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CHAPTER 1

THE U.S. ELECTRIC POWER INDUSTRY

Little more than a century ago, there were no motors, lightbulbs, refrigerators, air conditioners, or any of the other electrical marvels that we think of as being so essential today. Indeed, nearly 2 billion people around the globe still live without the benefits of such basic energy services. The electric power industry has since grown to be one of the largest enterprises in the world. It is also one of the most polluting of all industries, responsible for three-fourths of U.S. sulfur oxides (SO_x) emissions, one-third of our carbon dioxide (CO_2) and nitrogen oxides (NO_x) emissions, and one-fourth of particulate matter and toxic heavy metals.

The electricity infrastructure providing power to North America includes over 275,000 mi of high voltage transmission lines and 950,000 MW of generating capacity to serve a customer base of over 300 million people. While its cost has been staggering—over $1 trillion—its value is incalculable. Providing reliable electricity is a complex technical challenge that requires real-time control and coordination of thousands of power plants to move electricity across a vast network of transmission lines and distribution networks to meet the exact, constantly varying, power demands of those customers.

While this book is mostly concerned with the alternatives to large, centralized power systems, we need to have some understanding of how these conventional systems work. This chapter explores the history of the utility industry, the basic systems that provide the generation, transmission, and distribution of electric

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Renewable and Efficient Electric Power Systems, Second Edition. Gilbert M. Masters.

power, and some of the regulatory issues that govern the rules that control the buying and selling of electric power.

1.1 ELECTROMAGNETISM: THE TECHNOLOGY BEHIND ELECTRIC POWER

In the early nineteenth century, scientists such as Hans Christian Oersted, James Clerk Maxwell, and Michael Faraday began to explore the wonders of electromagnetism. Their explanations of how electricity and magnetism interact made possible the development of electrical generators and motors—inventions that have transformed the world.

Early experiments demonstrated that a voltage (originally called an *electromotive force*, or *emf*) could be created in an electrical conductor by moving it through a magnetic field as shown in Figure 1.1a. Clever engineering based on that phenomenon led to the development of direct current (DC) dynamos and later to alternating current (AC) generators. The opposite effect was also observed; that is, if current flows through a wire located in a magnetic field, the wire will experience a force that wants to move the wire as shown in Figure 1.1b. This is the fundamental principle by which electric motors are able to convert electric current into mechanical power.

Note the inherent symmetry of the two key electromagnetic phenomena. Moving a wire through a magnetic field causes a current to flow, while sending a current through a wire in a magnetic field creates a force that wants to move the wire. If this suggests to you that a single device could be built that could act as a generator if you applied force to it, or act as a motor if you put current into it, you would be absolutely right. In fact, the electric motor in today's hybrid electric vehicles does exactly that. In normal operation, the electric motor helps power the car, but when the brakes are engaged, the motor acts as a generator, slowing the car by

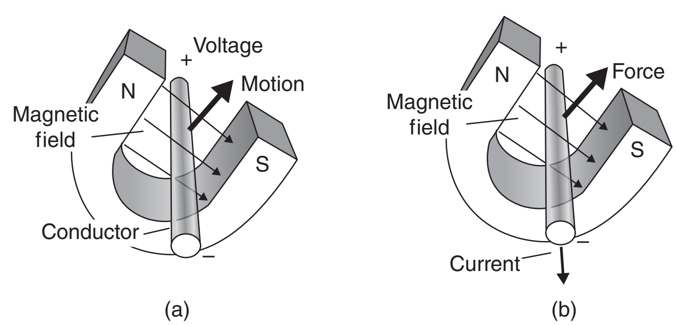

FIGURE 1.1 Moving a conductor through a magnetic field creates a voltage (a). Sending current through a wire located in a magnetic field creates a force (b).

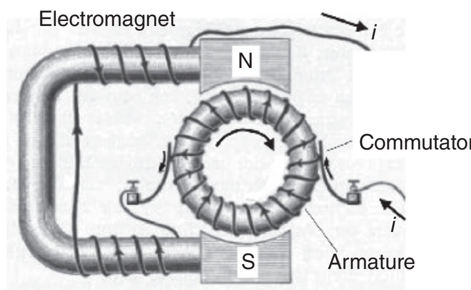

FIGURE 1.2 Gramme's "electromotor" could operate as a motor or as a generator.

converting the vehicle's kinetic energy into electrical current that recharges the vehicle's battery system.

A key to the development of electromechanical machines, such as motors and generators, was finding a way to create the required magnetic fields. The first *electromagnet* is credited to a British inventor, William Sturgeon, who, in 1825, demonstrated that a magnetic field could be created by sending current through a number of turns of wire wrapped around a horseshoe-shaped piece of iron. With that, the stage was set for the development of generators and motors.

The first practical DC motor/generator, called a dynamo, was developed by a Belgian, Zénobe Gramme. His device, shown in Figure 1.2, consisted of a ring of iron (the *armature*) wrapped with wire, which was set up to spin within a stationary magnetic field. The magnetic field was based on Sturgeon's electromagnet. The key to Gramme's invention was his method of delivering DC current to and from the armature using contacts (called a *commutator*) that rubbed against the rotating armature windings. Gramme startled the world with his machines at a Vienna Exposition in 1873. Using one dynamo to generate electricity, he was able to power another, operating as a motor, three-quarters of a mile away. The potential to generate power at one location and transmit it through wires to a distant location, where it could do useful work, stimulated imaginations everywhere. An enthusiastic American writer, Henry Adams, in a 1900 essay called "The Dynamo and the Virgin" even proclaimed the dynamo as "a moral force" comparable to European cathedrals.

1.2 THE EARLY BATTLE BETWEEN EDISON AND WESTINGHOUSE

While motors and generators quickly found application in factories, the first major electric power market developed around the need for illumination. Although many others had worked on the concept of electrically heating a filament to create light, it was Thomas Alva Edison who, in 1879, created the first workable incandescent lamp. Simultaneously he launched the Edison Electric Light Company, which was a full-service illumination company that provided not only the electricity but also the lightbulbs themselves. In 1882, his company began distributing power primarily for lights, but also for electric motors, from his Pearl Street Station in Manhattan. This was to become the first investor-owned utility in the nation.

Edison's system was based on DC, which he preferred in part because it not only provided flicker-free light, but also because it enabled easier speed control of DC motors. The downside of DC, however, was that in those days it was very difficult to change the voltage from one level to another—something that became simple to do in AC after the invention of the transformer in 1883. As we will show later, power line losses are proportional to the square of the current flowing through them, while the power delivered is the product of current and voltage. By doubling the voltage, for example, the same power can be delivered using half the current, which cuts power line losses by a factor of four. Given DC's low voltage transmission constraint, Edison's customers had to be located within just a mile or two of a generating station.

Meanwhile, George Westinghouse recognized the advantages of AC for transmitting power over greater distances and, utilizing AC technologies developed by Nicola Tesla, launched the Westinghouse Electric Company in 1886. Within just a few years, Westinghouse was making significant inroads into Edison's electricity market and a bizarre feud developed between these two industry giants. Rather than hedge his losses by developing a competing AC technology, Edison stuck with DC and launched a campaign to discredit AC by condemning its high voltages as a safety hazard. To make the point, Edison and his assistant, Samuel Insull, began demonstrating its lethality by coaxing animals, including dogs, cats, calves, and eventually even a horse, onto a metal plate wired to a 1000-V AC generator and then electrocuting them in front of the local press (Penrose, 1994). Edison and other proponents of DC continued the campaign by promoting the idea that capital punishment by hanging was horrific and could be replaced by a new, more humane approach based on electrocution. The result was the development of the electric chair, which claimed its first victim in 1890 in Buffalo, NY (also home of the nation's first commercially successful AC transmission system).

The advantages of high voltage transmission, however, were overwhelming and Edison's insistence on DC eventually led to the disintegration of his electric utility enterprise. Through buyouts and mergers, Edison's various electricity interests were incorporated in 1892 into the General Electric Company, which shifted the focus from being a utility to manufacturing electrical equipment and end-use devices for utilities and their customers.

One of the first demonstrations of the ability to use AC to deliver power over large distances occurred in 1891 when a 106 mi, 30,000 -V transmission line began to carry 75 kW of power between Lauffen and Frankfurt, Germany. The first transmission line in the United States went into operation in 1890 using 3.3 kV lines to connect a hydroelectric station on the Willamette River in Oregon to the city of Portland, 13 mi away. Meanwhile, the flicker problem for incandescent lamps with AC was resolved by trial and error with various frequencies until it was no longer a noticeable problem. Surprisingly, it was not until the 1930s that 60 Hz finally became the standard in the United States. Some countries had by then settled on 50 Hz, and even today, some countries, such as Japan, use both.

1.3 THE REGULATORY SIDE OF ELECTRIC UTILITIES

Edison and Westinghouse launched the electric power industry in the United States, but it was Samuel Insull who shaped what has become the modern electric utility by bringing the concepts of regulated utilities with monopoly franchises into being. It was his realization that the key to making money was to find ways to spread the high fixed costs of facilities over as many customers as possible. One way to do that was to aggressively market the advantages of electric power, especially, for use during the daytime to complement what was then the dominant nighttime lighting load. In previous practices, separate generators were used for industrial facilities, street lighting, street cars, and residential loads, but Insull's idea was to integrate the loads so that he could use the same expensive generation and transmission equipment on a more continuous basis to satisfy them all. Since operating costs were minimal, amortizing high fixed costs over more kilowatt-hour sales results in lower prices, which creates more demand. With controllable transmission line losses and attention to financing, Insull promoted rural electrification, further extending his customer base.

With more customers, more evenly balanced loads, and modest transmission losses, it made sense to build bigger power stations to take advantage of economies of scale, which also contributed to decreasing electricity prices and increasing profits. Large, centralized facilities with long transmission lines required tremendous capital investments; to raise such large sums, Insull introduced the idea of selling utility common stock to the public.

Insull also recognized the inefficiencies associated with multiple power companies competing for the same customers, with each building its own power plants and stringing its own wires up and down the streets. The risk of the monopoly alternative, of course, was that without customer choice, utilities could charge whatever they could get away with. To counter that criticism, he helped establish the concept of regulated monopolies with established franchise territories and prices controlled by *public utility commissions* (PUCs). The era of regulation had begun.

1.3.1 The Public Utility Holding Company Act of 1935

In the early part of the twentieth century, as enormous amounts of money were being made, utility companies began to merge and grow into larger conglomerates. A popular corporate form emerged, called a *utility holding company*. A holding company is a financial shell that exercises management control of one or more companies through ownership of their stock. Holding companies began to purchase each other and by 1929, 16 holding companies controlled 80% of the U.S. electricity market, with just three of them owning 45% of the total.

With so few entities having so much control, it should have come as no surprise that financial abuses would emerge. Holding companies formed pyramids with other holding companies, each owning stocks in subsequent layers of holding companies. An actual operating utility at the bottom found itself directed by layers of holding companies above it, with each layer demanding its own profits. At one point, these pyramids were sometimes ten layers thick. When the stock market crashed in 1929, the resulting depression drove many holding companies into bankruptcy causing investors to lose fortunes. Insull became somewhat of a scapegoat for the whole financial fiasco associated with holding companies and he fled the country amidst charges of mail fraud, embezzlement, and bankruptcy violations, charges for which he was later cleared.

In response to these abuses, Congress created the *Public Utility Holding Company Act of 1935* (PUHCA) to regulate the gas and electric industries and prevent holding company excesses from reoccurring. Many holding companies were dissolved, their geographic size was limited, and the remaining ones came under control of the newly created Securities and Exchange Commission (SEC).

While PUHCA had been an effective deterrent to the previous holding company financial abuses, recent changes in utility regulatory structures, with their goal of increasing competition, led many to say it had outlived its usefulness and it was repealed as part of the Energy Policy Act of 2005.

1.3.2 The Public Utility Regulatory Policies Act of 1978

With the country in shock from the oil crisis of 1973 and with the economies of scale associated with ever larger power plants having pretty much played out, the country was drawn toward energy efficiency, renewable energy systems, and new, small, inexpensive gas turbines (GTs). To encourage these systems, President Carter signed the Public Utility Regulatory Policies Act of 1978 (PURPA).

There were two key provisions of PURPA, both relating to allowing independent power producers (IPPs), under certain restricted conditions, to connect their facilities to the utility-owned grid. For one, PURPA allows certain industrial facilities and other customers to build and operate their own, small, on-site generators while remaining connected to the utility grid. Prior to PURPA, utilities could refuse service to such customers, which meant self-generators had to provide all of their own power, all of the time, including their own redundant, backup power systems. That virtually eliminated the possibility of using efficient, economical on-site power production to provide just a portion of a customer's needs.

PURPA not only allowed grid interconnection but it also required utilities to purchase electricity from certain *qualifying facilities* (QFs) at a "just and reasonable price." The purchase price of QF electricity was to be based on what it would have cost the utility to generate the power itself or to purchase it on the open market (referred to as the *avoided cost*). This provision stimulated the construction of numerous renewable energy facilities, especially in California, since PURPA guaranteed a market, at a good price, for any electricity generated.

PURPA, as implemented by the Federal Energy Regulatory Commission (FERC), allowed interconnection to the grid by *Qualifying Small Power Producers* or *Qualifying Cogeneration Facilities*, both are referred to as QFs. Small power producers were less than 80 MW in size that used at least 75% wind, solar, geothermal, hydroelectric, or municipal waste as energy sources. Cogenerators were defined as facilities that produced both electricity and useful thermal energy in a sequential process from a single source of fuel, which may be entirely oil or natural gas.

PURPA not only gave birth to the electric side of the renewable energy industry, it also enabled clear evidence to accrue which demonstrated that small, on-site generation could deliver power at considerably lower cost than the retail rates charged by utilities. Competition had begun.

1.3.3 Utilities and Nonutilities

Electric utilities traditionally have been given a monopoly franchise over a fixed geographical area. In exchange for that franchise, they have been subject to regulation by State and Federal agencies. Most large utilities were vertically integrated; that is, they owned generation, transmission, and distribution infrastructure. After PURPA along with subsequent efforts to create more competition in the grid, most utilities now are just distribution utilities that purchase wholesale power, which they sell to their retail customers using their monopoly distribution system.

The roughly 3200 utilities in the United States can be subdivided into one of four categories of ownership—investor-owned utilities, federally owned, other publicly owned, and cooperatively owned.

Investor-owned utilities (IOUs) are privately owned with stock that is publicly traded. They are regulated and authorized to receive an allowed rate of return on their investments. IOUs may sell power at wholesale rates to other utilities or they may sell directly to retail customers.

Federally owned utilities produce power at facilities run by entities such as the Tennessee Valley Authority (TVA), the U.S. Army Corps of Engineers, and the Bureau of Reclamation. The Bonneville Power Administration, the Western, Southeastern, and Southwestern Area Power Administrations, and the TVA, market and sell power on a nonprofit basis mostly to Federal facilities, publicly owned utilities and cooperatives, and certain large industrial customers.

Publicly owned utilities are state and local government agencies that may generate some power, but which are usually just distribution utilities. They generally sell power at a lower cost than IOUs because they are nonprofit and are often exempt from certain taxes. While two-thirds of the U.S. utilities fall into this category, they sell only a few percent of the total electricity.

Rural electric cooperatives were originally established and financed by the Rural Electric Administration in areas not served by other utilities. They are owned by groups of residents in rural areas and provide services primarily to their own members.

Independent Power Producers (IPPs) and Merchant Power Plants are privately owned entities that generate power for their own use and/or for sale to utilities and others. They are distinct in that they do not operate transmission or distribution systems and are subject to different regulatory constraints than traditional utilities. In earlier times, these nonutility generators (NUGs) had been industrial facilities generating on-site power for their own use, but they really got going during the utility restructuring efforts of the 1990s when some utilities were required to sell off some of their power plants.

Privately owned power plants that sell power onto the grid can be categorized as IPPs or merchant plants. IPPs have pre-negotiated contracts with customers in which the financial conditions for the sale of electricity are specified by power purchase agreements (PPAs). Merchant plants, on the other hand, have no predefined customers and instead sell power directly to the wholesale spot market. Their investors take the risks and reap the rewards. By 2010, some 40% of the U.S. electricity was generated by IPPs and merchant power plants.

1.3.4 Opening the Grid to NUGs

After PURPA, the Energy Policy Act of 1992 (EPAct) created additional competition in the electricity generation market by opening the grid to more than just the QFs identified in PURPA. A new category of access was granted to *exempt wholesale generators* (EWGs), which can be of any size, using any fuel, and any generation technology, without the restrictions and ownership constraints that PURPA and PUHCA imposed. EPAct allows EWGs to generate electricity in one location and sell it anywhere else in the country using someone else's transmission system to wheel their power from one location to another.

While the 1992 EPAct allowed IPPs and merchant plants to gain access to the transmission grid, problems arose during periods when the transmission lines were being used to near capacity. In these and other circumstances, the IOUs that owned the lines favored their own generators, and NUGs were often denied access. In addition, the regulatory process administered by the FERC was initially cumbersome and inefficient. To eliminate such deterrents, the FERC issued Order 888 in 1996, which had as a principal goal the elimination of

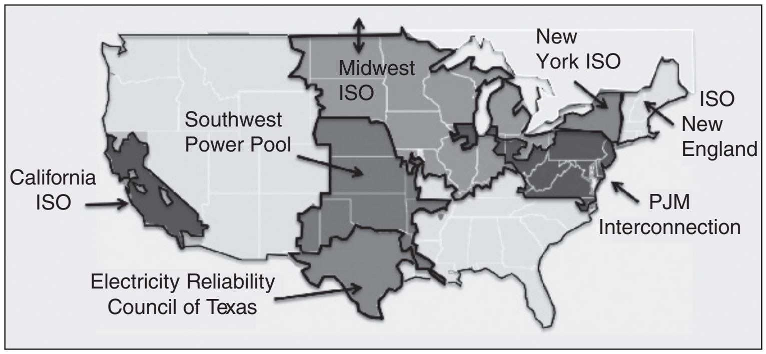

FIGURE 1.3 These seven ISO/RTOs deliver two-thirds of the U.S. electricity.

anticompetitive practices in transmission services by requiring IOUs to publish nondiscriminatory tariffs that applied to all generators.

Order 888 also encouraged the formation of *independent system operators* (ISOs), which are nonprofit entities established to control the operation of transmission facilities owned by traditional utilities. Later, in 1999, the FERC issued Order 2000, which broadened its efforts to break up vertically integrated utilities by calling for the creation of *regional transmission organizations* (RTOs). RTOs can follow the ISO model in which the ownership of the transmission system remains with the utilities, with the ISO being there to provide control of the system's operation, or they would be separate transmission companies that would actually own the transmission facilities and operate them for a profit. The goal has been for ISOs and RTOs to provide independent, unbiased transmission operation that would ensure equal access to the power grid for both utility and new, NUGs.

There are now seven ISO/RTOs in the United States (Fig. 1.3), which together serve two-thirds of the U.S. electricity customers. They are nonprofit entities that provide a number of services, including the coordination of generation, loads, and available transmission to help maintain system balance and reliability, administering tariffs that establish the hour-by-hour wholesale price of electricity, and monitoring the market to help avoid manipulation and abuses. In other words, these critical entities manage not only the flow of actual electrical power through the grid; they also manage the information about power flows as well as the flow of money between power plants and transmission owners, marketers, and buyers of power.

1.3.5 The Emergence of Competitive Markets

Prior to PURPA, the accepted method of regulation was based on monopoly franchises, vertically integrated utilities that owned some or all of their own generation, transmission, and distribution facilities, and consumer protections based on a strict control of rates and utility profits. In the final decades of the twentieth century, however, the successful deregulation of other traditional monopolies such as telecommunications, airlines, and the natural gas industry, provided evidence that introducing competition in the electric power industry might also work there. While the disadvantages of multiple systems of wires to transmit and distribute power continue to suggest they be administered as regulated monopolies, there is no inherent reason why there should not be competition between generators who want to put power onto those wires. The whole thrust of both PURPA and EPAct was to begin the opening up of that grid to allow generators to compete for customers, thereby hopefully driving down costs and prices.

In the 1990s, California's electric rates were among the highest in the nation—especially for its industrial customers—which led to an effort to try to reduce electricity prices by introducing competition among generation sources. In 1996, the California Legislature passed Assembly Bill (AB) 1890. AB 1890 had a number of provisions, but the critical ones included:

a. To reduce their control of the market, the three major IOUs, Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E), which accounted for three-fourths of California's supply, were required to sell off most of their generation assets. About 40% of California's installed capacity was sold off to a handful of NUGs including Mirant, Reliant, Williams, Dynergy, and AES. The thought was that new players who purchased these generators would compete to sell their power, thereby lowering prices.
b. All customers would be given a choice of electricity suppliers. For a period of about 4 years, large customers who stayed with the IOUs would have their rates frozen at the 1996 levels, while small customers would see a 10% reduction. Individual rate payers could choose non-IOU providers if they wanted to, and this "customer choice" was touted as a special advantage of deregulation. Some providers, for example, offered elevated percentages of their power from wind, solar, and other environmentally friendly sources as "green power."
c. Utilities would purchase wholesale power on the market, which, due to competition, was supposed to be comparatively inexpensive. The hope was that with their retail rates frozen at the relatively high 1996 levels, and with dropping wholesale prices in the new competitive market, there would be extra profits left over that could be used to pay off those costly stranded assets—mostly nuclear power plants.
d. The competitive process was set up so that each day there would be an auction run by an ISO in which generators would submit bids indicating the hour-by-hour price at which they were willing to provide power on the

> following day. The accumulation of the lowest bids sufficient to meet the projected demands would then be allowed to sell their power at the price that the highest accepted bidder received. Any provider who bid too high would not sell power the next day. So if a generator bid \$10/MWh (1 ¢/kWh) and the market clearing price was \$40/MWh, that generator would get to sell power at the full \$40 level. This was supposed to encourage generators to bid low so they would be assured of the ability to sell power the next day.

On paper, it all sounded pretty good. Competition would cause electricity prices to go down and customers could choose providers based on whatever criteria they liked, including environmental values. As wholesale power prices dropped, utilities with high, fixed retail rates could make enough extra money to pay off old debts and start fresh.

For 2 years, up until May 2000, the new electricity market seemed to be working with wholesale prices averaging about \$30/MWh (3 ¢/kWh). Then, in the summer of 2000, it all began to unravel (Fig. 1.4). In August 2000, the wholesale price was five times higher than it had been in the same month in 1999. During a few days in January 2001, when demand is traditionally low and prices normally drop, the wholesale price spiked to the astronomical level of \$1500/MWh. By the end of 2000, Californians had paid \$33.5 billion for electricity, nearly five times the \$7.5 billion spent in 1999. In just the first month and a half of 2001, they spent as much as they had in all of 1999.

What went wrong? Factors that contributed to the crisis included higher-than-normal natural gas prices, a drought that reduced the availability of imported electricity from the Pacific Northwest, reduced efforts by California utilities to pursue customer energy efficiency programs in the deregulated environment,

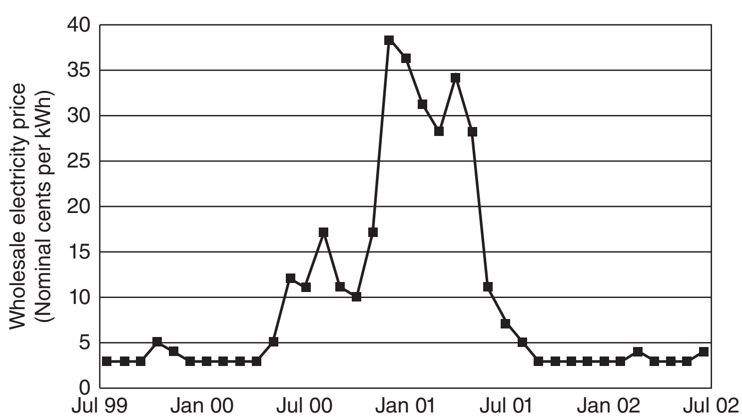

FIGURE 1.4 California wholesale electricity prices during the crisis of 2000–2001. Reproduced with permission from Bachrach et al. (2003).

and, some argue, insufficient new plant construction. But, when California had to endure rolling blackouts in January 2001, a month when demand is always far below the summer peaks and utilities normally have abundant excess capacity, it became clear that none of the above arguments were adequate. Clearly, the IPPs had discovered they could make a lot more money manipulating the market, in part by withholding supplies, than by honestly competing with each other.

The energy crisis finally began to ease by the summer of 2001 after the FERC finally stepped in and instituted price caps on wholesale power, the Governor began to negotiate long-term contracts, and the state's aggressive energy-conservation efforts began to pay off. Those conservation programs, for example, are credited with cutting the June, 2001, California energy demand by 14% compared with the previous June.

In March 2003, the FERC issued a statement concluding that California electricity and natural gas prices were driven higher because of widespread manipulation and misconduct by Enron and more than 30 other energy companies during the 2000–2001 energy crisis. In 2004, audio tapes were released that included Enron manipulators joking about stealing money from those "dumb grandmothers" in California. By 2005, Dynergy, Duke, Mirant, Williams, and Reliant had settled claims with California totaling $2.1 billion—a small fraction of the estimated $71 billion that the crisis is estimated to have cost the state.

While the momentum of the 1990s toward restructuring was shaken by the California experience, the basic arguments in favor of a more competitive electric power industry remain attractive. As of 2011, there were 14 states, mostly in the Northeast, that operate retail markets in which customers may choose alternative power suppliers. Those customers that choose not to participate in the market continue to purchase retail from their historical utility. Meanwhile, eight other states have suspended their efforts to create this sort of retail competition, including California.

A capsule summary of the most significant technological and regulatory developments that have shaped today's electric power systems is presented in Table 1.1.

1.4 ELECTRICITY INFRASTRUCTURE: THE GRID

Electric utilities, monopoly franchises, large central power stations, and long transmission lines have been the principal components of the prevailing electric power paradigm since the days of Insull. Electricity generated at central power stations is almost always three-phase, AC power at voltages that typically range from about 14 to 24 kV. At the site of generation, transformers step up the voltage to long-distance transmission line levels, typically in the range of 138–765 kV. Those voltages may be reduced for regional distribution using subtransmission lines that carry voltages in the range of 34.5–138 kV.

TABLE 1.1 Chronology of Major Electricity Milestones

Year	Event
1800	First electric battery (A. Volta)
1820	Relationship between electricity and magnetism confirmed (H.C. Oersted)
1821	First electric motor (M. Faraday)
1826	Ohm's law (G.S. Ohm)
1831	Principles of electromagnetism and induction (M. Faraday)
1832	First dynamo (H. Pixii)
1839	First fuel cell (W. Grove)
1872	Gas turbine patent (F. Stulze)
1879	First practical incandescent lamp (T.A. Edison and J. Swan, independently)
1882	Edison's Pearl Street Station opens
1883	Transformer invented (L. Gaulard and J. Gibbs)
1884	Steam turbine invented (C. Parsons)
1886	Westinghouse Electric formed
1888	Induction motor and polyphase AC systems (N. Tesla)
1889	Impulse turbine patent (L. Pelton)
1890	First single-phase AC transmission line (Oregon City to Portland)
1891	First three-phase AC transmission line (Germany)
1903	First successful gas turbine (France)
1907	Electric vacuum cleaner and washing machines
1911	Air conditioning (W. Carrier)
1913	Electric refrigerator (A. Goss)
1935	Public Utility Holding Company Act (PUHCA)
1936	Boulder dam completed
1962	First nuclear power station (Canada)
1973	Arab oil embargo, price of oil quadruples
1978	Public Utility Regulatory Policies Act (PURPA)
1979	Iranian revolution, oil price triples; Three Mile Island nuclear accident
1983	Washington Public Power Supply System $2.25 billion nuclear reactor bond default
1986	Chernobyl nuclear accident (USSR)
1990	Clean Air Act amendments introduce tradeable SO_2 allowances
1992	National Energy Policy Act (EPAct): market-based competition begins
1996	California begins restructuring
2001	Restructuring collapses in California; Enron and PG&E bankruptcy
2003	Great Northeast power blackout: 50 million people lose power
2005	Energy Policy Act of 2005 (EPAct05): revisits PUHCA, PURPA, strengthens FERC
2008	Tesla all-electric roadster introduced
2011	Fukushima nuclear reactor meltdown

When electric power reaches major load centers, transformers located in distribution-system substations step down the voltage to levels typically between 4.16 and 34.5 kV range, with 12.47 kV being the most common. Feeder lines carry power from distribution substations to the final customers. An example of a simple distribution substation is diagrammed in Figure 1.5. Note the combination of switches, circuit breakers, and fuses that protect key components and which

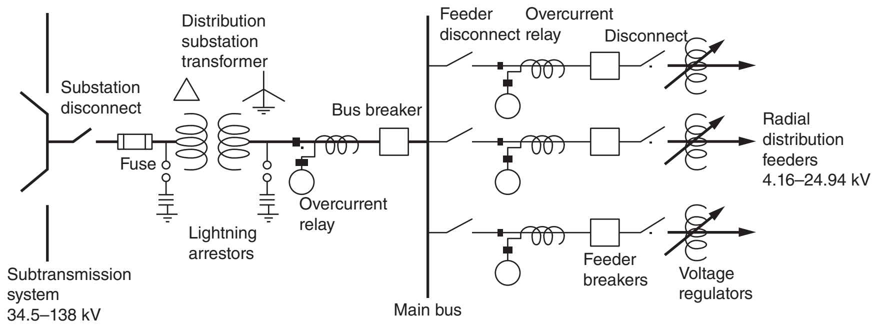

FIGURE 1.5 A simple distribution station. For simplification, this is drawn as a *one-line diagram*, which means a single conductor on the diagram corresponds to the three lines in a three-phase system.

allow different segments of the system to be isolated for maintenance or during emergency *faults* (short circuits) that may occur in the system. Along those feeder lines on power poles or in concrete-pad-mounted boxes, transformers again drop voltage to levels suitable for residential, commercial, and industrial uses.

A sense of the overall utility generation, transmission, and distribution system is shown in Figure 1.6.

1.4.1 The North American Electricity Grid

The system in Figure 1.6 suggests a rather linear system with one straight path from sources to loads. In reality, there are multiple paths that electric currents can take to get from generators to end users. Transmission lines are interconnected at switching stations and substations, with lower voltage “subtransmission” lines and distribution feeders extending into every part of the system. The vast array of transmission and distribution (T&D) lines is called a power “grid.” Within a grid, it is impossible to know which path electricity will take as it seeks out the path of least resistance to get from generator to load.

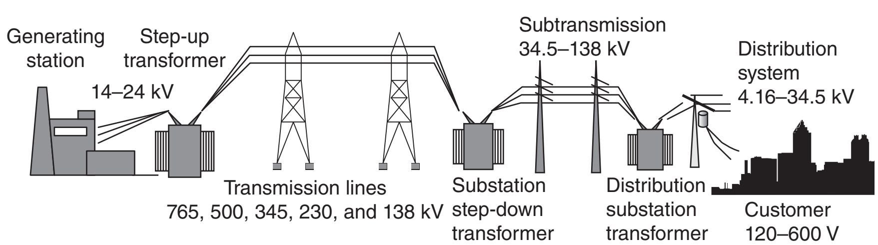

FIGURE 1.6 Simplified power generation, transmission, and distribution system.

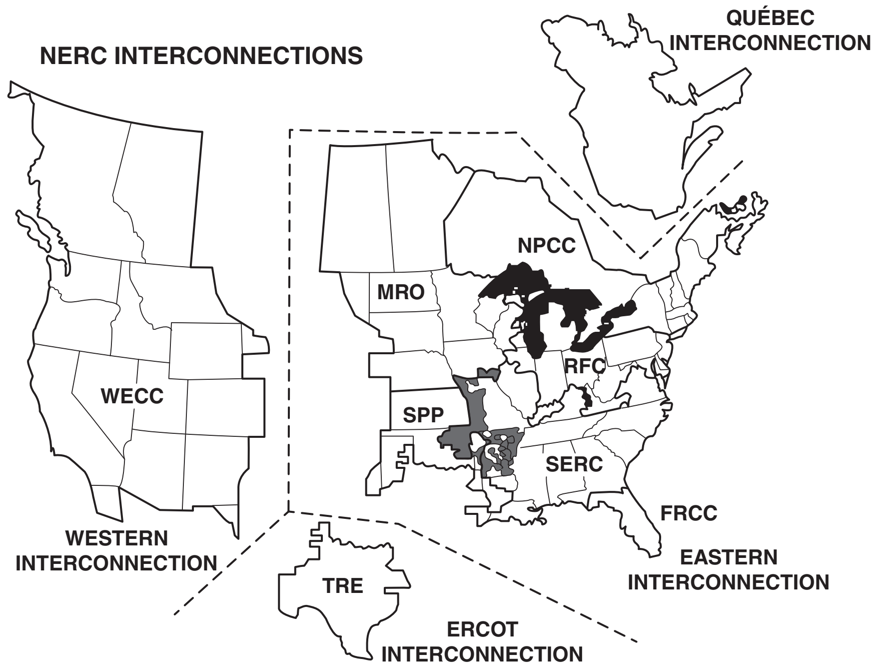

FIGURE 1.7 The U.S. portion of the North American power grid consists of three separate interconnect regions—the Western, Eastern, and ERCOT (Texas) interconnections. Also shown are the eight regions governed by the North American Electric Reliability Corporation (NERC).

As Figure 1.7 shows, the U.S. portion of the North American power grid actually consists of three separate interconnection grids—the Eastern Interconnect, the Western Interconnect, and Texas, which is virtually an electric island with its own power grid. Within each of these interconnection zones, everything is precisely synchronized so that every circuit within a given interconnect operates at exactly the same frequency. Interconnections between the grids are made using high voltage DC (HVDC) links, which consist of *rectifiers* that convert AC to DC, a connecting HVDC transmission line between the interconnect regions, and *inverters* that convert DC back to AC. The advantage of a DC link is that problems associated with exactly matching AC frequency, phase, and voltages from one interconnect to another are eliminated in DC. HVDC links can also connect various parts of a single grid, as is the case with the 3000 MW Pacific Intertie (also called Path 65) between the Pacific Northwest and Southern California. Quite often national grids of neighboring countries are linked this way as well (such as the Quêbec interconnection).

Also shown in Figure 1.7 are the eight regional councils that make up the North American Electric Reliability Corporation (NERC). NERC has the responsibility for overseeing operations in the electric power industry and for developing

TABLE 1.2 NERC Regional Reliability Councils

	Council Name	Capacity (MW)	Coal (%MWh)
FRCC	Florida Reliability Coordinating Council	53,000	19
MRO	Midwest Reliability Organization	51,000	51
NPCC	Northeast Power Coordinating Council	71,000	9
RFC	Reliability First Corporation	260,000	50
SERC	Southeastern Reliability Corporation	215,000	33
SPP	Southwest Power Pool RE	57,000	33
TRE (ERCOT)	Texas Reliability Entity	81,000	19
WECC	Western Electricity Coordinating Council	179,000	18

Source: EIA/DOE, 2008.

and enforcing mandatory reliability standards. Its origins date back to the great Northeast Blackout of 1965, which left 30 million people without power. Those councils are listed in Table 1.2.

The Western Electricity Coordinating Council (WECC) covers the 12 states west of the Rockies and the Canadian provinces of British Columbia and Alberta. A map showing the interstate transmission corridors within WECC is shown in Figure 1.8. Also, note the relatively modest transmission capabilities of the HVDC connections between the Western interconnection, the Eastern, and the Texas interconnect.

1.4.2 Balancing Electricity Supply and Demand

Managing the power grid is a constant struggle to balance power supply with customer demand. If demand exceeds supply, turbine generators, which can be very massive, slow down just a bit, converting some of their kinetic energy (inertia) into extra electrical power to help meet the increased load. Since the frequency of the power generated is proportional to the generator's rotor speed, increasing load results in a drop in frequency. If this is a typical power plant, it takes a few seconds for a governor (Fig. 1.9) to increase torque to bring it back up to speed. Similarly, if demand decreases, turbines speed up a bit before they can be brought back under control. Managing that system balance is the job of roughly 140 Control-Area Balancing Authorities located throughout the grid. Among those are the seven ISOs and RTOs described earlier.

The simple analogy shown in Figure 1.10 suggests thinking of electricity supply as being a set of nozzles delivering water to a bathtub that is constantly being drained by varying amounts of consumer demand. Using the water level to represent grid frequency, the goal is to keep the water at a nearly constant level corresponding to grid frequencies that typically are in the range of about 59.98–60.02 Hz. If the frequency drops below about 59.7 Hz emergency measures,

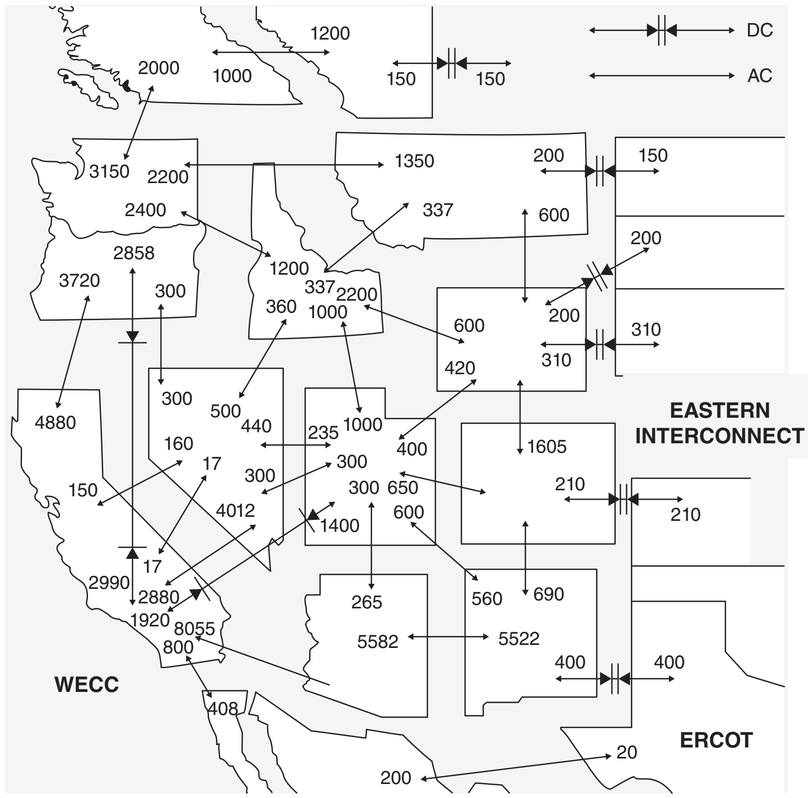

FIGURE 1.8 WECC nonsimultaneous interstate power transmission capabilities (MW). From Western Electricity Coordinating Council Information Summary, 2008.

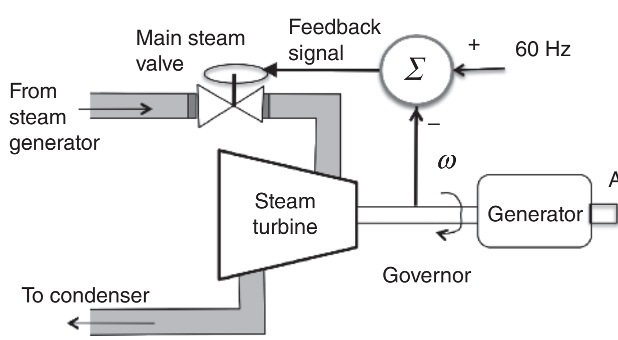

FIGURE 1.9 Frequency is often automatically controlled with a governor that adjusts the torque from the turbine to the generator.

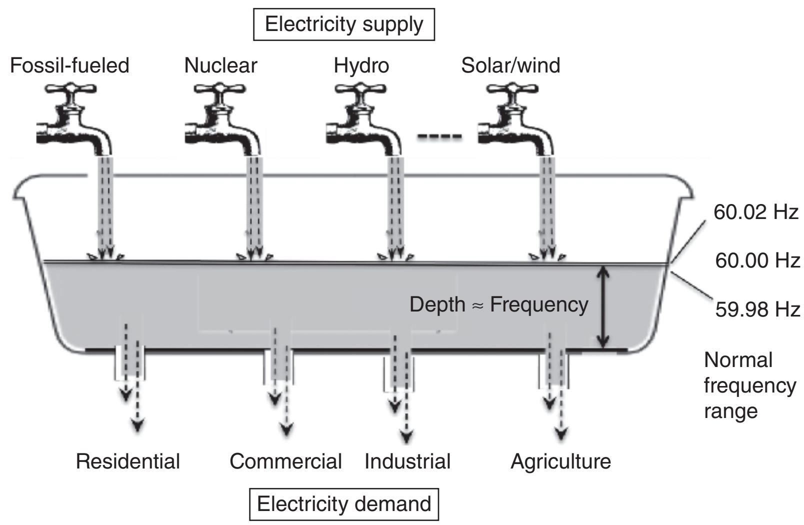

FIGURE 1.10 A simple analogy for a grid operating as a load-following system in which the supply is continuously varied to maintain a constant water level representing frequency.

such as shedding loads (blackouts) may be called for to prevent damage to the generators.

On a gross, hour-by-hour, day-by-day scale, a utility's power demand looks something like that shown in Figure 1.11. There is a predictable diurnal variation, usually rising during the day and decreasing at night, along with reduced demand on the weekends compared to weekdays.

Not all power plants can respond to changing loads to the same extent or at the same rates. Ramp rates (how fast they can respond) as well as marginal

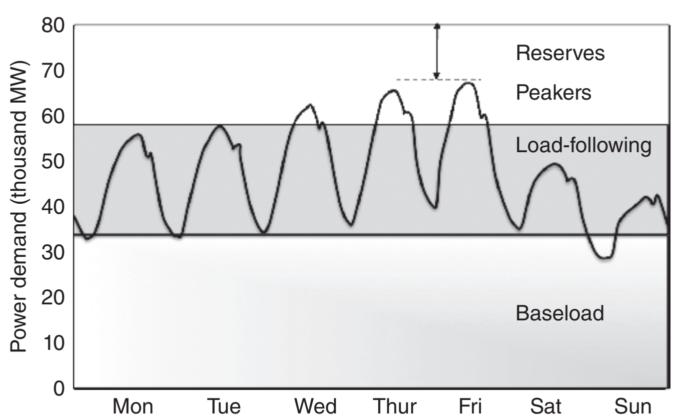

FIGURE 1.11 Example of weekly load fluctuations.

operational costs (mostly fuel related) can determine which plants get dispatched first. Some plants, such as nuclear reactors, are designed to run continuously at close to full power; so they are sometimes described as "must-run" plants. The intermittency aspect of renewables means they are normally allowed to run whenever the wind is blowing or the sun is shining since they have almost zero marginal costs. When the power available from renewables plus nuclear exceeds instantaneous demand, it is the renewables that usually have to be curtailed.

Most fossil-fueled plants, along with hydroelectric facilities, can easily be slowly ramped up and down to track the relatively smooth, predictable diurnal changes in load. These are load-following intermediate plants. Some small, cheap to build, but expensive to run, plants, sometimes referred to as *peakers*, are mostly used only a few tens of hours per year to meet the highest peak demands. Some plants are connected to the grid, but deliver no power until they are called upon, such as when another plant suddenly trips off line. These fall into the category of spinning reserves.

Finally, there are small, fast-responding plants that may purposely be run at something like partial output to track the second-by-second changes in demand. These provide what is referred to as *regulation* services, or *frequency regulation*, or *automatic generation control* (AGC) for the grid. They can provide *regulation up* power, which means they increase power when necessary, and/or, they can provide *regulation down* power, which means they can decrease power to follow decreasing loads. They are paid a monthly fee per megawatt of regulation up or regulation down services that they provide, whether or not they are ever called upon to do so.

If transmission is available, ISOs, RTOs, and other grid balancing authorities can also import power from adjacent systems or deliver power to them.

All of the above methods of changing power plant outputs to track changing loads are the dominant paradigm for maintaining balance on the grid. Newly emerging *demand response* (DR) approaches are changing that paradigm by bringing the ability of customers to control their own power demands into play. Especially, if given a modest amount of advanced notice, and some motivation to do so, building energy managers can control demand on those critical peak power days by dimming lights, adjusting thermostats, precooling buildings, shifting loads, and so forth. Another approach, referred to as *demand dispatch*, involves automating DR in major appliances such as refrigerators and electric water heaters by designing them to monitor, and immediately respond to, changes in grid frequency. So, for example, when frequency drops, the fridge can stop making ice, and the water heater can delay heating, until frequency recovers. All of these potential ways to control loads are often referred to as being *demand-side management*, or DSM.

Figure 1.12 extends the "bathtub" analogy to incorporate all of these approaches to keep the grid balanced.

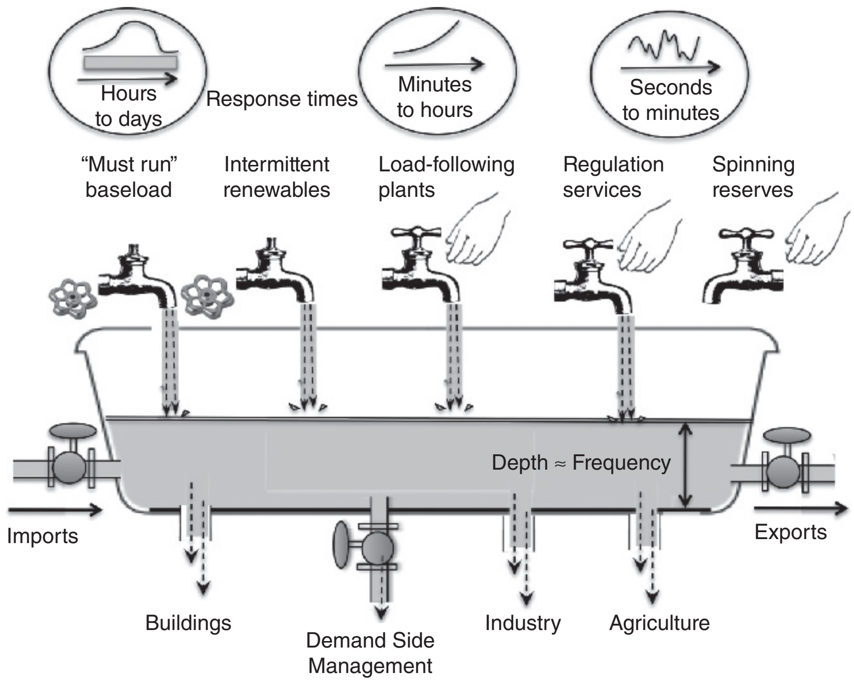

FIGURE 1.12 A more complicated bathtub analogy that incorporates the roles that different kinds of power plants provide as well as the potential for demand response.

1.4.3 Grid Stability

During normal operations, the grid responds to slight imbalances in supply and demand by automatically adjusting the power delivered by its generation facilities to bring system frequency back to acceptable levels. Small variations are routine; however, large deviations in frequency can cause the rotational speed of generators to fluctuate, leading to vibrations that can damage turbine blades and other equipment. Power plant pumps delivering cooling water and lubrication slow down as well. Significant imbalances can lead to automatic shutdowns of portions of the grid, which can affect thousands of people. When parts of the grid shut down, especially when that occurs without warning, power that surges around the outage can potentially overload other parts of the grid causing those sections to go down as well. Avoiding these calamitous events requires fast-responding, automatic controls supplemented by fast operator actions.

When a large conventional generator goes down, demand suddenly, and significantly, exceeds supply causing the rest of the interconnect region to almost immediately experience a drop in grid frequency. The inertia associated with all of the remaining turbine/generators in the interconnect region helps control the

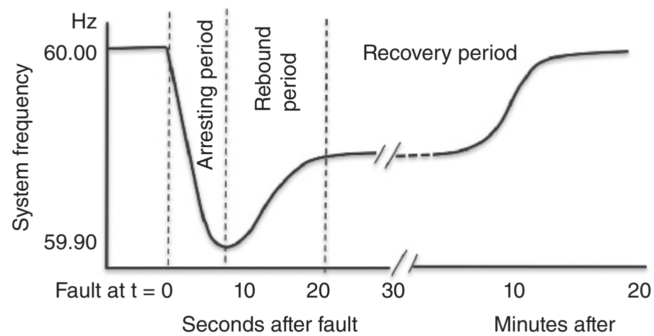

FIGURE 1.13 After a sudden loss of generation, automatic controls try to bring frequency to an acceptable level within seconds. Operator-dispatched power takes additional time to completely recover. From Eto et al., 2010.

rate at which frequency drops. In addition, conventional frequency regulation systems, which are already operating, ramp up power to try to compensate for the lost generation. If those are insufficient, frequency control reserves will automatically be called up. If everything goes well, as is suggested in Figure 1.13, within a matter of seconds frequency rebounds to an acceptable level, which buys time for grid operators to dispatch additional power from other generators. It may take 10 min or so for those other resources to bring the system back into balance at the desired 60 Hz.

Most often, major blackouts occur when the grid is running at near capacity, which for most of the United States occurs during the hottest days of summer when the demand for air conditioning is at its highest. When transmission line currents increase, resistive losses (proportional to current squared) cause the lines to heat up. If it is a hot day, especially with little or no wind to help cool the lines, the conductors expand and sag more than normal and are more likely to come in contact with underlying vegetation causing a short-circuit (i.e., a *fault*). Perhaps surprisingly, one of the most common triggers for blackouts on those hot days results from insufficient attention having been paid to simple management of tree growth within transmission-line rights-of-way. In fact, the August 2003 blackout that hit the Midwest and Northeastern parts of the United States, as well as Ontario, Canada, was initiated by this very simple phenomenon. That blackout caused 50 million people to be without power, some for as long as four days, and cost the United States roughly \$4–10 billion.

1.4.4 Industry Statistics

As shown in Figure 1.14, 70% of the U.S. electricity is generated in power plants that burn fossil fuels—coal, natural gas, and oil—with coal being the dominant source. Note that oil is a very minor fuel in the electricity sector, only about 1%,

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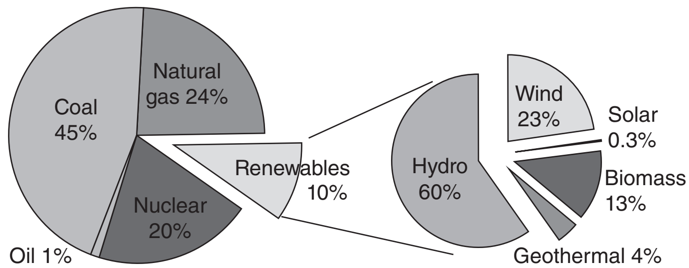


FIGURE 1.14 Energy sources for U.S. electricity in 2010 (based on EIA Monthly Energy Review, 2011).

and that is almost all residual fuel oil—literally the bottom of the barrel—that has little value for anything else. That is, petroleum and electricity currently have very little to do with each other. However that may change as we begin to more aggressively electrify the transportation sector.

About 20% of our electricity comes from nuclear power plants and the remaining 10% comes from a handful of renewable energy systems—mostly hydroelectric facilities. That is, close to one-third of our power is generated with virtually no direct carbon emissions (there are, still, emissions associated with the embodied energy associated with building those plants). Wind and solar plants in 2010 accounted for only about 2.5% of the U.S. electricity, but that fraction is growing rapidly.

Only about one-third of the energy content of fuels used to generate electricity ends up being delivered to end-use customers. The missing two-thirds is made up of thermal losses at the power plant (which will be described more carefully later), electricity used to help run the plant itself (much of that helps control emissions), and losses in T&D lines. As Figure 1.15 illustrates, if we imagine starting with 300 units of fuel energy, close to 200 are lost along the way and

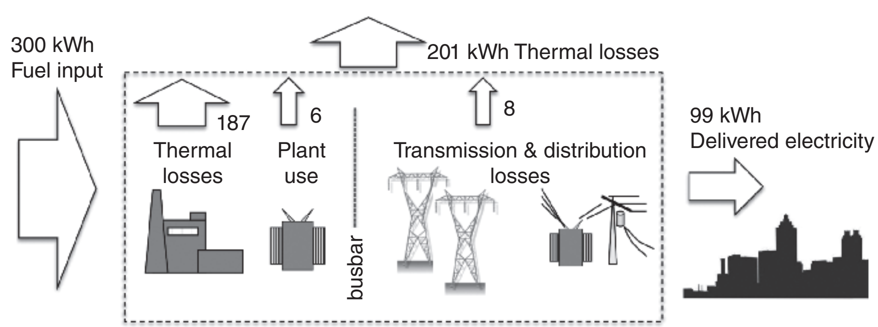
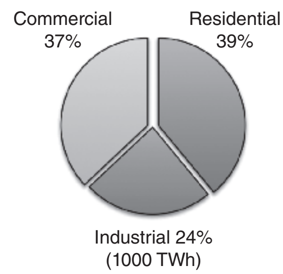


FIGURE 1.15 Only about one-third of the energy content of fuels ends up as electricity delivered to customers (losses shown are based on data in the 2010 EIA *Annual Energy Review*).

Commercial	Percentage
Lighting	26%
Space cooling	15%
Ventilation	13%
Refrigeration	10%
Electronics	7%
Computers	5%
Space heating	5%
Water heating	2%
Cooking	1%
Other	17%
TOTAL (TWh)	1500



Residential	Percentage
Space cooling	22%
Lighting	14%
Water heating	9%
Refrigeration	9%
Space heating	9%
Electronics	7%
Wet cleaning	6%
Computers	4%
Cooking	2%
Other	18%
TOTAL (TWh)	1600

FIGURE 1.16 End uses for U.S. electricity. Cooling and lighting are especially important both in terms of total electricity consumption, and in their role in driving peak demand (data based on *EIA Building Energy Databook*, 2010).

100 are delivered to customers in the form of electricity, which leads to a very convenient 3:2:1 ratio for estimating energy flows in our power systems.

Three-fourths of U.S. electricity that makes it to customers is used in residential and commercial buildings, with an almost equal split between the two. The remaining one-fourth powers industrial facilities. A breakdown of the way electricity is used in buildings is presented in Figure 1.16. A quick glance shows that for both residential and commercial buildings, lighting and space cooling are the most electricity-intensive activities. Those two are important not only because they are significant in total energy (about 30% of total kWh sold) but also because they are the principal drivers of the peak demand for power, which for many utilities occurs in the mid-afternoon on hot, sunny days. It is the peak load that dictates the total generation capacity that must be built and operated.

As an example of the impact of lighting and air conditioning on the peak demand for power, Figure 1.17 shows the California power demand on a hot, summer day. As can be seen, the diurnal rise and fall of demand is almost entirely driven by air conditioning and lighting. Better buildings with greater use of natural daylighting, more efficient lamps, increased attention to reducing afternoon solar gains, greater use of natural-gas-fired absorption air conditioning systems, load shifting by using ice made at night to cool during the day, and so forth, could make a significant difference in the number and type of power plants needed to meet those peak demands. The tremendous potential offered by building-energy efficiency and DR will be explored later in the book.

The “peakiness” of electricity demand caused by daytime-building-energy use is one of the reasons the price of electricity delivered to residential and commercial customers is typically about 50% higher than that for industrial facilities (Fig. 1.18). Industrial customers, with more uniform energy demand, can be served in a large part by less expensive, base-load plants that run more or less continuously. The distribution systems serving utilities are more uniformly loaded, reducing costs, and certainly the administrative costs to deal with customer billing and so forth are less. They also have more political influence.

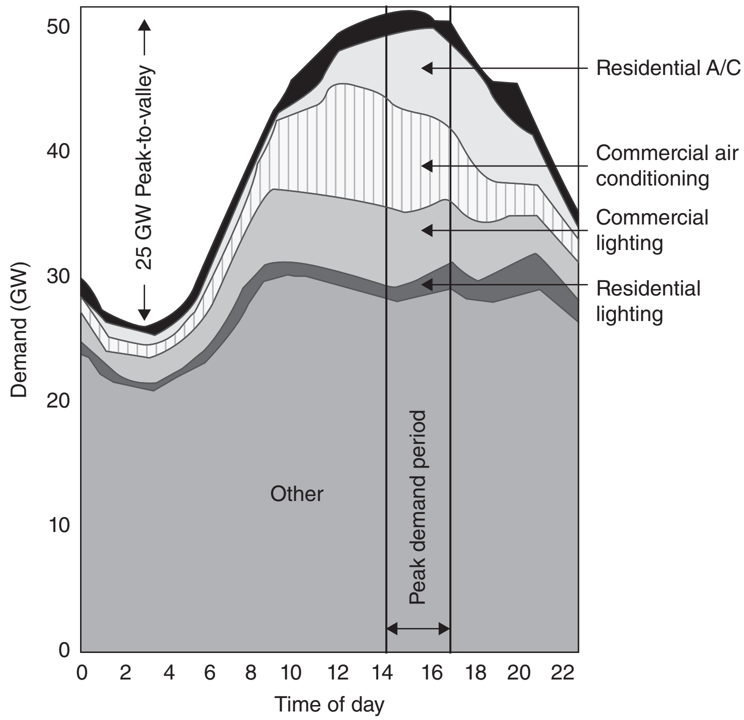


FIGURE 1.17 The load profile for a peak summer day in California (1999) showing that lighting and air conditioning account for almost all of the daytime rise. Adapted from Brown and Koomey (2002).

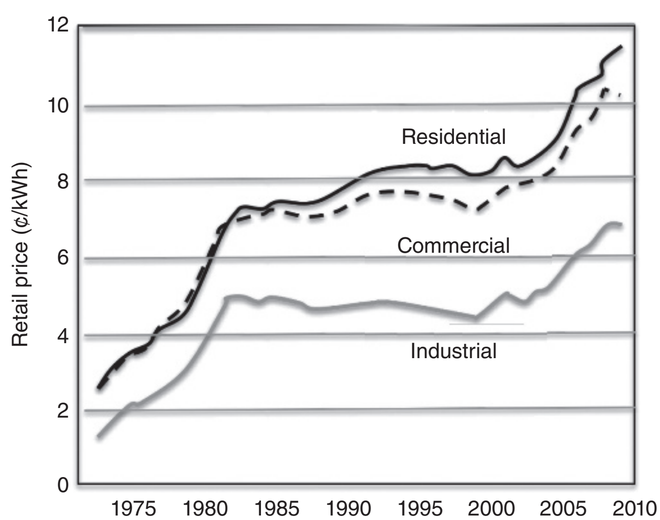


FIGURE 1.18 Average U.S. retail prices for electricity (1973–2010). Note prices are not adjusted for inflation. From *EIA Annual Energy Review* (2010).

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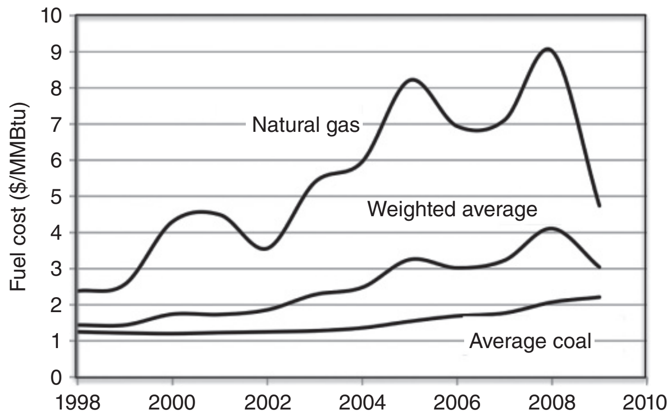

FIGURE 1.19 Weighted average fossil fuel costs for U.S. power plants, 1998–2009. Data from *EIA Electric Power Annual*, 2010.

It is interesting to note the sharp increases in prices that occurred in the 1970s and early 1980s, which can be attributed to increasing fuel costs associated with the spike in OPEC oil prices in 1973 and 1979, as well as the huge increase in spending for nuclear power plant construction during that era. For the following two decades, the retail prices of electricity were quite flat, basically just rising in parallel with the average inflation rate. Then, as Figure 1.19 shows, at the turn of the twenty-first century, fuel prices and hence electricity once again began a rapid rise. Within a decade, coal prices doubled while natural gas prices quadrupled, then dramatically fell by 50%. The volatility in natural gas makes it very difficult to make long-term investment decisions about what kind of power plants to build.

1.5 ELECTRIC POWER INFRASTRUCTURE: GENERATION

Power plants come in a wide range of sizes, run on a variety of fuels, and utilize a number of different technologies to convert fuels into electricity. Most electricity today is generated in large, central stations with power capacities measured in hundreds or even thousands of megawatts (MW). A single, large nuclear power plant, for example, generates about 1000 MW, also described as 1 gigawatt (GW). The total generation capacity of the United States is equivalent to about 1000 such power plants—that is, 1000 GW or 1 terrawatt (TW). With siting and permitting issues being so challenging, power plants are often clustered together into what is usually referred to as a *power station*. For example, the Three Gorges hydroelectric power station in China consists of 26 individual turbines, and the Fukushima Daiichi nuclear power station in Japan had six individual reactors.

About 90% of the U.S. electricity is generated in power plants that convert heat into mechanical work. The heat may be the result of nuclear reactions, fossil fuel combustion, or even concentrated sunlight focused onto a boiler. Utility-scale thermal power plants are based on either (a) the *Rankine cycle,* in which a working fluid is alternately vaporized and condensed, or (b) the *Brayton cycle,* in which the working fluid remains a gas throughout the cycle. Most *base-load* thermal power plants, which operate more or less continuously, are Rankine cycle plants in which steam is the working fluid. Most *peaking* plants, which are brought on line as needed to cover the daily rise and fall of demand, are gas turbines based on the Brayton cycle. The newest generation of thermal power plants use both cycles and are called combined-cycle plants.

1.5.1 Basic Steam Power Plants

The basic steam cycle can be used with any source of heat, including combustion of fossil fuels, nuclear fission reactions, or concentrated sunlight onto a boiler. The essence of a fossil-fuel-fired steam power plant is diagrammed in Figure 1.20. In the steam generator, fuel is burned in a firing chamber surrounded by a boiler that transfers heat through metal tubing to the working fluid. Water circulating through the boiler is converted to high pressure, high temperature steam. During this conversion of chemical to thermal energy, losses on the order of 10% occur due to incomplete combustion and loss of heat up the stack.

High pressure steam is allowed to expand through a set of turbine wheels that spin the turbine and generator shaft. For simplicity, the turbine in Figure 1.20 is shown as a single unit, but for increased efficiency it may actually consist of two or sometimes three turbines in which the exhaust steam from a higher pressure turbine is reheated and sent to a lower pressure turbine, and so forth. The generator and turbine share the same shaft allowing the generator to convert the rotational energy of the shaft into electrical power that goes out onto the transmission lines for distribution. A well-designed turbine may have an efficiency approaching 90%, while the generator may have a conversion efficiency even higher than that.

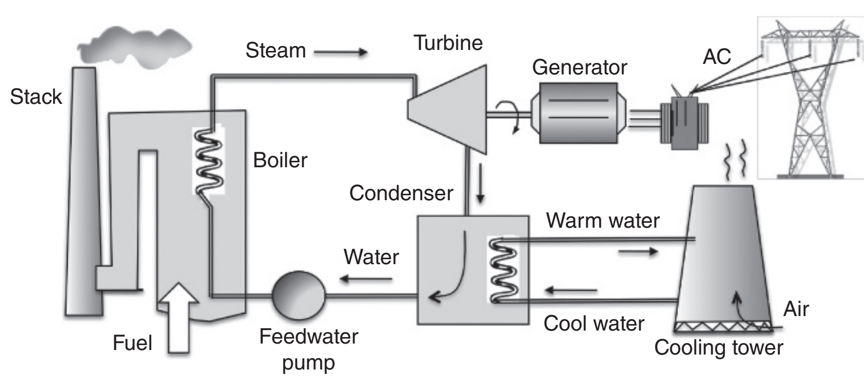

FIGURE 1.20 Basic fuel-fired, steam electric power plant.

The spent steam is drawn out of the last turbine stage by the partial vacuum created in the condenser as the cooled steam undergoes a phase change back to the liquid state. The condensed steam is then pumped back to the boiler to be reheated, completing the cycle.

The heat released when the steam condenses is transferred to cooling water, which circulates through the condenser. Usually, cooling water is drawn from a river, lake or sea, heated in the condenser, and returned to that body of water, in which case the process is called *once-through cooling*. The more expensive approach shown in Figure 1.20 involves use of a cooling tower, which not only requires less water but it also avoids the thermal pollution associated with warming up a receiving body of water. Water from the condenser heat exchanger is sprayed into the tower and the resulting evaporation transfers heat directly into the atmosphere (see Example 1.1).

1.5.2 Coal-Fired Steam Power Plants

Coal-fired power plants built before the 1960s were notoriously dirty. Fortunately, newer plants have effective, but expensive, emission controls that significantly decrease toxic emissions (but do little to control climate-changing CO_2 emissions). Unfortunately, many of those old plants are still in operation.

Figure 1.21 shows some of the complexity that emission controls add to coal-fired steam power plants. Flue gas from the boiler is sent to an electrostatic precipitator (ESP), which adds a charge to the particulates in the gas stream so they can be attracted to electrodes that collect this fly ash. Fly ash is normally

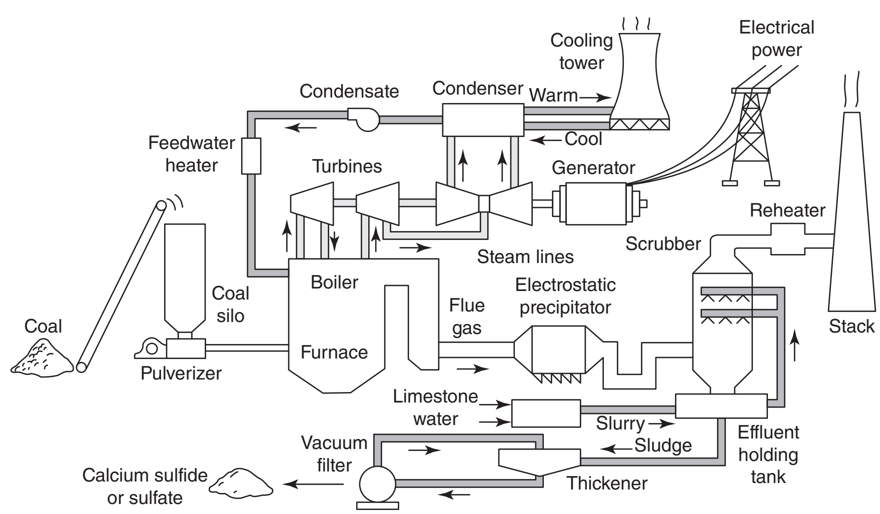

FIGURE 1.21 Typical coal-fired power plant using an electrostatic precipitator for particulate control and a limestone-based SO_2 scrubber.

buried, but it has a much more useful application as a replacement for cement in concrete. In fact, for every ton of fly ash used in concrete, roughly 1 ton of CO_2 emissions are avoided.

Next, a flue gas desulfurization (FGD, or *scrubber*) system sprays a limestone slurry over the flue gases, precipitating the sulfur to form a thick calcium sulfite sludge that must be dewatered and either buried in landfills or reprocessed into useful gypsum. As of 2010, less than half of the U.S. coal plants had scrubbers.

Not shown in Figure 1.21 are emission controls for nitrogen oxides, NO_x. Nitrogen oxides have two sources. Thermal NO_x is created when high temperatures oxidize the nitrogen (N_2) in air. Fuel NO_x results from nitrogen impurities in fossil fuels. Some NO_x emission reductions have been based on careful control of the combustion process rather than with external devices such as scrubbers and precipitators. More recently, *selective catalytic reduction* (SCR) technology has proven effective. The SCR in a coal station is similar to the catalytic converters used in cars to control emissions. Before exhaust gases enter the smokestack, they pass through the SCR where anhydrous ammonia reacts with nitrogen oxide and converts it to nitrogen and water.

Flue gas emission controls are not only very expensive, accounting for upward of 40% of the capital cost of a new coal plant, but they also drain off about 5% of the power generated by the plant, which lowers overall efficiency.

The thermal efficiency of power plants is often expressed as a *heat rate*, which is the thermal input (Btu or kJ) required to deliver 1 kWh of electrical output (1 Btu/kWh = 1.055 kJ/kWh) at the busbar. The smaller the heat rate, the higher the efficiency. In the United States, heat rates are usually expressed in Btu/kWh, which results in the following relationship between it and thermal efficiency, η.

$$\text{Heat rate (Btu/kWh)} = \frac{3412\ \text{Btu/kWh}}{\eta} \tag{1.1}$$

Or, in SI units,

$$\text{Heat rate (kJ/kWh)} = \frac{1\ \text{(kJ/s)/kW} \times 3600\ \text{s/h}}{\eta} = \frac{3600\ \text{kJ/kWh}}{\eta} \tag{1.2}$$

While Edison's first power plants in the 1880s had heat rates of about 70,000 Btu/kWh (≈5% efficient), the average pulverized coal (PC) steam plant operating in the United States today has an efficiency of 33% (10,340 Btu/kWh). These plants are referred to as being subcritical in that the steam contains a two-phase mixture of steam and water at temperatures and pressures around 1000°F and 2400 lbf/in^2 (540°C, 16 MPa). With new materials and technologies, higher temperatures and pressures are possible leading to greater efficiencies. Power plants operating above 1000°F/3200 lbf/in^2 (540°C/22 MPa), called *supercritical*

(SC) plants, have heat rates between 8500 and 9500 Btu/kWh. *Ultra-supercritical* (USC) plants operate above 1100°F/3500 lbf/in^2 (595°C/24 MPa) with heat rates of 7600–8500 Btu/kWh.

Example 1.1 Carbon Emissions and Water Needs of a Coal-Fired Power Plant. Consider an average PC plant with a heat rate of 10,340 Btu/kWh burning a typical U.S. coal with a carbon content of 24.5 kgC/GJ (1 GJ = 10^9 J). About 15% of thermal losses are up the stack and the remaining 85% are taken away by cooling water.

a. Find the efficiency of the plant.
b. Find the rate of carbon and CO_2 emissions from the plant in kg/kWh.
c. If CO_2 emissions eventually are taxed at \$10 per metric ton (1 metric ton = 1000 kg), what would be the additional cost of electricity from this coal plant (¢/kWh)?
d. Find the minimum flow rate of *once-through* cooling water (gal/kWh) if the temperature increase in the coolant returned to the local river cannot be more than 20°F.
e. If a cooling tower is used instead of once-through cooling, what flow rate of water (gal/kWh) taken from the local river is evaporated and lost. Assume 144 Btu are removed from the coolant for every pound of water evaporated.

Solution

a. From Equation 1.1, the efficiency of the plant is

$$\eta = \frac{3412\ \text{Btu/kWh}}{10{,}340\ \text{Btu/kWh}} = 0.33 = 33\%$$

b. The carbon emission rate would be

$$\text{C emission rate} = \frac{24.5\ \text{kgC}}{10^9\text{J}} \times \frac{10{,}340\ \text{Btu}}{\text{kWh}} \times \frac{1055\ \text{J}}{\text{Btu}} = 0.2673\ \text{kgC/kWh}$$

Recall, that CO_2 has a molecular weight of $12 + 2 \times 16 = 44$; so

$$CO_2\ \text{emission rate} = \frac{0.2673\ \text{kgC}}{\text{kWh}} \times \frac{44\ \text{gCO}_2}{12\ \text{gC}} = 0.98\ \text{kg CO}_2\text{/kWh}$$

This is a handy rule of thumb, that is, 1 kWh from a coal plant releases close to 1 kg of CO_2.

c. At \$10/t of CO_2, the value of savings is

$$0.98\,\text{kg CO}_2/\text{kWh} \times \$10/1000\,\text{kg} = \$0.0098/\text{kWh} \approx 1¢/\text{kWh}$$

That suggests another handy rule of thumb. That is, for every \$10/t CO_2 tax, add about a penny per kWh to the cost of coal-fired electricity.

d. With 67% of the input energy wasted and 85% of that being removed by the cooling water, the coolant flow rate needed for a 20°F rise will be

$$\text{Cooling water} = \frac{0.85 \times 0.67 \times 10{,}340\ \text{Btu/kWh}}{1\ \text{Btu/lb}^\circ\text{F} \times 20^\circ\text{F} \times 8.34\ \text{lb/gal}} = 35.3\ \text{gal H}_2\text{O/kWh}$$

(Note we have used the specific heat of water as 1 Btu/lb°F.)

e. With cooling coming from evaporation in the cooling tower,

$$\text{Make up water} = \frac{0.67 \times 0.85 \times 10{,}340\ \text{Btu/kWh}}{144\ \text{Btu/lb} \times 8.34\ \text{lb/gal}} = 4.9\ \text{gal/kWh}$$

So, to avoid thermal pollution in the river, you need to permanently remove about 5 gal of water per kWh generated.

The above example developed a couple of simple rules of thumb for coal plants based on per unit of electricity generated. Other simple generalizations can be developed based on the annual electricity generated. The annual energy delivered by a power plant can be described by its rated power (P_R), which is the power it delivers when operating at full capacity, and its capacity factor (CF), which is the ratio of the actual energy delivered to the energy that would have been delivered if the plant ran continuously at full rated power. Assuming rated power in kW, annual energy in kWh, and 24 h/d × 365 days/yr = 8760 h in a year, the annual energy delivered by a power plant is thus given by

$$\text{Annual energy (kWh/yr)} = \text{P}_\text{R}(\text{kW}) \times 8760\ \text{h/yr} \times \text{CF} \tag{1.3}$$

Another way to interpret the CF is to think of it as being the ratio of average power to rated power over a year's time.

For example, the average coal-fired power plant in the United States has a rated power of about 500 MW and an average CF of about 70%. Using Equation 1.3, the annual energy generated by such a plant would be

$$\text{Annual energy} = 500{,}000\ \text{kW} \times 8760\ \text{h/yr} \times 0.70 = 3.07 \times 10^9\ \text{kWh/yr} \tag{1.4}$$

Using the assumptions in Example 1.1, it was shown that a typical power plant emits 0.98 kg CO_2/kWh, which means our generic 500 MW plant emits almost exactly 3×10^9 kg (3 million metric tons) of CO_2 per year.

Similar, but more carefully done calculations than those presented above have led to a newly proposed energy-efficiency unit, called the *Rosenfeld*, in honor of Dr. Arthur Rosenfeld (Koomey et al., 2010). Dr. Rosenfeld is credited with advocating the description of the benefits of technologies that save energy (e.g., better refrigerators, lightbulbs, etc.) in terms of power plants that do not have to be built rather than in the less intuitive terms of billions of kWh saved.

The *Rosenfeld* is based on savings realized by not building a 500 MW, 33% efficient, coal-fired power plant, operating with a CF of 70%, sending power through a T&D system with 7% losses. One Rosenfeld equals an energy savings of 3 billion kWh/yr and an annual carbon reduction of 3 million metric tons of CO_2. As an example, since 1975 refrigerators have gotten 25% bigger, 60% cheaper, and the new ones use 75% less energy, resulting in an annual savings in the United States of about 200 billion kWh/yr. In Rosenfelds, that is equivalent to having eliminated the need for 200/3 = 67 500-MW coal-fired power plants and 200 million metric tons of CO_2 per year that is not pumped into our atmosphere.

1.5.3 Gas Turbines

The characteristics of gas turbines (GTs), also known as combustion turbines (CTs), for electricity generation are somewhat complementary to those of the steam turbine generators just discussed. Steam power plants tend to be large, coal-fired units that operate best with fairly fixed loads. They tend to have high capital costs, largely driven by required emission controls, and low operating costs since they so often use low-cost boiler fuels such as coal. Once they have been purchased, they are cheap to operate; so they usually are run more or less continuously. In contrast, GTs tend to be natural-gas-fired, smaller units, which adjust quickly and easily to changing loads. They have low capital costs and relatively high fuel costs, which means they are the most cost-effective as peaking power plants that run only intermittently. Historically, both steam and gas turbine plants have had similar efficiencies, typically in the low 30% range.

A basic simple-cycle GT driving a generator is shown in Figure 1.22. In it, fresh air is drawn into a compressor where spinning rotor blades compress the air, elevating its temperature and pressure. That hot, compressed air is mixed with fuel, usually natural gas, though LPG, kerosene, landfill gas, or oil are sometimes used, and burned in the combustion chamber. The hot exhaust gases are expanded in a turbine and released to the atmosphere. The compressor and the turbine share a connecting shaft, so that a portion, typically more than half, of the rotational energy created by the spinning turbine is used to power the compressor.

Gas turbines have long been used in industrial applications and as such were designed strictly for stationary power systems. These *industrial gas turbines*

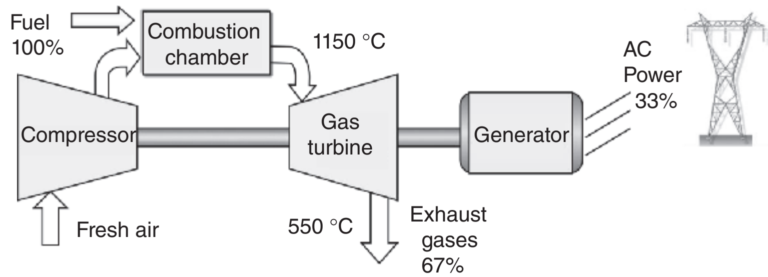

FIGURE 1.22 Basic simple-cycle gas turbine and generator.

tend to be large machines made with heavy, thick materials whose high thermal capacitance and moment of inertia reduces their ability to adjust quickly to changing loads. They are available in a range of sizes from hundreds of kilowatts to hundreds of megawatts. For the smallest units they are only about 20% efficient, but for turbines over about 10 MW they tend to have efficiencies of around 30%.

Another style of gas turbine takes advantage of the billions of dollars of development work that went into designing lightweight, compact engines for jet aircraft. The thin, light, superalloy materials used in these *aeroderivative turbines* enable fast starts and quick acceleration, so they easily adjust to rapid load changes and numerous startup/shutdown events. Their small size makes it easy to fabricate the complete unit in the factory and ship it to a site, thereby reducing the field installation time and cost. Aeroderivative turbines are available in sizes ranging from a few kilowatts up to about 50 MW. In their larger sizes, they achieve efficiencies exceeding 40%.

One way to increase the efficiency of gas turbines is to add a heat exchanger, called a heat recovery steam generator (HRSG) to capture some of the waste heat from the turbine. Water pumped through the HRSG turns to steam, which is injected back into the airstream coming from the compressor. The injected steam displaces a portion of the fuel heat that would otherwise be needed in the combustion chamber. These units, called steam-injected gas turbines (STIG), can have efficiencies approaching 45%. Moreover, the injected steam reduces combustion temperatures, which helps control NO_x emissions. They are considerably more expensive than simple GTs due to the extra cost of the HRSG and the care that must be taken to purify the incoming feedwater.

1.5.4 Combined-Cycle Power Plants

Note the temperature of the gases exhausted into the atmosphere in the simple-cycle GT shown in Figure 1.22 is over 500°C. Clearly that is a tremendous waste of high quality heat that could be captured and put to good use. One way to do so is to pass those hot gases through a heat exchanger to boil water and make steam.

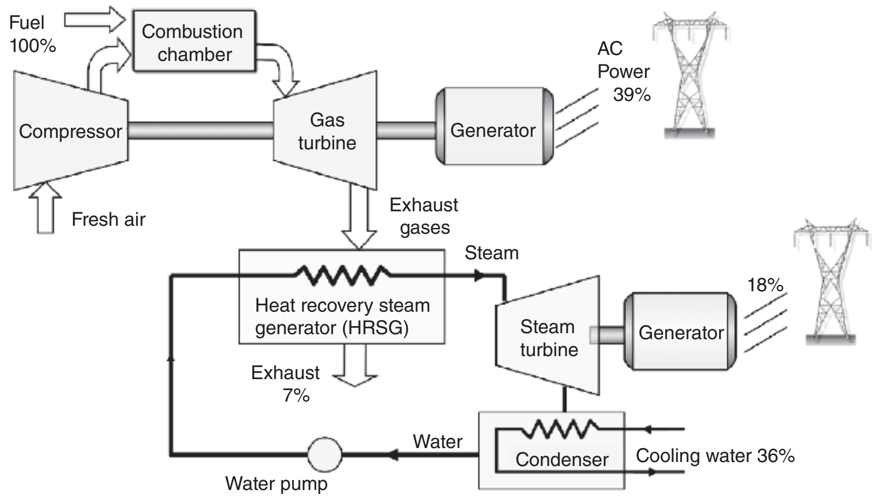

FIGURE 1.23 Combined-cycle power plants have achieved efficiencies approaching 60%.

The heat exchanger is called an HRSG and the resulting steam can be put to work in a number of applications, including industrial process heating or water and space heating for buildings. Of course, such *combined heat and power* (CHP) applications are viable only if the GT is located very close to the site where its waste heat can be utilized. Such CHP systems will be considered in a later chapter.

A more viable alternative is to use the steam generated in an HRSG to power a second-stage steam turbine to generate more electricity as shown in Figure 1.23. Working together, such natural-gas-fired, combined-cycle power plants (NGCCs) have heat rates of 6300–7600 Btu/kWh (45–54% efficiency). New ones being proposed may reach 60%. If the decline in natural gas prices and rise in coal prices shown in Figure 1.19 provides any indication of the future, coupled with the lower carbon emissions when natural gas is used, these NGCC plants will provide stiff competition for the next generation of supercritical or ultra-supercritical coal plants being proposed.

1.5.5 Integrated Gasification Combined-Cycle Power Plants

With combined-cycle plants achieving such high efficiencies, and with natural gas being an inherently cleaner fuel, the trend in the United States has been away from building new coal-fired power plants. Coal, however, is a much more abundant fuel than natural gas, but in its conventional, solid form, it cannot be used in a gas turbine. Erosion and corrosion of turbine blades due to impurities in coal would quickly ruin a gas turbine. However, coal can be processed to convert it into a synthetic gas, which can be burned in what is called an *integrated gasification, combined-cycle* (IGCC) power plant.

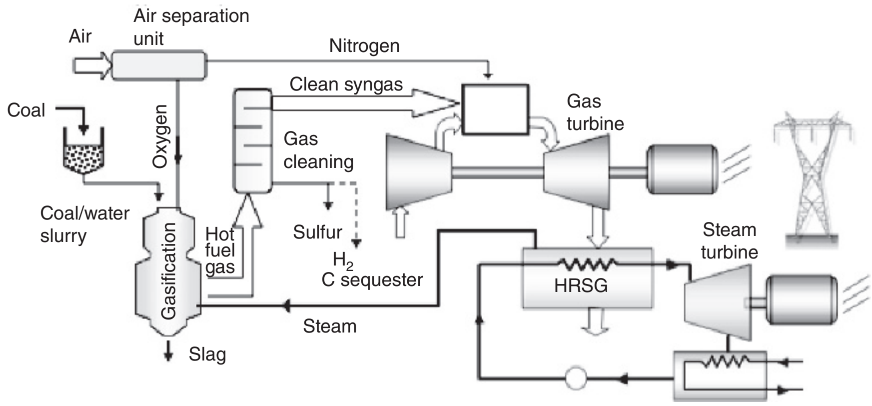

FIGURE 1.24 An integrated gasification, combined-cycle (IGCC) power plant.

Gas derived from coal, called “town gas,” was popular in the late 1800s before the discovery of large deposits of natural gas. One hundred years later, coal’s air pollution problems prompted the refinement of technologies for coal gasification. Several gasification processes have been developed, primarily in the Great Plains Gasification Plant in Beulah, ND, in the 1970s and later in the 100 MW Cool Water project near Barstow, CA, in the 1980s.

As shown in Figure 1.24, the essence of an IGCC consists of bringing a coal-water slurry into contact with steam to form a fuel gas consisting mostly of carbon monoxide (CO) and hydrogen (H_2). The fuel gas is cleaned up, removing most of the particulates, mercury and sulfur, and then burned in the GT. Air used in the combustion process is first separated into nitrogen and oxygen. The nitrogen is used to cool the GT and the oxygen is mixed with the gasified coal, which helps increase combustion efficiency. Despite energy losses in the gasification process, by taking advantage of combined-cycle power generation, an IGCC should be able to burn coal with an overall thermal efficiency of perhaps 40%. This is considerably higher than the conventional PC plants, about the same as SC plants, but below the efficiency of USC plants.

An advantage of IGCC, relative to SC plants, is that the CO_2 produced by the process is in a concentrated, high pressure gas stream, which makes it easier to separate and capture than is the case for ordinary low pressure flue gases. If a carbon sequestration technology could be developed to store that carbon in perpetuity, it might be possible to envision a future with carbon-free, high efficiency, coal-fired power plants capable of supplying clean electricity for several centuries into the future.

IGCC plants are more expensive than pulverized coal and they have trouble competing economically with NGCC plants. As of 2010, there were only five coal-based IGCC plants in the world; two of which were in the United States. The potential for future natural gas prices to rise, coupled with the possibility of a future cost for carbon emissions and the potential to remove and sequester carbon from the syngas before it is burned have kept the interest in IGCC plants alive. Their future, however, is quite uncertain.

1.5.6 Nuclear Power

Nuclear power has had a rocky history, leading it from its glory days in the 1970s as a technology thought to be "too cheap to meter," to a technology that in the 1980s some characterized as "too expensive to matter." The truth is probably somewhere in the middle. If the embodied carbon associated with construction is ignored, reactors do have the advantage of being essentially a carbon-free source of electric power, so climate concerns are helping nuclear power begin to enjoy a resurgence of interest. After the 2011 Japanese meltdowns at Fukushima, whether a new generation of cheaper, safer reactors can overcome public misgivings over safety, where to bury radioactive wastes, and how to keep plutonium from falling into the wrong hands, remains to be seen.

The essence of the nuclear reactor technology is basically the same simple steam cycle described for fossil-fueled power plants. The main difference is the heat is created by nuclear reactions instead of fossil fuel combustion.

Light Water Reactors: Water in a reactor core not only acts as the working fluid, it also serves as a *moderator* to slow down the neutrons ejected when uranium fissions. In *light water reactors* (LWRs), ordinary water is used as the moderator. Figure 1.25 illustrates the two principal types of LWRs—(a) *boiling water reactors* (BWRs), which make steam by boiling water within the reactor core itself and (b) *pressurized water reactors* (PWRs) in which a separate heat exchanger, called a steam generator, is used. PWRs are more complicated, but they can operate at higher temperatures than BWRs and hence are somewhat more efficient. PWRs can be somewhat safer since a fuel leak would not pass any radioactive contaminants into the turbine and condenser. Both types of reactors are used in the United States, but the majority are PWRs.

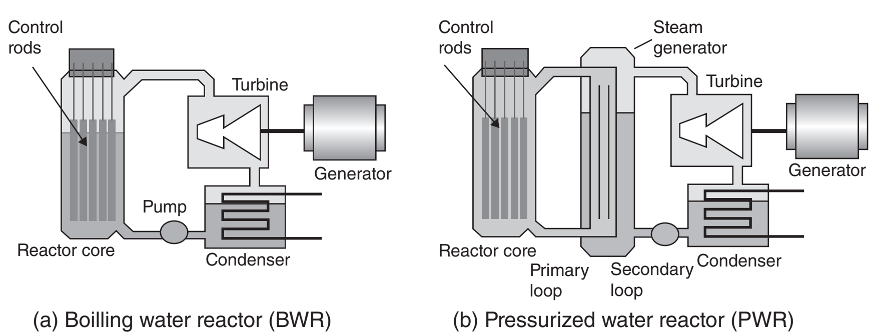

FIGURE 1.25 The two types of light water reactors commonly used in the United States.

Heavy Water Reactors: Reactors commonly used in Canada use heavy water; that is, water in which some of the hydrogen atoms are replaced with deuterium (hydrogen with an added neutron). The deuterium in heavy water is more effective in slowing down neutrons than ordinary hydrogen. The advantage in these Canadian deuterium reactors (commonly called CANDU) is that ordinary uranium as mined, which contains only 0.7% of the fissile isotope U-235, can be used without the enrichment that LWRs require.

High Temperature, Gas-Cooled Reactors (HTGR): HTGRs use helium as the reactor core coolant rather than water, and in some designs it is helium itself that drives the turbine. These reactors operate at considerably higher temperatures than conventional water-moderated reactors, which means their efficiencies can be higher—upward of 45% rather than the 33% that typifies LWRs.

There are two HTGR concepts under development—the Prismatic Fuel Modular Reactor (GT-MHR) based on German technology and the Modular Pebble Bed Reactor (MPBR) which is being developed in South Africa. Both are based on microspheres of fuel, but differ in how they are configured in the reactor. The MPBR incorporates the fuel microspheres in carbon-coated balls ("pebbles") roughly 2 in in diameter. One reactor will contain close to half a million such balls. The advantage of a pebble reactor is that it can be refueled continuously by adding new balls and withdrawing spent fuel balls without having to shut down the reactor.

The Nuclear Fuel "Cycle": The costs and concerns for nuclear fission are not confined to the reactor itself. Figure 1.26 shows current practice from mining and processing of uranium ores, to enrichment that raises the concentration of U-235, to fuel fabrication and shipment to reactors. Highly radioactive spent fuel removed from the reactors these days sits on-site in short-term storage facilities while we await a longer-term storage solution such as the underground federal repository that had been planned for Yucca Mountain, Nevada. Eventually, after

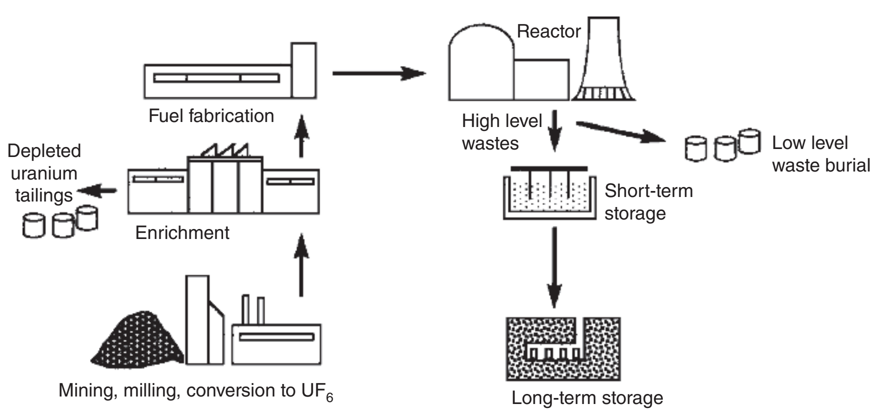

FIGURE 1.26 A once-through fuel system for nuclear reactors.

40 years or so, the reactor itself will have to be decommissioned and its radioactive components will also have to be transported to a secure disposal site.

Reactor wastes contain not only the fission fragments formed during the reactions, which tend to have half-lives measured in decades, but also include some radionuclides with very long half-lives. Of major concern is plutonium, which has a half-life of 24,390 years. Only a few percent of the uranium atoms in reactor fuel is the fissile isotope U-235, while essentially all of the rest is U-238, which does not fission. Uranium-238 can, however, capture a neutron and be transformed into plutonium as the following reactions suggest.

$$^{238}_{92}\mathrm{U} + n \rightarrow {}^{239}_{92}\mathrm{U} \xrightarrow{\beta} {}^{239}_{93}\mathrm{Np} \xrightarrow{\beta} {}^{239}_{94}\mathrm{Pu} \qquad (1.5)$$

This plutonium, along with several other long-lived radionuclides, makes nuclear wastes dangerously radioactive for tens of thousands of years, which greatly increases the difficulty of providing safe disposal. Removing the plutonium from nuclear wastes before disposal has been proposed as a way to shorten the decay period but that introduces another problem. Plutonium not only is radioactive and highly toxic, it is also the critical ingredient in the manufacture of nuclear weapons. A single nuclear reactor produces enough plutonium each year to make dozens of small atomic bombs and some have argued that if the plutonium is separated from nuclear wastes, the risk of illicit diversions for such weapons would cause an unacceptable risk.

On the other hand, plutonium is a fissile material, which, if separated from the wastes, can be used as a reactor fuel (Fig. 1.27). Indeed, France, Japan, Russia, and the United Kingdom have reprocessing plants in operation to capture and reuse that plutonium. In the United States, however, Presidents Ford and Carter

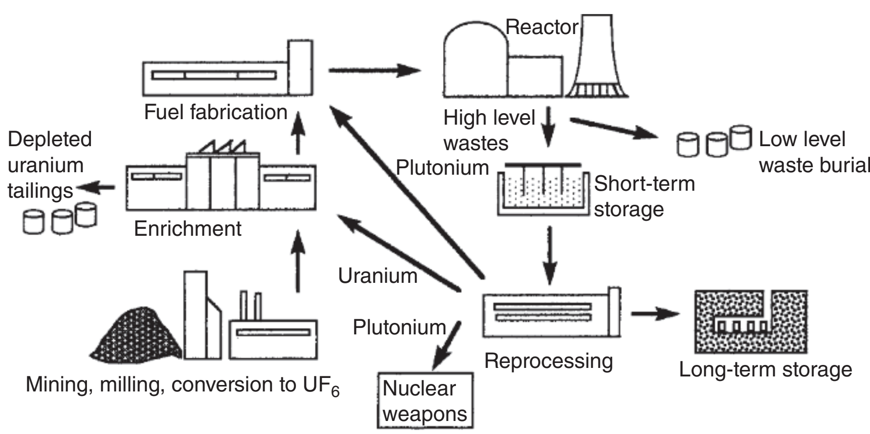

FIGURE 1.27 Nuclear fuel cycle with reprocessing.

considered the proliferation risk too high and commercial reprocessing of wastes has ever since not been allowed.

1.6 FINANCIAL ASPECTS OF CONVENTIONAL POWER PLANTS

A very simple model of power plant economics takes all of the costs and puts them into two categories—fixed costs and variable costs. Fixed costs are monies that must be spent even if the power plant is never turned on; they include such things as capital costs, insurance, property taxes, corporate taxes, and any fixed operations and maintenance (O&M) costs that will be incurred even when the plant is not operated. Variable costs are the added costs associated with actually running the plant. These are mostly fuel plus variable operations and maintenance costs.

1.6.1 Annualized Fixed Costs

To keep our analysis simple means ignoring many details which are more easily considered with a spreadsheet approach described in Appendix A. For example, a distinction can be made between "overnight" (or "instant") construction costs versus total installed cost (or "all-in cost"). The former refers to what it would cost to build the plant if no interest is incurred during construction, that is, if you could build the whole thing overnight. The installed cost is the overnight cost plus finance charges associated with capital during construction. The difference can be considerable for projects that take a long time to construct, which is an important distinction that needs to be made when comparing large conventional plants having long lead times versus smaller distributed generation.

A first cut at annualizing fixed costs is to lump all of its components into a single total that can then be multiplied by *fixed charge rate (FCR)*. The FCR accounts for interest on loans and acceptable returns for investors (both of which depend on the perceived risks for the project and on the type of ownership), fixed operation and maintenance (O&M) charges, taxes, and so forth. Since FCR depends primarily on the cost of capital, it varies as interest rates change. With rated power of the plant P_R and a capital cost expressed in the usual way ($/kW)

$$\text{Annual fixed costs (\$/yr)} = P_R \text{ (kW)} \times \text{Capital cost (\$/kW)} \times \text{FCR (\%/yr)} \tag{1.6}$$

Another complication is associated with the potentially ambiguous definition of the rated capacity of a power plant, P_R. It normally refers to the power delivered at the busbar connection to the grid, which means it includes on-site power needs as well as the transformer that raises the voltage to grid levels, but does not include the losses in getting the power to consumers. To do a fair comparison between a

TABLE 1.3 Example Capital-Cost Default Values

Ownership	Capital Structure		Cost of Capital		Weighted Average Cost of Capital (WACC) (%)
	Equity (%)	Debt (%)	Equity Rate (%)	Debt Rate (%)	
Merchant (fossil fuel)	60	40	12.50	7.50	10.50
Merchant (nonfossil)	40	60	12.50	7.50	9.50
Investor-owned utility (IOU)	50	50	10.50	5.00	7.75
Publicly owned utility (POU)	0	100	0.00	4.50	4.50

small, distributed generation system with no T&D losses versus a central power plant hundreds of miles away from loads, that distinction can be significant.

As described earlier, there are three types of ownership to be considered—investor owned utilities (IOUs), publicly owned utilities (POUs), and privately owned merchant plants. Merchant plants and IOUs are financed with a mix of loans (debt) and money provided by investors (equity). POUs are financed entirely with debt. Debt rates tend to be considerably below the returns expected by investors, so there are advantages to using high fractions of conventional loans subject to constraints set by lending agencies. As might be expected from the estimates of financing rates and investor participation shown in Table 1.3, merchant plants tend to be the most expensive since they have higher financing costs. Least expensive are POU plants since they have the lowest financing costs and are also exempt from a number of the taxes that other ownership structures must contend with.

We can annualize debt and equity by taking a weighted average and then treating that as a single loan interest rate that is to be repaid in equal annual payments. Annual payments A (\$/yr) on a loan of P (\$) with interest rate i (%/yr) paid over a term of n years can be calculated using the following *capital recovery factor* (*CRF*).

$$A(\$/\text{yr}) = P(\$) \cdot \text{CRF}(\%/\text{yr}) \quad \text{where } CRF = \frac{i(1+i)^n}{[(1+i)^n - 1]} \tag{1.7}$$

Most of the FCR in Equation 1.6 can be estimated using the above CRF. The rest of the FCR is made up of insurance, property taxes, fixed O&M, and corporate taxes. The California Energy Commission adds about 2 percentage points to the CRF to account for these factors. Merchant and IOU plants need to add another 3–4 percentage points to their CRF to cover their corporate taxes, which is another way that POUs that pay no corporate taxes have an advantage (CEC, 2010).

Annual fixed costs are often expressed with units of \$/yr-kW of rated power.

Example 1.2 Annual Fixed Costs for an NGCC Plant. Consider a natural-gas fired, combined cycle power plant with a total installed cost of \$1300/kW. Assume this is an IOU with 52% equity financing at 11.85% and 48% debt at 5.40% with investments "booked" on a 20-year term. Add 2% of the capital cost per year to account for insurance, property taxes, variable O&M, and another 4% for corporate taxes. Find the annual fixed cost of this plant (\$/yr-kW).

Solution. First, find the weighted average cost of capital.

$$\text{Average cost of capital} = 0.52 \times 11.85\% + 0.48 \times 5.40\% = 8.754\%$$

Using Equation 1.7 with this interest rate and a 20-year term gives

$$\text{CRF} = \frac{0.08754\,(1 + 0.08754)^{20}}{\left[(1 + 0.08754)^{20} - 1\right]} = 0.10763/\text{yr} = 10.763\%/\text{yr}$$

Adding the other charges gives a total FCR of

$$\begin{aligned}\text{FCR} &= 10.763\%\ (\text{finance}) + 2\%\ (\text{fixed O\&M, insurance, etc.}) + 4\%\ (\text{taxes})\\ &= 16.763\%\end{aligned}$$

From Equation 1.6, the annual fixed cost of the plant per kW of rated power would be

$$\text{Annual fixed cost} = \$1300/\text{kW} \times 0.16763/\text{yr} = \$218/\text{yr-kW}$$

1.6.2 The Levelized Cost of Energy (LCOE)

The variable costs, which also need to be annualized, depend on the annual fuel demand, the unit cost of fuel, and the O&M rate for the actual operation of the plant.

$$\text{Variable costs } (\$/\text{yr}) = [\text{Fuel} + \text{O\&M}]\ \$/\text{kWh} \times \text{Annual energy (kWh/yr)} \tag{1.8}$$

Annual energy delivered depends on the rated power of the plant and its capacity factor.

$$\text{Annual energy (kWh/yr)} = P_R\ (\text{kW}) \times 8760\ \text{hr/yr} \times \text{CF} \tag{1.9}$$

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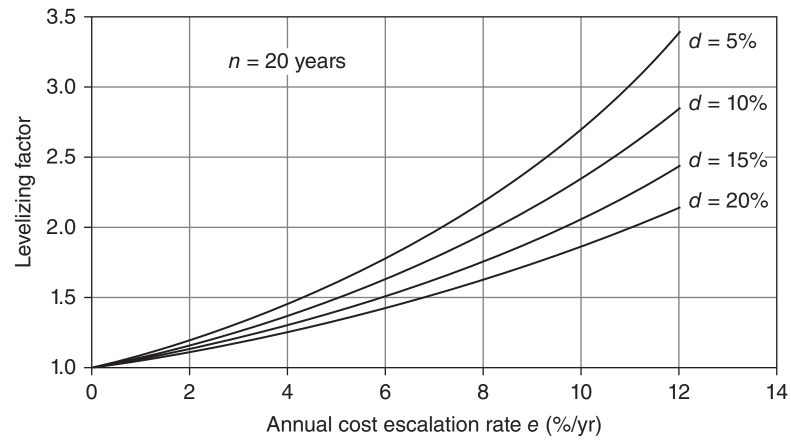

FIGURE 1.28 Levelizing factors for a 20-year term as a function of the escalation rate of annual costs with the owner's discount rate as a parameter. The derivation of this figure is provided in Appendix A.

The cost of fuel is often expressed in dollars per million Btu ($/MMBtu) at current prices. Since fuel costs are so volatile (e.g., Fig. 1.19), estimating the levelized cost of fuel over the life of the economic analysis is a challenge. One approach, described more carefully in Appendix A, introduces a levelizing factor (LF), which depends on an estimate of the fuel price escalation rate and the owner's discount factor. Figure 1.28 shows, for example, that if fuel escalates at a nominal 5%/yr and if future costs are discounted at a 10% rate (e.g., $1.10 cost a year from now has a discounted cost today of $1.00), the LF is about 1.5.

The annualized fuel cost is thus

$$\text{Fuel (\$/yr)} = \text{Energy (kWh/yr)} \times \text{Heat rate (Btu/kWh)} \times \text{Fuel cost (\$/Btu)} \times \text{LF} \tag{1.10}$$

The other important component of annual cost is the operations and maintenance (O&M) cost associated with running the plant. Those are often expressed in $/kWh.

Combining the annual fixed cost and the annualized variable cost, divided by the annual kWh generated gives the levelized cost of energy.

$$\text{LCOE (\$/kWh)} = \frac{[\text{Annual fixed cost} + \text{Annual variable cost}]\ (\$/\text{yr})}{\text{Annual output (kWh/yr)}} \tag{1.11}$$

or, on a per kW of rated power basis, LCOE can be written as

$$\text{LCOE (\$/kWh)} = \frac{\text{[Annual fixed cost + Annual variable cost] (\$/kW-yr)}}{8760\ \text{h/yr} \times \text{CF}} \tag{1.12}$$

Example 1.3 LCOE for an NGCC Plant. The levelized fixed cost of the NGCC plant in Example 1.2 was found to be \$218/yr-kW. Suppose natural gas now costs \$6/MMBtu and in the future it is projected to rise at 5%/yr. The owners have a 10% discount factor. Annual O&M adds another 0.4 ¢/kWh. If its heat rate is 6900 Btu/kWh and the plant has a 70% CF, find its LCOE.

Solution. Using Equation 1.9 with an assumed 1 kW of rated power, the annual energy delivered per kW of rated power is

$$\text{Annual energy} = 1\ \text{kW} \times 8760\ \text{h/yr} \times 0.70 = 6132\ \text{kWh/yr}$$

From Figure 1.28 the levelizing factor for fuel is 1.5. From Equation 1.10, the annualized fuel cost per kW is

$$\begin{aligned}\text{Annual fuel cost (per kW)} &= 6132\ \text{kWh/yr} \times 6900\ \text{Btu/kWh} \times \$6/10^6\ \text{Btu} \times 1.5 \\ &= \$381/\text{yr}\end{aligned}$$

Annual O&M adds another \$0.004/kWh × 6132 kWh/yr = \$25/yr

$$\text{Total variable costs (per kW)} = \$381 + \$25 = \$406/\text{yr}$$

Adding the \$218/yr-kW for annualized fixed costs gives a total

$$\text{Total annualized costs} = (\$218 + \$406)\ \$/\text{yr-kW}$$

Using Equation 1.12, the total levelized cost is therefore

$$\text{LCOE} = \frac{\$218/\text{yr-kW} + \$406/\text{yr-kW}}{8760\ \text{h/yr} \times 0.70} = \$0.1017/\text{kWh} = 10.17¢/\text{kWh}$$

The LCOE results derived in Example 1.3 were based on a particular value of capacity factor. As shown in Figure 1.29, it is very straightforward, of course, to vary CF and see how it affects LCOE. If we reinterpret capacity factor to have it represent the equivalent number of hours per year of plant operation at rated

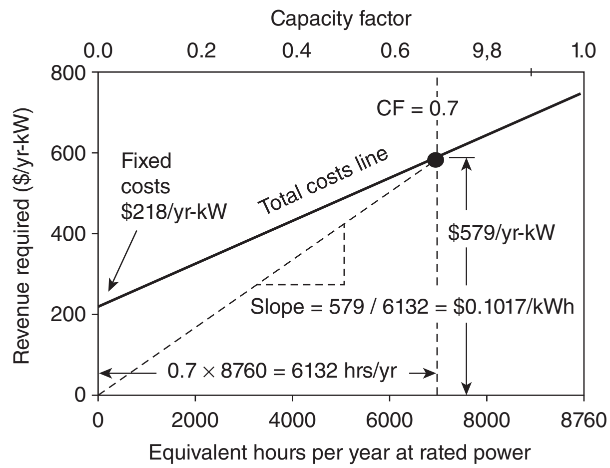

FIGURE 1.29 A graphical presentation of Examples 1.2 and 1.3. The average cost of electricity is the slope of a line drawn from the origin to the revenue curve that corresponds to the capacity factor.

power, then the slope of a line drawn from the origin to a spot on the total costs line is equal to the LCOE. Clearly, the average cost increases as CF decreases, which helps explain why peaking power plants that operate only a few hours each day have such a high average cost of electricity.

1.6.3 Screening Curves

Some technologies, such as coal and nuclear plants, tend to be expensive to build and cheap to operate, so they make sense only if they run most of the time. Others, such as combustion turbine (CT), are just the opposite—cheap to build and expensive to operate, so they are better suited as peakers. An economically efficient power system will include a mix of power plant types appropriate to the amount of time those plants actually are in operation.

Example 1.3 laid out the process for combining various key cost parameters to create an estimate of the levelized cost of electricity as a function of the CF. Based on the assumptions shown in Table 1.4, the LCOE for four types of power plants are compared—a simple-cycle CT, a pulverized coal plant, a combined-cycle plant, and a new nuclear power plant. These are referred to as *screening curves*. As can be seen, for this example, CT is the least expensive option as long as it runs with a CF < 0.27, which means it is the best choice for a peaker plant that operates only a few hours each day (in this case about 6.5 h/d). The coal plant is most cost-effective when it runs with CF > 0.65 (almost 16 h/d), which makes it a good base-load plant. The combined-cycle plant fits in the middle and is a good intermediate, load-following plant.

TABLE 1.4 Assumptions Used to Generate Figure 1.30

Technology	Fuel	Capital Cost ($/kW)	Heat Rate (Btu/kWh)	Variable O&M (¢/kWh)	Fuel Price ($/MMBtu)	Fuel Levelization	FCR
Pulverized coal-steam	Coal	2300	8750	0.40	2.50	1.5	0.167
Combustion turbine	Gas	990	9300	0.40	6.00	1.5	0.167
Combined cycle	Gas	1300	6900	0.40	6.00	1.5	0.167
Nuclear	U-235	4500	10,500	0.40	0.60	1.5	0.167

1.6.4 Load Duration Curves

We can imagine a load versus time curve, such as those shown in Figures 1.12 and 1.31, as being a series of one-hour power demands arranged in chronological order. Each slice of the load curve has a height equal to the power (kW) and a width equal to the time (1 h); so its area is kWh of energy used in that hour. As suggested in Figure 1.31, if we rearrange those vertical slices, ordering them from the highest kW demand to the lowest through an entire year of 8760 hours, we get something called a *load duration curve*. The area under the load duration curve is the total kWh of electricity used per year.

A smooth version of a load duration curve is shown in Figure 1.32. Note the *x*-axis is still measured in hours, but now a different way to interpret the curve presents itself. The graph tells how many hours per year the load (MW) is equal to or above a particular value. For example, in the figure, the load is always above 1500 MW and below 6000 MW. It is above 4000 MW for 2500 h each year, and

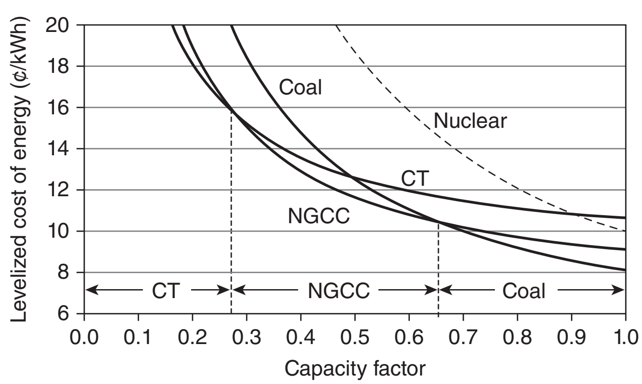

FIGURE 1.30 Screening curves for coal-steam, combustion turbine, combined-cycle, and nuclear plants based on assumptions given in Table 1.4.

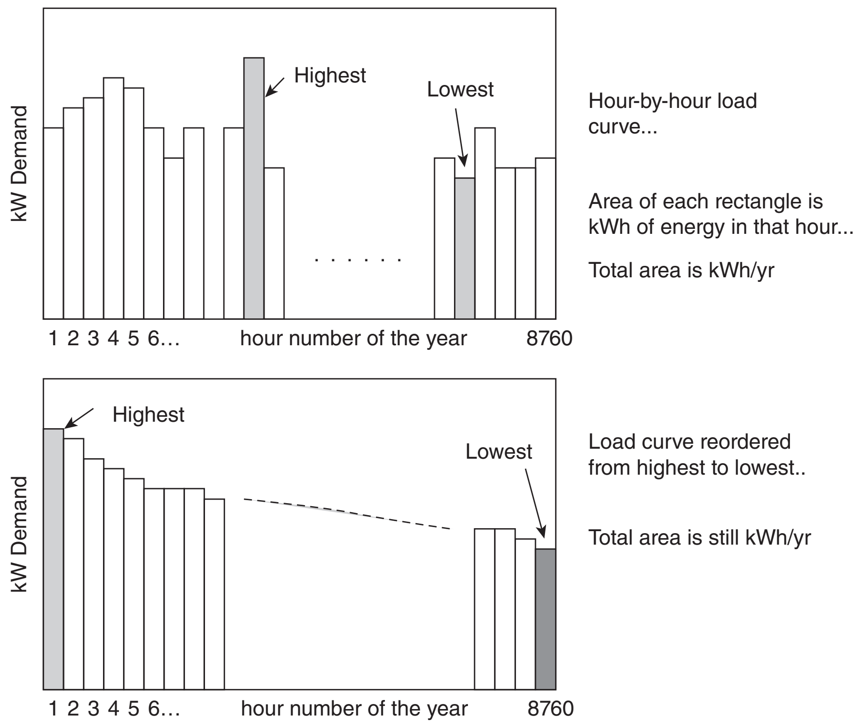

FIGURE 1.31 A load duration curve is simply the hour-by-hour load curve rearranged from chronological order into an order based on magnitude. The area under the curve is the total kWh/yr.

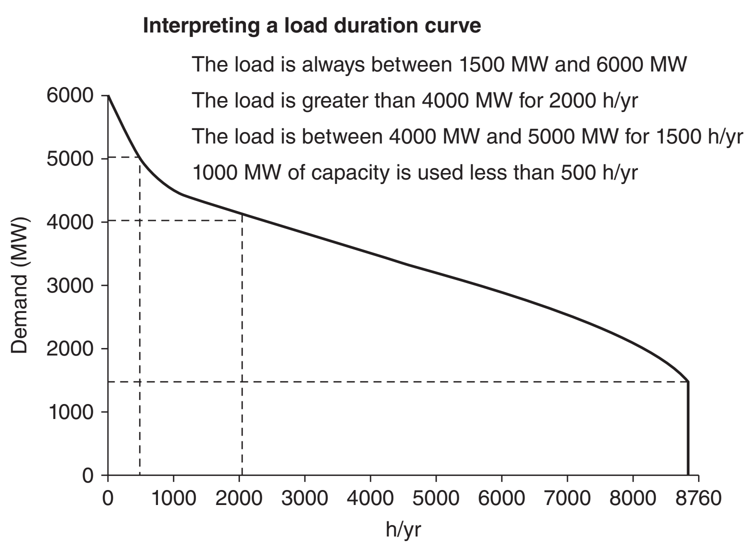

FIGURE 1.32 Interpreting a load duration curve.

it is above 5000 MW for only about 500 h/yr. That means it is between 4000 MW and 5000 MW for about 2000 h/yr. It also means that 1000 MW of generation, 16.7% is in use less than 500 h/yr and sits idle for 94% of the time. In California, 25% of generation capacity is idle 90% of the time.

By entering the crossover points from the resource screening curves (Fig. 1.30) into the load duration curve, it is easy to come up with a first-order estimate of the optimal mix of power plants. For example, the crossover between combustion turbines and combined-cycle plants in Figure 1.30 occurs at a CF of about 0.27, which corresponds to $0.27 \times 8760 = 2500$ h of operation (at rated power), while the crossover between combined cycle and coal-steam is at CF = 0.65 (5700 h). Putting those onto the load duration curve helps identify the number of MW of each kind of power plant this utility should have. As shown in Figure 1.30, coal plants are the cheapest option as long as they operate for more than 5700 h/yr. The load duration curve (Fig. 1.33) indicates that the demand is at least 3000 MW for 5700 hours. Therefore, we should have 3000 MW of base-load, coal-steam plants in the mix.

Similarly, combustion turbines are the most effective if they operate less than 0.27 CF or less than 2500 h/yr. Similarly, combined-cycle plants need to operate at least 2500 h/yr and less than 5700 h to be the most cost-effective. The screening curve tells us that 1000 MW of these intermediate plants would operate within that range. Finally, since CTs are the most cost-effective if they operate less than CF 2500 h/yr (CF, 0.27) and the load duration curve tells us the demand is between 4000and 6000 MW for 2500 h, the mix should contain 2000 MW of peaking CTs.

The generation mix shown on a load duration curve allows us to find the average capacity factor for each type of generating plant in the mix, which

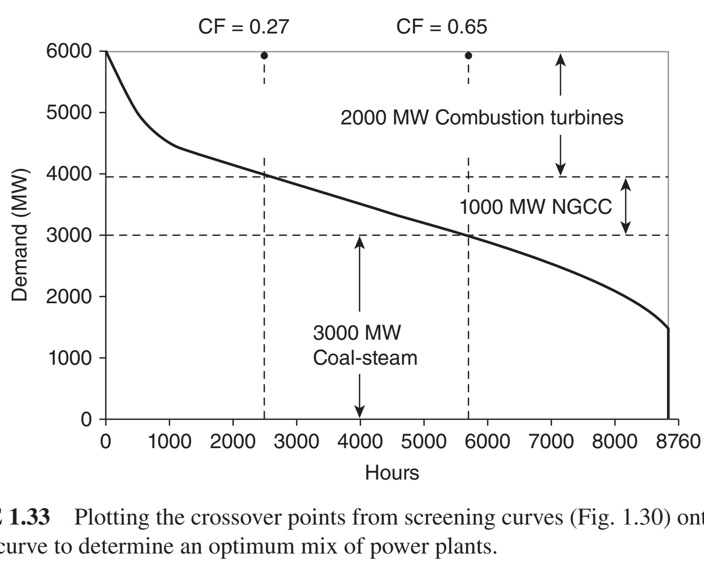

FIGURE 1.33 Plotting the crossover points from screening curves (Fig. 1.30) onto the load duration curve to determine an optimum mix of power plants.

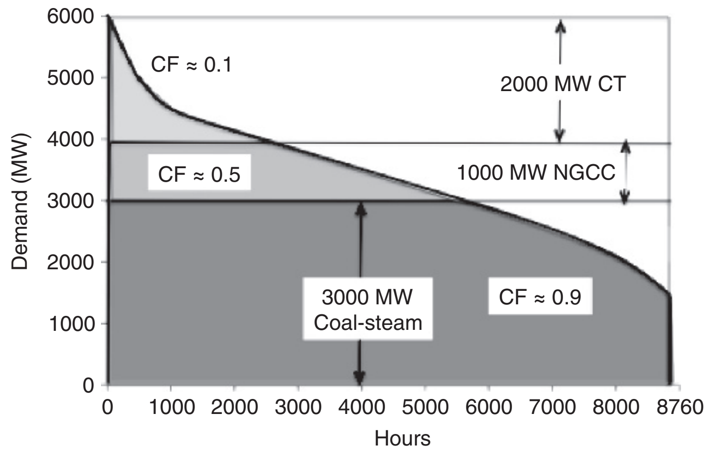

FIGURE 1.34 The fraction of each horizontal rectangle that is shaded is the capacity factor for that portion of generation facilities.

will determine the average cost of electricity for each type. Figure 1.34 shows rectangular horizontal slices corresponding to the energy that would be generated by each plant type if it operated continuously. The shaded portion of each slice is the energy actually generated. The ratio of shaded area to total rectangle area is the CF for each. The base-load coal plants operate with a CF of about 0.9, the intermediate-load combined-cycle plants operate with a CF of about 0.5, and the peaking combustion turbines have a CF of about 0.1.

Mapping those capacity factors onto the screening curves in Figure 1.30 indicates new coal plants delivering electricity at 8.6 ¢/kWh, the NGCC plants at 11.6 ¢/kWh, and the CTs delivering power at 27.7 ¢/kWh. The peaker plant electricity is so much more expensive in part because they have a lower efficiency while burning the more expensive natural gas, but mostly because their capital cost is spread over so few kilowatt-hours of output since they are used so little.

Using screening curves for generation planning is merely a first cut at determining what a utility should build to keep up with changing loads and aging existing plants. Unless the load duration curve already accounts for a cushion of excess capacity, called the *reserve margin*, the generation mix just estimated would have to be augmented to allow for plant outages, sudden peaks in demand, and other complicating factors.

The process of selecting which plants to operate at any given time is called *dispatching.* Since costs already incurred to build power plants (sunk costs) must be paid no matter what, it makes sense to dispatch plants in the order of their operating costs, from the lowest to the highest. Hydroelectric plants are a special case since they must be operated with multiple constraints, including the need for water supply, flood control, and irrigation, as well as insuring proper flows for downstream ecosystems. Hydro is especially useful as a dispatchable source backup to other intermittent renewable energy systems.

1.6.5 Including the Impact of Carbon Costs and Other Externalities

With such a range of generation technologies to choose from, how should a utility, or society in general, make decisions about which ones to use? An economic analysis is of course the central basis for comparison. Costs of construction, fuel, O&M, and financing are crucial factors. Some of these can be straightforward engineering and accounting estimates and others, such as the future cost of fuel and whether there will be a carbon tax and if so, how much and when, require something akin to a crystal ball. Even if these cost estimates can all be agreed upon, there are other additional *externalities*, that the society must bear that are not usually included in such calculations, such as health care and other costs of the pollution produced. Other complicating factors include the vulnerability we expose ourselves to with large, centralized power plants, transmission lines, pipelines, and other infrastructure that may fail due to natural disasters, such as hurricanes and earthquakes, or less natural ones, due to terrorism or war.

As concerns about climate change grow, there is increasing attention to the importance of carbon emissions from power plants. The shift from coal-fired power plants to more efficient plants powered by natural gas can greatly reduce those emissions. Reductions result from the increased efficiency that many of these plants have, especially, compared with the existing coal plants, as well as the lower carbon intensity of natural gas. As shown in Table 1.5, combined-cycle gas plants emit less than half as much carbon as coal plants.

At some point, carbon emissions will no longer be cost-free (already the case outside of the United States). As Figure 1.35 suggests, nuclear plants and gas-fired combined-cycle plants would be cost-competitive with already built coal plants if emissions were to be priced at around \$50/t of CO_2. The figure also provides a rough estimate of the cost of carbon savings through energy efficiency measures on the customer's side of the meter.

TABLE 1.5 Assumptions for Calculating Carbon Emissions. Carbon Intensity Based on EIA Data. Efficiency Is Based on HHV of Fuels.

Technology	Heat Rate (Btu/kWh)	Efficiency (%)	Fuel (kg C/GJ)	Emissions (kg C/kWh)	Emissions (kg CO_2/kWh)
New coal	8750	39.0	24.5	0.23	0.83
Old coal	10,340	33.0	24.5	0.27	0.98
CT	9300	36.7	13.7	0.13	0.49
NGCC	6900	49.4	13.7	0.10	0.37

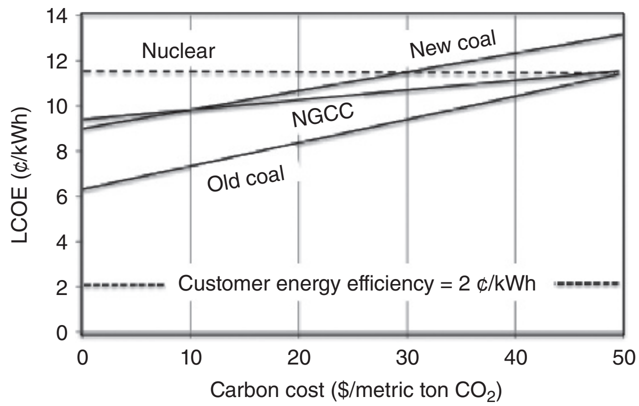

FIGURE 1.35 Impact of carbon cost on LCOE (plotted for equal CF = 0.85 and assumptions given in Table 1.5).

Epstein et al. (2011) estimate that the life cycle cost of coal and its associated waste streams exceeds $300 billion per year in the United States alone. Accounting for these damages, they estimate that these externalities add between 9.5 and 26.9 ¢/kWh, with a best estimate of almost 18 ¢/kWh, to the cost of coal-based electricity, making even current coal plants far more expensive than wind, solar, and other forms of nonfossil fuel power generation.

1.7 SUMMARY

The focus of this chapter has been on developing a modest understanding of how the current electricity industry functions. We have seen how it evolved from the early days of Edison and Westinghouse into the complex system that has served our needs remarkably well over the past century or so. That system, however, is beginning a major transformation from one based primarily on fossil fuels, with their adverse environmental impacts and resource limitations, into a more distributed system that emphasizes efficient use of energy coupled with more widely distributed generation based primarily on renewable energy sources. It is moving from a load-following system into one in which supply and demand will be balanced by a combination of generation response and demand response. Both sides of the meter will have to play active roles, not only to control costs, but also to address critical questions that arise when higher and higher fractions of supply come from intermittent renewables.

In other words, hopefully enough groundwork has been laid to motivate the rest of this book.

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PROBLEMS

1.1 A combined-cycle, natural gas, power plant has an efficiency of 52%. Natural gas has an energy density of 55,340 kJ/kg and about 77% of the fuel is carbon.

a. What is the heat rate of this plant expressed as kJ/kWh and Btu/kWh?

b. Find the emission rate of carbon (kg C/kWh) and carbon dioxide (kg CO_2/kWh). Compare those with the average coal plant emission rates found in Example 1.1.

1.2 In a reasonable location, a photovoltaic array will deliver about 1500 kWh/yr per kW of rated power.

a. What would its CF be?

b. One estimate of the maximum potential for rooftop photovoltaics (PVs) in the United States suggests as much as 1000 GW of PVs could be installed. How many "Rosenfeld" coal-fired power plants could be displaced with a full build out of rooftop PVs?

c. Using the Rosenfeld unit, how many metric tons of CO_2 emissions would be avoided per year?

1.3 For the following power plants, calculate the added cost (¢/kWh) that a \$50 tax per metric ton of CO_2 would impose. Use carbon content of fuels from Table 1.5.

a. Old coal plant with heat rate 10,500 Btu/kWh.

b. New coal plant with heat rate 8500 Btu/kWh.

c. New IGCC coal plant with heat rate 9000 Btu/kWh.

d. NGCC plant with heat rate 7000 Btu/kWh.

e. Gas turbine with heat rate 9500 Btu/kWh.

1.4 An average pulverized coal power plant has an efficiency of about 33%. Suppose a new ultra-supercritical (USC) coal plant increases that to 42%. Assume coal burning emits 24.5 kg C/GJ.

a. If CO_2 emissions are eventually taxed at \$50 per metric ton, what would the tax savings be for the USC plant (\$/kWh)?

b. If coal that delivers 24 million kJ of heat per metric ton costs \$40/t what would be the fuel savings for the USC plant (\$/kWh)?

1.5 The United States has about 300 GW of coal-fired power plants that in total emit about 2 Gt of CO_2/yr while generating about 2 million GWh/yr of electricity.

a. What is their overall capacity factor?

b. What would be the total carbon emissions (Gt CO_2/yr) that could result if all of the coal plants were replaced with 50%-efficient NGCC plants that emit 13.7 kgC/GJ of fuel?

c. Total U.S. CO_2 emissions from all electric power plants is about 5.8 Gt/yr. What percent reduction would result from switching all the above coal plants to NGCC?

1.6 Consider a 55%-efficient, 100-MW, NGCC merchant power plant with a capital cost of \$120 million. It operates with a 50% capacity factor. Fuel currently costs \$3/MMBtu and current annual O&M is 0.4 ¢/kWh. The utility uses a levelizing factor $LF = 1.44$ to account for future fuel and O&M cost escalation (see Example 1.3).

The plant is financed with 50% equity at 14% and 50% debt at 6%. For financing purposes, the "book life" of the plant is 30 years. The FCR, which includes insurance, fixed O&M, corporate taxes, and so on, includes an additional 6% on top of finance charges.

a. Find the annual fixed cost of owning this power plant (\$/yr).

b. Find the levelized cost of fuel and O&M for the plant.

c. Find the LCOE.

1.7 The levelizing factors shown in Figure 1.28 that allow us to account for fuel and O&M escalations in the future are derived in Appendix A and illustrated in Example A.5.

a. Find the LF for a utility that assumes its fuel and O&M costs will escalate at an annual rate of 4% and which uses a discount factor of 12%.

b. If natural gas now costs $4/MMBtu, use the LF just found to estimate the life cycle fuel cost ($/kWh) for a power plant with a heat rate of 7000 Btu/kWh.

1.8 Consider the levelizing factor approach derived in Appendix A as applied to electricity bills for a household. Assume the homeowner's discount rate is the 6%/yr interest rate that can be obtained on a home equity loan, the current price of electricity is $0.12/kWh, and the time horizon is 10 years.

a. Ignoring fuel price escalation ($e = 0$), what is the 10-year levelized cost of electricity ($/kWh)?

b. If fuel escalation is the same as the discount rate (6%), what is the levelizing factor and the levelized cost of electricity?

c. With a 6% discount rate and 4% electricity rate increases projected into the future, what is the levelizing factor and the LCOE?

1.9 Consider the levelizing factor approach derived in Appendix A as applied to electricity bills for a household. Assume the homeowner's discount rate is the 5%/yr interest rate that can be obtained on a home equity loan, the current price of utility electricity is $0.12/kWh, price escalation is estimated at 4%/yr, and the time horizon is 20 years.

a. What is the levelized cost of utility electricity for this household ($/kWh) over the next 20 years?

b. Suppose the homeowner considers purchasing a rooftop photovoltaic (PV) system that costs $12,000 and delivers 5000 kWh/yr. Assume the only costs for those PVs are the annual loan payments on a $12,000, 5%, 20-year loan that pays for the system (we are ignoring tax benefits associated with the interest portion of the payments). Compare the LCOE ($/kWh) for utility power versus these PVs.

1.10 Using the representative power plant heat rates, capital costs, fuels, O&M, levelizing factors and fixed charge rates given in Table 1.4, compute the cost of electricity from the following power plants. For each, assume an FCR of 0.167/yr.

a. Pulverized coal-steam plant with CF = 0.70.

b. Combustion turbine with CF = 0.20.

c. Combined-cycle natural gas plant with CF = 0.5.

d. Nuclear plant with CF = 0.85.

e. A wind turbine costing $1600/kW with CF = 0.40, O&M $60/yr-kW, LF = 1.5, FCR = 0.167/yr.

1.11 Consider the following very simplified load duration curve for a small utility.

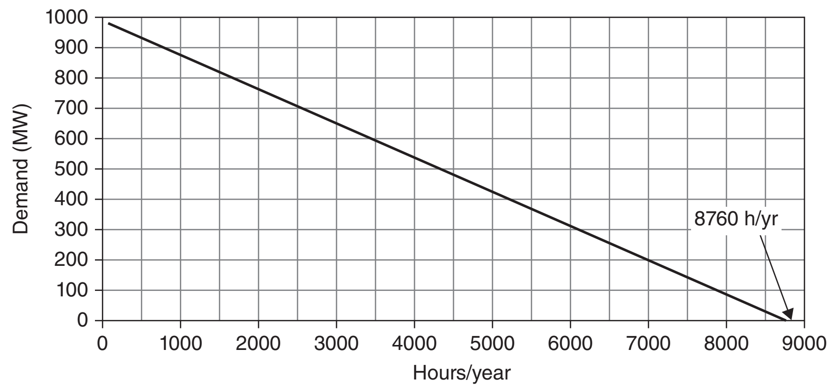

FIGURE P1.11

a. How many hours per year is the load less than 200 MW?

b. How many hours per year is the load between 200 MW and 600 MW?

c. If the utility has 600 MW of base-load coal plants, what would their average capacity factor be?

d. Find the energy delivered by the coal plants.

1.12 Suppose the utility in Problem 1.11 has 400 MW of combustion turbines operated as peaking power plants.

a. How much energy will these turbines deliver (MWh/yr)?

b. If these peakers have the "revenue required" curve shown below, what would the selling price of electricity from these plants (¢/kWh) need to be?

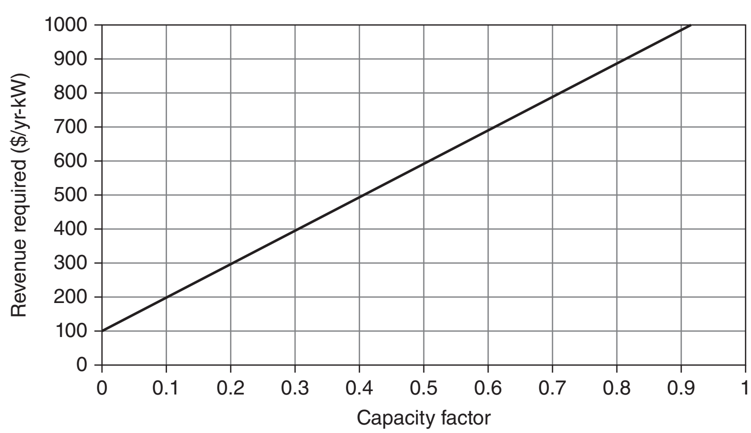

FIGURE P1.12

1.13 As shown below, on a per kW of rated power basis, the costs to own and operate a CT, an NGCC, and a coal plant have been determined to be:

$$\text{CT (\$/yr)} = \$200 + \$0.1333 \times \text{h/yr}$$
$$\text{NGCC (\$/yr)} = \$400 + \$0.0666 \times \text{h/yr}$$
$$\text{Coal (\$/yr)} = \$600 + \$0.0333 \times \text{h/yr}$$

Also shown is the load duration curve for an area with a peak demand of 100 GW.

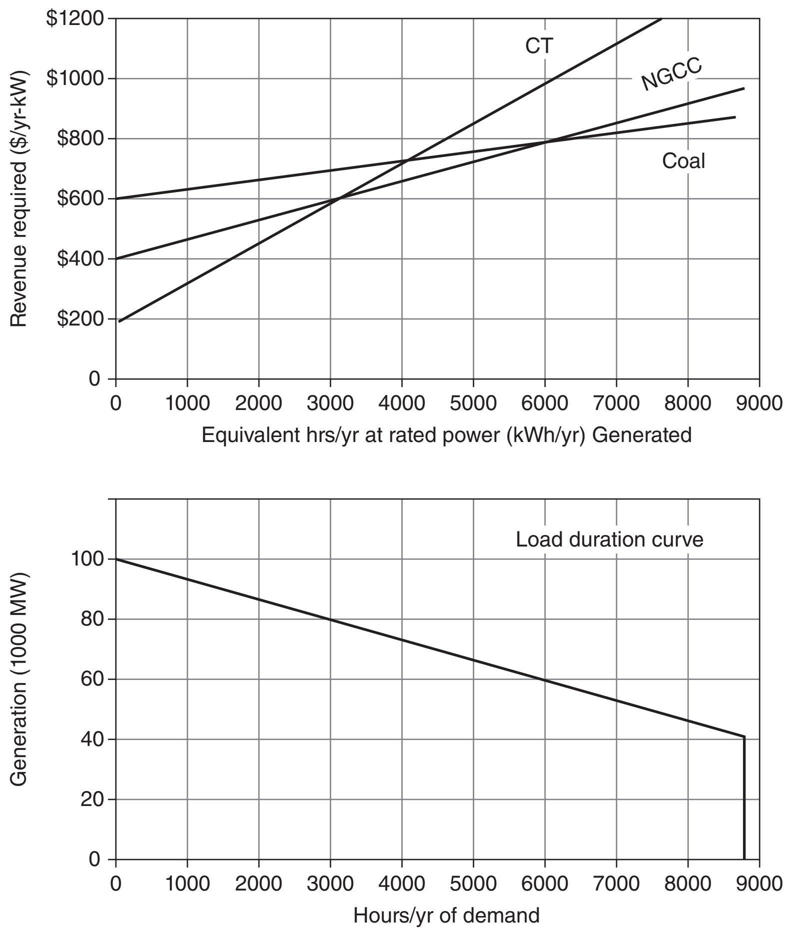

FIGURE P1.13

a. How many MW of each type of plant would you recommend?

b. What would be the capacity factor for the NGCC plants?

c. What would be the average cost of electricity from the NGCC plants?
d. What would be the average cost of electricity from the CT plants?
e. What would be the average cost of electricity from the coal plants?

1.14 The following table gives capital costs and variable costs for coal plants, NGCC plants, and natural-gas-fired CTs.

	Coal	NGCC	CT
Capital cost ($/kW)	2000	1200	800
Variable cost (¢/kWh)	2.0	4.0	6.0

This is a municipal utility with a low fixed charge rate of 0.10/yr for capital costs. Its load duration curve is shown below.

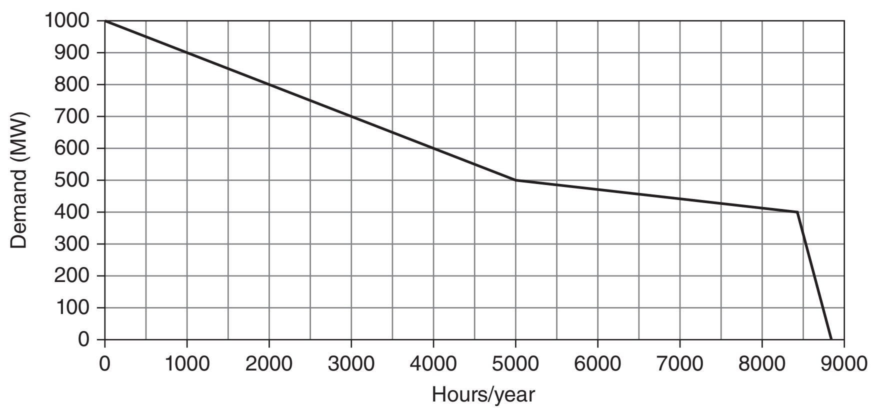

FIGURE P1.14

a. On a single graph, draw the screening curves (Revenue required $/yr-kW vs. h/yr) for the three types of power plants (like Figure 1.29).
b. For a least-cost system, what is the maximum number of hours a CT should operate, the minimum number of hours the coal plant should operate, and the range of hours the NGCC plants should operate. You can do this algebraically or graphically.
c. How many MW of each type of power plant would you recommend?