wastes into energy. These include digesters, which can convert dairy farm waste into a useful fuel gas, and power stations that utilize chicken farm litter, which they burn to generate electricity.

Compared to many other renewable energy options, biomass has the advantage of dispatchability, meaning it is controllable and available when needed, similar to fossil fuel electric generation systems. The disadvantage of biomass for electricity generation, however, is that the fuel needs to be procured, delivered, stored, and paid for. Also, biomass combustion produces emissions, which must be carefully monitored and controlled to comply with regulations.

Most biopower plants use direct-fired combustion systems. They burn biomass directly to produce high-pressure steam that drives a turbine generator to make electricity. In some biomass industries, the extracted or spent steam from the power plant is also used for manufacturing processes or to heat buildings. These combined heat and power (CHP) systems greatly increase overall energy efficiency to approximately 80%, from the standard biomass electricity-only systems with efficiencies of approximately 20%. Seasonal heating requirements will impact the CHP system efficiency.

In terms of conversion technologies, the following technologies are commonly used: (i) pile combustion, (ii) stoker combustion, (iii) suspension combustion, and (iv) fluidized-bed combustion.

16.3.4.1 Pile Combustion

The simplest form of direct firing involves a pile burner. This type of burner has a furnace, which contains a fixed grate inside a combustion chamber. Wood is fed (piled) onto the grate where it is burned in air, which passes up through the grate (called underfire air). The grate of a pile burner is within what is known as the primary combustion chamber, where the bulk of the combustion process takes place. Combustion at this stage is normally incomplete – there may be significant quantities of both unburned carbon and combustible carbon monoxide remaining – so further air (called overfire air) is introduced into a secondary combustion chamber above the first – where combustion is completed.

The boiler for raising steam is positioned above this second combustion chamber so that it can absorb the heat generated during combustion. The heat warms, and eventually boils water in the boiler tubes, providing steam to drive a steam turbine. From the steam turbine the steam is condensed and then returned to the boiler so that it can be cycled through the system again. In a combined heat and power system, steam will be taken from the steam turbine outlet to provide heat energy first.

Wood fuel is normally introduced from above the grate, though sometimes there is a more complicated arrangement, which feeds fuel from under the grate. The pile burner is capable of handling wet and dirty fuels but it is extremely inefficient. Boiler efficiencies are typically 50 to 60%.

There is no means to remove the ash from a pile burner except by shutting down the furnace. Thus the power plant cannot be operated continuously. Pile burners are also considered difficult to control and they are slow to respond to changes in energy input. This means that electricity output cannot easily be changed in response to changes in demand.

Power generation in a pile-burner-based power station will usually involve a single pass steam turbine generator operating at a relatively low steam temperature and pressure. This adds to the relatively low efficiency of the power plant, which can operate with an overall efficiency as low as 20%.

16.3.4.2 Stoker Combustion

The pile burner represents the traditional method of burning wood. However, its basic operation can be improved by introducing a moving grate or stoker. This allows continuous removal of ash so that the plant can be operated continuously. Fuel can also be spread more thinly on the grate, encouraging more efficient combustion. In the stoker combustor, which is a type of furnace, combustion air still enters below the grate of a stoker burner. This flow of air into the combustion chamber helps cool the grate. The air flow and consequent grate temperature determines the maximum operating temperature of the combustor. This, in turn, determines the maximum moisture content allowable in the wood fuel if combustion is to proceed spontaneously.

There are refinements of the basic stoker grate such as inclined grates and water-cooled grates, both of which can help improve overall performance and make the operation less sensitive to fuel moisture. Nevertheless stoker combustors are still relatively inefficient, with boiler efficiencies of 65-75% and overall efficiencies of 20-25%.

16.3.4.3 Suspension Combustion

Most modern coal-fired power stations burn pulverized coal, which is blown into the combustion chamber of a power plant through a specially designed burner. The burner mixes air with the powdered coal, which then burns in a flame in the body of the combustion chamber. This is suspension combustion and in this type of plant there is no grate. Finely ground wood, rice husk, bagasse, or sawdust can be burned in a similar way.

Suspension firing requires a special furnace. The size and moisture content of the biomass (wood) must also be carefully controlled. Moisture content should be below 15% and the biomass particle size has to be less than 15 mm. Suspension firing results in boiler efficiency of up to 80% and allows a smaller-sized furnace for a given heat output. However, it also requires extensive biomass drying and processing facilities to ensure that the fuel is of the right consistency. It also demands special furnace burners. A small number of plants designed to burn biomass in this way have been built. The technology is also of great interest as the basis for the cofiring of wood or other biomass with coal in pulverized coal plants.

16.3.4.4 Fluidized-Bed Combustion

Aside from suspension firing of wood, the most efficient method of directly burning biomass is in a fluidized-bed combustor (also known as the fluid-bed combustor, FBC). This is also the most versatile since the system can cope with a wide range of fuels and a range of moisture contents. The basis for an FBC system is a bed of an inert mineral such as sand or limestone through which air is blown from below. The air is pumped through the bed in sufficient volume and at a high enough pressure to entrain the small particles of the bed material so that they behave much like a fluid.

The combustion chamber of a fluidized-bed plant is shaped so that above a certain height the air velocity drops below that necessary to entrain the particles. This helps retain the bulk of the entrained-bed material towards the bottom of the chamber. Once the bed becomes hot, combustible material introduced into it will burn, generating heat as in a more conventional furnace. The proportion of combustible material such as biomass within the bed is normally only around 5%.

There are different designs of FBC systems which involve variations around this principle. The most common for biomass combustion is the circulating fluidized bed which incorporates a cyclone filter to separate solid material from the hot flue gases which leave the exhaust of the furnace. The solids from the filter are recirculated into the bed, hence the name.

The fluidized bed has two distinct advantages for biomass combustion: First, it has the ability to burn a variety of different fuels without affecting performance. Second is the ability to introduce chemical reactants into the fluidized bed to remove possible pollutants. In FBC plants burning coal, for example, limestone can be added to capture sulphur and prevent its release to the atmosphere as sulphur dioxide. Biomass tends to contain less sulphur than coal so this strategy may not be necessary in a biomass plant. A fluidized-bed boiler can burn wood with up to 55% moisture. One specialized application is in plants designed to burn chicken litter, the refuse from the intensive farming of poultry. Power stations have been built that are devoted specifically to this fuel source and these plants use fluid-bed combustors.

Of the four different types of combustion technologies discussed above, the fluidized-bed combustion technology is best suited for a range of small- and medium-scale operation for combined heat and power. With technological advancements the fluidized-bed combustion boilers give efficiency of as high as 80 to 82% and can be used for a wide variety of fuels.

16.3.4.5 Direct Combustion System

In a direct combustion system, biomass is burned in a combustor or furnace to generate hot gas, which is fed into a boiler to generate steam, which is expanded through a steam turbine or steam engine to produce mechanical or electrical energy. In a direct combustion system, processed biomass is the boiler fuel that produces steam to operate a steam turbine and generator to make electricity. The two principal types of chip-fired direct combustion systems are stationary- and traveling-grate combustors, otherwise known as fixed-bed systems and atmospheric fluidized-bed systems.

There are various configurations of fixed-bed systems, but the common characteristic is that fuel is delivered in some manner onto a grate where it reacts with oxygen in the air. This is an exothermic reaction that produces hot gases and generates steam in the heat exchanger section of the boiler. In either a circulating fluidized-bed or bubbling fluidized-bed system, the biomass is burned in a hot bed of suspended, incombustible particles, such as sand. Compared to grate combustors, fluidized-bed systems generally produce more complete carbon conversion, resulting in reduced emissions and improved system efficiency. In addition, fluidized-bed boilers can use a wider range of feedstocks. Furthermore, fluidized-bed systems have a higher parasitic electric load than fixed-bed systems due to increased fan power requirements.

The efficiency of a direct combustion or biomass gasification system is influenced by a number of factors, including biomass moisture content, combustion air distribution and amounts (excess air), operating temperature and pressure, and flue gas (exhaust) temperature.

The type of system best suited to a particular application depends on many factors, including availability and cost of each type of biomass (e.g., chip, pellet, or logs), competing fuel cost (e.g., fuel oil and natural gas), peak and annual electrical loads and costs, building size and type, space availability, operation and maintenance staff availability, and local emissions regulations. Projects that can make use of both electricity production and thermal energy from biomass energy systems are often the most cost effective. If a location has predictable access to year-round, affordable biomass resources, then some combination of biomass heat and electricity production may be a good option. Transportation of fuel accounts for a significant amount of its cost, so resources should ideally be available from local sources. In addition, a facility will typically need to store biomass feedstocks on-site, so site access and storage are factors to consider.

16.3.5 Environmental Issues

The biggest problems with biomass-fired plants are in handling and pre-processing the fuel. This is the case with both small grate-fired plants and large suspension-fired plants. Drying the biomass before combusting or gasifying it improves the overall process efficiency, but may not be economically viable in many cases.

Exhaust systems are used to vent combustion by-products to the environment. Emission controls might include a cyclone or multi-cyclone, a baghouse, or an electrostatic precipitator. The primary function of all of the equipment listed is particulate matter control, and is listed in order of increasing capital cost and effectiveness. Cyclones and multi-cyclones can be used as pre-collectors to remove larger particles upstream of a baghouse (fabric filter) or electrostatic precipitator. In addition, emission controls for unburned hydrocarbon derivatives, oxides of nitrogen, and sulfur might be required, depending on fuel properties and local, state, and Federal regulations.

In the manner of most carbonaceous feedstocks and in spite of claims to the contrary, biomass is not the environmentally benign fuel that is often claimed. Calculations of biomass being a net-zero fuel aside, a biomass fuel can create environmental issue such as (i) ash deposition, (ii) pollutant formation, and (iii) equipment corrosion.

16.3.5.1 Ash Formation

A part of any carbonaceous fuel can be inorganic, forming inorganic vapors and ash particles. The impaction of solid, molten or partially molten particles on surfaces is dependent on the particle and surface characteristics. For instance, a particulate deposit might capture incoming particles or be removed due to erosion, while a molten layer will collect all impacting particles, no matter if they are sticky or not. The main properties affecting the particle stickiness are the viscosity and surface tension for silicate-rich ashes. On the contrary, the stickiness of the salt-rich ash – typical for herbaceous biomass and wood-based fuels or waste-based fuels – is often described using the liquid melt fraction. Furthermore, the particle kinetic energy and the angle of impaction are crucial parameters. If all kinetic energy is dissipated during the impact, the particle will remain on the surface (Kleinhans *et al.*, 2018).

The large and non-spherical particles pose challenges for fuel conversion efficiency. Coal particles of such size would not nearly burnout in a coal boiler, but there are compensating properties of biomass. Biomass yields a much higher fraction of its mass through devolatilization than does coal. Typically biomass of the size and under the heating rates typical of pc-cofiring yields 90-95% of its dry, inorganic-free mass during devolatilization, compared with 55 to 60% for most coals.

Devolatilization occurs rapidly and is temperature driven; therefore most biomass fuels will yield at least this fraction of mass so long as they are entrained in the flue gases. Biomass particles too large or dense to be entrained sometimes enter the bottom ash stream with little or no conversion beyond drying. However, these are generally the exception for well-tuned fuel preparation systems. Second, the low particle densities help biomass particles oxidize at rates much higher than coal. However, excessive moisture or excessive size particles still may pose fuel conversion problems for biomass cofiring despite these mitigating effects.

16.3.5.2 Other Pollutants

Pollutant formation during biomass combustion exhibits all the complexities of pollutant formation during coal combustion. SOx generally decreases in proportion to the sulfur in the fuel, which is low for many (but not all) biomass fuels. NOx may increase, decrease, or remain the same, depending on fuel, firing conditions, and operating conditions. However, the NOx chemistry of biomass shows the same, complex but conceptually well understood behavior as NOx chemistry during coal combustion with the exception that biomass appears to produce much higher NH3 content and a lower HCN content as a nitrogen-laden product gas compared to coal. Some of the commercially most mature biomass fuels, notably wood, contain relatively little fuel nitrogen and cofiring with such fuels tends to decrease total NOx. However, general industrial experience is not consistent with the sometimes suggested truism that NOx reduction when cofiring biomass exceeds the fuel nitrogen displacement effect by 10%. Biomass fuels also commonly contain more moisture than coal, decreasing peak temperatures and leading to commensurate decreases in NOx.

Whether combusting directly or engaged in gasification, biomass resources do generate air emissions. These emissions vary depending upon the precise fuel and technology used. If wood is the primary biomass resource, little to no sulfur dioxide is in the emission from the stack. On the other hand, the emissions of the nitrogen oxides vary significantly among combustion facilities depending on the design and controls. Some biomass power plants show a relatively high NOx emission rate per kilowatt hour generated if compared to other combustion technologies. This high rate of the emissions of the nitrogen oxides is due to the high nitrogen content of many biomass fuels and is one of the top air quality issues that are associated with the combustion of biomass. In addition, carbon monoxide (CO) is also emitted and, in some instances, at levels higher than the emissions of carbon monoxide from coal-fired power plants.

Biomass plants also release carbon dioxide (CO_2), the primary greenhouse gas. However, the cycle of growing, processing, and burning biomass recycles carbon monoxide from the atmosphere. If this cycle is sustained, there is little or no net gain in atmospheric carbon dioxide. Given that short rotation woody crops (i.e., fast-growing woody plant types) can be planted, matured, and harvested in shorter periods of time than natural growth forests, the managed production of biomass fuels may recycle CO2 in one-third less time than natural processes. Biomass power plants also divert wood waste from landfills, which reduces the productions and atmospheric release of methane, another potent greenhouse gas.

Another air quality concern associated with biomass plants is particulates. These emissions can be readily controlled through conventional technologies. To date, no biomass facilities have installed advanced particulate emission controls. Still, most particulate emissions are relatively large in size. Their impacts upon human health remain unclear.

The collection of biomass fuels can have significant environmental impacts. Harvesting timber and growing agricultural products for fuel requires large volumes to be collected, transported, processed, and stored. Biomass fuels may be obtained from supplies of clean, uncontaminated wood that otherwise would be landfilled or from sustainable harvests. If the estimations of the environmental impacts of fossil fuels and biomass can be made on an equal basis, the net environmental plusses of biomass are significant when compared to fossil fuel collection alternatives. On the other hand, the collection, processing, and combustion of biomass fuels may cause environmental problems if, for example, the fuel source contains toxic contaminants, agricultural waste handling pollutes local water resources, or burning biomass deprives local ecosystems of nutrients that forest or agricultural waste may otherwise provide.

One advantage is that the combustion process can be applied to biomass feedstock with water contents up to 60% w/w but the constituents of the biomass (other than carbon, hydrogen and oxygen) are undesirable because they are related to pollutant and deposit formation, corrosion, and ash. The most relevant constituents in native biomass are nitrogen as a source of NOX, and ash components (such as potassium and chlorine as a source of potassium chloride, KCl) that lead to particulate emissions. Native wood is usually the most favorable bio fuel for combustion due to its low content of ash and nitrogen. Herbaceous biomass such as straw, Miscanthus, and switchgrass have higher contents of nitrogen, sulfur, potassium, and chlorine, which lead to higher emissions of nitrogen oxides, particulate matter, increased ash, corrosion, and deposits.

While wood is well-suited for household heating as well as for larger plants, herbaceous biomass is reserved for larger plants. The same is true for urban waste wood and demolition wood. The combustion of such contaminated biomass should be strictly limited to combustion plants with efficient flue gas cleaning for the abatement of toxic pollutants such as heavy metals and chlorine compounds.

Large potentials of both native biomass and biomass wastes are still available and allow a relevant increase of sustainable bio energy use in the future. Combustion is the most important technology available for biomass use. Improvements in efficiency, emissions, and cost are needed for further exploitation. In addition, alternatives such as gasification and combinations of different processes such as gasification as fuel pretreatment for co-combustion need to be considered.

In summary, biomass combustion exhibits relatively high emissions of nitrogen oxides and particulate matter in comparison to the combustion of natural gas or low-boiling fuel oil. Hence, biomass combustion contributes significantly to particulate matter, ozone, and nitrogen dioxide (NO_2) in the ambient air. Also, for wood combustion, the environmental impact of wood is higher than that for natural gas for a standard valuation of the greenhouse effect. Hence, improvements in the wood chain are necessary. On the other hand, in case of poor combustion conditions in manually operated wood stoves or boilers, particulate matter emissions can be high, thus leading to a high environmental impact (Klippel and Nussbaumer, 2007). In addition, at excessively high emissions of unburnt hydrocarbon derivatives including methane, even the greenhouse gas effect can be higher than from light fuel oil or natural gas due to the higher impact of methane (Johansson *et al.*, 2004). Hence wood combustion can only be assessed as being environmentally friendly in case of low airborne emissions (Burkhardt and Albrecht, 2008).

In addition, the so-called driving force for biomass combustion for energy purposes is either the questionable paper-exercise of carbon dioxide neutrality of sustainable cultivated biomass or the use of biomass residues and waste. In terms of the paper exercise of carbon neutrality, it must be recognized that the formation of carbon dioxide as a pollutant and its expulsion into the atmosphere is immediate while carbon dioxide sequestration (i.e., withdrawal of carbon dioxide from the atmosphere) by plant life is a different process and is not immediate.

16.4 Solid Waste

Municipal solid waste (often referred to as MSW) includes landfill solids of biogenic and non-biogenic origin, which can be used to produce electricity and heat. Generation from municipal solid waste has been fairly stable since 2010, as a result of increased recycling activity that has moderated the growth in the availability of municipal solid waste feedstocks. Municipal solid waste consists of everyday items such as product packaging, grass clippings, furniture, clothing, bottles, food scraps, newspapers, appliances, paint and batteries. However, municipal solid waste does not include medical, commercial and industrial hazardous or radioactive wastes, which must be treated separately.

Solid waste, combustion products aside, is in itself an environmental issue. Globally, increasing quantities of waste are being discarded by communities, and the composition of the waste is more complex than ever before, as plastic and electronic consumer products diffuse. Concurrently, the world is urbanizing at an unprecedented rate. These trends pose a challenge to cities, which are charged with managing waste in a socially and environmentally acceptable manner. Effective waste management strategies depend on local waste characteristics, which vary with cultural, climatic, and socioeconomic variables, and institutional capacity. Globally, waste governance is becoming regionalized and formalized. In industrialized nations, where citizens produce far more waste than do other citizens, waste tends to be managed formally at a municipal or regional scale. In less-industrialized nations, where citizens produce less waste, which is mostly biogenic, a combination of formal and informal actors manages waste. Many waste management policies, technologies, and behaviors provide a variety of environmental benefits, including climate change mitigation. Key waste management challenges include integrating the informal waste sector in developing cities, reducing consumption in industrialized cities, increasing and standardizing the collection and analysis of solid waste data (Vergara and Tchobanoglous, 2012).

Waste may be municipal solid waste (MSW) which had minimal presorting, or refuse-derived fuel (RDF) with significant pretreatment, usually mechanical screening and shredding. Other more specific waste sources (excluding hazardous waste) and possibly including crude oil coke may provide niche opportunities for co-utilization (Brigwater, 2003; Arena, 2012; Basu, 2013; Speight, 2013a, 2020).

In addition to biogenic waste streams, two non-biogenic wastes are often co-processed with biomass wastes to generate electricity: tire-derived fuel from used tires and the non-biogenic portion of municipal solid waste. Tire-derived fuel is notable because it has the highest heating value of any solid fuel and, as a result, is also used as a boiler fuel in addition to being co-possessed with municipal solid waste to generate electricity. Plastics comprise most of the combustible non-biogenic portion of municipal solid waste and typically account for 16% of the municipal solid waste stream. Landfill gas (LFG) is a methane-rich gas produced by decomposing organic material at landfills (Speight, 2019).

The term municipal solid waste describes the stream of solid waste (trash or garbage) generated by households and apartments, commercial establishments, industries, and institutions. Municipal solid waste is managed by a combination of disposal in landfill sites, recycling, and incineration.

However, municipal solid waste is not considered to be a renewable energy source, because the waste stream includes materials made from fossil resources; the sources of the plant material based content (e.g., paper and wood) are unpredictable; and the waste stream would be greatly reduced with environmentally preferable waste reduction and management practices.

In the United States and many other Western countries, municipal solid waste is simultaneously a significant disposal problem in many locations and a potentially valuable resource. In any case, municipal solid waste poses several key feedstock challenges relative to other biomass streams, which result in increased costs and impair economic viability, including (i) a relatively low energy content, high moisture content, and (iii) a diverse elemental composition.

While the composition of municipal solid waste varies geographically and seasonally, the energy density is low – on the order of 10 to 13 MMBTU/ton which is below the value of subbituminous coal that is on the order of 17 to 21 MMBTU/ton. In addition, significant portions of municipal solid waste feedstocks are comprised of >75% w/w moisture. Technologies that rely on the application of heat for conversion to either electricity or fuels are inherently disadvantaged as a high amount of energy is expended in heating or drying steps (i.e., evaporating the water beforehand). Energy intensive processes result in energy returns on investment and techno-economics that are unattractive because they require too much energy input.

In terms of the diverse elemental composition. In terms of the elemental composition, the levels of nitrogen, sulfur, and ash species in municipal solid waste are well above those observed for other lignocellulosic feedstocks, and create criteria pollutants (such as the oxides of nitrogen and the oxides of sulfur) when combusted. For some fractions of municipal solid waste (such as yard waste and food waste), concentrations of nitrogen and sulfur can be up to 20 times higher than other lignocellulosic feedstocks such as corn stover and pine.

Analyses of the composition of municipal solid waste indicate that plastics do make up measurable amounts (5 to 10% or more) of solid waste streams (EPCI, 2004; Mastellone and Arena, 2007). Many of these plastics are worth recovering as energy. In fact, many plastics, particularly the poly-olefins, have high calorific values and simple chemical constitutions of primarily carbon and hydrogen. As a result, waste plastics are ideal candidates for the gasification process. Because of the myriad of sizes and shapes of plastic products, size reduction is necessary to create a feed material of a size less than 2 inches in diameter. Some forms of waste plastics such as thin films may require a simple agglomeration step to produce a particle of higher bulk density to facilitate ease of feeding. A plastic, such as high-density polyethylene, processed through a gasifier is converted to carbon monoxide and hydrogen and these materials in turn may be used to form other chemicals including ethylene from which the polyethylene is produced – *closed the loop recycling*.

In addition, the inorganic fraction of municipal solid waste tends to include chlorine, which can produce dioxins when combusted. Technologies that are sensitive to these species and thus require intermediate clean-up and separation steps present techno-economic challenges for municipal solid waste feedstocks. The compositional variability is compounded, given that these waste streams (e.g., food waste, non-recyclable paper, and yard waste) are almost always comingled and individual municipalities can have significantly different waste sorting processes.

Furthermore, the disposal of municipal and industrial waste has become an important problem because the traditional means of disposal, landfill, are much less environmentally acceptable than previously. Much stricter regulation of these disposal methods will make the economics of waste processing for resource recovery much more favorable. One method of processing waste streams is to convert the energy value of the combustible waste into a fuel. One type of fuel attainable from waste is a low heating value gas, usually 100-150 Btu/scf, which can be used to generate process steam or to generate electricity (Gay *et al.*, 1980). Co-processing such waste with coal is also an option (Speight, 2013a, 2020).

Furthermore, municipal solid waste can contain every and any dangerous substance on the market in the United States. These substances include volatile organic compounds (VOCs), polychlorinated biphenyls (PCBs), heavy metals, radioactive materials, and pharmaceuticals. Tens of thousands of dangerous substances are spread throughout millions of tons of waste like paper, cardboard, food and yard waste, plastics, containers, and textiles.

Some landfills use a plastic liner system under its buried waste but plastic deteriorates over time, allowing leachate (a liquid made of the rain and melted snow that's fallen on the landfill and that gets contaminated by the buried waste with all the potential toxins noted above) to pass through it into the soil and groundwater. Likewise, clay or compacted soil liners become increasingly porous over time. Depending on how carefully liners are constructed and maintained, defects, holes, patches, and cracks may cause landfills to leak almost immediately.

16.4.1 Electricity Production

Electricity can be produced by combusting (burning) municipal solid waste as a fuel. Municipal solid waste power plants, also called waste-to-energy (WTE) plants, are designed to dispose of municipal solid waste and to produce electricity as a byproduct of the incinerator operation.

Thermal and non-thermal techniques are the most common and popular method for municipal solid waste (MSW) treatment to produce energy. Based on the study, these technologies are widely used to reduce the environmental impacts caused by inadequate waste management. Incineration and all other high temperature treatments are classified as waste thermal treatment. The basic idea of thermal process is to use heat resulting from burning waste to generate energy, while the non-thermal process is to generate energy without direct burning of waste or any burning resource (Porteous, 2001).

Combustion (incineration) is considered as one of the common thermal methods that is widely used as a treatment technique for municipal solid waste. All new waste-to-energy must meet strict emission standards, including those on nitrogen oxides (NO_x), sulfur dioxide (SO_2), heavy metals, and dioxin derivatives. Hence, modern incineration plants are vastly different from old types, some of which neither recovered energy nor materials. Modern incinerators reduce the volume of the original waste by 95 to 96% w/w, depending upon composition and degree of recovery of materials such as metals from the ash for recycling. Other concerns include management of residues such as (i) toxic fly ash, which must be handled in hazardous waste disposal installation as well as (ii) combustor bottom ash, which can only be reused in the appropriate environmentally benign manner. Also, by passing the smoke through the basic lime scrubbers, any acids that might be in the smoke are neutralized which prevents the acid from reaching the atmosphere and hurting the environment. Many other devices, such as fabric filters, reactors, and catalysts destroy or capture other regulated pollutants (Chapter 12).

One of the main advantages of incineration is to reduce the quantity and volume of the waste. Organic constituents of the waste are collected and burnt at high temperatures. The incineration technique is an active technique that directly controls the burning of mixed waste in the presence of air at temperature range of 600 to 850°C (1110 to 1560°F). In addition to incineration, there are two waste thermal techniques, which are known as advanced thermal treatment (ATT) used in waste industry as gasification. Thus, mass burn is the most common waste-to-energy technology, in which municipal solid waste is combusted directly in much the same way as fossil fuels are used in other direct combustion technologies. Burning municipal solid waste converts water to steam to drive a turbine connected to an electricity generator.

Refuse-derived fuel (RDF) facilities process the municipal solid waste prior to direct combustion. The level of pre-combustion processing varies among facilities, but generally involves shredding of the municipal solid waste and removal of metals and other bulky items. The shredded municipal solid waste is then used as fuel in the same manner as at mass burn plants.

Both combustion (incineration) and anaerobic digestion have a long history as management strategies for municipal solid waste in the United States and as alternatives to landfilling. Anaerobic digestion is applicable only to organic species found in municipal solid waste, whereas incineration works for all combustible materials. Both require prior separation of recyclables to achieve optimal resource recovery. Incineration and anaerobic digestion can produce electricity, heat, or both. However, existing market factors and rates make the production of heat and power economically challenging, particularly on the revenue side of the economic viability equation. Federal, state, and local policies may provide incentives for production of liquid and gaseous fuels, such as biogas and renewable natural gas; however, these policies are currently not equally available to incineration of waste streams to produce heat and electricity.

In fact, energy recovery from the combustion of municipal solid waste is a key part of the non-hazardous management, which ranks various management strategies from most to least environmentally preferred. Energy recovery ranks below source reduction and recycling/reuse but above treatment and disposal. Confined and controlled burning, known as combustion, can not only decrease the volume of solid waste destined for landfills, but can also recover energy from the waste burning process. This generates a renewable energy source and reduces carbon emissions by offsetting the need for energy from fossil sources and reducing methane generation from landfills.

In the process, several steps are involved. Thus: (i) the waste is dumped from garbage trucks into a large pit, (ii) a giant claw on a crane grabs waste and dumps it in a combustion chamber, (iii) the waste (fuel) is burned, releasing heat, (iv) the heat turns water into steam in a boiler, (v) the high-pressure steam turns the blades of a turbine generator to produce electricity, (vi) an air pollution control system removes pollutants from the combustion gas before it is released through a smoke stack, and (vii) ash is collected from the boiler and the air pollution control system.

The ash is collected and taken to a landfill where a high-efficiency baghouse filtering system captures particulates. As the gas stream travels through these filters, more than 99% w/w of the particulate matter is removed. Captured fly ash particles fall into hoppers (funnel-shaped receptacles) and are transported by an enclosed conveyor system to the ash discharger. They are then wetted to prevent dust and mixed with the bottom ash from the grate. The facility transports the ash residue to an enclosed building where it is loaded into covered, leak-proof trucks and taken to a landfill designed to protect against groundwater contamination. Ash residue from the furnace can be processed for removal of recyclable scrap metals.

The traditional waste-to-energy plant, based on mass-burn combustion on an inclined grate, has a low public acceptability despite the low emissions achieved over the last decade with modern flue gas clean-up equipment. This has led to difficulty in obtaining planning permissions to construct needed new waste-to-energy plants. After much debate, various governments have allowed options for advanced waste conversion technologies (gasification, pyrolysis and anaerobic digestion), but will only give credit to the proportion of electricity generated from non-fossil waste.

Electricity production or combined electricity and heat production remain the most likely areas for the application of combustion or co-combustion. The lowest investment cost per unit of electricity generated is the use of the gas in an existing large power station. This has been done in several large utility boilers, often with the gas fired alongside the main fuel. This option allows a comparatively small thermal output of gas to be used with the same efficiency as the main fuel in the boiler as a large, efficient steam turbine can be used. It is anticipated that addition of gas from a biomass or wood gasifier into the natural gas feed to a gas turbine to be technically possible but there will be concerns as to the balance of commercial risks to a large power plant and the benefits of using the gas from the gasifier.

The potential unreliability of biomass, longer-term changes in refuse and the size limitation of a power plant using only waste and/or biomass can be overcome combining biomass, refuse and coal. It also allows benefit from a premium electricity price for electricity from biomass and the gate fee associated with waste. If the power plant is gasification-based, rather than direct combustion, further benefits may be available. These include a premium price for the electricity from waste, the range of technologies available for the gas to electricity part of the process, and gas cleaning prior to the main combustion stage instead of after combustion and public image, which is currently generally better for gasification as compared to combustion. These considerations lead to current studies of co-gasification of wastes/biomass with coal (Speight, 2020).

Use of waste materials as co-combustion feedstocks may attract significant disposal credits. Cleaner biomass materials are renewable fuels and may attract premium prices for the electricity generated. Availability of sufficient fuel locally for an economic plant size is often a major issue, as is the reliability of the fuel supply. Use of more-predictably available coal alongside these fuels overcomes some of these difficulties and risks. Coal could be regarded as the *flywheel* which keeps the plant running when the fuels producing the better revenue streams are not available in sufficient quantities.

Co-combustion technology varies, being usually site specific and high feedstock dependent. At the largest scale, the plant may include the well-proven fixed-bed and entrained-flow gasification processes. At smaller scales, emphasis is placed on technologies which appear closest to commercial operation. Pyrolysis and other advanced thermal conversion processes are included where power generation is practical using the on-site feedstock produced. However, the needs to be addressed are (i) core fuel handling and gasification/pyrolysis technologies, (ii) fuel gas clean-up, and (iii) conversion of fuel gas to electric power (Ricketts *et al.*, 2002).

Co-utilization of waste and biomass with coal may provide economies of scale that help achieve the above identified policy objectives at an affordable cost. In some countries, governments propose cogasification processes as being *well suited for community-sized developments*, suggesting that waste should be dealt with in smaller plants serving towns and cities, rather than moved to large, central plants (satisfying the so-called *proximity principal*).

In fact, neither biomass nor wastes are currently produced, or naturally gathered at sites in sufficient quantities to fuel a modern large and efficient power plant. Disruption, transport issues, fuel use, and public opinion all act against gathering hundreds of megawatts (MWe) at a single location. Biomass or waste-fired power plants are therefore inherently limited in size and hence in efficiency (labor costs per unit electricity produced) and in other economies of scale. The production rates of municipal refuse follow reasonably predictable patterns over time periods of a few years. Recent experience with the limited current *biomass for energy* harvesting has shown unpredictable variations in harvesting capability with long periods of zero production over large areas during wet weather.

For large-scale power generation (>50 MWe), the gasification field is dominated by plant based on the pressurized, oxygen-blown, entrained-flow or fixed-bed gasification of fossil fuels. Entrained gasifier operational experience to date has largely been with well-controlled fuel feedstocks with short-term trial work at low co-gasification ratios and with easily handled fuels.

16.4.2 Environmental Issues

The use of solid waste for the production of electricity can relieve communities of some of the environmental issues of sending the waste to a landfill (as presented above). However, burning municipal solid waste can generate energy while reducing the volume of waste by up to 90% is not without environmental issues. Disposal of the combustion ash and the air polluting emissions from plant combustion operations are the primary environmental impact control issues.

Municipal solid waste contains a diverse mix of waste materials, some benign and some very toxic. Effective environmental management of municipal solid waste plants aims to exclude toxics from the municipal solid waste and to control air pollution emissions from the waste-to-energy plants. Toxic materials include trace metals such as lead, cadmium and mercury, and trace organics, such as dioxins and furans. Such toxics pose an environmental problem if they are released into the air with plant emissions or if they are dispersed in the soil and allowed to migrate into groundwater supplies and work their way into the food chain. The control of such toxics and air pollution are key features of environmental regulations governing municipal solid waste fueled electric generation.

Burning municipal solid waste in waste-to-energy plants produces comparatively high carbon dioxide emissions, a contributor to global climate change. The net climate change impact of these emissions is lessened because a major component of trash is wood, paper and food wastes that would decompose if not burned. If left to decompose in a solid waste landfill, the material produces methane — a potent greenhouse gas. These plants produce comparatively high rates of nitrogen oxide emissions. The on-site land use impacts are generally equal to those of coal- or oil-fueled plants.

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17

Gasification of Alternate Feedstocks

17.1 Introduction

For many decades, coal been the primary feedstock for gasification units (Speight, 2013a). However, with the concern on the issue of environmental pollutants and the potential shortage of coal in some areas there is a move to feedstocks other than coal for gasification processes. Gasification permits the utilization of various feedstocks (coal, biomass, crude oil resids, and other carbonaceous wastes) to their fullest potential (Figure 17.1) (Lee *et al.*, 2007; Speight, 2013a, 2020b). However, there are other potential carbonaceous feedstocks that would also be suitable for gasification with the proviso that the gases must also be presented to the gas cleaning section of the plant.

As for all such feedstocks, gasification will convert organic carbonaceous feedstocks (a feedstock containing carbon and hydrogen, as well as minor amounts of other elements) into carbon monoxide, carbon dioxide, and hydrogen by reacting the feedstock at high temperatures (>700°C, 1290°F), without combustion, with a controlled amount of oxygen and/or steam. The resulting gas mixture (synthesis gas, also called syngas) is called or producer gas and is itself a fuel. The power derived from carbonaceous feedstocks and gasification followed by the combustion of the product gas(es) is considered to be a source of renewable energy if the gaseous products are from a source (e.g., biomass) other than a fossil fuel.

The advantage of the gasification process when a carbonaceous feedstock (a feedstock containing carbon) or hydrocarbonaceous feedstock (a feedstock containing carbon and hydrogen) is employed is that the product of focus – synthesis gas – is potentially more useful as an energy source and results in an overall cleaner process. The production of synthesis gas is a more efficient production of an energy source than, say, the direct combustion of the original feedstock because synthesis gas can be (i) combusted at higher temperatures, (ii) used in fuel cells, (iii) used to produce methanol, (iv) used as a source of hydrogen, and (v) particularly because the synthesis gas can be converted via the Fischer-Tropsch process into a range of synthesis liquid fuels suitable for use in gasoline engines or diesel engines (Speight, 2013, 2020a).

Gasification plants are cleaner because fewer sulfur and nitrogen byproducts are produced, thereby contributing to a *decrease* in smog formation and acid rain deposition. For this reason, gasification is an appealing process for the utilization of relatively inexpensive feedstocks that might otherwise be declared as waste and sent to a landfill (where the production of methane – a so-called greenhouse gas – will be produced) or combusted which may not (depending upon the feedstock) be energy efficient. Overall, use of a gasification technology (Chapter 10) with the necessary gas cleanup options can have a smaller environmental footprint and lesser effect on the environment than landfill operations or combustion of the waste. Indeed, the increasing mounting interest in gasification technology

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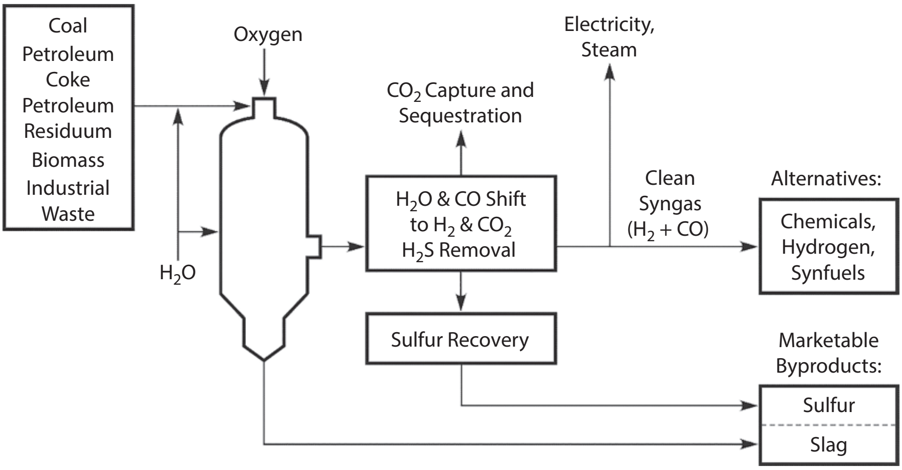

Figure 17.1 The gasification process can accommodate a variety of carbonaceous feedstocks.

reflects a convergence of two changes in the electricity generation marketplace: (i) the maturity of gasification technology, and (ii) the extremely low emissions from integrated gasification combined cycle (IGCC) plants – especially air emissions, and the potential for lower cost control of greenhouse gases than other coal-based systems (Speight, 2013).

With the rapid increase in the use of gasification technology, particularly using coal as the feedstock, from the 15th century onwards (Nef, 1957; Taylor and Singer, 1957) it is not surprising the concept of using coal to produce a flammable gas, especially the use of the water and hot coal (van Heek and Muhlen, 1991), became commonplace (Elton, 1958). In fact, the production of gas from coal has been a vastly expanding area of coal technology, leading to numerous research and development programs. As a result, the characteristics of rank, mineral matter, particle size, and reaction conditions are all recognized as having a bearing on the outcome of the process, not only in terms of gas yields but also on gas properties (Massey, 1974; van Heek and Muhlen, 1991). The products from the gasification of coal may be of low, medium, or high heat-content (high-Btu) content as dictated by the process as well as by the ultimate use for the gas (Fryer and Speight, 1976; Mahajan and Walker, 1978; Anderson and Tillman, 1979; Cavagnaro, 1980; Bodle and Huebler; 1981; Argonne, 1990; Baker and Rodriguez, 1990; Probstein and Hicks, 1990; Lahaye and Ehrburger, 1991; Matsukata *et al.*, 1992; Speight, 2013a).

The gasification of coal, biomass, crude oil, or any carbonaceous residues is typically focused on feedstock conversion to gaseous products. In fact, gasification offers one of the most versatile methods (with a reduced environmental impact with respect to combustion) to convert carbonaceous feedstocks into electricity, hydrogen, and other valuable energy products as well as a wide range of chemical products (Speight, 2013a, 2013, 2020b). Depending on the parameters of the gasifier (such as air-blown, enriched oxygen-blown) and the operating conditions, gasification can be used to produce a fuel gas that is suitable for several applications.

Liquid fuels, including gasoline, diesel, naphtha, and jet fuel, are usually processed by refining crude oil (Speight, 2014, 2017). Due to the direct distillation, crude oil is the most suited raw material for liquid fuel production. However, with fluctuating and rising process of crude oil, coal-to-liquids (CTL) and biomass-to-liquids (BTL) processes are alternative routes used for liquids production. Both feedstocks are converted to synthesis gas – a mixture of carbon monoxide and hydrogen – after which the tried-and-true Fischer-Tropsch (FT) technology is used to convert the synthesis gas to a mixture of liquid products, which is further upgraded using known crude oil refinery technologies upgraded to produce gasoline, naphtha, diesel fuel, and jet fuel (Dry, 1976; Parkash, 2003; Mukoma *et al.*, 2006; Gary *et al.*, 2007; Chadeesingh, 2011; Speight, 2014; Speight, 2016; Hsu and Robinson, 2014; Speight, 2017).

This chapter presents descriptions of the various types of alternate fuels that can be used to produce power. This includes (i) reduction in the total quantity of the alternate feedstock depending upon the waste composition and the gasification technology employed, (ii) improved commercial viability of the disposal of these materials from the sale of energy/products, and (iii) reduction in environmental pollution.

17.2 Viscous Feedstocks

Gasification processes can accept a variety of feedstocks that are produced in the refinery (Table 17.1) but the reactor must be selected on the basis of the feedstock properties and behavior in the process, especially when coal and biomass are considered as gasification feedstocks. Furthermore, because of the historical use of coal for gasification purposes (Speight, 2013a), it is the feedstock against which the suitability of all other feedstocks is measured. Therefore, inclusion of coal among the gasification feedstocks in this section is warranted.

Within the refinery, residuum coking and solvent deasphalting have been used for several decades to upgrade bottoms streams to intermediate products that may be processed to produce transportation fuels (Hsu and Robinson, 2006; Gary *et al.*, 2007; Speight, 2011a, 2014, 2017). The installation of a gasifier in a refinery is a realistic option for the conversion of heavy feedstocks leading to the production of added-value but must be applicable to the feedstock.

Typically, like all gasification processes, the process is carried out at high temperature (>1000°C, >1830°F) producing synthesis gas, some carbon black, and ash as major products – the yield of ash depends upon the amount of mineral matter in the feedstock. Integrated gasification combined cycle (IGCC) is an alternative process for residua conversion and is a known and used technology within the refining industry for (i) hydrogen production, (ii) fuel gas production, and (iii) power generation which, when coupled with efficient gas cleaning methods has minimum effect on the environment (low SOx and NOx) (Wolff, 2007; Speight, 2013).

The ability of the gasification process to handle heavy crude oil, extra heavy crude oil, tar sand bitumen or any refinery bottom streams enhances the economic potential of most refineries and oil fields. Upgrading heavy crude oil – either in the oil field at the source or residua in the refinery – is (and will continue to be) an increasingly prevalent means of extracting maximum value from each barrel of oil produced (Speight, 2011a, 2014, 2017). Upgrading can convert marginal heavy crude oil into light, higher value crude, and can convert heavy, sour refinery bottoms into valuable transportation fuels. On the other hand, most upgrading techniques leave behind an even heavier residue and the costs deposition of such a by-product may approach the value of the production of liquid fuels and other saleable products. In short, the gasification of residua, petroleum coke, or other heavy feedstocks to generate synthesis gas produces a clean fuel for firing in a gas turbine. Gasification is (i) a well-established technology, (ii) has broad flexibility of feedstock properties,

Table 17.1 Types of refinery feedstocks available for gasification on-site.

	Tar sand bitumen	*Resid >1000°F*	*Visbreaker bottoms*	*Deasphalter bottoms*	*C5 Asphaltene fraction**	*Delayed coke*
Ultimate Analysis						
Carbon, % w/w	83.0	85.4	83.1	85.9	80.5	88.6
Hydrogen, % w/w	10.6	12.1	10.4	9.5	8.5	2.8
Nitrogen, % w/w	0.5	0.7	0.6	1.4	1.3	1.1
Sulfur, % w/w*	4.9	2.5	2.4	2.4	1.9	7.3
Oxygen, % w/w	0.9	<0.5	0.5	0.5	7.9	0.0
Mineral matter, % w/w	<0.5	<0.5	<0.5	<0.5	<0.5	<1.0
Specific Gravity	1.03	1.026	1.008	1.036		0.863
API Gravity	5.8	16.6	8.9	5.1		

*The use of heptane as the precipitant yields an asphaltene fraction that is different from the pentane-insoluble material as exemplified by differences in the elemental analysis. For example, the H/C ratio of the heptane-asphaltene fraction is lower than the H/C ratio of the pentane asphaltene fraction, indicating a higher degree of aromaticity in the heptane asphaltene fraction. The N/C, O/C, and S/C atomic ratios are higher in the heptane asphaltene fraction, indicating higher proportions of the heteroelements in the C7 asphaltene fraction. Nevertheless, each fraction is suitable for use as a feedstock for a gasification process.

(iii) gasifier operational parameters, and (iv) is the most environmentally friendly route for handling these feedstocks for power production.

17.2.1 Crude Oil Residual

The gasification of viscous feedstocks (also known as heavy feedstocks, residua, process residues, process bottoms), which are non-volatile materials that are not truly hydrocarbons insofar as they contain elements other than carbon and hydrogen) involves, like all gasification processes, complete thermal decomposition of the feedstock into gaseous products (Wolff and Vliegenthart, 2011; Speight, 2014, 2017).

A crude oil *resid* (*residuum*, pl. *residua*, *resids*) is the residue obtained from crude oil after non-destructive distillation of the crude oil feedstock has removed all of the volatile materials (Figure 17.2). The temperature of the distillation is usually maintained below 350°C

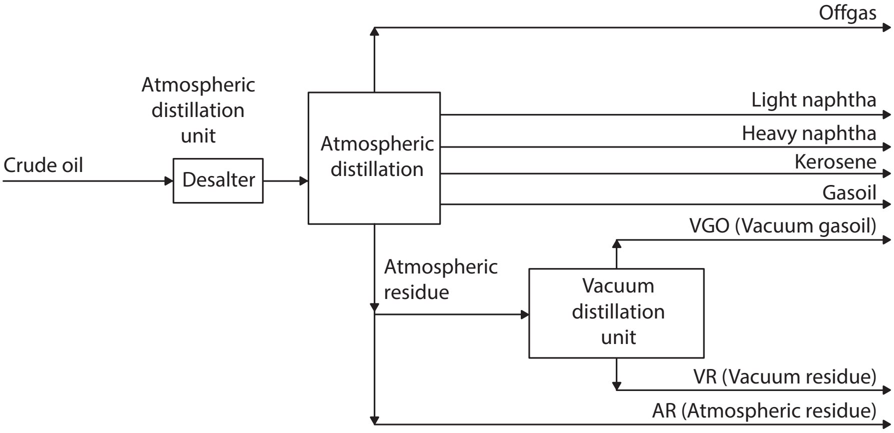

Figure 17.2 The distillation section of a refinery.

(660°F) since the rate of thermal decomposition of crude oil constituents is minimal below this temperature but the rate of thermal decomposition of crude oil constituents is substantial above 350°C (660°F) (Speight, 2014, 2017).

The term *heavy hydrocarbons* is often applied to residua but is, in fact, an incorrect term insofar as the residua are not composed of true hydrocarbons. The so-called *hydrocarbons* in residua contain elements other than carbon and hydrogen, and the distillation sequence that produced the resid(s) (Figure 17.2) has had a concentration effect insofar as the majority of the heteroatoms in the original crude oil contain a majority of the heteroatoms as well as the constituents (located in the resin fraction and the asphaltene fraction) which have a high coke-forming propensity in thermal and catalytic processes (Figure 17.3).

Resids are black, viscous materials and are obtained by distillation of a crude oil under atmospheric pressure (atmospheric residuum) or under reduced pressure (vacuum residuum). They may be liquid at room temperature (generally atmospheric residua) or almost solid (generally vacuum residua) depending upon the nature of the crude oil (Speight, 2014, 2017). When a residuum is obtained from a crude oil and thermal decomposition has commenced, it is more usual to refer to this product as *pitch* – although this term is usually applied to the non-volatile product from coal tar. The differences between the parent crude oil and the (atmospheric and vacuum) residua are due to the relative amounts of various constituents present, which are removed from or remain in the non-volatile residuum by virtue of their relative volatility.

The chemical composition of a residuum from an asphaltic crude oil is complex. Physical methods of fractionation usually indicate high proportions of asphaltene constituents (heptane-insoluble materials) and resin constituents (simply, heptane-soluble materials but propane-insoluble materials), even in amounts up to 50% (or higher) of the residuum. In addition, the presence of ash-forming metallic constituents, including such organometallic compounds as those of vanadium and nickel, is also a distinguishing feature of residua and the heavier oils. Furthermore, the deeper the *cut* into the crude oil, the greater is the concentration of sulfur and metals in the residuum and the greater the deterioration in physical properties (Speight, 2014, 2017).

Typically, crude oil resids can be routed to other conversion units or blended to high-boiling industrial fuel and/or asphalt. The high-boiling feedstocks typically have a relatively

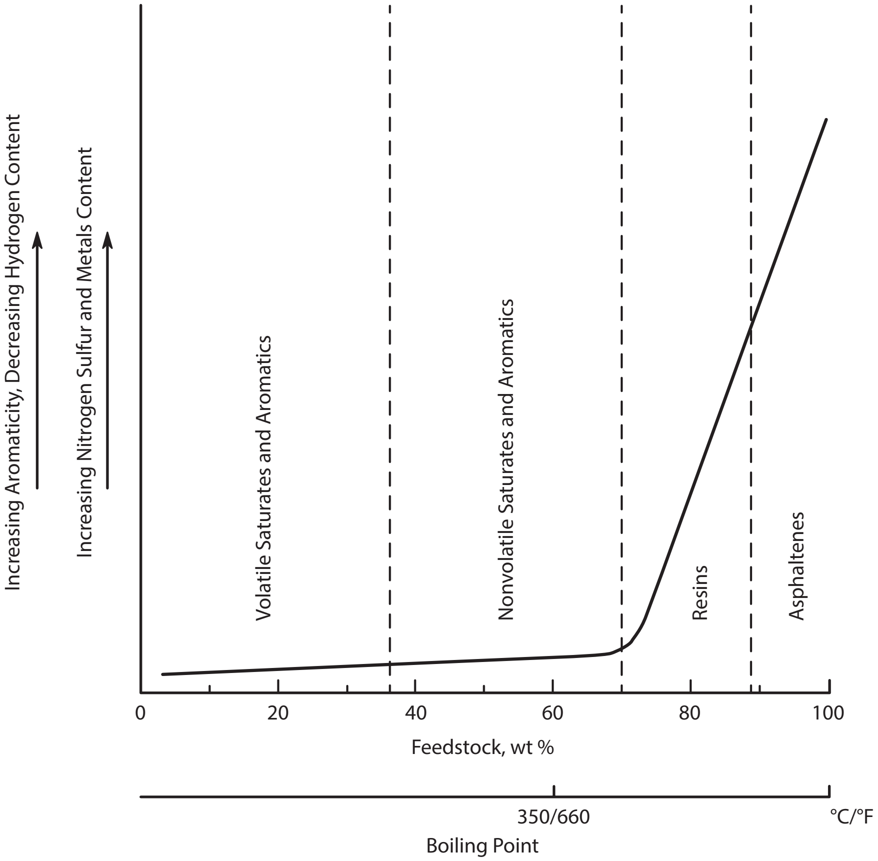

Figure 17.3 Relative distribution of heteroatoms in the various fractions of crude oil.

low economic value – often they are of lower value than the original crude oil. Most refineries convert, or upgrade, the low-value high-boiling feedstocks into more valuable low-boiling products (such as gasoline, jet fuel, and diesel fuel). Thus, high-boiling feedstock upgrading creates a need for additional bottom of the barrel processing, both for expansion and for yield improvement. Traditionally, this would automatically call for the addition of atmospheric distillation and/or vacuum distillation units as a starting point. However, there are alternative processing schemes for processing the vacuum or atmospheric residues to maximizing the value of the heavier crude oils. Thus, hydrogen management has become a priority for current and future refinery operations as consumption continues to rise for greater hydrotreating processes, and processing of heavier and higher sulfur crude oils. In many cases the hydrogen network is limiting refinery throughput and operating margins. The current main source for hydrogen is the steam methane reforming (SMR) of refinery off-gases and natural gas, an inefficient and cost incurring process.

In the current context, the refining industry is no stranger to the gasification and combustion of resids which are typically combusted or gasified to produce gaseous fuels (Chapters 8, 9) which are dependent upon the properties of the feedstock and the gasifier design (Chapters 10, 11) (Wolff, J., and Vliegenthart, 2011; Speight, 2014, 2017). As an example, the ExxonMobil Flexicoking technology is a proven fluidized-bed process that thermally converts heavy oils to lighter products and *flexigas* (a useable fuel gas) (Figure 17.4) (Speight, 2014, 2017).

In fact, the flexicoking technology focus is on coking without coke production and is amenable to accepting low-cost feedstocks such as deep-cut vacuum resid, atmospheric resid, tar sand bitumen, heavy crude oils and solvent deasphalter bottoms as well as bottoms (non-volatile products) from ebullated-bed units which are converted to high-value products through this process. The technology can be integrated with steam/air gasification offers and greater flexibility within the refinery and not only produces clean liquids of but also gasifies the low-value coke to produce a relatively clean (or easy-to-clean) gaseous product (flexigas) that can be used in place of natural gas and conventional fuel gas in refinery processes as well as (important to the present context) for the generation of electric power.

As another example, the resid from a solvent deasphalting unit is gasified by partial oxidation method under pressure of approximately 570 psi and at a temperature between 1300 and 1500°C (2370 and 2730°F) (Bernetti *et al.*, 2000). The high-temperature generated gas flows into the specially designed waste heat boiler, in which the hot gas is cooled and high-pressure saturated steam is generated. The gas from the waste heat boiler is then heat exchanged with the fuel gas and flows to the carbon scrubber, where unreacted carbon particles are removed from the generated gas by water scrubbing.

The gas from the carbon scrubber is further cooled by the fuel gas and boiler feed water and led into the sulfur compound removal section, where hydrogen sulfide (H_2S) and carbonyl sulfide (COS) are removed from the gas to obtain clean fuel gas. This clean fuel gas is

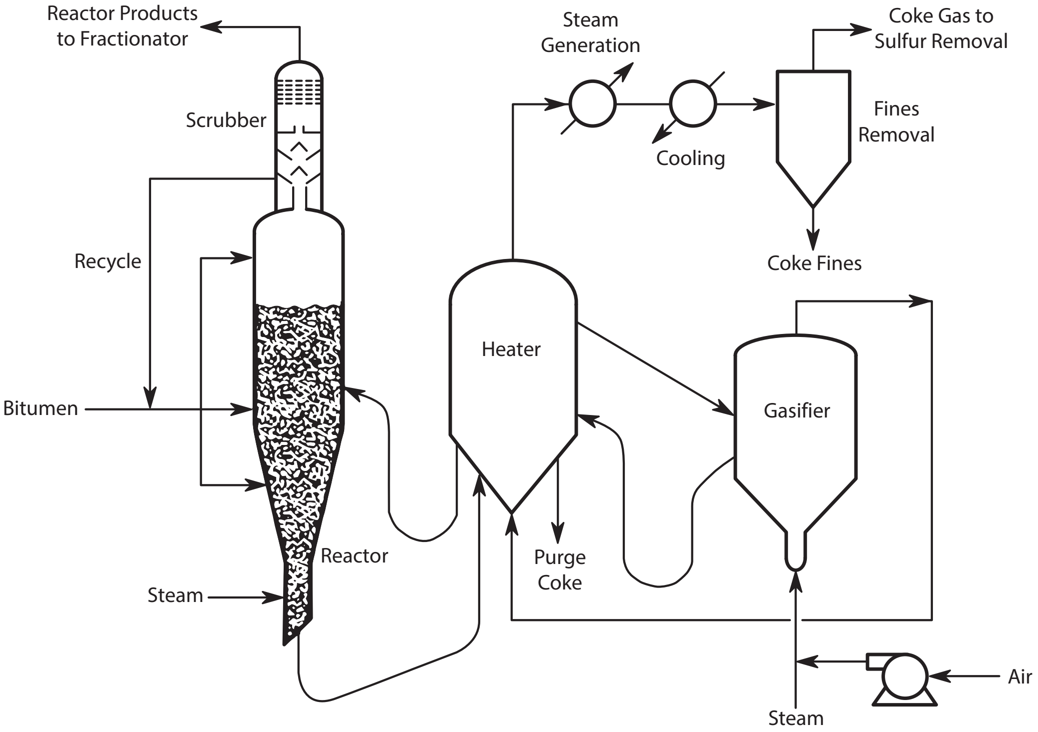

Figure 17.4 Flexicoking process.

heated with the hot gas generated in the gasifier and finally supplied to the gas turbine at a temperature of 250 to 300°C (480 to 570°F).

The exhaust gas from the gas turbine having a temperature of approximately 550 to 600°C (1020 to 1110°F) flows into the heat recovery steam generator consisting of five heat exchange elements. The first element is a superheater in which the combined stream of the high-pressure saturated steam generated in the waste heat boiler and in the second element (high-pressure steam evaporator) is super-heated. The third element is an economizer, the fourth element is a low-pressure steam evaporator and the final or the fifth element is a de-aerator heater. The off-gas from heat recovery steam generator having a temperature of approximately 130°C (265°F) is emitted into the air via stack.

In order to decrease the nitrogen oxide (NO_x) content in the flue gas, two methods can be applied. The first method is the injection of water into the gas turbine combustor. The second method is to selectively reduce the nitrogen oxide content by injecting ammonia gas in the presence of de-NO_x catalyst that is packed in a proper position of the heat recovery steam generator. The latter is more effective that the former to lower the nitrogen oxide emissions to the air.

In the hybrid gasification process, a slurry of resid and coal oil is injected into the gasifier where it is pyrolyzed in the upper part of the reactor to produce gas and char. The chars produced are then partially oxidized to ash. The ash is removed continuously from the bottom of the reactor. In this process, vacuum residue and coal are mixed together into slurry to produce clean fuel gas. The slurry fed into the pressurized gasifier is thermally cracked at a temperature of 850 to 950°C (1560 to 1740°F) and is converted into gas, tar, and char. The mixture oxygen and steam in the lower zone of the gasifier gasify the char. The gas leaving the gasifier is quenched to a temperature of 450°C (840°F) in the fluidized-bed heat exchanger, and is then scrubbed to remove tar, dust, and steam at around 200°C (390°F).

The resid-coal slurry is gasified in the fluidized-bed gasifier. The charged slurry is converted to gas and char by thermal cracking reactions in the upper zone of the fluidized bed. The produced char is further gasified with steam and oxygen that enter the gasifier just below the fluidizing gas distributor. Ash is discharged from the gasifier and indirectly cooled with steam and then discharged into the ash hopper. It is burned with an incinerator to produce process steam. Coke deposited on the silica sand is removed in the incinerator.

17.2.2 Other Feedstocks

Other gasification feedstocks are variable and will depend upon the location of the refinery into which the gasifier has been integrated. Such feedstock may arise from fossil fuel and from non-fossil fuel sources (Speight, 2011a, 2011b, 2020a). Thus, a wide variety of feedstocks can be considered for gasification, ranging from solids to liquids to gaseous streams. Although when the feed is a gas or liquid, the operation is frequently referred to as partial oxidation (POX) and the partial oxidation of gases and liquids is similar to the gasification of solids.

The major requirement for a suitable feedstock is that it contains a significant content of carbon and hydrogen. Solid feedstocks include coal, crude oil coke (often referred to as pet-coke), biomass, and other solid waste streams. There are many hydrocarbon-containing gas and liquid streams that may be used as a feedstock for gasification. However, the streams most commonly employed are generally low-value by-products or waste streams generated by the various processes. These feedstocks are often mixed feedstocks where two or more streams have been blended prior to introduction into the gasifier.

In such cases, as has been presented elsewhere in this text (Chapters 3, 7), caution is advised when using mixed feedstocks for gasification or, for that matter, for any conversion process. It has been the method in the past (and even continued to be the method in some cases) to assess the properties of the mixed feedstock by calculating an average value for one or more of the properties of the mixed feedstock. This is a dangerous practice because it ignores the potential for interaction of the contents of each feedstock that can cause changes in the chemistry and physics of the process as well as a loss of process efficiency.

With resids as gasification feedstocks, it is necessary to determine whether or not the resid constituents are unlikely to form a separate phase (of asphaltene-type material or the products of the reacted asphaltene constituents) as the feedstock passes through hot pipes and into the gasifier. Such a phenomenon may result in blocked pipes and (at best) a decrease in process efficiency or (at worst) a shutdown of the process.

In order to avoid a significant decrease in conversion efficiency when mixed feedstocks are employed, a formulation of mixed feedstocks is developed in order to produce a more consistent material (Chapters 7, 9). Formulation combines various preprocessed resources and/or additives to produce a feedstock that provides process consistency.

17.2.2.1 Solvent Deasphalter Bottoms

The deasphalting unit (deasphalter) is a unit in a crude oil refinery for bitumen upgrader that separates an asphalt-like product from crude oil, heavy crude oil, extra heavy oil, or tar sand bitumen. The deasphalter unit is usually placed after the vacuum distillation tower where, by the use of a low-boiling liquid hydrocarbon solvent (such as propane or butane under pressure), the insoluble asphalt-like product (*deasphalter bottoms*) is separated from the feedstock – the other output from the deasphalter is deasphalted oil (DAO).

17.2.2.2 Asphalt, Tar, and Pitch

Asphalt does not occur naturally but is manufactured from crude oil and is a black or brown material that has a consistency varying from a viscous liquid to a glassy solid (Speight, 2014, 2017). To a point, asphalt can resemble bitumen (isolated form tar sand formation), hence the tendency to refer to bitumen (incorrectly) as *native asphalt*. It is recommended that there be differentiation between asphalt (manufactured) and bitumen (naturally occurring) other than by use of the qualifying terms *crude oil* and *native* since the origins of the materials may be reflected in the resulting physicochemical properties of the two types of materials. It is also necessary to distinguish between the asphalt which originates from crude oil by refining and the product in which the source of the asphalt is a material other than crude oil, e.g., *Wurtzilite asphalt* (Speight, 2014). In the absence of a qualifying word, it should be assumed that the word *asphalt* (with or without qualifiers such as *cutback*, *solvent*, and *blown*, which indicate the process used to produce the asphalt) refers to the product manufactured from crude oil.

When the asphalt is produced simply by distillation of an asphaltic crude oil, the product can be referred to as *residual asphalt* or *straight-run asphalt*. For example, if the asphalt is prepared by *solvent* extraction of residua or by low-boiling hydrocarbon (propane) precipitation, or if *blown* or otherwise treated, the term should be modified accordingly to qualify the product (e.g., *solvent asphalt*, *propane asphalt*, *blown asphalt*).

Asphalt softens when heated and is elastic under certain conditions and has many uses. For example, the mechanical properties of asphalt are of particular significance when it is used as a binder or adhesive. The principal application of asphalt is in road surfacing, which may be done in a variety of ways. Low-boiling oil *dust layer* treatments may be built up by repetition to form a hard surface, or a granular aggregate may be added to an asphalt coat, or earth materials from the road surface itself may be mixed with the asphalt. Other important applications of asphalt include canal and reservoir linings, dam facings, and sea works. The asphalt so used may be a thin, sprayed membrane, covered with earth for protection against weathering and mechanical damage, or thicker surfaces, often including riprap (crushed rock). Asphalt is also used for roofs, coatings, floor tiles, soundproofing, waterproofing, and other building-construction elements and in a number of industrial products, such as batteries. For certain applications, an asphaltic emulsion is prepared, in which fine globules of asphalt are suspended in water.

Tar is a product of the destructive distillation of many bituminous or other organic materials and is a brown to black, oily, viscous liquid to semi-solid material. However, *tar* is most commonly produced from *bituminous coal* and is generally understood to refer to the product from coal, although it is advisable to specify *coal tar* if there is the possibility of ambiguity. The most important factor in determining the yield and character of the coal tar is the carbonizing temperature. Three general temperature ranges are recognized, and the products have acquired the designations: *low-temperature tar* (approximately 450 to 700°C; 540 to 1290°F); *mid-temperature tar* (approximately 700 to 900°C; 1290 to 1650°F); and *high-temperature tar* (approximately 900 to 1200°C; 1650 to 2190°F). Tar released during the early stages of the decomposition of the organic material is called *primary tar* since it represents a product that has been recovered without the secondary alteration that results from prolonged residence of the vapor in the heated zone.

Treatment of the distillate (boiling up to 250°C, 480°F) of the tar with caustic soda causes separation of a fraction known as *tar acids*; acid treatment of the distillate produces a variety of organic nitrogen compounds known as *tar bases*. The residue left following removal of the high-boiling oil, or distillate, is *pitch*, a black, hard, and highly ductile material.

In the chemical-process industries, pitch is the black or dark brown residue obtained by distilling coal tar, wood tar, fats, fatty acids, or fatty oils. The pitch produced in a refinery, like coal tar pitch is a soft to hard and brittle substance containing chiefly aromatic resinous compounds along with aromatic and other hydrocarbon derivatives and their derivatives; it is used chiefly as road tar, in waterproofing roofs and other structures, and to make electrodes. *Wood tar pitch* is a bright, lustrous substance containing resin acids; it is used chiefly in the manufacture of plastics and insulating materials and in caulking seams. *Pitch* derived from fats, fatty acids, or fatty oils by distillation are usually soft substances containing polymers and decomposition products; they are used chiefly in varnishes and paints and in floor coverings.

Any of the above derivatives can be used as a gasification feedstock. The properties of asphalt change markedly during the aging process (oxidation in service) to the point where the asphalt fails to perform the task for which it was designed. In some cases, the asphalt is recovered and reprocessed for additional use or it may be sent to a gasifier.

17.2.2.3 Black Liquor

Black liquor is the spent liquor from the Kraft process in which pulpwood is converted into paper pulp by removing lignin constituents, hemicellulose constituents and other and other extractable materials from wood to free the cellulose fibers. The equivalent spent cooking liquor in the sulfite process is usually called *brown liquor*, but the terms *red liquor*, *thick liquor*, and *sulfite liquor* are also used. Approximately seven units of black liquor are produced in the manufacture of one unit of pulp (Biermann, 1993).

Black liquor is an aqueous solution of lignin residues, hemicellulose, and the inorganic chemical used in the process and 15% w/w solids of which 10% w/w are inorganic and 5% w/w are organic. Typically, the organic constituents in black liquor are 40 to 45% w/w soaps, 35 to 45% w/w lignin, and 10 to 15% w/w other (miscellaneous) organic materials.

The organic constituents in the black liquor are made up of water/alkali soluble degradation components from the wood. Lignin is degraded to shorter fragments with sulfur content on the order of 1 to 2% w/w and sodium content at approximately 6% w/w of the dry solids. Cellulose (and hemicellulose) is degraded to aliphatic carboxylic acid soaps and hemicellulose fragments. The extractable constituents yield *tall oil soap* and crude turpentine. The tall oil soap may contain up to 20% w/w sodium. The residual lignin components currently serve for hydrolytic or pyrolytic conversion or combustion. Alternative, hemicellulose constituents may be used in fermentation processes.

Black liquor gasification has the potential to achieve higher overall energy efficiency than the conventional recovery boiler while generating an energy-rich *synthesis gas* from the liquor. The synthesis gas can be burned in a gas turbine combined cycle system (BLGCC – black liquor gasification combined cycle – and similar to IGCC, integrated gasification combined cycle) to produce electricity or converted (through catalytic processes) into chemicals or fuels such as methanol, dimethyl ether, Fischer-Tropsch hydrocarbon derivatives, such as diesel fuel.

17.3 Biomass

Biomass includes a wide range of materials that produce a variety of products which are dependent upon the feedstock (Balat, 2011; Demirbaş, 2011; Ramroop Singh, 2011; Speight, 2011a). The compositions of biomass among fuel types are variable, especially with respect to inorganic constituents important to the critical problems of fouling and slagging, and the properties of the biomass must be assessed accordingly (Table 17.2). Alkali and alkaline earth metals, in combination with other fuel elements such as silica and sulfur, and facilitated by the presence of chlorine, are responsible for many undesirable reactions in combustion furnaces and power boilers. Reductions in the concentrations of alkali metals and chlorine, created by leaching the elements from the fuel with water, can yield remarkable improvements in ash fusion temperatures. Other influences of biomass composition are observed for the rates of combustion and pollutant emissions (Jenkins *et al.*, 1998).

For example, typical biomass wastes include wood material (bark, chips, scraps, and sawdust), pulp and paper industry residues, agricultural residues, organic municipal material,

Table 17.2 Biomass properties that influence the gasification process.

Chemical properties	Elemental composition	C,H,N,O,S (% w/w)
	Proximate analysis	Moisture
		Fixed carbon
		Volatile matter
		Mineral matter
Physical properties	Density	
	Porosity	
	Particle size	
	Particle shape	
Thermal properties	Heating value	
	Elemental composition	
	Types of minerals	Mineral ash
		Ash fusion temperature

sewage, manure, and food processing by-products. Agricultural residues such as straws, nut shells, fruit shells, fruit seeds, plant stalks and stover, green leaves and molasses are potential renewable energy resources. Many developing countries have a wide variety of agricultural residues in ample quantities. Large quantities of agricultural plant residues are produced annually worldwide and are vastly underutilized. When agricultural residues are used as a fuel, through direct combustion, only a small percentage of their potential energy is available, due to inefficient burners used. Current disposal methods for these agricultural residues have caused widespread environmental concerns. For example, disposal of rice and wheat straw by open-field burning causes air pollution. In addition, the widely varying heat content of the different types of biomass varies widely and must be taken into consideration when designing any conversion process (Jenkins and Ebeling, 1985).

Biomass is biological material that has come from animal, vegetable or plant matter and is considered to be *carbon neutral* – while the plant is growing, it uses the energy of the sun to absorb the same amount of carbon from the atmosphere as it releases into the atmosphere. By maintaining this closed carbon cycle it is felt, with some mathematical meandering, that there is no overall increase in carbon dioxide levels through emissions to the atmosphere.

Raw materials that can be used to produce biomass fuels are widely available and arise from a large number of different sources and in numerous forms. Biomass can also be used to produce electricity – either blended with coal or by itself. However, each of the biomass materials can be used to produce fuel but not all forms are suitable for all the different types of energy conversion technologies such as biomass gasification (Rajvanshi, 1986; Brigwater, 2003; Dasappa *et al.*, 2004; Speight, 2011a; Basu, 2013). The main basic sources of biomass material are: (i) wood, including bark, logs, sawdust, wood chips, wood pellets and briquettes, (ii) high-yield energy crops, such as wheat, that are grown specifically for energy applications, (iii) agricultural crop and animal residues, like straw or slurry, (iv) food waste, both domestic and commercial, and (v) industrial waste, such as wood pulp or paper pulp. For processing, a simple form of biomass such as untreated and unfinished wood may be cut into a number of physical forms, including pellets and wood chips, for use in biomass boilers and stoves.

Thermal conversion processes use heat as the dominant mechanism to convert biomass into another chemical form. The basic alternatives of combustion, torrefaction, pyrolysis, and gasification are separated principally by the extent to which the chemical reactions involved are allowed to proceed (mainly controlled by the availability of oxygen and conversion temperature) (Speight, 2011a).

Energy created by burning biomass (fuel wood), also known as *dendrothermal energy*, is particularly suited for countries where the fuel wood grow more rapidly, e.g., tropical countries. There are a number of other less common, more experimental or proprietary thermal processes that may offer benefits such as hydrothermal upgrading (HTU) and hydroprocessing. Some have been developed for use on high moisture content biomass, including aqueous slurries, and allow them to be converted into more convenient forms. Some of the applications of thermal conversion are combined heat and power (CHP) and cofiring. In a typical dedicated biomass power plant, efficiencies range from 7 to 27% w/w of the energy content of the fuel. In contrast, cofiring biomass with coal, typically occurs at efficiencies near those of the coal combustor (30 to 40% of the energy content of the fuel) (Baxter, 2005; Liu *et al.*, 2011).

Many forms of biomass contain a high percentage of moisture (along with carbohydrates and sugars) and mineral constituents – both of which can influence the viability of a gasification process (Chapter 3) – the presence of high levels of moisture in the biomass reduces the temperature inside the gasifier, which then reduces the efficiency of the gasifier. Therefore, many biomass gasification technologies require that the biomass be dried to reduce the moisture content prior to feeding into the gasifier. In addition, biomass can come in a range of sizes. In many biomass gasification systems, the biomass must be processed to a uniform size or shape to feed into the gasifier at a consistent rate and to ensure that as much of the biomass is gasified as possible.

In respect of municipal solid waste, gasification is significantly different from and cleaner than incineration: (i) in the high-temperature environment in gasification, higher molecular weight materials such as plastics, are effectively decomposed to synthesis gas, which can be cleaned and processed before any further use, (ii) dioxin derivatives and furan derivatives need sufficient oxygen to form and the oxygen-deficient atmosphere in a gasifier does not provide the environment needed for the formation of dioxins and furans, (iii) when the synthesis gas is primarily used as a fuel for making heat, it can be cleaned as necessary *before* combustion; this cannot occur in incineration.

Biomass, such as wood pellets, yard and crop wastes, and the so-called *energy crops* such as switchgrass and waste from pulp and paper mills can be used to produce ethanol and synthetic diesel fuel. The biomass is first gasified to produce the synthetic gas (synthesis gas), and then converted via catalytic processes to these downstream products. Furthermore, most biomass gasification systems use air instead of oxygen for the gasification reactions (which is typically used in large-scale industrial and power gasification plants). Gasifiers that use oxygen require an air separation unit to provide the gaseous/liquid oxygen; this is usually not cost-effective at the smaller scales used in biomass gasification plants. Air-blown gasifiers use the oxygen in the air for the gasification reactions.

In general, biomass gasification plants are much smaller than the typical coal or crude oil coke gasification plants used in the power, chemical, fertilizer and refining industries – the sustainability of the fuel supply is often brought into question. As such, a biomass gasification plant is less expensive to construct and has a smaller environmental footprint. For example, while a large industrial gasification plant may take up 150 acres of land and process 2,500 to 15,000 tons per day of feedstock (such as coal or crude oil coke), the smaller biomass plants typically process 25 to 200 tons of feedstock per day and take up less than 10 acres.

Biomass gasification has been the focus of research in recent years to estimate efficiency and performance of the gasification process using various types of biomass such as sugarcane residue (Gabra *et al.*, 2001), rice hulls (Boateng *et al.*, 1992), pine sawdust (Lv *et al.*, 2004), almond shells (Rapagnà and Latif, 1997; Rapagnà *et al.*, 1997, 2000), wheat straw (Ergudenler and Ghali, 1993), food waste (Ko *et al.*, 2001), and wood biomass (Pakdel and Roy, 1991; Bhattacharaya *et al.*, 1999; Chen *et al.*, 1992; Hanaoka *et al.*, 2005). Recently, cogasification of various biomass and coal mixtures has attracted a great deal of interest from the scientific community. Feedstock combinations including Japanese cedar wood and coal (Kumabe *et al.*, 2007), coal and saw dust (Vélez *et al.*, 2009), coal and pine chips (Pan *et al.*, 2000), coal and silver birch wood (Collot *et al.*, 1999), and coal and birch wood (Brage *et al.*, 2000) have been reported in gasification practice. Cogasification of coal and biomass has some synergy – the process not only produces a low carbon footprint on the environment, but also improves the H_2/CO ratio in the produced gas which is required for liquid fuel synthesis (Sjöström *et al.*, 1999; Kumabe *et al.*, 2007). In addition, the inorganic matter present in biomass catalyzes the gasification of coal. However, cogasification processes require custom fittings and optimized processes for the coal and region-specific wood residues.

While cogasification of coal and biomass is advantageous from a chemical viewpoint, some practical problems are present on upstream, gasification, and downstream processes. On the upstream side, the particle size of the coal and biomass is required to be uniform for optimum gasification. In addition, moisture content and pretreatment (torrefaction) are important during upstream processing (Table 17.2).

Recently, the cogasification of various types of biomass and coal mixtures has attracted a great deal of interest (Usón *et al.*, 2004). However, biomass and coal require drying and size reduction before they can be fed into a gasifier. Size reduction is needed to obtain appropriate particle sizes; drying is required to achieve a moisture content suitable for gasification operations. In addition, densification of the biomass may be done to make pellets and improve density and material flow in the feeder areas. Both fixed-bed and fluidized-bed gasifiers have been used in cogasification of biomass with coal (McKendry, 2002).

While cogasification of coal and biomass is advantageous from a chemical viewpoint, some practical problems are present on upstream, gasification, and downstream processes. On the upstream side, the particle size of the coal and biomass is required to be uniform for optimum gasification. In addition, moisture content and pretreatment (torrefaction) are important during upstream processing. Also, biomass decomposition occurs at a lower temperature than coal and therefore different reactors compatible to the feedstock mixture are required (Brar *et al.*, 2012). Furthermore, feedstock and gasifier type along with operating parameters not only decide product gas composition but also dictate the amount of impurities to be handled downstream.

Downstream processes need to be modified if coal is cogasified with biomass. For example, heavy metal and impurities such as sulfur and mercury present in coal can make bio-synthesis gas difficult to use and unhealthy for the environment. Alkali metals (sodium and potassium) present in biomass can also cause corrosion problems at high temperatures in downstream pipes. An alternative option to downstream gas cleaning would be to process coal to remove mercury and sulfur prior to feeding into the gasifier. However, first and foremost, coal and biomass require drying and size reduction before they can be fed into a gasifier. Size reduction is needed to obtain appropriate particle sizes; however, drying is required to achieve moisture content suitable for gasification operations. In addition, biomass densification may be conducted to prepare pellets and improve density and material flow in the feeder areas.

While upstream processing is influential from a material handling point of view, the choice of gasifier operation parameters (temperature, gasifying agent, and catalysts) dictate the product gas composition and quality. Biomass decomposition occurs at a lower temperature than coal and therefore different reactors compatible to the feedstock mixture are required (Speight, 2011; Brar *et al.*, 2012; Speight, 2013). Furthermore, feedstock and gasifier type along with operating parameters not only decide product gas composition but also dictate the amount of impurities to be handled downstream.

It is recommended that biomass moisture content should be less than 15% w/w prior to gasification. High moisture content reduces the temperature achieved in the gasification zone, thus resulting in incomplete gasification. Forest residues or wood has a fiber saturation point at 30 to 31% moisture content (dry basis) (Brar *et al.*, 2012). Compressive and shear strength of the wood increases with decreased moisture content below the fiber saturation point. In such a situation, water is removed from the cell wall leading to shrinkage. The long-chain molecules constituents of the cell wall move closer to each other and bind more tightly. A high level of moisture, usually injected in form of steam in the gasification zone, favors formation of a water-gas shift reaction that increases hydrogen concentration in the resulting gas.

The torrefaction process is a thermal treatment of biomass in the absence of oxygen, usually at 250 to 300°C (480 to 570°F) to drive off moisture, decompose hemicellulose completely, and partially decompose cellulose (Speight, 2011a). Torrefied biomass has reactive and unstable cellulose molecules with broken hydrogen bonds and not only retains 79 to 95% of feedstock energy but also produces a more reactive feedstock with lower atomic hydrogen-carbon and oxygen-carbon ratios to those of the original biomass. Torrefaction results in higher yields of hydrogen and carbon monoxide in the gasification process.

Most small to medium-sized biomass/waste gasifiers are air blown, operate at atmospheric pressure and at temperatures in the range 800 to 100°C (1470 to 2190°F). They face different challenges to large gasification plants – the use of small-scale air separation plant should oxygen gasification be preferred. Pressurized operation, which eases gas cleaning, may not be practical.

Biomass fuel producers, coal producers and, to a lesser extent, waste companies are enthusiastic related to supplying cogasification power plants and realize the benefits of cogasification with alternate fuels (Speight, 2011a; Lee and Shah, 2013; Speight, 2013, 2020a). The benefits of a cogasification technology involving coal and biomass include the use of a reliable coal supply with gate-fee waste and biomass which allows the economies of scale from a larger plant to be supplied just with waste and biomass. In addition, the technology offers a future option of hydrogen production and fuel development in refineries. In fact,

Table 17.3 Advantages and disadvantages of using biomass as a gasification feedstock.

Advantages	Theoretically inexhaustible fuel source. Minimal environmental impact when direct combustion of plant mass is not used to generate energy (i.e. fermentation, pyrolysis, etc., are used instead), (iii) alcohol derivatives and other fuels produced by biomass are efficient, viable, and relatively clean-burning. Available on a worldwide basis.
Disadvantages	Possible adverse contribution to global climate change and particulate pollution if combusted directly. Not always a cheap source of energy, both in terms of producing biomass and the conversion to alcohols or other fuels. Life cycle assessments (LCA) should be taken into account to address energy inputs and outputs but there is most likely a net loss of energy when operated on a small scale which requires that energy to grow the plant mass must be taken into account.

oil refineries and petrochemical plants are opportunities for gasifiers when the hydrogen is particularly valuable (Speight, 2011b, 2014, 2017).

In addition, while biomass may seem to some observers to be the answer to the global climate change issue, the advantages and disadvantages must be considered and compared carefully (Table 17.3). For example, the advantages are (i) biomass is a theoretically inexhaustible fuel source, (ii) when direct conversion of combustion of plant mass – such as fermentation and pyrolysis – is not used to generate energy there is minimal environmental impact., (iii) alcohols and other fuels produced by biomass are efficient, viable, and relatively clean-burning, and (iv) biomass is available on a worldwide basis.

On the other hand, the disadvantages include (i) the highly variable heat content of different biomass feedstocks, (ii) the high water content that can affect the process energy balance, and (iii) there is a potential net loss of energy when a biomass plant is operated on a small scale – an account of the energy put used to grow and harvest the biomass must be included in the energy balance.

17.4 Solid Waste

Waste is an unavoidable by-product of human activity and rising living standards have led to increases in the quantity and complexity of generated waste, whilst industrial diversification and the provision of expanded health care facilities have added substantial quantities of industrial waste and biomedical waste into the waste. The properties of the waste are variable and dependent upon the source of the waste (Tables 17.4, 17.5).

Thus, there is a need for the management and disposal of the growing volume of waste, in addition to waste disposal (landfill) operations that are being stretched to the limit and suitable disposal areas are in short supply. In addition, the potential for rain water (and snow melt) to each chemical constituents from landfills and into the groundwater table is of immediate concern. Waste may be municipal solid waste (MSW) which had minimal presorting, or refuse-derived fuel (RDF) with significant pretreatment, usually mechanical

Table 17.4 Sources and types of waste.

Source	Examples	Waste types
Residential	Single and multifamily dwellings	Food wastes, paper, cardboard Plastics, textiles, leather Yard wastes, wood, glass, metals ash, special wastes oil, tires
Industrial	Light and heavy manufacturing	Housekeeping wastes, packaging food wastes
	Construction sites	Construction and demolition materials wood steel, concrete
	Power plants	Ash
	Chemicals plants	Special chemical waste
Commercial	Stores, hotels, restaurants	Paper, cardboard, plastics, wood Food wastes
	Markets, office building	Glass, metals, special wastes, Hazardous wastes
Institutional	Schools, hospitals	Paper, cardboard, plastics, wood
	Government centers	Food waste Glass, metals, special wastes, Hazardous wastes
Municipal	Street cleaning	Street sweepings; landscape waste, tree trimmings Wastes from parks Wastes from recreational areas
Agriculture	Crops, orchards, dairies	Agricultural wastes
	Farms, feedlots	Hazardous waste (e.g. pesticides)

screening and shredding. Other more specific waste sources (excluding hazardous waste) and possibly including crude oil coke may provide niche opportunities for co-utilization (Brigwater, 2003; Arena, 2012; Basu, 2013; Speight, 2013).

Furthermore, the disposal of municipal and industrial waste has become an important problem because the traditional means of disposal, landfill, are much less environmentally acceptable than previously. Much stricter regulation of these disposal methods will make the economics of waste processing for resource recovery much more favorable. One method of processing waste streams is to convert the energy value of the combustible waste into a fuel. One type of fuel attainable from waste is a low heating value gas, usually 100 to 150 Btu/scf, which can be used to generate process steam or to generate electricity (Gay *et al.*, 1980). Co-processing such waste with coal is also an option (Chapter 9) (Speight, 2020a). Before progressing to any further discussion, the various type of waste are presented here.

Table 17.5 General composition of municipal solid waste.

Component	**% w/w**
Paper	33.7
Cardboard	5.5
Plastics	9.1
Textiles	3.6
Rubber, Leather	2.0
Wood	7.2
Horticultural Waste	14.0
Food Waste	9.0
Glass and Metals	13.1

Thus, waste may be municipal solid waste (MSW) which had minimal presorting, or refuse-derived fuel (RDF) with significant pretreatment, usually mechanical screening and shredding. Other more specific waste sources (excluding hazardous waste) and possibly including crude oil coke may provide niche opportunities for co-utilization (Brigwater, 2003; Arena, 2012; Basu, 2013; Speight, 2013). Each type is different in composition and, therefore, will require different conversion parameters as the means of processing to produce energy.

In addition, because of the nature of the constituents in any of the above waste streams that are used in a waste-to-energy gasification plant, it is necessary to consider at this point the feedstocks properties and any safety (and health) issues that might arise from the use of such feedstocks. In fact, such feedstock materials typically comprise biomass waste (or biomass), municipal solid waste (MSW), refuse-derived fuel (RDF), or solid recovered fuel (SRF) and waste materials are not always of such a composition that behavior in the process can be predicted with any degree of accuracy (Speight, 2011a).

Analyses of the composition of municipal solid waste indicate that plastics do make up measurable amounts (5 to 10% or more) of solid waste streams (EPCI, 2004; Mastellone and Arena, 2007). Many of these plastics are worth recovering as energy. In fact, many plastics, particularly the poly-olefins, have high calorific values and simple chemical constitutions of primarily carbon and hydrogen. As a result, waste plastics are ideal candidates for the gasification process. Because of the myriad of sizes and shapes of plastic products size reduction is necessary to create a feed material of a size less than 2 inches in diameter. Some forms of waste plastics such as thin films may require a simple agglomeration step to produce a particle of higher bulk density to facilitate ease of feeding. A plastic, such as high-density polyethylene, processed through a gasifier is converted to carbon monoxide and hydrogen and these materials in turn may be used to form other chemicals including ethylene from which the polyethylene is produced – *closed the loop recycling.*

Thus, the individual feedstock constituents will typically have their own hazards including fire, dust explosion and toxic gas formation but when used in conjunction with the other constituent the need for safety and handling of the combined feedstocks may require extra precautions. For example, where feed materials such as biomass wood are stored in large piles, there is potential for self-heating (spontaneous ignition) – which is always an issue when coal is stockpiled (Speight, 2013). Wood fuel is a source of nutrients for microbial activity, which, in the presence of moisture, over extended time periods, can lead to the generation of heat, and self-ignition. Other feed safety considerations include hazards associated with dust, such as (i) explosion hazards requiring protection by, for example, hot particle detection and (ii) explosion venting to mitigate the effects of explosions.

17.4.1 Waste Types

Waste (also called in the United States *garbage* or *trash*) is a substance, object, or collection of substances and objects selected for disposal or are required to be disposed by the provisions of local, regional, or national laws. In addition, waste is also substances or objects that are not the prime products of a process (or processes) for which the initial users have no further use in terms of their own purposes of production, transformation or consumption, and of which they want to dispose. Wastes may be generated during (i) the extraction of raw materials, (ii) the processing of raw materials into intermediate and final products, (iii) the consumption of final products, and (iv) other human activities.

17.4.1.1 Solid Waste

Solid waste is a general term that includes garbage, rubbish, refuse, sludge from a wastewater treatment plant, water supply treatment plant, or air pollution control facility, sewage sludge, and other discarded material, including solid, liquid, semisolid, or contained gaseous material resulting from industrial, municipal, commercial, mining, and agricultural operations and from community and institutional activities. *Soil, dirt, rock, sand, and other inert solid materials, whether natural or of human origin,* used to fill land are not classified as waste if the object of the fill is to make the land suitable for the construction of surface improvements. Solid waste does not include waste materials that result from activities associated with the exploration, development, or production of oil or gas or geothermal resources, or other substance or material regulated by the local or federal governments.

Solid waste that is typically excluded from gasification feedstocks includes uncontaminated solid waste resulting from the construction, remodeling, repair and demolition of utilities, structures and roads; and uncontaminated solid waste resulting from land clearing. Such waste includes, but is not limited to, bricks, concrete and other masonry materials, soil, rock, wood (including painted, treated and coated wood and wood products), land clearing debris, wall coverings, plaster, drywall, plumbing fixtures, non-asbestos insulation, roofing shingles and other roof coverings, asphaltic pavement, glass, plastics that are not sealed in a manner that conceals other wastes, empty buckets ten gallons or less in size and having no more than one inch of residue remaining on the bottom, electrical wiring and components containing no hazardous liquids, and pipe and metals that are incidental to any of the above.

In summary, solid waste as the definition applies to this text, is any unwanted or discarded carbonaceous (containing carbon) or hydrocarbonaceous (containing carbon and hydrogen) material that originates from a variety of sources and is not a liquid or a gas.

Furthermore, the disposal of a wide variety of wastes has become an important problem because the traditional means of disposal to a landfill has become environmentally much less acceptable than previously. Newer and stricter regulation of the conventional disposal method(s) has made the economics of waste processing for resource recovery much more favorable.

However, before moving on to the various aspects of the gasification process, it is worthwhile to describe in more detail the types of waste that arise from human activities and which might be suitable for gasification.

17.4.1.2 Municipal Solid Waste

Municipal solid waste (MSW) is solid waste resulting from, or incidental to, municipal, community, commercial, institutional, and recreational activities; it includes garbage, rubbish, ashes, street cleanings, dead animals, medical waste, and all other non-industrial solid waste (Chapters 15, 16).

Municipal solid waste (MSW) is generated from households, offices, hotels, shops, schools and other institutions. The major components are food waste, paper, plastic, rags, metal and glass, although demolition and construction debris is often included in collected waste, as are small quantities of hazardous waste, such as electric light bulbs, batteries, automotive parts and discarded medicines and chemicals.

Municipal solid waste is a negatively priced, abundant and essentially renewable feedstock. Moreover, the composition of municipal solid waste (Table 17.4) can vary from one community to the next, but the overall differences are not substantial. In fact, there are several types of waste that might also be classified under the municipal solid waste umbrella. The heat content of raw municipal solid waste depends on the concentration of combustible organic materials in the waste and its moisture content. Typically, raw municipal solid waste has a heating value on the order of approximately 50% of the heating value of bituminous coal (Speight, 2013). The moisture content of raw municipal solid waste is usually 20% w/w.

17.4.1.3 Industrial Solid Waste

Industrial solid waste is solid waste resulting from or incidental to any process of industry, manufacturing, mining, or agricultural operations. Industrial solid waste is classified as either *hazardous* or *non-hazardous. Hazardous industrial waste* includes any industrial solid waste or combination of industrial solid wastes identified or listed as a hazardous waste.

Industrial solid waste encompasses a wide range of materials of varying environmental toxicity. Typically this range would include paper, packaging materials, waste from food processing, oils, solvents, resins, paints and sludge, glass, ceramics, stones, metals, plastics, rubber, leather, wood, cloth, straw, abrasives, etc. As with municipal solid waste, the absence of a regularly updated and systematic database on industrial solid waste ensures that the exact rates of generation are largely unknown.

Non-hazardous industrial waste is an industrial solid waste that is not identified or listed as a hazardous waste. A generator of non-hazardous industrial solid waste must further classify the waste as Class 1, Class 2, or Class 3 (Table 17.6).

Table 17.6 Classification of the different types of waste.

Waste type	Description
Class 1 waste	Includes any industrial solid waste or mixture of industrial solid wastes that – because of its concentration, or physical or chemical characteristics – is toxic; corrosive; flammable; a strong sensitizer or irritant; or a generator of sudden pressure by decomposition, heat, or other means; or may pose a substantial present or potential danger to human health or the environment when improperly processed, stored, transported, or disposed of or otherwise.
Class 2 waste	Consists of any individual solid waste or combination of industrial solid wastes that are not described as Hazardous, Class 1, or Class 3.
Class 3 waste	Consists of inert and essentially insoluble industrial solid waste, usually including, but not limited to, materials such as rock, brick, glass, dirt, and certain plastics, rubber, and other materials that are not readily decomposed.

17.4.1.4 Biowaste

Biowaste (sometimes referred to as biosolids) solids include livestock waste, agricultural crop residues and agro-industrial by-products. In most traditional, sedentary agricultural systems, farmers use the land application of raw or composted agricultural wastes as a means of recycling of valuable nutrients and organics back into the soil and this remains the most widespread means of disposal. Similarly, fish farming communities commonly integrate fish rearing with agricultural activities such as livestock husbandry, vegetable and paddy cultivation and fruit farming.

Many countries with agricultural-based economies use agricultural wastes to produce biogas through anaerobic digestion (Speight, 2011a, 2020a, 2020b). The biogas (approximately 60% v/v methane) is primarily used directly for cooking, heating and lighting, whilst the slurry from the anaerobic digesters is used as liquid fertilizer, a feed supplement for cattle and pigs and as a medium for soaking seeds.

17.4.1.5 Biomedical Waste

Biomedical waste is the waste materials produced by hospitals and health care institutions, which have been increasing over the past four decades to meet the medical and health care requirements of the growing world population. Until recent years, little attention was paid to the wastes generated from these facilities, which are potentially hazardous to human health and the environment. In fact, serious concern has arisen regarding the potential for spreading pathogens, as well as causing environmental contamination due to the improper handling and management of clinical and biomedical waste.

Regulated medical waste (RMW) is a waste stream that contains potentially infectious material – also called *red bag waste* or *biohazardous waste*. Regulated medical waste is regulated state by state, but also falls under the Blood-borne Pathogen Standard as defined by the US Office of Safety and Health Administration (OSHA). Such waste are subject to state and federal regulations and may not be suitable as gasification feedstock and require higher temperature to assure complete disposal of the constituents.

17.4.2 Waste to Energy

The traditional waste-to-energy plant, based on mass-burn combustion on an inclined grate, has a low public acceptability despite the low emissions achieved over the last decade with modern flue gas clean-up equipment. This has led to difficulty in obtaining planning permissions to construct needed new waste-to-energy plants. After much debate, various governments have allowed options for advanced waste conversion technologies (gasification, pyrolysis and anaerobic digestion), but will only give credit to the proportion of electricity generated from non-fossil waste.

The gasification of solid waste gasification includes a number of physical and chemical interactions that occur at temperatures generally higher than 600°C (1110°F), the exact temperature depending on the reactor type and the waste characteristics, in particular the ash softening and melting temperatures (Higman and van der Burgt, 2003; Arena, 2012). The different types of waste gasification processes are generally classified on the basis of oxidation medium: (i) partial oxidation with air, (ii) oxygen-enriched air or pure oxygen, (iii) steam gasification, or (iv) plasma gasification (Rajasekhar *et al.*, 2015).

Some processes are operated with oxygen-enriched air, i.e., a mixture of nitrogen and oxygen having oxygen content higher than 21% v/v but less than 50% v/v in order to higher heating value gas as a consequence of the reduced nitrogen content, that makes it possible to carry out auto-thermal processes at higher temperature, without expensive consumption of oxygen (Mastellone *et al.*, 2010a, 2010b). The partial oxidation process using pure oxygen generates synthesis gas free (or almost free) of atmospheric nitrogen. The steam gasification option generates a high hydrogen concentration, medium heating value nitrogen-free synthesis gas. In this case, steam is the only gasifying agent and the process does not include exothermic reactions but does need an external source of energy for the endothermic gasification reactions.

Thus, use of waste materials as cogasification feedstocks may attract significant disposal credits (Ricketts *et al.*, 2002). Cleaner biomass materials are renewable fuels and may attract premium prices for the electricity generated. Availability of sufficient fuel locally for an economic plant size is often a major issue, as is the reliability of the fuel supply. Use of more-predictably available coal alongside these fuels overcomes some of these difficulties and risks. Coal could be regarded as the base feedstock which keeps the plant running when the fuels producing the better revenue streams are not available in sufficient quantities.

Gas cleaning issues can also be different depending upon the feedstock and process parameters from which the case originated. For example, the presence of sulfur-containing constituents is a major concern for coal gasification and chlorine compounds and tars more important for waste and biomass gasification. It is possible that adjacent gasifiers and gas cleaning systems could be developed, one handling biomass or waste and one coal, to feed the same power production equipment. There are some advantages to such a design as compared with mixing fuels in the same gasifier and gas cleaning systems.

Gasification is a unique process that transforms any carbon-based material, such as municipal solid waste (MSW), into energy without burning it and converts the carbonaceous waste into gaseous products of which synthesis gas is (in the current context) of prime importance – removal of pollutants and impurities results in clean gas that can be converted into electricity and valuable products (Chapter 2). With gasification, municipal solid waste and other types of wastes are no longer of environmental concern but are feedstocks for a gasifier. Instead of the associated costs of disposal of and landfill management, using waste as a feedstock for a gasification process reduces disposal costs and required landfill space, and converts the carbonaceous wastes to electricity and fuels.

Electricity production or combined electricity and heat production remain the most likely area for the application of gasification or cogasification. The lowest investment cost per unit of electricity generated is the use of the gas in an existing large power station. This has been done in several large utility boilers, often with the gas fired alongside the main fuel. This option allows a comparatively small thermal output of gas to be used with the same efficiency as the main fuel in the boiler as a large, efficient steam turbine can be used. It is anticipated that addition of gas from a biomass or wood gasifier into the natural gas feed to a gas turbine to be technically possible but there will be concerns as to the balance of commercial risks to a large power plant and the benefits of using the gas from the gasifier.

Combustion (sometimes referred to as incineration) which does have a place in waste disposal operations, uses municipal solid waste as a fuel (Chapter 16). The waste is burned with high volumes of air to form carbon dioxide and heat. The traditional waste-to-energy plant, based on mass-burn combustion on an inclined grate, has a low public acceptability despite the low emissions achieved over the last decade with modern flue gas clean-up equipment. This has led to difficulty in obtaining planning permissions to construct needed new waste to energy plants. After much debate, various governments have allowed options for advanced waste conversion technologies (gasification, pyrolysis and anaerobic digestion), but will only give credit to the proportion of electricity generated from non-fossil waste.

Before the conversion of the waste in the gasifier, as might be expected, a pre-processing step (or steps) is (are) necessary to accomplish the extraction of metals, glass and inorganic materials, resulting in the increased recycling and utilization of materials.

Municipal solid waste is not a homogenous waste stream. Thus, the first treatment of the waste is to submit the waste to a front-end (pre-processing) system that accepts the solid waste directly from the collection vehicle and to separate the solid waste into two fractions – combustible waste and non-combustible waste. The front-end separation produces the feedstock for the gasification process.

Since inorganic materials (metals, glass, concrete, and rocks) do not enter into the thermal conversion reactions, part of the energy which could be used to gasify the feedstock is expended in heating the inorganic materials to the pyrolysis reactor temperature. Then the inorganic materials are cooled in clean-up processes, and the heat energy is lost, which reduces the overall efficiency of the system. To make the process more efficient, some pre-processing of waste is typically required and includes the separation of thermally non-degradable material such as metals, glass, and concrete debris. Pre-processing may include sorting, separation, size reduction, and densification (for reducing overall volume of feedstock being fed into the gasifier). Such pre-processing techniques are common in the waste recycling industry for recovery of paper, glass, and metals from the municipal solid waste streams.

In addition, a wide range of plastics cannot be recycled as feedstocks for gasification. Thus, the main steps involved in pre-processing of municipal solid waste are analogous to the pre-processing of coal (Speight, 2013) or biomass (Speight, 2011a, 2020a) and include (i) sorting, which can be manual and/or mechanical, (ii) shredding, (iii) grinding, (iv) blending with other materials, (v) drying, and (vi) pelletization. The purpose of pre-processing is to produce a feed material with, as best as can be achieved, near-consistent physical characteristics and chemical properties. Pre-processing operations are also designed to produce a material that can be safely handled, transported, and stored prior to the gasification process. In addition, particle size or pellet size affects the product distribution (Luo *et al.*, 2010).

If the municipal solid waste has high moisture content, a dryer may be added to the pre-processing stage to lower the moisture content of the waste stream to 25% w/w, or lower (CH2MHill, 2009). Lower moisture content of the feedstock increases its heating value and the system becomes more efficient. The waste heat or fuel produced by the system can be used to dry the incoming municipal solid waste.

In some cases, the pre-processing operation may be used for the production of a combustible fraction (i.e., a solid fuel) from municipal solid waste and from mixed waste and its thermal conversion requires two basic and distinct subsystems – the *front-end* and the *back-end*. The combustible fraction recovered from mixed municipal solid waste has been given the name *refuse-derived fuel* (RDF). The composition of the recovered combustible fraction is a mixture that has higher concentrations of combustible materials (e.g., paper and plastics) than those present in the parent mixed municipal solid waste.

The main components (i.e., unit operations) of a front-end subsystem are usually any combination of size reduction, screening, magnetic separation, and density separation (e.g., air classification). The types and configurations of unit operations selected for the front-end design depend on the types of secondary materials that will be recovered and on the desired quality of the recovered fuel fraction. The fuel quality must be specified by the designer or supplier of the thermal conversion system.

Typically, systems that recover a combustible fraction from mixed municipal solid waste utilize size reduction, screening, and magnetic separation. Some designs and facilities have used screening, followed by size reduction (e.g., pre-trommel screening – a trommel is a drum screen), as the fundamental foundation of the system design, while others have reversed the order of these two operations. A number of considerations enter into the determination and the selection of the optimum order of screening and size reduction for a given application. Among others, the considerations include composition of the waste. Other unit operations may also be included in the system design, including manual sorting, magnetic separation, air classification, and pelletization (i.e., densification), as the need dictates for recovery of other materials (e.g., aluminum, etc.) and for achieving the desired specification of the solid fuel product (Diaz and Savage, 1996).

In a waste-to-energy plant that uses combustion, the hot gaseous products are used to generate steam, which is then used to in a steam turbine to generate electricity. On the other hand, gasification converts municipal solid waste to usable synthesis gas and it is the production of this synthesis gas which makes gasification different from the combustion process. In the gasification process, the municipal solid waste is not a fuel but a feedstock for a high-temperature chemical conversion process. Instead of making just heat and electricity, as is done in a waste-to-energy plant using combustion, the synthesis gas produced by gasification can be turned into higher-value commercial products such as transportation fuels, chemicals, fertilizers, and substitute natural gas.

In addition, one of the concerns with combustion of municipal solid waste is the formation and reformation of toxic dioxin derivatives and furan derivatives, especially from PVC plastics (polyvinyl chloride plastics). These toxins end up in exhaust streams by three pathways: (i) by decomposition, as low-molecular weight volatile constituents, (ii) by re-forming in which lower molecular weight constituents combine to form new products, and/or (iii) by the unusual step of passing through the incinerator without change. Combustion does not always allow adequate control of these processes.

Cogasification technology varies, being usually site specific and high feedstock dependent. At the largest scale, the plant may include the well-proven fixed-bed and entrained-flow gasification processes. At smaller scales, emphasis is placed on technologies which appear closest to commercial operation. Pyrolysis and other advanced thermal conversion processes are included where power generation is practical using the on-site feedstock produced. However, the needs to be addressed are (i) core fuel handling and gasification/pyrolysis technologies, (ii) fuel gas clean-up, and (iii) conversion of fuel gas to electric power (Ricketts *et al.*, 2002). However, waste may be municipal solid waste (MSW) which had minimal presorting, or refuse-derived fuel (RDF) with significant pretreatment, usually mechanical screening and shredding. Other more specific waste sources (excluding hazardous waste) and possibly including crude oil coke, may provide niche opportunities for co-utilization.

The traditional waste-to-energy plant, based on mass-burn combustion on an inclined grate, has a low public acceptability despite the low emissions achieved over the last decade with modern flue gas clean-up equipment. This has led to difficulty in obtaining planning permissions to construct needed new waste-to-energy plants. After much debate, various governments have allowed options for advanced waste conversion technologies (gasification, pyrolysis and anaerobic digestion), but will only give credit to the proportion of electricity generated from non-fossil waste.

Co-utilization of waste and biomass with coal may provide economies of scale that help achieve the above-identified policy objectives at an affordable cost. In some countries, governments propose cogasification processes as being *well suited for community-sized developments*, suggesting that waste should be dealt with in smaller plants serving towns and cities, rather than moved to large, central plants (satisfying the so-called *proximity principal*).

In fact, neither biomass nor wastes are currently produced, or naturally gathered at sites in sufficient quantities to fuel a modern large and efficient power plant. Disruption, transport issues, fuel use, and public opinion all act against gathering hundreds of megawatts (MWe) at a single location. Biomass or waste-fired power plants are therefore inherently limited in size and hence in efficiency (labor costs per unit electricity produced) and in other economies of scale. The production rates of municipal refuse follow reasonably predictable patterns over time periods of a few years. Recent experience with the limited current *biomass for energy* harvesting has shown unpredictable variations in harvesting capability with long periods of zero production over large areas during wet weather.

The potential unreliability of biomass, longer-term changes in refuse and the size limitation of a power plant using only waste and/or biomass can be overcome combining biomass, refuse and coal. It also allows benefit from a premium electricity price for electricity from biomass and the gate fee associated with waste. If the power plant is gasification-based, rather than direct combustion, further benefits may be available. These include a premium price for the electricity from waste, the range of technologies available for the gas to electricity part of the process, gas cleaning prior to the main combustion stage instead of after combustion and public image, which is currently generally better for gasification as compared to combustion. These considerations lead to current studies of cogasification of wastes/biomass with coal (Chapter 9) (Speight, 2020a).

For large-scale power generation (>50 MWe), the gasification field is dominated by plant based on the pressurized, oxygen-blown, entrained flow or fixed-bed gasification of fossil fuels. Entrained gasifier operational experience to date has largely been with well-controlled fuel feedstocks with short-term trial work at low cogasification ratios and with easily-handled fuels.

Use of waste materials as cogasification feedstocks may attract significant disposal credits. Cleaner biomass materials are renewable fuels and may attract premium prices for the electricity generated. Availability of sufficient fuel locally for an economic plant size is often a major issue, as is the reliability of the fuel supply. Use of more-predictably available coal alongside these fuels overcomes some of these difficulties and risks. Coal could be regarded as the *flywheel* which keeps the plant running when the fuels producing the better revenue streams are not available in sufficient quantities.

Coal characteristics are different from the characteristics of other fuels such as biomass and waste. Hydrogen-to-carbon ratios are higher for younger fuels, as is the oxygen content. This means that reactivity is different under gasification conditions. Gas cleaning issues can also be different, being sulfur a major concern for coal gasification and chlorine compounds and tars more important for waste and biomass gasification. There are no current proposals for adjacent gasifiers and gas cleaning systems, one handling biomass or waste and one coal, alongside each other and feeding the same power production equipment. However, there are some advantages to such a design as compared with mixing fuels in the same gasifier and gas cleaning systems.

Electricity production or combined electricity and heat production remain the most likely area for the application of gasification or cogasification. The lowest investment cost per unit of electricity generated is the use of the gas in an existing large power station. This has been done in several large utility boilers, often with the gas fired alongside the main fuel. This option allows a comparatively small thermal output of gas to be used with the same efficiency as the main fuel in the boiler as a large, efficient steam turbine can be used. It is anticipated that addition of gas from a biomass or wood gasifier into the natural gas feed to a gas turbine to be technically possible but there will be concerns as to the balance of commercial risks to a large power plant and the benefits of using the gas from the gasifier.

In summary, coal may be co-gasified with waste or biomass for environmental, technical or commercial reasons. It allows larger, more efficient plants than those sized for grown biomass or arising waste within a reasonable transport distance; specific operating costs are likely to be lower and fuel supply security is assured.

In fact, neither biomass nor wastes are currently produced, or naturally gathered at sites in sufficient quantities to fuel a modern large and efficient power plant. Disruption, transport issues, fuel use, and public opinion all act against gathering hundreds of megawatts (MWe) at a single location. Biomass or waste-fired power plants are therefore inherently limited in size and hence in efficiency (labor costs per unit electricity produced) and in other economies of scale. The production rates of municipal refuse follow reasonably predictable patterns over time periods of a few years. Recent experience with the limited current *biomass* *for energy* harvesting has shown unpredictable variations in harvesting capability with long periods of zero production over large areas during wet weather.

The situation is different for coal which is generally mined or imported and thus large quantities are available from a single source or a number of closely located sources, and supply has been reliable and predictable. However, the economics of new coal-fired power plants of any technology or size have not encouraged any new coal-fired power plant in the gas generation market.

The potential unreliability of biomass, longer-term changes in refuse and the size limitation of a power plant using only waste and/or biomass can be overcome combining biomass, refuse and coal. It also allows benefit from a premium electricity price for electricity from biomass and the gate fee associated with waste. If the power plant is gasification-based, rather than direct combustion, further benefits may be available. These include a premium price for the electricity from waste, the range of technologies available for the gas to electricity part of the process, and gas cleaning prior to the main combustion stage instead of after combustion and public image, which is currently generally better for gasification as compared to combustion. These considerations lead to current studies of cogasification of wastes/biomass with coal (Chapter 9) (Speight, 2020a).

For large-scale power generation (>50 MWe), the gasification field is dominated by plant based on the pressurized, oxygen-blown, entrained flow or fixed-bed gasification of fossil fuels. Entrained gasifier operational experience to date has largely been with well-controlled fuel feedstocks with short-term trial work at low cogasification ratios and with easily handled fuels.

17.5 Process Products

By general definition, the goal of the gasification process is to produce gaseous products, in particular synthesis gas from which hydrogen can be isolated on an as-needed basis (Chapter 11). Furthermore, the product gas resulting from waste gasification contains carbon dioxide, tar, particulate matter, halogens/acid gases, heavy metals and alkaline compounds depending on the feedstock composition and the particular gasification process. The downstream power generating and gas cleaning equipment typically requires removal of these contaminants.

17.5.1 Synthesis Gas

Like many gasification processes, the goal of *waste gasification* is to produce a gas that can either be (i) be used as fuel gas or (ii) used for hydrocarbons and/or chemicals production. In either case, the gas is synthesis gas – mixtures of carbon monoxide and hydrogen – and the yield and composition of the gas and yield of byproducts are dependent upon (i) the properties and character of the feedstock, (ii) the gasifier type, and (iii) the conditions in the gasifier (Chapters 9, 10) (Orr and Maxwell, 2000; Speight, 2020b).

The raw synthesis gas produced in the gasifier contains trace levels of impurities that must be removed prior to its ultimate use. After the gas is cooled, virtually all the trace minerals, particulates, sulfur, mercury, and unconverted carbon are removed using commercially proven cleaning processes common to the gas processing industry as well as the chemical and refining industries (Mokhatab *et al.*, 2006; Hsu and Robinson, 2006; Gary *et al.*, 2007; Speight, 2014; Hsu and Robinson, 2017; Speight, 2017). For feedstocks containing mercury, more than 90% w/w of the mercury can be removed from the synthesis gas using relatively small and commercially available activated carbon beds.

17.5.2 Carbon Dioxide

Carbon dioxide can also be removed in the synthesis gas clean-up stage using a number of commercial technologies (Mokhatab *et al.*, 2006; Speight, 2019). In fact, carbon dioxide is routinely removed with a commercially proven process in gasification-based ammonia, hydrogen, and chemical manufacturing plants. Gasification-based plants for the production of ammonia are equipped to separate and capture approximately 90% v/v of their carbon dioxide and gasification-based methanol plants separate and capture approximately 70% v/v of the produced carbon dioxide. In fact, the gasification process is considered to offer a cost-effective and efficient means of capturing carbon dioxide during the energy production process.

Carbon dioxide can also be removed in the synthesis gas clean-up stage using a number of commercial technologies. In fact, carbon dioxide is routinely removed with a commercially proven process in gasification-based ammonia, hydrogen, and chemical manufacturing plants. Gasification-based ammonia plants already capture/separate approximately 90% v/v of the carbon dioxide and gasification-based methanol plants capture approximately 70% v/v. The gasification process offers the most cost-effective and efficient means of capturing carbon dioxide during the energy production process.

17.5.3 Tar

By definition for this text, tar is any condensable or non-condensable organic material in the product stream, and is largely intractable and comprised of aromatic compounds.

When municipal solid waste is gasified, significant amounts of tar are produced – If tar is allowed to condense (condensation temperatures range from 200 to 600°C, 390 to 1110°F) it can cause coke to form on fuel reforming catalysts, deactivate sulfur removal systems, erode compressors, heat exchangers, ceramic filters, and damage gas turbines and engines. Non-condensable tar can also cause problems for advanced power conversion devices, such as fuel cell catalysts, and complicate environmental emissions compliance.

The amount and composition of tars are dependent on the fuel, the operating conditions and the secondary gas phase reactions – tar can be subdivided into three categories based on the reaction temperature ranges in which they form (Table 8.3). This categorization is important for assessing gasification processes, as the effectiveness of conversion and/or removal schemes depend greatly on the specific tar composition and their concentration in the fuel gas.

The primary tars are mixed oxygenates and are a product of pyrolysis. As gasification takes over at higher temperatures, the primary products thermally decompose to lesser amounts of secondary and tertiary products and a greater quantity of light gases. Tertiary products are the most stable and difficult to crack catalytically. Provided that there is adequate gas mixing, primary and tertiary tars are mutually exclusive in the product gas. Both lignin and cellulose in the fuel result in the formation of tertiary tar compounds. However, lignin rich fuels have been shown to form heavier tertiary aromatics more quickly.

Both physical and chemical treatment processes can reduce the presence of tar in the product gas. The physical processes are classified into wet and dry technologies depending on whether water is used. Various forms of wet or wet/dry scrubbing processes are commercially available, and these are the most commonly practiced techniques for physical removal of tar.

Wet physical processes involve tar condensation, droplet filtration, and/or gas/liquid mixture separation. Cyclones, cooling towers, venturi scrubbers, baghouses, electrostatic precipitators, and wet/dry scrubbers are the primary tools. The main disadvantage to using wet physical processes is that the tar is transferred to wastewater, so the heating value is lost and the water must be disposed of in an environmentally acceptable way. Wastewater that contains tar is classified as *hazardous waste* – treatment and disposal can add significantly to the overall cost of the gasification plant.

Dry tar removal processes that use ceramic, metallic, or fabric filters are alternatives to wet tar removal processes. However, at temperatures above 150°C (300°F), tars can become semi-solid and adhesive and cause operational problems with such barriers – as a result, dry tar removal schemes are rarely implemented. Injection of activated carbon in the product gas stream or in a granular bed may also reduce tars through adsorption and collection with a baghouse. The carbonaceous material containing the tars can be recycled back to the gasifier to encourage further thermal and/or catalytic decomposition – i.e., the tar is recycled to extinction.

Chemical tar treatment processes are the most widely practiced in the gasification industry. They can be divided into four generic categories: (i) thermal, (ii) steam, (iii) partially oxidative, and (iv) catalytic processes. Thermal destruction has been shown to break down aromatics at temperatures above 1000°C (1830°F). However, such high temperatures can have adverse effects on heat exchangers and refractory surfaces due to ash sintering in the gasification vessel. The introduction of steam does encourage reformation of primary and some secondary oxygenated tar compounds, but has a lesser on many nitrogen-containing organic compounds.

The presence of oxygen during gasification has been shown to accelerate both the destruction of primary tar products and the formation of aromatic compounds from phenol cracking increases in the presence of low oxygen environments (less than 10% v/v) of the gas. Only above 10% v/v was a decrease in the amount of tertiary tars observed. A net increase in the carbon monoxide may also be observed as the product from the oxidative cracking of tar. Benzene levels are not usually affected by the presence of oxygen.

The most widely used and studied tar cracking catalyst is dolomite (a mixture of calcium carbonate, $CaCO_3$, and magnesium carbonate, $MgCO_3$). Dolomite has been shown to work more effectively when placed in a vessel downstream from the gasifier and in a low carbon monoxide environment. However, when used within the gasifier, catalytic materials often accumulate a layer of coke that causes rapid loss of catalytic efficiency.

The specific tar conversion and destruction schemes are chosen to depend on the nature and composition of the tars present, as well as the intended end-use equipment. However, the advantages of recycling the tar product for further treatment include (i) increased waste-to-energy efficiency, (ii) lower emissions, and (iii) lower effluent treatment costs. Although progress in mitigating tar formation and increasing tar remove (if formed), the need for effective and less costly tar removal processes has a barrier to widespread commercialization municipal solid waste integrated gasification combined cycle (IGCC) power generation.

17.5.4 Particulate Matter

The detrimental effect of particulate matter on the atmosphere has been of some concern for several decades. Species such as mercury, selenium, and vanadium which can be ejected into the atmosphere and from fossil fuel combustion are particularly harmful to the flora and fauna. There are many types of particulate collection devices in use and they involve a number of different principles for removal of particles from gasification product streams (Speight, 2013). However, the selection of an appropriate particle removal device must be based upon equipment performance as anticipated/predicted under the process conditions. To enter into a detailed description of the various devices available for particulate removal is well beyond the scope of this text but it is essential for the reader to be aware of the equipment available for particulate removal and the means by which this might be accomplished: (i) cyclones, which are particle collectors that have many potential applications in coal gasification systems, (ii) electrostatic precipitators, which are efficient collectors of fine particulates matter and are capable of reducing the amount of submicron particles by 90%, or more and they also have the capability of collecting liquid mists as well as dust, (iii) granular-bed filters, which comprise a class of filtration equipment that is distinguished by a bed of separate, closely packed granules which serve as the filter medium and have the to collect particulates at high temperature and pressure; (iv) wet scrubbers, which represent a simple method to clean exhaust air or exhaust gas and remove toxic or smelling compounds using the principle of close contact with fine water drops in a co-current or countercurrent flow of the gas stream.

17.5.5 Halogens/Acid Gases

The principal combustion products of halogen-containing organic waste is either hydrogen halides (such as hydrogen chloride, HCl, or hydrogen bromide, HBr) or metal halides (such as mercuric chloride, $HgCl_2$, or mercurous chloride, HgCl) that volatilize out of the reactor along with the other gases. In the gasification of *pure* municipal solid waste (i.e., without coal, biomass, or any other feedstock added), hydrogen chloride is the prevailing chlorine-containing product while bromine constituents can accumulate to a greater extent in the bottom ash but in the presence of hydrogen bromine is transformed to hydrogen bromide (HBr), which with the hydrogen chloride (HCl) is readily removed in a scrubbing systems and hence cause no emission problems.

A significant advantage of gasification is that it takes place in a reducing atmosphere, which prevents sulfur and nitrogen compounds from oxidizing. As a result, most elemental nitrogen or sulfur in the waste stream end up as hydrogen sulfide (H_2S), carbonyl sulfide (COS), nitrogen (N_2) or ammonia (NH_3) rather than sulfur oxides (SOx) or nitrogen oxides (NOx), respectively. The reduced sulfur species can then be recovered as elemental sulfur at efficiencies between 95 and 99% w/w, or converted to a sulfuric acid by-product (Mokhatab *et al.*, 2006; Speight, 2019).

The typical sulfur removal and recovery processes used to treat the raw synthesis gas are the same as commercially available methods used in other industrial applications, such as oil refining and natural gas recovery (Speight, 2014, 2019, 2020a). One commonly used process to remove sulfur compounds is the selective-amine (olamine) technology where sulfur species are removed from the synthesis gas using, for example, an amine-based solvent in an absorber tower. The reduced sulfur species removed in the solvent stripper are converted to elemental sulfur in a sulfur recovery process such as the Selectox/Claus process.

When municipal solid waste is gasified, nitrogen in the fuel is converted primarily to ammonia, which when fired in a turbine or other combustion engine forms nitrogen oxides, a harmful pollutant. Removal of ammonia and other nitrogen compounds in the product gas prior to combustion can be accomplished with wet scrubbers or by catalytic destruction. Catalytic destruction of ammonia has been studied with dolomite and iron-based catalysts. This technique is of interest because tars are simultaneously decomposed (cracked) to lower weight gaseous compounds. Destruction of 99% v/v of the ammonia in the gas stream has been demonstrated with these catalysts.

If the product gas is cooled first, wet scrubbing with lime is also an effective ammonia removal technique. Gasification processes that use pure oxygen, steam or hydrogen, will only have nitrogen contents brought in through the fuel stream. Typical municipal solid waste has a nitrogen content of less than 1% w/w.

17.5.6 Heavy Metals

Trace amounts of metals and other volatile materials are also present in MSW. These are typically toxic substances that pose ecological and human health risks when released into the environment.

Mercury found in the fly ash and flue gas is likely to be in the elemental form but when oxidizing conditions are prevalent in the gasifier, the presence of hydrogen chloride (HCl) and chlorine (Cl_2) can cause some of the elemental mercury to form mercuric chloride ($HgCl_2$):

$$Hg + 4HCl + O_2 \leftrightarrow 2HgCl_2 + 2H_2O$$

$$Hg + Cl_2 \leftrightarrow HgCl_2$$

Volatilized heavy metals (or heavy metals that are entrained in the gas stream due to the high gas velocity) that are not collected in the gas cleanup system can bio-accumulate in the environment and can be carcinogenic and damage human nervous systems (Speight and Arjoon, 2012). For this reason, mercury must be removed from the product gas prior to combustion or further use. However, there has been extraordinary success removing heavy metals with activated carbon, baghouses filters and electrostatic precipitators (Mokhatab *et al.*, 2006; Speight, 2013, 2019).

17.5.7 Alkalis

The primary elements causing alkali slagging are potassium, sodium, chlorine and silica. Sufficient volatile alkali content in a feedstock will cause a reduction in the ash fusion temperature and promotes slagging and/or fouling. Alkali compounds in the ash from the gasification of municipal solid waste gasification can cause serious slagging in the boiler or gasification vessel. Sintered or fused deposits can form agglomerates in fluidized beds and on grates. Potassium sulfate (K_2SO_4) and potassium chloride (KCl) have been found to mix with flue dust and deposit/condense on the upper walls of the gasifier.

Alkali deposit formation is a result of particle impaction, condensation, and chemical reaction. Unfortunately, most deposits occur subsequent to gasification and cannot always be predicted solely on the basis of analysis of the feedstock. There are two characteristic temperature intervals for alkali metal emission. A small fraction of the alkali content is released below 500°C (930°F) and is attributed to the decomposition of the organic structure. Another fraction of alkali compounds is released from the char residue at temperatures above 500°C (930°F).

Thus, the presence of alkali metals in gasification processes is known to cause several operational problems. Eutectic systems consisting of alkali salts are formed on the surfaces of fly ash particles or on the fluidized-bed material – the eutectic system is a mixture of chemical compounds or elements that have a single chemical composition that solidifies at a lower temperature than any other composition made up of the same ingredients. The semi-solid or adhesive particle surfaces can lead to the formation of bed material agglomerates, which must be replaced by fresh material. The deposition of fly ash particles and the condensation of vapor-phase alkali compounds on heat exchanging surfaces lower the heat conductivity and may eventually require temporary plant shutdowns for the removal of deposits.

The challenges of removing alkali vapor and particulate matter are connected, since alkali metal compounds play an important role in the formation of new particles as well as the chemical degradation of ceramic barrier filters used in some hot gas cleaning systems. The most convenient method is to cool the gas and condense out the alkali compounds.

17.5.8 Slag

Most solid and liquid feed gasifiers produce a hard glass-like by-product (*slag*, also called *vitreous frit*) that is composed primarily of sand, rock, and any minerals (or thermal derivatives thereof) originally contained in the gasifier feedstock. Slag is the result of gasifier operation at temperatures above the fusion, or melting temperature of the mineral matter. Under these conditions, non-volatile metals are bound together in a molten form until it is cooled in a pool of water at the bottom of a quench gasifier, or by natural heat loss at the bottom of an entrained-bed gasifier. Volatile metals such as mercury, if present in the feedstock, are typically not recovered in the slag, but are removed from the raw synthesis gas during cleanup. Typically, the slag is non-hazardous (depending upon the type of mineral matter in the feedstock) and can be used in roadbed construction, cement manufacturing or in roofing materials.

Slag production is a function of the amount of mineral matter present in the gasifier feedstock, so materials such as municipal solid waste (as well as, for example, coal and biomass) produce much more slag than crude oil residua. Regardless of the character of the feedstock, as long as the operating temperature is above the fusion temperature of the ash (true for the modern gasification technologies under discussion), slag will be produced. As well as dependency on the waste feedstock, the physical structure of the slag is sensitive to changes in operating temperature and pressure and, in some cases, physical examination of the appearance of the slag can provide a good indication of carbon conversion in the gasifier.

Furthermore, because the slag is in a fused vitrified state, it rarely fails the toxicity characteristic leaching procedure (TCLP) protocols for metals (Speight and Arjoon, 2012).

Slag is not a good substrate for binding organic compounds so it is usually found to be nonhazardous, exhibiting none of the characteristics of a hazardous waste. Consequently, it may be disposed of in a nonhazardous landfill, or sold as an ore to recover the metals concentrated within its structure. The hardness of slag also makes it suitable as an abrasive or road-bed material as well as an aggregate in concrete formulations (Speight, 2013, 2014).

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18

Coal and Energy Security

18.1 Introduction

As defined by the International Energy Agency, energy security is the uninterrupted availability of energy sources at an affordable price. Energy security has many aspects of which the two major ones are (i) long-term energy security which deals with timely investments to supply energy in line with economic developments and environmental needs, and (ii) short-term energy security which focuses on the ability of the energy system to react promptly to sudden changes in the supply-demand balance (US IEA, 2020).

Thus, energy security is the association between national security and the availability of natural resources for energy consumption. Access to relatively cheap energy has become essential to the functioning of modern economies. However, the uneven distribution of energy supplies among countries has led to significant vulnerabilities. International energy relations have contributed to the globalization of the world leading to energy security and energy vulnerability at the same time.

Throughout this book, frequent reference has been made to the use of coal as a source of energy and its role in determining whether or not the United States can develop energy independence (also often referred to as *energy security*) insofar as energy independence means a reduced reliance on foreign sources of energy, particularly foreign crude oil. Generally, coal supply is especially secure because coal is mined in many countries throughout the world and trade operates in accordance with free market principles, which (in theory) ensure more stable prices. Abundant and widely distributed coal reserves offer guarantees of energy supply (Reisch, 2012; Speight, 2013a, 2020a).

The distribution of coal reserves around the world varies significantly from the distribution of the reserves of natural gas and crude oil. For example, substantial reserves of coal occur in the United States and Russia but not in the crude oil exporting countries of the Middle East. Thus, there is a strong case to be made for energy independence (at a level to be determined). On the other hand, environmental issues may be the basis for equally strong arguments against energy independence (at any level) based on coal. However, the environment and coal mining can coexist in harmony when mined land is restored to its pre-mining condition and the lakes, rivers, and streams are protected from environmental damage.

Energy independence has been variously played up and then ignored by the members of the Congress of the United States (as politicians determine which path will garner them the most votes for re-election) since the first Arab crude oil embargo in 1973. In spite of the calls for energy independence, the United States is even more than ever dependent upon imports of foreign crude oil with no end in sight (Speight, 2011a, 2011b).

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The dependency on foreign supplies of energy, such as crude oil, by the energy-importing countries such as the United States has increased steadily since the mid-1980s when the daily imports of crude oil and crude oil products (as percentage of consumption) increased from approximately 50% thence to approximately 60% in the early 1990s to the almost unbelievable current (2011a, 2011b) levels of 65-70% of the daily crude oil and crude oil products.

It is not *rocket science* to know that when imports of a necessary commodity exceed domestic production of this same commodity a dangerous situation exists. Especially when the commodity is supplied by countries where the governments cannot, by any stretch of the imagination, be classified as stable.

Events such as civil war, *coup d'état*, and the occasional (some would say *frequent*) labor strike will occur with sufficient frequency to severely restrict imports into the United States. It is even more worrying that the countries where highest levels of disruption can occur contain the majority of the proven worldwide crude oil reserves and provide the majority of the imports into the United States.

For example, the United States currently requires approximately 18,000,000 barrels of crude oil per day and, hypothetically, through events that are not within the control sphere of the United States, a shortfall of imported crude oil on the order of 2,000,000 barrels per day would leave a large gap in the domestic energy availability.

Furthermore, the crude oil industry itself cannot be held immune from crude oil shortages. Periods when there has been overproduction, when low prices and profits led crude oil producers to devise ways to restrict output and raise prices, and periods of underproduction have been known. Supply and demand is one thing, but holding a country to ransom is another! In addition, the crude oil supply pessimists would have everyone believe that the *era of crude oil* is over while realistically there is sufficient crude oil to last for another 100 years, providing that recovery methods and refining technology advance with time.

In the years to come, technology will focus on the search for new sources of crude oil (including heavy crude oil) while refining will focus on higher rates of conversion of heavy crude oil to saleable products. There is no recognition here of the so-called undiscovered crude oil which is difficult to define (and may even by mythological). The focus is on crude oil left in the ground when wells have been shut in.

It might be argued that the degree of dependence has no impact on energy security as long as foreign crude oil is imported form secure sources. However, if the degree of dependence on non-secure sources increases, energy security would be in jeopardy. In this case, vulnerability would increase and economic and national security of individual crude oil-importing countries would be compromised.

Dependency and vulnerability to crude oil imports in the United States and, for that matter, in other crude oil-importing countries can be reduced not only by diversification of suppliers (and this is largely controlled by the crude oil holding countries) but also by diversification of energy sources (Tables 18.1, 18.2). There would be a cost, but this must be measured against the cost of future disruptions due to geopolitical issues that cannot be controlled by the United States.

The dependence on foreign crude oil by the United States is a threat to national security and to the economy. Growing demand and shrinking domestic production means that the United States is importing more and more crude oil each year – much of it from the countries controlled by unfriendly governments and/or politically unstable governments.

Table 18.1 Future sources of fuels.

Source	Type
Non-conventional oil	Tar sand - Athabasca Canada (*in situ* recovery)
	Tar sand (mining recovery)
	Extra heavy crude oil
	Synthetic crude oil (from natural gas and/or coal)
	Crude oil in shale and tight sands
Non-conventional gas	Coalbed methane (CBM)
	Shale gas
	Tight gas sands
	Gas in geo-pressured aquifers
Non-conventional locations	Deep-water (>1,500 feet or <3,000 feet)
	Antarctic
Uneconomic hydrocarbons	Small fields (approximately 1-10 million barrels)
	Improved EOR technologies
Non-conventional hydrocarbons	Oil shale
	Gas hydrates

As each year passes, the Congress fails to reduce this dependency and continues to rely on factors outside of national control, thereby exposing the United States to greater security risks in the name of unrestrained consumption without any thought of the consequences of such actions (or *inactions*). The only real solution is for the United States to reduce the demand for crude oil and therefore take the guesswork out of the economic and security risks of dependence on crude oil imports.

As the supplies of crude oil decrease (crude oil from tight formation notwithstanding), the desirability of producing gas from other carbonaceous feedstocks will increase, especially in those areas where natural gas is in short supply. It is also anticipated that costs of natural gas will increase, allowing coal gasification to compete as an economically viable process. Research in progress on a laboratory and pilot-plant scale should lead to the invention of new process technology by the end of the century, thus accelerating the industrial use of coal gasification.

The conversion of the gaseous products of gasification processes to synthesis gas, a mixture of hydrogen (H_2) and carbon monoxide (CO), in a ratio appropriate to the application, needs additional steps, after purification. The product gases – carbon monoxide, carbon dioxide, hydrogen, methane, and nitrogen – can be used as fuels or as raw materials for chemical or fertilizer manufacture.

Table 18.2 Examples of crude oil and viscous feedstocks that can be used as a source of fuels in a refinery.

Conventional Crude Oil
Mobile in the reservoir; API gravity: >25° High-permeability reservoir Primary recovery Secondary recovery
Tight Oil
Similar properties to the properties of conventional crude oil; API gravity: >25° Immobile in the reservoir Low-permeability reservoir Horizontal drilling into reservoir Fracturing (typically multi-fracturing) to release fluids/gases
Heavy Crude Oil
More viscous than conventional crude oil; API gravity: 10-20° Mobile in the reservoir High-permeability reservoir Secondary recovery Tertiary recovery (enhanced oil recovery – EOR, e.g. steam stimulation)
Extra Heavy Crude Oil
Similar properties to the properties of tar sand bitumen; API gravity: <10° Mobile in the reservoir High-permeability reservoir Secondary recovery Tertiary recovery (enhanced oil recovery – EOR, e.g. steam stimulation)
Tar Sand Bitumen
Immobile in the deposit; API gravity: <10° High-permeability reservoir Mining (often preceded by explosive fracturing) Steam assisted gravity draining (SAGD) Solvent methods (VAPEX) Extreme heating methods Innovative methods**

*This list is not intended for use as a means of classification.

**Innovative methods excludes tertiary recovery methods and methods such as steam assisted gravity drainage (SAGD) and vapor assisted extraction (VAPEX) methods but does include variants or hybrids thereof (Speight, 2016).

Thus, through the careful and responsible use of coal, the United States can become more energy secure by putting coal to work in ever-increasing amounts while still paying attention to the environmental consequences. Instead of investing hundreds of billions of dollars expanding crude oil production in the Persian Gulf and other politically unstable regions, the United States needs to defray some of this money to developing domestic resources. Since a reduction in dependency cannot happen overnight, the so-called leaders in Washington (the Members of Congress) must make it happen by use of common-sense policies. Otherwise, the energy policy leaves the United States too dependent on crude oil and the politically unstable regimes that supply the crude oil.

In North America, energy security focuses on sources of energy such as the fossil fuels natural gas, crude oil, heavy crude oil, extra heavy crude oil, tar sand bitumen, and coal as well as the potential for the use of biomass and solid waste as sources of energy (Chapter 15).

18.2 Energy Security

Energy security is the continuous and uninterrupted availability of energy, to a specific country or region. The security of energy supply conducts a crucial role in decisions that are related to the formulation of energy policy strategies. The economies of many countries are dependent on energy imports in the sense that their balance of payments is affected by the magnitude of the vulnerability that they have through imported crude oil.

Energy security has become uncertain over the past four decades because of (i) the political instability of several energy-producing countries, (ii) the manipulation of energy supplies, (iii) the competition over energy sources now that China and India are providing large additional markets for crude oil, (iv) attacks on supply infrastructure, as well as (v) accidents, natural disasters, rising terrorism, and dominant countries' reliance on the supply of foreign crude oil (Speight, 2011b; Reisch, 2012).

The limited supplies, uneven distribution, and rising costs of crude oil and natural gas, create a need to change to more sustainable energy sources. With as much dependence that the United States currently has on crude oil and with the peaking limits of the production of crude oil (Hubbert's peak), various countries are already feeling the decline in the resource on which they have become dependent (Speight, 2011b). Energy security has become one of the leading issues in the modern world as crude oil and other resources have become as vital to the population of the world.

Briefly, the Hubbert theory of peak crude oil (Hubbert, 1962) assumes that crude oil reserves will not be replenished (i.e., that abiogenic replenishment is negligible) and predicts that future world crude oil production must inevitably reach a peak and then decline as these reserves are exhausted (Speight, 2011a, 2011b). Controversy surrounds the theory since predictions for the time of the global peak are dependent on the past production and discovery data used in the calculation.

For the United States, the prediction of crude oil being a depletable resource turned out to be correct (as it would with any naturally occurring resource) and, after the United States peaked in 1971 and thus lost its excess production capacity, the OPEC consortium was (literally) given a free hand at the manipulation of crude oil prices. Since then crude oil production in several other countries has also peaked. However, for a variety of reasons, it is difficult to predict the oil peak in any given region. Based on available production data, proponents have previously (and incorrectly) predicted the peak for the world to be in 1989, 1995, or in the 1995 to 2000 period. Other predictions chose 2007 and beyond for the peak of crude oil production.

But more important, several trends that should have been established in the wake of the decreasing crude prices have never been put into practice. For example, and most important, the failure of politicians to recognize the need for a measure of energy independence through the development of alternate resources as well as the development of technologies that would assist in maximizing crude oil recovery.

The fact that crude oil producing countries in the Middle East provide more than 50% of the world consumption (Speight, 2011b) is indicative of the low diversification of energy sources and the accompanying risks to smooth energy supply. The diversification that is offered by the alternative supplies from Russia and Africa cannot provide a sound solution for a supply disruption that may occur in the Middle East region. An overview of the crude oil market and the related risks and incidents clearly indicate that the risks associated to energy supply are many. War and civil conflicts might have been replaced, to some extent, by weather conditions and monopolistic practices, but they are still playing a crucial factor in energy supply. Therefore, the high dependency that most countries have on energy imports made it essential for policy makers to focus on the concept of security of energy supply. In this context, the need is to assess the current energy system and the risks of energy disruptions in order to better design and adopt the required policies.

Uncertainty related to future demand for crude oil – which will influence how quickly the remaining crude oil is used – contributes to the uncertainty related to the timing of peak crude oil production. It is likely that crude oil will continue to be a major source of energy well into the future and world consumption of crude oil products may even grow during the next four decades (Speight and Islam, 2016).

Future world crude oil demand will depend on such uncertain factors as world economic growth, future government policy, and consumer choices.

Environmental concerns related to the emissions of carbon dioxide (a greenhouse gas) from the use of liquid fuels such as gasoline and diesel may encourage future reductions in crude oil demand if these concerns are translated into policies that promote biofuels, although the uncertainty of the extent to which biofuels will be a major facet of energy production in the foreseeable future is still debatable (Lee *et al.*, 2007; Giampietro and Mayumi, 2009; Langeveld *et al.*, 2010; Nersesian, 2010; Seifried and Witzel, 2010; Speight, 2011a, 2011c, 2020a).

A more rapid rate of increase in the use of other fuels, particularly biomass fuels, could lead to a perceived increase in the share of total energy consumption. Some observers might see this as a decline in the share of total energy provided by coal (US EIA 2011a, US EIA 2011b, US EIA 2012, US EIA 2013). However, with the ever-increasing demand for electrical power, the amount of coal used for power generation and the amount of biomass used for the same purpose might march ahead side by side. Thus, growth rates for the consumption of all fuels (except liquid fuels) could maintain the share of total energy use in the electricity sector provided by coal relatively stable through 2050 when the relative amounts of coal and biomass used for electric power generation might appear to remain stable.

Consumer choices related to conservation also can affect crude oil demand and thereby influence the timing of a peak. For example, if US consumers were to purchase more fuel-efficient vehicles in greater numbers, this could reduce future crude oil demand in the United States, potentially delaying a time at which crude oil supply is unable to keep pace with crude oil demand. Such uncertainties that lead to changes in future crude oil demand ultimately make estimates of the timing of a peak uncertain. Specifically, using future annual increases in world crude oil consumption, ranging from 0%, to represent no increase, to 3%, to represent a large increase, and out of the various scenarios examined, it may be up to 75 years before the peak occurs.

Factors that affect crude oil exploration and production also create uncertainty related to the rate of production decline and the timing of the peak. The rate of decline after a peak is an important consideration because a decline that is more abrupt will likely have more adverse economic consequences than a decline that is less abrupt.

Consumer actions could help mitigate the consequences of a near-term peak and decline in crude oil production through demand-reducing behaviors such as carpooling; teleworking; and eco-driving measures, such as proper tire inflation and slower driving speeds. Clearly these energy savings come at some cost of convenience and productivity, and limited research has been done to estimate potential fuel savings associated with such efforts. However, estimates by the United States Department of Energy (DOE) indicate that teleworking could reduce total fuel consumption in by 1 to 4%, depending on whether teleworking is undertaken for 2 days per week or the full 5-day week, respectively.

If the peak occurs in the more distant future or the decline following a peak is less severe, alternative technologies have a greater potential to mitigate the consequences. The DOE projects that the alternative technologies have the potential to displace up to the equivalent of 34% of annual US consumption of crude oil products from 2025 through 2030. However, the DOE also considers these projections optimistic – since the assumption is that sufficient time and effort are dedicated to the development of these technologies to overcome the challenges they face.

The prospect of a peak in crude oil production presents problems of global proportion whose consequences will depend critically on our preparedness. The consequences would be most dire if a peak occurred soon, without warning, and was followed by a sharp decline in crude oil production because alternative energy sources, particularly for transportation, were not yet available in large quantities. Such a peak would require sharp reductions in crude oil consumption, and the competition for increasingly scarce energy would drive up prices, possibly to unprecedented levels, causing severe economic damage. While these consequences would be felt on the global scale, the United States remains the largest consumer of crude oil and one of the nations that is heavily dependent on crude oil for transportation and is especially vulnerable to geopolitics (Speight, 2011b).

The subject of energy security has been for many years an important concern among energy policy makers. The devastating short- and long-term effects of the crude oil crisis of 1973 in the global economy made clear since then that the need to guarantee the availability of energy resource supply in a sustainable and timely manner, such that the energy price is at a level that will not adversely affect European economic performance, is of utmost importance.

The continuous instability of several oil-producing countries, growing fears related to further military intervention in this fragile geopolitical area, environmental catastrophes, the advent of organized terrorist operations across the globe, political risks and legal reforms have profoundly increased the possibility of potential energy disruptions that will have detrimental effects, considering the dependence of Europe on external energy suppliers.

The popularity of the *energy risk-premium* concept has led to the formulation of a vast pool of knowledge encompassing an abundance of derivatives models. Traders have the ability to hedge against various risks and create risk-neutral portfolios using a diversified mix of energy derivative securities. However, up to now the risk-premium concept has not been used in the energy domain to quantify an energy security indicator. The main reason for this is that current techniques used in the energy domain do not incorporate the necessary probabilistic models that reflect on risk parameters associated with rare *catastrophic* events that cause adverse movements on the sport price of the underlying instrument.

A catastrophic event in general (or catastrophe) is an event which *has severe losses injury or property damage, affects large population of exposures and is caused by natural or hand-made events*. Examples of catastrophic events include natural disasters (hurricanes, earthquakes, floods) and terrorist attacks. In the last 20 years, natural catastrophes have been happening with increasing intensity.

Catastrophic events in the energy context have a slightly different meaning than in many other contexts. They can be events with low frequency of occurrence that cause the spot price of the energy commodity to soar (*price volatility*). Usually a price increase due to the catastrophic event does not have a lasting effect and the spot price tends to return to (or close to) its initial value. To combat such events, it will be necessary for the non-crude oil producing nations to commence development of sources of energy other than crude oil.

Once all risk indicators associated with catastrophic events have been identified and properly estimated in terms of frequency of occurrence and impact in the underlying spot price, then the respective premium can be calculated under the common assumptions of derivatives pricing.

In the longer term, there are many possible alternatives to using crude oil, including using biofuels and improving automotive fuel efficiency, but these alternatives will require large investments, and in some cases, major changes in infrastructure or breakthrough technological advances. In the past, the private sector has responded to higher crude oil prices by investing in alternatives, and it is doing so now. Investment, however, is determined largely by price expectations, so unless high crude oil prices are sustained, we cannot expect private investment in alternatives to continue at current levels. If a peak were anticipated, crude oil prices would rise, signaling industry to increase efforts to develop alternatives and consumers of energy to conserve and look for more energy-efficient products.

Finally, with the onset of the 21st century, crude oil technology is driven by the increasing supply of heavy crude oil with decreasing quality and the fast increases in the demand for clean and ultra-clean vehicle fuels and petrochemical raw materials. As feedstocks to refineries change, there must be an accompanying change in refinery technology. This means a movement from conventional means of refining heavy feedstocks using (typically) coking technologies to more innovative processes (including hydrogen management) that will produce the ultimate amounts of liquid fuels from the feedstock and maintain emissions within environmental compliance (Penning, 2001; Davis and Patel, 2004; Speight, 2011a, 2011b, 2020a).

During the next 20 to 30 years, the evolution future of crude oil refining and the current refinery layout will be primarily on process modification with some new innovations coming on-stream. The industry will move predictably on to (i) deep conversion of heavy feedstocks, (ii) higher hydrocracking and hydrotreating capacity, and (iii) more efficient conversion processes.

Although gasification technology has been used commercially for more than 200 years, the commercial applications of coal gasification technology have mostly been in niche markets in the energy and/or chemical industries. Coal gasification technology, however, is now attracting considerable interest among electricity production companies and appears to be at a strategic crossroads. Unlike most energy technologies, gasification processes can use almost any feedstock provided the correct choice of gasifier is made (Speight, 2011c, 2020a). Once in a gaseous form, scrubbers and distillation columns are used to separate the gases and remove impurities. Furthermore, gasification of coal is a proven, mature technology (that still offers holds significant potential for improvement and growth) that is capable of meeting the future energy needs of the United States. Indeed, gasification of coal blended with other feedstocks such as crude oil residua and biomass offers additional opportunities.

Hence it would not be surprising (it may even be expected) that high conversion refineries will move to gasification of feedstocks for the development of alternative fuels and to enhance equipment usage. A major trend in the refining industry market demand for refined products will be in synthesizing fuels from simple basic reactants (e.g., synthesis gas) when it becomes uneconomical to produce super-clean transportation fuels through conventional refining processes. Fischer-Tropsch plants together with IGCC systems will be integrated with, or even into refineries, which will offer the advantage of high-quality products (Davis and Occelli, 2010; Chadeesingh, 2011; Speight, 2011c).

In summary, the crude oil industry is indeed at the verge of a major decision period with the onset of processing high volumes of heavy crude oil and residua. Several technology breakthroughs have made this possible but many technical challenges remain and some are being met, including the production of fuels derived from sources other than crude oil (Høygaard Michaelsen *et al.*, 2009; Luce, 2009; Speight, 2011a, 2020a).

Furthermore, coal use need not be incompatible with sustainable development. Coal already contributes in a major way to social and economic development. It can also be used in a way that is compatible with environmental protection. With a favorable policy environment to facilitate the continued deployment of existing clean coal technologies (often cited as CCTs) and the development of the next generation of technologies, the vision of an ultra-low emissions energy production system for the 21st century can be realized, and the coal industry is committed to working with others to achieving this goal.

18.3 The Future of Coal

The projections for the continued use of fossil fuels indicate that there will be at least another five decades of fossil fuel use (especially coal and crude oil) before biomass and other forms of alternate energy take a firm hold, although significant inroads are being made into the gasification of various feedstocks (Kumar *et al.*, 2009; Pytlar, 2010; Speight, 2011a, 2011b; Chhiti and Kemiha, 2013; Speight, 2013a, 2013b, 2013c, 2020a). Furthermore, estimations that the era of fossil fuels (natural gas, crude oil, coal, and natural gas) will be almost over when the cumulative production of the fossil resources reaches 85% of their initial total reserves may or may not have some merit. In fact, the relative scarcity (compared to a few decades ago) of crude oil was real but it seems that the remaining reserves make it likely that there will be an adequate supply of energy for several decades (Martin, 1985; MacDonald, 1990; Banks, 1992; Krey *et al.*, 2009; Speight, 2011c, 2013a, 2013b, 2013c, 2014, 2017). The environmental issues are very real and require serious and continuous attention.

Thus, gasification can be proposed as a viable alternative solution for energy recovery from a variety of feedstocks. On the other hand, the process still faces some technical and economic problems, mainly related to the highly heterogeneous nature of unconventional feedstocks such as biomass and municipal solid wastes and the relatively limited number of gasification plants worldwide based on this technology that have continuous operating experience under commercial conditions.

However, technologies which ameliorate the effects of fossil fuels combustion on acid rain deposition, urban air pollution, and global warming must be pursued vigorously (Vallero, 2008). There is a challenge that must not be ignored and the effects of acid rain in soil and water leave no doubt that there is need to control the causes of acid rain (Mohnen, 1988). Indeed, recognition of the need to address these issues is the driving force behind recent energy strategies as well as a variety of research and development programs (Stigliani and Shaw, 1990; United States Department of Energy, 1990; United States General Accounting Office, 1990).

While regulations on the greenhouse gas (GHG) carbon dioxide (CO_2) would be an immediate hurdle to deployment of coal plants, gasification plants are in the best position compared to other coal-based alternatives to capture carbon dioxide. However, with the continued uncertainty of carbon dioxide regulation, there is industry reluctance to make large investments in projects with high emissions of carbon dioxide since a cost-effective solution for reducing such emissions is not yet available. Nevertheless, the reduction in greenhouse gas emissions can be an enhancing factor for gasification in the long run because the carbon dioxide from a gasification plant is more amenable to capture.

As new technology is developed, emissions may be reduced by repowering in which aging equipment is replaced by more advanced and efficient substitutes. Such repowering might, for example, involve an exchange in which an aging unit is exchanged for a newer combustion chamber, such as the atmospheric fluidized-bed combustor (AFBC) or the pressurized fluidized-bed combustor (PFBC).

Indeed, recognition of the production of these atmospheric pollutants in considerable quantities every year has led to the institution of national emission standards for many pollutants. Using sulfur dioxide as the example, the various standards are not only specific but will become more stringent with the passage of time. Atmospheric pollution is being taken very seriously and there is also the threat, or promise, of heavy fines and/or jail terms for any pollution-minded miscreants who seek to flaunt the laws (Vallero, 2008). Nevertheless, a trend to the increased use of fossil fuels will require more stringent approaches to environmental protection issues than we have ever known at any time in the past. The need to protect the environment is strong.

18.3.1 Environmental Issues

The careless combustion of fossil fuels can account for the large majority of the sulfur oxides and nitrogen oxides released to the atmosphere. Whichever technologies succeed in reducing the amounts of these gases in the atmosphere should also succeed in reducing the amounts of urban smog, those notorious brown and grey clouds that are easily recognizable at some considerable distances from urban areas, not only by their appearance but also by their odor.

$$SO_2 + H_2O \rightarrow H_2SO_4 \text{ (sulfurous acid)}$$

$$2SO_2 + O_2 \rightarrow 2SO_3$$

$$SO_3 + H_2O \rightarrow H_2SO_4 \text{ (sulfuric acid)}$$

$$2NO + H_2O \rightarrow HNO_2 + HNO_3 \text{ (nitrous acid + nitric acid)}$$

$$2NO + O_2 \rightarrow 2NO_2$$

$$NO_2 + H_2O \rightarrow HNO_3 \text{ (nitric acid)}$$

The most obvious issue with fossil fuel use relates to the effects on the environment. As technology evolves, the means to reduce the damage done by fossil fuel use also evolves and the world is on the doorstep of adapting to alternative energy sources. In the meantime, gasification offers alternatives to meet the demand for fuels of the future and to reduce the potentially harmful emissions.

Recent policy to tackle climate change and resource conservation, such as the Kyoto Protocol, the deliberations at Copenhagen in 2009 and the Landfill Directive of the European Union, stimulated the development of renewable energy and landfill diversion technology, so providing gasification technology development a renewed impetus. However, even though they are the fastest-growing source of energy, renewable sources of energy will still represent only 15% of the world energy requirements in 2035 (up from the current estimation of 10%) and divesting from fossil fuels does not mean an end to environmental emissions. Crude oil, tar sand bitumen, coal, natural gas, and perhaps oil shale will still be dominant energy sources – and will grow at a relatively robust rate over, at least, the next two decades. These estimates are a reality check on the challenge ahead for clean technologies if they are to make an impact in reducing greenhouse gas emissions and satisfy future energy demands (US EIA, 2013).

Current awareness of these issues by a variety of levels of government has resulted, in the United States, of the institution of the Clean Fossil Fuels Program to facilitate the development of pollution abatement technologies. And it has led to successful partnerships between government and industry (United States Department of Energy, 1993). In addition, there is the potential that new laws, such as the passage in 1990 of the Clean Air Act Amendments in the United States (United States Congress, 1990; Stensvaag, 1991) will be a positive factor and supportive of the controlled clean use of fossil fuels. However, there will be a cost but industry is supportive of the measure and confident that the goals can be met.

Besides fuel and product flexibility, gasification-based systems offer significant environmental advantages over competing technologies, particularly coal-to-electricity combustion systems. Gasification plants can readily capture carbon dioxide, the leading greenhouse gas, much more easily and efficiently than coal-fired power plants. In many instances, this carbon dioxide can be sold, creating additional value from the gasification process.

Carbon dioxide captured during the gasification process can be used to help recover oil from otherwise depleted oil fields. The Dakota Gasification plant in Beulah, North Dakota, captures its carbon dioxide while making substitute natural gas and sells it for enhanced oil recovery. Since 2000, this plant has captured and sent the carbon dioxide via pipeline to the Weyburn oil fields in Saskatchewan, Canada, where it is used for enhanced oil recovery. More than five million tons of carbon dioxide have been sequestered.

18.3.1.1 Carbon Dioxide

In a gasification system, carbon dioxide can be captured using commercially available technologies (such as the *water gas shift reaction*) before it would otherwise be vented to the atmosphere. Converting the carbon monoxide to carbon dioxide and capturing it prior to combustion is more economical than removing carbon dioxide after combustion, effectively "de-carbonizing" or, at least, reducing the carbon in the synthesis gas.

Gasification plants manufacturing ammonia, hydrogen, fuels, or chemical products routinely capture carbon dioxide as part of the manufacturing process. According to the Environmental Protection Agency, the higher thermodynamic efficiency of the IGCC cycle minimizes carbon dioxide emissions relative to other technologies. IGCC plants offer a least-cost alternative for capturing carbon dioxide from a coal-based power plant. In addition, IGCC will experience a lower energy penalty than other technologies if carbon dioxide capture is required. While carbon dioxide capture and sequestration will increase the cost of all forms of power generation, an IGCC plant can capture and compress carbon dioxide at one-half the cost of a traditional pulverized coal plant. Other gasification-based options, including the production of motor fuels, chemicals, fertilizers, or hydrogen, have even lower carbon dioxide capture and compression costs, which will provide a significant economic and environmental benefit in a carbon-constrained world.

18.3.1.2 Air Emissions

Gasification can achieve greater air emission reductions at lower cost than other coal-based power generation, such as supercritical pulverized coal. Coal-based IGCC offers the lowest emissions of sulfur dioxide nitrogen oxides and particulate matter (PM) of any coal-based power production technology. In fact, a coal IGCC plant is able to achieve low air-emissions rates that approach those of a natural gas combined cycle (NGCC) power plant. In addition, mercury emissions can be removed from an IGCC plant at one-tenth the cost of removal from a coal combustion plant. Currently, the technology does exist that enables removal of more than 90% w/w of the volatile mercury from the synthesis gas in a coal-based gasification-based plant.

18.3.1.3 Solids Generation

During gasification, virtually all of the carbon in the feedstock is converted to synthesis gas. The mineral material in the feedstock separates from the gaseous products, and the ash and other inert materials melt and fall to the bottom of the gasifier as a non-leachable, glass-like solid or other marketable material. This material can be used for many construction and building applications. In addition, more than 99% w/w of the sulfur can be removed using commercially proven technologies and converted into marketable elemental sulfur or sulfuric acid.

18.3.1.4 Water Use

Gasification uses approximately 14 to 24% v/v less water to produce electric power from coal compared to other coal-based technologies, and water losses during operation are approximately 32 to 36% v/v less than other coal-based technologies. This is a major issue in many countries – including the United States – where water supplies have already reached critical levels in certain regions.

18.3.2 Electric Power Generation

The use of electricity has been an essential part of the US economy since the turn of the century. Coal is an established electricity source that provides vast quantities of reliable power has become more important as supplies of oil and natural gas diminish.

The generation of electricity from coal involves combustion of the coal to generate heat which is used to generate steam that is used to spin one or more turbines to generate electricity.

Coal has played a major role in electrical production since the first power plants that were built in the United States in the 1880s. The earliest power plants used hand fed wood or coal to heat a boiler and produce steam. This steam was used in reciprocating steam engines which turned generators to produce electricity. In 1884, the more efficient high-speed steam turbine was developed by British engineer Charles A. Parsons, which replaced the use of steam engines to generate electricity.

In the 1920s, the pulverized coal firing was developed. This process brought advantages that included a higher combustion temperature, improved thermal efficiency and a lower requirement for excess air for combustion. In the 1940s, the cyclone furnace was developed. This new technology allowed the combustion of poorer grade of coal with less ash production and greater overall efficiency.

In the modern world, electricity generation from coal is still based on the same methods started over 100 years ago, but improvements in all areas have brought coal power to be the inexpensive power source.

The importance of coal to electricity generation worldwide is set to continue, with coal providing the power plant fuel for 44% of global electricity in 2030. *Steam coal*, also known as *thermal coal*, is used in power stations to generate electricity.

The concept of burning coal, which has been pulverized into a fine powder, stems from the belief that if the coal is made fine enough, it will burn almost as easily and efficiently as a gas. The feeding rate of coal according to the boiler demand and the amount of air available for drying and transporting the pulverized coal fuel is controlled by computers. Pieces of coal are crushed between balls or cylindrical rollers that move between two tracks (*races*). The raw coal is then fed into the pulverizer along with air heated to approximately 340°C (650°F) from the boiler.

As the coal is crushed by the rolling action, the hot air dries it and blows the usable fine coal powder out to be used as fuel. The powdered coal from the pulverizer is directly blown to a burner in the boiler in which the powdered coal is mixed in the air suspension with additional pre-heated combustion air and forces it out of a nozzle similar in action to fuel being atomized by a fuel injector in modern cars. Under operating conditions, there is enough heat in the combustion zone to ignite all the incoming fuel.

Cyclone furnaces were developed after pulverized coal systems and require less processing of the coal fuel. They can burn poorer-grade coals with higher moisture contents and ash contents to 25%. The crushed coal feed is either stored temporarily in bins or transported directly to the cyclone furnace. The furnace is basically a large cylinder jacketed with water pipes that absorb the some of the heat to make steam and protect the burner itself from melting down. A high-powered fan blows the heated air and chunks of coal into one end of the cylinder. At the same time additional heated combustion air is injected along the curved surface of the cylinder causing the coal and air mixture to swirl in a centrifugal "cyclone" motion. The whirling of the air and coal enhances the burning properties producing high heat densities (approximately 4700 to 8300 kW/m^2) and high combustion temperatures.

The hot combustion gases leave the other end of the cylinder and enter the boiler to heat the water-filled pipes and produce steam. As in the pulverized coal burning process, all the fuel that enters the cyclone burns when injected once the furnace is at its operating temperature. Some slag remains on the walls insulating the burner and directing the heat into the boiler while the rest drains through a trench in the bottom to a collection tank where it is solidified and disposed of.

This ability to collect ash is the biggest advantage of the cyclone furnace burning process. Only 40% of the ash leaves with the exhaust gases compared with 80% for pulverized coal burning. However, cyclone furnaces do have some disadvantages, such as (i) the coal used must have a relatively low sulfur content in order for most of the ash to melt for collection, (ii) high-power fans are required to move the larger coal pieces and air forcefully through the furnace, (iii) more nitrogen oxide pollutants are produced compared with pulverized coal combustion, and (iv) the actual burner may require regular replacement of its liners due to the erosion caused by the high velocity of the coal.

However, improvements continue to be made in conventional pulverized coal-fired power plant design and new combustion technologies are being developed. These allow more electricity to be produced from less coal – known as improving the thermal efficiency of the power station. Efficiency gains in electricity generation from coal-fired power stations will play a crucial part in reducing emissions of carbon dioxide at a global level.

Improving the efficiency of pulverized coal-fired power plants has been the focus of considerable efforts by the coal industry. There is huge scope for achieving significant efficiency improvements as the existing fleet of power plants are replaced over the next two to three decades with new, higher efficiency supercritical and ultra-supercritical plants and through the wider use of *integrated gasification combined cycle* (IGCC) systems for power generation.

As a general rule of thumb, one percentage point improvement in the efficiency of a conventional pulverized coal combustion plant results in a 2 to 3% reduction in emissions of carbon dioxide.

18.3.3 Hydrogen from Coal

Large quantities of hydrogen are currently used worldwide in the crude oil refining industry to desulfurize and upgrade crude oil and in the manufacture of ammonia for fertilizers. Hydrogen for these applications is produced predominantly by steam reforming of natural gas and as a by-product from naphtha reforming. Some hydrogen is also produced from coal gasification, coke oven gas, and electrolysis of water.

The gasification process combines the coal with steam in a hot environment to produce synthesis gas composed mostly of carbon monoxide (CO) and hydrogen. In the process, coal is first gasified with oxygen and steam to produce a synthesis gas consisting mainly of carbon monoxide (CO) and hydrogen (H), with some carbon dioxide (CO_2), sulfur, particulates, and trace elements.

Oxygen is added in less than stoichiometric quantities so that complete combustion does not occur. This process is highly exothermic, with temperatures controlled by the addition of steam. Increasing the temperature in the gasifier initiates devolatilization and breaking of weaker chemical bonds to yield tar, oils, phenol derivatives, and hydrocarbon gases. These products generally further react to form hydrogen, carbon monoxide, and carbon dioxide.

$$C + H_2O \rightarrow CO + CO_2 + H_2$$

The coke or char carbon that remains after devolatilization is gasified through reactions with oxygen, steam, and carbon dioxide to form additional amounts of hydrogen and carbon monoxide.

Once the synthesis gas is produced, it can be burned directly in a turbine to produce power, or further reacted with more steam to shift the remaining carbon monoxide to carbon dioxide and produce more hydrogen.

$$CO + H_2O \rightarrow CO_2 + H_2$$

The carbon dioxide can be stored in oil and gas fields and the hydrogen can be used for the many applications that make up the hydrogen economy – such as to power a car in an engine or a fuel cell, to power a turbine to produce electricity or to power a stationary fuel cell to make electricity.

Minerals in the feedstock separate as ash and leave the bottom of the gasifier as an inert slag (or bottom ash), a potentially marketable solid product. The fraction of the ash entrained with the synthesis gas, which is dependent upon the type of gasifier employed, requires removal downstream in particulate control equipment, such as filtration and water scrubbers.

The temperature of the synthesis gas as it leaves the gasifier is generally slightly below 1040°C (1900°F). With current technology, the gas has to be cooled to ambient temperatures to remove contaminants, although with some designs, steam is generated as the synthesis gas is cooled. Depending on the system design, a scrubbing process is used to remove hydrogen cyanide (HCN), ammonia (NH_3), hydrogen chloride (HCl), hydrogen sulfide (H_2S) and particulate matter. The scrubber system usually operates at low temperatures with synthesis gas leaving the process at approximately 23°C) (72°F). Hydrogen sulfide and carbonyl sulfide (COS), once hydrolyzed, are removed by dissolution in, or reaction with, an organic solvent and converted to valuable by-products, such as elemental sulfur or sulfuric acid. The recovery of sulfur is usually near quantitative (99%+ v/v). The residual gas from this separation can be combusted to satisfy process-heating requirements.

This raw clean synthesis gas must be reheated to 315 to 370°C (600 to 700°F) for the first of two water gas shift reactors that produce additional hydrogen through the catalytically assisted equilibrium reaction of carbon monoxide with steam to form carbon dioxide and hydrogen. The exothermic reaction in the water gas shift reactor increases the temperature to approximately 430°C (800°F), which must be cooled to the required inlet temperature for the second water gas shift reactor in the range of 120 to 345°C (250 to 650°F), depending on design. The water gas shift reaction alters the H2/CO ratio in the final mixture.

Typically, approximately 70% of the heating value of the feedstock fuel is associated with the carbon monoxide and hydrogen components of the gas, but can be higher depending upon the gasifier type. Hydrogen must be separated from the gas product stream (which also contains carbon dioxide and carbon monoxide as well as other trace contaminants) and *polished* to remove remaining sulfur, carbon monoxide and other contaminants to meet the requirements for various end uses.

Concerns over global climate change and eventual resource depletion of fossil fuel resources have revived the concept of the hydrogen economy, where hydrogen is used as an energy carrier. This concept would use hydrogen to provide energy to all sectors including central generating electric power, distributed power, industrial, residential, and transportation. Eventually the hydrogen would be produced from water using energy derived from sustainable resources, for example, nuclear fusion technology and photovoltaic technology.

Combustion of the hydrogen or electrochemical conversion via fuel cell technology would produce water, thus completing the cycle. In the shorter term, the hydrogen could be produced from fossil resources including natural gas, coal, crude oil coke, etc. The use of fossil carbon as a reductant and the conversion inefficiencies associated with hydrogen production from these resources would result in the production of large quantities of carbon dioxide. With the continued concern over climate change this carbon dioxide would have to be sequestered.

Hydrogen currently produced from the gasification of coal is essentially used as an intermediate for the synthesis of chemicals. However, with the increasing awareness of the necessity to control greenhouse gas emissions there is an incentive to move towards the production of hydrogen for power generation with carbon dioxide capture/sequestration.

New concepts for the production of hydrogen from coal are under development and include concepts based on either the steam gasification or the hydrogasification of coal with carbon dioxide capture/separation, membrane reactors directly used for the production of hydrogen from coal, molten bath processes originally used for metal smelting processes and adapted to the production of hydrogen.

18.4 Sustainable Development

To meet the challenges from the changing trends in power generation, the power plant will adapt. Furthermore, due to the stringent specifications imposed by environmental complex chemical operations involving legislation, the power generating industry in the near future will become increasingly flexible to handle a variety of feedstocks. During the next 30 years, the focus will be primarily on process modification with some new innovations in order for the power plant to meet the various environmental regulations. The industry will move predictably on to accommodate (i) viscous feedstocks, (ii) biomass, and (iii) solid waste, recognizing that these feedstocks are not without fault when it comes to consideration of the various environmental issues associated with the use of these feedstocks. The most likely path is the increased development of non-renewable resources such as energy from biomass.

Alternative sources of clean energy, such as solar and wind power can be used both to generate electricity and to fuel electric vehicles, and they have seen substantial progress in reducing costs, but at least in the short term and the middleterm, they are unlikely to play a major role in base-load electrical capacity or in replacing internal combustion engines fueled by the products from the processing of fossil fuels. The main sources are (i) water for hydropower, (ii) wind, for electric power, (iii) solar, (iv) geothermal power. These sources of renewable energy are used to generate electric power. The overall environmental impact of each source depends on its overall lifecycle emissions, including manufacturing of equipment and materials, installation as well as land-use impacts.

In order to achieve energy security, a long-term effort of a balanced and diversified portfolio of feedstocks and alternate energy sources is needed and includes fossil fuel resources and renewable energy sources. In addition, there should be a legislative backing and mandate and a policy initiated to demonstrate the importance of coal. Worldwide reserves of coal indicate that this resource could last 200-300 years at current rates of usage. However, coal (if used indiscriminately) does exhibit environmentally unfriendly properties as a result of the pollutants that are emitted during usage (Chapter 14). Efforts have gone into addressing this over three decades, with most efforts focused on gas cleaning (Chapter 12) and clean-coal technologies (Chapter 13).

It might be argued that coal, being a finite resource, should have no part in sustainable development. This somewhat biased view overlooks the benefits of coal as well as the ability (or need) to substitute one form of energy source for another. To the extent that substitution is possible, depletion of one type of energy source capital is consistent with sustainability if offset by an increase in other types of energy sources, with any accompanying disadvantages that arise from energy sources that have not been fully developed.

Therefore, the use of coal is consistent with sustainable development if, while meeting our present needs, it produces new capital and options for future generations – such as infrastructure, new technologies and new knowledge. An associated risk is that the use of coal may degrade natural capital, such as the environment to an unacceptable or irreversible extent, leading to unsustainable development.

However, apart from their inherent practical limitations at that time, supplies of biomass, wind and water are limited and cannot be cited as fulfilling the current needs for electric power. Coal is abundant and the environmental consequences of rapidly growing and uncontrolled coal use were, of course, unacceptable. Continual technology development over time will allow coal to be used with much greater efficiency and with greatly reduced environmental impact.

For example, the oxygen-fired pulverized coal combustion process (oxy-fuel process), offers a low-risk step development of existing power generation technology to enable carbon dioxide capture and storage. Oxy-firing of pulverized coal in boilers involves the combustion of pulverized coal in a mixture of oxygen and recirculated flue gas in order to reduce the net volume of flue gases from the process and to substantially increase the concentration of carbon dioxide (CO_2) in the flue gases – compared to the normal pulverized coal combustion in air.

Many developed countries rely on coal to support living standards and industrial development. In fact coal plays a significant economic role in coal producing and consuming countries alike and remains the main fuel of choice for electricity generation worldwide and is an essential input to two-thirds of the world steel production. The challenge for coal, as for other energy sources, is to ensure that it meets all the objectives of sustainable development and, in particular, ensuring and acceptable environmental performance that is in keeping with modern regulations (Word Coal Institute).

Energy sources, particularly coal, will also become more and more important in power generation in certain parts of the world over the coming decades (China and India in particular) as a result of the significant rise in demand for energy. It is therefore essential for the right framework to be established for the development and distribution of sustainable coal technologies, and thus limit emissions of carbon dioxide from the use of coal for electricity generation.

The improvements already made in coal technologies – increase in energy efficiency and a reduction in acid rain and local atmospheric pollution due to emissions of sulfur oxides (SOx), nitrogen oxides (NOx), and particulate matter – show that significant technological progress is possible, in particular by applying the principle of carbon capture and storage (often cited as CCS).

Technologies for the sustainable use of coal will be based on an optimum combination of clean coal technologies (improving yield and reducing atmospheric emissions) and technologies related to carbon capture and storage. Continued development of these technologies and demonstrating their commercial viability will lead to their large-scale use.

Coal is an extremely important fuel and will remain so as it is the most abundant and widely distributed fossil fuel source in the world. Development of new clean coal technologies is necessary so that the coal resources can be utilized for future generations without contributing to serious environmental effects. Much of the challenge is in commercializing the technology so that coal use remains economically competitive despite the cost of achieving low and eventually near *zero emissions*. As many coal-fired power stations approach retirement, their replacement gives much scope for the introduction of more modern facilities and cleaner production of electricity.

It has been recognized worldwide that the utilization of an enormous amount of coal has created adverse effects on the environment, including acid rain and the so-called global climate change. There is no denying that global climate change is a fact – the Earth is currently in an interglacial period when climatic temperatures are expected to increase. The extent of this temperature increase in unknown because no one was around to take notes and make records at the last interglacial period – the current ice age (the Quaternary glaciation) has been subject to extensive glaciation on 40,000 to 100,000 year cycles. Thus, there is no way that anyone can estimate with a high degree of accuracy the contribution and effects of fossil fuel-related emissions to the current global climate change debate. Global climate change is occurring but assignment of the extent of the temperature change to the causative effects of fossil fuel use is extremely difficult – if not impossible.

Nevertheless, another important aspect of the continuing coal use is the management of wastes, especially waste from coal combustion as might be produced at an electricity generating plant (Senapati, 2011; Ansari *et al.*, 2011). This does not mean that other uses of coal and the waste generated should be ignored. It is merely a notation of the extremely important aspect of the management of waste materials from coal use (Chapters 12, 13).

Burning coal, such as for power generation, gives rise to a variety of wastes which must be controlled or at least accounted for. The *clean coal technologies* (Chapter 14) are a variety of evolving responses to late 20th century environmental concerns, including that of global climate change due to carbon dioxide releases to the atmosphere. However, many of the elements have in fact been applied for many years.

For example, coal cleaning by washing (Chapter 3) has been standard practice in developed countries for some time. It reduces emissions of ash and sulfur dioxide when the coal is burned. Furthermore, electrostatic precipitators and fabric filters can remove 99% of the fly ash from the flue gases and such technologies are in widespread use (Chapters 12, 14). In addition, flue gas desulfurization reduces the output of sulfur dioxide to the atmosphere and low-NOx burners allow coal-fired plants to reduce nitrogen oxide emissions. Both technologies are in wide use.

Other technologies such as *integrated gasification combined cycle* (IGCC) and *pressurized fluidized-bed combustion* (PFBC) enable higher thermal efficiencies. Ultra-clean coal (UCC) from new processing technologies which reduce ash below 0.25% and sulfur to very low levels mean that pulverized coal might be used as fuel for very large marine engines, in place of heavy fuel oil.

Carbon capture and storage or *carbon capture and sequestration* (CCS) technologies are in the forefront of measures for use of coal as a clean fuel. A number of means exist to capture carbon dioxide from gas streams (Chapters 12, 13), and the focus in the past has often been on obtaining pure carbon dioxide for industrial purposes rather than reducing carbon dioxide levels in power plant emissions.

However, capture of carbon dioxide from flue gas streams following combustion of coal in air is reputed to be more difficult and expensive than from natural gas streams, as the carbon dioxide concentration is only approximately 14% at best, with nitrogen most of the rest, and the flue gas is hot. The main process treats carbon dioxide like any other pollutant, as flue gases are passed through an amine solution in which the carbon dioxide is absorbed (Chapters 12, 13). It can later be released by heating the solution (Mokhatab *et al*., 2006; Speight, 2013a, 2014, 2020a).

Sustainable development (meeting the needs of the present without compromising the ability of future generations to meet their own needs) has been an important part of public policy debate for the last decade. It has evolved into a widely subscribed ideal for how business and society should interact and function. Technological advances have diminished the traditional disadvantages of coal use, although local and regional environmental impacts are still issues. The use of state of the art technology can make a contribution to coal meeting stringent environmental standards. However, state-of-the-art technologies are not universally deployed and this remains a high priority for governments, coal users and suppliers. Improvement in environmental performance is technologically feasible and should be a priority of industry and government to enhance the reputation of coal and its contribution to environmental sustainability.

Coal stands out as an affordable resource that is relatively straightforward to convert to electrical power. It is also abundant and reliable and will inevitably form a significant part of the future energy mix in many countries. Therefore adapting clean coal technologies to coal use is of worldwide particular importance. This presents a challenge to the coal industry in giving practical effect to the notion of sustainable development by helping to facilitate the transfer of environmentally friendly coal technologies to developing economies.

Many of the potential new markets for coal may necessitate that it be processed in ways other than traditional combustion. For example, if coal is to be used as a source of liquid fuels, there will be the need to refine such products, as many of the product constituents are not (in the produced state) compatible with crude oil-based fuels – the liquids from coal would need to be refined further. Such a refinery could well be a system consisting of one or more individual processes integrated in such a way as to allow coal to be processed into two or more products supplying two or more markets.

While there are differing points of view as to the configuration of such a refinery, eventually it would be advisable if there was a close relationship in a crude oil refinery in that a full slate of liquid products must be possible and the system must be capable of changing product yields with temporal changes in market conditions.

Obviously, coal needs to play an important role in energy systems that support sustainable development for the foreseeable future. This is because of the unique combination of advantages that are exhibited by coal, such as (i) the affordability of coal, (2) coal can be safely transported and stored, and (iii) coal is available from a wide range of sources and geographical regions. Coal therefore remains essential in achieving a diverse balanced and secure energy mix in developed countries; it can also meet the growing energy needs of many developing countries. Concerns related to climate change add a most complex challenge to the long-term use of coal in a sustainable development context. In disregarding the great underlying uncertainties of future climate, emissions, and the efficacy of response options, climate change is commonly presented simply as an environmental issue requiring urgent intervention.

Coal-fired power generation is a significant component of the generation mix in the United States, and will continue to be so for the foreseeable future. On the other hand, coal will continue to face challenges due to concerns related to air quality, uncertainty related to future greenhouse gas regulations and competition from other sources of generation such as renewables, natural gas, and nuclear power. Any projection will be subject to considerable uncertainty until more is known related to the direction of future greenhouse gas regulations, and the cost and reliability of new, clean coal technologies. If carbon sequestration and storage proves practical, it would address a major concern related to coal-fired power generation and tend to promote the construction of new coal-fired power plants and associated carbon dioxide pipelines.

One factor in improving air quality has been the pollution-control technologies used by coal-fired power plants. Modern coal-fired electricity-generating plants produce more power, with less emission of criteria pollutants, than ever before. Air quality will continue to improve in the future because of improved technology.

Further improvement in the environmental performance of coal will not only be required but will be a necessity. While improved coal technologies have provided very substantial efficiency and emission improvements to date, accelerated technological effort is required to reduce greenhouse gas emissions. Deployment of cleaner and higher efficiency technologies will be important in both developed and developing countries.

Coal combustion products (CCPs), consisting of fly ash, bottom ash, boiler slag, and flue-gas-desulfurization material, also have become important in the economy. As coal burns, it emits sulfur in the form of sulfur oxide. Flue gas desulfurization (Chapters 12, 14) is the process by which a chemical, such as limestone ($CaCO_3$), is injected into the flue-gas stream to trap the sulfur by combining with it to produce gypsum ($CaSO_4$). Gypsum is heavy and falls to the bottom of the flue gas desulfurization unit as sludge in a wet process, or as a powder in a dry process (Mokhatab *et al*., 2006).

Fly ash is used mainly as an additive in concrete and may also be used as structural fill or as road-base material and may also be used in waste stabilization and mining applications. Bottom ash is used mainly as road-base and structural-fill material as well as in concrete and as grit for snow and ice control. Of the boiler slag that is used, most is used as blasting grit and roofing granules. Gypsum, from flue gas desulfurization units, is used mainly in wallboard, with small amounts being used in concrete and agricultural applications.

There are also other products that can be derived from coal-fired power plant waste. For example, sulfur oxides can be captured from flue gas and used to make sulfuric acid, an important industrial raw material. Other valuable elements, such as mercury and chlorine (also industrial raw materials) may be recovered from flue gas (Finkelman and Brown, 1991).

In order to regulate environmental concerns and focus on sustainable development, the idea is to go into technologies that use indigenous resources wisely, cleanly and efficiently. These new technologies are designed to achieve significant improvements in the area of fuel effectiveness, technical performance and environmental impact protection (Aziz *et al.*, 2012). The technologies that have gained acceptance and are in use are the fluidized-bed combustion (Chapters 8, 14) and fluidized-bed gasification (Chapters 10, 14). A third technology that is gaining momentum in the coal-fired power generation market is the integrated gasification combined cycle (IGCC) (Chapters 11, 14) that may have the potential to move coal-fired power generation toward a near-to-zero emissions technology. Furthermore, for coal to remain relevant and to be a viable source of secure energy, investment in new technology is a necessary. The technology should be such that it could be described as energy-efficient, economically competitive, capable of retrofitting, repowering or replacing existing facilities while achieving significant reductions in SO_x and NO_x.

In the United States, the Department of Energy (DOE) is providing the foundation needed to build a future generation of fossil energy-based power systems capable of meeting the future energy and environmental demands of the 21st century. But even with these emerging technologies, the emission of gases such as carbon dioxide (CO_2) and the production of fly ash is not yet eliminated. Achieving truly clean-coal technology will require an intensive, long-range research and development effort that emphasizes innovation and commercialization of revolutionary technologies. Once a full understanding of the chemistry and the engineering aspects of the various technologies is reached, coal combustion and coal gasification will move into realms of clean coal technologies.

In the context of the use of coal and other fossil fuels, the potential for climate change must always be considered but for the right reasons, and emotion must be removed from the equation. Also, biomass – which is often looked upon as the fuel of the future – is not without some blame in terms of the production of pollutants (Chapters 15, 16, 17). In fact, offering the mathematical or statistical excuse of carbon dioxide in and carbon dioxide out does not clear the way for the unlimited use of biomass as a fuel source (Speight, 2020b).

By definition, climate change is a long-term shift in weather conditions that is identified by changes in temperature, precipitation, winds, and other indicators which can involve both changes in average conditions and changes in variability, including, for example, extreme events. The physical climate system involves the atmosphere, land surfaces, and oceans of the Earth, along with the snow and ice that is so prominent in many northern climes. These components interact with one another and with aspects of the biosphere of the Earth to determine not only the day-to-day weather, but also the long-term averages that are referred to as *climate*.

The issue of global climate change is often associated with the use of fossil fuels as sources of energy. Of most concern is the increase in emissions of carbon dioxide (CO_2) due to emissions from fossil fuel combustion. Other factors, including land use, ozone depletion, animal agriculture, and deforestation, are also of concern in the roles they play – both separately and collectively – in affecting climate, microclimate, and various climate variables.

It must never be forgotten or ignored that the Earth has been constantly changing since its formation and has gone through different eras like glaciations, among others. However, these changes need thousands of years to be made visible, and the current increase in the average temperature of the Earth since the pre-industrial period is happening – provided that the measurements of past climatic temperatures are accurate and beyond reproach. Thus, the assessment that the warming trend that has occurred (somewhat erratically) over the past 100 years is very likely to have some origins in natural events – the precise contributions of natural effects and anthropogenic effects on the climate is not known, but it is more accurate to conclude that many natural factors continue to influence the climate of the Earth and whether or not human activities have become the dominant force that is responsible for global warming is still very much open to question (Speight, 2020b).

Thus, any response must be affordable and provide the basis for sustainable development by addressing ongoing economic requirements and social requirements as well as the environmental challenge. Thus, the challenge is to extract energy from coal in more efficient and cleaner ways. This meets the necessity of moving to a sustainable future by replacing resource-depleting technologies with new options of at least equivalent value.

If coal will be a basic energy source for future sustainable development (a scenario that is highly likely), it is necessary to build new plants that work with this type of clean coal technology, in order to reduce emissions of greenhouse gases and help to achieve the targets. The provision of such technologies could bring benefits for both the environment and the same companies that are currently before an uncertain future.

In summary, it is unlikely that humans will cease to rely on fossil fuels as the primary source of energy. The physical supply of fossil fuels is highly unlikely to run out, especially if future technological change makes major new sources like oil shale and methane hydrates commercially viable. Alternative sources of clean energy such as solar and wind power, which can be used both to generate electricity and to fuel electric vehicles, have seen substantial progress in reducing costs, but at least in the short term and in the middle term, they are unlikely to play a major role in base-load electrical capacity or in replacing internal combustion engines fueled by the products from the processing of fossil fuels.

While not the main subject of this book, other sources of electricity are worthy of mention so that electricity from fossil fuels can be placed in the correct perspective for the future. These sources are often referred to as renewable energy sources which, like biomass but unlike fossil fuels, can be regenerated or naturally replenished. The main sources are (i) water for hydropower, (ii) wind for electric power, (iii) solar, (iv) geothermal power. These sources of renewable energy are used to generate electric power. The overall environmental impact of each source depends on its overall lifecycle emissions, including manufacturing of equipment and materials, installation as well as land-use impacts.

In terms of available data (C2ES, 2020; US EIA, 2020), in 2019, approximately 4,118 billion kilowatt hours (kWh) (or about 4.12 trillion kWh) of electricity were generated at utility-scale electricity generation facilities in the United States. Approximately 63% of this electricity generation was from fossil fuels – coal, natural gas, crude oil, and other gases while approximately 20% of the electric power was from nuclear energy, and approximately 18% was from renewable energy sources. To place the role of fossil fuels in the correct perspective, it is anticipated that over the next three to five decades the amount of power generated from non-fossil fuel sources will at least double.

Currently there are a number of renewable energy technologies which can supply baseload power (https://www.skepticalscience.com/print.php?r=374). The intermittency of other sources such as wind and solar photovoltaic can be addressed by interconnecting power plants which are widely geographically distributed, and by coupling them with peakload plants such as gas turbines fueled by biofuels or natural gas which can quickly be switched on to fill in gaps of low wind or solar production. Numerous regional and global case studies – some incorporating modeling to demonstrate their feasibility – have provided plausible plans to meet 100% of energy demand with renewable sources.

It is time for both sides of the energy equation – the energy-from-fossil-fuels aficionados and the energy-from-renewables aficionados – to work together to resolve the energy future instead of initiating conflicting views. As a start, some of the power-generating companies have also moved into the arena of power generation using wind energy. However, until the time when the use of fossil fuels for power generation can be reduced to a miniscule amount, the use of fossil fuels will continue to dominate the power industry (Plummer, 2020). It is a matter of reaching a decision in which renewable energy sources replace fossil fuels (if ever that can happen) by consideration of all of the evidence in a logical manner rather than allowing emotion to rule the decision making. It is also a matter of recognizing that the power industry is continuing to institute and update cleanup methods (contaminant removal methods) that are applied to the fuel before the fuel enters the power plant and the gases emanating from the power-producing process are also cleaned of any contaminants produced in the process.

To outlaw the use of fossil fuels at this time would be foolhardy, unless the persons who make such a decision would prefer to freeze (during the cold months of the year) in the green darkness!

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Common Conversion Factors used in Coal Technology

To convert	To	Multiply by
Acres	Hectares	0.4047
Acres	square feet	43,560
Acres	square miles	0.001562
Acres	sq. feet	43,560
Acre foots	Barrels	7758.0
Atmosphere	centimeters of mercury	76
Atmosphere	Torr	760
Atmosphere	mm Hg	760
Atmosphere	Psia	14.686
Atmosphere	inches Hg	29.91
Atmosphere	Bars	1.0133
Atmosphere	feet H_2O	33.899
Barrel (oil)	US gallons	42
Barrel	cubic feet	5.6146
Barrel	lbs water @ 60°F	350
Barrel per day	cubic centimeters/second	1.84
Btu	Foot pounds	778.26
Btu/lb	kcal/kgm	1.8
Btu/lb	kJ/kgm	2.33
Btu/hour	horsepower	0.0003930
Btu	kilowatt-hour	0.0002931

(*Continued*)

To convert	To	Multiply by
Btu/hour	watts	0.2931
Centimeters	inches	0.3937
Centimeters	feet	0.03281
Cubic foot	cubic meters	0.0283
Cubic foot	cubic centimeters	28,317
Cubic foot	gallons	7.4805
Cubic meters	cubic feet	35.3145
Cubic meters	cubic yards	1.3079
Cubic yards	cubic meters	0.7646
Density of water @ 60°f	gram/cubic centimeter	0.999
Density of water @ 60°f	lb/cu ft	62.367
Density of water @ 60°f	Lb/US gallon	8.337
Feet	meters	.3048
Feet	miles (nautical)	.0001645
Feet	miles (statute)	.0001894
Gallons (US)	liters	3.7853
Gallon	cubic inches	231
Gallon	cubic centimeters	3,785.4
Gallon	cubic feet	0.13368
Grams	ounces (avoirdupois)	0.0353
Grams	pounds	0.002205
Hectares	acres	2.4710
Inches	millimeters	25.4000
Inches	centimeters	2.5400
Kilograms	pounds (avdp)	2.2046
Kilograms	pounds (troy)	2.679
Kilometers	miles	0.6214
Kilowatt-hour	Btu	3412

(*Continued*)

To convert	To	Multiply by
Liters	gallons (US)	0.2642
Liters	pints (dry)	1.8162
Liters	pints (liquid)	2.1134
Liters	quarts (dry)	0.9081
Liters	quarts (liquid)	1.0567
Meters	feet	3.2808
Meters	miles	0.0006214
Meters	yards	1.0936
Metric tons	tons (long)	0.9842
Metric tons	tons (short)	1.1023
Miles	kilometers	1.6093
Miles	feet	5280
Miles (nautical)	miles (statute)	1.1516
Miles (statute)	miles (nautical)	0.8684
Millimeters	inches	0.0394
Ounces (avoirdupois)	grams	28.3495
Ounces (avoirdupois)	pounds	0.0625
Ounces (liquid)	pints (liquid)	0.0625
Ounces (liquid)	quarts (liquid)	0.03125
Ounces (troy)	ounces (avoirdupois)	1.09714
Pints (dry)	liters	0.5506
Pints (liquid)	liters	0.4732
Pints (liquid)	ounces (liquid)	16
Pounds (troy)	kilograms	0.3782
Pounds (avoirdupois)	kilograms	0.4536
Pound	grams	453.59
Pound	ounces	16
1 psi	kPa	6.895

(*Continued*)

To convert	To	Multiply by
Quarts (dry)	liters	1.1012
Quarts (liquid)	liters	0.9463
Quarts (liquid)	ounces (liquid)	32
Square feet	square meters	0.0929
Square kilometers	square miles	0.3861
Square meters	square feet	10.7639
Square meters	square yards	1.1960
Square miles	square kilometers	2.5900
Square mile	Acres	640
Square yards	square meters	0.8361
Tons (long)	metric tons	1.016
Tons (short)	metric tons	0.9072
Tons (long)	pounds	2240
Tons (short)	pounds	2000
Torr	atmospheres	0.001316
Torr	mm Hg	1
Yards	meters	.9144
Yards	miles	.0005682

Glossary

Abandoned workings: sections, panels and other areas that are not ventilated and examined in the manner required for work places.

Abutment: the weight of the rocks above a narrow roadway is transferred to the solid coal along the sides, which act as abutments of the arch of strata spanning the roadway. Also the weight of the rocks over a longwall face is transferred to the front abutment, that is, the solid coal ahead of the face and the back abutment – the settled packs behind the face.

Accessed: coal deposits that have been prepared for mining by construction of portals, shafts, slopes, drifts, and haulage ways; by removal of overburden; or by partial mining.

Acid: any of a class of substances whose aqueous solutions are characterized by a sour taste, the ability to turn blue litmus red, and the ability to react with bases and certain metals to form salts; a substance that yields hydrogen ions when dissolved in water and which can act as a proton (H^+) donor.

Acid deposition or acid rain: a mixture of wet and dry *deposition* (deposited material) from the atmosphere containing higher than typical amount of nitric and sulfuric acids.

Acid drainage: the runoff of acidic liquids from coal production waste piles. Such runoff can contaminate ground and surface waters.

Acid gas: hydrogen sulfide (H_2S) or carbon dioxide (CO_2).

Acid mine drainage: any acid water draining or flowing on, or having drained or flowed off, any area of land affected by mining.

Acid mine water: mine water that contains free sulfuric acid, mainly due to the weathering of iron pyrites.

Acid rain: a solution of acidic compounds formed when sulfur and nitrogen oxides react with water droplets and airborne particles.

Acre-foot (acre-ft): the volume of coal that covers 1 acre at a thickness of 1 foot (43,560 cubic feet; 1,613.333 cubic yards; 1,233.482 cubic meters). The weight of coal in this volume varies according to rank.

Acre-inch (acre-in.): the volume of coal that covers 1 acre at a thickness of 1 inch (3,630 cubic feet; 134.44 cubic yards; 102.7903 cubic meters). The weight of coal in this volume varies according to rank.

Active workings: any place in a mine where miners are normally required to work or travel and which are ventilated and inspected regularly.

Adit: a nearly horizontal passage from the surface by which a mine is entered and dewatered; a blind horizontal opening into a mountain, with only one entrance.

Advance: mining in the same direction, or order of sequence; first mining as distinguished from retreat.

Afterdamp: gases remaining after an explosion in a mine consisting of carbon dioxide, carbon monoxide, nitrogen, and hydrogen sulfide; the toxic mixture of gases left in a mine following an explosion caused by firedamp (methane), which itself can initiate a much larger explosion of coal dust.

Agglomerate: if operating temperature of the reactor is higher than the initial deformation temperature of ash, the ash commences melting and forms agglomerates.

Agglomerating coal: coal that, during volatile matter determinations, produces either an agglomerate button capable of supporting a 500-gram weight without pulverizing, or a button showing swelling or cell structure.

Agglomeration: formation of larger coal or ash particles by smaller particles sticking together.

Airshaft: a vertical shaft in which air is blown down through the various sections of the underground mine. The air is generated by a large fan on the surface providing oxygen for the miners below.

Air split: the division of a current of air into two or more parts.

Airway: any passage through which air is carried. Also known as an air course.

Alcohol: the family name of a group of organic chemical compounds composed of carbon, hydrogen, and oxygen. The molecules in the series vary in chain length and are composed of a hydrocarbon plus a hydroxyl group. Alcohol includes methanol and ethanol.

Aliphatic: any non-aromatic organic compound having an open chain structure.

Alkali: a soluble mineral salt.

Allothermal gasification: the heat required for gasification reactions is afforded by an external source.

Alternative fuel: as defined in the United States Energy Policy Act of 1992 (EPACT): methanol, denatured ethanol and other alcohols, separately or in blends of at least 10% by volume with gasoline or other fuels; compressed natural gas; liquefied natural gas, liquefied propane gas, hydrogen, coal-derived liquid fuels, fuels other than alcohols derived from biological materials, electricity, biodiesel, and any other fuel deemed to be substantially not crude oil and yielding potential energy security benefits and substantial environmental benefits.

Ammoniated ash: ash that contains ammonia and/or ammonium salts as a result of the addition of ammonia or ammonium salts to the flue gas at the power plant.

Anemometer: instrument for measuring air velocity.

Angle of dip: the angle at which strata or mineral deposits are inclined to the horizontal plane.

Angle of draw: this angle is assumed to bisect the angle between the vertical and the angle of repose of the material and is 20° for flat seams; for dipping seams, the angle of break increases, being 35.8° from the vertical for a 40° dip; the main break occurs over the seam at an angle from the vertical equal to half the dip.

Angle of repose: the maximum angle from horizontal at which a given material will rest on a given surface without sliding or rolling.

Anthracene oil: the heaviest distillable coal tar fraction, with distillation range 270 to 400C (520 to 750F), containing creosote oil, anthracene, phenanthrene, carbazole, and so on.

Anthracite (hard coal): a hard, black, shiny coal very high in fixed carbon and low in volatile matter, hydrogen, and oxygen; a rank class of non-agglomerating coals as defined by the American Society for Testing and Materials having more than 86% fixed carbon and less than 14% volatile matter on a dry, mineral-matter-free basis; this class of coal is divisible into the semi-anthracite, anthracite, and meta-anthracite groups on the basis of increasing fixed carbon and decreasing volatile matter. The heat content of anthracite ranges from 22 to 28 million Btu per short ton on a moist, mineral-matter-free basis. The heat content of anthracite coal consumed in the United States averages 25 million Btu per short ton, on the as-received basis (i.e., containing both inherent moisture and mineral matter); since the 1980s, anthracite refuse or mine waste has been used for steam electric power generation. This fuel typically has a heat content up to 15 million Btu per short ton.

Anthracosis: *See* Black lung.

Anthraxylon: U.S. Bureau of Mines term for vitrinite viewed by transmitted light.

Anticline: an upward fold or arch of rock strata.

Aquifer: a water-bearing formation through which water moves more readily than in adjacent formations with lower permeability.

Arching: fracture processes around a mine opening, leading to stabilization by an arching effect.

Area (of an airway): average width multiplied by average height of airway, expressed in square feet.

Area (surface) mining: a method used on flat terrain to recover coal by mining long cuts or pits successively. The material excavated from the cut being mined is deposited in the cut previously mined.

Aromatics: a range of hydrocarbons which have a distinctive sweet smell (and include benzene and toluene) that occur naturally in crude oil and are also extracted as a petrochemical feedstock, as well as for use as solvents.

Ash: the noncombustible residue remaining after complete coal combustion; the final form of the mineral matter present in coal. It is customary (but chemically incorrect) to refer to the mineral content of a coal as ash, and it is usually reported as such in coal quality descriptions. Ash producing propensity is determined by combusting the coal in air and converting the inorganic elements to their respective oxide.

Ash analysis: the determination of the percentages of inorganic oxides present in an ash sample. Ash analyses are used for evaluation of the corrosion, slagging, and fouling potential of coal ash. The ash constituents of interest are silica (SiO_2) alumina (Al_2O_3), titania (TiO_2), ferric oxide (Fe_2O_3), lime (CaO), magnesia (MgO), potassium oxide (K_2O), sodium oxide (Na_2O), and sulfur trioxide (SO_3). An indication of ash behavior can be estimated from the relative percentages of each constituent.

Ash deformation temperature: the temperature at which ash begins to fuse and become soft.

Ash free: a theoretical analysis calculated from basic analytical data expressed as if the total ash had been removed.

Ash-fusion temperatures: a set of temperatures that characterize the behavior of ash as it is heated. These temperatures are determined by heating cones of ground, pressed ash in both oxidizing and reducing atmospheres.

As-received basis: represents an analysis of a sample as received at a laboratory.

As-received moisture: the moisture present in a coal sample when delivered.

Attritus: a microscopic coal constituent composed of macerated plant debris intimately mixed with mineral matter and coalified. U.S. Bureau of Mines usage, viewed by transmitted light.

Auger: a rotary drill that uses a screw device to penetrate, break, and then transport the drilled material (coal).

Auger mine: a surface mine where coal is recovered through the use of a large-diameter drill driven into a coalbed in a hillside. It usually follows contour surface mining, particularly when the overburden is too costly to excavate.

Auger mining: mining generally practiced but not restricted to hilly coal-bearing regions of the country that uses a machine designed on the principle of the auger, which bores into an exposed coal seam, conveying the coal to a storage pile or bin for loading and transporting. May be used alone or in combination with conventional surface mining. When used alone, a single cut is made sufficient to expose the coal seam and provide operating space for the machine. When used in combination with surface mining, the last cut pit provides the operating space.

Autothermal gasification: the heat required for gasification reactions is supplied by partial oxidation of the syngas; air or a steam/oxygen mixture is used as oxidant agents.

Auxiliary operations: all activities supportive of but not contributing directly to mining.

Auxiliary ventilation: portion of main ventilating current directed to face of dead end entry by means of an auxiliary fan and tubing.

Average recovery percentage: represents the percentage of coal that can be recovered from coal reserves at reporting mines, averaged for all mines in the reported geographic area.

Azimuth: a surveying term that references the angle measured clockwise from any meridian (the established line of reference); the bearing is used to designate direction; the bearing of a line is the acute horizontal angle between the meridian and the line.

Back: the roof or upper part in any underground mining cavity.

Backfill: the operation of refilling an excavation. Also, the material placed in an excavation in the process of backfilling.

Background level: the average amount of a substance present in the environment. Originally referring to naturally occurring phenomena; used in toxic substance monitoring.

Baghouse: an air pollution control device that removes particulate matter from flue gas, usually achieving a removal rate above 99.9%.

Barrel: liquid volume measure equal to 42 U.S. gals, commonly used in measuring crude oil or crude oil products.

Barren: said of rock or vein material containing no minerals of value, and of strata without coal, or containing coal in seams too thin to be workable.

Barricading: enclosing part of a mine to prevent inflow of noxious gases from a mine fire or an explosion.

Barrier: something that bars or keeps out. Barrier pillars are solid blocks of coal left between two mines or sections of a mine to prevent accidents due to inrushes of water, gas, or from explosions or a mine fire.

Batholith: a large, deep-seated intrusion (sometimes called a pluton) that forms as thick, viscous magma slowly makes its way toward the surface.

Beam: a bar or straight girder used to support a span of roof between two support props or walls.

Beam building: the creation of a strong, inflexible beam by bolting or otherwise fastening together several weaker layers. In coal mining this is the intended basis for roof bolting.

Bearing: a surveying term used to designate direction. The bearing of a line is the acute horizontal angle between the meridian and the line. The meridian is an established line of reference. Azimuths are angles measured clockwise from any meridian.

Bearing plate: a plate used to distribute a given load. In roof bolting, the plate used between the bolt head and the roof.

Bed (coalbed): a stratum of coal or other sedimentary deposit.

Bedrock: the rock material directly above and below the coal seam.

Beehive oven: a dome-shaped oven not equipped to recover the by-product gas and liquids evolved during the coking process.

Belt conveyor: a looped belt on which coal or other materials can be carried and which is generally constructed of flame-resistant material or of reinforced rubber or rubber-like substance.

Belt feeder (feeder breaker): a crawler-mounted surge bin often equipped with a crusher or breaker and used in room-and-pillar sections positioned at the end of the section conveyor belt. It allows a quick discharge of the shuttle car. It sizes the coal, and a built-in conveyor feeds it at an appropriate rate onto the conveyor belt.

Belt idler: a roller, usually of cylindrical shape, which is supported on a frame and which, in turn, supports or guides a conveyor belt. Idlers are not powered but turn by contact with the moving belt.

Belt take-up: a belt pulley, generally under a conveyor belt and in the drive pulley, kept under strong tension parallel to the belt line. Its purpose is to automatically compensate for any slack in the belting created by start-up.

Bench: the surface of an excavated area at some point between the material being mined and the original surface of the ground, on which equipment can sit, move, or operate. A working road or base below a high wall, as in contour stripping for coal.

Beneficiation: the treatment of mined material, making it more concentrated or richer; *See also* Physical coal cleaning.

Berm: a pile or mound of material capable of restraining a vehicle.

Binder: a streak of impurity in a coal seam.

Biogas: a combustible gas derived from decomposing biological waste under anaerobic conditions. Biogas normally consists of 50 to 60% methane. *See also* landfill gas.

Biomass: feedstock derived from plant-based matter such as trees, grasses, and agricultural crops.

Bit: the hardened and strengthened device at the end of a drill rod that transmits the energy of breakage to the rock – the size of the bit determines the size of the hole; a bit may be either detachable from or integral with its supporting drill rod.

Bitumen: a naturally occurring material that has little or no mobility under reservoir conditions and which cannot be recovered through a well by conventional oil well production methods including currently used enhanced recovery techniques; current methods involve mining for bitumen recovery; also, on occasion, incorrectly referred to as native asphalt, and extra heavy crude oil.

Bituminous (soft) coal: a relatively soft dark brown to black coal, lower in fixed carbon than anthracite but higher in volatile matter, hydrogen, and oxygen; a rank class of coals as defined by the American Society for Testing and Materials (ASTM) high in carbonaceous matter, having less than 86% fixed carbon, and more than 14% volatile matter on a dry, mineral-matter-free basis and more than 10,500 Btu on a moist, mineral-matter-free basis. This class may be either agglomerating or non-agglomerating and is divisible into the high-volatile C, B, A; medium; and low-volatile bituminous coal groups on the basis of increasing heat content and fixed carbon and decreasing volatile matter. Bituminous coal is the most abundant coal in active mining regions in the United States. Its moisture content usually is less than 20%. The heat content of bituminous coal ranges from

21 to 30 million Btu per ton on a moist, mineral-matter-free basis. The heat content of bituminous coal consumed in the United States averages 24 million Btu per ton, on the as- received basis (i.e., containing both inherent moisture and mineral matter).

Blackdamp: a deadly gas that is caused from coal burning in an atmosphere which lacks oxygen; mostly a mixture of carbon dioxide and nitrogen found in mines after fires and explosions.

Black liquor: solution of lignin-residue and the pulping chemicals used to extract lignin during the manufacture of paper.

Black lung (anthracosis): a respiratory disease caused by prolonged inhalation of coal dust.

Blasting agent: any material consisting of a mixture of a fuel and an oxidizer.

Blasting cap: a detonator containing a charge of detonating compound, which is ignited by electric current or the spark of a fuse. Used for detonating explosives.

Blasting circuit: electric circuits used to fire electric detonators or to ignite an igniter cord by means of an electric starter.

Bleeder or bleeder entries: special air courses developed and maintained as part of the mine ventilation system and designed to continuously move air-methane mixtures emitted by the gob or at the active face away from the active workings and into mine-return air courses.

Blending: the process of achieving a final product with a well-defined composition, from two or more coal types, so that the elements are very well distributed and no large pockets of one type can be identified. On the other hand, mixing is the process of mixing two or more coals types and traces of the individual components can still be identified.

Blue gas: a mixture consisting chiefly of carbon monoxide and hydrogen formed by action of steam on hot coal or coke.

Boghead coal: same as cannel coal except that algal remains can be seen under the microscope.

Boiler slag: a molten ash collected at the base of slag tap and cyclone boilers that is quenched with water and shatters into black, angular particles having a smooth glassy appearance.

Bolt torque: the turning force in foot-pounds applied to a roof bolt to achieve an installed tension.

Bone coal or bone: impure coal that contains much clay or other fine-grained detrital mineral matter; the term bone coal has been erroneously used for cannel coal, canneloid coal, and well-cemented to metamorphosed coaly mudstone and (or) claystone. Bone coal has also been applied to carbonaceous partings; the term *impure coal* accompanied by adjective modifiers such as *silty*, *shaly*, or *sandy* is the preferred usage because the definition of bone coal does not specify the type or weight percentages of impurities.

Borehole: any deep or long drill-hole, usually associated with a diamond drill.

Boss: any member of the managerial ranks who is directly in charge of miners (e.g., shift-boss, face-boss, fire-boss).

Bottom: floor or underlying surface of an underground excavation.

Bottom ash: consists of agglomerated ash particles formed in pulverized coal boilers that are too large to be carried in the flue gases and impinge on the boiler walls or fall through open grates to an ash hopper at the bottom of the boiler. Bottom ash is typically gray to black in color, is quite angular, and has a porous surface structure.

Bottom ash: consists of agglomerated ash particles formed in combustors or gasification reactors that are too large to be carried in the flue gases and impinge on the reactor boiler walls or fall through open grates to an ash hopper at the bottom of the reactor; typically gray to black in color, is quite angular, and has a porous surface.

Box-type magazine: a small, portable magazine used to store limited quantities of explosives or detonators for short periods of time at locations in the mine which are convenient to the blasting sites at which they will be used.

Brattice or brattice cloth: fire-resistant fabric or plastic partition used in a mine passage to confine the air and force it into the working place; also termed *line brattice*, *line canvas*, or *line curtain*.

Break line: the line that roughly follows the rear edges of coal pillars that are being mined; the line along which the roof of a coal mine is expected to break.

Breakthrough: a passage for ventilation that is cut through the pillars between rooms.

Bridge carrier: a rubber-tire-mounted mobile conveyor, about 10 meters long, used as an intermediate unit to create a system of articulated conveyors between a mining machine and a room or entry conveyor.

Bright coal: U.S. Bureau of Mines term for a combination of clarain and vitrain with small amounts of fusain.

Bridge conveyor: a short conveyor hung from the boom of mining or lading machine or haulage system with the other end attached to a receiving bin that dollies along a frame supported by the room or entry conveyor, tailpiece – as the machine boom moves, the bridge conveyor keeps it in constant connection with the tailpiece.

Briquetting: a process of applying pressure to coal fines, with or without a binder, to form a compact or agglomerate.

British thermal unit (Btu): the quantity of heat required to raise the temperature of 1 pound of water 1°F at, or near, its point of maximum density of 39.1°F (equivalent to 251.995 gram calories; 1,054.35 Joules; 1.05435 kilojoules; 0.25199 kilocalorie).

Brow: a low place in the roof of a mine, giving insufficient headroom.

Brushing: digging up the bottom or taking down the top to give more headroom in roadways.

Btu: *See* British thermal unit. Bug dust: the fine particles of coal or other material resulting from the boring or cutting of the coal face by drill or machine.

Bump (or burst): a violent dislocation of the mine workings which is attributed to severe stresses in the rock surrounding the workings.

Burn line: the contact between burned and unburned coal in the subsurface. In the absence of definitive information, the subsurface position of a burn line is assumed to be vertically below the surface contact between unaltered and altered rocks.

Butt cleat: a short, poorly defined vertical cleavage plane in a coal seam, usually at right angles to the long face cleat.

Butt entry: a coal mining term that has different meanings in different locations – it can be synonymous with panel entry, sub-main entry, or in its older sense it refers to an entry that is *butt* onto the coal cleavage (that is, at right angles to the face).

Cage: a rectangular transporting device used to haul mine cars (pit cars) loaded with coal or dirt and rock from the earth below. The cage was also used to transport miners, mules and supplies to and from the workplace below.

Cage: person who worked at the cages loading and unloading the mine cars, etc., on to the cages.

Calorie: the quantity of heat required to raise 1 gram of water from 15 to 16°C; a calorie is also termed gram calorie or small calorie (equivalent to 0.00396832 Btu; 4.184 Joules; 0.001 kilogram calorie).

Calorific value: the quantity of heat that can be liberated from one pound of coal or oil measured in Btu/lb.

Cannel coal: predominately durain with lesser amounts of vitrain than splint coal and small quantities of fusain. Spores can be seen under the microscope.

Canopy: a protective covering of a cab on a mining machine.

Car: a railway wagon, especially any of the wagons adapted to carrying coal, ore, and waste underground.

Carbon dioxide (CO_2): a product of combustion that acts as a greenhouse gas in the Earth's atmosphere, trapping heat and contributing to climate change.

Carbon monoxide (CO): a lethal gas produced by incomplete combustion of carbon-containing fuels in internal combustion engines; it is colorless, odorless, and tasteless and poisons by displacing the oxygen in hemoglobin (the oxygen carrier in the blood).

Carbon monoxide: a colorless, odorless, very toxic gas formed by incomplete combustion of carbon, as in water gas or producer gas production.

Carbon neutral cycle: the carbon cycle that can be repeated indefinitely, as long as biomass is regrown in the next management cycle and harvested for use. The sustainable management of the biomass source is thus critical to ensuring that the carbon cycle is not interrupted; although the sequestered carbon dioxide (in the biomass) is introduced (released) into atmosphere, new plant or tree growth keeps the carbon cycle of the atmosphere in balance by recapturing carbon dioxide; also called the net-zero carbon cycle.

Carbon sequestration: the absorption and storage of carbon dioxide from the atmosphere; naturally occurring in plants.

Carbonization: a process whereby a carbonaceous feedstock is converted to char or coke by devolatilization.

Carbonization: a process whereby coal is converted to coke by devolatilization.

Carbureted blue gas: *See* Water gas.

Car-dump: the mechanism for unloading a loaded car.

Class C fly ash: fly ash that meets criteria defined in ASTM C618 for use in concrete.

Class F fly ash: fly ash that meets criteria defined in ASTM C618 for use in concrete.

Clean coal technologies: a number of innovative, new technologies designed to use coal in a more efficient and cost-effective manner while enhancing environmental protection; technologies include (i) fluidized-bed combustion, (ii) integrated gasification combined cycle, IGCC, (iii) limestone injection multi-stage burner, (iv) enhanced flue gas desulfurization or scrubbing, (v) coal liquefaction, and (vi) coal gasification.

Cleaning: *See* Coal cleaning.

Coal: an organic rock; a stratified combustible carbonaceous rock, formed by partial to complete decomposition of vegetation; varies in color from dark brown to black; not fusible without decomposition and very insoluble.

Coal (agglomerating): agglomeration describes the caking properties of coal. The agglomerating character of the coal is determined by examination and testing of the residue when a small powdered sample is heated to 950°C (1740°F) under specific conditions. If the coal agglomerating, the residue will be coherent, show swelling or cell structure, and be capable of supporting a 500-gram weight without pulverizing. *See also* Coal (caking).

Coal ash: a collective term referring to any solid materials or residues (such as fly ash, bottom ash, or boiler slag) produced primarily from the combustion of coal. Current usage of the coal ash collective term is synonymous with the term coal combustion ash and coal combustion residue. Also, coal ash is a component of the term coal utilization by-product (cub) covering only the materials or residues associated with the combustion of coal.

Coal (caking): a coal which, when heated, leaves a solid coherent residue. The caking coal might give a coke which may not be accepted by the steel plants as it does not possess the requisite physical and chemical properties of the coke. A coking coal is that coal which on heating in absence of air leaves a solid residue. *See also* Coal (non-caking).

Coal (coking): a coal which, when heated in absence of air, leaves a solid coherent residue possessing metallic grayish luster and which possesses all the physical and chemical properties in the coke when manufactured commercially. Coking coal are those coals which after heating in absence of air leaves a residual coke.

Coal (non-caking): coal which when heated in the absence of air, for example, as in the determination of volatile matter, leaves a powdery residue. A non-caking coal is always a non-coking coal. A non-coking coal may not be non-caking coal. A non-coking coal can also produce coke which is never suitable for steel industry. A noncaking coal is that coal which on heating in absence of air doesn’t form a coherent mass of residue. *See also* Coal (caking).

Coal (non-coking): a coal that leaves a solid coherent residue which may not possess the physical and chemical properties of the coke. The non-coking coals are those coals which may form a solid-residue but may not be suitable for manufacture of coke. This coal may form a coke which will not meet the physical & chemical properties as laid down by the steel industry, the primary coke consumer. *See also* Coal (coking).

Coal cleaning: a process (or a sequence of processes) by which impurities such as sulfur, ash, and rock are removed from coal to upgrade its value. Coal cleaning processes are categorized as either physical cleaning or chemical cleaning. Physical coal cleaning processes involve the mechanical separation of coal from its contaminants using differences in density.

Coal dust: particles of coal that can pass a No. 20 sieve.

Coal gangue: the material generated during coal mining and processing as a solid waste which has low carbon and high ash content.

Coal gas: the mixture of volatile products (mainly hydrogen, methane, carbon monoxide, and nitrogen) remaining after removal of water and tar, obtained from carbonization of coal, having a heat content of 400-600 Btu/ft^3.

Coal gasification: production of gas from coal.

Coal liquefaction: conversion of coal to a liquid.

Coal preparation: the treatment of coal to reject waste. In its broadest sense, preparation is any processing of mined coal to prepare it for market, including crushing and screening or sieving the coal to reach a uniform size, which normally results in removal of some non-coal material. The term coal preparation most commonly refers to processing, including crushing and screening, passing the material through one or more processes to remove impurities, sizing the product, and loading for shipment. Many of the processes separate rock, clay, and other minerals from coal in a liquid medium; hence the term washing is widely used. In some cases coal passes through a drying step before loading.

Coal quality: the term used to refer to the properties and characteristics of coal that influence its behavior and use. Among the coal-quality characteristics that are important for coal-fired power plants are the concentration, distribution, and forms of the many elements contained in the coal feedstock.

Coal rank: indicates the degree of coalification that has occurred for a particular coal. Coal is formed by the decomposition of plant matter without free access to air and under the influence of moisture, pressure, and temperature. Over the course of the geologic process that forms coal—coalification—the chemical composition of the coal gradually changes to compounds of lower hydrogen content and higher carbon content in aromatic ring structures. As the degree of coalification increases, the percentage of volatile matter decreases and the calorific value increases. The common ranks of coal are anthracite, bituminous, subbituminous, and brown coal/lignite.

Coal reserves: measured tonnages of coal that have been calculated to occur in a coal seam within a particular property.

Coal sampling: the collection and proper storage and handling of a relatively small quantity of coal for laboratory analysis. Sampling may be done for a wide range of purposes, such as: coal resource exploration and assessment, characterization of the reserves or production of a mine, to characterize the results of coal cleaning processes, to monitor coal shipments or receipts for adherence to coal quality contract specifications, or to subject a coal to specific combustion or reactivity tests related to the intended use by the customer. During pre-development phases, such as exploration and resource assessment, sampling typically is from natural outcrops, test pits, old or existing mines in the region, drill cuttings, or drilled cores. Characterization of a reserves of a mine or the coal production may use sample collection in the mine, representative cuts from coal conveyors or from handling and loading equipment, or directly from stockpiles or shipments (coal rail cars or barges). Contract specifications rely on sampling from the production flow at the mining or coal handling facility or at the load-out, or from the incoming shipments at the facility of the receiver. In all cases, the value of a sample taken depends on its being representative of the coal under consideration, which in turn requires that appropriate sampling procedures be carefully followed.

For coal resource and estimated reserve characterization, appropriate types of samples include (alphabetically):

Bench sample: a face or channel sample taken of just that contiguous portion of a coalbed that is considered practical to mine, also known as a bench; for example, bench samples may be taken of minable coal where impure coal that makes up part of the geologic coalbed is likely to be left in the mine, or where thick partings split the coal into two or more distinct minable seams, or where extremely thick coal beds cannot be recovered by normal mining equipment, so that the coal is mined in multiple passes, or benches, usually defined along natural bedding planes.

Column sample: a channel or drill core sample taken to represent the entire geologic coalbed; it includes all partings and impurities that may exist in the coalbed.

Composite sample: a recombined coalbed sample produced by averaging together thickness-weighted coal analyses from partial samples of the coalbed, such as from one or more bench samples, from one or more mine exposures or outcrops where the entire bed could not be accessed in one sample, or from multiple drill cores that were required to retrieve all local sections of a coal seam.

Face channel or channel sample: a sample taken at the exposed coal in a mine by cutting away any loose or weathered coal then collecting on a clean surface a sample of the coal seam by chopping out a channel of uniform width and depth; a face channel or face sample is taken at or near the working face, the most freshly exposed coal where actual removal and loading of mined coal is taking place. Any partings greater than 3/8 inch and/or mineral concretions greater than ½ inch thick and 2 inches in maximum diameter are normally discarded from a channel sample so as better to represent coal that has been mined, crushed, and screened to remove at least gross non-coal materials.

Coal seam: a layer, vein, or deposit of coal. A stratigraphic part of the surface of the Earth that contains coal.

Coal sizes: in the coal industry, the term *5 inches to ¾ inch* means all coal pieces between 5 inches and ¾ inch at their widest point. *Plus 5 inches* means coal pieces over 5 inches in size; *1½ inches to 0* or *-1½ inches* means coal pieces 1½ inches and under.

Coal tar: the condensable distillate containing light, middle, and heavy oils obtained by carbonization of coal. About 8 gal of tar is obtained from each ton of bituminous coal.

Coal upgrading: generally refers to upgrading technology that removes moisture and certain pollutants from lower-rank coals such as subbituminous coal and lignite by raising the calorific value; upgrading technologies are typically pre-combustion treatments and/or processes that alter the characteristics of a coal before it is burned; the product is often referred to as *refined coal*; may also refer to gasification and liquefaction processes in which the coal is upgraded to a gaseous or liquid product.

Coal utilization by-products (CUBS): fly ash, bottom ash, flue gas desulfurization material, and fluidized-bed combustion material.

Coal washing: the process of separating undesirable materials from coal based on differences in densities; pyrite (FeS_2) is heavier and sinks in water – coal is lighter and floats. *See also* Coal preparation.

Coal zone: a series of laterally extensive and (or) lenticular coal beds and associated strata that arbitrarily can be viewed as a unit; generally, the coal beds in a coal zone are assigned to the same geologic member or formation.

Coalbed methane (coal bed methane): methane produced during the coalification process that remains in the coal seam. *See also* Methane.

Coalification: the processes involved in the genetic and metamorphic history of the formation of coal deposits from vegetable matter; *See also* Metamorphosis.

Coarse coal: coal pieces larger than ½ mm in size.

Cogeneration: a process by which electricity and steam, for space heating or industrial-process heating, are produced simultaneously from the same fuel.

Cogenerator: a generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, and cooling purposes. To receive status as a qualifying facility (QF) under the Public Utility Regulatory Policies Act (PURPA), the facility must produce electric energy and *another form of useful thermal energy through the sequential use of energy*, and meet certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC).

Coke: a gray, hard, porous, and coherent cellular-structured combustible solid, primarily composed of amorphous carbon; produced by destructive distillation or thermal decomposition of certain bituminous coal that passes through a plastic state in the absence of air.

Coke-oven gas: a medium-Btu gas, typically 550 Btu/ft^3, produced as a by-product in the manufacture of coke by heating coal at moderate temperatures.

Coking coal: bituminous coal suitable for making coke.

Colliery: British name for coal mine.

Column flotation: a precombustion coal cleaning technology in which coal particles attach to air bubbles rising in a vertical column – the coal is then removed at the top of the column.

Combustion (burning): the transformation of coal, biomass, or waste into heat, chemicals, and gases through chemical combination of hydrogen and carbon in the fuel with oxygen in the air.

Combustion (incomplete): *See* Incomplete combustion.

Combustion (rapid): *See* Rapid combustion.

Combustion (slow): *See* Slow combustion

Combustion (spontaneous): *See* Spontaneous combustion.

Combustion gases: the gases released from a combustion process.

Comminution: breaking, crushing, or grinding of coal, ore, or rock.

Compliance coal: a coal or a blend of coals that meets sulfur dioxide emission standards for air quality without the need for flue gas desulfurization.

Concretion: a volume of sedimentary rock in which mineral cement fills the spaces between the sediment grains; often ovoid or spherical in shape, although irregular shapes also occur.

Conditioned ash: ash that has been moistened with water during the load out process at the temporary storage silo at the power plant to allow for its handling, transport, and placement without causing fugitive dusting.

Contact: the place or surface where two different kinds of rocks meet; applies to sedimentary rocks, as the contact between a limestone and a sandstone, for example, and to metamorphic rocks; and it is especially applicable between igneous intrusions and their walls.

Continuous miner: a mechanical mining machine consisting of a cutting head, a coal-gathering device, a chain conveyor with flexible loading boom, and a crawler-equipped chassis. Its function is to excavate the mineral and to load it onto shuttle cars or continuous-haulage systems. It is electrically powered, with a hydraulic subsystem for auxiliary functions. Power is supplied through a trailing cable.

Continuous mining: a form of room-and-pillar mining in which a continuous mining machine extracts and removes coal from the working face in one operation; no blasting is required.

Contour: a line on a map that connects all points on a surface having the same elevation.

Contour mining (contour stripping): the removal of overburden and mining from a coal seam that outcrops or approaches the surface at approximately the same elevation in steep or mountainous areas.

Conventional crude oil: crude oil that is pumped from the ground and recovered using the energy inherent in the reservoir; also recoverable by application of secondary recovery techniques.

Conventional mining: the oldest form of room-and-pillar mining which consists of a series of operations that involve cutting the coal bed so it breaks easily when blasted with explosives or high-pressure air, and then loading the broken coal.

Conversion efficiency: a comparison of the useful energy output to the potential energy contained in the fuel; the efficiency calculation relates to the form of energy produced and allows a direct comparison of the efficiency of different conversion processes can be made only when the processes produce the same form of energy output.

Cooling tower drift: in cooling tower, water pumped from the tower basin is routed through the process coolers and condensers. The cool water absorbs heat from the hot process streams which need to be cooled or condensed, and the absorbed heat warms the circulating water. The warm water returns to the top of the cooling tower and trickles downward over the fill material inside the tower. As the water trickles down the tower, it contacts ambient air rising up through the tower either by natural draft or by forced draft using large fans in the tower. That contact causes a small amount of the water to be lost as windage or drift and some of the water to evaporate.

Core drilling: the process by which a cylindrical sample of rock and other strata is obtained through the use of a hollow drilling bit that cuts and retains a section of the rock or other strata penetrated.

Core sample: a cylinder sample generally 1 to 5 inches diameter drilled out of an area to determine the geologic and chemical analysis of the overburden and coal.

Cover: the overburden of any deposit.

Creep: the forcing of pillars into soft bottom by the weight of a strong roof; in surface mining, a slow movement of slopes downhill.

Crib: a roof support of prop timbers or ties, laid in alternate cross-layers, log-cabin style; it may or may not be filled with debris and is also may be called a chock or cog.

Cribbing: the construction of cribs or timbers laid at right angles to each other, sometimes filled with earth, as a roof support or as a support for machinery.

Crop coal: coal at the outcrop of the seam; usually considered to be of inferior quality due to partial oxidation, but this is not always the case.

Cross entry: an entry running at an angle with the main entry.

Crossbar: the horizontal member of a roof timber set supported by props located either on roadways or at the face.

Crosscut: a passageway driven between the entry and its parallel air course or air courses for ventilation purposes; also, a tunnel driven from one seam to another through or across the intervening measures; sometimes called *crosscut tunnel* or *breakthrough*; in vein mining, an entry perpendicular to the vein.

Crusher: a machine for crushing rock or other materials – among the various types of crushers are the ball mill, gyratory crusher, Handsel mill, hammer mill, jaw crusher, rod mill, rolls, stamp mill, and tube mill.

Culm: waste from Pennsylvania anthracite preparation plants, consisting of coarse rock fragments containing as much as 30% small-sized coal; sometimes defined as including fine coal particles called silt. Its heat value ranges from 8 to 17 million Btu per short ton.

Cutter; Cutting machine: a machine, usually used in coal, that will cut a 10- to 15-cm slot which allows room for expansion of the broken coal; also applies to the man who operates the machine and to workers engaged in the cutting of coal by prick or drill.

Cycle mining: a system of mining in more than one working place at a time, that is, a miner takes a lift from the face and moves to another face while permanent roof support is established in the previous working face.

Cyclone: a cone-shaped air-cleaning apparatus which operates by centrifugal separation that is used in particle collecting and fine grinding operations.

Cyclone collectors: equipment in which centrifugal force is used to separate particulates from a gas stream.

Cyclone firing: refers to slagging combustion of coarsely pulverized coal in a cylindrical (cyclone) burner. Some wet-bottom boilers are not cyclone-fired. The primary byproduct is a glassy slag referred to as boiler slag.

Deformation temperature: the temperature at which the corners of the mold first become rounded.

Demonstrated reserve base: a collective term for the sum of coal in both measured and indicated resource categories of reliability which represents 100% of the coal in these categories in place as of a certain date.

Demonstrated reserves: a collective term for the sum of coal in both measured and indicated resources and reserves.

Dense media (heavy media): liquids, solutions, or suspensions having densities greater than that of water.

Dense-media separation: a coal-cleaning method based on density separation, using a heavy-media suspension of fine particles of magnetite, sand, or clay.

Dense medium: a dense slurry formed by the suspension of heavy particles in water; used to clean coal.

Density: the mass (or weight) of a unit volume of any substance at a specified temperature; *See also* Specific gravity.

Depleted resources: resources that have been mined; includes coal recovered, coal lost-in-mining, and coal reclassified as sub-economic because of mining.

Deposit: mineral deposit or ore deposit is used to designate a natural occurrence of a useful mineral, or an ore, in sufficient extent and degree of concentration to invite exploitation.

Depth: the vertical depth below the surface; in the case of incline shafts and boreholes it may mean the distance reached from the beginning of the shaft or hole, the borehole depth, or the inclined depth.

Descending-bed system: gravity downflow of packed solids contacted with upwardly flowing gases – sometimes referred to as *fixed-bed* or *moving-bed* system.

Desulfurization: the removal of sulfur or sulfur compounds from a feedstock.

Detectors: specialized chemical or electronic instruments used to detect mine gases.

Detonator: a device containing a small detonating charge that is used for detonating an explosive, including, but not limited to, blasting caps, exploders, electric detonators, and delay electric blasting caps.

Development mining: work undertaken to open up coal reserves as distinguished from the work of actual coal extraction.

Devolatilization: the removal of vaporizable material by the action of heat.

Dewatering: the removal of water from coal by mechanical equipment such as a vibrating screen, filter, or centrifuge.

Diffuser fan: a fan mounted on a continuous miner to assist and direct air delivery from the machine to the face.

Diffusion: blending of a gas and air, resulting in a homogeneous mixture; blending of two or more gases.

Dilute: to lower the concentration of a mixture; in this case the concentration of any hazardous gas in mine air by addition of fresh intake air.

Dilution: the contamination of ore with barren wall rock in stopping.

Dip: the inclination of a geologic structure (bed, vein, fault, etc.) from the horizontal; dip is always measured downwards at right angles to the strike.

Dipping strata: strata which have a pronounced downdip; the strata that form either side of the typical crude oil anticline are often referred to as dipping strata.

Direct hydrogenation: hydrogenation of coal without use of a separate donor solvent hydrogenation step.

Downcast: air forced down into the mine below, by way of the airshaft which is adjacent to the escape shaft.

Downdraft gasifier: a gasifier in which the product gases pass through a combustion zone at the bottom of the gasifier.

Dragline: an excavating machine that uses a bucket operated and suspended by means of lines or cables, one of which hoists or lowers the bucket from a boom; the other, from which the name is derived, allows the bucket to swing out from the machine or to be dragged toward the machine for loading. Mobility of draglines is by crawler mounting or by a walking device for propelling, featuring pontoon-like feet and a circular base or tub. The swing of the machine is based on rollers and rail. The machine usually operates from the highwall.

Drainage: the process of removing surplus ground or surface water either by artificial means or by gravity flow.

Draw slate: a soft slate, shale, or rock from approximately 1 cm to 10 cm thick and located immediately above certain coal seams, which falls quite easily when the coal support is withdrawn.

Dredge mining: a method of recovering coal from rivers or streams.

Drift: a horizontal passage underground. A drift follows the vein, as distinguished from a crosscut that intersects it, or a level or gallery, which may do either.

Drift mine: an underground coal mine in which the entry or access is above water level and generally on the slope of a hill, driven horizontally into a coal seam.

Drill: a machine utilizing rotation, percussion (hammering), or a combination of both to make holes; if the hole is much over 0.4 meter in diameter, the machine is called a borer.

Drilling: the use of such a machine to create holes for exploration or for loading with explosives.

Dry ash: the ash has not melted because the operating temperature of the reactor is lower than the initial deformation temperature of the ash.

Dry, ash-free (daf) basis: a coal analysis basis calculated as if moisture and ash were removed.

Dry fly ash: fly ash that has been collected by particulate removal equipment such as electrostatic precipitators, baghouses, mechanical collectors, or fabric filters.

Drying: the removal of water from coal by thermal drying, screening, or centrifuging.

Dull coal: coal that absorbs rather than reflects light, containing mostly durain and fusain lithotypes.

Dump: to unload; specifically, a load of coal or waste; the mechanism for unloading, e.g., a car dump (sometimes called tipple); or, the pile created by such unloading, e.g., a waste dump (also called heap, pile, tip, spoil pike).

Durain: a macroscopic coal constituent (lithotype) that is hard and dull gray in color.

Dyke: a geological formation that forms as magma pushes up towards the surface through cracks in the rock; typically vertical or steeply-dipping sheets of igneous rock.

Ebullating-bed reactor: a system similar to a fluidized bed but operated at higher gas velocities, such that a portion of the solids is carried out with the upflowing gas.

Electrostatic precipitation: separation of liquid or solid particles from a gas stream by the action of electrically charged wires and plates.

Electrostatic precipitator (ESP): collection of coal combustion fly ash requires the application of an electrostatic charge to the fly ash, which then is collected on grouped plates in a series of hoppers. Fly ash collected in different hoppers may have differing particle size and chemical composition, depending on the distance of the hopper from the combustor. The ESP ash may also be collected as a composite.

Elemental analysis: the determination of carbon, hydrogen, nitrogen, oxygen, sulfur, chlorine, and ash in a sample.

Emissions: substances discharged into the air during combustion, e.g., all that stuff that comes out of your car.

Endothermic reaction: a process in which heat is absorbed.

Entrained flow system: solids suspended in a moving gas stream and flowing with it.

Entry: an entrance into a series of dugout tunnels and/or passageways in the mine below.

Environment: the external conditions that affect organisms and influence their development and survival.

Equilibrium moisture: the moisture capacity of coal at 30C (86F) in an atmosphere of 95% relative humidity.

Escape shaft: a stairway reaching from the bottom of the mine to the top of the mine used in case of an emergency.

Estimated recoverable reserves: *See* recoverable reserves.

Excluded minerals: minerals that may be mined with the coal but are not an intrinsic part of the coal.

Exinite: a microscopic coal constituent (maceral) or maceral group containing spores and cuticles. Appears dark gray in reflected light.

Exothermic reaction: a process in which heat is evolved.

Exploration: the search for mineral deposits and the work done to prove or establish the extent of a mineral deposit. Alt: Prospecting and subsequent evaluation.

Explosive: any rapidly combustive or expanding substance; the energy released during this rapid combustion or expansion can be used to break rock.

Extraction: the process of mining and removal of cal or ore from a mine.

Face: the solid unbroken surface of a coal bed that is at the advancing end of the mine workplace.

Face cleat: the principal cleavage plane or joint at right angles to the stratification of the coal seam.

Face conveyor: a conveyor used on longwall mining faces and consisting of a metal trough with an integrated return channel. Steel scrapers attached to an endless round link or roller-type chain force through the trough any material deposited inside the trough by the mining machine. Spill plates and guides for mining equipment are attached. For flexibility and ease of installation the conveyor is made up of 5-ft sections. Commonly, two electrically powered drives (one on each end) move chain, scrapers (flights), and material along.

Face supports: hydraulically powered units used to support the roof along a longwall face. They consist of plates at the roof and floor and two to six hydraulic cylinders that press these plates against the respective surfaces with forces of 200-800 tons.

Factor of safety: the ratio of the ultimate breaking strength of the material to the force exerted against it – if a rope will break under a load of 6,000 lbs., and it is carrying a load of 2,000 lbs., its factor of safety is 3 (6,000 divided by 2,000).

Fall: a mass of roof rock or coal which has fallen in any part of a mine.

Fan, auxiliary: a small, portable fan used to supplement the ventilation of an individual working place.

Fan, booster: a large fan installed in the main air current, and thus in tandem with the main fan.

Fan signal: automation device designed to give alarm if the main fan slows down or stops.

Fault zone: a fault, instead of being a single clean fracture, may be a zone hundreds or thousands of feet wide; the fault zone consists of numerous interlacing small faults or a confused zone of gouge, breccia, or mylonite.

Faults: fractures in the rock sequence along which strata on each side of the fracture appear to have moved, but in different directions; a slip-surface between two portions of the surface of the Earth that have moved relative to each other; a failure surface and is evidence of severe earth stresses.

FBC materials: unburned coal, ash, and spent bed material used for sulfur control. The spent bed material (removed as bottom ash) contains reaction products from the absorption of gaseous sulfur oxides (SO_2 and SO_3).

Feedstock: raw material used in an industrial process.

FGD materials: derived from a variety of processes used to control sulfur emissions from boiler stacks. These systems include wet scrubbers, spray dry scrubbers, sorbent injectors, and a combined sulfur oxide (SO_x) and nitrogen oxide (NO_x) process. Sorbents include lime, limestone, sodium-based compounds, and high-calcium coal fly ash.

Fill: typically any material that is put back in place of the extracted coal – sometimes to provide ground support.

Fine coal: coal pieces less than 0.5 mm in size.

Fines: the content of fine particles, usually less than in., in a coal sample.

Firedamp: an explosive mixture of carbonaceous gases, mainly methane, formed in coal mines by the decomposition of coal.

Fischer-Tropsch process: process for producing liquid fuels, usually diesel fuel, from natural gas or synthetic gas from gasified coal or biomass.

Fissure: an extensive crack, break, or fracture in the rocks.

Fixed-bed system: *See* Descending-bed system.

Fixed carbon: the combustible residue left after the volatile matter is driven off. In general, the fixed carbon represents that portion of the fuel that must be burned in the solid state.

Flexicoking: a technology in which any coke produced in a fluid coking unit is gasified by incorporation of a gasifier; essentially, the flexicoking process is coking without coke production.

Float-and-sink analysis: separation of crushed coal into density fractions using a series of heavy liquids. Each fraction is weighed and analyzed for ash and often for sulfur content. Washability curves are prepared from these data.

Flocculants: water-soluble or colloidal chemical reagents that when added to finely dispersed suspensions of solids in water, promote the formation of flocs of the particles and their rapid settlement.

Floor: the layer of rock directly below a coal seam or the floor of a mine opening.

Flow temperature: the temperature when the molten ash collapses to a flattened button on the furnace floor; also called the fluid temperature.

Flue gas desulfurization (FGD): is removal of the sulfur gases from the flue gases (stack gases) of a coal-fired boiler – typically using a high-calcium sorbent such as lime or limestone. The three primary types of FGD processes commonly used by utilities are wet scrubbers, dry scrubbers, and sorbent injection.

Flue gas desulfurization (FGD or scrubbing): the removal of sulfur oxides.

Flue gas recirculation: a procedure in which part of the flue gas is recirculated to the furnace, can be used to modify conditions in the combustion zone (lowering the temperature and reducing the oxygen concentration) to reduce NOx formation; another use for FGR is as a carrier to inject fuel into a reburn zone to increase penetration and mixing.

Fluidity: the degree of plasticity exhibited by a sample of coal heated in the absence of air under controlled conditions, as described in ASTM Standard Test Methods D1812 and D2639.

Fluidization: *See* fluidized-bed system.

Fluidized-bed boiler: a large, refractory-lined vessel with an air distribution member or plate in the bottom, a hot gas outlet in or near the top, and some provisions for introducing fuel; the fluidized bed is formed by blowing air up through a layer of inert particles (such as sand or limestone) at a rate that causes the particles to go into suspension and continuous motion; the super-hot bed material increased combustion efficiency by its direct contact with the fuel.

Fluidized-bed combustion (FBC): accomplishes coal combustion by mixing the coal with a sorbent such as limestone or other bed material. The fuel and bed material mixture is fluidized during the combustion process to allow complete combustion and removal of sulfur gases. Atmospheric FBC (AFBC) systems may be bubbling (BFBC) or circulating (CFBC). Pressurized FBC (PFBC) is an emerging coal combustion technology.

Fluidized-bed combustion (FBC) ash: the fly ash and bed ash produced by an FBC boiler.

Fluidized-bed combustion (FBC) bed ash: the spent bed material that is produced by an FBC boiler. The bed ash is usually collected separately and can be considered as being equivalent to bottom ash in dry bottom or wet-bottom wall-fired furnace.

Fluidized-bed combustion (FBC) products: the unburned coal, ash, spent bed material, and unreacted sorbent produced by an FBC boiler.

Fluidized-bed system: solids suspended in space by an upwardly moving gas stream.

Fluid temperature (ash fluid temperature): the temperature at which the coal ash becomes fluid and flows in streams.

Fly ash: coal ash that exits a combustion chamber in the flue gas; non-burnable ash that are carried into the atmosphere by stack gases; coal ash that exits a combustion chamber in the flue gas and is captured by air pollution control equipment such as electrostatic precipitators, baghouses, and wet scrubbers.

Folded strata: strata that are bent or curved as a result of permanent deformation.

Formation: any assemblage of rocks which have some character in common, whether of origin, age, or composition. Often, the word is loosely used to indicate anything that has been formed or brought into its present shape.

Fossil fuel: solid, liquid, or gaseous fuels formed in the ground after millions of years by chemical and physical changes in plant and animal residues under high temperature and pressure. Oil, natural gas, and coal are fossil fuels.

Fouling: the accumulation of small, sticky molten particles of coal ash on a boiler surface.

Fracture: a general term to include any kind of discontinuity in a body of rock if produced by mechanical failure, whether by shear stress or tensile stress. Fractures include faults, shears, joints, and planes of fracture cleavage.

Free moisture (surface moisture): the part of coal moisture that is removed by air-drying under standard conditions approximating atmospheric equilibrium.

Free swelling index: a measure of the agglomerating tendency of coal heated to 800C (1470F) in a crucible. Coals with a high index are referred to as coking coals; those with a low index are referred to as free-burning coal.

Friability: the tendency of coal particles to break down in size during storage, transportation, or handling; quantitatively expressed as the ratio of average particle size after test to average particle size before test, times 100.

Friable: easy to break, or crumbling naturally. Descriptive of certain rocks and minerals.

Froth flotation: a process for cleaning coal fines in which separation from mineral matter is achieved by attachment of the coal to air bubbles in a water medium, allowing the coal to gather in the froth while the mineral matter sinks.

Fusain: a black macroscopic coal constituent (lithotype) that resembles wood charcoal; extremely soft and friable. Also, U.S. Bureau of Mines term for mineral charcoal seen by transmitted light microscopy.

Fuse: a cord-like substance used in the ignition of explosives – black powder is entrained in the cord and, when lit, burns along the cord at a set rate; a fuse can be safely used to ignite a cap, which is the primer for an explosive.

Fusinite: a microscopic coal constituent (maceral) with well-preserved cell structure and cell cavities empty or occupied by mineral matter.

Gallery: a horizontal or a nearly horizontal underground passage, either natural or artificial.

Gas purification: gas treatment to remove contaminants such as fly ash, tars, oils, ammonia, and hydrogen sulfide.

Gas turbine (combustion turbine): a turbine that converts the energy of hot compressed gases (produced by burning fuel in compressed air) into mechanical power – often fired by natural gas or fuel oil.

Gaseous emissions: substances discharged into the air during combustion, typically including carbon dioxide, carbon monoxide, water vapor, and hydrocarbons.

Gasification: a chemical or heat process used to convert carbonaceous material (such as coal, crude oil, and biomass) into gaseous components such as carbon monoxide and hydrogen.

Gasification, underground (*in situ* gasification): a method of utilizing coal by burning in place and extracting the released gases, tars, and heat.

Gasifier: a device for converting solid fuel into gaseous fuel; in biomass systems, the process is referred to as pyrolytic distillation.

Gob: the term applied to that part of the mine from which the coal has been removed and the space more or less filled up with waste; also, the loose waste in a mine which is also called *goaf*.

Global climate change: refers to the gradual warming of the Earth caused by the greenhouse effect; believed to be the result of man-made emissions of greenhouse gases such as carbon dioxide, chlorofluorocarbons (CFC) and methane, although there is no agreement among the scientific community on this controversial issue; however, there are natural causes other than the combustion of fossil fuels.

Grade: a term indicating the nature of coal as mainly determined by the sulfur content and the amount and type of ash; not recommended for use in coal resource estimations; definitive statements as to the contents and types of sulfur and ash are preferable – statements indicating high, medium, or low grade are inappropriate without documentation; *See also* Quality.

Grain: in petrology, that factor of the texture of a rock composed of distinct particles or crystals which depends upon their absolute size.

Granular bed filters: equipment that uses a bed of a separate, tightly packed solids as the separation medium.

Gravity separation: treatment of coal particles that depends mainly on differences in specific gravity of particles for separation.

Green energy: energy that can be extracted, generated, and/or consumed without any significant negative impact to the environment.

Greenhouse effect: the effect of certain gases in the Earth's atmosphere in trapping heat from the sun.

Greenhouse gases: gases that trap the heat of the sun in the Earth's atmosphere, producing the greenhouse effect. The two major greenhouse gases are water vapor and carbon dioxide. Other greenhouse gases include methane, ozone, chlorofluorocarbons, and nitrous oxide.

Grindability index: a number that indicates the ease of pulverizing a coal in comparison to a reference coal. This index is helpful in estimating mill capacity. The two most common methods for determining this index are the Hardgrove Grindability Method and Ball Mill Grindability Method. Coals with a low index are more difficult to pulverize.

Grizzly: course screening or scalping device that prevents oversized bulk material from entering a material transfer system; constructed of rails, bars, beams.

Ground control: the regulation and final arresting of the closure of the walls of a mined area; the term generally refers to measures taken to prevent roof falls or coal bursts.

Ground pressure: the pressure to which a rock formation is subjected by the weight of the superimposed rock and rock material or by diastrophic forces created by movements in the rocks forming the crust of the Earth; such pressures may be great enough to cause rocks having a low compressional strength to deform and be squeezed into and close a borehole or other underground opening not adequately strengthened by an artificial support, such as casing or timber.

Gunite: a cement applied by spraying to the roof and sides of a mine passage.

Hand loading: an underground loading method by which coal is removed from the working face by manual labor through the use of a shovel for conveyance to the surface.

Hard coal: coal with a heat content greater than 10,260 Btu/lb. on a moist ash-free basis. Includes anthracite, bituminous, and the higher-rank subbituminous coals.

Hardgrove grindability index (HGI): The weight percent of coal retained on a No. 200 sieve after treatment as specified in ASTM Standard Test Method D409.

Haulage: the horizontal transport of ore, coal, supplies, and waste; the vertical transport of the same is called hoisting.

Haulageway: any underground entry or passageway that is designed for transport of mined material, personnel, or equipment, usually by the installation of track or belt conveyor.

Head section: a term used in both belt and chain conveyor work to designate that portion of the conveyor used for discharging material.

Headframe: the structure surmounting the shaft which supports the hoist rope pulley, and often the hoist itself.

Heading: a vein above a drift; an interior level or airway driven in a mine; in longwall workings – a narrow passage driven upward from a gangway in starting a working in order to give a loose end.

Heat of combustion, heat value: the amount of heat obtainable from coal expressed in British thermal units per pound, joules per kilogram, kilojoules or kilocalories per kilogram, or calories per gram: to convert Btu/lb to kcal/kg, divide by 1.8. To convert kcal/kg to Btu/lb, multiply by 1.8.

Heaving: applied to the rising of the bottom after removal of the coal; a sharp rise in the floor is called a *hogsback*.

Heavy media: *See* Dense media.

Heavy oil: a heavy coal tar fraction with distillation range usually 250 to 300C (480 to 570F), containing naphthalene and coal tar bases.

Hemisphere temperature: the temperature when the entire mold takes on a hemisphere shape.

High temperature tar: the heavy distillate from the pyrolysis of coal at a temperature of about 800C (1470F).

High-volatile bituminous coal: three related rank groups of bituminous coal as defined by the American Society for Testing and Materials which collectively contain less than 69% fixed carbon on a dry, mineral-matter-free basis; more than 31% volatile matter on a dry, mineral-matter-free basis; and a heat value of more than 10,500 Btu per pound on a moist, mineral-matter-free basis.

Highwall: the unexcavated face of exposed overburden and coal in a surface mine or the face or bank on the uphill side of a contour strip mine excavation.

Highwall mining: a highwall mining system consists of a remotely controlled continuous miner which extracts coal and conveys it via augers, belt, or chain conveyors to the outside; the cut is typically a rectangular, horizontal cut from a highwall bench, reaching depths of several hundred feet or deeper.

Hogsback: a sharp rise in the floor of a seam.

Hoist: a drum on which hoisting rope is wound in the engine house, as the cage or skip is raised in the hoisting shaft.

Hoisting: the vertical transport coal or material.

Homogenization: the processing of one type of material so that the inherent fluctuations in respect of quality and/or size distribution are evened out.

Horizon: in geology, any given definite position or interval in the stratigraphic column or the scheme of stratigraphic classification; generally used in a relative sense.

Horseback: a mass of material with a slippery surface in the roof; shaped like a back of a horse.

Hydraulic: of or pertaining to fluids in motion. Hydraulic cement has a composition which permits it to set quickly under water. Hydraulic jacks lift through the force transmitted to the movable part of the jack by a liquid. Hydraulic control refers to the mechanical control of various parts of machines, such as coal cutters, loaders, etc., through the operation or action of hydraulic cylinders.

Hydrocarbon compounds: chemical compounds containing only carbon and hydrogen.

Hydrocarbonaceous material: a material such as tar sand bitumen that is composed of carbon and hydrogen with other elements (heteroelements) such as nitrogen, oxygen, sulfur, and metals chemically combined within the structures of the constituents; even though carbon and hydrogen may be the predominant elements, there may be very few true hydrocarbons.

Hydrocyclone: a hydraulic device for separating suspended solid particles from liquids by centrifugal action. Cyclone action splits the inlet flow, a small part of which exits via the lower cone, the remainder overflowing the top of the cylindrical section. Particles are separated according to their densities, so that the denser particles exit via the cone underflow and less dense particles exit with the overflow.

Hydrogasification: reaction of carbonaceous material such as coal with hydrogen to produce methane.

Hydrogenation: chemical reaction in which hydrogen is added to a substance.

Hydrology: the science that relates to the water systems of the earth.

Hydrophilic: possessing polar surfaces that are readily wetted by water; literally, water-loving.

Hydrophobic: possessing nonpolar surfaces that are not wetted by water; literally, water-hating.

Igneous intrusion: an intrusion into another geologic formation that occurs when magma cools and solidifies before it reaches the surface; coal and associated strata may have been intruded by once molten igneous rocks forcibly injected into the sedimentary sequence from below.

Igneous rock: one of the three main types of rock; the others are sedimentary rock and metamorphic rock; formed through the cooling and solidification of magma or lava; also referred to as magmatic rock. *See also* Sedimentary rock, Metamorphic rock, Protolith.

Immediate roof: the roof strata immediately above the coalbed, requiring support during the excavation of coal.

Impure coal: coal having 25 weight percent or more, but less than 50 weight percent ash on the dry basis (ASTM, 1981, D-2796, p. 344); impure coal having more than 33 weight percent ash is excluded from resource and reserve estimates unless the coal is cleanable to less than 33 weight percent ash*; See also* Bone coal.

***In situ*:** in the natural or original position. Applied to a rock, soil, or fossil when occurring in the situation in which it was originally formed or deposited.

Inby: in the direction of the working face.

Incline: any entry to a mine that is not vertical (shaft) or horizontal (adit). Often incline is reserved for those entries that are too steep for a belt conveyor (+17 degrees -18 degrees), in which case a hoist and guide rails are employed. A belt conveyor incline is termed a slope. Alt: Secondary inclined opening, driven upward to connect levels, sometimes on the dip of a deposit; also called *inclined shaft*.

Inclined grate furnace: a type of furnace or gasifier in which fuel enters at the top part of a grate in a continuous ribbon, passes over the upper drying section where moisture is removed, and descends into the lower burning section; ash is removed at the lower part of the grate.

Included minerals: minerals that are part of the coal particle and matrix.

Incompetent: applied to strata, a formation, a rock, or a rock structure not combining sufficient firmness and flexibility to transmit a thrust and to lift a load by bending.

Incomplete combustion: occurs when there is insufficient oxygen to allow the hydrocarbon to react completely with the oxygen to produce carbon dioxide and water; also occurs when the combustion is quenched by a heat sink such as a solid surface or flame trap.

Indicated coal resources: coal for which estimates of the rank, quality, and quantity have been computed partly from sample analyses and measurements and partly from reasonable geologic projections; the points of observation are ½ to 1 ½ miles apart. Indicated coal is projected to extend as an ½ mile wide belt that lies more than ¼ mile from the outcrop or points of observation or measurement.

Indirect hydrogenation: coal is first gasified to make a synthesis gas. The gas is then passed over a catalyst to produce methanol or paraffinic hydrocarbons.

Inferred coal resources: coal in unexplored extensions of the demonstrated resources for which estimates of the quality and size are based on geologic evidence and projection; quantitative estimates are based largely on broad knowledge of the geologic character of the deposit and for which there are few, if any, samples or measurements – the estimates are based on an assumed continuity or repletion of which there is geologic evidence; this evidence may include comparison with deposits of similar type; bodies that are completely concealed may be included if there is specific geologic evidence of their presence; the points of observation are 1 ½ to 6 miles apart.

Inferred reserves (unproved reserves): the term *inferred reserves* is commonly used in addition to, or in place of, *potential reserves*.

Initial deformation temperature (ash initial deformation temperature): the temperature at which coal begins to fuse and become soft.

Intake: the passage through which fresh air is drawn or forced into a mine or to a section of a mine.

Interburden: the material that lies between two areas of economic interest, such as the material separating coal seams within strata.

Intermediate section: a term used in belt and chain conveyor network to designate a section of the conveyor frame occupying a position between the head and foot sections.

Isopach: a line, on a map, drawn through points of equal thickness of a designated unit. Synonym for isopachous line; isopachyte.

Jackleg: a percussion drill used for drifting or stopping that is mounted on a telescopic leg which has an extension of about 2.5 m. The leg and machine are hinged so that the drill need not be in the same direction as the leg.

Jackrock: a caltrop or other object manufactured with one or more rounded or sharpened points, which when placed or thrown present at least one point at such an angle that it is peculiar to and designed for use in puncturing or damaging vehicle tires; jackrocks are commonly used during labor disputes.

Jigs: machines that produce stratification of the particles in a bed or particles of differing densities by repeated differential agitation of the bed, the heaviest particles migrating to the lowest layer. The jigging action may be carried out in air or with the bed immersed in water or other liquids.

Job Safety Analysis (JSA): a job breakdown that gives a safe, efficient job procedure.

Joint: a divisional plane or surface that divides a rock and along which there has been no visible movement parallel to the plane or surface.

Kerf: the undercut of a coal face.

Kettle bottom: a smooth, rounded piece of rock, cylindrical in shape, which may drop out of the roof of a mine without warning. The origin of this feature is thought to be the remains of the stump of a tree that has been replaced by sediments so that the original form has been rather well preserved.

Lamp: the electric cap lamp worn for visibility; also, the flame safety lamp used in coal mines to detect methane gas concentrations and oxygen deficiency.

Landfill gas: a type of biogas that is generated by decomposition of organic material at landfill disposal sites. Landfill gas is approximately 50% methane. *See also* biogas.

Layout: the design or pattern of the main roadways and workings – the proper layout of mine workings is the responsibility of the manager aided by the planning department.

Lift: the amount of coal obtained from a continuous miner in one mining cycle.

Light oil: a coal tar and coal gas fraction with distillation range between 80 and 210C (175 to 410F) containing mainly benzene with smaller amounts of toluene and xylene.

Lignite: a brownish-black woody-structured coal, lower in fixed carbon and higher in volatile matter and oxygen than either anthracite or bituminous coal – similar to the *brown coal* of Europe and Australia; a class of brownish-black, low-rank coal defined by the American Society for Testing and Materials as having less than 8,300 Btu on a moist, mineral-matter-free basis; in the United States, lignite is separated into two groups: Lignite A (6,300 to 8,300 Btu) and lignite B (< 6,300 Btu).

Liquefaction: the conversion of coal into nearly mineral-free hydrocarbon liquids or low-melting solids by a process of direct or indirect hydrogenation at elevated temperatures and pressures and separation of liquid products from residue by either filtration or distillation or both.

Liquefied petroleum gas (LPG): a mixture of propane and butane.

Lithology: the character of a rock described in terms of its structure, color, mineral composition, grain size, and arrangement of its component parts; all those visible features that in the aggregate impart individuality of the rock; lithology is the basis of correlation in coal mines and commonly is reliable over a distance of a few miles.

Lithotypes: coal lithotypes represent the macrostructure of coal and are, in fact, descriptive of the coal.

Load: to place explosives in a drill hole. Also, to transfer broken material into a haulage device.

Loader: a crawler-mounted unit equipped with a coal-gathering device mounted to an inclined feed plate at the front side. A chain conveyor with an articulated loading boom discharges the coal at the opposite end into shuttle cars or any other conveying systems. It is used primarily on conventionally mined room-and-pillar sections and resembles a continuous miner without the cutting head.

Loading machine: any device for transferring excavated coal into the haulage equipment.

Loading pocket: transfer point at a shaft where bulk material is loaded by bin, hopper, and chute into a skip.

Long ton: a unit of weight in the U.S. Customary System and in the United Kingdom equal to 2,240 pounds (1.0160469 metric tons; 1.1200 short tons; 1,016.0469 kilograms).

Longwall mining: a mining method in which a large rectangular section of coal is removed in one continuous operation. Equipment is installed along one side of the section (the longwall face), and the coal is removed in slices 2-4 ft thick. The excavated area behind the equipment is allowed to cave.

Loose coal: coal fragments larger in size than coal dust.

Low-Btu gas: a nitrogen-rich gas with a heat content of 100-200 Btu/ft^3 produced in gasification processes using air as the oxygen source. The air-blown form of producer gas.

Low-NOx burners: burners designed to control mixing of fuel and air to achieve staged combustion that results in a lower maximum flame temperature and a reduced oxygen concentration during some phases of combustion; the outcome is lower thermal NOx and lower fuel NOx production.

Low voltage: up to and including 660 volts by federal standards.

LPG: *See* Liquefied petroleum gas.

Maceral: microscopic petrographic units of coal.

Main entry: a main haulage road. Where the coal has cleats, main entries are driven at right angles to the face cleats.

Main fan: a mechanical ventilator installed at the surface; operates by either exhausting or blowing to induce airflow through the mine roadways and workings.

Man trip: a carrier of mine personnel, by rail or rubber tire, to and from the work area.

Manhole: a safety hole constructed in the side of a gangway, tunnel, or slope in which miner can be safe from passing locomotives and car. Also called a refuge hole.

Manway: an entry used exclusively for personnel to travel form the shaft bottom or drift mouth to the working section; it is always on the intake air side in gassy mines. Also, a small passage at one side or both sides of a breast, used as a traveling way for the miner, and sometimes, as an airway, or chute, or both.

Measured coal resources: coal for which estimates of the rank, quality, and quantity have been computed from sample analyses and measurements from closely spaced and geologically well-known sample sites, such as outcrops, trenches, mine workings, and drill holes. The points of observation and measurement are so closely spaced and the thickness and extent of coals are so well defined that the tonnage is judged to be accurate within 20% of true tonnage. Although the spacing of the points of observation necessary to demonstrate continuity of the coal differs from region to region according to the character of the coal beds, the points of observation are no greater than ½ mile apart. Measured coal is projected to extend as a ¼-mile wide belt from the outcrop or points of observation or measurement.

Meridian: a surveying term that establishes a line of reference. The bearing is used to designate direction. The bearing of a line is the acute horizontal angle between the meridian and the line. Azimuths are angles measured clockwise from any meridian.

Metallurgical coal: coal used in the steelmaking process to manufacture coke; metallurgical coal; an informally recognized name for bituminous coal that is suitable for making coke by industries that refine, smelt, and work with iron – other uses are space heating, blacksmithing, smelting of base metals, and power generation; generally, metallurgical coal has less than 1% sulfur and less than 8% ash on an as-received basis – most premium metallurgical coal is low- to medium-volatile bituminous coal.

Metamorphic rock: rock that arises from the transformation of existing rock types; the original rock (the protolith) is subjected to heat (temperatures greater than 150 to 200°C) and pressure (15,000 psi) or more), causing profound physical or chemical change; the protolith may be a sedimentary rock, an igneous rock, or an existing metamorphic rock. *See also* Igneous rock, Sedimentary rock, Protolith.

Metamorphosis: the changes in coal in response to temperature and time – the coal changes from lignite through bituminous coal to anthracite. With extreme metamorphism, anthracite can change to graphite. The rank of coal is the stage the coal has reached on the coalification path. The changes, with increasing rank, include an increase in carbon content, and decreases in moisture content and volatile matter as shown in the table below; sometimes referred to as coalification.

Methanation: a process for catalytic conversion of 1 mole of carbon monoxide and 3 moles of hydrogen to 1 mole of methane and 1 mole of water.

Methane: a potentially explosive gas formed naturally from the decay of vegetative matter, similar to that which formed coal. Methane, which is the principal component of natural gas, is frequently encountered in underground coal mining operations and is kept within safe limits through the use of extensive mine ventilation systems.

Methane monitor: an electronic instrument often mounted on a piece of mining equipment, that detects and measures the methane content of mine air.

Microlithotypes: the microscopic analogs of the coal lithotypes and, hence, represent a part of the fine microstructure of coal; associations of coal macerals with the proviso that the *associations* should occur within an arbitrary minimum bandwidth (50 micron, 50 x 10 mm).

Middle (carbolic or creosote) oil: a coal tar fraction with a distillation range of 200 to 270C (390 to 520F), containing mainly naphthalene, phenol, and cresols.

Middlings: coal of an intermediate specific gravity and quality.

Mine development: the term employed to designate the operations involved in preparing a mine for ore extraction. These operations include tunneling, sinking, cross-cutting, drifting, and raising.

Mine mouth electric plant: a coal burning electric-generating plant built near a coal mine.

Mined land: land with new surface characteristics due to the removal of minable commodities by surface-mining methods and subsequent surface reclamation.

Miner: a person who is engaged in the business or occupation of extracting ore, coal, precious substances, or other natural materials from the crust of the Earth.

Mineral: an inorganic compound occurring naturally in the crust of the Earth, with a distinctive set of physical properties, and a definite chemical composition.

Mineral-matter: the solid inorganic material in coal.

Mineral-matter-free basis: a theoretical analysis calculated from basic analytical data expressed as if the total mineral-matter had been removed; used in determining the rank of a coal.

Misfire: the complete or partial failure of a blasting charge to explode as planned.

Moisture content: The total moisture content of a sample customarily determined by adding the moisture loss obtained when air-drying the sample and the measured moisture content of the dried sample. Moisture does not represent all of the water present in coal, as water of decomposition (combined water) and hydration are not given off under standardized test conditions.

Moisture free basis: biomass composition and chemical analysis data is typically reported on a moisture free or dry weight basis – moisture (and some volatile matter) is removed prior to analytical testing by heating the sample at 105°C (221°F) to constant weight; by definition, samples dried in this manner are considered moisture free.

Molten bath gasifier: a reaction system in which coal and air or oxygen with steam are contacted underneath a pool of liquid iron, ash, or salt.

Mountain top removal (mountaintop removal): a form of surface mining in which the summit or summit ridge of a mountain is removed in order to permit easier access to coal seams; after the coal is extracted, the overburden is either put back onto the ridge to approximate the original contours of the mountain or dumped elsewhere, often in neighboring valleys; generally associated with coal mining in the Appalachian Mountain areas.

Moving-bed system: *See* Descending-bed system.

Mud cap: a charge of high explosive fired in contact with the surface of a rock after being covered with a quantity of wet mud, wet earth, or sand, without any borehole being used. Also termed adobe, dobie, and sandblast (illegal in coal mining).

Multiple-seam mining: mining in areas where several seams are recovered from the same area.

Municipal wastes: residential, commercial, and institutional post-consumer wastes contain a significant proportion of plant-derived organic material that constitutes a renewable energy resource; waste paper, cardboard, construction and demolition wood waste, and yard wastes are examples of biomass resources in municipal wastes.

Natural gas: a naturally occurring gas with a heat content over 1000 Btu/ft^3, consisting mainly of methane but also containing smaller amounts of the C_2-C_4 hydrocarbons as well as nitrogen, carbon dioxide, and hydrogen sulfide.

Natural ventilation: ventilation of a mine without the aid of fans or furnaces.

Net-zero carbon cycle: *See* Carbon neutral cycle.

Nip: a device at the end of the trailing cable of a mining machine used for connecting the trailing cable to the trolley wire and ground.

Nitrogen oxides (NOx): products of combustion that contribute to the formation of smog and ozone.

Oil agglomeration: treatment of a suspension of fine coal particles suspended in water with a light hydrocarbon oil so that the particles are preferentially collected by the oil, which separates as a floating pasty agglomerate and can be removed by skimming. First developed as a method for recovering fine coal particles by Trent in 1914.

Open end pillaring: a method of mining pillars in which no stump is left; the pockets driven are open on the gob side and the roof is supported by timber.

Open-pit mining: surface mining, a type of mining in which the overburden is removed from the product being mined and is dumped back after mining; may refer specifically to an area from which overburden has been removed, which has not been filled.

Outby; outbye: nearer to the shaft, and hence farther from the working face. Toward the mine entrance. The opposite of inby.

Outcrop: an area at which a coal seam is naturally exposed at the surface.

Overburden: the earth, rock, and other materials that lie above the coal seam.

Overcast (undercast): enclosed airway which permits one air current to pass over (under) another without interruption.

Over-fire air: air that is injected into the furnace above the normal combustion zone; over-fire air is generally used in conjunction with operating the burners at a lower than normal air-to-fuel ratio, which reduces formation nitrogen oxides; the over-fire air completes the combustion at a lower temperature.

Oxidation gas cleaning: typically accomplished using gases such as oxygen, chlorine, fluorine, ozone, and nitric oxide. If non-volatile products result from oxidation (such as silica from the use of silicone oil), a residue is left on the surface. Oxidation cleaning can be used on surfaces where surface oxidation is not a problem.

Oxidized coal: bituminous coal, the properties of which have been fundamentally modified as a result of chemisorption of oxygen in the air or oxygen dissolved in groundwater. The chemisorption is a surface phenomenon rarely detectable by chemical analysis but usually detectable by petrographic examination. It reduces the affinity of coal surfaces for oil and seriously impairs coking, caking, and agglutinating properties.

Oxy-fuel process: the process of burning a fuel using pure oxygen instead of air as the primary oxidant. Since the nitrogen component of air is not heated, fuel consumption is reduced, and higher flame temperatures are possible.

Panel: a coal mining block that generally comprises one operating unit.

Panic bar: a switch, in the shape of a bar, used to cut off power at the machine in case of an emergency.

Particle density: the weight of a unit volume of solid including the pores and cracks.

Particulate: a small, discrete mass of solid or liquid matter that remains individually dispersed in gas or liquid emissions.

Particulate emissions: particles of a solid or liquid suspended in a gas, or the fine particles of carbonaceous soot and other organic molecules discharged into the air during combustion.

Particulate matter: a collection of particulates.

Parting: a layer or stratum of non-coal material in a coal bed which does not exceed the thickness of coal in either the directly underlying or overlying benches.

Peat: partially carbonized plant matter, formed by slow decay in water.

Percentage extraction: the proportion of a coal seam which is removed from the mine. The remainder may represent coal in pillars or coal which is too thin or inferior to mine or lost in mining. Shallow coal mines working under townships, reservoirs, etc., may extract 50%, or less, of the entire seam, the remainder being left as pillars to protect the surface. Under favorable conditions, longwall mining may extract from 80 to 95% of the entire seam. With pillar methods of working, the extraction ranges from 50 to 90% depending on local conditions.

Percussion drill: a drill, usually air powered, that delivers its energy through a pounding or hammering action.

Permissible: that which is allowable or permitted. It is most widely applied to mine equipment and explosives of all kinds which are similar in all respects to samples that have passed certain tests of the MSHA and can be used with safety in accordance with specified conditions where hazards from explosive gas or coal dust exist.

Permit: as it pertains to mining, a document issued by a regulatory agency that gives approval for mining operations to take place.

Petrography: a branch of coal petrology that specifically deals with the analysis of the maceral composition and rank of coal and therefore plays an essential role in predicting coal behavior.

Petrology: the study of the organic and inorganic constituents of coal and their transformation via metamorphism.

pH: a measure of acidity and alkalinity of a solution on a scale with 7 representing neutrality; lower numbers indicate increasing acidity, and higher numbers increasing alkalinity; each unit of change represents a tenfold change in acidity or alkalinity.

Physical coal cleaning: processes that employ a number of different operations, including crushing, sizing, dewatering, and clarifying, and drying, which improve the quality of the fuel by regulating its size and reducing the quantities of ash, sulfur, and other impurities. In this text the term coal cleaning is synonymous with the terms coal preparation, beneficiation, and washing.

Pick: a tool for loosening or breaking up coal or dirt consisting of a slightly curved bar at both ends and fitted onto a long handle.

Piggy-back: a bridge conveyor.

Pillar: an area of coal left to support the overlying strata in a mine; sometimes left permanently to support surface structures.

Pillar robbing: the systematic removal of the coal pillars between rooms or chambers to regulate the subsidence of the roof; also termed *bridging back the pillar*, *drawing the pillar*, or *pulling the pillar*.

Pinch: a compression of the walls of a vein or the roof and floor of a coal seam so as to *squeeze out* the coal.

Pinning: roof bolting.

Pipeline gas: a methane-rich gas with a heat content of 950 to 1050 Btu/ft^3 compressed to 1000 psi.

Pit: used in reference to a specifically describable area of open-cut mining. May be used to refer to only that part of the open-cut mining area from which coal is being actively removed or may refer to the entire contiguous mined area; also used in Britain to refer to a mine.

Pit Car: a small railroad-type car approximately 6 x 3 in size, used to haul coal, dirt, and rock.

Pitch: the inclination of a seam; the rise of a seam; also, the non-volatile portion of coal tar.

Plan: a map showing features such as mine workings or geological structures on a horizontal plane.

Plasticity: a property of certain coals when heated in the absence of air. For a relative and a semiquantitative method for determining the relative plastic behavior of coal, refer to ASTM Standard Test Methods D2639 and D1812, respectively.

Pneumoconiosis: a chronic disease of the lung arising from breathing coal dust.

Ponded ash: ash that is in an ash pond or that has been excavated from an ash pond.

Portal: the structure surrounding the immediate entrance to a mine; the mouth of an adit or tunnel.

Portal bus: track-mounted, self-propelled personnel carrier that holds 8 to 12 people.

Post: the vertical member of a timber set.

Potential reserves: reserves of coal that are believed to exist in the earth.

Power shovel: a large machine for digging, the digging part of which is a bucket as the terminal member of an articulated boom. Power to the bucket is supplied through hydraulic cylinders or cables.

Precision: a measure of the maximum random error or deviation of a single observation. It may be expressed as the standard error or a multiple thereof, depending on the probability level desired.

Preheating (coke making): the heating of coal in a preheating column to 180-300C (355-570F) to dry off all the moisture and leave a hot, dry fluid coal that can be charged by gravity or pipeline.

Preparation: the process of upgrading run-of-mine coal to meet market specifications by washing and sizing.

Preparation (coke making): fine grinding of coal to ensure adequate fusion of the particles. Usual practice is to grind the coal so that 65-85% will pass through a -in. screen opening.

Preparation plant: a place where coal is cleaned, sized, and prepared for market.

Pretreatment: mild oxidation of coal to eliminate caking (agglomeration) tendencies.

Primary roof: the main roof above the immediate top. Its thickness may vary from a few to several thousand feet.

Primer (booster): a package or cartridge of explosive which is designed specifically to transmit detonation to other explosives and which does not contain a detonator.

Producer gas: mainly carbon monoxide with smaller amounts of hydrogen, methane, and variable nitrogen, obtained from partial combustion of coal or coke in air or oxygen, having a heat content of 110-160 Btu/ft^3 (air combustion) or 400-500 Btu/ft^3 (oxygen combustion).

Productive capacity: the maximum amount of coal that a mining operation can produce or process during a period with the existing mining equipment and/or preparation plant in place, assuming that the labor and materials sufficient to utilize the plant and equipment are available, and that the market exists for the maximum production.

Prop: coal mining term for any single post used as roof support. Props may be timber or steel; if steel – screwed, yieldable, or hydraulic.

Protolith: the original, unmetamorphosed rock from which a given metamorphic rock is formed; for example, the protolith of a slate is a shale or mudstone. *See also* Igneous rock, Metamorphic rock, Sedimentary rock.

Proven reserves: coal reserves that are actually found (proven), usually by drilling and coring.

Proximate analysis: the determination by prescribed methods of moisture, volatile matter, fixed carbon (by difference), and ash; unless specified, proximate analyses do not include determinations of sulfur or phosphorous or any determinations other than those named; proximate analyses are reported by percent and on as-received, moisture-free, and moisture- and ash-free bases.

Pulverized coal combustion: refers to any combustion process that uses very finely ground (pulverized) coal in the process.

Pyrite: a hard, heavy, shiny, yellow mineral, iron disulfide (FeS_2), generally in cubic crystals; also called iron pyrites, fool's gold, sulfur balls – the most common sulfide found in coal mines.

Pyrolysis: the thermal decomposition of biomass at high temperatures (greater than 200°C, 400°F) in the absence of air; the end product of pyrolysis is a mixture of solids (char), liquids (oxygenated oils), and gases (methane, carbon monoxide, and carbon dioxide) with proportions determined by operating temperature, pressure, oxygen content, and other conditions.

Quality: an informal classification of coal relating to its suitability for use for a particular purpose. Refers to individual measurements such as heat value, fixed carbon, moisture, ash, sulfur, phosphorus, major, minor, and trace elements, coking properties, petrologic properties, and particular organic constituents. The individual quality elements may be aggregated in various ways to classify coal for such special purposes as metallurgical, gas, petrochemical, and blending use; See *also* Grade.

Raise: a secondary or tertiary inclined opening, vertical or near-vertical opening driven upward form a level to connect with the level above, or to explore the ground for a limited distance above one level.

Ramp: a secondary or tertiary inclined opening, driven to connect levels, usually driven in a downward direction, and used for haulage.

Rank: a complex property of coals that is descriptive of their degree of coalification (i.e., the stage of metamorphosis of the original vegetal material in the increasing sequence peat, lignite, subbituminous, bituminous, and anthracite).

Rank of coal: the classification of coal by degree of hardness, moisture, and heat content. *Anthracite* is hard coal, almost pure carbon, used mainly for heating homes. *Bituminous coal* is soft coal. It is the most common coal found in the United States and is used to generate electricity and to make coke for the steel industry. *Subbituminous coal* is a coal with a heating value between bituminous and lignite. It has low fixed carbon and high percentages of volatile matter and moisture. *Lignite* is the softest coal and has the highest moisture content. It is used for generating electricity and for conversion into synthetic gas. In terms of Btu or heat content, anthracite has the highest value, followed by bituminous, subbituminous and lignite.

Rapid combustion: a form of combustion in which large amounts of heat and light energy are released, which often results in a fire.

Raw coal: run-of-mine coal that has been treated by the removal of tramp material, screening, or crushing.

Reactive gas cleaning: relies on the formation of volatile reaction products of the contaminant. The process uses a reaction with a gas at high temperature to form a volatile material. For example, air firing of an oxide surface oxidizes all of the hydrocarbon derivatives and they are volatilized.

Reburning: a process in which part of the boiler fuel input (typically 10 to 25%) is added in a separate reburn zone in which the fuel-rich reducing conditions lead to the reduction of NOx formed in the normal combustion zone; over-fire air is injected above the reburn zone to complete combustion; with reburning there are three zones in the furnace: (1) a combustion zone with an approximately normal air-to-fuel ratio, (2) a reburn zone, where added fuel results in a fuel-rich condition; and (3) a burnout zone, where over-fire air leads to completion of combustion; coal, oil, or gas can be used as the reburn fuel.

Reclamation: the process of reconverting mined land to its former or other productive uses.

Recoverability: in reference to accessible coal resources, the condition of being physically, technologically, and economically minable. Recovery rates and recovery factors may be determined or estimated for coal resources without certain knowledge of their economic minability; therefore, the availability of recovery rates or factors does not predict recoverability.

Recoverable reserves (coal): unmined coal deposits that can be removed by current technology, taking into account economic, legal, political, and social variables; reserve estimates (broad meaning) based on a demonstrated reserve base adjusted for assumed accessibility factors and recovery factors.

Recovery: the proportion or percentage of coal or ore mined from the original seam or deposit.

Recovery factor: the percentage of total tons of coal estimated to be recoverable from a given area in relation to the total tonnage estimated to be in the demonstrated reserve base. For the purpose of calculating depletion factors only, the estimated recovery factors for the demonstrated reserve base generally are 50% for underground mining methods and 80% for surface mining methods. More precise recovery factors can be computed by determining the total coal in place and the total coal recoverable in any specific locale.

Recovery percentage: the percentage of coal that can be recovered from the coal deposits at existing mines.

Red dog: a nonvolatile combustion product of the oxidation of coal or coal refuse. Most commonly applied to material resulting from *in situ*, uncontrolled burning of coal or coal refuse piles. It is similar to coal ash.

Reduction ratio: the ratio between the feed top size and the product top size; the ratio between the feed and product sizes.

Refined coal: *See* Coal upgrading.

Refractory lining: a lining which isolates the reactor and helps to keep the temperature; it can operate at 1600°C (2910°F); the main failure problems of such linings are due to chemical corrosion caused by the silica compounds contained in coal ash – in addition to sodium compounds, other alkali compounds diffuse into the refractory lining in addition to the chemical attack; physical erosion can be caused by the molten slag flowing down the wall.

Refuse bank: a repository for waste material generated by the coal cleaning process.

Refuse-derived fuel (RDF): fuel prepared from municipal solid waste; non-combustible materials such as rocks, glass, and metals are removed, and the remaining combustible portion of the solid waste is chopped or shredded.

Refuse recovery: a surface mine where coal is recovered from previously mined coal. It may also be known as a silt bank, culm bank, refuse bank, slurry dam, or dredge operation.

Regulator: a device (wall, door) used to control the volume of air in an air split.

Remaining (resources/reserves): the amount of coal in the ground after some mining, excluding coal in the ground spoiled or left in place for which later recovery is not feasible.

Repeatability: the closeness of agreement between test results carried out by one person with one instrument in one laboratory.

Replicate: a measurement or observation that is part of a series performed on the same sample.

Reproducibility: the measure of agreement between test results carried out by more than one person with more than one instrument in more than one laboratory.

Reserve: that portion of the identified coal resource that can be economically mined at the time of determination. The reserve is derived by applying a recovery factor to that component of the identified coal resource designated as the reserve base.

Residuum (pl. residua, also known as resid or resids): the non-volatile portion of crude oil that remains as residue after refinery distillation; hence, atmospheric residuum, vacuum residuum.

Resin bolting: a method of permanent roof support in which steel rods are grouted with resin.

Resources: concentrations of coal in such forms that economic extraction is currently or may become feasible. Coal resources broken down by identified and undiscovered resources. Identified coal resources are classified as demonstrated and inferred. Demonstrated resources are further broken down as measured and indicated. Undiscovered resources are broken down as hypothetical and speculative.

Respirable dust: dust particles 5 microns or less in size.

Respirable dust sample: a sample collected with an approved coal mine dust sampler unit attached to a miner, or so positioned as to measure the concentration of respirable dust to which the miner is exposed, and operated continuously over an entire work shift of such miner.

Retreat mining: a system of robbing pillars in which the robbing line, or line through the faces of the pillars being extracted, retreats from the boundary toward the shaft or mine mouth.

Return: the air or ventilation that has passed through all the working faces of a split.

Return idler: the idler or roller underneath the cover or cover plates on which the conveyor belt rides after the load which it was carrying has been dumped at the head section and starts the return trip toward the foot section.

Rib: the side of a pillar or the wall of an entry. The solid coal on the side of any underground passage. Same as rib pillar.

Rider: a thin seam of coal overlying a thicker one.

Ripper: a coal extraction machine that works by tearing the coal from the face.

Rob: to extract pillars of coal previously left for support.

Robbed out area: that part of a mine from which the pillars have been removed.

Roll: (1) a high place in the bottom or a low place in the top of a mine passage, (2) a local thickening of roof or floor strata, causing thinning of a coal seam.

Roll protection: a framework, safety canopy, or similar protection for the operator when equipment overturns.

Roof: the stratum of rock or other material above a coal seam; the overhead surface of a coal working place; *See also* Back or Top.

Roof bolt: a long steel bolt driven into the roof of underground excavations to support the roof, preventing, and limiting the extent of roof falls. The unit consists of the bolt (up to 4 feet long), steel plate, expansion shell, and pal nut. The use of roof bolts eliminates the need for timbering by fastening together, or laminating, several weaker layers of roof strata to build a beam.

Roof fall: a coal mine cave-in especially in permanent areas such as entries.

Roof jack: a screw- or pump-type hydraulic extension post made of steel and used as temporary roof support.

Roof sag: the sinking, bending, or curving of the roof, especially in the middle, from weight or pressure.

Roof stress: unbalanced internal forces in the roof or sides, created when coal is extracted.

Roof support: posts, jacks, roof bolts and beams used to support the rock overlying a coal seam in an underground mine. A good roof support plan is part of mine safety and coal extraction.

Roof trusses: a combination of steel rods anchored into the roof to create zones of compression and tension forces and provide better support for weak roof and roof over wide areas.

Room-and-pillar mining: a mining method in which a designated area is divided into regular-shaped coal pillars through the parallel development of entries and cross-cuts. After the area is so developed, the remaining pillars are mined by slicing them into smaller pillars.

Room neck: the short passage from the entry into a room.

Round: planned pattern of drill holes fired in sequence in tunneling, shaft sinking, or stopping. First the cut holes are fired, followed by relief, lifter, and rib holes.

Royalty: the payment of a certain stipulated sum on the mineral produced.

Rubbing surface: the total area (top, bottom, and sides) of an airway.

Run-of-mine coal: raw coal as it leaves the mine prior to any type of crushing or preparation.

Safety fuse: a train of powder enclosed in cotton, jute yarn, or waterproofing compounds, which burns at a uniform rate; used for firing a cap containing the detonation compound which in turn sets off the explosive charge.

Safety lamp: a lamp with steel wire gauze covering every opening from the inside to the outside so as to prevent the passage of flame should explosive gas be encountered.

Safety pillar: a large unmined area left between a mining section and mine openings designated for long-term use. It is laid out to absorb the abutment loads created by the mining activity and to prevent any adverse effects on the openings designated for long-term use.

Salable coal: the shippable product of a coal mine or preparation plant. Depending on customer specifications, salable coal may be run-of-mine, crushed-and-screened (sized) coal, or the clean coal yield from a preparation plant.

Sampling: cutting a representative part of an ore (or coal) deposit, which should truly represent its average value.

Sandstone: a sedimentary rock consisting of quartz sand united by some cementing material, such as iron oxide or calcium carbonate.

Sapropelic coal: non-banded coal which has its origin in lakes and is formed by the degradation of standard coal-peat swamp materials and the addition of other remains, such as algae and wind- or water-borne spores; sapropelic coals is thin and lenticular and they often occur at the base and top of seams.

Scaling: removal of loose rock from the roof or walls. This work is dangerous and a long bar (called a scaling bar) is often used.

Scoop: a rubber tired battery-powered or diesel-powered piece of equipment designed for cleaning runways and hauling supplies.

Scoop Loading: an underground loading method by which coal is removed from the working face by a tractor unit equipped with a hydraulically operated bucket attached to the front; also called a front-end loader.

Scrubbers: any of several forms of chemical/physical devices that remove sulfur compounds formed during coal combustion. These devices, technically known as flue gas desulfurization systems, combine the sulfur in gaseous emissions with another chemical medium to form inert sludge, which must then be removed for disposal; *See also* Flue gas desulfurization.

Seam: underground layer of coal or other mineral of any thickness.

Secondary roof: the roof strata immediately above the coalbed, requiring support during the excavating of coal.

Section: a portion of the working area of a mine.

Sedimentary rock: a type of rock that is formed by the accumulation or deposition of small particles and subsequent cementation of mineral or organic particles on the floor of oceans or other bodies of water at the surface of the Earth. *See also* Igneous rock, Metamorphic rock, Protolith.

Selective Catalytic Reduction (SCR): a process in which a catalyst vessel is installed downstream of the coal-fired furnace; ammonia (NH3) is injected into the flue gas before it passes over the fixed-bed catalyst, which promotes a reaction between NOx and ammonia (NH_3) to form nitrogen and water vapor; NOx reductions as high as 90% are achievable, but careful design and operation, such as control of the reagent dosage and assuring good mixing, are necessary to keep ammonia emissions (referred to as *NH3 slip*) to a concentration of a few ppm.

Selective mining: the object of selective mining is to obtain a relatively high-grade mine product; this usually entails the use of a much more expensive stopping system and high exploration and development costs in searching for and developing the separate bunches, stringers, lenses, and bands of ore.

Selective non-catalytic reduction (SNCR): a process in which a reducing agent (typically ammonia or urea) is injected into the furnace above the combustion zone, where it reacts with NOx as in the case of SCR; critical factors in applying selective non-catalytic reduction are (1) sufficient residence time in the appropriate temperature range and (2) even distribution and mixing of the reducing agent across the full furnace cross section.

Self-contained breathing apparatus: a self-contained supply of oxygen used during rescue work from coal mine fires and explosions; same as SCSR (self-contained self-rescuer).

Self-rescuer: a small filtering device carried by a coal miner underground, either on his belt or in his pocket, to provide him with immediate protection against carbon monoxide and smoke in case of a mine fire or explosion. It is a small canister with a mouthpiece directly attached to it. The wearer breathes through the mouth, the nose being closed by a clip. The canister contains a layer of fused calcium chloride that absorbs water vapor from the mine air. The device is used for escape purposes only because it does not sustain life in atmospheres containing deficient oxygen. The length of time a self-rescuer can be used is governed mainly by the humidity in the mine air, usually between 30 minutes and one hour.

Severance: the separation of a mineral interest from other interests in the land by grant or reservation. A mineral dead or grant of the land reserving a mineral interest, by the landowner before leasing, accomplishes a severance as does his execution of a mineral lease.

Shaft: a deep vertical passage used to enter the mine below; a shaft has to be *sunk* or dug out until the vein of coal is reached. When a coal vein or layer was found, then the digging began in a mainly horizontal direction to follow the vein.

Shaft mine: an underground mine in which the main entry or access is by means of a vertical shaft.

Shale: a rock formed by consolidation of clay, mud, or silt, having a laminated structure, and composed of minerals essentially unaltered since deposition.

Shale parting (shale break): typically a layer of shale in a coal seam that runs parallel to the bedding plane of the seam.

Sheave: a large pulley used to guide a cable. Sheaves at the mine were placed at the highest point of the tipple called the headframe. These sheaves guided the cables that raised and lowered the cages.

Short ton: a unit of weight equal to 2,000 pounds.

Shortwall mining: a mining method with a panel layout similar to longwall mining but at a panel width reduced by approximately 50%. It uses continuous-mining equipment for coal cutting and haulage and a specially designed hydraulic roof support.

Shovel: an excavating or coal-loading machine that uses a bucket mounted on and operated by means of a handle or dipper stick that moves longitudinally on gears and is lifted or lowered by cable. The entire machine is mounted on crawlers for mobility, and the upper structure is mounted on rollers and rail for swing or turn.

Shuttle car: a rubber-tired vehicle used to haul coal from the continuous miner or loader to a belt feeder or conveyor belt. It is usually electrically powered, with the power supplied through a trailing cable. Some new models are equipped with diesel engines.

Side slope: the slope of the sides of a canal, dam, or embankment. It is customary to name the horizontal distance first as 1.5 to 1.0 or frequently 1½:1, meaning a horizontal distance of 1.5 ft to 1 ft vertical.

Silicosis: a respiratory disease (fibrosis of the lung) caused by the prolonged inhalation of silica dust.

Sill: a geological feature that forms when magma intrudes between the rock layers, forming a horizontal or gently dipping sheet of igneous rock.

Silt: waste from Pennsylvania anthracite preparation plants, consisting of coarse rock fragments containing as much as 30% small-sized coal; sometimes defined as including fine coal particles called silt. Its heat value ranges from 8 to 17 million Btu per short ton. Synonymous with culm.

Sinking: the process by which a shaft is driven.

Skid: a track-mounted vehicle used to hold trips or cars from running out of control. Also it is a flat-bottom personnel or equipment carrier used in low coal.

Skip: a car being hoisted from a slope or shaft.

Skipjack: a triggering mechanism that causes mine cars (pit cars) to dump its load of coal or rock to a designated area at the mine.

Slack: small coal; the finest-sized soft coal, usually less than one inch in diameter.

Slag: the nonmetallic product resulting from the interaction of flux and impurities in the smelting and refining of metals.

Slag cyclone: the primary combustion chamber for a cyclone-fired boiler. Ash from the coal melts in the cyclone and is removed as a slag.

Slag pile: a significant amount of dirt and rock excavated from the earth below that is dumped into a pile.

Slagging: the accumulation of coal ash on the wall tubes of a coal-fired boiler furnace, forming a solid layer of ash residue and interfering with heat transfer.

Slate: a mining term for any shale or slate accompanying coal. Geologically, slate is a dense, fine-textured, metamorphic rock, which has excellent parallel cleavage so that it breaks into thin plates or pencil-like shapes.

Slate bar: the proper long-handled tool used to pry down loose and hazardous material from roof, face, and ribs.

Slickenside: a smooth, striated, polished surface produced on rock by friction.

Slip: a fault. a smooth joint or crack where the strata have moved on each other.

Slope: primary inclined opening, connection the surface with the underground workings.

Slope mine: an underground mine with an opening that slopes upward or downward to the coal seam.

Slot oven: a long, narrow refractory chamber charged with coal heated in the absence of air by adjacent heating flues. Ovens are arranged in batteries with heating flues between each pair, like books on a shelf. Typical ovens are 457 mm wide, 12-15 m long, and 4-6 m high.

Sloughing: the slow crumbling and falling away of material from roof, rib, and face.

Slow combustion (smoldering): the slow, low-temperature, flameless form of combustion, sustained by the heat evolved when oxygen directly attacks the surface of a condensed-phase hydrocarbon.

Slurry: a mixture of pulverized insoluble material and water.

Slurry pipeline: a pipeline that can transport a coal-water mixture for long distances.

Smoldering: *See* Slow combustion.

Softening temperature: the temperature when the top of the mold takes on a spherical shape; also called the sphere temperature.

Solid: mineral that has not been undermined, sheared out, or otherwise prepared for blasting.

Sorption capacity: the ability of coal to absorb/adsorb gases such as methane. The sorption capacity of coal increases with rank; high-rank coal can absorb more gas and the adsorptive capacity of coal for methane increases with coal rank. The sorption capacity of coal can be influenced by different intrusions and by the tectonic events such as folding and faulting. Coals near igneous intrusions, such as dykes, may contain calcites and pyrites which are likely to influence the drainability of gases.

Sounding: knocking on a roof to see whether it is sound and safe to work under.

Spad: a flat spike hammered into a wooden plug anchored in a hole drilled into the mine ceiling from which is threaded a plumbline. The spad is an underground survey station similar to the use of stakes in marking survey points on the surface. A pointer spad, or sight spad, is a station that allows a mine foreman to visually align entries or breaks from the main spad.

Span: the horizontal distance between the side supports or solid abutments along sides of a roadway.

Sparging: bubbling a gas into the bottom of a pool of liquid.

Specific energy: the energy per unit of throughput required to reduce feed material to a desired product size.

Specific gravity: the ratio of weight per unit volume of a substance to the weight of the same unit volume of water.

Splint coal: U.S. Bureau of Mines term for durain with some vitrain and clarain and small amount of fusain.

Split: any division or branch of the ventilating current; also, the workings ventilated by one branch. Also, to divide a pillar by driving one or more roads through it.

Split coal: coal that is disturbed by layers of other geologic material, usually layers of shale.

Spoil: the overburden or non-coal material removed in gaining access to the coal or mineral material in surface mining.

Spontaneous combustion: the ignition of a combustible material caused by the accumulation of heat from oxidation reactions; the self-ignition of coal through oxidation under extremely specific conditions. Different types of coal vary in their tendency toward self-ignition.

Spontaneous heating: the slow oxidation of an element or compound which causes the bulk temperature of the element/compound to rise without the addition of an external heat source.

Spragger: a person whose occupation it was to apply braking to the mine cars below by means of placing wood blocks or wedges underneath the wheels to prevent them from rolling down slight grades.

Square mile-foot: the volume of coal (27,878,400 cubic feet; 789,428.38 cubic meters; 1,032,533.33 cubic yards) that covers 1 square mile to a thickness of 1 foot; the weight of coal varies according to the rank.

Squeeze: the settling, without breaking, of the roof and the gradual upheaval of the floor of a mine due to the weight of the overlying strata.

Stack gas: the product gas evolved during complete combustion of a fuel.

Stage loader: a chain conveyor of a design similar to the face conveyor. It provides a connection between the face conveyor and the section conveyor belt.

Steam turbine: a device for converting energy of high-pressure steam (produced in a boiler) into mechanical power which can then be used to generate electricity.

Steeply inclined: said of deposits and coal seams with a dip of from 0.7 to 1 rad (40 degrees to 60 degrees).

Stemming: the noncombustible material used on top or in front of a charge or explosive.

Stinkdamp: a mine gas containing a high proportion of hydrogen sulfide.

Stocks: the supply of coal or coke at a mine, plant, or utility at the end of the reporting period.

Stoker firing: the combustion of coal on a grate, which may be stationary or moving.

Strike: the direction of the line of intersection of a bed or vein with the horizontal plane; the strike of a bed is the direction of a straight line that connects two points of equal elevation on the bed; also the withdrawal of labor by miners and their associates.

Strip mining: a procedure of mining that entails the complete removal of all material from over the product to be mined in a series of rows or strips; also referred to as *open cut*, *open pit*, or *surface mine*.

Stripping: the removal of earth or non-ore rock materials as required to gain access to the ore or mineral materials wanted. The process of removing overburden or waste material in a surface mining operation.

Stripping ratio: the unit amount of spoil or waste (overburden) that must be removed to gain access to a similar unit amount of ore or mineral material.

Stump: any small pillar.

Subbituminous coal: a glossy-black-weathering and non-agglomerating coal that is lower in fixed carbon than bituminous coal, with more volatile matter and oxygen; a rank class of non-agglomerating coals having a heat value content of more than 8,300 Btu/lb and less than 11,500 Btu/lb on a moist, mineral-matter-free basis – this class of coal is divisible on the basis of increasing heat value into the subbituminous C, B, and A coal groups. The heat content of subbituminous coal ranges from 17 to 24 million Btu per ton on a moist, mineral-matter-free basis. The heat content of subbituminous coal consumed in the United States averages 17 to 18 million Btu per ton, on the as-received basis (i.e., containing both inherent moisture and mineral matter).

Subsidence: the gradual lowering of the surface area over an extended period of time as a result of an underground excavation.

Substitute natural gas: *See* Synthetic natural gas.

Subsurface water: water that occurs beneath the surface of the earth in a liquid, solid, or gaseous state; consists of suspended water and groundwater.

Sulfur (total sulfur): sulfur found in coal as iron pyrites, sulfates, and organic compounds. It is undesirable because the sulfur oxides formed when it burns contribute to air pollution, and sulfur compounds contribute to combustion-system corrosion and deposits.

Sulfur forms: the analytical percentage by weight of coal sulfate, pyritic, and organic sulfur.

Sump: the bottom of a shaft, or any other place in a mine, that is used as a collecting point for drainage water.

Sumping: to force the cutter bar of a machine into or under the coal. Also called a sumping cut, or sumping in.

Support: the all-important function of keeping the mine workings open. As a verb, it refers to this function; as a noun it refers to all the equipment and materials--timber, roof bolts, concrete, steel, etc., that are used to carry out this function.

Surface mine: a coal mine that is usually within a few hundred feet of the surface. Earth and rock above or around the coal (overburden) is removed to expose the coal bed, which is then mined with surface excavation equipment such as draglines, power shovels, bulldozers, loaders, and augers. Surface mines include area, contour, open-pit, strip, or auger mine.

Surface mining: a mining method whereby the overlying materials are removed to expose the mineral for extraction; *See also* Strip mine.

Suspension: weaker strata hanging from stronger, overlying strata by means of roof bolts.

Sustainable energy: the provision of energy that meets the needs of the present without compromising the ability of future generations to meet their needs; sources include renewable energy sources and, in the near term because of the wealth of reserves, coal and oil shale.

Sweetened gas: gas from which acid (sour) gases such as H_2 S and CO_2 have been removed.

Syncline: a fold in rock in which the strata dip inward from both sides toward the axis; the opposite of anticline.

Syncrude: synthetic crude oil produced by pyrolysis or hydrogenation of coal or coal extracts.

Syngas: *See* Synthesis gas.

Synthesis gas (syngas): approximately 2:1 molar mixture of hydrogen and carbon monoxide with varying amounts of carbon dioxide.

Synthetic (substitute) natural gas: pipeline-quality gas that is interchangeable with natural gas (mainly methane).

Tail gas: residual gas leaving a process; gas produced in a refinery and not usually required for further processing.

Tail section: a term used in both belt and chain conveyor work to designate that portion of the conveyor at the extreme opposite end from the delivery point. In either type of conveyor it consists of a frame and either a sprocket or a drum on which the chain or belt travels, plus such other devices as may be required for adjusting belt or chain tension.

Tailgate: a subsidiary gate road to a conveyor face as opposed to a main gate. The tailgate commonly acts as the return airway and supplies road to the face.

Tailpiece: also known as foot section pulley. The pulley or roller in the tail or foot section of a belt conveyor around which the belt runs.

Tar sand (bituminous sand): a formation in which the bituminous material (bitumen) is found as a filling in veins and fissures in fractured rocks or impregnating relatively shallow sand, sandstone, and limestone strata; a sandstone reservoir that is impregnated with a heavy, extremely viscous, black hydrocarbonaceous, crude oil-like material that cannot be retrieved through a well by conventional or enhanced oil recovery techniques; (FE 76-4): the several rock types that contain an extremely viscous hydrocarbon which is not recoverable in its natural state by conventional oil well production methods including currently used enhanced recovery techniques.

Tension: the act of stretching.

Ten-Wheeler: an old-time train locomotive consisting of ten wheels, also referred to as a 4-6-0, four small wheels up front near the pilot (cow catcher) and six larger wheels under the middle of the loco and zero wheels at the rear or under the cab where the engineer sat.

Tertiary: lateral or panel openings (e.g., ramp, crosscut).

Thermal conversion: a process that uses heat and pressure to break apart the molecular structure of organic solids.

Through-steel: a system of dust collection from rock or roof drilling. The drill steel is hollow, and a vacuum is applied at the base, pulling the dust through the steel and into a receptacle on the machine.

Timber: a collective term for underground wooden supports.

Timber set: a timber frame to support the roof, sides, and sometimes the floor of mine roadways or shafts.

Timbering: the setting of timber supports in mine workings or shafts for protection against falls from roof, face, or rib.

Tipple: originally the place where the mine cars were tipped and emptied of their coal; still used in that sense, although now more generally applied to the surface structures of a mine, including the preparation plant, and loading tracks. The tracks, trestles, screens, and so on at the entrance to a colliery where coal is screened and loaded.

Ton: a short or net ton is equal to 2,000 pounds; a long or British ton is 2,240 pounds; a metric ton is approximately 2,205 pounds.

Top: a mine roof; *See also* Back.

Top size: the smallest sieve size upon which is retained a total of less than 5% w/w of a total sample.

Torque wrench: a wrench that indicates, as on a dial, the amount of torque (in units of foot-pounds) exerted in tightening a roof bolt.

Town gas: a gaseous mixture of coal gas and carbureted water gas manufactured from coal with a heat content of 600 Btu/ft^3.

Toxic spoil: acid spoil with pH below 4.0; also spoil having amounts of minerals, such as aluminum, manganese, and iron, that adversely affect plant growth.

Trace element: any element present in minute quantities, such as lead and mercury.

Trackman: person whose duty it was to lay railroad track to selected areas wherein miners could conveniently load the pit cars with coal.

Tractor: a battery-operated piece of equipment that pulls trailers, skids, or personnel carriers. Also used for supplies.

Tram: used in connection with moving self-propelled mining equipment. A tramming motor may refer to an electric locomotive used for hauling loaded trips or it may refer to the motor in a cutting machine that supplies the power for moving or tramming the machine.

Transfer: a vertical or inclined connection between two or more levels and used as an ore pass.

Transfer point: location in the materials handling system, either haulage or hoisting, where bulk material is transferred between conveyances.

Trapper: a person, usually of a young age, who opened and closed doors down below in the mine for drivers. The doors down below were used to guide the downcast or airflow to desired areas of the mine.

Traveling grate: a type of furnace or gasifier in which assembled links of grates are joined together in a perpetual belt arrangement; fuel is fed in at one end and ash is discharged at the other.

Tumbling-bed gasifier: an apparatus in which coal is lifted vertically in a revolving cylinder and dropped through an axially flowing stream of oxygen and steam.

Two-stage gasification: partial gasification or pyrolysis in a first step followed by complete gasification of the resultant char in a second step.

Trip: a train of mine cars.

Troughing idlers: the idlers, located on the upper framework of a belt conveyor, which support the loaded belt. They are so mounted that the loaded belt forms a trough in the direction of travel, which reduces spillage and increases the carrying capacity of a belt for a given width.

Tumbling-bed gasifier: an apparatus in which a carbonaceous feedstock is lifted vertically in a revolving cylinder and dropped through an axially flowing stream of oxygen and steam.

Tunnel: a horizontal, or near-horizontal, underground passage, entry, or haulageway, that is open to the surface at both ends. A tunnel (as opposed to an adit) must pass completely through a hill or mountain.

Turbine: a machine for converting the heat energy in steam or high-temperature gas into mechanical energy. In a turbine, a high-velocity flow of steam or gas passes through successive rows of radial blades fastened to a central shaft.

Two-stage gasification: the partial gasification or pyrolysis in a first step followed by complete gasification of the resultant char in a second step.

Ultimate analysis: the analytical percentage by weight of coal carbon, hydrogen, nitrogen, sulfur, oxygen, and ash; the determination by prescribed methods of the ash, carbon, hydrogen, nitrogen, oxygen (by difference), and sulfur contents – quantities of each analyzed substance are reported by percentage for the following conditions: as-received, dried at 105°C (221°F), and moisture-and ash-free.

Undercut: to cut below or undermine the coal face by chipping away the coal by pick or mining machine; in some localities the terms *undermine* or *underhole* are used.

Underground mine: also known as a *deep mine*; usually located several hundred feet below the surface of the Earth in which the coal is removed mechanically and transferred by shuttle car or conveyor to the surface.

Underground mining: the extraction of coal or its products from between enclosing rock strata by underground mining methods, such as room and pillar, longwall, and shortwall, or through *in situ* gasification.

Underground station: an enlargement of an entry, drift, or level at a shaft at which cages stop to receive and discharge cars, personnel, and material. An underground station is any location where stationary electrical equipment is installed. This includes pump rooms, compressor rooms, hoist rooms, battery-charging rooms.

Undiscovered reserves: reserves that are yet to be discovered; the term and the associated *speculative data* are often used in reserve estimation.

Unit train: a long train of between 60 and 150 or more hopper cars, carrying only coal between a single mine and destination; a railway train designated to achieve economies of scale by transporting a single commodity (such as coal), loading fully and operating nonstop.

Universal coal cutter: a type of coal cutting machine which is designed to make horizontal cuts in a coal face at any point between the bottom and top or to make shearing cuts at any point between the two ribs of the place. The cutter bar can be twisted to make cuts at any angle to the horizontal or vertical.

Unproved reserves: *See* Inferred reserves.

Upcast shaft: a shaft through which air leaves the mine.

Valuation: the act or process of valuing or of estimating the value or worth; appraisal.

Vein (coal): a layer of coal found in the Earth; the deeper the vein, the older and better quality of coal.

Velocity: rate of airflow in lineal feet per minute.

Ventilation: the provision of a directed flow of fresh and return air along all underground roadways, traveling roads, workings, and service parts.

Violation: the breaking of any state or federal mining law.

Virgin: unworked; untouched; often said of areas where there has been no coal mining.

Vitrain: a macroscopic coal constituent (lithotype) that appear as brilliant black bands of uniform appearance and greater than 10^{-2} m thick.

Vitrinite: a microscopic coal constituent (maceral) that appears translucent by transmitted light and gray in reflected light; termed anthraxylon when viewed by transmitted light.

VOCs: the name given to low-boiling organic hydrocarbons which escape as vapor from fuel tanks or other sources, and during the filling of tanks; VOCs contribute to smog; *See also* Volatile organic compounds.

Void: a general term for pore space or other openings in rock. In addition to pore space, the term includes vesicles, solution cavities, or any openings either primary or secondary.

Volatile matter: hydrogen, carbon monoxide, methane, tar, other hydrocarbons, carbon dioxide, and water obtained on coal pyrolysis; those products, exclusive of moisture, given off as gas and vapor, determined by definite prescribed methods.

Volatile organic compounds (VOCs): name given to light organic hydrocarbons which escape as vapor from fuel tanks or other sources, and during the filling of tanks; *See also* VOCs.

Vortex flow: the whirling motion of a gas stream in a round vessel that causes separation by downward flow of solid or liquid particulates contained in the gas.

Washability: a term used to describe the ease with which mineral matter can be separated from the coal, and depends on the degree of incorporation of the mineral matter in the organic matrix of the coal and its specific gravity relative to the coal.

Washability analysis: a procedure used in a laboratory before preparation plant design to determine the cleaning processes to be employed and used during normal operation to evaluate the performance of the cleaning equipment and the amenability of the raw coal feed to the cleaning processes chosen.

Washout: the sudden erosion of soft soil or other support surfaces by a gush of water; if a washout occurs in a crater-like formation it is a sinkhole.

Waste: rock or mineral which must be removed from a mine to keep the mining scheme practical, but which has no value.

Water (carbureted blue) gas: a mixture of carbon monoxide and hydrogen formed by the action of air and then steam on hot coal or coke and enriched with hydrocarbon gases from the pyrolysis of oils.

Water-cooled vibrating grate: a boiler grate made up of a tuyere grate surface mounted on a grid of water tubes interconnected with the boiler circulation system for positive cooling; the structure is supported by flexing plates allowing the grid and grate to move in a vibrating action; ash is automatically discharged.

Water gauge (standard U-tube): instrument that measures differential pressures in inches of water.

Weathering: the action of air and water on coal in surface stockpiles, causing size reduction, oxidation, and decreases of any caking or coking properties.

Wedge: a piece of wood tapering to a thin edge and used for tightening in conventional timbering.

Weight: fracturing and lowering of the roof strata at the face as a result of mining operations, as in *taking weight*.

White damp: carbon monoxide, CO. A gas that may be present in the afterdamp of a gas- or coal-dust explosion, or in the gases given off by a mine fire; also one of the constituents of the gases produced by blasting. Rarely found in mines under other circumstances. It is absorbed by the hemoglobin of the blood to the exclusion of oxygen. One-tenth of 1% (.001) may be fatal in 10 minutes.

Width: the thickness of a lode measured at right angles to the dip.

Winning: the excavation, loading, and removal of coal or ore from the ground; winning follows development.

Winze: secondary or tertiary vertical or near-vertical opening sunk from a point inside a mine for the purpose of connecting with a lower level or of exploring the ground for a limited depth below a level.

Wire rope: a steel wire rope used for winding in shafts and underground haulages. Wire ropes are made from medium carbon steels. Various constructions of wire rope are designated by the number of strands in the rope and the number of wires in each strand. The following are some common terms encountered: airplane strand; cable-laid rope; cane rope; elevator rope; extra-flexible hoisting rope; flat rope; flattened-strand rope; guy rope; guy strand; hand rope; haulage rope; hawser; hoisting rope; lang lay rope; lay; left lay rope; left twist; non-spinning rope; regular lay; reverse-laid rope; rheostat rope; right lay; right twist; running rope; special flexible hoisting rope; standing rope; towing hawser; transmission rope.

Working: when a coal seam is being squeezed by pressure from roof and floor, it emits creaking noises and is said to be *working*; this often serves as a warning to the miners that additional support is needed.

Working face: any place in a mine where material is extracted during a mining cycle.

Working place: from the outby side of the last open crosscut to the face.

Working section: from the faces to the point where coal is loaded onto belts or rail cars to begin its trip to the outside.

Workings: the entire system of openings in a mine for the purpose of exploitation.

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About the Author

Dr. James G. Speight has doctorate degrees in Chemistry, Geological Sciences, and Petroleum Engineering and is the author of more than 85 books in petroleum science, petroleum engineering, biosciences, and environmental sciences as well as books relating to ethics and ethical issues.

Dr. Speight has more than fifty years of experience in areas associated with (i) the properties, recovery, and refining of reservoir fluids, (ii) conventional petroleum, heavy oil, and tar sand bitumen, (iii) the properties and refining of natural gas, gaseous fuels, crude oil quality, (iv) the production and properties of petrochemicals from various sources, (v) the properties and refining of biomass, biofuels, biogas, and the generation of bioenergy, (vi) reactor and catalyst technology, and (vii) the environmental and toxicological effects of crude oil and crude oil product. His work has also focused on safety issues, environmental effects, remediation, reactors associated with the production and use of fuels and biofuels, process economics, as well as ethics in science and engineering and in ethics in the universities.

In 1996, Dr. Speight was elected to the Russian Academy of Sciences and awarded the *Gold Medal of Honor* that same year for outstanding contributions to the field of petroleum sciences. In 2001, he received the *Scientists without Borders Medal of Honor* of the Russian Academy of Sciences and was also awarded the *Einstein Medal* for outstanding contributions and service in the field of Geological Sciences. In 2005, the Academy awarded Dr. Speight the *Gold Medal - Scientists without Frontiers*, Russian Academy of Sciences, in recognition of Continuous Encouragement of Scientists to Work Together Across International Borders. In 2007 Dr. Speight received the *Methanex Distinguished Professor* award at the University of Trinidad and Tobago in recognition of excellence in research. In 2018 he was awarded the American Excellence Award for *Excellence in Client Solutions*, United States Institute of Trade and Commerce, Washington, DC.