A Brief History of U.S. Coal

Coal was reportedly used by the Indians of the Southwest long before the early explorers arrived in America. The first record of coal in what is now the United States is a map prepared in 1673-74 by Louis Joliet. It shows “charbon de terra” along the Illinois River in northern Illinois. About a quarter of a century later, in 1701, coal was discovered near Richmond, Virginia. A map drawn in 1736 shows the location of several “cole mines” along the upper Potomac River, near what is now the border of Maryland and West Virginia. Before the end of the 1750’s coal was reported in Pennsylvania, Ohio, Kentucky, and West Virginia. Pennsylvania’s anthracite deposits were found about 1762.

Blacksmiths in colonial days used small amounts of “fossil coal” or “stone coal” to supplement the charcoal normally burned in their forges. Farmers dug coal from beds exposed at the surface and sold it by the bushel. Although most of the coal for the larger cities along the eastern seaboard was imported from England and Nova Scotia, some came from Virginia. The first commercial U.S. coal production began near Richmond, Virginia, in 1748, more than a century before the beginning of the domestic oil industry. By the late 1800’s, coal was being produced in most of the States.

Coal became the principal fuel used by locomotives. As the railroads branched into the coalfields, they became a vital link between mines and markets. Coal also found growing markets as fuel for households and steamboats. Another use of coal was to produce illuminating oil and gas. In 1816, Baltimore, Maryland, became the first city to light streets with gas made from coal. With the beginning of the U.S. coke industry in the latter half of the 1800’s, coke soon replaced charcoal as the chief fuel for iron blast furnaces. Briquetting of coal was introduced in the United States about 1870. Coal-fired steam generators began to produce electricity in the 1880’s. The first practical coal-fired electric generating station, developed by Thomas Edison, went into operation in New York City in 1882 to supply electricity for household lights.

In the earliest mines, coal was quarried from beds that were exposed at the surface. To get more coal, the miners had to follow the coalbed underground. Before coal-cutting machines became available in the late 1880’s, coal was mined underground by hand. Mechanical coal-loading equipment introduced in the early 1920’s replaced hand loading and increased productivity. Mules and, to a lesser degree, horses and oxen were used to haul coal and refuse in and around the early mines; a few dogs were used in small mines working thin coalbeds. In time, the animals were replaced by electric locomotives, dubbed “electric mules,” and other haulage equipment.

Strip mining began in 1866 near Danville, Illinois, when horse-drawn plows and scrapers were used to remove overburden so the coal could be dug and hauled away in wheelbarrows and carts. In 1877, a steam-powered shovel excavated some 10 feet of overburden from a 3-foot-thick coalbed near Pittsburg, Kansas. In 1885, a converted wooden dredge with a 50-foot boom was used to uncover a coalbed under 35 feet of overburden. In 1910, surface mining was underway with steam shovels specifically designed for coal mining.

Young workers, mules, open-flame lamps, and soft hats were common in early coal mines.

United States Coal: An Overview

Introduction

The history of America's progress is inextricably linked to the use of coal from its abundant coal resources. In the early 1900's, coal was so widely used that it reigned as the Nation's principal source of energy. Coal fueled industries, powered locomotives, and heated homes. The coal industry provided jobs for workers numbering in the hundreds of thousands and was the foundation of the economy in many areas.

Later, the Nation's use of coal slumped because of competition from other energy sources, chiefly oil and natural gas, which are cleaner and easier to use. The coal industry lost the railroads as consumers of coal, nearly all of the home heating market, and many of the smaller industries. Some predictions made after World War II saw the development of atomic power as leading to the demise of the coal industry. However, history has shown that coal has weathered competition from other energy sources, although the coal mining workforce has decreased dramatically because of extensive mechanization of mine operations.

The traumatic Arab oil embargo of the early 1970's underscored the Nation's precarious dependence on foreign oil and renewed interest in the vast, widely distributed domestic coal deposits. Clean air legislation, ushered in around the same time, shifted coal development to the large, easily mined deposits of low-sulfur coal in the West. Since then, the market for coal has improved almost steadily, and the production and use of coal have reached unprecedented levels. Today, however, coal is used mostly to generate electricity and accounts for about half of the electricity generated annually. So, through its role in generating electricity, coal has indirectly recaptured part of the market it lost years ago.

The coal industry has become the Nation's largest energy-producing industry, representing nearly one-third of U.S. energy production. Coal also accounts for almost one-fourth of total energy consumed and is the only energy source for which exports are greater than imports. The coal industry is the Nation's leading mining industry, based on value of production. Of all mineral commodities mined, the quantity of coal currently produced ranks second only to that of crushed stone.

The importance of the coal industry to the U.S. economy is illustrated by a study made at Pennsylvania State University in 1994 for the National Coal Association. Analyzing the coal industry's economic effects in 1992, the study found that, while the direct contribution of coal production that year was valued at $21 billion, the industry's total contribution to the economy was $132 billion through its impact on other business sectors. Similarly, the coal industry's workforce of about 136,000 persons, including non-production employees, was indirectly responsible for another 1.4 million jobs.

In 1993, the Nation consumed more than 2 million tons[1] of coal per day—about 20 pounds for each person every day. To produce the 1993 coal output, valued at about $19 billion, more than 100,000 miners worked in some 2,500 mines. Although the coal produced was largely for domestic use, a significant amount was shipped to other countries. These coal exports, averaging more than $4 billion in value in recent years, help the Nation's balance of trade. The Nation has always had a trade surplus in coal. Internationally, the United States is prominent as both a producer and exporter of coal.

The magnitude of annual U.S. coal output—currently about 1 billion tons—is difficult to grasp unless it is placed in some familiar perspective. One ton of broken coal occupies about 40 cubic feet, so the 1993 coal output would cover 1 square mile to a height of more than one-fourth of a mile. In other terms, the rate of coal production in 1993 averaged around 30 tons per second, enough to fill a railroad car every 3 seconds.

About 58 billion tons of coal have been produced in the United States since the first commercial mine was opened more than 200 years ago. Even so, U.S. coal deposits still contain more than 200 billion tons of minable coal, a reserve of energy that contributes to the

[1]In this report, "tons" refers to short tons (1 short ton = 2,000 pounds).

Nation's security. Furthermore, the coal deposits in some States have also become significant sources of coalbed methane. Once considered only as a danger to miners, coalbed methane is now being produced and added to the supply of natural gas.

Coal Data: A Reference provides an overview of the many facets of coal mentioned in this section. It spans a range of topics, covering coal deposits, reserves, mining, employment, transportation, use, and environmental issues. Its principal aim is to summarize basic trends, highlighting factors that have influenced the use of coal and, therefore, controlled the rate of coal production. Also included is a review of new technologies being developed to increase the usefulness of coal as a natural resource, making it both a cleaner-burning fuel and a source of chemicals.

The Nature of Coal

Coal, sometimes called "Nature's Black Diamond," is a black or brownish-black, combustible, sedimentary organic rock that contains more than 50 percent carbonaceous material by weight. In popular usage, coal is often called a mineral because it was formed in the earth. However, the scientific use of the term "mineral" is reserved for a naturally occurring inorganic material that has a definite chemical composition and a regular internal structure. Coal is of organic origin and has neither of these.

Compared with other rocks, coal is relatively light, a solid piece weighing about 80 pounds per cubic foot, less than half the weight of granite, limestone, or most other rocks. Coal is also a relatively soft rock, more easily excavated than most other mined material.

Coal is called a fossil fuel because it is derived from plants that grew in vast swamps millions of years ago and were later buried by sediments when the land subsided. Geological and chemical processes involving high pressures and temperatures, working over vast periods of time, compressed and altered the plant remains, increasing the percentage of carbon present, and thus producing the different ranks, or varieties, of coal: lignite, subbituminous, bituminous, and anthracite. Of the various coal ranks in the United States, bituminous coal is the most abundant and widespread. The water-saturated plant debris called peat is not considered a rank of coal, although it is the first stage in the alteration of plants to coal. With increasing rank, or degree of coalification, coal becomes harder and brighter, and its heat value rises. Coal rank is commonly determined by a combination of heat value and chemical analysis of organic matter. The rank of coal can also be determined by measuring the intensity of light reflected from its vitrinite, one of the macerals in coal. Macerals are the combustible organic portions derived from plant substances and comprise three microscopic groups: vitrinite, exinite (or liptinite), and inertinite. The reflectivity of vitrinite increases with coal rank. Macerals are also helpful in identifying and correlating different coals and in predicting the coking properties of coal and coal blends.

Fossil plant material is revealed in this photomicrograph of subbituminous coal from Wyoming's Powder River Basin. As an indication of magnification, the longer side of the photo represents 0.25 millimeters.

Coal occurs in beds, sometimes called "seams" or "veins," that are interlayed between beds of sandstone, shale, and limestone. The thin layers of shale ("partings") sometimes found in a coalbed are mineral sediments that settled from muddy flood waters while the vegetable matter was accumulating. Coalbeds range in thickness from less than an inch to more than 100 feet. According to some estimates, an accumulation of 3 to 10 feet of compacted material was needed for each foot of bituminous coal. Based on estimates that hundreds of years were needed to build up enough plant material to make a foot of bituminous coal, thick coalbeds represent accumulations of plant material spanning many thousands of years. Although generally flat lying, coalbeds are sometimes inclined, folded, or faulted as a result of geologic forces.

Coal is a complex material, its chemical structure still not completely understood. It is composed chiefly of carbon, hydrogen, and oxygen, with smaller amounts of sulfur and nitrogen and variable quantities of trace elements ranging from aluminum to zirconium. All but 16 of the 92 naturally occurring elements have been detected in coal, mostly as trace elements below 0.1 percent (1,000 parts per million, or ppm). Coals of the same rank may appear similar, but their compositions can vary widely, not only from deposit to deposit but also within the same coalbed, because of differences in the environment of the coal swamps and the nature of the original plant debris. The elements found in coal were introduced into the coalbed in one or more different ways: as material washed into the coal swamp, as a biochemical precipitate from the swamp water, as a minor constituent of the original plants, or as a later addition, after the coal was formed, primarily by ground water.

Fossil plant debris gives coal its most obvious and most useful characteristic, namely, that it can be burned. The heat energy of coal ranges from an average of 13 million British thermal units (Btu) per ton for lignite to about 30 million Btu per ton for some bituminous coals (Figure 1). Most of the heat produced from coal is generated from carbon, by far its major component, with the amount present typically more than 70 percent. Although hydrogen generates about four times more heat per pound than carbon, it accounts for a small part of coal (generally less than 5 percent) and not all of this element is available for heat. During combustion, part of it combines with oxygen to form water vapor. The higher the oxygen content of coal, the lower its heating value. This inverse relationship occurs because the oxygen in the coal is bound to the carbon and has, therefore, already partially oxidized the carbon, decreasing its ability to generate heat. The amount of heat from the combustion of sulfur in coal is very small. Because coal has a high ratio of carbon to hydrogen, the burning of coal releases more carbon dioxide per unit of heat than does the burning of oil or natural gas.

Figure 1. Approximate Heat Content of Different Coal Ranks[1]

[1]As received. (Includes natural moisture and combustible and incombustible materials.)

The heat content, or Btu value, of coal is approximately related to its rank, except for anthracite.

Although the quantity of coal produced and consumed is commonly measured in tons, the heating value of a ton of coal varies considerably, reflecting differences by rank as well as variations within rank due to the kinds of plant material from which the coal was formed. For instance, the heating value of bituminous coal delivered to electric utilities in 1993 averaged 24 million Btu per ton, but the range was from 20 million to 27 million Btu per ton. Similarly, the heating value for subbituminous coal averaged 18 million Btu per ton, but it ranged from 16 million to 19 million Btu per ton. Lignite's average heating value of 13 million Btu per ton was based on a range of 12 million to 14 million Btu per ton. Anthracite production averaged about 23 million Btu per ton. Using these averages, 1.3 tons of subbituminous coal, 1.8 tons of lignite, or a little more than 1 ton of anthracite would be needed to produce the amount of heat in 1 ton of bituminous coal. For this reason, coal purchases are often priced in terms of "dollars per million Btu" in addition to "dollars per ton."

Because the annual "mix" in the ranks of coal comprising total coal production includes growing shares of low rank coals, which generate relatively less heat, the average heat content of U.S. coal production is declining. Currently, it is about 22 million Btu per ton. This is approximately equivalent to the energy obtained by burning 21,000 cubic feet of natural gas, 160 gallons of distillate fuel oil, or 1 cord of seasoned hardwood.

Among the various elements in coal, sulfur is the most undesirable. Burning converts the sulfur in coal mostly into sulfur dioxide, an air pollutant as well as the cause of corrosion and deposits in boilers. Sulfur in mine wastes inhibits the growth of vegetation and causes stream pollution. Sulfur in coking coal used by the steel industry lowers the quality of both the coke produced and the resulting iron and steel products; consequently, coal with a low sulfur content is required for making coke. Various laws have been enacted to limit the amount of sulfur released to the environment. The sulfur content (by weight) of the coal produced for electric power plants, the largest market, in recent years ranged from less than 1 percent to about 4 percent, and averaged 1 percent (20 pounds per ton).

Sulfur occurs in coal in three forms: (1) iron sulfides (pyrite and marcasite), (2) secondary sulfates (gypsum and hydrous ferrous sulfate), and (3) organic sulfur chemically bonded to the coal-forming plant material. Most of the iron sulfides occur in the form of pyrite, which is distributed in many ways: as lenses, bands, fractures, and nodules, and as finely disseminated particles. The larger particles can be partly removed by conventional cleaning processes, but the fine particles are difficult to remove unless the coal is finely crushed and the pyrite separated by special treatment. Sulfate sulfur is less easily removed; however, it is normally present in small amounts (generally less than 0.05 percent) and usually of no great concern. Organic sulfur predominates in low-sulfur coal. As the total sulfur content of coal increases, the amount of organic sulfur can rise to more than 1 percent. Organic sulfur cannot be removed by conventional coal-cleaning processes.

High-sulfur coal is a product of swamps that were covered by sea water. Bacteria in the swamp converted the sulfate in the sea water into pyrite that became part of the coal. Low-sulfur coal deposits were developed primarily under fresh-water conditions.

Although the subbituminous coals and lignites mined in the West contain much lower levels of sulfur than do typical bituminous coals, they contain fairly high levels of the alkali metals sodium and potassium. These elements, which generally are chemically bound to the organic coal matrix, affect the physical and chemical properties of the coal ash. Boilers using these coals are specially designed to avoid serious ash-related equipment malfunctions.

Minerals are the incombustible matter in coal that becomes ash after burning. Minerals represent the inorganic parts of coal and include clay (the most abundant inorganic constituent), carbonates, sulfides, and quartz. The ash content of coal produced for electric power plants in recent years ranged from about 5 to 19 percent (by weight) and averaged about 10 percent (about 200 pounds per ton). Ash not only poses significant disposal problems, but it can form incombustible residues in furnaces, causing combustion problems and erosion of boiler components. Some ash is used in land fills and in making concrete and cinder blocks.

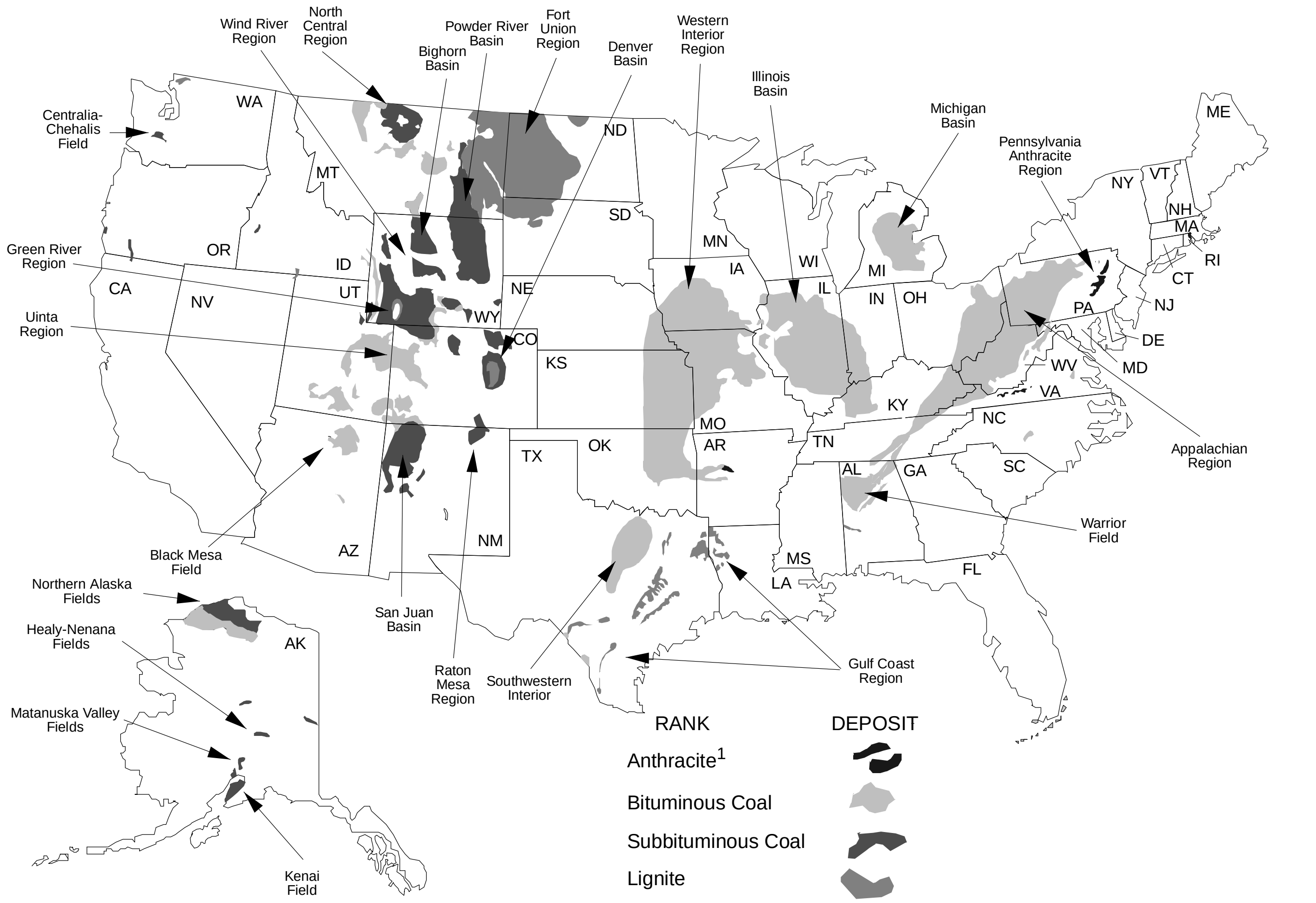
Methane in coal is the result of the chemical and physical processes involved in coal formation. The methane is contained within the structure of the coal and in fractures in the coalbed. Higher rank coals such as bituminous coal generally contain more methane than low ranks such as lignite. Because coal formed under high pressure is apt to contain more methane than otherwise, the methane content of coalbeds increases with depth.

U.S. Coal Deposits

The United States contains some of the world's largest coal deposits. Coal is present in 38 States and underlies a total of 458,600 square miles or 13 percent of the land area of the United States (Figure 2). The U.S. Geological Survey has identified more than 400 fields and small deposits of coal in the United States. They were formed during periods of Earth's history when the face and climate of what is now North America were markedly different than they are today. The coal deposits in the East date back mainly to the Pennsylvanian period of the Earth's geologic history, approximately 300 million years ago, long before the age of dinosaurs. By contrast, most of the coal in the West is geologically younger, formed less than 140 million years ago in the Cretaceous period, when dinosaurs were alive, and in the subsequent Tertiary period, when they became extinct.

Coal in the East generally occurs in beds that tend to be less than 15 feet thick. Geological conditions in the East prevented the coal-forming material from building up; instead, they led to the formation of numerous coalbeds

Figure 2. U.S. Coal Deposits



Note: Alaska not to scale of conterminous United States. Small fields and isolated occurrences are not shown.

1 Principal anthracite deposits are in Pennsylvania. Small deposits occur in Alaska, Arkansas, Colorado, Massachusetts-Rhode Island, New Mexico, Utah, Virginia, Washington, and West Virginia.

Coal is found in 38 States, underlying 458,600 square miles, about 13 percent of the total land area.

Sources: U.S. Geological Survey, Coalfields of the United States, 1960-61 and Coal Map of North America, 1988; Texas Bureau of Economic Geology, Lignite Resources in Texas, 1980; and Louisiana Geological Survey, Near Surface Lignite in Louisiana, 1961.

located between other strata in repetitive sequences. By comparison, thicker coalbeds are common in the West, particularly in Wyoming, where geological conditions enabled large amounts of vegetation to accumulate. Although about 300 coalbeds were mined across the United States in 1993, nearly half of the coal produced was from only 10 beds (Table 1). The average thickness of all coalbeds mined ranged widely, from less than 2 feet to about 65 feet (Figure 3). Individual coalbeds commonly cover large geographic areas. For instance, the heavily mined Pittsburgh coalbed underlies parts of Pennsylvania, West Virginia, Ohio, and Maryland; the Wyodak coalbed, the Nation's leading source of coal, is estimated to cover at least 10,000 square miles in the Powder River Basin of Wyoming and Montana, according to the Wyoming State Geological Survey.

The most important coal deposits in the East are in the Appalachian Region, an area encompassing more than 72,000 square miles and parts of nine States. The region contains the Nation's principal deposits of anthracite (in northeastern Pennsylvania) and large deposits of low- and medium-volatile bituminous coal. Historically, the Appalachian Region has been the major source of U.S.

Table 1. U.S. Coal Production from the 10 Leading Coalbeds, 1993
(Million Short Tons)

Coalbed Name[a]	Production	State with Largest Production by Coalbed
Wyodak	185.7	WY
Pittsburgh	49.4	WV
No. 9	34.8	KY(W)
Hazard No. 5-A	32.4	KY(E)
No 6.	30.7	IL
Beulah-Zap	27.7	ND
Hazard No. 4.	24.5	KY(E)
Lower Kittanning	22.6	WV
Lower Elkhorn	18.0	KY(E)
Rosebud	16.2	MT
Total	**442.0**	--
Percentage of U.S. Total	**46.8**	--

[a]Name most commonly used.
-- = Not applicable.
Note: Total does not equal sum of components because of independent rounding.
Source: Energy Information Administration, *Coal Industry Annual 1993*, DOE/EIA-0584(93) (Washington, DC, December 1994).

coal, accounting for about three-fourths of the total annual production as recently as 1970. Although the region's output currently is less than half of the national total because of increased coal production in the West, it continues to be the principal source of bituminous coal (including coking coal) and anthracite. The number of coalbeds mined in the Appalachian Region reaches more than 60 in West Virginia, with the bed thickness generally ranging from 3 to 8 feet. In the northern part of the region is the Pittsburgh coalbed, an important source of coal during the development of the U.S. iron and steel industry. For many years the Pittsburgh coalbed was the leading source of coal, but it now ranks second to the Wyodak coalbed in Wyoming. The intensely folded and faulted anthracite fields of northeastern Pennsylvania once supplied a large amount of coal for domestic heating, a major part of it from a series of beds comprising the Mammoth coal zone. Two important sources of bituminous coal in the southern part of the Appalachian Region are Alabama's Blue Creek and Mary Lee coalbeds.

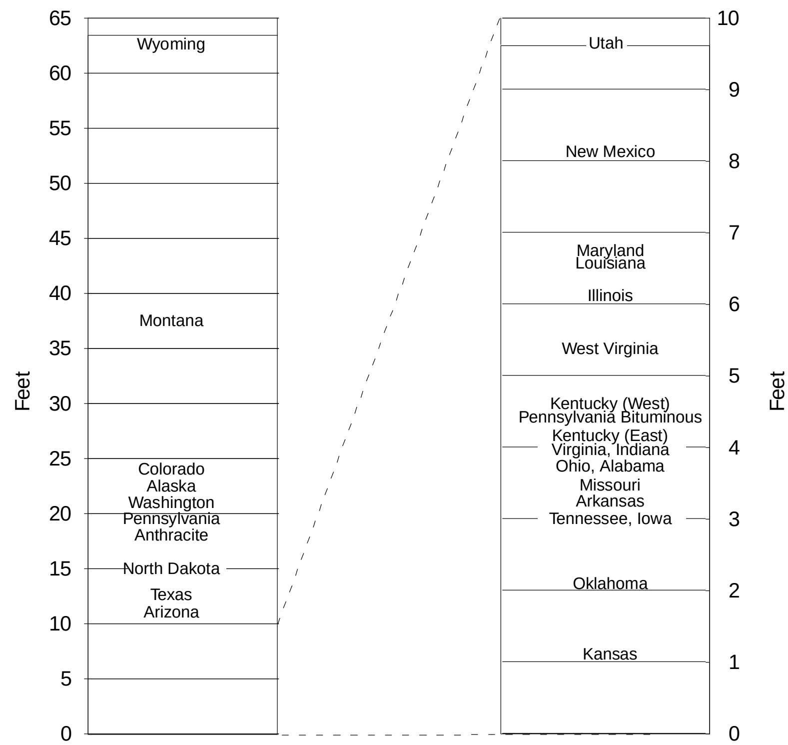
In contrast with the concentration of coal in Appalachia, the coal deposits in the interior region of the United States occur in several separate basins located from Michigan to Texas. The northern part of the region contains large deposits of high-volatile bituminous coal, but their generally high percentage of sulfur and ash hampers their use as a fuel and for coke production. The major sources of bituminous coal are two coalbeds commonly known as No. 6 and No. 9, but also known locally by other names. These beds, which average about 6 feet in thickness, account for a large share of the coal produced in Illinois, Indiana, and western Kentucky. A small area of anthracite is present in Arkansas. In the Gulf Coastal Plain in the southern part of the region are large deposits of lignite that have been used for electricity generation in Texas since the 1970's and in Louisiana since the 1980's. The most important lignite beds are in a succession of strata known as the Wilcox Group and are generally 3 to 10 feet thick.

The western part of the United States has a number of coal basins that contain all ranks of coal. The largest lignite deposit is in the northern Great Plains, underlying parts of North Dakota, South Dakota, and Montana; most of the lignite produced is from the Beulah-Zap bed in North Dakota. In the nearby Powder River Basin of northeastern Wyoming and southeastern Montana is the Nation's major source of low-sulfur subbituminous coal, used primarily for electricity generation. The basin has been the fastest growing coal-producing area in the past two decades and today accounts for about half of the coal mined in the West. The Powder River Basin contains the Wyodak coalbed, which is the leading source of U.S. coal production and one of the thickest coalbeds, averaging 70 feet and exceeding 100 feet in places. The principal deposits of bituminous coal mined in the West are in Utah, Colorado, and Arizona. Alaska has deposits of all coal ranks, but currently the only production is subbituminous coal from the Nenana field, north of Anchorage.

Resources and Reserves

Coal is by far the Nation's most abundant fossil fuel, with the total resources of both identified and undiscovered coal estimated at nearly 4 trillion tons. The quantity of coal considered technically and commercially minable constitutes a *demonstrated reserve base* currently estimated at more than 400 billion short tons. About half of the tonnage is bituminous coal (Figure 4), concentrated in Appalachia and the Interior Region; around 38 percent is subbituminous coal in the West, about 9 percent is lignite, located mostly in the West and the Interior Region; and 1 percent is Pennsylvania anthracite. Underground mining is required for about two-thirds of the reserve base; the rest can be surface mined. The largest reserves of low-sulfur coal are in the West. By contrast, the coal reserves with the highest heat content are mostly in the East.

Figure 3. Average Thickness of U.S. Coalbeds Mined, by State, in 1993
(Weighted Average in Feet)



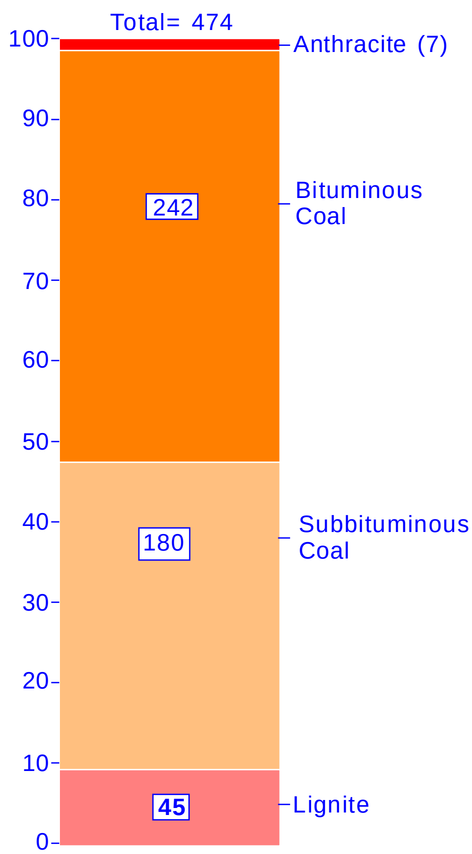
The thickest coalbeds mined in the United States are in the West. The average thickness of all coalbeds mined in 1993 was about 22 feet.

Source: Energy Information Administration, EIA-7A, "Coal Production Report."

The amount of coal that can actually be recovered from the reserve base varies from area to area and ranges from 40 percent at some underground mines to more than 90 percent at some surface mines. The recovery rate is lower for underground mining because some coal must be left untouched to form supporting pillars to prevent the mine from collapsing and the surface from subsiding. At both underground and surface mines, geologic features such as folded, faulted, and interlayered rock strata can reduce the amount of coal that can be recovered. In some areas, coal deposits underlie towns and cities and consequently may not be mined. Other factors that limit mining include environmental and legal restrictions, economic constraints, lack of suitable technology for using low-quality coal, and the fact that many of the highest quality and most accessible coal deposits have already been mined. Nevertheless, for the Nation as a whole, at least half of the reserve base—about 265 billion tons—is estimated to be recoverable. U.S. recoverable coal reserves are estimated to be the second largest in the world, slightly below those in the former Soviet Union.

Based on coal quality, as measured in pounds of sulfur emitted per million Btu, U.S. recoverable coal reserves include an estimated 100 billion tons of low-sulfur coal (0.60 pounds or less of sulfur per million Btu), with 87 percent of this in the West. Medium-sulfur recoverable coal reserves (0.61-1.67 pounds of sulfur per million Btu) are estimated at 84 billion tons, of which 62 percent is in the West and 24 percent in Appalachia. High-sulfur recoverable coal reserves (more than 1.67 pounds of sulfur per million Btu) total 80 billion tons, and are mostly in the interior region (60 percent) and Appalachia (28 percent).

Figure 4. U.S. Demonstrated Reserve Base of Coal, January 1, 1993
(Billion Short Tons)



The reserve base is comprised chiefly of two ranks of coal-bituminous and subbituminous.

Source: Energy Information Administration, *Coal Production 1992*, DOE/EIA-0118(92) (October 1993).

The recoverable coal reserves reported at active mines in 1993 totaled nearly 22 billion tons. About 15 billion tons were at surface mines, mostly in the Western Region. Of the 7 billion tons in underground mines, nearly two-thirds were in Appalachia.

Another energy source from coal is methane, a gas formed by the decomposition of the organic matter in coal. Coalbed methane is recovered in some States (for example, Alabama, New Mexico, and Wyoming) and added to the supply of natural gas, which is composed chiefly of methane. Proved reserves of coalbed methane total 10 trillion cubic feet, located mostly in the San Juan Basin of Colorado and New Mexico. The recoverable resource base for coalbed methane currently comprises an estimated 90 trillion cubic feet in the lower 48 States and 57 trillion cubic feet in Alaska.

Mining

Once a coal deposit has been selected for mining, some 4 to 7 years of planning and development are needed before production begins. Apart from the market for coal, the questions that must be addressed include land ownership, mineral rights, the quality and quantity of the available coal, and the method of mining and transporting the coal.

The mining method used depends on the depth of the coalbed from the surface and the character of the terrain (Figure 5). Coalbeds deeper than 200 feet are usually mined by underground methods. Those that are at shallower depths are worked by surface methods.

Although most underground mines are less than 1,000 feet deep, several reach depths of about 2,000 feet. Underground mines are classified according to the type of opening, or entry, used to reach the coalbed; some mines have several different openings. A *drift* mine is one that has a horizontal entry to a coalbed in a hillside. In a *slope* mine, the entry is inclined from the surface to the coalbed. A *shaft* mine, equipped with elevators, provides vertical access to a coalbed generally deeper than one reached by a slope mine. In addition to the passages providing entry to the coalbed, a network of other passages are also dug to provide access to various parts of the mine and for ventilation.

When the coalbed is reached, it is sectioned into panels, or blocks, several hundred feet wide and several thousand feet long (Figure 6). The actual mining of these blocks is accomplished by three techniques: room-and-pillar, longwall, and shortwall. Sometimes several techniques are used at the same time in different sections of a mine.

Most underground coal is mined by the room-and-pillar system (Figure 7). With this system, the miners extract the coal by cutting a series of rooms into the coalbed and leaving pillars, or columns of coal, to help support the mine roof. As mining advances, a grid-like pattern is formed in the panel of coal, which is about 400 feet wide and more than half a mile long. Generally, the rooms are 20 to 30 feet wide and the pillars 20 to 90 feet wide; the height usually is the same as the coalbed thickness. When mining reaches the end of the panel, the direction of mining usually is reversed. During this "retreat" phase of mining, the miners recover as much coal as possible from the pillars in a

Figure 5. Coal Mining Methods

The method of mining a coal deposit depends on the depth of the coalbed and the nature of the terrain.

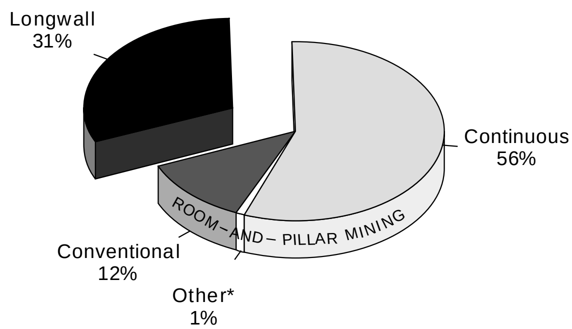
systematic manner until the roof caves in. When this phase of mining is completed, the area is abandoned. Although the goal is to extract all of the coal in the panel, this is not always possible because of natural restraints, such as poor mine roof and floor conditions. Furthermore, pillars are usually left to prevent subsidence of the land surface above the mine. Pillars that are not mined include those along property lines, around shaft bottoms or portals, and around oil and gas wells that penetrate the coalbed. Generally, 50 to 60 percent of the minable coal is recovered with room-and-pillar mining.

Two basic variations are used in room-and-pillar mining: (1) conventional mining, the oldest, which consists of a series of operations that involve cutting the coalbed so it breaks easily when blasted and then loading the broken coal; and (2) continuous mining, which uses a machine called a continuous miner that combines cutting, drilling, and loading coal in one operation and requires no blasting. Because of the steps involved, conventional mining requires a larger crew at the coal face—for example, 10 miners as compared with 6 for continuous mining. Generally, mining advances into the coalbed in steps of about 10 feet for conventional mining and about twice that in continuous mining. Since the 1950's, continuous mining has increased and now accounts for 56 percent of the coal output from underground mines, whereas the share from conventional mining has fallen to about 12 percent. Regardless of the mining variation used, room-and-pillar mining usually is not suitable for coalbeds at depths greater than about 1,000 feet. As depth increases, larger pillars are needed to support the overlying strata and less coal can be produced.

Figure 6. Underground Mining Systems

Room-and-pillar mining is the most common way to mine coal undergound. Longwall mining is used to mine large blocks of coal where the bed is relatively flat and thick. A continuous mining operation includes roof bolting equipment and can use a coal-loading machine and shuttle cars (not shown) instead of a conveyor belt.

Figure 7. Underground Coal Production by Mining Techniques, 1993



*Includes shortwall, scoop loading, and hand loading.

Underground coal is mined mostly with continuous mining machines, which dig and load coal in one operation.

Source: Energy Information Administration, *Coal Industry Annual 1993,* DOE/EIA-0584(93) (Washington, DC, December 1994).

The second technique of underground coal mining is longwall mining, which is gaining importance in the United States and can be used at greater depths than room-and-pillar mining. Nearly one-third of the coal currently produced underground is from about 100 longwall mining operations, most of them in the Appalachian Region. In longwall mining, a cutting machine operates back and forth across a panel of coal averaging about 800 feet in width and 7,000 in length, with the broken coal removed from the coal face by an armored flexible conveyor. Two types of cutting devices are used, shearers and plows. The shearer, by far the more widely used, has a large drum-shaped cutting head that strips 20 to 36 inches from the coal face on each pass. It rides on a special track on the armored flexible conveyor. A plow is a much simpler machine that is blade-like and fitted with bits or a saw-tooth edge that cuts the coal face into slices up to 6 inches deep as the plow is pulled across the coal face. Longwall mining is done under movable hydraulic roof supports, or shields, that are advanced as the bed is cut; the roof in the mined-out area is allowed to fall as mining advances, forming an area of broken rock called "gob."

The widely used continuous mining machine excavates coal through the use of cutting heads, while the broken coal is gathered by loading arms.

In longwall mining, a shearing machine excavates coal as it moves back and forth across a coal face hundreds of feet long.

Production of coal per shift from longwall mining generally is higher than that of either conventional or continuous mining. The longwall technique often has a better recovery rate. It is also safer because the working area is protected by overhead steel supports, coal haulage is simplified, and ventilation is better controlled. However, longwall mining has certain limitations. It is generally not suitable if the coalbed thickness varies widely or if the coalbed is broken by geologic faults. The mine roof or floor also must be strong enough to provide a solid surface for the supports, and the mine roof must cave evenly and not "hang up." Also constraining are high capital costs for equipment and mine development.

The third technique of underground mining is shortwall mining, used in a few mines. Shortwall mining involves the use of a continuous mining machine and movable roof supports to shear coal panels 150 to 200 feet wide and more than half a mile long. Although similar to longwall mining, shortwall mining is generally more flexible because of the smaller working area. Productivity is lower than with longwall mining because the coal is hauled by shuttle cars rather than by conveyor.

All underground coal mining is a complex undertaking requiring the miners to use not only special machinery to cut and remove coal, but also special techniques such as roof bolting to prevent the mine roof from collapsing. A number of safety procedures must be followed to comply with Federal and State health and safety regulations. Entries, or passage ways, consist of at least three parallel entries, so that if one is accidentally blocked, the others afford a means of escape. Multiple entries also provide adequate ventilation to carry away methane, other gases, and coal dust, with brattices and other stoppings used to direct the flow of air; they also are used to drain water from the mine.

Areas where underground mining has occurred are subject to subsidence when the mine roof collapses. Subsidence can affect buildings and other structures, and can also have hydrologic impacts, disrupting the flow of water on the surface and underground. Subsidence from longwall mining is generally more uniform and more predictable because it usually begins as coal extraction progresses. By contrast, subsidence due to room-and-pillar mining is difficult to predict because the supporting pillars deteriorate at some later time. The amount of subsidence from both types of mining depend on such factors as the depth of mining, the thickness of the coalbed extracted, and the thickness and strength of the overlying rock.

A coalbed can be surface mined when it is less than 200 feet deep. Surface mining, also called strip mining, is the least expensive mining method, and sometimes it is the only safe and efficient way of mining coal at shallow depths. Surface mining is also less restrictive than underground mining, because equipment can be easily moved, although heavy equipment requires stable ground. Coal-recovery rates at surface mines can exceed 90 percent.

Surface mining is essentially large-scale earthmoving that consists of excavating the overburden from the coalbed and then removing the coal. At some surface mines, mainly those in Appalachia, two or more coalbeds are mined during the same mining operation. The amount of overburden, or spoil, excavated per ton of coal recovered, called the *overburden ratio,* ranges from 1 to more than 30 cubic yards. The lower the overburden ratio, the more productive the mine. The lowest overburden ratios are generally in the West.

Area surface mining is practiced on flat ground and consists of a series of cuts 100 to 200 feet wide, with the overburden from one cut used to fill the mined-out area of the preceding cut (Figure 8). By comparison, *contour surface mining* follows a coalbed along hillsides. When contour mining becomes uneconomical, additional coal can be produced from the mine's highwall

Figure 8. Area Surface Mining with Dragline and Shovel

In area mining, long strips are excavated to uncover the coal. The overburden from the strip being mined is deposited in the strip previously mined.

Thick coalbeds that can be easily surface mined, such as this one in Wyoming, enable a mine to achieve a high rate of productivity.

by the use of augers to drill 100 feet or more into the bed, or by opening a small drift mine called a *punch mine. Open-pit mining* is used where thick coalbeds are steeply inclined, as in southwestern Wyoming and the anthracite area of Pennsylvania. An open-pit mine, which combines the techniques of contour mining and area mining, can reach depths of several hundred feet. The equipment used at surface mines includes dragline excavators, power shovels, hydraulic shovels, bulldozers, front-end loaders, and bucketwheel excavators.

Draglines remove overburden while power shovels and hydraulic shovels load coal. However, bulldozers and front-end loaders are often used to remove overburden in small mines; front-end loaders can also load coal. The few bucketwheel excavators in use operate in flat areas with soft overburden, such as in parts of the Midwest and Texas. Continuous surface mining machines equipped with rotating cutting heads and conveyors are used in some lignite mines.

In the anthracite area of Pennsylvania, surface mining includes the mining of culm and silt banks—waste accumulations of coal and rock from earlier mining operations that are now being used as fuel. Another form of surface mining in parts of Appalachia is dredging, which recovers coal that was dumped into rivers from early preparation plants or eroded from coal stockpiles or coalbeds beneath the rivers.

Because surface mining disturbs the land and can produce unsightly areas, surface mine operators are required to reclaim mined land by restoring natural vegetation and drainage. Properly reclaimed mining areas can be restored to a variety of uses, such as farmland, wildlife areas, or parkland.

Production

Coal has been mined commercially in the United States for more than 200 years, beginning in 1748 near Richmond, Virginia. Westward expansion across the country stimulated local demands for coal, so that by the beginning of the 20th century coal was being produced in most of the Nation's coalfields. The historical record of coal production reflects a record of industrial progress, competition from other fuels, coal miners' strikes, economic conditions, wars, environmental regulations, and health and safety laws.

Coal was produced in 26 States in 1993, with more than half of the total output (almost 1 billion tons) from three States: Wyoming, Kentucky, and West Virginia (Table 2). Although Wyoming was the leader in tonnage produced, Kentucky was the leader based on the energy content of the coal produced and on the value of production.

Table 2. The 10 Leading U.S. Coal-Producing States, 1993
(Million Short Tons)

States	Production	Percent of Total
Wyoming	210.1	22.2
Kentucky	156.3	16.5
West Virginia	130.5	13.8
Pennsylvania	59.7	6.3
Texas	54.6	5.8
Illinois	41.1	4.3
Virginia	39.3	4.1
Montana	35.9	3.8
North Dakota	32.0	3.4
Indiana	29.3	3.1
Total	**788.8**	**83.4**
U.S. Total	**945.4**	**100.0**

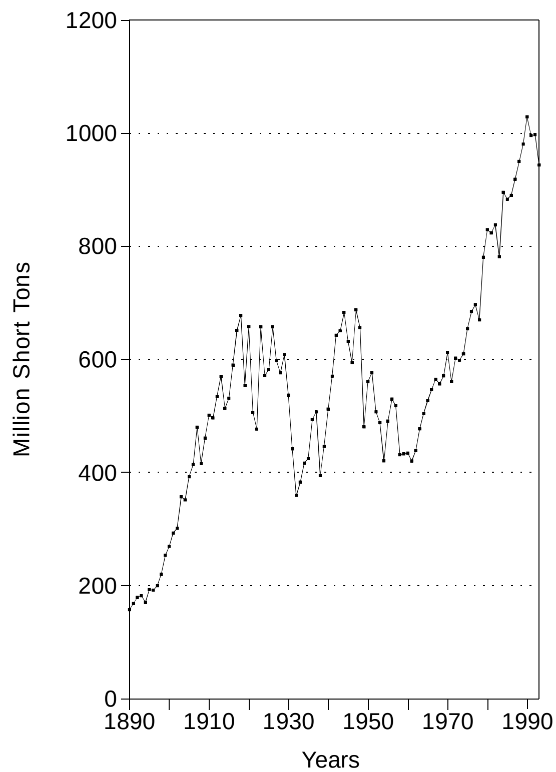
Source: Energy Information Administration, *Coal Industry Annual 1993*, DOE/EIA-0584(93) (Washington, DC, December 1994).

About 60 percent of the coal produced was bituminous coal, historically the predominant rank. Most of the balance was subbituminous coal and lignite, both of which have been produced in increasingly larger quantities since 1970 to satisfy the demand for utility coal. The share of total production from subbituminous coal has risen from 4 percent in 1970 to 29 percent in 1993, and that from lignite has risen from less than 2 percent to 9 percent. By contrast, anthracite production, which accounted for less than 1 percent of the 1993 total, has been declining for several decades because of competition from other fuels and difficult mining conditions, which keep the price of anthracite relatively high. Internationally, the 1993 U.S. coal output was estimated to rank second to China among the more than 50 coal-producing countries.

Historically, annual coal production, fueling industrial development, reached 200 million tons before 1900 (Figure 9). It then climbed to more than 600 million tons before declining during the Depression years. Production increased during World War II and peaked at nearly 700 million tons in 1947, before trending downward in the postwar years as coal markets were lost to low-cost oil and natural gas. Not only was oil easier and cleaner to handle, with low-cost oil imports supplementing the domestic supply, but long-distance pipelines were built to bring natural gas from the Southwest to eastern markets, where its convenience of use cut sharply into the market for coal for home heating and other uses. Coal was also confronted with another rival in the utility market—the development of nuclear generated electricity. Further hampering the use of utility coal was a growth in hydroelectric power. As the market for coal weakened, coal production dropped from more than 500 million tons in the 1950's to a little more than 400 million tons in the early 1960's, although it rose from time to time mostly because of increased exports.

In the 1970's, however, coal production once again rose. Following the Arab oil embargo, which disrupted the

Figure 9. U.S. Coal Production, 1890-1993



The trend of U.S. coal production reflects competition from other energy sources, economic conditions, strikes and wars. The rise since 1960 is due to increased use of coal to generate electricity.

Sources: Energy Information Administration, *State Coal Profiles*, DOE/EIA-0576 (Washington, DC, January 1994), and *Coal Industry Annual 1993*, DOE/EIA-0584(93) (Washington, DC, December 1994).

supply of foreign oil and sharply increased oil prices, interest was renewed in the largely unused domestic coal reserves as a way of reducing dependence on foreign oil. In addition, the enactment of clean air standards spurred the opening of large mines in the West to supply low-sulfur coal for electric utilities. As the coal market improved and new mines opened, coal production expanded to record levels, surpassing 800 million tons in 1980 and 1 billion tons in 1990, dropping only slightly since then. In the last two decades, the coal output from many States reached an all-time high (Table 3). The upward trend for coal production, despite several coal miners' strikes, was in notable contrast with the generally declining production trends (based on total Btu content) for domestic crude oil and natural gas. Cumulative U.S. coal production from 1890 through 1993 is about 58 billion tons (Table 4).

Table 3. Peak Year of U.S. Coal Production by State, Through 1993
(Thousand Short Tons)

State	Year	Production
Alabama	1990	29,030
Alaska	1988	1,745
Arizona	1991	13,203
Arkansas	1907	2,670
California	1880	237
Colorado	1993	21,886
Georgia	1903	417
Illinois	1918	89,291
Indiana	1984	37,555
Iowa	1917	8,966
Kansas	1918	7,562
Kentucky	1990	173,322
Louisiana	1992	3,240
Maryland	1907	5,533
Michigan	1907	2,036
Missouri	1984	6,733
Montana	1992	38,889
New Mexico	1993	28,268
North Carolina	1922	79
North Dakota	1993	31,973
Ohio	1970	55,351
Oklahoma	1978	6,070
Oregon	1904	112
Pennsylvania	1918	277,377
Anthracite	1917	99,612
Bituminous	1918	178,551
South Dakota	1941	71
Tennessee	1972	11,260
Texas	1990	55,755
Utah	1990	22,058
Virginia	1990	46,917
Washington	1992	5,251
West Virginia	1947	176,157
Wyoming	1993	210,129
U.S. Total	**1990**	**1,029,076**

Sources: U.S. Department of the Interior, Bureau of Mines, *Minerals Yearbook*, various issues, and Energy Information Administration, *Coal Production*, DOE/EIA-0118, various issues; and *Coal Industry Annual 1993*, DOE/EIA-0584(93) (Washington, DC, December 1994).

Table 4. Cumulative Coal Production by State, 1890-1993
(Billion Short Tons)

States	Production	Percent of Total
Pennsylvania	[a]15.3	26.3
West Virginia	10.8	18.5
Kentucky	7.1	12.2
Illinois	5.6	9.6
Ohio	3.5	6.0
Wyoming	2.9	5.0
Indiana	2.1	3.6
Virginia	2.0	3.5
Alabama	1.9	3.2
Other States	**7.1**	**12.2**
Total	**58.1**	**100.0**

[a]Includes 10.7 billion short tons of bituminous coal and 4.6 billion short tons of anthracite.

Source: U.S. Department of the Interior, Bureau of Mines, *Minerals Yearbook*, and Energy Information Administration, *Coal Production*, DOE/EIA-0118, various issues; and *Coal Industry Annual 1993*, DOE/EIA-0584(93) (Washington, DC, December 1994).

The high level of coal production was accompanied by shifts in both the geographic distribution of coal production and in the share of coal produced by surface mining. In 1970, most of the coal was mined east of the Mississippi River, principally from the Appalachian Region. By 1993, however, the share of production from eastern coal mines was only about 55 percent, while the rest was from western mines. Equally significant, surface mines gained a larger proportion of production, about 60 percent in 1993 as opposed to 44 percent in 1970, most of it in the West.

The major share of the additional coal production has been from leases on federally administered lands, principally Federal lands but also Indian lands. Coal production from Federal leases—the fastest-growing segment of U.S. coal production—has risen from 7 million tons in 1970, when it accounted for about 1 percent of the U.S. total, to 258 million tons in 1993, when it comprised 30 percent, due chiefly to highly productive leases in Wyoming. During the same period, the coal output from leases on Indian lands increased from 5 million to 28 million tons. Indian coal leases

Wyoming's Black Thunder surface mine, shown here, is the Nation's largest coal mine. Its 1993 output of 34 million short tons was more than the entire production of many States.

leases are on the tribal lands of the Navajo and Hopi in Arizona, the Navajo in New Mexico, and the Crow in Montana. They are administered by the U.S. Department of the Interior's Bureau of Indian Affairs. Coal sales from Federal coal leases generate substantial royalties ($265 million in 1993) that are distributed to the U.S. Department of the Treasury and to the States in which the leases are located. Royalties from Indian coal sales ($65 million) are disbursed to the tribal governments and Indian allotment owners.

The large amount of coal currently produced is from fewer but larger mines than in the past. The 1993 coal output, for example, was from about 2,500 mines, whereas in 1970 about 6,000 mines produced 40 percent less coal. The greater output from today's coal mines is due to advances in mechanization that brought continuous mining machines and longwall mining systems to underground mines and large-capacity power shovels, draglines, and coal-hauling equipment to surface mines. In 1970, mines with an annual output of more than 500,000 tons represented about 5 percent of the total number of mines and accounted for almost 60 percent of total coal production. By comparison, in 1993 this category of mines represented 14 percent of the total number, but supplied more than three-fourths of a considerably larger output. In addition, nearly 200 mines in 1993 produced at a level of 1 million tons or more, together accounting for two-thirds of the total coal mined. Of the 10 leading U.S. coal mines in 1993, 8 were surface mines in Wyoming. The largest surface coal mine was the Black Thunder, which was operated by ARCO Coal Company in Wyoming's Powder River Basin; it produced 34 million tons—more coal than was mined in 18 States. The largest underground coal production, 7 million tons, was from the Enlow Fork Mine of Consol Energy, Inc., in Pennsylvania.

Paralleling the trend of increasing mine size, coal-producing companies have also become larger. This has occurred because the mechanization of mines requires larger capital investments. Some small coal companies, lacking the financial resources to continue independently, have merged with other coal companies; however, many small mining companies have closed. In addition, some large coal consumers, such as electric utilities, have acquired interests in coal mining companies in order to secure long-term coal supplies. Some petroleum companies have expanded their interest in energy by acquiring shares in coal-producing companies.

Because the bigger coal companies generally operate a number of large mines, often in different States, they have gained a greater share of total production. In the mid-1950's, for example, the 10 largest coal companies produced about one-third of the Nation's coal output. In 1993, with production at a much greater level, the top 10 coal companies accounted for more than 40 percent of the output (Table 5). Although foreign companies have interests in U.S. companies, the coal industry is predominantly controlled by domestic companies. Currently the top three coal-producing companies are the Peabody Holding Company, which is controlled by Hanson PLC, a British firm; Cyprus Minerals, a U.S. company; and Consolidation Coal Company, which is affiliated with Du Pont / Rheinbraun AG, which represents U.S., Canadian, and German interests. In 1993, these three companies together were responsible for about one-fifth of the total U.S. coal output.

Table 5. The 10 Leading U.S. Coal-Producing Companies, 1993
(Million Short Tons)

Company	Production	Percent of Total Production
Peabody Holding Co., Inc.	69.7	7.4
Cyprus Minerals Co.	65.3	6.9
Consol Energy, Inc.	50.7	5.4
Zeigler Coal Holding Co.	37.5	4.0
ARCO Coal Co.	37.4	4.0
Kennecott Energy Co.	36.7	3.9
Exxon Coal USA Inc.	28.1	3.0
Texas Utilities Co.	27.6	2.9
Montana Power Co.	26.4	2.8
North American Coal Corp.	26.3	2.8
Total	**405.6**	**43.0**
U.S. Total	**945.4**	**100.0**

Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, *Coal Industry Annual 1993*, DOE/EIA-0584(93) (Washington, DC, December 1994).

Quality of Coal Production

If coal were a uniform product, it could be used with fewer problems. However, its composition varies significantly. Although characteristics such as fixed carbon, volatile matter, grindability, ash-fusion temperature, and coking ability have long been important in using and marketing coal, the heat value and the percentage of sulfur and ash, by weight, are of special interest. The heat value indicates how much energy is purchased per dollar. The sulfur content is an environmental concern because sulfur dioxide, a pollutant, is emitted when coal is burned. The ash content represents the incombustible material that can be emitted as particulate matter and also contributes to the erosion of boiler components.

The average heat value of coal is highest in the East, where virtually all of the coal is bituminous in rank, and relatively low for coal in the West, which has large deposits of subbituminous coal and lignite. Although annual coal production has increased, the total heat content of production has not risen at the same rate because of the greater amounts of low-rank coal mined for electric utilities. For example, in 1970, the average heat value of the 613 million tons of coal produced was 23.8 million Btu per ton, resulting in energy production of 14.6 quadrillion Btu. By comparison, the 1993 production was nearly 1 billion tons, more than 50 percent larger, but the energy value was 20.2 quadrillion Btu, only about 38 percent higher, because the average heat value of the coal declined to 21.4 million Btu per ton. For utility coal, the average heat content dropped from 22.6 million Btu per short ton in 1970 to 20.6 million Btu in 1993, whereas the estimated heat content of coking coal was relatively constant during the period, averaging 26.8 million Btu per short ton annually. Coal consumed by other industrial users declined slightly in heat value, from 23.0 million Btu per short ton in 1970 to 22.2 million Btu in 1993. The small amount of coal used by residential and commercial consumers fluctuated between an estimated 22.2 million and 23.7 million Btu per short ton during the period.

The average sulfur content of coal production, based on utility coal production, has been declining because of the larger amounts of low-sulfur coal from the West. Over the 1973-1993 period, the average sulfur content (by weight) of utility coal fell from 2.3 percent to 1.2 percent. Similarly, the average ash content (by weight) of utility coal also decreased over the period, dropping from 13.0 percent to 9.5 percent, due to the greater use of Wyoming utility coal, which has a relatively low ash content. Coal for industrial use in 1993 contained an average of 2.5 percent sulfur and 13.5 percent ash.

Coal Prices

In general, coal is the least expensive domestic fossil fuel produced, based on its heat content. Coal is about one-third as expensive as crude oil and nearly half as costly as natural gas. When adjusted for inflation, the average price of coal in 1993 (about $20 per ton) was about 44 percent lower than it was a decade earlier and less than half of the price in the mid 1970's. The highest price of coal in "real" dollars (adjusted for inflation and expressed in 1987 dollars) was $39 per ton in 1975, which amounted to $19 per short ton in current dollars and was the result of the oil embargo in 1973-74. The embargo caused a sharp rise in oil prices, and coal prices also rose mainly because producers expected a rapid and widespread switch from oil to coal. Coal prices reached $27 per ton in 1982 (real price of $32 per ton) before falling as the price of oil declined and the conversion from oil to coal slowed.

The price of coal varies by coal rank, mining method, geographic region, and coal quality. Surface-mined coal is generally lower-priced than underground-mined coal. Where coalbeds are thick and near the surface, as in Wyoming, mining costs and, therefore, coal prices tend to be lower than where the beds are thinner and deeper, as in Appalachia. The higher cost of coal from underground mines reflects the more difficult mining conditions and the need for more miners. Coals with a high heat content are generally higher priced. Low-sulfur coals can command a higher price than high-sulfur coals. The average price per ton of coal in 1993 was about $9 for subbituminous coal, $11 for lignite, $26 for bituminous coal, and $33 for anthracite.

Transportation costs add significantly to the delivered price of coal. In some cases, as in long-distance shipments of Wyoming coal, transportation costs can be more than the price of coal at the mine. The average delivered price of coal shipped to electric utilities, the major coal consumers, reached highs in the early 1980's of about $35 per ton (real price of about $39 per ton). Since then, the average delivered price of utility coal has generally declined, dropping in 1993 to about $29 per ton (real price of $24 per ton).

Employment, Productivity, and Earnings

The number of workers employed in the coal industry has declined so precipitously that the size of the coal mining labor force today is less than one-third the size it was a century ago—despite record levels of coal production. In contrast to a range of 400,000 to 800,000 workers employed in coal mining from 1900 to 1950, the number was around 100,000 in 1993. About 6,000 women were employed by the coal industry in production and other work. Before 1973, government records showed no women coal miners, reflecting biases and superstitions, such as the belief that women brought bad luck into the mine. By 1979, however, their ranks had grown to about 2,600, and in 1982, employment of women coal miners peaked at 11,600. The rise was spurred by the 1964 Civil Rights Act, a 1965 Executive order barring discrimination in employment and requiring affirmative action plans for businesses receiving Federal contracts, and a 1978 U.S. Department of Labor training program for women who wanted to begin coal-mining careers.

The drop in the size of the total coal mining workforce has been due to the replacement of manual labor by machines in virtually every phase of mining. At underground mines, the improvement of equipment and the introduction of remote-controlled mining and roof-bolting and other innovations have reduced crew sizes while improving safety and productivity. At surface mines, operations have speeded up and the number of employees has dropped through the use of larger and faster excavating and transporting equipment and improved blasting techniques. At both types of mines, computers have become an integral part of mine planning and operations and are also having a positive influence on productivity.

The greatest loss of miners has been in the coalfields in Appalachia, where the number has been reduced by more than half since 1980, falling from 171,000 to 71,000 in 1993. Nevertheless, Appalachia continues to be the center of the U.S. coal mining workforce, with about 7 out of every 10 U.S. coal miners in 1993. Nearly half of the coal miners worked in Kentucky and West Virginia (Table 6).

Table 6. The 10 Leading States in U.S. Coal Mine Employment, 1993

State	Average Number of Miners	Percent of Total
Kentucky	24,063	23.7
West Virginia	22,979	22.7
Pennsylvania	10,940	10.8
Virginia	8,339	8.2
Illinois	7,303	7.2
Alabama	5,399	5.3
Ohio	3,866	3.8
Indiana	3,331	3.3
Wyoming	3,159	3.1
Texas	1,841	1.8
Total	**91,220**	**90.0**
U.S. Total	**101,322**	**100.0**

Note: Average number working daily. Includes employees engaged in production, preparation, processing, development, maintenance, repair, shop or yard work at mining operations. Excludes office workers and mines producing less than 10,000 short tons of coal during the year and preparation plants with less than 5,000 employee hours.

Source: Energy Information Administration, *Coal Industry Annual 1993*, DOE/EIA-0584(93) (Washington, DC, December 1994).

About 100,000 coal miners were employed in 1993. On average, they produced 5 short tons of coal per hour, earning $17 per hour.

Although coal mine employment has fallen, overall productivity in the U.S. coal industry has reached record levels. Productivity in 1993 was nearly 5 tons per miner per hour, almost six times higher than in 1950, due mostly to a higher rate at surface mines. Productivity at surface mines has consistently been higher than at underground mines, primarily because fewer workers are required. Productivity rose from about 2 tons per miner hour in the 1950's to a peak of nearly 5 tons per miner hour in 1974, dropped to about 3 tons in 1978, and since then steadily grew to 7 tons in 1993. The decline in 1978 was due to several factors. One was the opening of smaller, less efficient mines (often worked by younger, inexperienced miners) in response to rising coal prices due to the oil embargo in the early 1970's. Many of these mines later closed when the price of coal dropped and mining became uneconomical. Another factor that initially depressed surface mining productivity was the enactment of the Federal Surface Mining and Reclamation Act of 1977 and State reclamation laws, which require restoration of mined land, thereby diverting some employees and equipment from production activities. Factors that have been significant in raising the average productivity at surface mines are increases in the size and power of surface mining equipment and the large-scale mining of very thick coalbeds in the West.

In underground mines, improvements in productivity have been less dramatic. As recently as the early 1950's, underground miners averaged less than 1 ton per hour. The rate approached 2 tons per hour when the Federal Coal Mine Health and Safety Act of 1969 imposed many new safety regulations (such as the need to stop work between coal cuts to install roof supports). These initially hampered underground productivity, which fell to a low point of about 1 ton per miner hour in 1978. However, the regulations became less of a constraint as miners learned to adapt to the changes without compromising safety. As with surface mines, productivity was also hampered by the opening of many small, less efficient mines in response to rising coal prices and rising demand due to the oil embargo, mines that later became uneconomical and closed. Also taking their toll on productivity in the 1970's were several major coal miners' strikes by the United Mine Workers of America. However, by 1993 underground productivity reached nearly 3 tons per miner hour, reflecting the greater use of continuous-mining machines and longwall mining.

Coal miners, in general, are the highest paid workers in the mining industry, including oil and gas extraction; their wages are above the average paid in the steel, automobile, and chemical industries, according to the U.S. Department of Labor. In 1993, coal mine production workers averaged $765.90 per week (in current dollars), or $17.25 per hour, working an average of 44.4 hours. A decade earlier they earned $547.83 per week (current dollars), or $13.73 per hour, for 39.9 hours.

Health and Safety

Coal mining, particularly underground coal mining, historically has been a dangerous occupation, but the risk has been reduced dramatically. In recent years, the injury incidence rate for coal mining has been generally below that in many sectors of the construction and manufacturing industries, according to the U.S. Bureau of Labor Statistics.

The Federal Government has been involved in mine safety since 1910, when Congress established the Bureau of Mines as a research and fact-finding agency on coal mining. In 1941, Congress authorized Federal inspection—but not regulation—of coal mines. After 119 miners were killed in a coal mine explosion in West Frankfort, Illinois, in 1951, Congress enacted the Federal Coal Mine Safety Act of 1952, which increased the Bureau's inspection authority and empowered it to close underground mines engaged in interstate commerce that did not follow mandatory safety standards for underground coal mines; surface mines and underground mines operations employing fewer than 15 workers were exempted. The Federal Coal Mine Health and Safety Act of 1969 vastly increased the Government's enforcement powers by covering virtually every aspect of coal mining and by mandating fines for violations, authorizing criminal penalties for intentional violations, and enabling miners to request safety inspections. In addition to imposing mandatory safety training, the new law requires coal-mine operators to have plans for ventilation, roof support, and emergency evacuation approved by the Mining Enforcement and Safety Administration (MESA). MESA was created in 1973 in the U.S. Department of the Interior to handle mine inspections previously performed by the Bureau of Mines. It is the predecessor of today's Mine Safety and Health Administration (MSHA), formed in 1978 as part of the U.S. Department of Labor. MSHA is required to inspect underground coal mines four times per year and surface coal mines two times per year. It has the authority to issue citations and stop mining operations when conditions are dangerous.

As a result of more stringent safety regulations, mechanization, and roof bolting, the record for mine safety has greatly improved. In 1993, coal mining claimed 47 lives. In the 1980's, an average of 79 coal miners lost their lives each year, whereas in the 1970's, the toll averaged 129. The worst year in the history of coal mining was 1907, when 3,242 miners perished.

Explosions of coalbed methane and coal dust, which are ignited by a flame or spark, cause the major coal mine disasters and claim the greatest number of lives where coal is mined underground. In the United States, the first reported coal mine explosion occurred around 1810 near Richmond, Virginia. The worst U.S. coal mine disaster, taking the lives of 362 miners, was due to an explosion at Monongah, West Virginia, in December 1907. Mine safety regulations and practices have markedly reduced the danger of explosions by requiring sufficient mine ventilation to prevent the accumulation of high levels of methane and coal dust in the mine atmosphere. Coal dust is also controlled by making it noncombustible through the use of watersprays and by "rockdusting" mine areas with pulverized limestone or similar noncombustible material. Other safety measures include the use of explosives and electrical equipment that have passed certain safety tests and are formally approved as "permissible" by MSHA.

Historically, winter is the most hazardous time for coal mine explosions. From October through March, MSHA notifies underground coal miners of a "Winter Alert," warning them that methane and coal dust explosions are more likely to occur during this period than at any other time of the year. Hazards increase because dry winter air entering a mine becomes warm and absorbs moisture from the mine workings. As the mine "dries out," more coal dust becomes suspended in the mine air, increasing the risk of ignition. In addition, a sudden drop of barometric pressure causes methane to expand and flow from inactive areas of the mine to areas where the miners are working.

Mining research includes the development of technology that will enable a miner to be located in a safe place while using a computer to control a mining machine.

Although explosions are responsible for the most dramatic disasters in underground coal mines, roof falls historically have been the single most frequent cause of fatal accidents in U.S. coal mines. Roof falls occur when part of the mine roof or rib (side) breaks away. Usually this occurs within 25 feet of the working face, before the area is permanently supported. More roof fall fatalities occur with the room-and-pillar mining method than with longwall mining. Fatalities at surface mines are largely caused by falls of rock from the side of the mine and accidents involving machinery. Haulage-related accidents generally rank second as the cause of coal mine fatalities.

Apart from accidents, coal miners also face the danger of contracting coal workers pneumoconiosis, or “black lung,” the consequence of breathing and retaining too much coal dust. When coal dust collects in the small passages leading to air spaces in the lungs, the lung tissues react with the dust to form masses of dense fibrous tissue. Black lung, a progressive disease, causes difficulty in breathing and persistent coughing, and can put a fatal strain on the heart. Miners with the disease are eligible for disability under the Federal Black Lung Benefits Act of 1977 and its amendments, a program funded through taxes paid on coal production at a rate of $1.10 per ton for underground mines and 55 cents per ton for surface mines. However, most of the Black Lung claims filed before 1973 are administered through the Social Security Administration.

Coal Miners’ Unions and Strikes

The United Mine Workers of America (UMWA) ranks first among about 40 labor unions that represent U.S. coal miners. Formed in 1890, the UMWA has been the leading coal miners union and has been in the forefront as a collective bargaining organization representing coal miners. It is the major union in the coalfields in the East. UMWA coal miners currently account for about 40 percent of the U.S. coal mining workforce and produce about one-fourth of the total coal output. Other unions represent 4 percent of the coal miners and account for a 9-percent share of production. By contrast, nonunion workers compose about 55 percent of the coal mining workforce and account for about two-thirds of U.S. coal production.

Major coal miners' strikes—those creating a significant disruption on coal supplies—are generally precipitated when a contract expires and no agreement is reached between the UMWA and the Bituminous Coal Operators Association (BCOA) over the terms of a new contract. The principal bargaining issues focus on wage and fringe benefits, including health and retirement benefits. Contract agreements between the UMWA and the BCOA traditionally set the pattern for contracts between smaller unions representing coal miners and other mining companies or associations that do not belong to the BCOA, such as the Independent Bituminous Coal Bargaining Alliance. Overall production is usually not significantly affected by the small "wildcat" strikes that occur locally from time to time, usually over miners' grievances and local issues.

During a major strike, nonunion mines may also be idled by pickets or by miners walking out in "sympathy" strikes. Generally, strikes by the UMWA are most significant at underground mines in Appalachia, the center of UMWA membership. Before 1984, major coal miners' strikes were generally nationwide. Since then, the UMWA's tactic has been to call selective strikes against one or more companies. The striking miners are supported through UMWA payroll assessments into a selective strike fund.

The early history of the coal industry often featured long strikes, commonly over needed reforms. In 1922, anthracite miners in Pennsylvania went on strike for 160 days and bituminous coal miners for 140 days. The Nation's longest coal miners' strike—166 days in the anthracite region—was in the fall and winter of 1925-26, before the Taft-Hartley Act for ending strikes was enacted. In 1949-1950, a coal miners' strike lasted 116 days, although the miners went back to work several times during that period. Since 1960, major coal miners' strikes have occurred in 1966 (16 days), 1968 (13 days), 1971 (44 days), 1974 (28 days), 1977-78 (111 days), and 1981 (72 days). In October 1984, a nationwide strike was averted for the first time in 20 years with the signing of a new UMWA-BCOA contract extending through January 1988, and in early February 1988 another new agreement was ratified without striking. The new contract was for 5 years, whereas past contracts usually lasted about 3 years.

From April 1989 through most of February 1990, a UMWA strike against the Pittston Coal Company, with which it was negotiating a separate contract, affected the company's mines in Virginia, West Virginia, and Kentucky before a 4 1/2-year agreement was reached. At issue were job security and health and retirement benefits. In 1993, unsuccessful contract negotiations between the UMWA and the BCOA led to a series of selective strikes that idled more than 16,000 miners in seven States in Appalachia. The first selective strikes were against the operations of Peabody Holding Company, the Nation's top producer, and Eastern Associated Coal Corporation. The strikes lasted from February 2 to March 3 and ended when the negotiators agreed to extend the contract for 60 days. Failing to reach an agreement at the end of the period, the union expanded its selective strikes to include large mines operated by other companies. This new series of strikes lasted from May 10 until December 14, 1993, when an agreement was reached that will remain in effect through August 1, 1998. In addition to increasing wages and pensions, the new agreement provides for 60 percent of new job openings to be filled by UMWA workers, increases health care benefits, and gives the company the right to establish 7-day work schedules. In a separate collective bargaining agreement signed June 20, 1994, the UMWA and the Pittston Coal Company concluded a new labor pact in June 1994 that extends through 1998.

Preparation

Most of the coal produced in the United States undergoes some degree of processing, or preparation, to make it a more marketable product. The amount of preparation required depends on the customer's specifications. Some coal is blended at the mine where, for example, high-sulfur coal from one area can be mixed with low-sulfur coal from another to produce a medium-sulfur coal that is acceptable to a consumer. Roughly half of the bituminous coal currently mined is sent to preparation (or processing) plants for some form of coal cleaning. About two-thirds of the bituminous coal mined in the East for electric power plants is cleaned, whereas the subbituminous coal and lignite shipped from western mines to electric utilities is generally only crushed and screened to facilitate handling and to remove extraneous material introduced during mining. Nearly all of the coal used to make coke for steelmaking undergoes a high level of cleaning.

Cleaning upgrades the quality and heating value of coal by removing or reducing the amount of pyritic sulfur, *Coal quality is upgraded in a preparation plant. This plant in western Maryland can process 1,500 short tons of coal per hour.*

rock, clay, and other ash-producing material. Cleaning also removes materials that becomes mixed with the coal during mining, such as wire and wood. Conventional cleaning methods generally remove up to one-third of the inorganic (pyritic) sulfur in coal, but none of the organic sulfur. Currently, commercial technology is not available for reducing the levels of the alkali metals sodium and potassium. In general, about 30 tons of refuse are removed from every 100 tons of raw (as-mined) coal that is cleaned.

Coal cleaning is based on the principle that coal is lighter than the rock and other impurities mixed or embedded in it. The impurities are separated by various mechanical devices using pulsating water currents and rapidly spinning water. The large buoyancy difference between coal's combustible matter and its mineral impurities is exploited efficiently with the use of liquids of different densities in dense-medium systems, which are used in about two-thirds of the plants. The finely powdered coal (coal fines) produced during mining, handling, and crushing operations is usable but difficult to clean and handle. Finely sized coal is cleaned by froth flotation, a relatively high-cost chemical/physical process in which the coal adheres to air bubbles in a reagent and floats to the top of the washing device while the refuse sinks to the bottom. About 40 percent of the U.S. coal cleaning capacity consists of plants that use froth flotation to recover coal fines. The remaining plants either discard the coal fines as refuse or mix uncleaned coal fines with the cleaned coal for shipment to customers. Oil agglomeration has been used to a limited extent to clean ultra fine coal. The oil clings to the coal surface, causing it to agglomerate while other refuse particles remain suspended and are removed.

Coal cleaning consists of the following basic steps involving physical preparation and physical cleaning: (1) crushing, grinding and / or breaking, to prepare the coal for the washing process; (2) sizing, to separate coal into different dimensions, both to match the specifications for the various cleaning devices and to meet market requirements; (3) washing, to remove ash and sulfur components from coal; (4) dewatering and drying, to remove excess moisture and prepare the cleaned coal for shipment and also to increase its heat value (Figure 10). Cleaned coal of different sizes and properties can be blended at the plant to meet consumer requirements.

Figure 10. Basic Flow of Coal Through a Preparation Plant

Coal preparation reduces the amount of impurities (sulfur and ash-producing minerals) and improves the heating value; coals with different characteristics can be blended to meet certain specifications.

There were 270 coal preparation plants operating in the United States in 1993, according to *Coal* magazine. Varying widely in levels of complexity, the plants had capacities ranging from 40 tons to 3,200 tons per hour. Most of the plants were in the East, with those in West Virginia and Pennsylvania accounting for nearly half of the U.S. total. The largest preparation plant was the Bailey plant of Consol Pennsylvania Coal Company in Graysville. Preparation plants in the bituminous coal region are sometimes called “tipples,” because in the past coal cars were “tippled,” or dumped, into the top of the plant; today, transfer is accomplished by conveyor. In the anthracite region, preparation plants are often called “breakers,” a name originating in the fact that anthracite, a relatively hard coal, is broken and sized in the plant.

Transportation

The coal industry depends heavily on the transportation network for delivering coal to customers across the country. The flow of coal is carried by railroads, barges, ships, trucks, conveyors, and a slurry pipeline. Coal deliveries are usually handled by a combination of transportation modes before finally reaching the consumer. The methods of transportation and the shipping distance greatly influence the total cost of coal to the consumer. For some western coals shipped over a great distance, the freight cost may represent three-fourths of the delivered cost of coal.

Railroads are the foundation of the coal distribution system, annually handling about 60 percent of the coal shipped to domestic customers. Just as railroads are important to the coal industry, coal shipments, in turn, are the leading source of freight and revenue for the railroad industry. In 1993, coal constituted nearly 40 percent of railroad freight tonnage and provided over $6 billion in revenue, generating about 21 cents out of every dollar of freight revenue earned, according to the Association of American Railroads.

Since 1970, railroads have accounted for a steadily larger share of coal shipments from the West (increasing from 61 percent to nearly 70 percent of the total in 1993), reflecting a greater demand for low-sulfur western coal as well as improvements in the area’s rail transportation system, particularly in Wyoming. Over the same period, railroads handled an average of 55 percent of Appalachia’s coal shipments. Rail’s share of coal shipments in the interior region dropped from 51 percent to 45 percent, due mainly to a fall in the demand for the region’s high-sulfur coal to produce electricity and for its coking coal. Currently, the three leading States in which domestic coal shipments originate by rail are Wyoming (35 percent of U.S. rail shipments in 1993), Kentucky (18 percent), and West Virginia (10 percent). The largest coal-carrying railroads are CSX Transportation Incorporated, Burlington Northern Railroad Company, and Norfolk Southern Corporation, which together handle over three-fourths of all U.S. coal shipped by rail.

Unit trains account for more than half of railroad coal shipments. Unlike a conventional coal train or a mixed freight train carrying individual carloads of coal, a unit coal train carries coal from a specified loading facility straight through to a specified customer without stopping. It uses dedicated equipment, whereas other trains carrying coal generally draw the equipment needed from the railroad’s operating pool of locomotives and cars. Sometimes termed “the train with a one-track mind,” a unit coal train operates on a predetermined schedule, following the most direct route and providing high productivity and low shipping rates. Comprising as many as four or five locomotives and 100 to 110 cars, a unit coal train is over a mile long. It can be loaded with 10,000 to 11,000 tons of coal in 2.5 to 3 hours and unloaded in 4 to 5 hours. In some States, unit coal train traffic can be heavy. In Wyoming, the leading coal-producing State, about 40 unit coal trains left the State daily in 1990 while a like number returned for reloading, according to the Wyoming State Geological Survey.

Two types of railroad cars are used for transporting coal, the gondola and the hopper. Gondola cars have flat bottoms, straight sides, and open tops and are unloaded by being tipped over by rotary dumpers. Hopper cars have sloping bottoms with gates that open to discharge the coal. Today’s rail cars hold an average of about 96 tons, nearly 20 percent more than in the early 1970’s and almost double the capacity of railroad cars in the 1930’s. Cars used for eastern coal are slightly smaller than those for western coal, the difference reflecting the density of the coal carried. Eastern coal is denser than western coal and so the equipment designed to haul it has a smaller capacity. Most cars are made of steel, but a large number of aluminum-bodied cars are also used. Lighter in weight, aluminum cars offer a savings in transportation costs because they can carry 5 to 10 tons more than steel cars without exceeding track weight limitations. On the return trip, the lighter cars also result in fuels savings.

Waterborne shipments rank next to railroads in coal shipments, accounting for nearly 2 out of every 10 tons of coal shipped annually to domestic markets. However, the proportion of total domestic coal

The unit coal train is the symbol of coal transportation. Railroads are the foundation of the coal distribution system. Conversely, coal is the leading source of railroad freight and revenue.

shipments moved by water has declined from 29 percent in 1970 to about 17 percent in recent years, reflecting in part the shift of coal production away from the Northeast and Midwest, the regions with the greatest use of water transportation. Kentucky and West Virginia are the leaders in water transport of coal, together accounting for a little more than half of the total in recent years. Coal's approximate share of total domestic shipments of major commodities by type of waterway in 1991, according to the U.S. Army Corps of Engineers, was as follows: coastal, 5 percent; Great Lakes, 17 percent; and inland waterways, 30 percent.

Barges and ships move coal on rivers, the Great Lakes, and tidewater areas. The major inland waterways for coal traffic are the Mississippi, Ohio, and Black Warrior-Tombigbee rivers. Towboats plying these waters typically push 15 to 20 barges loaded with 20,000 to 30,000 tons of coal. The amount of coal shipped in a single tow (a string of barges) is determined by the lock size on the waters navigated. Large tows can be handled in the deeper waters of the lower Mississippi River. On the Great Lakes, domestic coal traffic generally ranks second to iron ore. Shipments are typically made by lake carriers, which are about 700 feet long and 70 feet wide and hold about 20,000 tons of coal. Several lake carriers are about 1,000 feet long and have about three times more capacity. The most extensive coal traffic on the lakes is to destinations in the north and west. Lake carriers sailing south generally contain iron ore or grain. Shipping on the Great Lakes usually is immobilized by ice from mid-December through mid-March. Some coal deliveries from eastern ports to power plants in Massachusetts are carried by a coal-burning collier, *Energy Independence*, placed in service in 1983.

Coal deliveries by truck account for about 1 out of every 10 tons of coal shipped. The level of coal transportation by truck has not varied significantly in the past two decades. Although the use of trucks for hauling coal is widespread, it is very important in a number of States, including Alabama, Indiana, Pennsylvania, Texas, and Utah. Trucks are used for short hauls, generally of less than 50 miles. Frequently, coal transported by rail or barge is first trucked to the loading dock or transferred by truck at some point. In some areas, such as parts of the Appalachian Region, trucks are the only economical way to transport coal. Individual coal shipments by truck are relatively small. Three-axle dump trucks hold about 20 tons; tractor-trailers carry up to 35 tons. The maximum load a truck can carry on highways is limited by State regulations.

Aerial tramways, conveyors, and a coal slurry pipeline together account for about the same amount of coal deliveries as trucks. The percentage of coal shipped by this transportation category has increased from about 4 percent in 1970 to about 13 percent in recent years. This growth was partly due to the rapid growth of coal production in the West, where conveyors are often used to deliver coal directly from mines to nearby power plants.

Aerial tramways cover relatively short distances, but conveyors usually are many miles long, commonly linking mines with power plants. The Nation's only coal slurry pipeline is the Black Mesa line. Spanning 273 miles, this pipeline is 18 inches in diameter and connects a coal mine in northern Arizona to a power plant in southern Nevada. It carries about 4.5 million tons of coal annually in a slurry composed equally of finely ground coal and water, the journey from mine to plant taking about 3 days. About 1 billion gallons of groundwater are used annually. There are 9.7 million gallons of water and 45,000 tons of coal in the pipeline at any one time. The Black Mesa coal slurry pipeline began operations in 1970, about 7 years after the closing of the Nation's first long-distance coal slurry pipeline, the Eastlake, which carried coal from Cadiz, Ohio, to a power plant east of Cleveland.

Supply and Stocks

In recent years the supply of coal from U.S. mines has averaged about 19 million tons per week. This is more than enough to provide the fuel required to generate electricity for a metropolitan area the size of New York City for about a year. The weekly supply of coal from the mines varies considerably. Sharp rises occur in response to increased demand, including increased use of coal-fired electricity generation to offset declines in generation from other sources. These declines occur, for example, when nuclear power generation drops because of scheduled maintenance, when hydroelectric generation falls during periods of low water, or when coal stockpiles are built up in anticipation of a coal miners' strike.

Downward swings in weekly coal production and supply usually are caused by miners' vacations and holidays. Strikes by coal miners and workers involved with coal shipments can sharply curtail the supply of coal from the mines. Delays in delivering railroad cars to the mines can result in a drop in coal shipments. Freezing temperatures can hamper the unloading of railroad cars. Although coal shipped by rail in winter is generally treated with freeze-control agents, this protective treatment can be washed away and the coal can freeze solid in the railroad cars. Coal frozen in railroad cars is thawed in heated sheds and/or mechanically broken into pieces of manageable size. Heavy rains and flooding can also impede mining operations and coal shipments. For instance, from June through August 1993, severe flooding along the upper Mississippi and Missouri river basins disrupted coal deliveries to power plants in about nine Midwest States and to power plants in States beyond that area, because trains were delayed or rerouted around the flooded region.

As insurance against a disruption in deliveries, large coal consumers generally maintain a 45- to 60-day stockpile of coal. Large quantities of coal are generally stored in open stockpiles on the ground, piled in diverse forms, such as cones, blocks, and rows. Coal is also stored in covered ground storage—in bins, bunkers, and silos.

Year-end coal stocks since 1990 have averaged nearly 190 million tons, equivalent to about one-fifth of the average annual coal consumption. More than 80 percent of the stockpiled coal was at electric power plants.

Use

Coal is used in all 50 States and the District of Columbia. In 1993, 10 States accounted for about half of the total coal consumed (Table 7). Of these, Texas, Indiana, Ohio, and Pennsylvania consumed the largest amounts, with a combined share of 29 percent of the tonnage. However, based on the estimated energy content of the coal consumed, the ranking was as follows: Ohio, Pennsylvania, Texas, and Indiana.

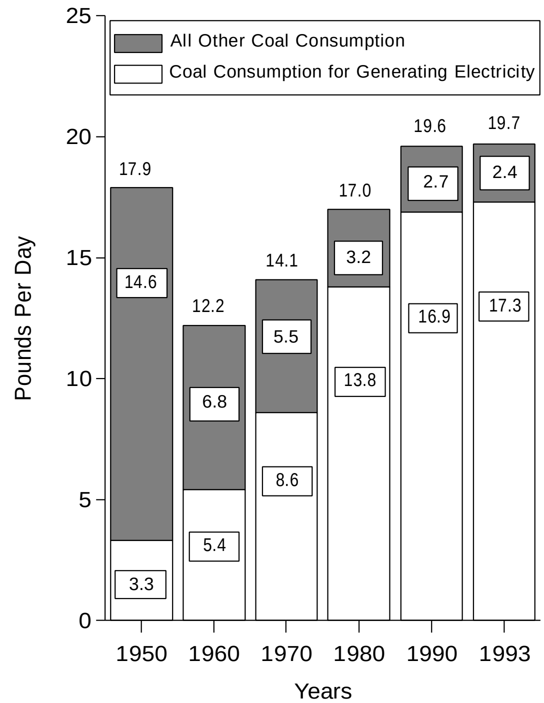
The use of coal in the United States has risen almost steadily since the early 1970's, reaching record levels and totaling 926 million tons in 1993. On a per capita basis, coal consumption in 1993 was nearly 20 pounds per person per day, which continued an upward trend

Table 7. The 10 Leading U.S. Coal-Consuming States, 1993
(Million Short Tons)

State	Consumption	Percent of Total
Texas	96.8	10.5
Indiana	60.4	6.5
Ohio	59.0	6.3
Pennsylvania	56.2	6.1
Kentucky	39.1	4.2
Illinois	38.1	4.1
Alabama	33.0	3.6
Michigan	32.2	3.5
West Virginia	32.0	3.5
North Dakota	30.3	3.3
Total	**477.2**	**51.4**
U.S. Total	**925.9**	**100.0**

Note: Total does not equal sum of components because of independent rounding.
Source: Energy Information Administration, *Quarterly Coal Report October-December 1993,* DOE/EIA-0121(93/4Q) (Washington, DC, May 1994); and *Quarterly Coal Report January-March 1994*, DOE/EIA-0121(94/1Q) (Washington, DC, August 1994).

Figure 11. U.S. Daily Per Capita Coal Consumption, 1950-1993



U.S. daily per capita coal consumption has risen since the 1960's due chiefly to an increase in the amount of coal used for generating electricity.

Source: Bureau of Mines, U.S. Department of Interior, "Mineral Yearbook," various issues; Energy Information Administration, "Quarterly Coal Report," DOE/EIA-0121, various issues; and Bureau of the Census, U.S. Department of Commerce, "Statistical Abstracts of the United States," various issues.

that began in the 1960's (Figure 11). Virtually all of the growth has been due to the increasing amounts of coal used to generate electricity.

The upward trend in coal consumption was spurred by the Arab oil embargo in the first half of the 1970's, which caused substantial price increases for petroleum, and by a natural gas shortage in the second half of the 1970's. As a result, the share of total U.S. energy consumption supplied by coal has increased significantly. At the time of the Arab oil embargo, coal accounted for 17 percent of U.S. energy consumption. In 1993 its share was 23 percent. Historically, however, this is a markedly smaller proportion than in the early 1900's, when coal supplied nearly all of the U.S. energy needs, or 1940, when it supplied about half.

In recent years, the increase in energy supplied by coal has not matched the increase in coal tonnage. For example, the amount of coal consumed increased by 32 percent from 1980 through 1993, but the energy derived from the coal in 1993 was only 26 percent higher than in 1980. The difference is due to the greater use of subbituminous coal and lignite, which are mined in the West. Both have a relatively low heat content as compared with bituminous coal, which held a larger share of consumption in earlier years.

More than 8 out of every 10 tons of the coal used in the United States are for electricity generation, the most important market for coal since the 1950's. The coal is used to produce high-pressure steam for driving an electrical generator (Figure 12). Due to the cost advantage that coal offers over oil and gas, the amount of coal used by utilities annually has trended upwards. Although electricity generated from nuclear power increased in the 1970's and 1980's, at the expense of petroleum and gas, coal's contribution was on an upward trend, generally keeping pace with the growing demand for electricity. Part of the reason for the rise was the Powerplant and Industrial Fuel Act of 1978. The law prohibited the use of oil or gas in most new large boilers and compelled utilities to convert many

Figure 12. Schematic of a Coal-Fired Power Plant

Most coal-fired power plants burn pulverized coal to produce high-pressure steam. The steam, in turn, runs a turbine that drives an electric generator. Most of the coal ash is carried in flue gas as fly ash and removed chiefly by electrostatic precipitators, but fabric filters are also used. Plants with scrubbers remove over 90 percent of the sulfur dioxide in the flue gases. About one-third of the energy released during coal combustion is converted into electricity.

existing oil- and gas-fired boilers to coal. The law was amended in 1978 to repeal restrictions on the use of oil or gas in new baseload power plants if they were designed to permit future conversion to coal, but the later regulations became redundant because rapidly rising petroleum prices and natural gas shortages in the 1970's gave coal the economic advantage.

Utility coal consumption has risen from less than 400 million tons per year during the early 1970's to more than 800 million tons in 1993. The electricity generated from coal has increased from 704 billion kilowatthours in 1970, when it accounted for 46 percent of the total, to a record 1,580 billion kilowatthours in 1993, when its share was 57 percent. By comparison, of the total electricity generated in 1993, nuclear power supplied 21 percent; natural gas and hydropower, 9 percent each; petroleum, 3 percent; and geothermal and other sources, 1 percent.

In addition to the electricity produced by utility companies, a small amount of electricity is generated by nonutility power producers, chiefly industrial plants that produce it for their own use. In 1993, coal-fired generation in this sector totaled about 43 billion kilowatthours.

Most of the coal used to generate electricity is burned in pulverized-coal-fired boilers. Pulverized-coal firing, introduced in the electric utility industry in the early 1920's, is a major improvement over other methods of coal combustion because it permits the use of larger, more efficient boilers. Pulverized coal, which is ground as fine as flour, is blown into the furnace and ignited instantly to burn in suspension. The most common pulverized-coal boilers are classified as having a "dry bottom" because the coal ash does not reach fusion temperature. About 80 percent of the coal ash produced is carried in the flue gases as fly ash, while only 20 percent of the ash settles to the bottom of the furnace. This type of unit operates most efficiently with coals that have an ash fusion temperature that is above the furnace temperature, so that slag (molten ash) does not form. A "wet bottom furnace" is designed so that ash fuses to form slag. The coal ash produced consists of approximately half fly ash and half bottom ash, which is drawn off as slag.

A smaller amount of utility coal is used in stoker furnaces, which are supplied with crushed coal on a moving grate; and in cyclone furnaces, which burn crushed coal carried in a whirling stream of air. A few generating plants use fluidized-bed combustion, a technique for burning crushed coal (often of low quality) in a bed that behaves like a boiling fluid as currents of high-velocity air flows through it.

Currently, U.S. coal-fired power plants produce about 90 million tons of combustion byproducts in the form of fly ash, bottom ash, boiler slag, and flue-gas desulfurization material. About one-fourth of these byproducts are used in various ways, such as in cement and concrete production and as roadbase materials; the rest is disposed of in surface impoundments, landfills, and waste piles.

Nearly 500 of the 3,000 power plants in the United States use coal. In 1993, these coal-burning plants were located in 44 States. Eight of the States relied on coal for over three-fourths of their generating capability. Another 14 States depended on coal for 50 to 75 percent of their electricity generation. The five leading States generating electricity from coal were Ohio, Texas, Pennsylvania, Indiana, and Kentucky. The largest U.S. coal-fired power plants are the Scherer plant (3.3 million kilowatts of summer generating capability) and the Bowen plant (3.2 million kilowatts) of Georgia Power Company; the Gibson plant (3.1 million kilowatts) of PSI Energy, Inc., in Indiana; and the Monroe plant (3.0 million kilowatts) of Detroit Edison Company, in Michigan. Each of these power plants can generate enough electricity for a city with a population of over 1 million. Large power plants consume coal at rates of more than 20,000 tons per day, the amount of coal held by about 200 railroad cars. Some power plants are minemouth plants, constructed near one or more mines that provide a convenient source of coal. In general, each ton of coal consumed at a power plant generates about 2,000 kilowatt hours of electricity. A pound of coal supplies enough electricity to light ten 100-watt bulbs for about an hour.

Another use of coal is to make coke for the iron and steel industry, foundries, and other industries. The presence of large domestic deposits of coking coal, or metallurgical coal, played an important role in the development of the U.S. iron and steel industry. Coke is used chiefly to smelt iron ore and other iron-bearing materials in blast furnaces, acting both as a source of heat and as a chemical reducing agent, to produce pig iron, or hot metal (Figure 13). About 1,100 pounds of coke are consumed for every ton of pig iron produced. Foundries use coke as a source of heat for producing metal castings. Other industrial uses of coke include the smelting of phosphate rock to produce elemental phosphorous and the production of calcium carbide. Small sizes of coke, termed breeze, are used as fuel in sintering finely sized particles of iron ore and other iron-bearing material to produce an agglomerate that can be used in a blast furnace.

Figure 13. Using Coke in a Blast Furnace to Make Iron

Coke, iron ore, and limestone are fed into the blast furnace, which runs continuously. Hot air blown into the furnace burns the coke, which serves as a source of heat and an oxygen-reducing agent to produce metallic iron. Limestone acts as a flux and also combines with impurities to form slag.

Source: American Iron and Steel Institute.

Coke is made by baking a blend of selected bituminous coals (called metallurgical coal or coking coal) in special high-temperature ovens without contact with air until almost all of the volatile matter is driven off. The resulting product, coke, consists principally of carbon. A ton of coal yields about 1,400 pounds of coke and a variety of by-products such as crude coal tar, light oils, and ammonia, which are refined to obtain various chemical products (Figure 14).

The coke industry was once a major market for coal, accounting for about one-fourth of U.S. coal consumption as recently as the late 1950's. Since then, coke production has fallen dramatically and its share of total coal consumption currently is about 4 percent because of a decline in the U.S. iron and steel industry, the principal consumer of coke. In general, the iron and steel industry now requires less coke because it produces smaller amounts of raw steel, relying on imports of finished and semi-finished steel to help meet its needs, and because improved blast-furnace technology has reduced the amount of coke needed to produce a ton of pig iron. Furthermore, less coke is needed due to the greater use of certain steel-making technologies, such as the basic oxygen furnace, which enables scrap iron to replace pig iron in some processes, and the electric arc furnace, which produces steel from a charge consisting of 99 percent scrap iron and recycled steel and 1 percent iron pellets. (The steel industry has not used the open-hearth furnace since 1991.) The substitution of other products for steel (such as plastics, aluminum, magnesium, and titanium) has also indirectly reduced the need for coke.

Among the recent technological changes that are responsible for reducing the use of traditional coke in blast furnaces is the use of pulverized coal injection, a process developed in the 1960's by Armco Steel. By using pulverized coal injection, steel companies can reduce the need for coke by as much as 40 percent, cut down on environmental problems associated with coke production, and reduce the need for other, more costly supplemental blast furnace fuels, such as natural gas. Pulverized coal, which has the consistency of face powder, is made from the relatively abundant lower grades of coal and blown into the blast furnace. Granular coal, similar in size to sugar, is also being tested in blast furnaces.

At the beginning of 1994, 31 coke plants were in operation, less than half the number a decade earlier. Although some plants were closed because of the decline in the steel industry, many closings targeted older plants that were shut down because of the high cost of refurbishing them to meet air pollution

Figure 14. Production of Coke and Coal Chemicals
(Approximate Yields per Ton of Coal)

Metallurgical (coking) coal is converted in special high-temperature ovens into coke, which is used in smelting iron ore in a blast furnace. The coking process also yields useful coal chemicals as by-products.

standards. More than half of the active plants are *furnace plants*, operated by iron and steel companies to produce coke for their blast furnaces; these plants account for about 80 percent of the U.S. coke capacity. The other coke plants, called *merchant plants*, sell coke on the open market. Both segments of the coke industry are faced with the advanced age of many of their coke ovens and the rising costs of replacing them with environmentally clean ovens. Indiana and Pennsylvania are the leading coke-producing States.

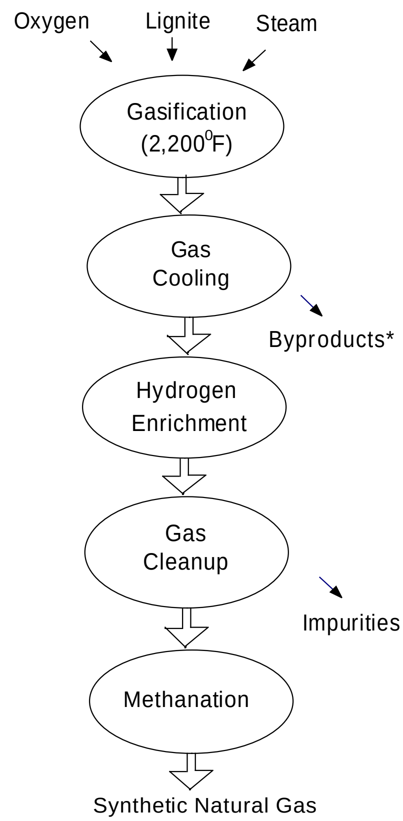
Coal is also used as a source of heat in other industrial, manufacturing, and commercial establishments, as well as in homes. Most U.S. cement plants burn coal, using about a ton for each 3.5 tons of cement produced. A number of cogeneration plants consume coal to produce steam for generating electricity and for heating.

Since December 1984, lignite has been converted into pipeline-quality gas at the Great Plains Synfuels Plant, near Beulah, North Dakota (Figure 15). The first of its type to operate commercially in the United States, the plant converts an average of 16,000 tons of lignite per day into 142 million cubic feet of gas. In 1987, a coal gasification facility began operations at Plaquemine, Louisiana, to produce gas for the cogeneration of steam and electricity for the Dow Chemical Company. The plant has a coal processing capacity of 2,400 tons per day.

Some coal is used for transportation, but the amount is insignificant. The coal-burning locomotives of the past, now replaced by more efficient diesel-electric locomotives, were once major coal consumers requiring a coal supply that often exceeded 100 million tons per year. Today's coal-burning locomotives are used for tourist attractions and excursions, although one was in regular, short-haul revenue service in Illinois as recently as 1986. (It is interesting to note that research is underway to develop a new generation of coal-fired locomotives fueled with coal-oil mixtures, coal-derived liquids, or coal gas.) A coal-fired ship more than 60 years old was reported in service on the Great Lakes in 1991. A large coal-fired ship, the *Energy Independence*, placed in service in 1983, transports coal from eastern ports to power plants in Massachusetts. The ship, 665 feet long and with a coal-capacity of about 36,000 tons, is the first of its type built in the United States since 1929.

Although primarily a fuel, coal has other uses. The process of converting coal into coke yields by-products of benzene, coal tars, naphtha, and similar chemicals that are used to manufacture solvents, varnishes, perfumes, medicines, dyes, and plastics. In the past, coke plants were a major source of chemicals, but today their output is overshadowed by chemicals produced from petroleum. Coal is also used to manufacture diverse products such as calcium carbide, silicon carbide, refractory bricks, carbon and graphite electrodes, adsorbents, carbon black, and fillers. Since 1983, coal has been used as a raw material at Eastman Kodak's plant in Kingsport, Tennessee, to manufacture acetic anhydride, which is used in making photographic film base, acetate yarns, and other plastic-based materials. Montan wax is extracted from certain lignites at Ione, in northern California, for use in polishes,

Figure 15. Schematic of Coal Gasification, Great Plains Synfuels Plant, Beulah, North Dakota



*Includes ammonia, sulfur, liquid nitrogen, krypton, xenon, and phenols.

In coal gasification, the molecular structure of coal is broken down to produce hydrogen and carbon, which are combined to form (CH_4), the main constituent of natural gas. Synthetic natural gas forms when carbon monoxide and carbon dioxide react with hydrogen in the presence of a nickel catalyst.

Source: Dakota Gasification Company.

waxes, carbon paper, phonograph records, inks, coatings, and electrical insulating materials. Resin recovered from coal in Utah is used in making adhesives, rubber, varnish, enamel, paint, coating, thermoplastics, and ink. Oxidized lignite, or leonardite, from North Dakota has been used in oil-drilling mud, in water treatment, in certain wood stains, and as soil conditioners. Activated carbon is manufactured from lignite in Marshall, Texas. Some of the ash from coal-fired power plants is used in manufacturing concrete and cinder blocks, in constructing roads, and in reclaiming surface-mined areas.

Coal and Coke Trade

Coal exports comprise a small but important market for U.S. coal production. The level of coal exports, consisting of nearly all Appalachian bituminous coal, is influenced by a number of factors, such as changes in the economic conditions in the coal-importing countries, coal-miners' strikes in the United States and other coal-exporting countries, and price competition, as well as changes in the international exchange rate of the U.S. dollar, which determines the price foreign consumers pay for U.S. coal.

U.S. coal is currently exported to more than 30 countries (Figure 16). The United States was the world's leading coal exporter until 1984, when Australia gained first place. Annual U.S. coal exports, valued at $3 billion to $6 billion from 1980 through 1993, are a significant contribution to the Nation's balance of trade.

Since 1960, an average of 1 out of every 10 tons of coal mined has been exported. The amount has ranged widely, from 36 million tons in 1961 to a record 113 million tons in 1981 and totaled 75 million tons in 1993. The 1993 coal exports were the lowest since 1979, a decline generally attributed to a combination of adverse factors: a slump in the world economy, a strike by the United Mine Workers of America, a slowdown of barge shipments due to flooding in the Midwest, and price competition from foreign coal producers. Although coal was exported in 1993 from 15 States, West Virginia, Virginia, and Kentucky predominated, together accounting for three-fourths of the total.

Metallurgical coal, or coking coal, is the mainstay of U.S. coal exports, accounting for 67 percent of the 1993 total. However, exports of bituminous steam coal have expanded because many foreign electric power plants, cement plants, and other industries converted from oil to coal when oil prices rose in the 1970's.

Canada, historically, has been the principal export market for U.S. coal, including some anthracite for use in a smelting process to produce paint pigments. Western Europe became a major market for U.S. coal following World War II, especially for metallurgical coal, with the largest tonnages currently shipped to Italy, Belgium and Luxembourg, and the Netherlands. Japan has been predominant as a market for metallurgical coal since 1967. Brazil is the largest South American importer of U.S. metallurgical coal.

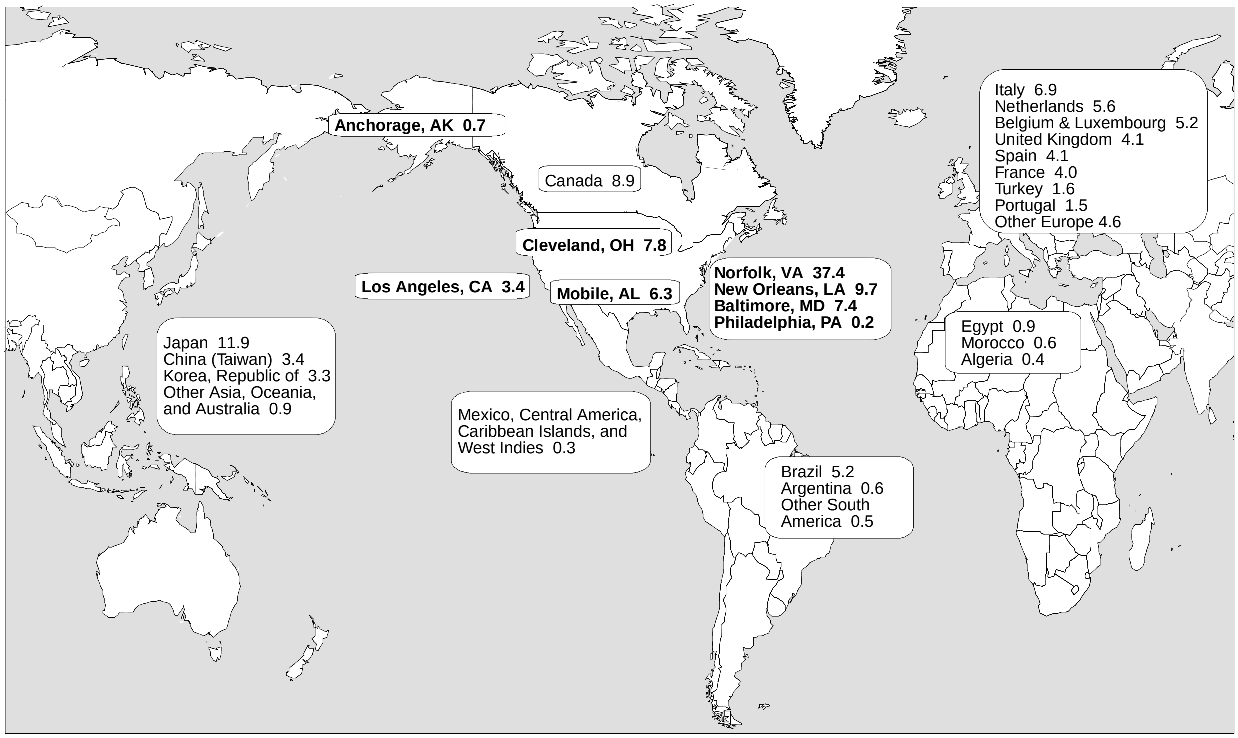
About half of the total U.S. coal exported is shipped from the Norfolk, Virginia, customs district. Other large coal-exporting customs districts are New Orleans, Louisiana; Cleveland, Ohio; Baltimore, Maryland; and Mobile, Alabama.

Channel depths at most U.S. coal-loading terminals limit the vessel size to less than 100,000 deadweight tons. When a large collier (more than 100,000 deadweight tons) cannot be fully loaded because of channel-depth restrictions, it is sometimes loaded by a two stage "top-off" operation. With this technique, the ship is partially loaded at the port and then sails to deeper waters where it is topped-off to full capacity with coal from a self-unloading barge. However, vessels using the Panama Canal are limited in size to 65,000 deadweight tons and are often described as "Panamax" ships. "Capesize" ships are oceangoing vessels too large for the Panama Canal that must travel routes around the capes of Africa or South America.

Coal imports, contrasted with coal exports, are relatively insignificant. In 1993, the 7 million tons of bituminous coal imported were valued at about $219 million. The coal was imported chiefly from Colombia, Venezuela, and Canada. Coal imported from Canada was used primarily to meet the needs of U.S areas not easily supplied by domestic sources. The coal imported from the other countries was delivered to electric power plants in the Southeast at prices below those of competing U.S. coal. Imported coal typically has a low sulfur content and is sometimes blended with high-sulfur domestic coal to enable the latter to meet air-quality emission standards.

U.S. coke exports have been small and chiefly to Canada. Coke exports totaled 0.8 million tons in 1993. Coke imports over the past two decades typically have been less than 1 million tons, although larger amounts have been imported when needed to offset a shortfall in the domestic supply. Coke imports in 1993 amounted to 1.5 million tons, mostly from Japan. Some coke was imported from Canada for use by nonferrous industries in the West.

Figure 16. Major Destinations of U.S. Coal Exports and Shipments from Selected U.S. Coal-Exporting Customs Districts, 1993
(Million Short Tons)



In 1993, a total of 75 million short tons of U.S. coal was exported to more than 30 countries. More than half of the coal was shipped from Norfolk, Virginia.

Source: Energy Information Administration, *Quarterly Coal Report October-December 1993*, DOE/EIA-0121(93/4Q) (Washington, DC, May 1994).

Coal and the Environment

Coal has played an important role in the advancement of civilization, but its use has sometimes been accompanied by environmental penalties, due partly to the mining process and partly to the composition of coal itself. Because of this, a number of laws have been enacted to protect the environment.

Coal mining, like all other mining, has a direct impact on the environment. Most visible are surface-mined areas, although proper reclamation can restore the land for other uses after mining. The Surface Mining Control and Reclamation Act of 1977, which was extended and amended by the Abandoned Mine Reclamation Act of 1990, requires surface mine operators to maintain certain environmental standards during mining and reclamation. The Act also requires operators of underground mines to take measures to control land subsidence, which can have a severe impact on roads, water and gas pipelines, buildings, and water-bearing strata. Although subsidence can occur during underground mining, as when longwall methods are employed, it poses a potential threat many years after a room-and-pillar mine has been abandoned because the pillars left to support the overlying strata can deteriorate and collapse. To help pay the costs of reclaiming land and water resources affected by past mining operations, the Act imposes fees on coal production at both surface and underground mines. Companies pay 35 cents per ton of coal mined by surface methods, 15 cents per ton mined underground, and 10 cents per ton of lignite. (These fees were extended through the year 2004 by the Energy Policy Act of 1992.) The 1977 Act also provides funds to control fires in abandoned underground mines. Such fires can travel long distances, fueled by coal remaining in the abandoned workings, and endanger life and property in communities situated above the burning area.

Waste piles from mining and coal preparation and from coal-fired power plants can also create environmental problems. They are regulated by the Resource Conservation and Recovery Act of 1976, the principal law governing the disposal of solid wastes. However, much of the material piled up during surface mining is used during reclamation, when soil and other materials are replaced to reflect natural conditions.

The impact of mining and coal preparation on water quality is controlled by the Federal Water Pollution Control Act of 1972, which has been incorporated into the Clean Water Act of 1977 and its amendments. One of the environmental consequences of coal mining is acid mine drainage, which contains sulfuric acid produced when pyrite and other iron sulfides react with air and water. The acid water increases the solubility of toxic heavy metals, such as arsenic, lead, and mercury, and renders the water toxic to aquatic life and unfit for domestic and municipal use. Acid mine drainage can be reduced by a variety of methods, such as adding alkaline minerals to neutralize the acidity, sealing abandoned underground mines, controlling drainage, and constructing wetlands with cattails, mosses, and other plants to clean the mine water.

When coal is burned, the sulfur in it is converted mostly into sulfur dioxide. In addition, nitrogen oxides are produced from nitrogen in the coal and the air used in combustion, and ash is produced from incombustible material. In the atmosphere, sulfur dioxide and nitrogen oxides are converted to sulfuric and nitric acids, which can react with rain or snow to produce acid rain. Most of the ash produced at coal-fired powered plants is in the form of powder-like particulates called “fly ash,” which are carried in the flue gas. Fly ash is composed mainly of silica and alumina, and may contain potentially hazardous trace elements. The remaining ash is bottom ash, or boiler slag, which is collected at the bottom of the boiler or furnace.

Sulfur dioxide emissions are usually controlled by the technique of “flue gas desulfurization,” generally with the use of “wet scrubbers.” These spray the flue gas with a mixture of water and lime or limestone, which combines with sulfur dioxide to form a sludge. With the less common “dry scrubbers,” a similar spray produces a dry residue. The level of nitrogen oxides emissions usually is controlled by reducing the amount of air used during combustion and by lowering combustion temperatures. Particulates can be removed from flue gas by mechanical devices, but electrostatic precipitators and baghouses are more efficient. With electrostatic precipitators, the most common device in power plants, the particulates are electrically charged and collected on metal plates. In baghouses, powerful fans draw the flue gases through an array of fabric filters that trap the particulates.

To maintain air quality, emission levels for sulfur dioxide, nitrogen oxides, and particulates have been established by the New Source Performance Standards of the Clean Air Act of 1970 and its amendments. Electric utilities and other industrial coal consumers built before 1971 are subject to emission controls set by the States and approved by the Environmental Protection Agency. Those built after 1971 must meet the following Federal limits, in pounds per million Btu: sulfur dioxide, 1.2; nitrogen oxides, 0.7; particulates, 0.1. Electric generating units constructed or modified after September 1978 are subject to the more stringent standards of the Revised New Source Performance Standards. These are based on the level of uncontrolled emissions and defined in terms of percentage reductions. A minimum of 70 percent reduction is required for coal with a low-sulfur content, and a 90 percent reduction for coal with a high-sulfur content. The emission rate for sulfur dioxide under the new standards range from 0.6 to 1.2 pounds per million Btu. For nitrogen oxides, the standards range from 0.5 to 0.8 pound per million Btu, depending on the rank of coal burned and the method of combustion. The limit for particulates is 0.03 pound per million Btu. The emission standards for industrial boilers constructed or modified after June 1986 are similar to those for electric generating units.

In November 1990, the Clean Air Act was amended to strengthen the National commitment to improve air quality. The new legislation establishes as a goal for the year 2000 a reduction in annual sulfur dioxide emissions of at least 10 million tons from the 1980 level. Total sulfur dioxide emissions from all power plants will be limited to 8.9 million tons annually. The reduction will be in two phases. In Phase I (January 1, 1995, through 1999), the 110 largest sulfur-emitting power plants will be allowed to emit an average of 2.5 pounds of sulfur dioxide per million Btu of heat input. In Phase II, beginning in 2000, these plants and almost all others will be required to reduce sulfur dioxide emissions to 1.2 pounds per million Btu.

Near Colstrip, Montana, mined land has been reclaimed for livestock grazing as mining continues in the background.

One of the major breakthroughs in the 1990 Clean Air Act is a permit program for power plants that release pollutants into the air. The Environmental Protection Agency issues annual allowances to power plants, with each allowance permitting 1 ton of sulfur dioxide to be released from the smokestack. Plants may release only as much sulfur dioxide as their allowances cover. If a plant expects to release more sulfur dioxide than it has allowances, it has to get more allowances. It can buy them from another power plant that has reduced its sulfur dioxide emissions, due perhaps to switching to low-sulfur fuel or installing scrubbers, and therefore has allowances to sell or trade. Allowances can also be bought and sold by “middlemen,” such as brokers, and can be traded and sold nationwide. The program provides bonus allowances to power plants for, among other things, installing clean coal technology that reduces sulfur dioxide emissions, using renewable energy sources, or encouraging energy conservation by customers. The new legislation also requires a reduction of nitrogen oxides by 2 million tons. EPA will establish new limits for emissions of nitrogen oxides. All power plants under the program will have to install continuous emission monitoring systems to keep track of the amount of sulfur dioxide and nitrogen oxides released into the atmosphere.

Since passage of the Clean Air Act in 1970, billions of dollars have been spent by the Nation’s utilities to reduce emissions of sulfur dioxide. Because of this huge investment, the Nation’s air is cleaner today than it was about two decades ago. Emissions of sulfur oxides (comprised principally of sulfur dioxide) from all coal-burning sources are responsible for about three-fourths of total sulfur oxide emissions. However, between 1970 and 1992, coal-generated emissions have fallen by about 11 percent even though coal consumption increased by 70 percent. The decline reflects not only a greater number of plants meeting air quality standards through an increased use of scrubbers, but also a drop in the average sulfur content of coal burned.

Also of environmental concern are emissions of carbon dioxide from coal combustion and of methane from coal mines, although controls on the emission of these gases from the use of coal and other fossil fuels have not been imposed. Both carbon dioxide and methane are major greenhouse gases and may contribute to global warming.

The amount of carbon dioxide emitted when coal is burned varies widely, depending on the rank of coal and the State in which it is produced. Potential carbon dioxide emissions from the combustion of bituminous coal, the leading rank of coal consumed, average 205 pounds per million Btu, but range from 201 to 212 pounds per million Btu. By comparison, the average for subbituminous coal, the second leading rank of coal consumed, is 212 pounds per million Btu, while it ranges from 207 to 214 pounds per million Btu. The emission factor averages 216 pounds per million Btu for lignite and 227 pounds per million Btu for anthracite.

Estimates of carbon dioxide emissions from coal combustion must take into account the “mix” of coals received from various sources. A voluntary program for companies to report reductions in gas emissions to the Energy Information Administration was among the provisions of the Energy Policy Act of 1992. The Act addresses many energy-related issues, including the attainment of higher energy efficiency standards and the environmentally sound use of fossil fuels.

Methane emissions occur mostly during production in underground mines. Bituminous coal generally emits more methane than the lower rank coals such as lignite. The amount of methane contained in a coalbed increases with depth. Small amounts of methane can also be released when coal is transported and when it is pulverized for combustion.

Coal Outlook

The Nation’s abundant coal reserves are expected to continue as an important source of energy in the foreseeable future. Annual coal production is projected to remain around 1 billion tons into the next century. Nearly 90 percent of this is projected to be for domestic consumption, principally to generate electricity. The rest of the output is expected to be exported.

Research and development are underway to make coal a more competitive and cleaner-burning fuel, as well as a greater source of chemicals. All parts of the “coal chain” are being investigated, from mine to consumer. Both Federal and State pollution control regulations are giving impetus to the coal industry’s effort to produce a cleaner, more efficient fuel.

Computer-assisted mining systems under development have the potential to advance mining technology through automation, robotics, and networking programs that can monitor a variety of mining activities, resulting in improved health, safety, productivity, reliability, and economy. Equally important are studies concerned with the human factors involved in coal mining.

Although mining disrupts the land for a period of time, considerable progress has been made in reclaiming mined land. This includes the restoration of the land surface, the rehabilitation of soil materials, and revegetation. The goal of reclamation is to restore the mined land to its original use or enable it to be put to another use.

Advanced coal preparation, geared to improving current state-of-the-art techniques, could remove as much as 90 percent of the sulfur and ash from the coal, improving its burning and environmental qualities. This can be accomplished by using sophisticated physical, chemical, and biological methods to clean finely ground coal. The removal of sulfur not associated with mineral impurities and of alkali metal impurities in western coals are challenging goals, because these elements are generally bonded to the organic coal matrix, requiring the use of chemical reagents. Innovative approaches to future coal preparation could include use of microwave and microbial and enzymatic techniques.

Drying techniques are being developed to lower the moisture content in western coals (30 percent is not uncommon). When dried, low-rank coals typically crumble and become very dusty. New drying methods will produce solid pellets of coal that have about two-thirds less moisture and about one-third more heating value. This dried coal can be blended with raw sub-bituminous coal or lignite to raise the overall heating value, or with high-sulfur coal to reduce sulfur emissions.

Traditional coal-burning methods will continue to be used for many years. However, clean coal technology —a term that entered the energy vocabulary in the 1980’s—offers the potential for a cleaner environment and lower power costs. Included are more effective pre-combustion coal-cleaning processes, such as methods for keeping sulfur and nitrogen pollutants inside the furnace and scrubber systems capable of removing pollutants in the form of dry solid waste, reducing the disposal problems created by wet sludge. Some clean coal technologies depart from conventional coal-burning methods in that the coal is converted into a gas or liquid that is used as fuel.

Advanced pulverized coal technologies can take pulverized coal combustion—the most widely accepted technology for coal-fired power generation—one step further, by refining the process to gain major improvements. Included are low emission boiler systems, which incorporate emission controls at the outset of design and development instead of adding them to a completed system, and cogeneration, which produces both steam and power for power generation and also heat for process and space heating, and can result in improvement in plant efficiency of over 70 percent.

Coal gasification, an old technology that is being modernized, converts coal into a gaseous product by heating it with steam and oxygen or air. The gas

Pristine coal samples are used by researchers investigating cleaner and more efficient coal use.

produced can be cleaned and used as a fuel or processed further to produce synthesis gas. Synthesis gas (mostly carbon monoxide and hydrogen) can be converted to a substitute for natural gas, chemicals, or liquid fuel. The amount of gas that can be produced from a ton of bituminous coal depends on the technology used and ranges from about 15,000 cubic feet of high-Btu gas (about 1,000 Btu per cubic foot) to 75,000 cubic feet of low-Btu gas (up to 200 Btu per cubic foot). In 1993, three coal gasification plants were in commercial operation in the United States. The Great Plains Synfuels Plant, near Beulah, North Dakota, operated by the Dakota Gasification Company to convert lignite into pipeline-quality gas, obtaining chemical byproducts as part of the process. Tennessee Eastman Company's coal gasification plant in Kingsport, Tennessee, converted bituminous coal into chemicals. At Plaquemine, Louisiana, subbituminous coal was converted by Louisiana Gasification Technology into gas for use in generating electricity and superheated steam for an adjacent chemical complex.

Coal gasification also has potential in development of fuel cells, which generate electricity from the reaction of hydrogen and oxygen. Currently, most fuel cells approaching commercialization are fueled with natural gas. Because hydrogen is produced in coal gasification, coal gasifiers could be integrated into future fuel cell technologies to provide a new approach to power generation.

The research and development of "mild gasification" is aimed at processing coal under lower temperatures and pressures than in a typical coal gasification process. This leads to the production of liquids and solids that can be upgraded into high-value industrial raw material and chemical feedstock, in addition to gas, which can be used to provide heat for the process.

Underground coal gasification is the technology of converting coal to gas without mining. Wells are drilled into a coalbed, which is ignited and encouraged to burn. The burning coal generates combustible gases that can be collected at the surface for use as fuel or as feedstock for producing chemicals, such as ammonia and urea. The Federal Government has sponsored underground gasification tests in Wyoming, West Virginia, and Washington.

Coalbed methane, a danger to mining, is a potentially important source of energy. It is currently produced in some States (principally Alabama, New Mexico, and Wyoming) to supplement the supply of natural gas, which is composed largely of methane; its potential is being evaluated in other States. Methane can be produced from unmined beds or in advance of mining a coalbed. Degasification of a coalbed not only supplies a useful product, but also provides a safety measure because it reduces the amount of methane released into the working areas of a mine.

Coal liquefaction, another old technology, converts coal into liquid fuels by three techniques: indirect, direct, and pyrolysis. With an indirect process, coal is first gasified, and then the coal-derived synthesis gas is converted into a variety of liquid fuels, such as methanol, gasoline, diesel fuel, and octane enhancers. The best-known indirect coal liquefaction facilities are operated in South Africa by South African Coal, Oil and Gas Corporation, Ltd. (SASOL), which produces a range of liquid fuels including gasoline, diesel oil, and jet fuel. With a direct coal liquefaction process, finely ground coal in a solvent is mixed with hydrogen and heated to a high temperature under high pressure to produce "synthetic crude oil." This can be upgraded into higher quality fuels by further processing with existing petroleum-refining techniques. With pyrolysis, dry coal is subjected to high temperatures in a chemically reducing atmosphere to produce a heavy synthetic crude oil, which can be refined, and char, a solid residue that can be used as a fuel. Depending on the process used, a ton of bituminous coal can be converted into 0.5 to 3 barrels (21 to 126 gallons) of liquid fuel.

Solvent-refined coal processes produce a low-ash, low-sulfur fuel from coal high in both ash and sulfur by dissolving pulverized coal in a solvent. The final form of the fuel, whether a liquid or a solid, is determined by the process used.

Mixtures of finely ground coal and oil or water can be substituted for fuel oil in oil-burning facilities. They have the advantage of being transported, stored, and burned in a manner similar to fuel oil. By weight, coal constitutes 40 to 50 percent of coal-oil mixtures and about 70 percent of coal-water mixtures; some chemicals are added to the mixtures to prevent the coal particles from settling out in storage. The technology for producing coal-liquid mixtures has been broadened to include methanol and solvent-refined coal. The idea of using coal-oil mixtures is not new. They were tested in the 1930's as an oil substitute for ships in trans-Atlantic service, and in the 1950's they were evaluated as fuel for blast furnaces. The potential of using coal-water mixtures was first demonstrated at a U.S. power plant in 1961. More recently, mixtures of coal and recycled paper have been tested on a small scale for use as fuel.

Direct coal-fired heat engines represent another aspect of clean coal technologies. They include direct coal-fired gas turbines, which involve the use of both a coal-water slurry and dry pulverized coal, and direct coal-fired diesels, which involve the development of diesel engines that will burn a coal-water slurry rather than distillate petroleum fuels.

Fluidized-bed combustion, a technology dating back to the early 1920's, is well-suited for burning high-sulfur and low-quality coals in an environmentally acceptable manner. It has become commercially competitive for large industrial applications and is currently used to generate electricity. With this technology, crushed coal is burned on a hot turbulent bed of limestone or dolomite, which absorbs most of the sulfur dioxide produced. As a result, the need for flue gas desulfurization units is eliminated. Only a small amount of nitrogen oxides is produced because of relatively low combustion temperatures. The fluidized-bed units in operation burn coal under normal atmospheric pressures. Advanced units under development—pressurized fluidized-bed combustion systems—operate at higher pressures to achieve greater efficiency.

Formcoke is of potential importance as a blast furnace fuel. It is made by heating briquettes of finely pulverized coking coal or other coal, including some subbituminous coals, that has been carbonized to obtain a char, which is further carbonized to produce metallurgical coke. Although pulverized coal is being used in blast furnaces, replacing some of the coke, a clean coal technology project entitled "blast furnace granulated-coal injection system" involves retrofitting blast furnaces with technology to operate with a variety of coal particle sizes. Also under development is COREX (Coal/Ore Reduction), a novel "cokeless" ironmaking process in which coal can be substituted for coke in a special furnace to smelt iron ore. It could replace the conventional two-step coke oven/blast furnace procedure for producing pig iron, eliminating the environmental problems associated with coke making. Sulfur in the coal is captured in the by-product slag.

Magnetohydrodynamic (MHD) conversion is a potential method of burning coal cleanly and at high efficiencies to generate electricity. MHD systems differ from other advanced coal-fired systems in that coal is burned at very high temperatures to produce ionized combustion gases that pass through a magnetic field to create electricity. Linked with a conventional steam turbine-generator, commercial MHD systems are expected to achieve power generating efficiencies of well above 50 percent—more than one-and-a-half times those of conventional coal-burning power plants.

As the complex nature of coal becomes better understood, it could once again become important as a raw material for manufacturing a variety of chemicals. Many of the organic chemicals made today from petroleum were originally by-products of the coke-making process. With the development of sophisticated chemical processes, coal-derived chemicals could provide the building blocks for making special products, such as carbon fibers, composite materials, and fullerenes (a form of carbon discovered in 1985 that has possible applications in high-temperature lubricants, microfilters, more efficient superconductors, and gas adsorbents).

All these and other applied research efforts are being supplemented by fundamental studies of the atomic and molecular structure, composition, and characteristics of coal. Such work provides the basic information that enables practical research to succeed.

The U.S. Department of Energy (DOE) is investing in a Clean Coal Technology (CCT) Demonstration Program, a government-industry co-funded effort to develop new technology with the dual goals of attaining environmental quality and energy security from coal. The CCT program, which started in 1986, is confined to perfecting the early stages of long-term, high-risk research that industry is reluctant to pursue. At the end of 1993, the program comprised 45 demonstration projects either underway or completed in 21 States, representing nearly $2.5 billion in Federal funding and more than $4 billion in cost-sharing from private and State sources. DOE also funds coal projects at U.S. colleges and universities. Since 1979, DOE's University Coal Research Program has provided $76 million for fundamental studies of coal and coal-related topics.

Looking ahead, there is little doubt that the United States has the resources to remain self-sufficient in coal well into the 21st century. The Nation has enormous coal reserves, a well-developed coal industry, and advancing coal technologies. The U.S. coal industry continues to adjust to changes in economic conditions, governmental actions, and environmental constraints that influence the production and use of coal. As a producer of an important source of energy, the coal industry will continue to directly or indirectly touch on almost every phase of our daily lives.