*Kirk-Othmer Encyclopedia of Chemical Technology.*


# POWER GENERATION

Power, *P,* defined as the rate at which work is performed, is expressed in terms of energy divided by time and is most commonly given in units of horsepower, as for the power supplied by mechanical devices such as diesel engines, or in the SI units of watts, especially when measuring electrical power. One horsepower is equivalent to the amount of power needed to lift 33,000 pounds (14,982 kg) one foot (30.5 cm) in one minute. One watt is equivalent to the power required to perform one joule of work per second. In a simple direct-current circuit where potential is represented by *E:*

$$P = EI = I^2R$$

One watt of power is required to force oneampere of electric current, *I,* through a length of conductor having a resistance, *R,* to flow of one ohm. The calculation of power in alternating-current circuits is more complex because of the characteristics of these circuits and their loads. For a single-phase circuit having an effective line voltage, *E,* and an effective line current, *I:*

$$P = EI \times PF$$

where *PF*is the power factor corresponding to the lag between the voltage and current wave forms. For multiphase systems, a factor is introduced on the right-hand side of the equation. The factor is two for a two-phase system; 1.73 for a three-phase system.

## 1. History

In the industrial arena, the term power generation most typically refers to the production of electrical or mechanical power via any of several energy conversion processes. Early examples of practical power generation devices include water-wheel-powered mills for grinding grain, which were reportedly used as early as 100 BC in the Balkans and areas of the Middle East, and wind-powered mills, which were widely used as early as the tenth century in the Middle East.

In the early eighteenth century, the advent of large-scale coal mining in England led to the development of a steam-powered pump for evacuating ground water for the deep coal (qv) mines. The first practical steam (qv) engine, on which the steam-powered pump relied, was developed in England in 1690 by Newcomen. The device consisted of a piston that reciprocated in a cylinder by the alternating admittance and condensation of steam generated in a large copper vessel located beneath the cylinder. The engine, similar in principle to steam engines later applied during the industrial revolution to power ships, was successfully used for pumping water at an English mine in 1711.

In the mid-1700s, Watt was commissioned to repair a model of the Newcomen steam engine. Realizing that the device's need to condense steam in its cylinder following the power stroke via a jet of cold water made the engine a voracious consumer of steam and therefore inefficient, Watt built a working model of a new type of steam engine that avoided the need to condense steam within the cylinder. A separate condensing chamber was employed that, by avoiding the need to heat and cool the working cylinder alternately, reduced steam and fuel consumption. Another benefit was the ability to admit steam alternately above and below the piston, which created a double-acting cylinder. This doubled the work that the machine was capable of doing. In addition, the cylinder of Watt's steam engine was insulated to further stem heat loss and improve the efficiency of the device. Watt's steam engine was patented in 1769 and by 1776 it was being developed for commercial use in pumping applications.

A sun-and-planet gear arrangement was then adapted to enable this reciprocating machine to drive rotating equipment. The ability to power rotating machinery using steam engines was an important development during the industrial revolution because factories no longer needed to be located next to rivers or waterfalls where water wheels could be employed to drive the factories' rotating machinery. Instead, factories could be located where it was most economical in terms of available work forces, such as in cities, and means of transport, such as near harbors.

The industrial revolution, often said to have commenced in the 1750s upon the widespread use of mechanized shuttle looms in textile factories, ended in the 1880s upon the advent of the electric lamp. The revolution relied heavily on power supplied by steam engines. In addition to revolutionizing manufacturing, the steam engine was used to power ships and locomotives, greatly improving the ability to deliver goods reliably over long distances and thereby expanding international trade. By the end of the nineteenth century, internal combustion engines, steam- and water-turbine-powered electric generators, and electric motors were being applied commercially.

The first centralized electric generating plant in the United States was Edison's three-unit steam-engine-based station, which supplied electric power to light approximately 5000 electric lamps in a group of homes and businesses in New York City in 1882. Also in 1882, the first hydroelectric power plant went into operation in Appleton, Wisconsin, generating approximately 25 kW of power, enough to power more than 200 100-watt light bulbs.

Early power plants had to be located close to the users of the electricity to minimize power losses associated with the resistance to current flow through the transmission lines. The development of transformers significantly improved the ability to transport electricity efficiently over long distances. By boosting the voltage of the electricity, a given amount of power can be transmitted over long distances at much lower line losses compared to that transmitted at lower voltages. Where loads exist along a line, step-down transformers can be used.

In the early part of the twentieth century, many industrial plants had fossil-fuel-fired boilers that produced steam for both mechanical-drive equipment, such as turbine-driven refrigeration compressors, and steam-turbine-powered electric generators serving the plant's electrical needs, eg, motors. As extensive electric power transmission and distribution systems were erected, industrial power users came to rely more on power supplied by centralized utility-owned power plants. Electric utilities made huge investments in generation and delivery equipment. It was not economically feasible for more than one power company to install transmission and distribution systems in a given geographic area. Thus utilities were considered to be natural monopolies and were subjected to tight government controls to ensure fair business practices and consumer protection.

A significant number of energy-intensive industrial facilities, such as many steel (qv) mills and paper (qv) plants, have maintained on-site power generation capacity to meet their unique electric needs. These and other nonutility generators (NUGs) have formed a growing industry in the late twentieth century. In the United States, this industry has been driven by regulations that allow NUGs to generate power for sale to utilities, and other factors such as the widespread availability of low cost natural gas (see Gas, natural). Internationally, many countries have paved the way for NUGs by privatizing their power generation sectors, which were previously government controlled.

The widespread availability of electrical energy completely transformed modern society and enabled a host of breakthroughs in manufacturing, medical science, communications, construction, education, and transportation. Centralized fossil fuel-powered, steam-turbine-based power plants remain the dominant means of electricity production. However, hydropower facilities such as the 1900-MW Hoover Dam Power Project located on the Arizona–Nevada border, commissioned by the U.S. Bureau of Reclamation during the 1930s, have also made significant contributions.

In 1956, the world's first commercial nuclear power plant started operation in England. By the 1960s, many nuclear power plants were built worldwide. At the end of the twentieth century, nuclear generating plants are used widely by U.S. electric utilities. Since 1984, these plants have provided the second largest share of total U.S. electricity generation, 21% of annual $\mathrm{GW{\cdot}h}$ generated, behind coal-fired power plants (see Nuclear reactors).

The use of nuclear power has been a topic of debate for many years. Nuclear fuel represents a resource for generating energy well into the future, whereas economically recoverable fossil fuel reserves may become depleted. Worker exposure, injuries, and fatalities in nuclear fuel mining are reportedly far less compared to those associated with recovery and handling of fossil fuels. Potential hazards associated with transporting and storing radioactive wastes do exist, however.

At the same time that utilities began utilizing nuclear power, combustion turbine generators became an important means by which extra power required during times of peak demand were produced. Widely installed during the late 1960s and 1970s in the United States for peaking power service, the combustion turbines, also referred to as gas turbines, were based on a thermodynamic cycle similar to that used in jet aircraft. However, instead of creating thrust for propulsion, the explosive power developed by the combustion of compressed air and fuel, oil, or gas is used to drive a power turbine which in turn drives an electric generator. Combustion turbines proved to be ideal for peaking power applications because of rapid start-up capabilities. Unlike steam-based power plants, which can take hours to come on-line owing to thermal stress constraints, combustion turbines can be started and brought to full load in a matter of minutes. However, frequent and rapid start-ups can shorten a combustion turbine's operating life and necessitate increased maintenance.

Early combustion turbine/generators were fairly inefficient and expensive to operate compared to base-load steam power plants. These were therefore used predominantly for special applications where rapid start-up capability, small size, and ease of operation proved advantageous. Such applications included remote sites in oil and gas fields, off-shore drilling platforms, gas transmission pipelines (qv), emergency power for buildings and plants, and peaking power service. By the 1980s, however, improvements in gas turbines; reduced prices and increased availability of natural gas; the technology's adaptability to efficient cogeneration power plants, which coproduce thermal and electrical energy; and advanced combined-cycle power systems, all converged to make combustion-turbine-based power options competitive with conventional steam-turbinebased cycles.

In the United States, laws passed since the late 1970s have encouraged the development of cogeneration plants and independent power plants developed by nonutility power producers. Combustion-turbine-based facilities have become extremely popular among nonutility power plant developers. Among the many reasons for selecting this technology is the ability to develop compact, modular, combustion-turbine-based power plants within one or two years.

The idea of harnessing renewable energy sources for power generation has long intrigued those in the power industry. Types of renewable energy facilities used in the United States include hydroelectric, geothermal, biomass, photovoltaic, solar thermal, and wind. However, except for hydropower, financial and technological obstacles have prevented widespread utilization of these power options. In 1993, renewable energy sources accounted for 11% of total net electric utility generation and 25% of total nonutility generation in the United States. However, excluding hydropower, these percentages drop to 0.3% and 21%, respectively (see Chemurgy; Fuels from biomass; Geothermal energy; Photovoltaic cells; Renewable energy sources; Solar energy).

In the United States and elsewhere, governmental agencies have long been involved in the electric power business. Public agencies were formed to build and operate power generation, transmission, and distribution

**Table 1. U.S. Power Supply by Ownership for 1993[a]**

| | Utility ownership | | | |
|---|---|---|---|---|
| Parameter | Investors | Public | Federal | Cooperative |
| generating capability, % of 700 GW | 76 | 11 | 9 | 4 |
| net generation, % of $2883 \times 10^9$ kWh | 79 | 9 | 8 | 4 |
| total sales, % of $2861 \times 10^9$ kWh | 76 | 14 | 2 | 8 |

[a]Ref. 1.

systems. For example, the U.S. Rural Electrification Administration was established primarily to provide power to agricultural regions. Numerous state-run and municipal power systems were also established. These have long provided inexpensive power, benefitting residents and also attracting and/or retaining businesses and industry. However, investor-owned utilities have come to be the main suppliers of electric power in the United States (Table 1). For example, investor-owned utilities supplied approximately 80% of the total power generated by utilities in 1993. Nonutility power producers having a capacity of 1 MW or greater supplied approximately $325 \times 10^9$ kWh of electricity in the United States in 1993, accounting for approximately 11% of the power generated that year. The 1993 total installed generating capacity for electric utilities was nearly 700,000 MW; for nonutility power producers, 61,000 MW (Table 2). Consumption of the $2.861 \times 10^{12}$ kWh of electricity in the United States was 35% to residential consumers, 34% to industrial, 28% to commercial, and the remaining 3% to others (1).

During the 1980s and 1990s, there was an international trend toward privatization of the electric power industry within countries where the industry was previously government controlled. In the United States as of 1995, where the electric power industry has been dominated by investor-owned utilities subject to tight government controls, deregulation was bringing sweeping changes and increased competition among utilities and from nonutility power producers (see Regulatory agencies, power generation).

## 2. Combustion Fundamentals

The combustion of fossil fuels, typically coal, oil (see Petroleum), or natural gas, is central to the energy conversion process by which most electric power is generated worldwide, particularly in the United States (Table 3). Thus, an understanding of the principles of fossil fuel combustion is integral to the understanding of modern power plant operation. A fundamental goal of power plant designers and operators is to ensure that the maximum economical amount of energy is extracted for practical use from a given amount of fuel burned (see Combustion science and technology).

Combustion is basically an exothermic chemical reaction by which the potential chemical energy stored in a fuel is released during its reaction with oxygen in the presence of heat. Thus, the basic constituents of combustion are fuel, oxygen, and heat. At normal temperatures, the oxygen, usually from air, and fuel can typically mingle without any combustion effect. However, upon the addition of sufficient heat, the fuel and air are excited to a point at which high velocity molecular collisions occur. If the velocity of these collisions is high enough, the bonds holding the various molecules together break and release heat.

The point at which enough heat has been added to start combustion is known as the ignition point. Once initiated, external heating sources are typically not required to maintain the combustion process, because most fuels release sufficient heat during the combustion process.

Designers of combustion equipment, including boilers, reciprocating engines, and gas turbines, rely heavily on combustion calculations to determine the rate of fuel and air input required to achieve the desired thermal output. The main fossil fuel constituents enabling combustion are carbon (qv), hydrogen (qv), and

**Table 2. U.S. Electric Power Industry Summary for 1993**[a]

| Parameter | Electric utilities | Nonutilities |
|---|---|---|
| generating capability[b], MW | 699,971[c] | 60,778 |
| coal | 300,795 | 9,772[d] |
| petroleum | 69,519 | 2,043[e] |
| gas | 132,495 | 23,463[f] |
| petroleum–natural gas[g] | | 8,505 |
| nuclear | 99,041 | 20[h] |
| renewable | | |
| hydroelectric, conventional | 74,763 | 2,741 |
| geothermal | 1,747 | 1,318 |
| biomass[i] | 459 | 10,177 |
| wind | 1 | 1,813 |
| solar thermal | 0 | 354 |
| photovoltaic | 4 | 7 |
| other | 21,146[j] | 566[k] |
| generation[l], kWh × $10^6$ | 2,882,525 | 325,226 |
| coal | 1,639,151 | 53,367[d] |
| petroleum | 99,539[m] | 13,364[e] |
| gas | 258,915 | 174,282[f] |
| nuclear | 610,291 | 78 |
| renewable | | |
| hydroelectric, conventional | 269,098 | 11,511 |
| geothermal | 7,571 | 9,749 |
| biomass[i] | 1,990 | 55,746 |
| wind | 0 | 3,052 |
| solar thermal | 0 | 895 |
| photovoltaic | 4 | 2 |
| other | 4,036[j,n] | 3,181[k] |

[a]Ref. 2.
[b]Values for the nonutilities are installed capacity values.
[c]Net summer capability based on primary energy source. Waste heat, waste gases, and waste steam are included in the original primary energy source, ie, coal, petroleum, or gas. Historical data have been revised to reflect this change.
[d]Includes coal, anthracite culm, and coal waste.
[e]Includes petroleum coke, diesel, kerosene, petroleum sludge, and tar.
[f]Includes natural gas, butane, ethane, propane, waste heat, and waste gases.
[g]Combined fuel.
[h]Nuclear reactor and generator at Argonne National Laboratory used primarily for research and development in testing reactor fuels as well as for training. The generation from the unit is used for internal consumption.
[i]Includes wood, wood waste, peat, wood liquors, railroad ties, pitch, wood sludge, municipal solid waste, agricultural waste, straw, tires, landfill gases, fish oils, and/or other waste.
[j]Hydroelectric pumped storage.
[k]Includes hydrogen, sulfur, batteries, chemicals, and spent sulfite liquor.
[l]Values for utilities are net; values for nonutilities are gross.
[m]Includes petroleum coke.
[n]Represents total pumped storage facility production minus energy used for pumping.

various hydrocarbons (qv). The main products resulting from combustion are water (qv) and carbon dioxide (qv). However, a variety of trace compounds and unburned matter may also be released during the combustion of power plant fuels. These materials vary, depending on the specific fuel being burned and whether complete combustion occurs. For example, coal and fuel oil may contain small amounts of sulfur (qv). This is an

**Table 3. 1993 U.S. Power Generation by Energy Source[a]**

| Source | Quantity consumed | Fraction of power generated[b], % |
|---|---|---|
| coal, t | 738 | 57 |
| petroleum, $m^3$[c] | $25.8 \times 10^6$ | 4 |
| natural gas, $m^3$[d] | $75.9 \times 10^6$ | 9 |
| nuclear | | 21 |
| hydroelectric | | 9 |
| other | | 21 |

[a]Refs. 1 and 2.
[b]Total net generation was $2883 \times 10^9$ kWh.
[c]To convert $m^3$ to barrels, multiply by 6.29.
[d]To convert $m^3$ to $ft^3$, multiply by 35.31.

undesirable constituent, despite its nominal heat content, because sulfur reacts during combustion to form acidic sulfur dioxide.

Common combustion reactions and heat releases for 0.454 kg of reactant under ideal combustion conditions are as follows, where Btu represents British thermal unit:

$$C + O_2 \longrightarrow CO_2 + 14{,}756 \text{ kJ} \ (14{,}000 \text{ Btu/lb C})$$

$$2H_2 + O_2 \longrightarrow 2H_2O\ (g) + 64{,}400 \text{ kJ} \ (61{,}100 \text{ Btu/lb } H_2)$$

$$2C + O_2 \longrightarrow 2CO + 4{,}216 \text{ kJ} \ (4{,}000 \text{ Btu/lb C})$$

$$2CO + O_2 \longrightarrow 2CO_2 + 4{,}532 \text{ kJ} \ (4{,}300 \text{ Btu/lb CO})$$

$$CH_4 + 2O_2 \longrightarrow CO_2 + H_2O\,(g) + 25{,}164 \text{ kJ} \ (23{,}875 \text{ Btu/lb } CH_4)$$

$$S + O_2 \longrightarrow SO_2\,(g) + 4{,}216 \text{ kJ} \ (4{,}000 \text{ Btu/lb S})$$

## 3. Steam Cycles

Conventional fossil fuel-fired power plants, nuclear power facilities, cogeneration systems, and combined-cycle facilities all have one key feature in common: some type of steam generator is employed to produce steam. Except for simple-cycle cogeneration facilities, the steam is used to drive one or more rotating turbines coupled to rotating electric generators for electricity production. The thermodynamic cycle by which water is boiled in

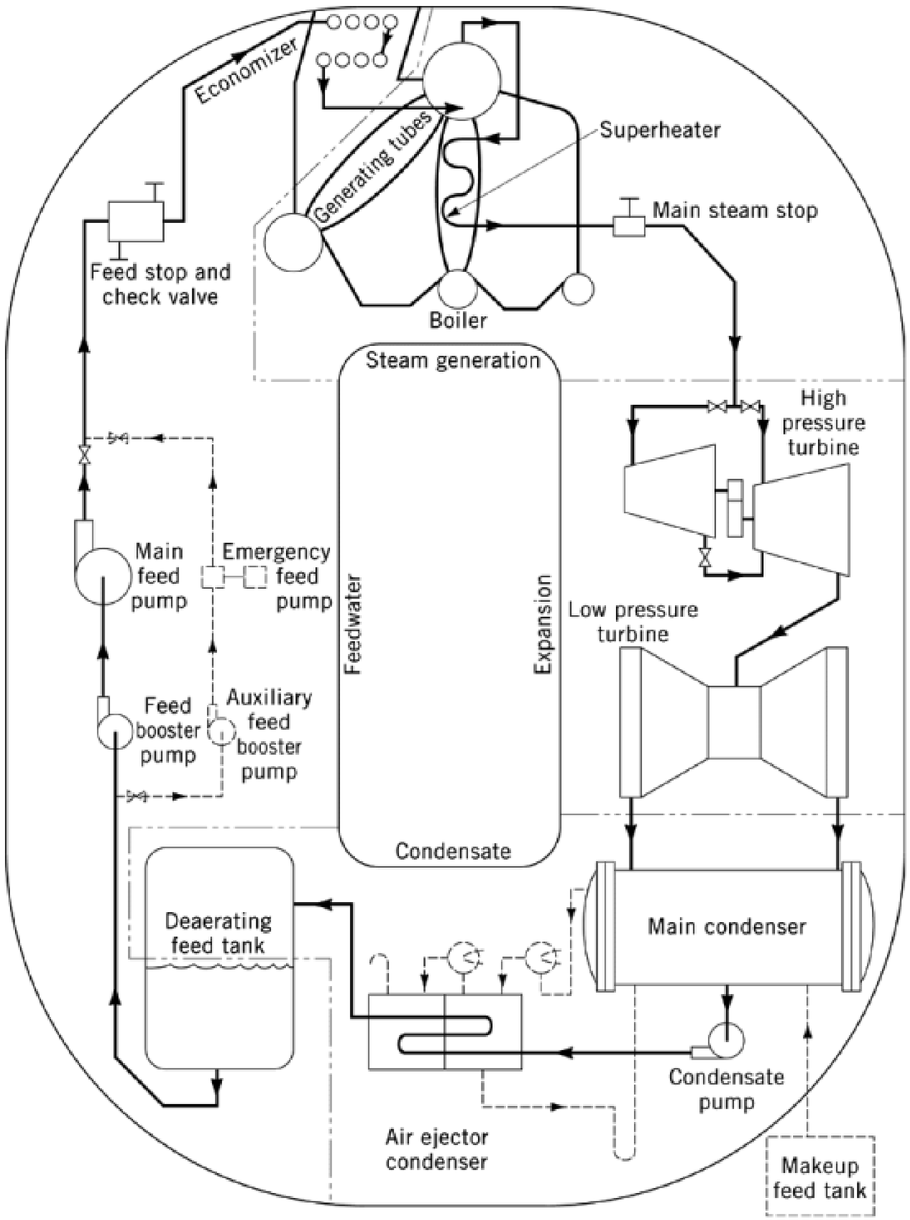



**Fig. 1.** The simplified steam cycle. (Courtesy of the U.S. Naval Institute.)

a steam generator (heat addition), forced through a turbine (expansion), and then condensed (heat rejection) before being pumped back to the steam generator is known as the Rankine cycle (Fig. 1).

Because of the simplicity and reliability of the Rankine cycle, facilities employing this method have dominated the power industry in the twentieth century and typically play an important role in most modern combined-cycle facilities. Water is the working fluid of choice in nearly all Rankine cycle power plants because water is nontoxic, abundant, and low cost.

Under standard pressure and temperature conditions of 101.3 kPa and 15°C (14.7 psia and 60°F), the amount of heat (or thermal energy in transition) that must be added to one pound of water to raise the temperature of the pound of water 1°F is known as one British thermal unit (Btu). One Btu, a common unit of measure in the energy field, is equivalent to 1.05435 kJ. The heating content of fuels is often measured in heat energy per unit mass or heat energy per unit volume. In addition, the heat rate of a fossil fuel-fired power plant, a measure of plant efficiency, describes how much heat energy per hour of fuel input is required to generate a continuous 1-kW power output. Because water vapor is a combustion by-product of all hydrogen-bearing fuels, a fuel's actual measured heating value varies based on whether the heat of vaporization is included. In the United States, a fuel's higher heating value (HHV) is most commonly referenced for combustion calculations. The HHV gives a gross heat content for the fuel, including the heat of vaporization. In Europe, a fuel's lower heating value (LHV) is often used, which does not include the heat of vaporization. When calculating thermal efficiency based on a fuel's lower heating value, a given combustion system seems to have a higher efficiency compared to use of the fuel's HHV in the calculation. In the SI system, a fuel's heating content is typically given in kilojoules per unit mass or volume.

The generation of steam (qv) is essentially a two-stage process. Through the addition of heat, the temperature of water is first raised to its boiling point, ie, 100°C at atmospheric pressure. After the boiling point is reached, the temperature at the contact point between the liquid and vapor remains constant as long as the pressure is not permitted to build, such as in a partially closed vessel, until vaporization is completed. When water is boiled in a closed vessel, such as in the steam drum of a utility boiler, vapor generation increases the pressure within the vessel. As the pressure increases, the boiling point (or saturation temperature) increases. Thus, in a boiler operating at 8.27 MPa (1200 psia), water must be heated to nearly 299°C to achieve boiling (Fig. 2).

In most utility boilers, steam pressure regulation is achieved by the throttling of turbine control values where steam generated by the boiler is admitted into the steam turbine. Some modern steam generators have been designed to operate at pressures above the critical point where the phase change between liquid and vapor does not occur.

The visible plume associated with steam leaks, or the vapor that spouts from a tea kettle, is actually caused by fine particles of water entrained in the steam flow. When steam is free of entrained moisture, it is invisible. Because moisture can damage piping, turbines, and other steam path components found in a power plant, the steam is generally superheated to a point where the potential for moisture carryover is minimized. In addition, superheating of steam (adding more heat beyond the boiling point) is also generally desirable to maximize the achievable output from a given size boiler. Designing a plant to operate at higher superheated steam temperatures enables higher plant efficiencies because a smaller percentage of the steam's total heat input remains as it exits the turbine and is condensed.

## 4. Rankine Cycle Power Plants

Power plants based on the Rankine thermodynamic cycle have served the majority of the world's electric power generation needs in the twentieth century. The most common heat sources employed by Rankine cycle power plants are either fossil fuel-fired or nuclear steam generators. The former are the most widely used.

### 4.1. Fossil Fuel-Fired Plants

In modern, fossil fuel-fired power plants, the Rankine cycle typically operates as a closed loop. In describing the steam–water cycle of a modern Rankine cycle plant, it is easiest to start with the condensate system (see Fig. 1). Condensate is the water that remains after the steam employed by the plant's steam turbines exhausts into the plant's condenser, where it is collected for reuse in the cycle. Many modern power plants employ a series of heat

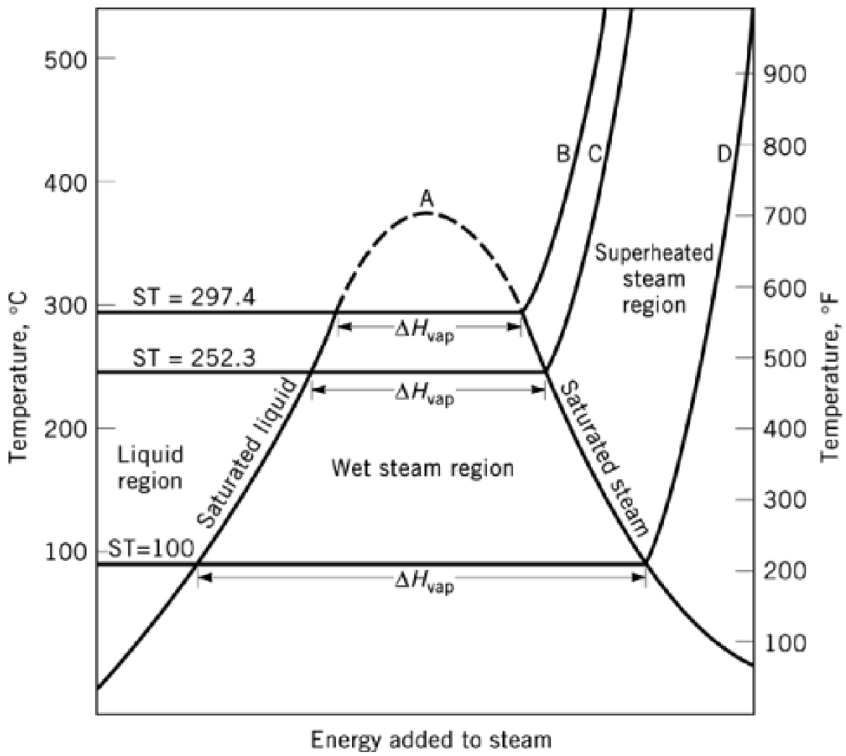



**Fig. 2.** Properties of steam, where ST=saturation temperature and numbers are in °C. Point A corresponds to 22.1 MPa, and lines B, C, and D to 8.27, 4.13, and 0.101 MPa, respectively. To convert MPa to psia, multiply by 145. (Courtesy of the U.S. Naval Institute.)

exchangers to boost efficiency. As a first step, the condensate is heated in a series of heat exchangers, usually shell-and-tube heat exchangers, by steam extracted from strategic locations on the plant's steam turbines.

Another stage of heating occurs in a direct contact, deaerating heater before the water is directed to the boiler feed pumps. The deaerating heater serves a dual role: it not only adds heat to the water, but also improves the water quality by removing dissolved oxygen and other noncondensable gases in the condensate that can cause corrosion within the plant's steam and water piping, steam generator, and steam turbines. Condensate is introduced into the upper portion of the deaerating heater via spray nozzles. There, the fine droplets of condensate are heated to the boiling point by swirling jets of low pressure steam, liberating the entrained, noncondensable components of air, including oxygen and carbon dioxide. The steam literally scrubs the gas molecules off of the water molecules to which they cling. The liberated gas travels up through the top of the deaerater where a vent condenser separates out any vaporized condensate for return to the system before the air is ejected through a vent line. Deaerated water collects in the bottom of the heater vessel.

The deaerator is typically considered the dividing point between the condensate and feedwater systems. Water exiting the deaerator is fed directly to a boiler's high speed centrifugal feedwater pump, which boosts the water's pressure to a level high enough to enable its ultimate introduction into the steam drum where boiling occurs. The steam drum, located at the top of a boiler, is a cylindrical rolled-steel vessel serving multiple purposes. These include (*1*) receiving point and short-term storage location for feedwater before the water enters the boiler tubes; (*2*) serving as the start and termination point for heat-transfer tubes in the boiler; and (*3*) being the chemical dosing and solids blowdown point for water treatment. In a boiler that has a steam drum operating at 4.13 MPa (600 psig), the feedwater pump may be required to boost the feedwater pressure to 5.17 MPa (750 psig) to ensure positive flow to the boiler. Thus, unlike condensate systems that operate at relatively low pressures, the boiler feedwater system operates at a high pressure.

Because boiler feedwater pumps operate at such high pressures and volumetric throughputs, it is critical that the inlet pressure to the pump be maintained at a pressure high enough to prevent the pump from reducing the pressure at its inlet to a point where the heated feedwater would flash into steam. For this reason, the deaerating feedwater tank is typically located at the highest elevation possible in a power plant, with the feedwater pumps in the lowest practical location. In some plants, feedwater booster pumps are employed to ensure sufficient pressure at the inlet to the main feedwater pump. Flashing of steam at a feed pump's suction side can result in overheating and loss of that pump, and possibly even boiler damage if insufficient water is being supplied to generate steam and dissipate the heat produced by the combustion taking place in the refractory-lined furnace (see Furnaces, fuel-fired).

After exiting the feedwater pump and before entering the boiler's steam drum, feedwater usually goes through additional high pressure feedwater heaters (heated by steam turbine extraction steam) as well as another stage of heating in the plant's economizer. The economizer consists of a bank of heat exchanger tubes located in the boiler's backpass section, where heat is transferred from the hot exhaust gas exiting the boiler to the incoming feedwater flowing through the economizer tubes. Most modern fossil fuel-fired power plants share these design features. However, many different types of feedwater heater and boiler arrangements are available, based on the specific steam needs of an application, ie, the required steam temperature and pressure, the type of fuel being burned, space constraints, desired efficiency, and emissions regulations. For example, compact prepackaged boilers have been widely used in industrial and small utility applications. These units can be delivered via rail, barge, or truck fully preassembled or as modular components, which greatly reduces the amount of on-site construction required. Shop assembly of components under controlled conditions can help ensure high quality construction. However, packaged boilers have a limited size range. Thus, field-erected boilers are still required for most large industrial and utility installations.

Boilers can be further categorized by the type of firing system as well as the configuration and type of steam-generating tube employed. Only the basics of furnace heat transfer and steam-generator design are discussed herein. A simplified description of a steam boiler that employs a steam drum is used. However, certain high pressure, once-through supercritical boilers do not employ steam drums. Instead, feedwater is pumped directly into boiler heat-transfer tubes that ultimately terminate at a header where steam is collected for use in the steam turbine.

After exiting the economizer, the feedwater is directed into the boiler's cylindrical steam drum via a common header pipe that penetrates the drum's wall and distributes the water evenly within the drum through holes drilled in the upper side of the distribution pipe. Because the distribution pipe is located axially below the waterline in the lower section of the steam drum, the incoming feedwater mixes thoroughly with the water in the drum and prevents any significantly uneven temperature distributions within the drum.

In modern natural-circulation watertube boilers, the steam drum makes up the uppermost end of a thermal circuit (Fig. 3). Downcomer tubes make up one side of this thermal circuit, bringing hot, high pressure water from the steam drum down to waterwall headers (or manifolds) located at the bottom of the furnace. The downcomers initiate along the length of the steam drum's underside and run vertically downward on the outside of the hot furnace. Waterwall tubes (risers) extend upward from the waterwall headers, forming a box around the furnace, within which combustion takes place (Fig. 4). Heat is released to the waterwall tubes mainly through radiant heating. As the water in the waterwall riser tubes is heated, its density decreases, causing it to rise upward in the tubes, where it eventually reaches its saturation temperature and steam bubbles form. The saturated steam formed in the waterwalls exits into the upper portion of the steam drum.

It is important that the rate of circulation within the waterwall tubes be great enough to carry heat away from the metal tube walls fast enough to prevent the walls from overheating. Because the circulation is dependent on the difference in density between the cooler water found in the downcomers and the hotter water

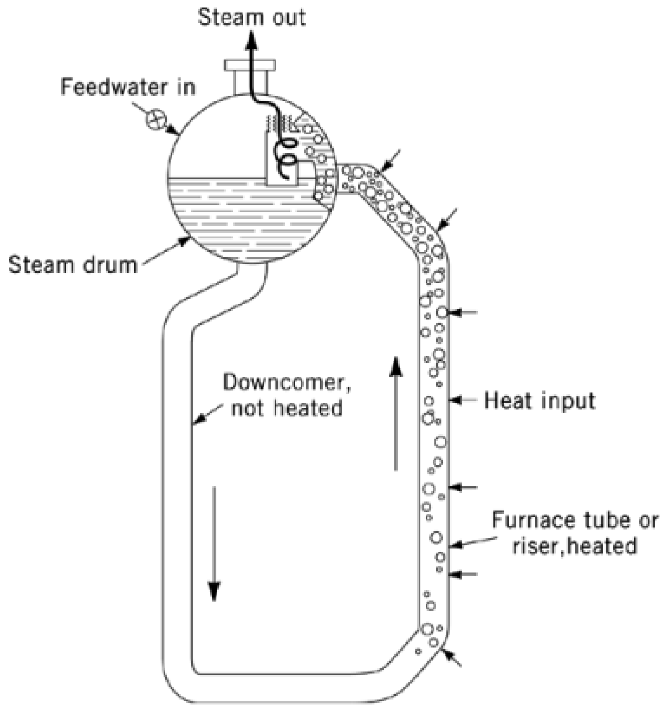



**Fig. 3.** Simple schematic of a natural or thermal circulation loop. (Courtesy of The Babcock and Wilcox Co.)

and steam located in the waterwalls, the rate of circulation increases as this differential pressure increases. Thus, the rate of heat transfer from the combustion zone to waterwalls, the height of the boiler, and its operating pressure all combine to determine the rate of circulation.

Certain boilers employ forced circulation, whereby a pump helps impart the circulation through the downcomer lines to the waterwall header, particularly to improve or control circulation at low loads. Forced-circulation pumps are also required in high pressure and supercritical pressure boilers, because once the pressure within a boiler approaches the critical pressure, 22.1 MPa (3208 psia), the densities of the water and steam become similar, limiting or eliminating the potential for natural circulation.

After the waterwall tubes deliver the saturated steam back into the top of the boiler drum, moisture is separated out by a series of baffles, steam separators, and corrugated screens. The water removed drops down into the hot water contained in the steam drum. The steam travels out through either a dry pipe, which leads to a superheater header, or a series of superheater tubes that connect directly into the top of the steam drum. The superheater tubes wind back into the top of the furnace and/or a hot flue-gas backpass section, next to the economizer, where heat from the combustion gases exiting the furnace superheats the steam traveling through the tubes.

The superheated steam generated in the superheater section is collected in a header pipe that leads to the plant's high pressure steam turbine. The steam turbine's rotor consists of consecutive sets of large, curved, steel alloy disks, each of which anchors a row of precision-cast turbine blades, also called buckets, which protrude tangentially from the shaft and impart rotation to the shaft when impacted by jets of high pressure steam. Rows of stationary blades are anchored to the steam turbine's outer shell and are located between the rows of moving rotor blades.

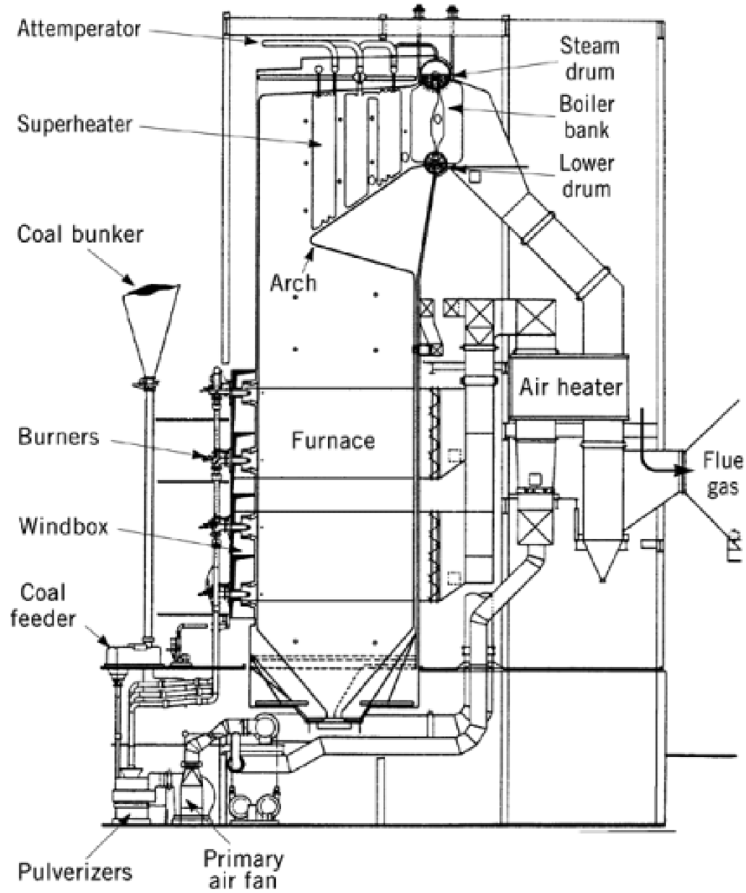



**Fig. 4.** Two-drum Stirling power boiler system for pulverized coal. The flue gas exits via back-end environmental control devices. (Courtesy of The Babcock and Wilcox Co.)

Superheated steam first enters the high pressure (HP) turbine, after passing through a control valve, via a nozzle box where the steam is allowed to expand through nozzles, creating a controlled, high energy jet of steam directed at the first stage of moving buckets. Each subsequent stage of interstage nozzles further expands and redirects the steam, so that it impacts the succeeding row of moving blades at the optimum angle for imparting maximum rotational force. As the steam travels axially through each row of turbine blades, it loses energy and expands. Thus, subsequent rows of blades are proportionally larger to accommodate the expanding steam volume and to ensure that maximum energy is transferred from the steam to the moving blades.

Some steam may be extracted from the turbine at interstage locations for use in feedwater heating. Optimizing the plant's overall efficiency via such extraction and heat exchange is one of the many complex thermodynamic challenges facing designers of modern high efficiency power plants. Another way that plant efficiency is optimized is through the use of a reheat turbine, often located on the same shaft as the high pressure turbine. Here, steam exiting the last stage of the HP turbine is collected in a header and directed to a reheater tube bank located within the boiler's upper furnace or flue-gas backpass near the superheater tubes. This reheated steam is then used to drive the reheat turbine. A principal benefit of using reheat is that thermal and friction losses associated with condensation in the latter turbine stages can be minimized.

In many large plants, an intermediate pressure (IP) turbine is located on the same shaft as either the HP turbine or the low pressure (LP) turbine. In this arrangement, a common gearbox translates the torque from the high speed turbine shaft to a generator shaft turning at a much lower speed. Unless reheat is used, the steam exiting the HP turbine is typically used directly in the IP turbine.

Steam exiting the IP turbine is used to power a LP turbine, which usually, but not always, drives a separate generator. LP turbines employ larger blades than those of IP and HP turbines to best utilize the expanded steam volume available in this latter stage of the cycle. By the time the steam exits the last stage of the LP turbine, a significant amount of energy has been extracted and condensation begins to occur.

A wide variety of turbine types and arrangements are used in modern power plants. For example, some small industrial plants may use only a single condensing turbine. Prepackaged steam/turbine generator systems can be economical for small-to-midsize installations.

To accommodate the expanding steam exiting the LP turbine, the steam is directed into a condenser, typically a large rectangular shell-and-tube heat exchanger within which thousands of cooling water tubes are located. The incoming steam flows over the cold tubes, condenses, then drops to the bottom of the vessel for recycling into the condensate system. The rapid contraction and condensation of steam that occurs in the condenser causes a partial vacuum to form there. Air ejectors are used to draw out noncondensable gases, eg, air, that can build up in the condenser. A loop seal is located in the line that feeds the condensate back to the feed system to enable the withdrawal of condensate without loss of vacuum within the condenser.

The materials used in the Rankine cycle power plant must be carefully chosen to ensure long service life in the severe temperature, pressure, and cyclic conditions that exist in modern power plants. Steam turbines, piping, and valving must be resistant to high temperature corrosion and erosion by entrained moisture. The exteriors of steam generation tubes located in the path of the hot flue-gas stream must stand up to the erosive forces of uncombusted and partially combusted particulates in those gases. Components must also be designed to allow for significant thermal expansion and contraction.

#### *4.1.1. Water Treatments*

As for many other industrial processes, water treatment and monitoring is critical for the integrity of system components. The goal of water treatment is to ensure that the water used for steam generation is pure, such that any contaminants that could lead to corrosion, erosion, or scaling of boiler components are absent. The deaerating feedwater heater is one means by which noncondensable gases are removed from the system. Air and contaminant in-leakage can occur in a number of locations, but particularly through joints, seals, and leaks in the low pressure turbine and condenser, because of the vacuum present in the condenser. Oxygen scavenging chemicals, such as hydrazine, hydroquinine, or erythorbic acid, are also dosed into the feedwater system to eliminate any oxygen not removed by the deaerator or air ejectors.

As the water evaporates into steam and passes on to the superheater, solid matter can concentrate in a boiler's steam drum, particularly on the water's surface, and cause foaming and unwanted moisture carryover from the steam drum. It is therefore necessary either continuously or intermittently to blow down the steam drum. Blowdown refers to the controlled removal of surface water and entrained contaminants through an internal skimmer line in the steam drum. Filtration and coagulation of raw makeup feedwater may also be used to remove coarse suspended solids, particularly organic matter.

Scaling of boiler tubes is a particularly serious problem because it can cause overheating and failure of tubes. Thus, to control scaling, compounds of magnesium and calcium can be removed from the makeup water added to the cycle, or in some cases the condensate, by treatment in a softener or polishing system or a demineralizer. In one type of softener, an ion-exchange (qv) process is used whereby undesirable cations, particularly dissolved magnesium and calcium, are exchanged for comparatively harmless sodium ions present on the surface of small resin balls located in a closed vessel. Periodically, the sodium ions on the resin balls become depleted and it is necessary first to backwash, then to regenerate the resin bed by passing a salt solution through it. Polishing with a sodium-cycle softener can also help filter out suspended metal oxides, which are corrosion by-products. Another type of system, the hot lime zeolite softener, can be used if there is a need to reduce greatly the amount of total dissolved solids in the water. A two-stage zeolite process can be employed for improved control of the pH of the plant's water supply. The goal is to control alkalinity that can cause foaming and accelerated corrosion. The addition of chemical amines is also applied for pH control. The optimal pH for boiler water is in the 8–9.5 range for minimizing the corrosion of steel and copper components.

Demineralizers are often used to treat raw makeup water or condensate where high purity is required, such as in large central station boilers that operate at high steam pressures. Demineralizers employ a combination of cation and anion exchange to remove additional material, including sodium and ammonium cations. Virtually all salt anions, such as bicarbonate, sulfate, and chloride, are removed and replaced by hydroxide ions in the demineralizer.

#### *4.1.2. Fuel System*

Many different types of boilers are available, depending on site-specific requirements. The furnace design and combustion system employed are the primary differences distinguishing boilers based on the fuel burned. However, the main goals of any firing system are the same, ie, to ensure that fuel and air are delivered in such a way as to promote safe, efficient, smooth combustion, and to minimize pollutant emission formation and maximize heat transfer to the waterwall tubes. Properly controlling the air-to-fuel ratio is central to these goals. Insufficient air leads to incomplete combustion, the formation of high levels of carbon monoxide, high particulate emissions, and the potential for hazardous buildup of unburned fuel in the boiler and exhaust stack. Excessive air can significantly decrease boiler efficiency. To maximize both safety and efficiency, boilers are typically operated having 10–20% excess air over the level required to achieve complete or stoichiometric combustion. Oxygen monitors are employed and incorporated into combustion control systems for this reason. Whether a boiler fires liquid fuel, coal, or natural gas, there are typically multiple burners which serve to direct the fuel into the furnace for combustion and which ensure that proper fuel–air mixing occurs so that combustion takes place at the desired rate and in the desired location.

Many liquid fuel-fired boilers burn residual, ie, No. 6, oil, which has a high heating value (HHV) of approximately 44,270–46,600 kJ/kg (19,000–20,000 Btu/lb). Oil fuel is typically delivered to a power plant via barge, rail, or pipeline. The liquid fuel is stored in large tanks featuring explosion-proof gooseneck vents and a surrounding spill-containment basin. Oil is delivered under pressure to the boiler's burners by a positive displacement pump. Strainers upstream from the pump filter out sediment and contaminants. A recirculation line from the pump's outlet to its suction side helps prevent damage to the pump when pressure fluctuations occur, such as in a sudden shutdown.

Oil-firing systems use either pressurized steam, air, or mechanical means of atomizing the fuel oil into small droplets as it is sprayed from the burner. Atomizing maximizes the surface area of fuel oil exposed to air, ensuring thorough mixing of fuel and air, and efficient combustion. Pressurized air is introduced through primary, secondary, and sometimes tertiary ports in and around the burner. Forced-draft fans deliver the air to the burner through windboxes, which are essentially flow-ways built into the walls of the furnace, exterior to the waterwalls. Combustion air is preheated via heat exchangers that extract heat from the boiler's hot exhaust gases. Induced-draft (ID) fans located in the exhaust duct near the stack may be applied to provide further control of gas flow and heat transfer within the boiler. ID fans may also help compensate for the pressure drop that occurs across equipment located in the flue-gas stream, such as cyclone separators, fabric filters, or electrostatic precipitators (ESPs) systems used to capture flyash entrained in the exhaust gas.

Natural gas, which has a heating content of 51,260–55,290 kJ/kg (22,000–24,000 Btu/lb) HHV, is usually delivered to a power plant via pipeline (see Pipelines). The gas pressure typically must be stepped down from

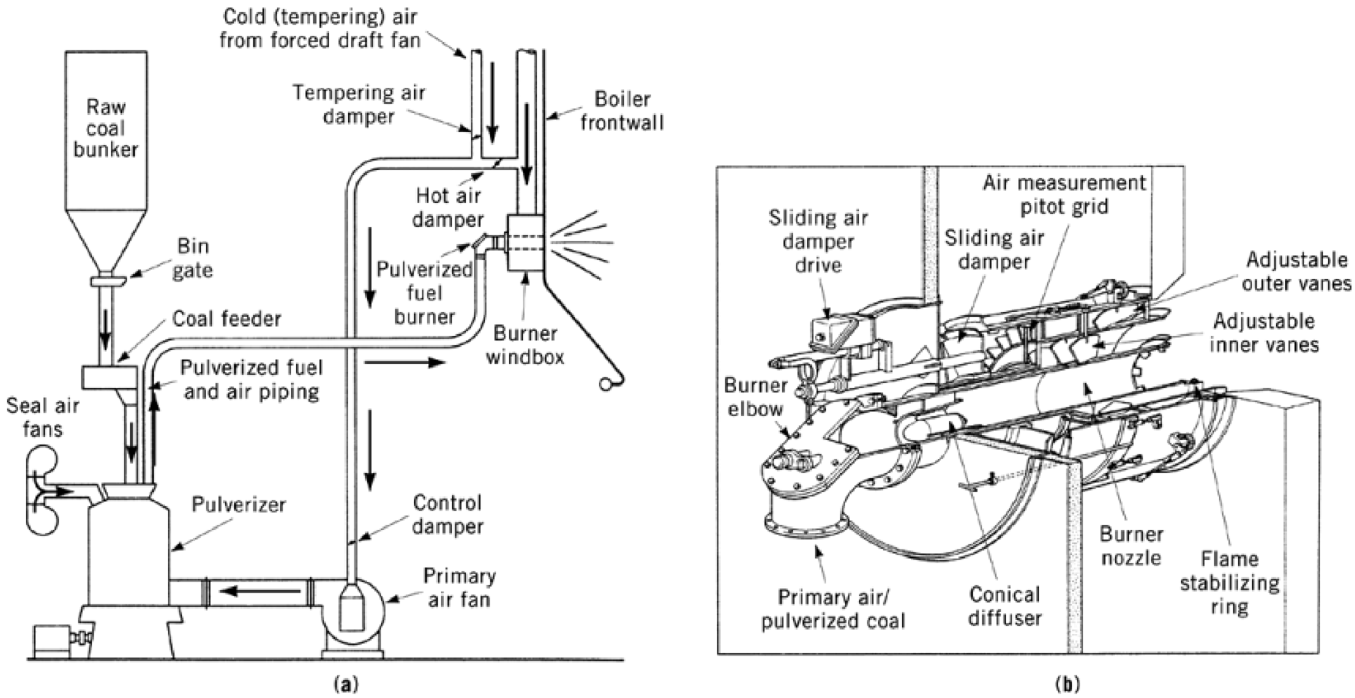



**Fig. 5.** Schematics of (**a**) direct-firing hot-fan system for pulverized coal; and (**b**) low $NO_x$ burner for coal firing. (Courtesy of The Babcock and Wilcox Co.)

the gas-supply line pressure via pressure reducing valving for use in the plant. Gas distributors maintain a fuel-gas-metering station at the fence line of gas-fired power plants. From that point on, the specific gas-handling equipment requirements vary significantly, depending on site-specific factors. Pipeline-quality gas is generally clean and dry. However, shell-and-tube heat exchangers may be required to keep gas temperatures safely above the dew point and eliminate the potential for condensation of water or liquid hydrocarbons. Piping runs must also be designed to eliminate pockets or low points where condensate might collect to form slugs.

Gas-fired boilers employ burners that are similar in appearance to oil-fired burners. However, these do not require atomizers and are designed predominantly for controlling the mixing of fuel and air in the desired combustion zone. Natural gas-fired plants typically have relatively low air pollutant emissions when compared to oil- or coal-fired facilities, because only minute levels of trace compounds are present in natural gas. For example, gas-fired facilities require no controls for sulfur dioxide, $SO_2$, the main precursor to the formation of acidified rain. Emissions of oxides of nitrogen, $NO_x$, although much lower when compared to typical oil- or coal-fired facilities, may require control. $NO_x$ emissions can lead to the formation of low level ozone (qv) or smog and contribute to acid rain, but to a much lower degree compared to $SO_2$. Many plants feature dual-fuel burners, which allow either gas or oil to be burned.

Coal-fired plants utilize much different fuel-firing systems. The most common firing system is found in pulverized coal-fired (PC-fired) facilities. Central to this system is a pulverizer that crushes the raw coal into a fine powder and dries it by using hot, incoming combustion air. The pulverized coal can then be delivered pneumatically to burners where additional air is added via the furnace's windbox (Figs. 5 and 6). The burners are normally located on the furnace's wall (wall firing) or mounted in every corner (tangential firing).

Although PC-fired units account for a large portion of the coal-fired facilities in the United States and elsewhere, other firing options are available for solid fuel firing. For example, fluidized-bed-fired boilers have

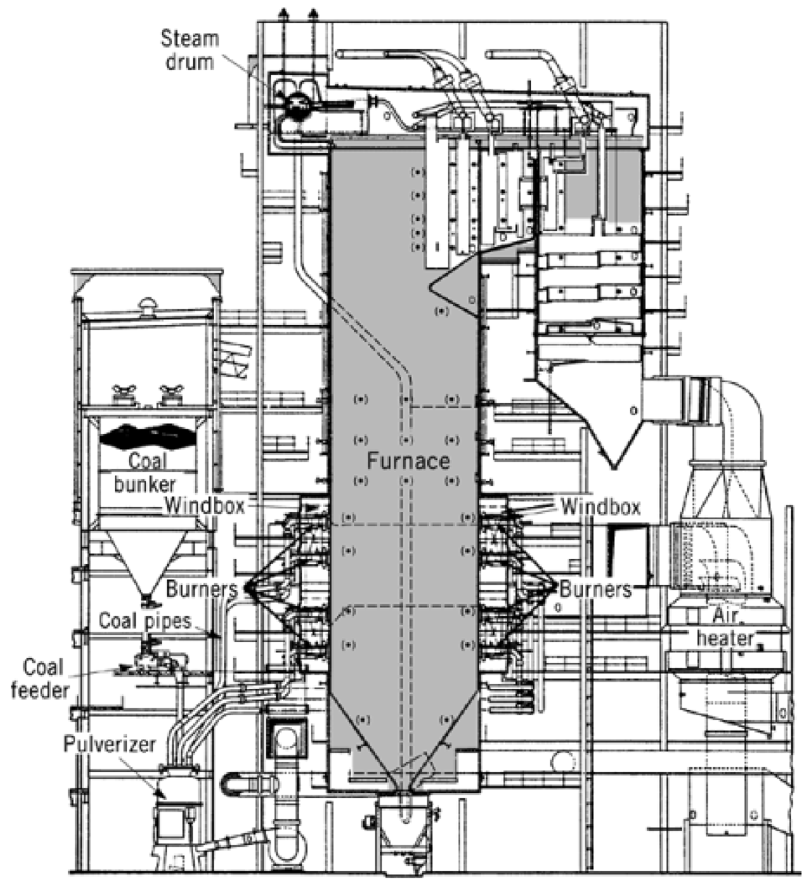



**Fig. 6.** Conventional pulverized coal-fired system. (Courtesy of The Babcock and Wilcox Co.)

become increasingly popular because these can control pollutant emissions to low levels as well as fire a wide variety of solid fuels, such as low grade coals and coal wastes, petroleum coke from the oil-refining process, wood (qv) and agricultural wastes, and de-inking sludge from newspaper recycling.

Fluidized-bed combustors (FBCs) employ a unique combustion process whereby the fuel is injected into and burned in a highly turbulent bed of combustion air, inert material such as sand, and burning fuel. FBCs can typically be classified as either fixed-bed, bubbling-bed, or circulating fluidized-bed combustors (CFBCs), depending on the velocity of burning solids within the unit (see Fluidization). Fixed- and bubbling-bed FBCs feature relatively low velocities and the burning fuel bed is isolated to the lower furnace region. In CFBs, a portion of the burning solids leaves the combustion bed and becomes entrained in the hot gases of combustion that rise up out of the bed. The burning particles are recirculated back into the bed, before reaching the boiler's convective backpass, by a cyclone separator–loop seal arrangement.

In most cases, FBCs employ some type of air injection system in the floor of the furnace both to impart turbulence into the burning fuel bed and supply combustion air. Secondary and tertiary air ports may be located above the burning fuel bed.

Other types of solid fuel-firing systems used in modern power plants include traveling grate stokers, ie, fuel injected onto a burning pile on a moving grate; roller grates; inclined grates; cyclonic burners; and suspension burning. Traveling grate systems have been widely used for burning waste fuels, including refuse-derived fuels (RDF), municipal solid waste, and wood chips (see Fuels from waste).

#### *4.1.3. Emission Control*

In 1993, for a net electric power generation of $3196 \times 10^9$ kWh, power industry emissions were as follows:

| Air pollutant | Quantity, $t \times 10^6$ |
|---|---|
| $SO_2$ | 13.8 |
| $NO_x$ | 6.25 |
| $CO_2$ | 2124 |

In oil-, gas-, and coal-fired facilities, low $NO_x$ burners have been successfully applied to reduce $NO_x$ emissions by limiting the peak burner flame temperatures either by rapid premixing of fuel and air, or by staging the introduction of air or fuel to achieve a longer, cooler flame. A key design goal of rich-burn low $NO_x$ systems is to limit the amount of oxygen available in the peak temperature zone where $NO_x$ formation occurs. Post-combustion or back-end $NO_x$-control treatments, such as selective catalytic reduction (SCR) or selective noncatalytic reduction (SNCR) of $NO_x$ via ammonia injection, can be applied where stringent $NO_x$-control regulations are in effect.

$$4NO + 4NH_3 + O_2 \longrightarrow 4N_2 + 6H_2O$$

$$6NO + 8NH_3 + 3O_2 \longrightarrow 7N_2 + 12H_2O$$

A schematic of a SCR system is shown in Figure 7. Systems capable of operating at higher temperatures than those shown in Figure 7**b** were under development as of 1995.

Emissions control systems play an important role at most coal-fired power plants. For example, PC-fired plants sited in the United States require some type of sulfur dioxide control system to meet the regulations set forth in the Clean Air Act Amendments of 1990, unless the boiler burns low sulfur coal or benefits from offsets from other highly controlled boilers within a given utility system. Flue-gas desulfurization (FGD) is most commonly accomplished by the application of either dry- or wet-limestone systems. Wet FGD systems, also referred to as wet scrubbers, are the most effective solution for large facilities. Modern scrubbers can typically produce a saleable wallboard-quality gypsum as a by-product of the $SO_2$ control process (see Sulfur removal and recovery).

Similar to oil-fired plants, either low $NO_x$ burners, SCR, or SNCR can be applied for $NO_x$ control at PC-fired plants. Likewise, fabric filter baghouses or electrostatic precipitators can be used to capture flyash (see Air pollution control methods). The collection and removal of significant levels of bottom ash, unburned matter that drops to the bottom of the furnace, is a unique challenge associated with coal-fired facilities. Once removed, significant levels of both bottom ash and flyash may require transport for landfilling. Some beneficial reuses of this ash have been identified, such as in the manufacture of Portland cement.

A principal advantage of fluidized-bed combustors for firing high sulfur fuel is that limestone sorbent can be injected directly into the burning bed where the sorbent reacts directly with the $SO_2$ and other acidic gases requiring control to achieve high capture rates. Another advantage of FBCs relates to $NO_x$ control. Because of the thorough mixing of the burning fuel, temperatures within the burning bed and furnace are relatively uniform and comparatively low. This limits the $NO_x$ production associated with higher combustion region temperatures, ie, thermal $NO_x$. In addition, ammonia or other reagents can be injected into the upper furnace

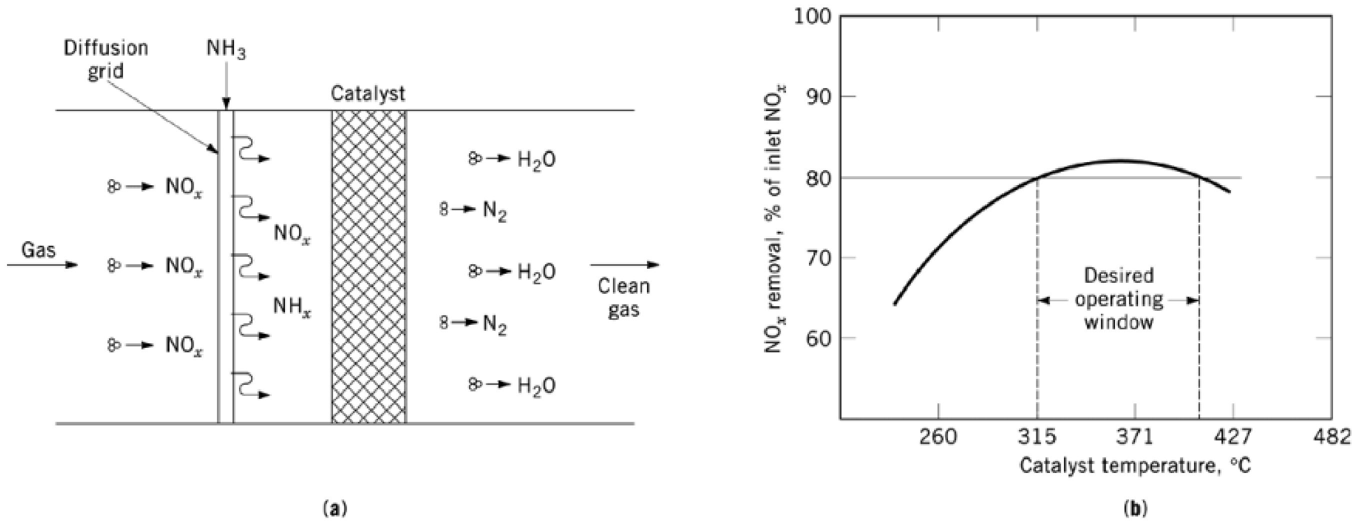



**Fig. 7.** $NO_x$ reduction using selective catalytic recovery (SCR): (**a**) basic principles of the SCR process where represent gas particles; and (**b**) effect of temperature on $NO_x$ removal. (Courtesy of General Electric.)

area to achieve low $NO_x$ levels at the plant's stack. Because the solids entrained in CFBs can be abrasive, these units must be well designed to ensure that the refractory lining protects key components and withstands rapid erosion by the circulating solids.

#### 4.2. Nuclear Fuel-Fired Plants

There are some basic design differences of the nuclear plants steam cycles (see Nuclear reactors) as compared to conventional fossil fuel plants. In nuclear power plants, thermal energy is released during the fissioning of a nuclear fuel (or fissile), such as uranium-235. Fission, the splitting of a heavy nucleus, is typically initiated when the material is struck by a neutron. When the nucleus of a fissile material's atom is split, the energy associated with the atom is released. This energy, approximately 100 billion times that released during the combustion of one carbon atom in fossil fuels, is significant. In addition, extra neutrons are released that impact other nuclei, creating chain reaction.

Extremely safe means of controlling the nuclear reaction process have been devised by introducing materials that can moderate the production and absorption of neutrons released during fission. The two most popular types of lightwater nuclear reactors are boiling-water reactors (BWRs) and pressurized-water reactors (PWRs). These feature similar fuel assemblies consisting of 2–4% enriched uranium dioxide fuel pellets stacked in zirconium alloy cladding tubes. In both designs, the fuel is housed within water-filled pressure vessels. Control rods consisting of a moderating material can be lowered (for PWRs) or raised (for BWRs) into the reactor core to absorb neutrons and temper the reaction.

In BWRs, steam is generated in a single-loop arrangement, whereby water enters through the bottom of the reactor vessel, picks up heat from the reacting nuclear fuel assembly, and exits through the top of the vessel. For safety reasons, the fuel assembly remains immersed in water. However, steam is generated and released in the top of the reactor vessel. A series of mechanical separators and dryers serve to remove water entrained in the steam to protect downstream piping and steam turbine. Overall, steam conditions in nuclear power plants are much less severe than those in conventional fossil-fired stations. For example, steam exiting a BWR has an average temperature below 300°C, compared to 550°C or higher for a similar-sized fossil-fired steam generator.

PWRs operate differently from BWRs. In PWRs, no boiling takes place in the primary heat-transfer loop. Instead, only heating of highly pressurized water occurs. In a separate heat-exchanger vessel, heat is transferred from the pressurized water circuit to a secondary water circuit that operates at a lower pressure and therefore enables boiling. Because of thermal transfer limitations, ultimate steam conditions in PWR power plants are similar to those in BWR plants. For this reason, materials used in nuclear plant steam turbines and piping must be more resistant to erosion and thermal stresses than those used in conventional units.

## 5. Cogeneration

In the power industry, cogeneration refers to the simultaneous generation of heat and power. One example of a cogeneration plant is the central utility boiler that provides steam for both electric power generation and supply to a local district heating system where it can be used for facilities or process heating, or cooling, via absorption coolers or steam-turbine-driven refrigeration and/or air conditioning systems. Such a plant can use a noncondensing steam turbine to supply some or all of the steam required by the district heating system. Because of the significant (up to 48%) losses associated with condensing, all or part of the steam exiting the turbine can be eliminated. A well-designed cogeneration facility can convert 80% or more of the fuel energy input for useful purposes, ie, power generation and process heating. In a conventional Rankine cycle power plant, the thermal energy remaining in the steam as it enters the condenser can range up to 50% or more of the fuel energy input, boiler associated losses are ca 15%, and other losses about 2%. Thus, a conventional Rankine cycle plant may convert only 35% of the fuel energy for power generation. In a modern coal-fired cogeneration system, heat losses can be cut to 16%, 15% of which are boiler-associated. Such a system, where the waste heat is recovered from the main power generation cycle for reuse, is often referred to as a topping cycle (see Energy management; Process energy conservation).

Another example of a topping cycle cogeneration system is one based on recovering the thermal energy exhausting from a gas turbine/generator. Gas turbines are ideal for cogeneration because the high temperature, high flow exhaust gas streams contain a large amount of recoverable heat energy. Heat recovery steam generators (HRSGs) can be used to capture much of the heat in a gas turbine's exhaust (Fig. 8). Unfired-HRSGs are essentially convective steam generators through which a turbine's exhaust gas is directed. Steam generated in the HRSG can be applied in the same fashion as that exhausting from the noncondensing steam turbine. HRSGs can also contain additional burners that require only fuel injection. No combustion air system is needed because gas turbine exhaust streams contain a significant volume of hot, fresh air which is used to prevent overheating of the gas turbine's rotating blades and other hot gas path components.

## 6. Gas Turbines and Combined-Cycle Power Plants

Gas turbine engines have undergone substantial improvement in efficiency and have become increasingly popular for power generation and cogeneration. Units introduced as of the mid-1990s feature simple-cycle efficiencies of more than 40% LHV for just the gas turbine. Combined-cycle power plants based around these units having power conversion efficiencies as high as 60% LHV have been introduced. Combined-cycle facilities recover the waste heat remaining in the combustion turbine's exhaust to drive another power cycle. In this case, the 60% efficiency refers only to energy conversion for electrical output. If steam is also recovered for heating or use in an industrial process, overall plant efficiencies can be significantly higher.

Gas turbines are based on the Brayton thermodynamic cycle (Fig. 9). Most modern units operate in the following manner. Combustion and cooling air is first drawn in and compressed in a multistage axial compressor

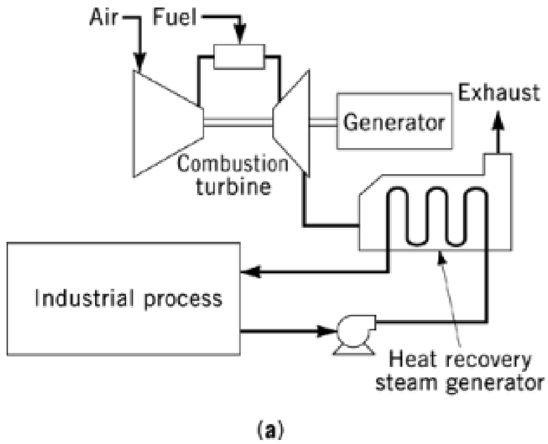



**Fig. 8.** Combustion turbines with process heat recovery: (**a**) represents direct use of exhaust gas for process heating where industrial process includes refinery, chemicals, food processing, and ethanol production; and (**b**) exhaust-to-water heat exchanger where industrial process includes material drying, water chiller, and $CO_2$ production. (Courtesy of General Electric.)

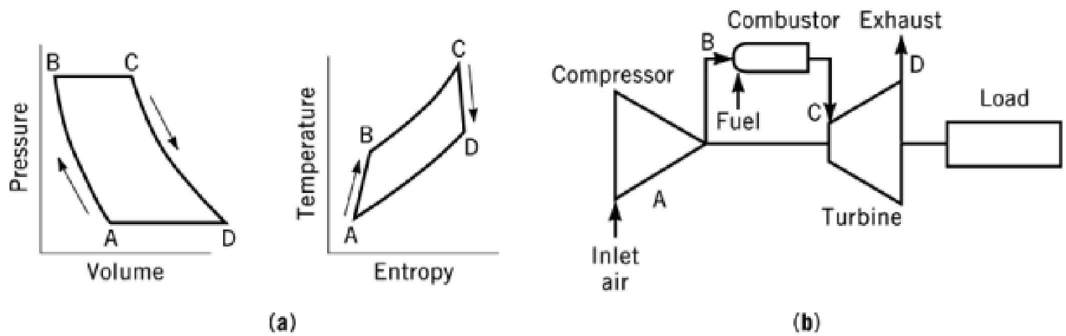



**Fig. 9.** Brayton cycle, where A=compressor inlet, B=combustor inlet, C=power turbine inlet, and D=exhaust: (**a**) thermodynamic relationships and (**b**) schematic of a simple-cycle, single-shaft gas turbine. (Courtesy of General Electric.)

located on the cold end of the gas turbine's rotor (point A of Fig. 9**b**). The compressed air is injected into a combustor section where it is combined with fuel for combustion, generating hot, expanding gaseous exhaust. The expanding combustion gases are then directed axially along the rotor into a power turbine or turbines. There the gases impart torque on the tangential turbine blades in a manner similar to a steam turbine, before exhausting to atmosphere or a heat recovery steam generator. Depending on the size of the gas turbine, the unit's rotor may be linked directly to a generator or attached via a speed-reducing gearbox.

Because gas turbine efficiency and power output can be maximized by increasing a unit's mass throughput and combustor-inlet temperature, gas turbines require a huge volume of air, both for combustion and component cooling. For example, one 168-MW unit, introduced in 1990, employs an 18-stage axial compressor to ingest ambient air at a rate of 409 kg/s at full load. The air exits the compressor at 1.4 MPa (200 psig) for injection into the machine's combustors. Thus, up to 50% or more of the power generated in a gas turbine's power turbine section may be required to drive the unit's compressor. This is one of the reasons that many gas turbines, particularly those derived from aircraft engine designs that feature high compression ratios, are designed with two separate shafts. One shaft incorporates the compressor and initial turbine stage or stages used to drive the

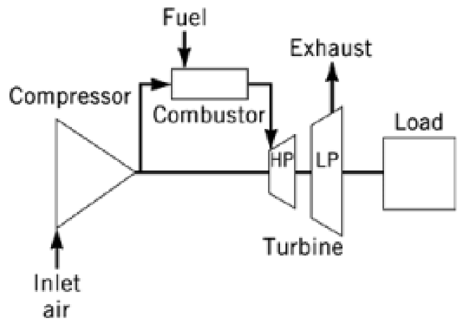



**Fig. 10.** Simple-cycle, two-shaft gas turbine where HP and LP are high and low pressure, respectively. (Courtesy of General Electric.)

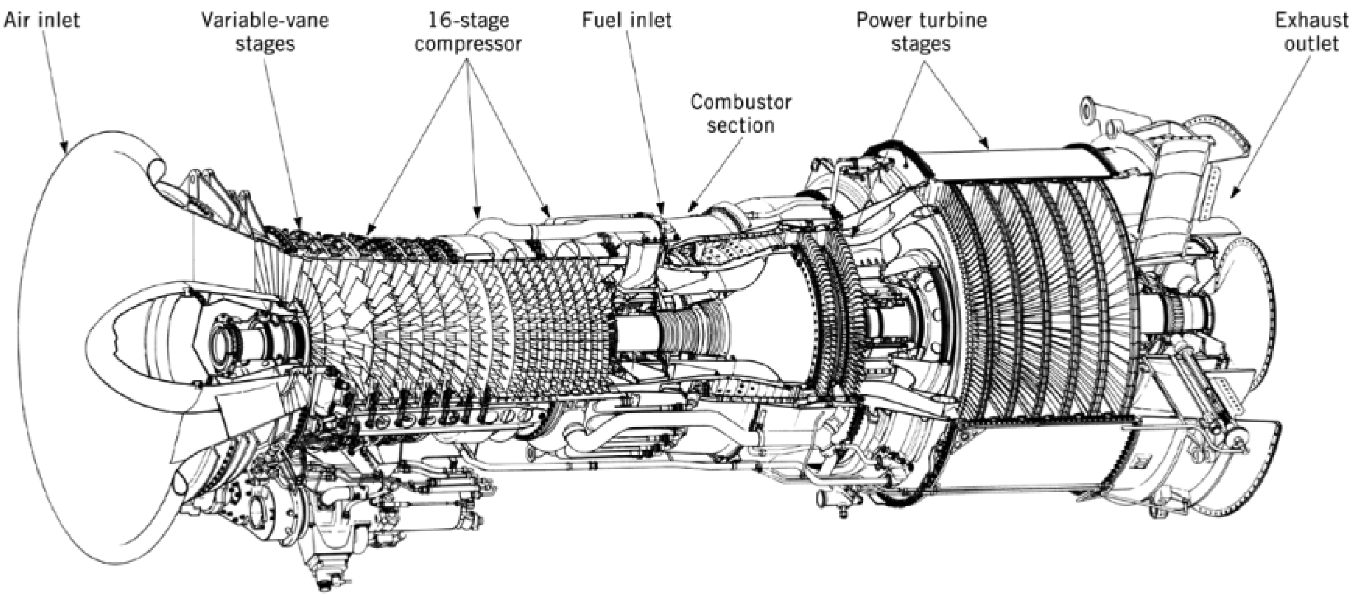



**Fig. 11.** Two-shaft combustion turbine engine. (Courtesy of General Electric Marine and Industrial Engines.)

compressor; the second shaft contains the power turbine stages that drive the unit's generator (Figs. 10 and 11). However, large heavy-duty gas turbines are generally designed to have a single shaft. Because increasing mass throughput can boost plant output, many utility facilities employ inlet-air cooling schemes to maximize plant output, particularly during peak-load hours.

Gas turbine/generators have long been used in remote, and often compact, locations, such as on oil rigs, at gas pipeline pumping stations, and on ships. These systems have evolved to be extremely compact and modular, making them ideal for modern utility and industrial power applications. Site work thus consists mainly of connecting prepackaged modules having a low profile compared to conventional power facilities.

Gas turbine-based power plants, particularly natural gas-fired cogeneration and combined-cycle facilities, have proven to be highly reliable, efficient, and environmentally attractive. Advances in machine design, more efficient plant integration, and optimistic forecasts for the availability of affordable natural gas worldwide have boosted the appeal of these systems for both base-load and peaking service.

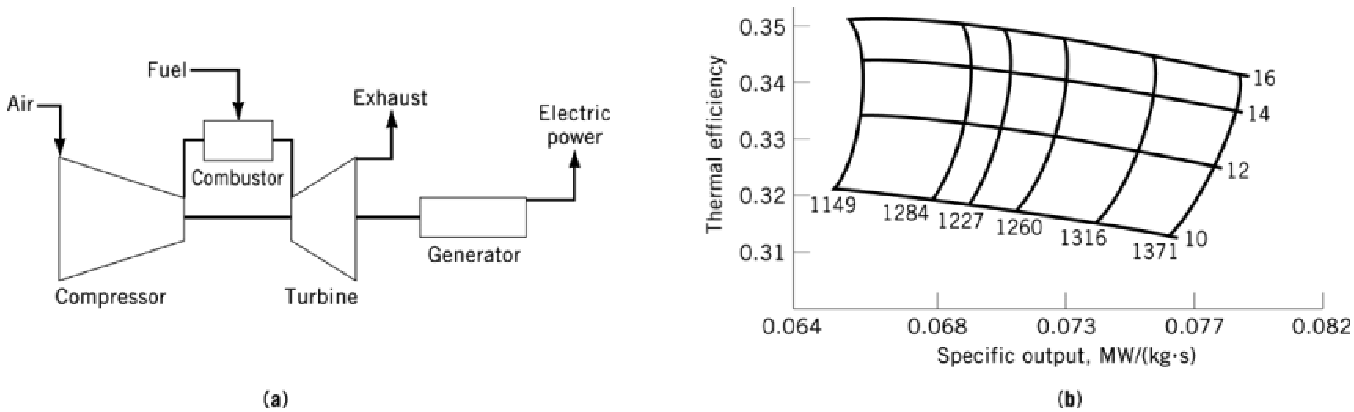



**Fig. 12.** Combustion turbine engine simple cycle: (**a**) schematic of plant; and (**b**) thermodynamics, where the horizontal lines correspond to the pressure ratio, $X_c$, given and vertical lines to the combustor temperature, $T_F$, in °C as indicated. (Courtesy of General Electric.)

Combined-cycle power plants, typically facilities that utilize waste heat from a gas turbine cycle or such technology as reciprocating engines to generate steam for use in a second power generation cycle, have become the most efficient and economical means of generating power in many areas of the world (Figs. 12 and 13). The combined-cycle facility, based on linking the gas turbine or Brayton cycle and the Rankine cycle, is the most common type.

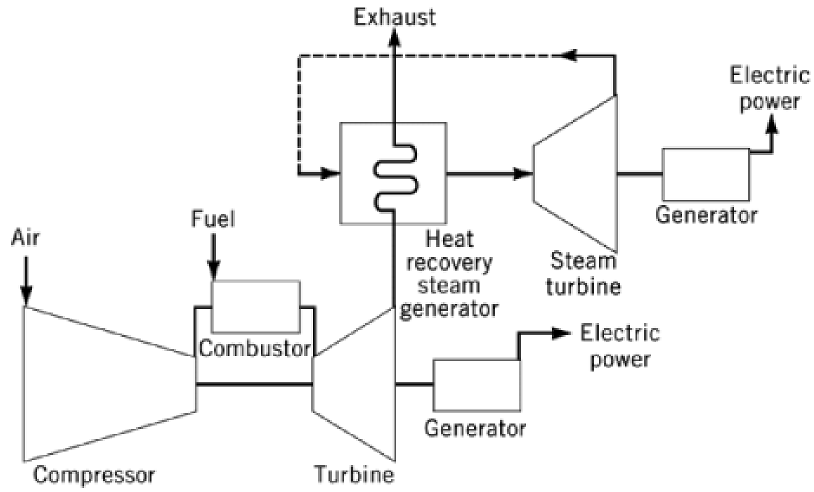
The next generation of gas turbine-based, combined-cycle power plants, under construction in many parts of the world, is to feature net plant efficiencies in the 60% range based on LHV of fuel input. These facilities, scheduled for start-up in the latter 1990s, are anchored by large gas turbines capable of simple-cycle efficiencies >40% LHV in some cases. To develop these machines, manufacturers have scaled up and improved upon designs that have already proved to be highly reliable.

New units can be ordered having dry, low $NO_x$ burners that can reduce $NO_x$ emissions below 25 ppm on gaseous fuels in many cases, without back-end flue-gas cleanup or front-end controls, such as steam or water injection which can reduce efficiency. Similar in concept to low $NO_x$ burners used in boilers, dry low $NO_x$ gas turbine burners aim to reduce peak combustion temperatures through staged combustion and/or improved fuel–air mixing.

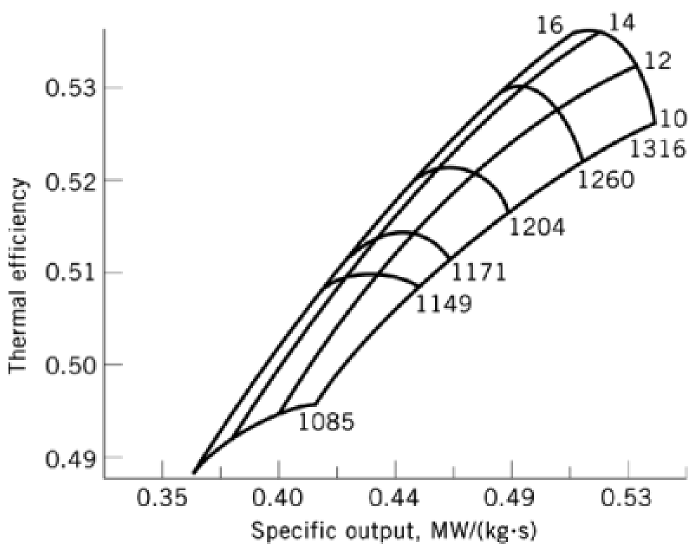
One of the principal challenges faced by burner designers is achieving low $NO_x$ levels and stable combustion simultaneously over a machine's entire load range. Thus some low $NO_x$ burners operate in different modes, depending on what works best at a given load range. For example, one two-stage, low $NO_x$ burner design acts more like a conventional burner at low loads, then biases combustion toward lean/premix operation at higher loads (Fig. 14).

Improved materials, coatings, and cooling techniques permit newer machines to operate at higher turbine inlet temperatures, yielding both increased output and efficiency. Further efficiency gains result from improved aerodynamics in the hot gas path, compressor, and turbine sections. Use is also made of variable inlet guide vanes (IGV).

Manufacturers have also strived to improve the reliability, availability, and maintainability (RAM) of the newer units. Many existing designs have achieved availabilities in the 95–99% range. Based on this performance, makers have introduced ever-larger machines, some up to 282 MW. A more recently introduced, integrated steam-cooled combined-cycle gas turbine is even larger. Although untested as of 1995, the newer gas turbines, to judge from existing designs, should operate reliably in both base-load and utility-peaking service. Facilities based around one large gas turbine/generator typically have lower capital requirements and




(a)




(b)

**Fig. 13.** Combustion turbine engine combined cycle: (**a**) schematic of plant; and (**b**) thermodynamics, where the vertical lines correspond to the pressure ratio, $X_c$, given and the horizontal lines to the combustor temperature, $T_F$, in °C as indicated. (Courtesy of General Electric.)

operating costs compared to plants based around multiple gas turbines. In addition, the large units being introduced in the mid-1990s retain much of the start-up and cycling flexibility displayed by smaller machines and are also better suited for future conversion to coal-gas firing (see Coal conversion processes).

Natural gas-fired combined cycles are usually less expensive to install and maintain than are conventional oil- or coal-fired power plants. The only clear disadvantage of natural gas as a fuel is the high delivered cost in certain areas. Per unit of heating value, gas is about 100 times bulkier than oil. Even when liquefied in

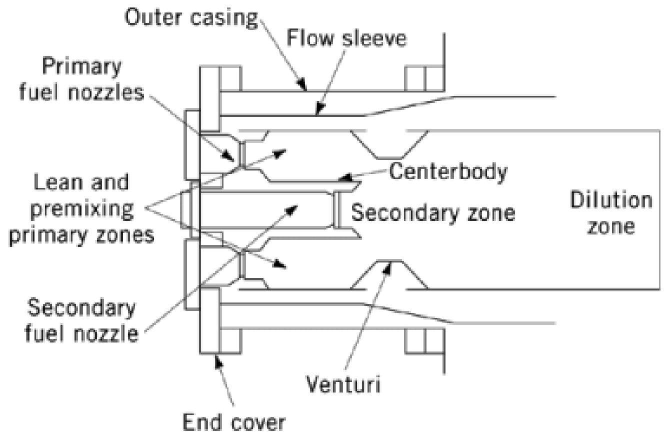



**Fig. 14.** Dry, low $NO_x$ combustor schematic (3, 4). (Courtesy of General Electric.)

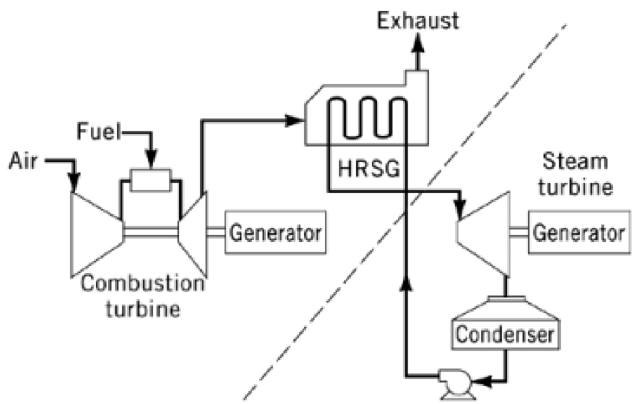



**Fig. 15.** Repowering schematic where the modules to the left of the dashed line have been added to the existing Rankine cycle plant shown on the right of the dashed line. HRSG=heat recovery steam generator. (Courtesy of Black and Veatch.)

a costly process (see Liquefied petroleum gas), natural gas is still 60% bulkier than oil. Only about 15% of the world's gas supply is traded internationally, compared to half of the world's oil. However, the combination of increasingly stringent emissions regulations, advances in natural gas exploration and recovery techniques, and international cooperation on new gas drilling and pipeline projects, has decreased the delivered cost of gas compared to coal and oil in many regions.

Electric utilities and others are beginning to apply combustion turbines in a number of unique ways. For example, gas turbines can be used to repower aging Rankine cycle power plants. Repowering typically refers to the retirement of a plant's boiler, combined with the installation of a new combustion turbine/generator and HRSG capable of generating enough steam to operate the plant's original steam turbine in a combined-cycle configuration (Fig. 15).

Other innovative concepts include the incorporation of coal-gas-fired gas turbine generators into highly efficient combined-cycle arrangements with integrated coal gasification and air separation facilities (Figs. 16, 17, 18) (see Nitrogen). Integrated gasification combined-cycle (IGCC) facilities can achieve net efficiencies above 40% while maintaining extremely low emissions. For example, 98–99% of the sulfur can be removed from the coal gas and recovered as a potentially saleable by-product. Some utilities installing large natural

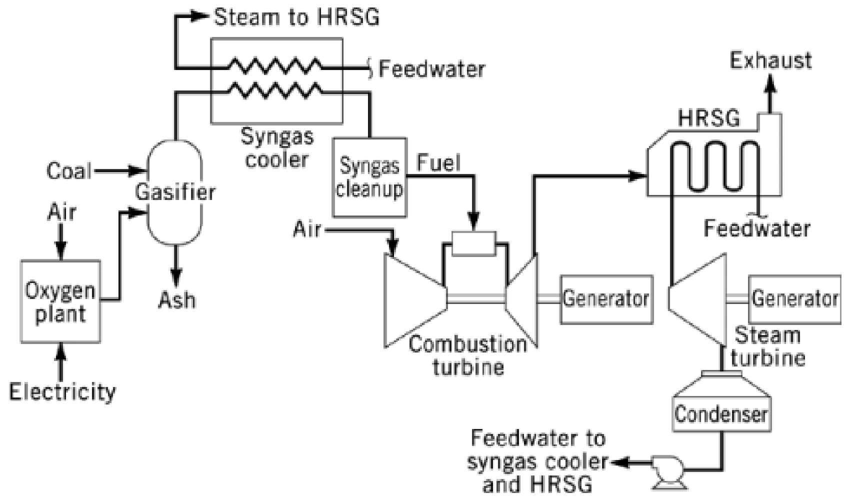



**Fig. 16.** Coal gasification power plant; HRSG=heat recovery steam generator. Courtesy of Black and Veatch.

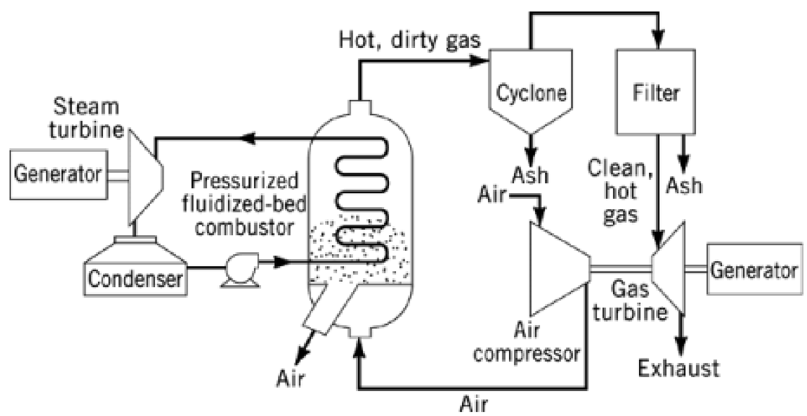



**Fig. 17.** Pressurized fluidized-bed combustion. (Courtesy of Black and Veatch.)

gas-fired peaking turbines plan eventually to convert these facilities for combined-cycle operation as required load grows. Others are keeping the option open to add coal gasification equipment at some future date if natural gas prices rise dramatically.

Several utility-scale demonstration facilities having power outputs in the 300-MW class have been constructed in the United States and Europe. These started accumulating operating experience in 1995 and 1996. Other IGCC plants have been constructed, including units fueled by petroleum coke and refinery bottoms. Advanced 500-MW class IGCC plants based around the latest heavy-duty combustion turbines are expected to be priced competitively with new pulverized-coal-fired plants utilizing scrubbers.

## 7. Advanced Gas Turbine Designs

Scaled-up gas turbine designs typically have higher efficiencies than their predecessors. Power increases by roughly the square of the scaling factor whereas machine losses increase in a linear manner. Output and

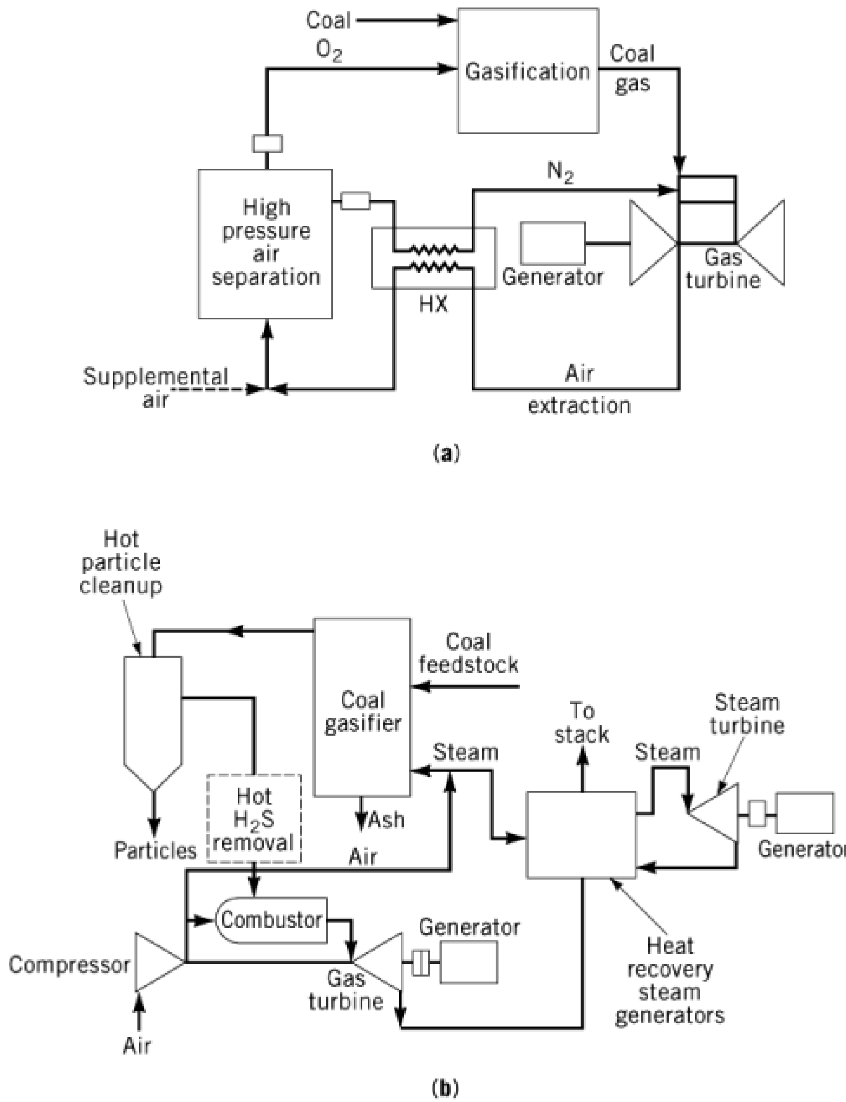



**Fig. 18.** Integrated gasification combined-cycle (IGCC) process: (**a**) integrated air separation; and (**b**) simplified IGCC. (Courtesy of General Electric.)

efficiency are further boosted in some cases because the larger machines operate at slower speeds and therefore do not have the gearing-related losses inherent in small high speed designs.

Gas turbine technology has advanced rapidly in the latter 1990s. The most up-to-date information in combustion turbine technology is available in the *Annual Technology Report* published by the International Gas Turbine Institute (IGTI) in Atlanta, Georgia, part of the American Society of Mechanical Engineers (ASME) International.

Beyond increases directly linked to scaling up, manufacturers can extract higher outputs and efficiencies from new designs by increasing the turbine inlet temperature and the relative mass flow of air, and therefore of combustion gases. One European manufacturer has introduced a 170-MW gas turbine/generator for 60-Hz service and a 240-MW unit for 50-Hz service. These are basically scaled-up versions of what was originally an advanced 60-MW machine. The newer machines reportedly feature simple-cycle efficiencies of 38%. Combined cycles based around two such machines, a single reheat steam turbine and triple-pressure heat recovery steam generators (HRSG) yield plant efficiencies up to 58% or a heat rate of under 5687 kJ/kWh (6000 Btu/kWh).

The 170-MW machine, a popular size for reasons of economics and applicability to phased construction, features a 15-stage compressor and a four-stage power turbine section. Compared to a 106-MW unit developed by the manufacturer during the 1980s, the pressure ratio, $X_c$, ie, the compressor outlet pressure divided by the air-inlet pressure, has increased from 10.8 to 16.5. Total mass flow through the compressor has increased from 353 to 454 kg/s. To accommodate increased mass flow and elevated pressure, the 170-MW machine features compressor-intake dimensions that are 15% larger. In addition, the first two compressor stages are designed to permit stable supersonic flow velocities there. This is an important feature for maximizing the flow without drastically increasing a unit's size and length compared to earlier models.

The firing temperature for the newest gas turbines being put into service as of the mid-1990s has reached 1310°C. The value was only 1105°C for earlier designs. To accommodate this high firing temperature, newer machines feature a double-shell construction. An inner wall of metallic heat-shield pads keeps the high temperature gas flow away from the turbine's horizontally split outer shell. Impingement air cooling and film cooling are used to minimize hot spots on the metallic heat shields. Both external cooling air and intercooled compressor–extraction air are used to cool various stages of the power turbine. Air is directed to cooling passages in the blades via internal pathways in the rotor and turbine casing.

The unit's annular combustor is also a significant modification. Earlier models featured relatively large, cylindrical silo combustion chambers which, for models designed in the 1980s, were arranged vertically and for machines designed in the early 1990s, horizontally. Newer combustor design is essentially an annular ring that circumscribes the cylindrical engine and houses 24 burners which penetrate the cylindrical ring. This design reportedly reduces the combustion chamber surface area compared to silo-type combustors and thereby decreases cooling air requirements, leaving more air for combustion. In addition, the shorter combustor residence time cuts $NO_x$ production. Other important design features enabling reliable high temperature operation include the use of (*1*) advanced manufacturing techniques, such as directionally solidified and single-crystal cast turbine blades having improved creep rupture strength; (*2*) special high temperature alloys (qv); and (*3*) vacuum-plasma coating techniques refined in the 1990s (see Plasma technology; Refractory coatings).

The newer turbine/generators also include features designed to improve reliability and maintainability. All moving blades can be replaced without lifting the rotor off its bearings, all stationary blade carriers can be removed by removing only one half of the shell, compressor blade carriers can be aligned from outside the machine's casing, and exhaust bearings without horizontal joints permit axial assembly and disassembly of components, thus easing these processes. Using hybrid, dry, low $NO_x$ burners, full-load $NO_x$ emissions can be held below 25 ppm for gas fuel firing. Units firing No. 2 oil can maintain full-load $NO_x$ emissions below 45 ppm by using water or steam injection to temper thermal $NO_x$ production.

A 165-MW-class gas turbine/generator has been introduced by another manufacturer. This machine, also developed by scaling up a proven design, features a simple-cycle efficiency of 37.5%; a turbine inlet temperature of 1235°C; a pressure ratio of 30:1, up from 16:1 on the previous generation; and an output of 165 MW for gas fuel firing under International Standards Organization (ISO) conditions (101 kPa, 15°C (14.7 psia, 59°F)). A combined-cycle facility based around this machine could achieve efficiencies up to 58% or a heat rate of about 6209 kJ/kWh (5885 Btu/kWh).

The unit features a single-shaft, welded rotor supported by two bearings, a 22-stage subsonic compressor, five turbine stages, and forced-air cooling of the turbine rotor, blade carriers, and early turbine stages. An annular combustor is used, reducing the overall height of the machine by 4 m. There is no increase in length compared to the previous machine in this power range.

The machine's dual annular combustor is a continuous chamber containing 72 double-cone, low $NO_x$ burners. One of the main goals of using an annular design is to optimize the flow of hot gases to the turbine, thereby minimizing thermal losses. The annular arrangement also yields a homogeneous mixture of hot gases having a uniform temperature distribution during start-up, part-load, and full-load conditions, thereby helping to limit thermal $NO_x$ production. The unit's lean-premix burners can maintain $NO_x$ levels below 25 ppm on a continuous basis for natural-gas firing, and 42 ppm for oil firing using water or steam injection. The premix burners consist of an axial split cone, the two halves of which are offset by two constant-width air-inlet slots. For gas firing, fuel is injected through fine holes at the end of the slots. The geometry of the burner causes a high speed vortex flow to develop within the cone, yielding a lean mixture as the fuel and air enter the detached flame. The flame is stabilized by an aerodynamically induced recirculation zone in the free space, eliminating the need for any type of flame holder. For oil firing, fuel is sprayed into the burner via an atomizer at the base of the inner cone that vaporizes the oil and permits it to mix with the air and burn in a similar fashion as the gas fuel. Advanced combined-cycle facilities based on this machine can potentially attain net efficiencies of 58% if a three-pressure reheat cycle is employed. In this case, the gas turbine exhausts through an HRSG that generates steam at three separate pressure and temperature levels.

At least two manufacturers have developed and installed machines rated to produce more than 210 MW of electricity in the simple-cycle mode. In both cases, the machines were designed and manufactured through cooperative ventures between two or more international gas turbine developers. One 50-Hz unit, first installed as a peaking power facility in France, is rated for a gross output of 212 MW and a net simple-cycle efficiency of 34.2% for natural-gas firing. When integrated into an enhanced three-pressure, combined-cycle with reheat, net plant efficiencies in excess of 54% reportedly can be achieved.

The 212-MW unit features a turbine inlet temperature of 1260°C and a pressure ratio of 13.5:1. The manufacturer has subsequently installed a number of larger, more powerful versions of this unit, which produce up to 226.5 MW. Turbine inlet temperature is 1288°C; the pressure ratio is 15:1. Five of these high output machines anchor a 1675-MW facility in the Netherlands. These machines were developed by geometric scaling from a 168-MW, 60-Hz unit. To accommodate the higher firing temperatures and mass flows, these units employ advanced alloys, coatings, and modified cooling schemes. Many features of these units were derived from aircraft engine designs.

A notable difference between the newer large machines and the somewhat smaller units is the use of multiple, reverse-flow can combustors configured annularly. Because the individual cans are relatively small, they reportedly lend themselves well to laboratory experimentation with various fuel types, including reduced-heat value synfuels (see Fuels, synthetic). A dry, low $NO_x$ version of the can combustors has been developed for both gas and liquid fuel firing. $NO_x$ emissions can reportedly be held below 25 ppm when firing gas fuel. By employing water injection, $NO_x$ emissions can be held below 60 ppm for oil-fired units.

Similar to other newer gas turbines, the 226-MW design has been optimized for integration into a high efficiency combined-cycle plant featuring a triple-pressure, reheat steam cycle. In this case, the gas turbine and steam turbine can be configured on a single power train to drive one large generator.

The principal advantages of the single-shaft design include its compactness and slightly lower capital costs compared to the conventional multishaft configuration where the gas and steam turbines drive separate generators (Fig. 19). When the 226-MW gas turbine/generator is linked with a vertical HRSG and a 118-MW steam turbine, the single-shaft power block requires a ground space smaller than $135 \times 40$ m.

The design also has the advantages of component reduction. For example, only one thrust bearing and one main transformer is required. In addition, both the steam and gas turbines can be automated from a single prepackaged control center. Finally, a single, larger, more efficient water-cooled generator can be used. In contrast, principal advantages of using the multishaft arrangement include the possibility of phased construction and start-up, which can reduce the lag time between initial investment and revenue generation, and increased flexibility in the ability to extract steam reliably for district heating and cogeneration.

The most popular HRSG for use with these machines is a vertical, assisted-circulation design featuring a built-in stack and low groundspace requirements. More recently, an L-shaped HRSG has been developed to reduce the hot flue-gas temperature abruptly after the gas turbine's exhaust diffuser by locating both the

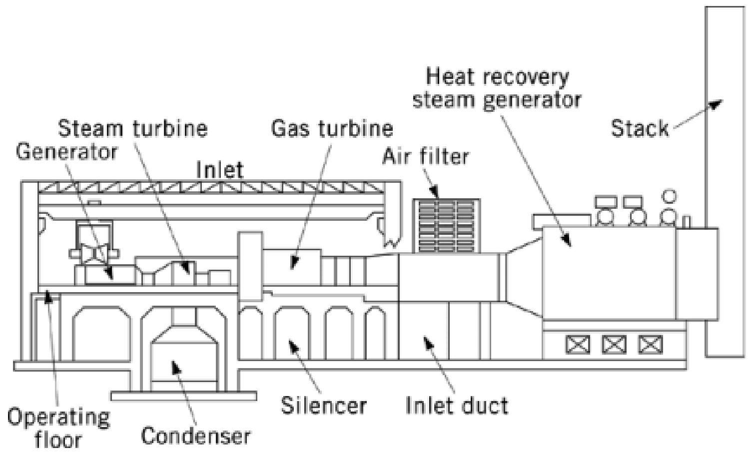



**Fig. 19.** Single-shaft combined-cycle elevation. (Courtesy of General Electric.)

reheater and HP and IP superheaters in the horizontal inlet section to the HRSG. This design reportedly simplifies and reduces the cost of the exhaust duct and expansion joint design. Like most popular designs, the L-shaped HRSG incorporates prefabricated tube bundles packaged and shipped to ease on-site construction. For this design, a typical three-pressure HRSG having reheat capability requires about 30 separate tube bundles.

In May of 1995, one gas turbine manufacturer introduced a new engine series expected to push the achievable net efficiency ratings for base-load combined-cycle power plants to the 60% level. The power ratings for these units are 240 and 280 MW for simple cycle, and 350 and 480 MW for combined cycle using turbine inlet (firing) temperatures of 1430°C. To achieve the 60% thermal efficiency level, either of the machines can be integrated into a single-shaft combined-cycle configuration and employ steam cooling on the four-stage power turbine. The steam cooling, as well as thermal barrier coatings (qv) and single-crystal cast first-stage turbine blades, enables the units to operate at the higher firing temperature at a high combined-cycle efficiency. The intermediate pressure steam used for cooling is extracted from the combined-cycle arrangement's HP steam turbine. Some is directed through the gas turbine's hollow rotor to cool the rotating turbine blades; some is directed through the engine's outer shell to cool the stationary vanes and shrouds. To conserve energy, the steam cooling system is a closed loop. As the steam passes through the gas turbine, it is heated to near-reheat temperature and can therefore be injected into the reheat steam, which drives the unit's LP–IP steam turbine. Also helping to boost efficiency is the unit's 18-stage compressor, a geometrically scaled-up aeroengine design, which achieves pressure ratios of 23:1, compared to 15:1 on the previous generation of machines.

## 8. Natural Gas for Power Plant Use

Most gas-fired, heavy-duty gas turbines installed as of 1996 operate at gas pressures between 1.2 and 1.7 MPa (180–250 psig). However, aeroderivative gas turbines and newer heavy-duty units can have such high air-inlet compression ratios as to require booster compressors to raise gas inlet pressures, in some cases as high as 5.2 MPa (750 psig).

Motor-driven, multistage reciprocating compressors have reportedly been the most popular choice for aeroderivatives. Motor-driven, oil-flooded screw compressors are also used in some cases. High horsepower, multistage centrifugal compressors, similar to those used at many pipeline compressor stations, may be required for the newer heavy-duty units if the distribution pipeline pressure is insufficient (see Pipelines). Gas turbines have more stringent fuel-gas specifications in terms of cleanliness than do gas-fired boilers. Thus oil- and water-knockout systems, coalescing filters, and fine-mesh filters are used.

All gas-fired power plants require oxygen analyzers to ensure that air has not been drawn into the piping system. Oxygen intake can lead to the presence of an explosive mixture in the pipeline before the fuel reaches the burner or combustor zone. When gas-fired units are located in an enclosed area, multiple ultraviolet flame detectors are used to shut down equipment and flood the area with $CO_2$ or a chemical fire suppressant whenever a spark or flame is detected.

Consumption of natural gas, as of the mid-1990s, was about $2000 \times 10^9\ \mathrm{m^3/yr}$. Using seismic detection equipment, exploration firms search for gas reserves buried deep underground and beneath the sea floor. Advanced computer systems process the seismic data to pinpoint the most likely locations for reserves. These advanced systems have both cut the time required for data analysis, by 80%, and greatly improved the success rate for new drill rigs.

In North America, other technological breakthroughs, such as drilling multiple wells from a single platform, drilling deeper underground, horizontal drilling, and deep-water drilling, have increased yield by over 50% in the 1980s. In addition, tax incentives have enticed producers to recover gas from less conventional sources, including tight-sand formations and coal beds. As of 1995, approximately 272,000 wells were operating in the United States and Canada (see Gas, natural).

Processed gas is compressed for transmission through interstate and intrastate pipelines (qv). These pipelines vary in size according to system needs, but typically have diameters between 0.6–1.1 m and a wall thickness up to 1.3 cm. Average operating pressures for new pipelines range from 5–7 MPa (700–1000 psig). To guard against corrosion, epoxy-coated piping and cathodic protection systems are used.

Modern pipeline companies control gas flow through their systems in response to and anticipation of demand swings via computerized operations centers. These facilities typically use satellite or modem-based telemetry systems to monitor gas flow and automatically regulate valves and compressor stations located along the pipeline and at gas storage facilities. In addition to continuously reviewing data collected from the telemetry system, dispatchers also closely monitor weather conditions in various regions so that gas can be delivered to key areas in anticipation of greater demand. Similarly, operators must maintain close communications with power plant dispatchers and other gas system operators.

On a typical pipeline, compressor stations are located at 81–161-km intervals and may contain up to 15 compressors. These stations may use either gas-turbine, reciprocating-engine, and/or motor-driven centrifugal compressors capable of boosting pipeline pressure and keeping gas moving at an average speed of about 24 km/h. Gas-turbine-driven units are the most popular.

Filtration and water-knockout systems are used to clean up the gas before it enters a compressor. Cooling systems are sometimes required to maintain compressor discharge temperatures below 54°C to avoid damage to the pipeline's protective coatings. Automated compressor stations are typically staffed by maintenance and repair personnel eight hours per day, five days per week. Other stations are staffed on a 24-hour basis because personnel must start, stop, and regulate compressors in response to orders from the dispatch office.

The demand for gas is highly seasonal. Thus pipeline companies economize by sizing production facilities to accommodate less than the system's maximum wintertime demand. Underground storage facilities are used to meet seasonal and daily demand peaks. In North America, gas is stored in three main types of underground formations: depleted oil or gas fields, aquifers that originally contained water, and caverns formed by salt domes or mines.

When full, storage reservoirs may exhibit pressures above 14 MPa (2000 psig). The rate at which a storage facility can deliver gas declines as more volume is withdrawn from it. Thus a certain volume of permanent cushion gas is needed to maintain required rates of delivery. Peaking reservoirs may contain up to 75% cushion gas; base-load storage basins may contain closer to 50%. Specific cushion gas volumes vary greatly, depending on the application and the properties of the reservoir. In aquifer storage systems, for example, excessive withdrawals may allow water to encroach, rendering pockets of gas irretrievable.

In certain areas, the lack of underground storage capacity necessitates the use of liquefying stations. Cooled liquefied natural gas (LNG) occupies only about 1/600 the volume required when it is in the gaseous form. However, above-ground LNG storage facilities reportedly are significantly more expensive to operate than underground storage reservoirs and gaining permits can be difficult. In addition to fuel storage, many power producers improve system reliability and control costs by ensuring that gas-fired units can be rapidly switched over to liquid fuel firing or that a separate unit in the system can be engaged if gas supplies are curtailed for any reason.

## 9. Other Generation Options

### 9.1. Reciprocating Engines

Reciprocating engines, particularly medium- and slow-speed diesels similar to those used for shipboard propulsion and power generation, have been used for land-based power generation since the 1940s. Because of their relatively high efficiency (up to 45%), reliability, and quick start-up capability, these units have been popular for peaking, emergency, and base-load power generation. However, reciprocating units have not been nearly as popular as combustion turbines for cogeneration or combined-cycle power generation. The exhaust exiting a reciprocating unit has a comparatively lower volumetric flow, entrained air, and overall energy content compared to combustion turbines. In addition, available machine sizes are smaller for reciprocating engines.

Advantages of reciprocating engines for small power plant applications include the following: in gas-fired applications, reciprocating engines require much lower gas inlet pressures (14–28 kPa (20–40 psig) compared to combustion turbines; reciprocating engines are not significantly impacted by changes in ambient air temperature (achievable gas turbine output falls at higher temperatures); and reciprocating engines have better part-load efficiency characteristics than gas turbines.

### 9.2. Nuclear Reactors

Nuclear power facilities account for about 20% of the power generated in the United States. Although no new plants are planned in the United States, many other countries, particularly those that would otherwise rely heavily on imported fuel, continue to increase their nuclear plant generation capacity. Many industry observers predict that nuclear power may become more attractive in future years as the price of fossil fuels continues to rise and environmental regulations become more stringent. In addition, advanced passive-safety reactor designs may help allay concerns over potential safety issues.

### 9.3. Fuel Cells

Fuel cells (qv) are essentially batteries (qv) that run on fuel and therefore do not run down. Advanced fuel cells feature efficiencies above 40% and consist of a series of porous, conducting electrode layers (a layer corresponding to one anode and one cathode), separated by an electrolyte (an ionic charge carrier). The multiple cells are configured in series to achieve the voltages required for industrial and commercial use.

As of 1995, the cost for fuel cell-based power plants was prohibitive when compared to conventional options. This cost may come down in the latter 1990s if manufacturers of these devices receive enough orders to achieve economies of scale. Fuel cells have many potential advantages compared to conventional power cycles. For example, fuel cells generate very little pollution either in emissions or noise. Thus these cells are ideal for siting in populated areas close to loads where it may be difficult to site conventional power sources because of permitting issues. In addition, small fuel cell power plants can potentially run as unstaffed facilities. Finally, fuel cells do generate significant levels of waste heat that can be captured and utilized to improve overall plant efficiency (see Process energy conservation).

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