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Energy Management: Storage, Transportation, and Distribution 17

The web of our life is of a mingled yarn, good and ill together.
—William Shakespeare, *All's Well that Ends Well*

17.1 Overview of Energy Management Systems

The primary energy sources and technologies now widely used to meet societal energy demands have been described in the preceding chapters, along with their costs and associated impacts. Alternative technologies that may have lower greenhouse gas (GHG) emissions or other less problematic side effects have also been described, along with their pros and cons. As humanity starts to respond to concerns about climate change, modifications in energy production systems are being driven through policy initiatives and technological innovations. Because our energy appetites are so large, changing these large-scale systems to other energy sources with different characteristics presents major challenges. Society has come to assume that energy will be available on demand in the desired form (heat, work, electricity, etc.) whenever it is needed for transportation or in industrial activities, buildings, or communication systems. The existing energy dispatch, transmission, storage, and distribution systems meet a variety of demand needs that vary depending on time of day, season, and weather patterns.

The traditional infrastructures for electrical energy have evolved based on large continuous output source locations (called "baseload" plants, e.g., coal, nuclear, natural gas) which feed transmission and distribution (T&D) networks to bring energy to end-use locations, many of which are heavily populated urban areas. To deal with the fluctuations in demand, dispatchable energy sources (e.g., natural-gas turbine generators, hydroelectric plants) are connected to the grid and operated as needed. In addition, to meet peak energy demands, combinations of energy storage, pricing incentives to shift demand to off-peak times, and more expensive "peak-shaving" energy sources (e.g., propane, liquefied natural gas) are used. With a variety of independent utilities able to feed different amounts of electricity at different prices into the grid, energy management to match supply and demand in near real-time is provided in the US by regional independent system operators (ISOs).

The recent National Academies study entitled *America's Energy Future* (NRC, 2009) discusses the existing electric T&D systems, the problems they have, and the modernization they require. The expert study committee noted that the system was mostly constructed over 40 years ago and is based on 1950s technology. Investment in the maintenance of these systems dropped from around \$6 billion (2007US\$) annually in the 1970s to around \$3 billion annually in the late 1990s. Since 2000, investments are again increasing, with almost \$8 billion spent in 2007. According to

the North American Electric Reliability Corporation, the transmission system is being operated at or near its physical limits most of the time.

The executive summary of the NRC (2009) study finds that

> expansion and modernization of the nation's electrical transmission and distribution systems (i.e., the power grid) are urgently needed. Expansion and modernization would enhance reliability and security, accommodate changes in load growth and electricity demand, and enable the deployment of new energy efficiency and supply technologies, especially intermittent wind and solar energy.

They estimate that the investments needed to modernize the US electric grid over the next 20 years will be (in 2007US\$) about \$225 billion for transmission systems and \$640 billion for distribution systems, including integration of modern communications technologies.

They note that modernization is proceeding much more rapidly abroad—not just in China and India, which are constructing new grids of high-voltage AC and DC transmission lines, but in Europe, where policies and grid investments encourage shifts to renewable energy sources (see the European Commission's Energy website, http://ec.europa.eu/energy/index_en.htm). For example, two-way metering is being deployed to encourage rooftop PV in Germany. Also, in 2010, about 20% of Denmark's electricity was supplied from wind, requiring major adjustments to the nation's energy management systems and construction of high voltage, direct current (HVDC) submarine cables to carry energy from large offshore wind farms. One lesson is that renewable energy mixes will vary regionally because of the local nature of renewable resource and energy storage options. In the US, as intermittent renewables increase in use, grid planning and upgrading will have to evolve regionally—through the ISOs and the larger power interconnection systems.

A more detailed assessment of the future of the electric grid (MIT, 2011) expands on the findings of the 2009 NRC study. This more recent assessment also recognizes the need for major investments to modernize the existing infrastructure, but further emphasizes the importance of regulatory reform so that effective future changes in the US electric power system are not hampered by layers of fragmented and often inconsistent policy regimes. As greater amounts of intermittent sources of renewable energy enter the supply side and as demands change or expand, perhaps with real-time pricing policies or with more electricity used for transportation, they state that the US would benefit from a comprehensive shared vision of future system priorities and structures. Such an overarching vision could be implemented at regional levels with consistent incentives and policies that also recognize differences among regions and states.

Major energy infrastructures in the US consist not only of the electric power grid, but also of natural-gas pipeline transmission systems, coal shipments by barge and rail, and petroleum distribution systems including shipping, pipelines, and road/rail transport. Coal and petroleum are relatively easy to store; natural gas systems contain some storage capability through pressure variations and use of liquefied natural gas (LNG). Since electrical energy storage is more challenging and expensive, most infrastructure focus has been on the US power grid, which also is sorely in need of repair and modernization. As large amounts of intermittent or variable energy sources are added to an existing grid, the problem of matching supply with demand in real time requires concomitant dispatch strategies along with T&D system upgrades to maintain reliability.

Many countries outside the US have a variety of policy initiatives that encourage introduction of primary energy source technologies with lower GHG emissions. These policies can be seen as the recognition by those nations of the hidden costs of climate change impacts. Without an international agreement on the costs of these impacts, and with many other nations not recognizing such costs, there are short-term distortions and disruptions of the global market. Hopefully, the proactive countries will also provide an accelerated learning curve for the rest of the world—not only on the technologies themselves, but on their integration into our regional, national, and global energy systems. From a sustainability viewpoint, we all must remember that these changes must also be scrutinized for adverse impacts on other global life-support systems—water, land use, standard of living inequities, social stability, etc. (see chapters 5, 6, and 7).

Several critical elements need to function properly in order to have a viable energy supply system. Requirements include a means for storing energy to provide it when needed and an infrastructure for supplying energy to locations where it is consumed. In earlier chapters, we concentrated on describing renewable and non-renewable energy technologies, focusing mostly on the capture, recovery, and conversion aspects of energy. In this chapter, we will consider three important elements of the supply system: energy storage, transmission, and distribution.

Energy storage permits decoupling of energy supply and demand periods, which is desirable for both economic and technical reasons. Economically, demand for energy and power has significant variation—both diurnally and seasonally. To maintain the capacity to meet peak demand periods without any storage would require more energy conversion equipment and capital investment. From a technical perspective, some types of renewable energy cannot be captured and converted when the demand requires energy. For example, solar and wind energy are intermittent on a daily and seasonal basis, while biomass energy varies seasonally, requiring storage to function most effectively.

Storage addresses four major needs:

1. *Dispatchability*—responding to fluctuations in electricity demand;
2. *Interruptibility*—reacting to intermittent energy supplies such as wind and solar energy, the seasonal variations of hydropower and biomass, and the periodic instabilities that occur in fossil-fuel supplies;

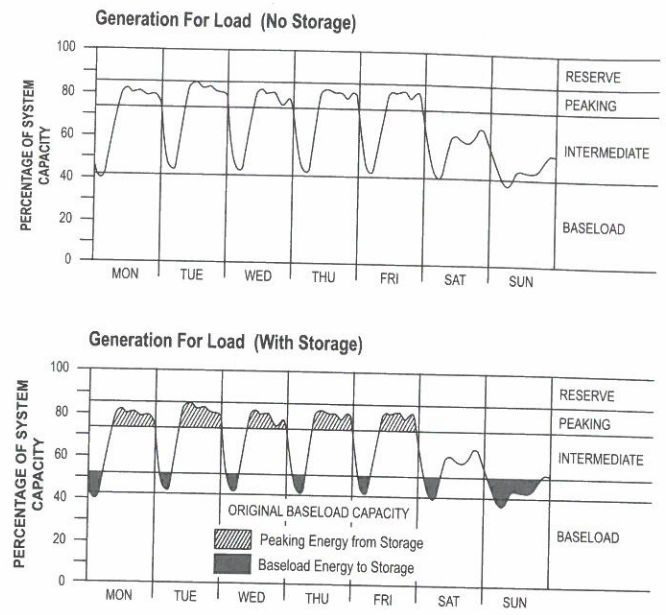


Figure 17.1
Typical weekly load curve of an electric utility. Source: National Academy of Sciences (1976).

3. *Efficiency*—recovering wasted energy for reuse;
4. *Regulatory-driven needs*—meeting national, regional, state, and local requirements for performance, while expanding distribution and other transmission capacity.

Electricity demand fluctuates on several cycles—daily and weekly due to variations in industrial and domestic loads, and seasonally due to weather and average temperature changes. As shown in figure 17.1, these variations can be significant, placing strain on the electric supply system to vary its output on a regular basis.

The opportunity afforded by storage is illustrated in figure 17.2, where the fraction of peak power is plotted as a function of the fraction of time or load duration curve. Jensen and Sorensen (1984) selected representative electric and heating loads over a one-year period. Note that the electric load never goes to zero, as some demand remains at night throughout the year, because of industrial users, while the heating load does go to zero during the midsummer period. The crosshatched areas on the electric curve illustrate how electric energy could be stored during periods of low demand and supplied from a suitable storage reservoir during peak demand periods. The nominal cycle time for shifting electric power to and from the storage system typically occurs during a 24-hour period. A similar scenario could be developed for using thermal storage to distribute the heating load, but the cycle time

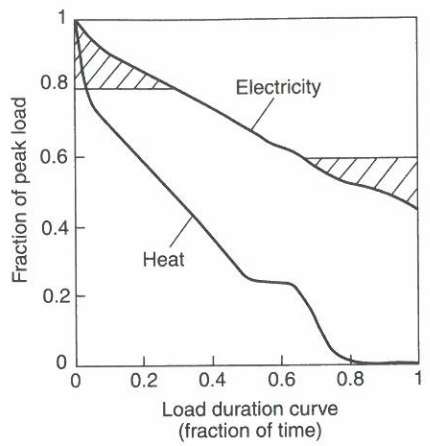


Figure 17.2
Opportunities for storage of electricity and heat based on a typical energy load or demand curve. The crosshatched regions indicate the potential for storage to level out the demand. Adapted from Jensen and Sorensen (1984).

now would be seasonal, or in a range from hundreds to thousands of hours. For these reasons, load management on energy grids using storage is important in applications for both electric power and natural gas supply. Nonetheless, for smaller, more distributed energy systems, thermal storage is sometimes used, and it can be particularly effective when integrated with electric power storage in combined heat and power applications (see section 17.5.2).

Natural gas is used to provide both thermal energy and electricity. Demand variability depends on diurnal and seasonal variations—for example, a large heating demand exists in colder climates. In warm weather, natural gas can be fed to gas holding tanks, compressed or liquefied, and stored for later peak sharing purposes, or it can be used to generate electricity to meet electric peaks when air-conditioning loads are high. Although natural gas and electric systems are managed separately, they are not really independent. When variable renewable energy sources, fuel cells, and other distributed generators are in the mix, integrated energy planning is even more important.

For over a century, electric utilities have used conventional impounded and pumped storage hydropower systems (see chapter 12) and rapidly dispatchable fossil-fired peaking power units to meet demand fluctuations and to achieve some measure of load leveling. Backup generators employing diesel fuel and natural gas have also seen increasing use to ensure a noninterruptible supply, as have electrochemical storage batteries. Recovery of wasted energy also enables energy storage technologies to increase efficiency. Recent deployment initiatives for renewable and

distributed energy resources have reactivated interest in storage technologies. The value of both intermittent renewable energy sources and more distributed combined heat and power networks increases substantially if they can be dispatched when needed and if they have self-contained storage systems that make this possible.

In transportation applications, electrochemical batteries are typically used to store electric energy for later use to start the engine and to meet high auxiliary loads during operation. Today, there is increasing emphasis on making cars and trucks more fuel-efficient by conserving energy. Hybrid electric vehicles provide a means for doing this. They utilize an electric propulsion system that contains a generator powered by a small, fuel-fired engine. The smaller engine provides enough power, while operating at maximum efficiency, to maintain normal cruising speeds on the highway. When more power is needed for acceleration, additional power is supplied to the electric motor from a robust battery storage system. When less power is needed, the engine continues to operate at maximum efficiency with excess power being used to charge the batteries. Because considerable energy is wasted by stop-and-go cycles in heavy traffic, regenerative braking systems are also being developed for hybrid electric vehicles to recover a fraction of dissipated energy as electric energy that can then be stored in the vehicle's battery system or as mechanical energy in a rotating-flywheel storage system. All of these measures increase fuel efficiency.

The final motivation for developing and deploying energy storage systems comes from regulatory policies that promote more efficient, reliable, and secure energy supply systems. Recent arguments made in the US suggest that deregulation and restructuring of the electric power industry will lead to new opportunities for energy storage, particularly when it enhances power quality or reliability or eliminates a need to expand the transmission and distribution infrastructure. Smarter energy control systems also have the potential to increase the efficiency of primary energy use throughout the life-cycle chain, from production to end uses (Schoenung et al., 1996; Gordon and Falcone, 1995; Yeager, 2003; NRC, 2009; MIT, 2011).

17.2 Connected Efficiencies and Energy Chains

An important aspect of supplying energy is that each step in the process carries some losses. For example, when electricity is transmitted in the US national grid, about 11% of the generated electricity is lost before it ever reaches the consumer. During the generation process, another 70%, on average, is lost. These effects are cumulative and lead us to think of the entire energy system as a chain of processes, each with a specified efficiency, η_i. Equation (17.1) captures this idea mathematically:

$$\text{Overall efficiency} = \eta_{overall} = \prod_{i=1}^{n} \eta_i. \tag{17.1}$$

Obviously, this is for a simplified energy transmission and distribution system (see figure 2.1) where energy flows sequentially from a primary energy source to a final end use. In real systems consisting of energy flow networks that incorporate energy storage and control features with possible feedbacks and interconnections, this is not strictly true. However, it is a fundamental aspect of how energy losses aggregate in sequential energy flow systems. If we were evaluating a total energy system across its life cycle, we would have to include all efficiencies along the path, from extraction to final utilization, to obtain a total efficiency. Consider the case of a gas-fired power station that supplies electricity to an electric motor located in a home in a large city on the East Coast of the US located about 400 miles from the plant. The natural gas is supplied from a field in western Wyoming where it is produced, processed, and purged through a natural gas pipeline system to the power plant. Here, we might estimate the overall efficiency, using equation (17.1), as

$$\eta_{overall} = \eta_{gas\ extraction}\ \eta_{gas\ processing}\ \eta_{gas\ transmission}\ \eta_{power\ plant}\ \eta_{electricity\ transmission}\ \eta_{distribution}\ \eta_{motor}. \tag{17.2}$$

Another feature of specific component and overall efficiencies is that their magnitude depends on definitions that can vary considerably. Although common sense would suggest that the value of a particular η_i should never exceed 100% or 1.0, depending on specific definitions, this is not necessarily the case. Work or heat produced, or power (the time derivative or rate of work or heat), are typical measures of output used. In some cases, the efficiency is defined as a ratio of power or work produced relative to the energy input to the system. In other cases, it is a ratio of power or work produced to the maximum amount of power or work that could be produced from the same input of energy. The first set commonly includes the so-called thermal cycle efficiency or fuel efficiency of a conversion process that produces electric or mechanical power by burning fossil fuel. In other words,

$$\eta_{thermal\ or\ fuel} \equiv \frac{\text{Work or power produced}}{\text{Energy input}} = \frac{W_{net}}{m_{fuel}\Delta H_{combustion}}\ or\ \frac{W_{net}}{Q_{hot}}. \tag{17.3}$$

Relevant performance metrics also include the efficiency of work exchange processes, such as pumped hydropower or compressed-air energy storage, where the cycle efficiency is given by:

$$\eta_{cycle} \equiv \frac{W_{recovered}}{W_{in}}. \tag{17.4}$$

For these systems, η_{cycle} is given by the product of the input and output efficiencies of the power converter:

$$\eta_{cycle} = \eta_{in}\eta_{out}. \tag{17.5}$$

In typical applications of pumped hydropower and compressed-air storage, η_{cycle} can approach 0.6 or more as η_{in} and η_{out} generally are in the range of 0.8 to 0.9.

The second set of efficiencies are often called *utilization* or *thermodynamic efficiencies*, where

$$\eta_{utilization} \equiv \frac{\text{Work or power produced}}{\text{Maximum work or power produced}} = \frac{W_{net}}{W_{\max}}\ or\ \frac{P_{net}}{P_{\max}}, \tag{17.6}$$

$$\eta_u = \frac{W_{net}}{\Delta \underline{B}} = \frac{W_{net}}{m(\Delta H - T_o\Delta S)},$$

where $\Delta \underline{B}$ is the availability or maximum work function. For most properly engineered applications involving heat-to-work conversions, η_u generally ranges from 0.5 to 0.7.

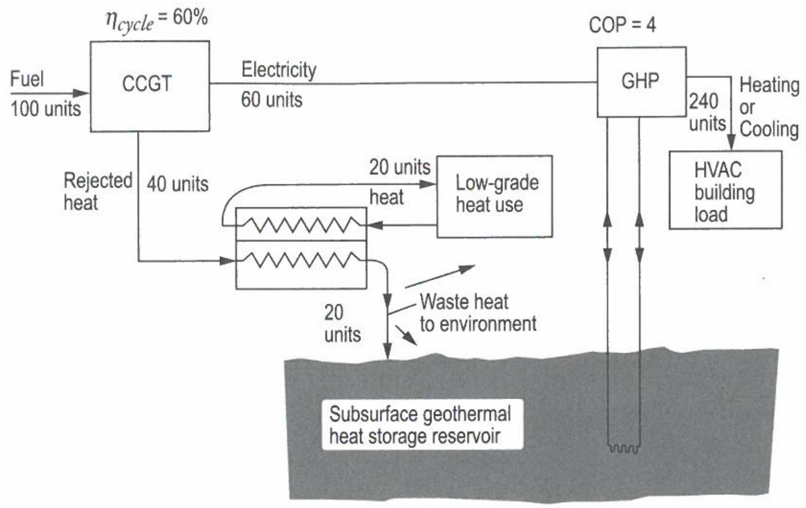
When only heat exchange is involved, such as in thermal energy storage and recovery, the efficiency of the overall process might be defined in terms of heat recovered to heat initially provided from the energy source or fuel. In this case,

$$\eta_{heat\ exchange} \equiv \frac{\text{Heat recovered}}{\text{Heat supplied}} = \frac{Q_{out}}{Q_{in}} \tag{17.7}$$

and efficiencies typically exceed 0.9 (or 90%).

For systems that involve the exchange and conversion of both heat and work, the situation is more complex. As we know from discussions in chapter 3, heat and work are not equivalent, as the Second Law of Thermodynamics places an upper limit on the amount of heat that can be converted to useful work or power. We illustrate the effects of Second Law conversion efficiency in figure 17.3 for the combined-cycle gas turbine (CCGT), which uses natural gas as the fuel source. The current state-of-the-art cycle efficiency for the CCGT is $\eta_{cycle} = 0.60$. In other words, for every 100 units of fuel energy fed to the combustion chamber, 60 units of electrical energy are produced and 40 units of thermal energy are rejected. In addition, figure 17.3 shows the effect of definition on the magnitude of the overall efficiency for the entire system. In this case, the system is a fully integrated heat and power system connected to a thermal energy storage reservoir with a high-efficiency geothermal heat pump (COP = 4.0).

If we define the overall efficiency as the ratio of thermal energy utilized to the thermal energy content of the natural gas fuel, its value is an incredible 2.60 (or 260%). There are no violations of thermodynamic laws. The specific value of $\eta_{overall}$



$$\text{Overall fuel efficiency} = \eta_{fuel} = \frac{60 \times 4 + 20}{100} = \frac{260}{100} \text{ or } 260\%!$$

Figure 17.3
Efficiency of a combined gas turbine–steam Rankine cycle (CCGT) coupled to a geothermal heat pump system with heat integration and waste heat recovery for supplying heating and cooling loads in a building application.

often depends only on how it is defined. Clearly, one has to be careful in applying or interpreting efficiencies as measures of performance. Proper attention to definitions and conventions employed is essential to obtaining an unambiguous assessment.

17.3 Modes of Energy Storage

17.3.1 General characteristics

Energy can be stored in a variety of physical and chemical forms. In this chapter, we limit the discussion to energy stored in physical form as potential, kinetic, thermal, electrical, or magnetic energy. Chemical energy is usually associated with the molecular energy stored in chemical bonds. Energy is released for use as the chemical compounds that make up these fuels are transformed by combustion or oxidation and other means to more thermodynamically stable compounds. Important examples include the chemical energy released by the exothermic combustion of methane, petroleum liquids, coal, and wood to produce water and carbon dioxide.

Table 17.1
Conversion Energy Storage Modes

Mode	Primary Energy Type	Characteristic Energy Density (kJ/kg)	Primary Application Sector
Pumped hydropower	Potential	1 (100 m head)	Electric
Compressed-air energy storage	Potential	15,000 in kJ/m^3	Electric
Flywheels	Kinetic	30–360	Transport
Thermal	Enthalpy (sensible + latent)	Water (100–40°C): 250 Rock (250–50°C): 180 Salt (latent): 300	Buildings
Fossil fuels	Reaction enthalpy	Gas: 47,000 Oil: 42,000 Coal: 32,000	Transport, electric, industrial, buildings
Biomass	Reaction enthalpy	Dry wood: 15,000	Transport, electric, industrial, building
Batteries	Electrochemical	Lead-acid: 60–180 Nickel–metal hydride: 370 Li ion: 400–600 Li polymer: ~ 1,400	Transport, buildings
Superconducting magnetic energy storage (SMES)	Electromagnetic	100–10,000	Electric
Supercapacitors	Electrostatic	18–36	Transport

Sources: Jensen and Sorensen (1984); Schoenung et al. (1996); Boes, Goldstein, and Nix (2000).

The physical modes of energy storage may involve one or more mechanical, thermal, or electromagnetic forms. Table 17.1 lists common energy storage types and their characteristics. A particular energy storage technology may entail both a storage reservoir and a converter and transmission system for moving the power to and from the reservoir to its point of use. Compressed-air and pumped hydropower systems, for example, contain both elements, whereas a molten-salt thermal storage system would typically involve only a reservoir for storing energy.

Energy storage modes are frequently determined by the particular end-use application. The magnitude of the energy or power load and the time scales involved are especially important (see tables 17.1 and 17.2 and figure 17.4). For example, to provide electric power for transportation or to remedy power outages requiring substantial power fluxes for only short periods of seconds to minutes, capacitors, batteries, and flywheels would be particularly well suited. When larger amounts of electrical or thermal energy are needed for periods of hours or longer, pumped hydropower or compressed-air storage systems would be preferred for electric power, while hot-water or molten-salt storage reservoirs would be commonly employed to meet thermal loads.

The natural gas transmission and distribution system also requires storage as part of a system management program. Natural gas demand is variable on diurnal and

Table 17.2
Energy Storage Technology Characteristics

Characteristic	Pumped Hydro	CAES[a]	Flywheels	Thermal	Batteries	Supercapacitors	SMES[b]
Energy range	1.8×10^6–36×10^6 MJ	180,000–18 $\times 10^6$ MJ	1–18,000 MJ	1–100 MJ	1,800–180,000 MJ	1–10 MJ	1,800–5.4 $\times 10^6$
Power range	100–1,000 MW_e	100–100 MW_e	1–10 MW_e	0.1–10 MW_e	0.1–10 MW_e	0.1–10 MW_e	10–1,000 MW_e
Overall cycle efficiency[c]	64–80%	60–70%	~90%	~80–90%	~75%	~90%	~95%
Charge/discharge time	Hours	Hours	Minutes	Hours	Hours	Seconds	Minutes to hours
Cycle life	≥ 10,000	≥ 10,000	≤ 10,000	>10,000	≤ 2,000	>100,000	≥ 10,000
Footprint/unit size	Large if above ground	Moderate if under ground	Small	Moderate	Small	Small	Large
Siting ease	Difficult	Difficult to moderate	N/A	Easy	N/A	N/A	Unknown
Maturity	Mature	Early development	Early development	Mature	Lead-acid mature, others under development	Available	Early R&D stage, under development

Sources: Jensen and Sorensen (1984); Schoenung et al. (1996); Boes, Goldstein, and Nix (2000).
[a] CAES = compressed-air energy storage.
[b] SMES = superconducting magnetic energy storage.
[c] For 1 full charge-discharge cycle.

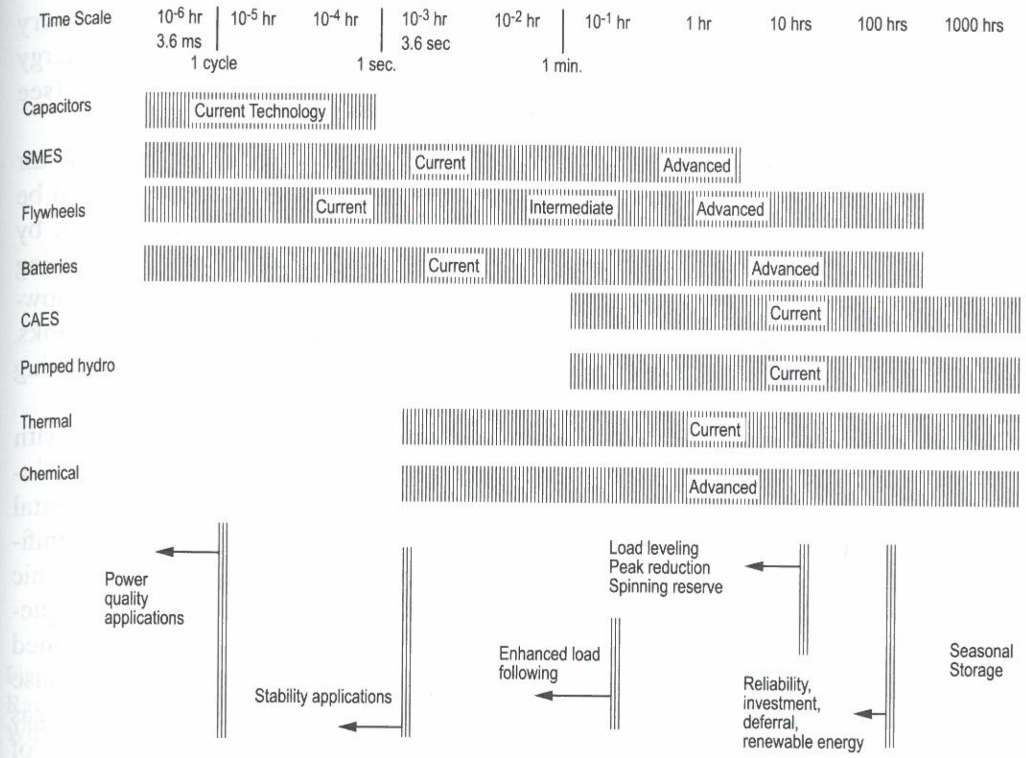


Figure 17.4
Characteristic times for energy storage. Adapted from Boes, Goldstein, and Nix (2000).

seasonal time scales. Some gas can be stored in the pipeline system by raising the system pressure within design limits. Fifty years ago, many cities were dotted with large cylindrical "gas holders," which stored gas at slightly above-atmospheric pressure in a tank with a floating roof and a water seal. Later, higher-pressure gas storage was developed, using in-ground caverns located near transmission lines. These formations are similar to those used for compressed-air storage. Obviously, pressurization increases energy storage density.

In the future, if hydrogen is to be used as an energy carrier, safe and compact H_2 storage will become a critical issue. Hydrogen is a light gas (MW = 2, versus 16 for methane) and, though it has a good energy density per unit weight of fuel, is difficult to store compactly. Storage tanks to handle high-pressure gas are heavy, and cryogenic systems to produce and hold liquid hydrogen (20 K [= −253°C]) are cumbersome. At present, R&D on H_2 storage is receiving much attention, with goals to design storage systems that will hold at least 5% hydrogen by weight. Even with these limitations on H_2 storage, the storage systems are still better than battery storage of electricity. This fact makes hydrogen interesting as a CO_2-free energy source that may be better than electricity for transportation applications (see chapter 18).

Peak shaving in natural gas systems can also be provided by use of propane-air mixtures, blended to give a heating value that matches that of natural gas to be compatible with system appliance adjustments. Liquefaction of natural gas, by cooling it to around its boiling point of −260°F (−160°C), is another peak-shaving possibility. Many gas utilities have built liquefaction plants that operate during low-demand periods to liquefy gas and store it in large insulated cryogenic storage tanks. The costs of such an operation are consistent with those of other peak-shaving alternatives.

Some natural gas is located in remote areas, where it may be associated with remote oil production. Such stranded gas may not be produced, or it may be reinjected, vented, or flared. The latter two practices have significant environmental consequences and are rapidly being phased out. Where gas quantities are significant, liquefaction near a seaport allows transoceanic shipment in special cryogenic tankers. Japan generates a significant portion of its electricity using imported liquefied natural gas (LNG). In the US, several LNG importation projects were planned in the 1980s, but most were mothballed, not because of safety concerns, but because the availability of pipeline natural gas from Canada and, more recently, shale gas was more cost effective. (For more information on LNG, see Lom, 1974.) As of 2010, many major LNG projects are deployed globally.

A useful way of showing key performance characteristics for various energy storage technologies was originally developed by Ragone (1963), where energy density is plotted as a function of power density on a log-log scale. Figure 17.5 is a general Ragone plot with a range of storage technologies depicted to illustrate inherent differences between different storage modes. In the sections that follow, common storage technologies are discussed according to the inherent form of energy they utilize. Readers interested in exploring the full range of storage modes in detail should consult the monographs by Hassenzahl (1981) and Jensen and Sorensen (1984).

17.3.2 Energy storage technologies

Potential energy storage Pumped hydropower and compressed-air energy storage (CAES) are the two main storage systems that employ potential energy. In pumped hydropower systems (as illustrated in figure 17.6), a reservoir containing water at an elevated location represents stored potential energy that can be recovered by lowering it in the earth's gravitational field. In a typical cycle, when electric capacity exceeds demand during an off-peak period, the excess electrical power is

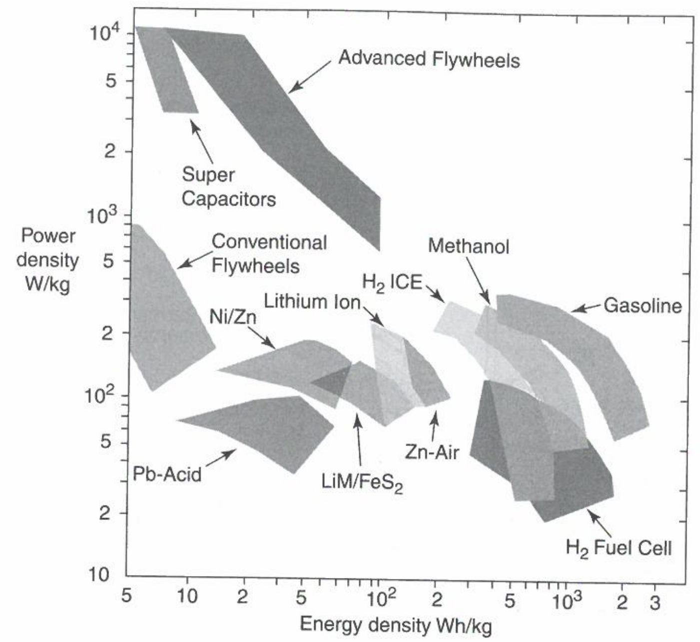


Figure 17.5
Ragone plot of power density (specific power/W per kg) versus energy density (specific energy/Wh/kg).

used to pump water up to the storage reservoir. During high-demand periods, the water flows downward through a hydro turbine generator to produce additional power as needed. Pumped-hydro systems can employ separate units for pumping and power generation or may use a reversible pump-turbine apparatus. Switching between pumping and power generation can usually be accomplished rapidly. Pumped-hydro systems are in widespread use worldwide, with over 300 systems operating with capacities ranging from about 20 MW_e to more than 2,000 MW_e (Schoenung et al., 1996).

The basic physics of power generation is the same as for normal hydropower (as described in chapter 12). The energy density appropriate for pumped hydro corresponds to the energy content per unit mass of pumped fluid, which is proportional to the product of the gravitational acceleration (g), fluid density (ρ), and the total head (z) or elevation gain that occurs, or $g\rho z$. A well-designed pump or turbine expander or a combined pump-turbine apparatus can operate at efficiencies approaching 85% to 90% for each step. Thus, the overall efficiency of pumped hydro typically ranges from about (0.85)(0.85) = 0.72 or 72% to (0.90)(0.90) = 0.81 or 81%.

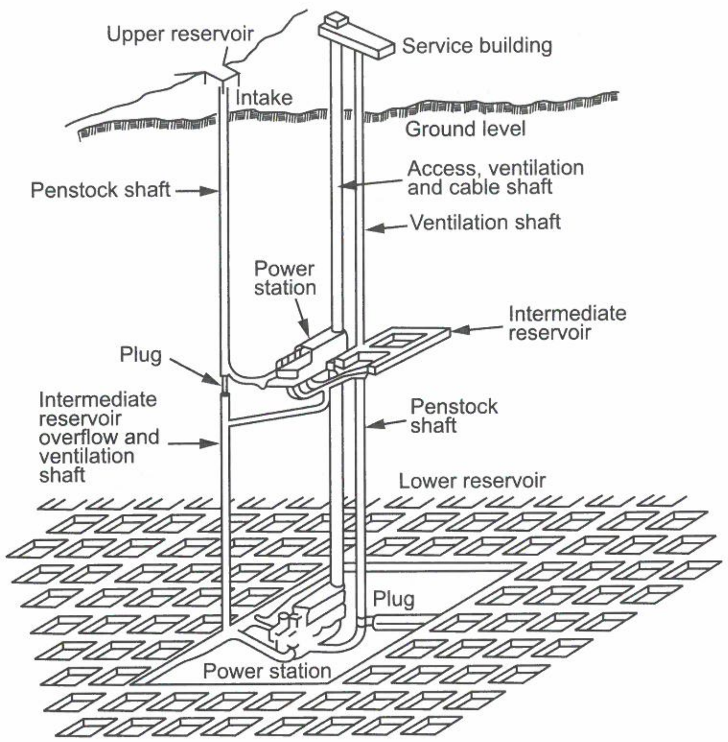


Figure 17.6
Schematic illustration of an energy storage technology: aboveground and underground pumped hydro. Source: Jensen and Sorensen (1984). Reprinted with permission of Elsevier.

Commonly, pumped-hydro systems use naturally available sites where appropriate changes in topography (i.e., elevation) exist. The engineered system would be similar to a normal impoundment-type hydropower installation where a dam structure would be used to contain the pumped water. Land-use issues associated with pumped-hydropower systems are important, and there can be significant public resistance to development. One way of avoiding the need for suitable topography and reducing the footprint of aboveground pumped-hydro plants is to engineer an underground storage reservoir (as shown in figure 17.6).

CAES systems utilize the compressive energy associated with pressurized air contained either in a closed underground reservoir consisting of natural or mined rock or salt cavities or in porous aquifers that are geologically contained. (Figure 17.7 schematically illustrates these three types of CAES systems.) Finding a suitable site for CAES requires detailed assessment of geotechnical resources and engineering feasibility and, frequently, development of staged plans to achieve a full-scale

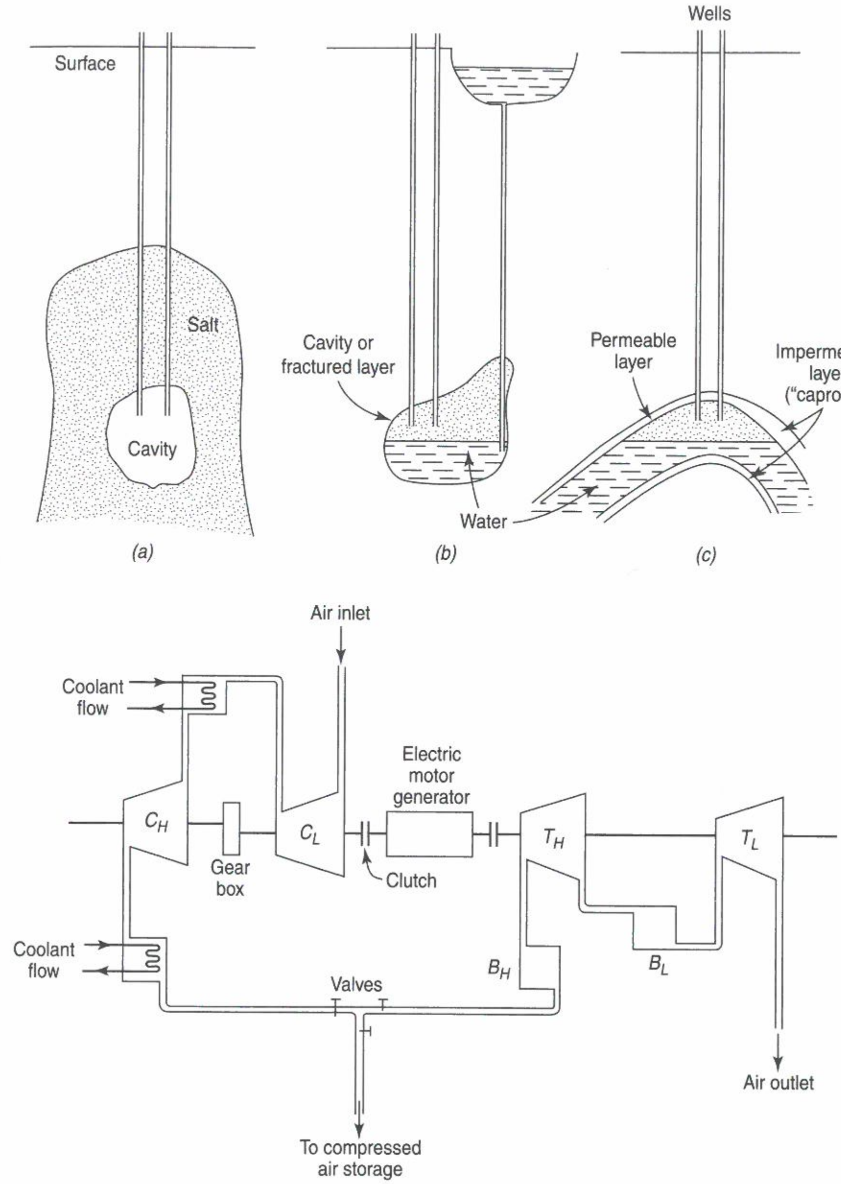


Figure 17.7
Schematic illustrations of several energy storage technologies: types of compressed-air energy storage. Source: Jensen and Sorensen (1984). Reprinted with permission of Elsevier.

system. Although there are currently only a few CAES installations operating worldwide, their potential is large, particularly if new lower-cost technologies appear for mining cavities in rock and salt. According to some experts, the most appropriate size range for CAES systems is between 10 and 1,000 MW_e with storage capacity sufficient to operate 3–12 hours per day (Gordon and Falcone, 1995; Thrasher and Lange, 1988). Nonetheless, there were only two CAES systems in operation in 2011, one at Huntorf in Germany, in a salt cavity rated at 290 MW_e with an active storage volume of 310,000 m^3, and the other in Alabama, also in a mined salt cavity, rated at 110 MW_e for 6 hours of operation. Several other CAES systems are in various stages of development at this time.

The large compressibility of air is utilized in CAES to produce power by expansion in a gas turbine at relatively high efficiency. Charging of the reservoir is accomplished by high-efficiency compression, typically using the turbine expander operating in reverse. The energy transfer can be expressed as pressure-volume work that is represented by a simple equation:

$$\delta W = -PdV + d(PV) = +VdP \tag{17.8}$$

where the PdV term represents the total work done on or by a fluid element as it passes through the compressor or expander, and the $d(PV)$ accounts for the work associated with mass flow that is pushing the fluid element in and out of the compressor or expander. The sign convention used for work is as follows: $\delta W > 0$ means that work is done on the system or device. Therefore, $\delta W < 0$ if work is produced by the system or device, for example, by a turbine. Equation (17.8) can be easily integrated, assuming that air obeys the ideal gas law—namely that $PV = nRT$. This is a good assumption for most of the pressure and temperature operating conditions currently envisioned for CAES. Assuming ideal gas behavior and using the mechanical efficiency of the turbine-compressor, the overall work or power levels for compression and expansion can be estimated as

$$\text{Net work} = W_{net} = W_{turbine} - W_{compressor} \tag{17.9}$$

by integration of equation (17.8) over appropriate pressure limits with defined reversible, quasi-static paths for both expansion and compression with $\eta_{turbine}$ and $\eta_{compressor}$ specified. The network associated with one cycle of operation is given by

$$W_{net} = \eta_{turbine} \int VdP\big|_{turbine} - \eta_{compressor}^{-1} \int VdP\big|_{compressor}\,. \tag{17.10}$$

For the ideal gas case, closed-form integrals result from equation (17.10) for isothermal, adiabatic, or polytropic paths. The net power for a complete cycle is easily obtained from equation (17.10) by using the average mass flow rate of fluid that passes through the device. When the compression and expansion paths are roughly

the same, the overall efficiency of the cycle can be defined in terms of the ratio of work released as gas is expanded from the pressurized CAES reservoir to the work needed to compress the gas as provided by excess power used to drive the compressor:

$$\eta_{overall} \equiv \frac{\text{Work output}}{\text{Work input}} = \frac{W_{turbine}}{W_{compressor}} = \eta_{turbine}\eta_{compressor}. \tag{17.11}$$

Kinetic energy storage The most common form of kinetic energy storage is achieved using mechanical flywheels, with rotational energy being transferred to and from the device. Flywheels have been used for decades for a range of applications involving transportation propulsion, electric power generation, and other energy-intensive industrial processes. The most common functions for flywheels in the past have been for electric load leveling and pulse dampening, as well as providing short bursts of additional power. Specific applications include regenerative braking in large locomotives and in most hybrid electric automobiles.

Because rotational kinetic energy can easily be stored and transformed to other mechanical or electrical energy forms, flywheels are well suited for energy storage. The basic physics is captured in a simple expression that relates the kinetic energy to the product of the moment of inertia and rotational speed of the device:

$$E_{rotational} = \frac{1}{2} I\omega^2 \tag{17.12}$$

where ω is the rotational speed or angular velocity in radians per unit time and I is defined as the moment of inertia in units of mass × length^2. For an axisymmetric body like a solid or hollow cylinder, I is given by

$$I = \int_0^R \rho(r) r^2 dr \tag{17.13}$$

where $\rho(r)$ is the mass density of the rotating body as a function of position from its rotational axis in units of kg/m. Thus, for a solid cylinder of uniform thickness t, $\rho(r)$ is given by

$$\rho(r) = \rho_m 2\pi rt = \frac{m2\pi rt}{\pi R^2 t} = \frac{m2\pi r}{\pi R^2} \tag{17.14}$$

where R is the radius of the cylinder in meters, m is the total mass of the rotating cylinder in kg, and ρ_m is the volumetric mass density in kg/m^3 or similar units. For the cylinder, then,

$$I = \frac{1}{2} mR^2. \tag{17.15}$$

Thus, using equation (17.12):

$$E_{rotational} = \frac{1}{4} m R^2 \omega^2 . \tag{17.16}$$

Equation (17.16) illustrates the relative importance of mass, radius, and rotational speed to the amount of rotational energy that can be stored in a solid cylinder or disc. At first glance, it would appear that one would maximize the amount of energy stored in a flywheel by increasing its mass, particularly the amount that is contained at large radii, and by increasing its rotational speed. Ultimately, the strength of the material that the flywheel is constructed of will set the upper practical limit. Furthermore, other important issues are the frictional losses associated with the rotation of the flywheel itself and the need to add and extract power at high efficiency over a range of rotational speeds.

Although estimating the strength limit for a given flywheel requires careful engineering analysis, a simple expression has been developed to describe the effect quantitatively (Jensen and Sorensen, 1984). The energy density for the flywheel is given by

$$\text{Specific energy density} = \frac{E_{rotational,\,max}}{m} = \frac{k_m \sigma_{\max}}{\rho_m} \tag{17.17}$$

where k_m is a shape factor that depends on the flywheel's geometry and $\sigma_{\max}$ is the maximum allowable tensile stress for the material. Here, high-strength, large $\sigma_{\max}$ and low-density, small ρ_m increase specific energy density. The shape factor k_m varies from about 1.0 for a well-designed constant stress disc to about 0.3 for a solid disc with a center hole. (Figure 17.8 shows a few representative designs and their shape factors.)

Steel and other metals are commonly used for flywheels because of their machinability, low cost, and high tensile strength. However, the generally high density of metals has limited practical devices to rotational speeds of about 3,600 rpm. Thus, in order to have a large power or energy capacity, massive steel flywheels are needed (see equation (17.16)). The energy and power densities for first-generation metallic flywheels range from about 5–10 $W_e h/kg$ for specific energy and from about 100–900 W_e/kg for specific power, as shown in figure 17.5.

Advanced flywheel concepts improve the energy density, power density, and overall efficiency by using lower-density, high-strength materials, such as fiber-reinforced epoxy polymer composites, and advanced bearings that may employ magnetic levitation to reduce friction. Projections indicate that specific energy densities may range from about 5–100 $W_e h/kg$ and that specific power densities will exceed 1,000 and may be as high as 10,000 W_e/kg for advanced composite designs.

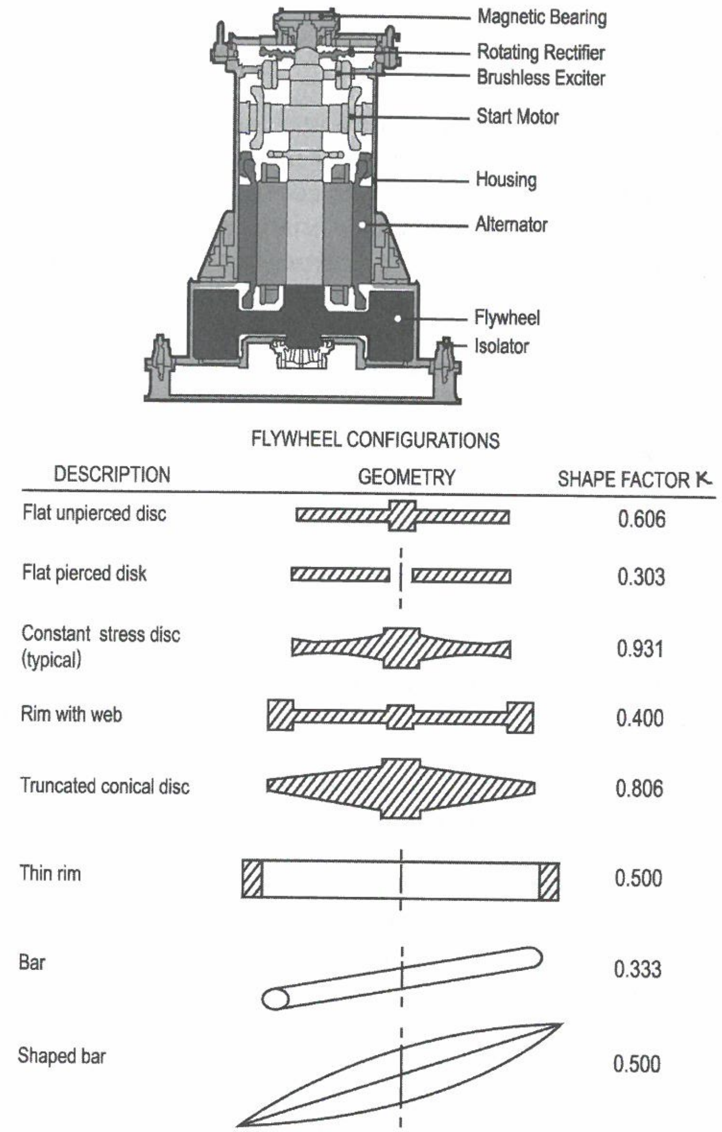


Figure 17.8
Schematic illustrations of an energy storage technology: flywheels. Adapted from Simpson, Oldaker, and Sterscheg (1975).

Units with capacities as large as 1,000 kW_eh are becoming available for utility load management, while smaller units in the 1–5 kW_eh range are now used in hybrid electric vehicles.

Thermal energy storage About 40% of our primary energy today is actually consumed as thermal, rather than electrical or mechanical, energy at temperatures of 250°C or less. Therefore, it makes sense to consider storing thermal energy. This is particularly true given daily and seasonal variations in demand and the intermittent availability of many renewable energy types, such as solar. The price fluctuations that exist for purchased bulk electricity during high- and low-demand periods also create an incentive for thermal energy storage.

There are two primary mediums used for thermal storage. One involves sensible heat stored in the heat capacity of single-phase materials by changing their temperature, while the other involves the latent heat associated with changing the phase of a material at a fixed temperature and pressure. Latent-heat storage systems have some advantages, in that thermal energy can be supplied or removed at essentially constant temperature, which is desirable for many applications. Large-scale solar installations that use molten-salt storage systems to extend the daily dispatch time are discussed in chapter 13.

In order to make thermal storage economically viable, low-cost stable materials need to be used. For sensible heat storage, water and solids like crushed rock, adobe, or concrete are commonly used. For latent heat storage, ice is often used for cooling, whereas eutectic salt mixtures with a phase transition temperature selected in a desirable range are commonly used for heating. Table 17.1 shows that the range of energy densities possible for thermal storage systems is from 180 to 300 kJ/kg, which is relatively low in comparison to the range for fossil fuels or biomass. Furthermore, the thermodynamic quality per kJ of thermal energy at temperatures less than 250°C is a factor of four or more, less than storing a comparable amount of electrical energy. Nonetheless, there are many end-use applications in which thermal storage is the most appropriate and economic option; good examples are solar water heating, or making ice using off-peak electricity for refrigeration-based building air-conditioning systems.

The inherent storage of thermal energy in a geothermal ground source or subsurface aquifer represents an attractive resource that can substantially increase the efficiency of an overall energy supply system (consider the combined heat and power cogeneration example illustrated in figure 17.3). In principle, applications for subterranean thermal-energy storage could be greatly expanded to include seasonal energy storage as well. For example, solar energy as heat (or cold) would be captured during the summer (or winter) months and used months later when needed. Obviously, this would require an expanded infrastructure for capturing, storing, and

distributing thermal energy. Taking such an aggressive path toward energy conservation has more to do with policy than with the need for new technology to become available. By using water or ice as the storage medium, other benefits might arise with a distribution infrastructure in place, such as augmenting municipal water supplies during times of need.

Chemical energy storage A considerable amount of energy is contained in the chemical bonds that hold atoms in place within molecules. Breaking these bonds selectively, such as during the oxidation of fossil or biomass fuels as they are combusted, can release a large amount of energy at high temperatures (see table 17.1). Such chemical energy is stored either for millennia, in the case of coal, oil, and other fossil fuels; for years, in the case of wood and forest products; or for one season, in the case of agricultural crop residuals, such as wheat chaff and rice straw.

In another proposed application of chemical energy storage, hydrogen would be produced from renewable or nuclear energy sources and then stored; later, it could be utilized for transportation needs by being combined with oxygen in a fuel cell, or to generate distributed electric power in heat-to-work cycles employing microturbines. As discussed earlier, deploying hydrogen on a large scale, particularly for use in the transportation and building sectors, raises the need to develop infrastructure to produce, distribute, and store hydrogen in a safe, economic manner. For example, if hydrogen is to become a commodity transportation fuel like gasoline or diesel fuel, then both energy converters (fuel cells or internal combustion engines) and on-board storage technologies will have to be available at reasonable costs. In chapter 18, some specific issues are discussed in more detail, but here it is appropriate to mention the storage of hydrogen as a transportation fuel.

One of the advantages of having gasoline and diesel as primary transportation fuels is their high energy density and their ability to be stored on-board as liquids at ambient pressures and temperatures. The infrastructure for producing and distributing these fuels is highly developed. While hydrogen has a reasonable energy density on a mass basis of 120,000 kJ/kg compared to about 45,000 kJ/kg for gasoline or diesel, its low density as a gas at ambient temperature and pressure results in a volumetric energy density of only 10 MJ/m^3 compared to 35,000 MJ/m^3 for gasoline or diesel. The energy content of a full 20-gallon gasoline tank in an automobile is about 2.8 GJ. If we were to fill that same tank with hydrogen gas at 1 atmosphere, the energy content would only be 0.0008 GJ. One way around this problem is to pressurize the hydrogen and store it as a compressed gas, which introduces both infrastructure and safety challenges. Liquefaction and cryogenic storage is another option, which also has major infrastructure and safety issues. Yet another solution would be to develop a suitable storage medium for hydrogen that has an acceptable energy density. Metal and chemical hydrides and carbon nanotube structures may provide such a medium, but more research and development is required before they will be competitive with conventional liquid fuel storage.

In other settings, chemical energy could be transferred in a reversible chemical reaction to augment the transfer and conversion of heat to work at high efficiency. Rapidly equilibrating chemical reactions have been proposed to manage energy in the carbon-hydrogen-oxygen system and for hydrogen storage in metal hydride systems. (For more details, see Jensen and Sorensen, 1984.)

Electrical energy storage There are three major mechanisms for storing electrical energy: *electrochemical*, *electrostatic*, and *electromagnetic*. In this section, we focus on one technology for each storage mode: (1) batteries for electrochemical energy storage, (2) supercapacitors for electrostatic energy storage, and (3) superconducting magnetic energy storage (SMES) systems for electromagnetic energy.

1. **Batteries.** Electrical energy is stored and released in an electrochemical reaction cell that transports electrons to electrodes to carry out specific reduction/oxidation (redox) reactions. These reactions involve ionic conductors, which could be contained in liquid solutions, solid conductive polymers or gels, or ceramic host media. Frequently, catalysts are needed to accelerate reaction rates to acceptable levels. The important thermodynamic relationship that governs the amount of energy transfer that occurs per mole of reactant is the Gibbs-Faraday form of the Nernst equation, in which the free energy change of the reaction is expressed in terms of a standard reference potential and activities of the reactants and products of the reaction. In mathematical terms, this is given by

$$-\Delta G_{rx} = n_e F\varepsilon = n_e F\varepsilon^o - RT\ln\left[\prod_{i\,species}(a_i)^{v_i}\right] \tag{17.18}$$

where ΔG_{rx} is the Gibbs free energy change for the electrochemical reaction, F is the Faraday constant = 96,500 coulombs per mole, ε is the cell voltage, ε^o is the standard cell voltage with all reactants and products in their reference states (usually taken to be unit activity), a_i is the activity of species i, v_i is the stoichiometric coefficient of species i in the electrochemical reaction, n_e is the number of electrons transferred in the reaction, R is the universal gas constant, and T is the absolute temperature. Although equation (17.18) looks complicated, the key element to remember is that the ideal maximum work that can be produced from an electrochemical battery operating isothermally is equal to ΔG_{rx}. Most standard cell voltages are in the range of 0.5–2.5 volts DC, which require stacking and conversion to AC for most applications.

In batteries, electrical energy is stored in the electrodes in the form of chemical reactants that have a strong affinity for one another, i.e., there is a difference in chemical potential between the electrodes. However, because the electrodes are separated by an ionically conductive medium called the electrolyte, chemical reaction between reactants in opposite electrodes can occur only via electron transfer reactions at the electrode/electrolyte interfaces—one reaction involves electron production (oxidation at the anode) and the other reaction involves electron consumption (reduction at the cathode). The intensity of the driving force for the reaction is expressed as the voltage, and the rate at which the reaction can proceed is expressed by the current. Since such reactions necessarily produce a DC current, for utility applications it is normally converted to AC form using a suitable power inverter. During charging, the action of electric current forced through the battery converts the products of the spontaneous discharge reaction into the original reactants.

The efficiency of energy transfer in batteries is a function of several linked effects. Frequently, it is expressed in the format of equation (17.2) as a continuous product of specific efficiencies:

$$\eta_{battery} = \eta_{rev,\,max}\eta_{rx}\eta_{voltage\ losses} \tag{17.19}$$

where the maximum or reversible efficiency, $\eta_{rev,\,max}$, represents cell operation at zero current and yields the maximum theoretical energy for the device. The other two efficiencies, η_{rx} and $\eta_{voltage\ losses}$, capture nonidealities associated with operating the cell at practical current densities. Practical battery operation at finite currents places limits on energy and power densities that are considerably lower than their theoretical maximums—sometimes by a factor of 5 to 10 or more. Typical ranges are shown in the Ragone plot (figure 17.5) for a number of battery types.

Mass and volumetric energy density for batteries become critically important for transportation applications. For utility or buildings applications, the size or weight of the battery storage system is usually not a limiting factor. Nonetheless, there are several common performance factors that apply for all applications. These include (1) lifetime (maximum number of charge and discharge cycles), (2) overall cycle efficiency, (3) depth of discharge per cycle, and (4) cost per unit of power or energy stored.

Although electrochemical batteries were discovered about 200 years ago, only one, the lead-acid battery, had been extensively commercialized until recently. Since their initial release in 1859, lead-acid batteries for both stationary and mobile applications have been incrementally improved. Overall cycle efficiencies now exceed 80%, with cycle lifetimes up to 2,000, and relatively low costs (<$200/kWh). The largest stationary lead-acid system for a utility application was installed by Southern California Edison in 1991 (Schoenung et al., 1996). It uses over 8,000 battery modules to deliver up to 10 MW_e power for four hours of continuous discharge. Other units are in operation as well, and more are planned.

Despite 150 years of slow, steady progress, nothing can be done to overcome the inherent limitations of lead-acid batteries in terms of energy and power density (see figure 17.5). An average family-sized electric vehicle using the best lead-acid batteries available in 2010 would need nearly a ton of batteries to provide reasonable levels of performance in terms of speed and range.

In order to achieve the higher performance levels needed for totally electric or hybrid electric vehicles or other transportation applications, different electrochemical systems must be selected that preserve the efficiency and cycle lifetime advantages of lead-acid systems but have lower weight and volume requirements. Over the past 30 years, new battery technologies have been aggressively pursued to find a replacement for lead-acid systems. Much progress has been made with the discovery and development of sodium-sulfur, zinc-air, nickel-zinc, nickel–metal hydride, and lithium ion systems. Figure 17.5 shows the position of several advanced battery systems that all perform at higher energy and power densities than lead-acid systems. Nonetheless, radical improvements that would revolutionize battery technology have not yet been achieved. A paper by Sadoway and Mayes (2002) suggests that the linkage of lithium ion chemistry with the modern tools for developing molecularly engineered materials may provide a platform to create a new generation of advanced Li ion solid polymer electrolyte batteries. (Figure 17.9 illustrates the

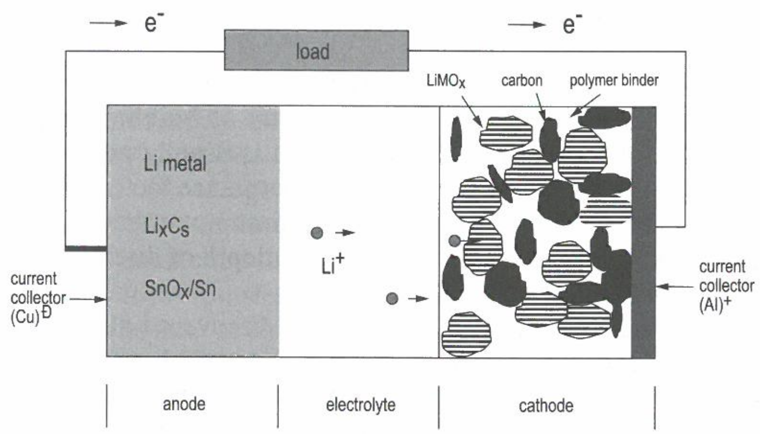


Figure 17.9
Schematic illustrations of an energy storage technology: Lithium ion–solid polymer electrolyte battery. Source: Sadoway and Mayes (2002).

main elements of this newly engineered battery.) Early testing of its concepts at MIT suggests that they may meet specific energy and power densities needed for vehicles, namely 400 Wh/kg and 1,440 kJ/kg, respectively.

2. **Supercapacitors.** Capacitors store electrical energy in the form of confined electrostatic charges in a device consisting of two conductive plates separated by a dielectric medium. Recovery of the stored energy is achieved by connecting the conducting plates to a suitable load.

The governing equations for specific energy and power densities for capacitors can be represented as follows:

$$\text{Energy density} = \frac{E}{Ad} = \frac{1}{2}\frac{A_{eff}}{(Ad)A}\varepsilon_m V^2, \tag{17.20}$$

$$\text{Power density} = \frac{E/\tau}{Ad} = \frac{\frac{1}{2}\varepsilon_m V^2}{(Ad)RC}\frac{A_{eff}}{A} = \frac{\frac{1}{2}\varepsilon_m V^2 A_{eff}}{RCdA^2}, \tag{17.21}$$

where τ is the characteristic time, equal to RC, for the capacitor, A is the nominal surface area of the conducting plate or electrode, A_{eff} is the effective surface area of the capacitor, d is the spacing between plates, V is the applied voltage, R is the total effective resistance of the capacitor, and ε_m is the permittivity of the dielectric medium.

Since the overall capacitance C is given by

$$C = \frac{\varepsilon_m A_{eff}}{d}, \tag{17.22}$$

equation (17.21) becomes

$$\text{Power density} = \frac{E/\tau}{Ad} = \frac{\frac{1}{2}V^2}{RA^2}. \tag{17.23}$$

From these operating equations, we can see that low-resistance systems will give high power densities and that the ratio of effective to nominal surface area A_{eff}/A could be important in influencing the magnitude of the energy density.

Capacitors have the ability to be charged and discharged quickly, on the order of seconds or less, which makes them useful for responding to power interruptions of short duration. Given that the power density of capacitors is inherently large, they have been used for mitigating power interruptions for many years in stationary utility applications over a range of scales. However, the specific energy densities of early generation capacitors were low, <<1 W_eh/kg, making them unattractive for energy storage applications. The appearance of "supercapacitors" that utilize advanced materials that greatly increase the effective surface area of the capacitor's electrodes per unit mass has changed performance metrics in a manner that results in enormous gains in energy storage capacity. Typical ranges for energy and power densities are shown in figure 17.5. Here we see that 3,000–10,000 W_e/kg at up to 10 W_eh/kg are achievable. This makes supercapacitors attractive for regenerative braking and other power needs in electric and hybrid electric vehicles.

3. **Superconducting magnetic energy storage (SMES).** In SMES systems, electromagnetic energy is stored and retrieved directly and with negligible losses using direct current (DC) flowing through superconducting coils to generate a magnetic field. The volumetric energy density is given by

$$Volumetric\ energy\ density = \frac{1}{2}\mu_m H^2 \Omega \qquad (17.24)$$

where H is the magnetic field intensity, μ_m is the magnetic permeability, and | is the characteristic volume of the SMES device. Resistive losses in the SMES unit are low, as are other losses associated with required AC to DC conversions and general power conditioning. To achieve superconductivity conditions will require some level of cryogenic refrigeration to maintain low temperatures. While initial designs required liquid helium temperature near 0 K, materials discovered in the 1980s have enabled superconductivity at liquid nitrogen temperatures of about 77 K, which reduces heat losses considerably and provides for more practical and economic SMES designs.

To sum up, SMES has many attractive features for utility-scale electric power applications. In principle, large amounts of energy (up to 1,500 MW_eh) can be stored for long periods and utilized when needed at extremely high rates (10–1000 MW_e) with overall cycle efficiencies of 95% or more. One of the disadvantages of such large units is their high total capital costs. To offset this, new technology is under development that could lead to micro-SMES units that would be less capital-intensive and would be useful in distributed power applications from 1–30 MW_e.

By 1985, SMES technology had been demonstrated at a small scale (30 MJ) in a project managed by the Bonneville Power Administration (BPA) in the northwestern US. A 30 MW_e SMES demonstration unit has been designed by Babcock and Wilcox for use in Alaska (Schoenung et al., 1996). Micro-SMES units at a capacity level of 1–2 MW_e became available in 2001. Nonetheless, even with these demonstrations, SMES is not yet ready for widespread

Table 17.3
Estimated Capital Costs for Representative Energy Storage Systems for Supplying Electric Power

System	Typical Size Range (MW_e)	\$/kW_e	\$/kW_eh
Pumped hydropower	100–1000	600–1000	10–15
Batteries:			
Lead-acid	0.5–100	100–200	150–300
Nickel–metal hydride	0.5–50	200–400	
Lithium ion	0.5–50	200–400	
Mechanical flywheels	1–10	200–500	100–800
Compressed-air energy storage (CAES)	50–1,000	500–1,000	10–15
Superconducting magnetic energy storage (SMES)	10–1,000	300–1,000	300–3,000
Supercapacitors	1–10	300	3,600

Sources: Turkenburg et al. (2000); Schoenung et al. (1996); Boes, Goldstein, and Nix (2000).

deployment. Long-term performance testing and a number of economic issues need to be resolved. In 2011, international research is continuing on new superconductor materials and on SMES at liquid hydrogen temperatures (20 K), which might be of interest in further development of hydrogen as an energy carrier.

In general, there is substantial latitude in choosing a specific energy storage technology for a particular application. For example, capacity and capital cost ranges for electrical storage applications are given in table 17.3.

17.4 Energy Transmission

17.4.1 General characteristics of energy transmission systems

Energy can be safely and economically transported for long distances in a variety of modes. Pipelines are commonly used for oil and gas and have potential for coal transport in the form of coal-water slurries. Trucks, trains, barges, and tanker ships are heavily employed for distributing coal and oil. Biomass fuels can also be transported between their source and a power generator or chemical processing plant using these methods. Specialized refrigerated tankers haul LNG across the world's oceans. Electricity is primarily transported by wires, which are frequently interconnected in a complex distribution system or grid. Electric grids regulate and control currents and voltages at various levels from the generation site to the final use point. Even geothermal energy is transported from production wells by pipelines to electric power generation plants or to district heating distribution centers. Uranium ore is shipped to separation and processing plants by trucks or trains to be enriched into fissile power reactor fuels.

The efficiencies of most of the common energy transport modes are high—usually consuming only a small percentage of equivalent energy content of the delivered fuel. This is especially so for high-energy-density fuels like oil, gas, and coal. The equivalent energy efficiency for transporting lower-energy-density fuels, such as geothermal steam, hot water, or residual biomass, is lower. The infrastructures for fossil energy transportation and electricity transmission systems are also highly developed, particularly in North America and Europe.

Although there are many factors that control costs, a useful way to compare transmission modes for alternative energy is to plot cost per unit of energy transported per unit distance as a function of distance. Hottel and Howard (1973) presented such a correlation in their energy monograph (updated to 2000 in figure 17.10). Readers should keep in mind that these estimates are rough—they indicate trends and are not site-specific. Local terrain, labor rates, and regulatory constraints vary widely from place to place. For example, compare the complexity of designing and constructing the Trans-Alaska Oil Pipeline System in the 1970s with constructing a new gas pipeline in 2002 in eastern Wyoming. Careful attention to details must be given to develop accurate cost estimates.

17.4.2 Oil transport

Liquid petroleum is usually transported in one of two forms: as crude oil or as refined product. There are three primary modes of oil transport: pipelines, barge or tanker ship, and truck. Oil pipelines, ranging in diameter from about 10 cm to over 1 m, are common in developed countries. For example, in the US there are over 160,000 km (100,000 mi) of crude oil pipelines (Glasstone, 1983). Smaller, secondary pipelines are frequently used to transport crude oil from producing fields to major trunk lines, which bring the crude to centrally located refineries for processing into final products or to shipping ports, where they are loaded onto suitably sized tankers.

There can be large distances between the places where oil is produced and where it is refined or used. For example, consider the 900-mile, 48-inch Trans-Alaska Pipeline System (TAPS) that pumps oil from above the Arctic Circle at Prudhoe Bay over Alaska's Brooks mountain range to the all-season, deep-sea port in Valdez, where it is shipped to the lower 48 states. When it was completed in 1977, TAPS represented one of the world's largest and most complex civil construction projects, with a total cost of over $6 billion. Given the environmental sensitivity of the Arctic region, with permafrost and large herds of migrating caribou to deal with, the success of the Trans-Alaska pipeline is an engineering marvel. Thirty years later, depletion of the North Slope fields at Prudhoe Bay have reduced the pipeline flow from its peak flow of 2 million bbl/day in 1988 to around 500,000 bbl/day. Without

development of additional Arctic reserves, around 2030 the pipeline flow will drop to the minimum operational flow of about 200,000 bbl/day.

In 2011, a controversial proposal to develop a major new oil pipeline from Canada (supplied by production of the Alberta tar sands) to oil hubs in Texas is being hotly debated on several levels: the US need to reduce reliance on oil imports, the potential for creating many new construction jobs during a recession, concerns about GHG emissions, and about environmental impacts associated with the pipeline route.

Large tanker ships are regularly employed for transporting oil over long distances. Transoceanic trips are common. For example, oil produced in the fields of the Middle East is transported for thousands of kilometers in supertankers to the US and Japan. These supertankers have capacities ranging from about 200,000–300,000 tons, which is the equivalent of 1.4–2.1 million barrels of oil. Special mooring in deep-water locations is needed to accommodate these supertankers. Smaller tankers and barges are used to ship oil over smaller distances on rivers and other smaller waterways. Trucks are commonly employed to deliver petroleum-based products such as gasoline and diesel jet fuel to their points of use (e.g., gasoline stations or airports).

17.4.3 Natural gas transport

Over its almost 200-year history, the infrastructure for transporting and distributing natural gas from a producing gas well to its final use point has become highly developed and sophisticated. Pipelines carry much of the load (75% or more) in North America and Europe. The US is the largest consumer of natural gas, produced both domestically and in Canada. It is delivered using 420,000+ km (250,000+ mi) of pipelines. (Major US gas pipelines are diagrammed in figure 17.11.) In Europe, Norway now provides a substantial portion of the natural gas to Western Europe from its North Sea fields (Ager-Hanssen, 1990).

Compression of the gas to elevated pressures is used to drive gas through the pipeline system. Consequently, a premium is placed on operating gas compressors at high efficiencies. In addition, some natural gas is frequently stored in pressurized tanks, natural aquifers, or caverns in order to buffer supplies during peak-demand periods.

A smaller, but important, portion of the natural gas market is assigned to refrigerated tanker ships that haul LNG from sites in Africa, such as Algeria, and Asia to load centers throughout the world. (Global movements of LNG in 2010 are shown in plate 1, bottom.) Although the energy requirements associated with liquefying natural gas are significant, the energy density of methane in its liquefied state (1 atm, –162°C) is about 600 times larger than its density as a gas at ambient conditions (1 atm, 25°C).

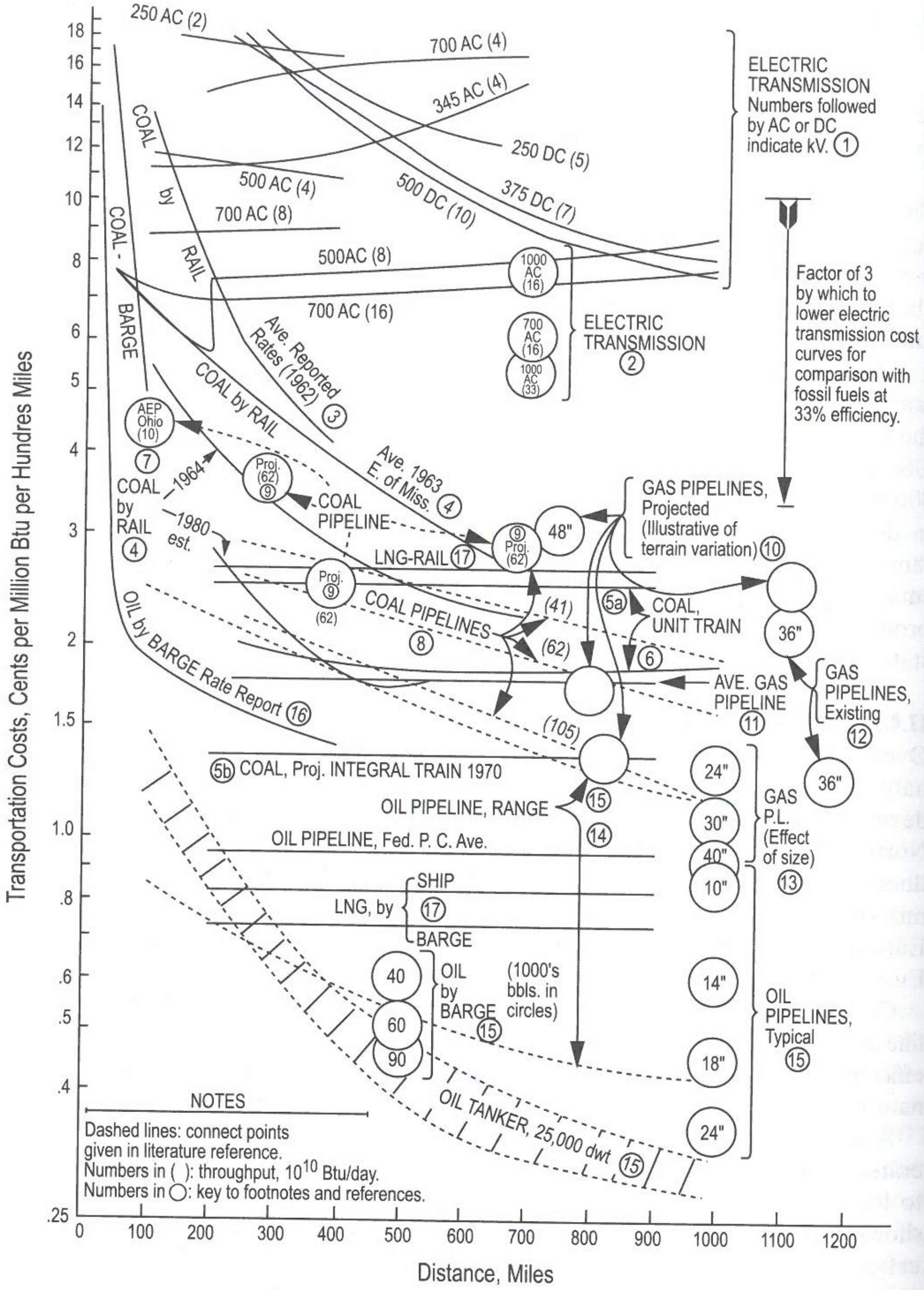


Figure 17.10
Estimated costs in 2000US$ for energy transmission. Adapted and updated from Hottel and Howard (1973).

Key to figure 17.10

Electricity Transmission:

1. Point-to-point transmission costs, 85% load factor.
2. Point-to-point transmission costs for higher voltages, 90% load factor.

Coal Transportation:

3. Average reported rates by rail for 1962.
4. Average 1963 rail rates, 1964 volume rates, and 1964 estimate of 1980 volume rates.

5a. Average 1970 unit train.

5b. Projected 1970 integral train.

6. 1964 estimates for unit train.
7. Actual costs, AEP Ohio pipeline (1964).
8. 1964 projected costs as a function of distance for coal pipelines of various sizes.
9. 1962 projected costs for pipelines from (left to right) southern Illinois to Chicago, West Virginia to New York City, and Utah to Los Angeles, showing effect of distance and terrain on costs.

Gas Transmission:

10. 1970 projected pipeline costs, showing effect of terrain. From top: 48″ pipeline from Prudhoe Bay to Valdez; Ft. Nelson, Canada, to Portland, Oregon; Portland to Los Angeles; (at right) Prudhoe Bay to Ft. Nelson. All except first case assume 100% load factor.
11. Average cost by pipeline (1970).
12. Existing pipelines in Canada and Canada to US West Coast, showing range of current [1970] costs.
13. 1954 estimates of costs for various pipeline diameters; absolute values are obsolete because of inflation, but relative values are of interest.

Oil Transportation:

14. 1970 average oil pipeline cost.
15. Ranges of cost for oil transportation in various quantities by various methods (1966).
16. Rates by barge in 1962.

LNG Transportation:

17. Average costs by barge (1970).

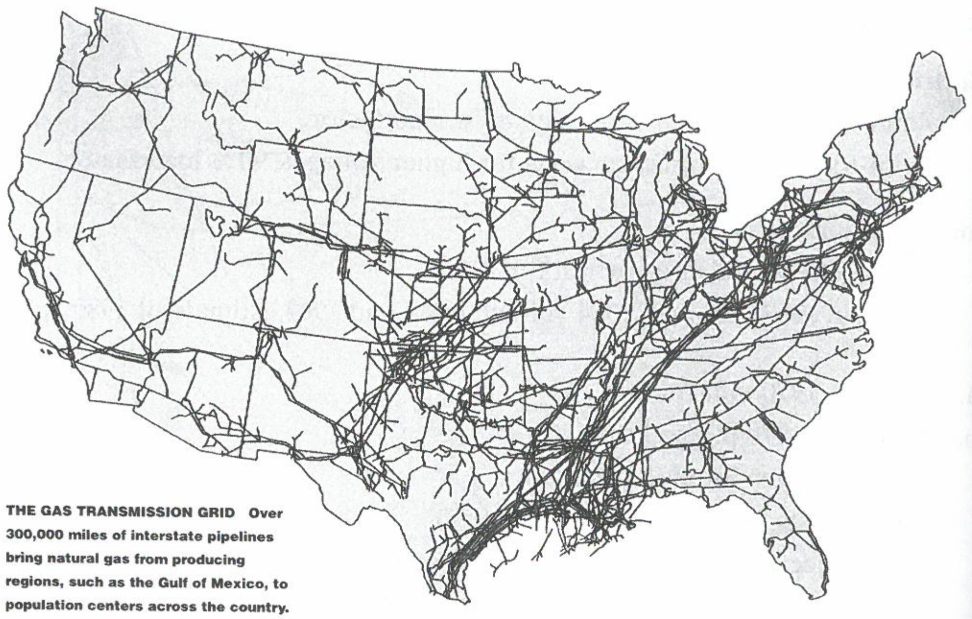


Figure 17.11
Illustration of the major gas transmission pipelines in North America. Source: Platts website, http://www.platts.com

Advances in materials technology, automated welding, and nondestructive pipe inspection and testing have greatly enhanced the performance of natural gas pipeline systems. Larger-diameter, higher-pressure systems can reduce both frictional pressure losses and, with turbine expanders used to recover compressed energy, can be quite efficient. GHG methane leakage from the pipeline system, especially from the older sections, is also a concern and provides an incentive to construct new lines to minimize leakages.

Mohitpour, Glover, and Trefanenko (2001) predicted that growth in the global production of natural gas would require an additional 120,000 km (72,000 mi) of gas pipelines by 2010, with North American expenditures alone exceeding $80 billion. Trends since 2001 have been directed toward larger-diameter, high-strength steel pipes that significantly increase the throughput capacity of the pipeline. In 2011, additional Alaskan gas pipeline proposals are emerging: development of large shale gas discoveries on the North Slope will require pipelines to supply US markets; new unproven gas discoveries in Cook Inlet would require new pipelines to markets and are reviving discussions of additional LNG projects. Plans for decommissioning an existing LNG liquefaction plant in Kenai (shipping Alaskan LNG to Japan since

1969) are being reconsidered. Comparable expansion in gas production and transmission is envisioned in the former Soviet Union to serve expanding European and other markets.

17.4.4 Coal transport

Most of the coal in the world is delivered from mines by rail or barge to power plants or other points of use. In contrast to the costs for liquid and gaseous fossil fuels, the transportation costs for delivering coal are usually a major portion of the fuel cost for electric power generation. For example (as shown in table 17.4), in the last 30 years in the US, interstate coal transportation costs have increased from less than 25% to over 35% of the delivered coal price. Interestingly, the average delivered cost for coal in the US over this same period decreased from 28¢/ton mile to 13¢/ton mile (in constant 1996US$) due to improved technology for mining operations as well as for transportation systems (Peters, 2001). (Table 17.4 provides other insights into the changing landscape of options that are used for transporting coal.) Barge shipments are typically limited to about 350–650 km (200–400 mi), while rail transport distances increased during the last 30 years from about 850 km (500 mi) to 1,400 km (800 mi). Multimode shipments involving a combination of rail, truck, and/or barge become important over long distances, while truck transport predominates for distances of 150 km (100 mi) or less. An alternative to these conventional modes for coal transport is the use of a coal-water slurry pipeline. This concept uses a mixture of about equal proportions of finely ground coal particles and water to create a slurry, which is pumped at near-ambient pressures in a steel pipeline. Although this idea was proposed about 110 years ago, and was operated at small scale in the UK in 1914 and at somewhat larger scale (108 mi) in the US in Ohio from 1956 to 1963 (Glasstone, 1983), only a few practical systems are in use today. A notable installation is the Black Mesa slurry pipeline, which started operation in 1970 between a mine in northern Arizona and a 1,500 MW_e coal-fired power plant in Nevada.

17.4.5 Electric power transmission

The infrastructure for transmitting electricity from its points of generation to a multiple set of industrial and residential users has evolved over the last century to a sophisticated and interconnected level in most developed countries. In these developed areas, the great majority of customers are connected to a grid that provides them with electricity when needed. In remote locations, customers may not be on the grid, and thus must generate their own power in a distributed manner. The situation in undeveloped countries is far different: there is no national grid, and, in most cases, only major cities have operating electricity generation and

Table 17.4
Coal Transportation Statistics for the US

Year	US Average		Rail			Barge			Truck			Multimode			Other		
	% of total cost	¢/ton-mile[a]	% of total shipped	Average distance shipped (miles)	¢/ton-mile[a]	% of total shipped	Average distance shipped (miles)	¢/ton-mile[a]	% of total shipped	Average distance shipped (miles)	¢/ton-mile[a]	% of total shipped	Average distance shipped	¢/ton-mile[a]	% of total shipped	Average distance shipped	¢/ton-mile[a]
1980	24	28	59	550	2.8	10	310	1.6	7	50	12.3	10	—	5.8	14	60	3.0
1990	32	22	60	600	2.2	8	200	1.0	10	25	19.2	10	—	1.6	12	100	3.5
2000	37	13	73	850	1.2	10	300	0.9	5	40	15.0	6	—	1.1	5	100	2.4

Source: Peters (2001).
[a] In 1996US$.

distribution systems. In fact, it is estimated that over two billion of the world's people were without any electricity at the beginning of the twenty-first century.

Our focus in this section is on grid-based transmission and distribution. Major transmission lines in the US are shown in plate 11. Transmission is usually characterized by overhead high-voltage lines carrying power long distances between central generation plants and main junction points on the grid. Distribution usually applies to lower-voltage transmission over shorter distances from these nodal junctions to end users. Both AC and DC transmission systems are employed in practice. While there are advantages to each, AC is the dominant mode in most applications.

For transmission, the amount of power that can be transported increases in proportion to the voltage used. This is a result of Ohm's Law ($V = IR$), where power scales as follows:

$$\text{Power} = I_{eff}V_{eff} = \frac{V^2}{R} = I_{rms}V_{rms} \text{ (in phase)} \tag{17.25}$$

where the subscripts *eff* and *rms* refer to effective and root mean square levels of current (I) and voltage (V) carried by the wires with a total resistance (R). Note that *rms* values for normal sinusoidal AC power are equal to maximum values divided by 2. Equation (17.25), although somewhat simplified in the sense that inductance or capacitance effects are not explicitly included, shows that higher voltage and lower resistance will yield higher power-carrying capacity with lower losses. To account for inductance and capacitance effects, the so-called "power factor" is commonly introduced, where

$$\text{Power factor} \equiv \frac{P_{actual}}{P_{apparent}} = \frac{P_{actual}}{I_{eff}V_{eff}}. \tag{17.26}$$

Typically, copper or aluminum wires are used to transport electrical power in both AC and DC systems. Copper has the advantage of lower electrical resistance than aluminum, but aluminum has a lower mass density, which partially offsets its lower conductivity. In AC systems, three wires are needed, and the major portion of the energy is transmitted near the surface of the wires, which favors using stranded lines to increase the surface area to volume ratio of the transmission line. Long-distance AC power transmission generally uses voltages between 250 and 765 kV, with a few systems at even higher voltages. The capacity of large AC transmission lines is over 3,000 MW_e.

In DC systems, there is no "skin effect," as the entire cross-section of the wire is utilized for energy transport. Also, only two wires are needed. But where AC power is used by consumers, a rectifier must be employed to convert DC to AC. Even with this additional requirement, DC systems tend to have somewhat lower capital costs.

In the US, transmission and distribution losses average about 11% of the electrical energy supplied. These losses are attributed to Corona discharge, resistive (Ohmic) heating in the wires because of their finite electrical conductivity, and other irreversible losses in the power conditioning equipment that is required to step up and step down voltage levels using transformers. Transmission losses generally increase as the voltage level is lowered. According to Ilic (2001), a high-voltage AC (>500 kV) system loses about 3–5% over a distance of 1,000 miles, while a low-voltage AC (<10 kV) distribution leg loses about 5–7% on the same basis. Without skin effects in the wires, DC transmission has lower losses on average for the same amount of energy transported.

Several environmental, safety, and health concerns directly related to high-voltage power transmission strengthened public opposition toward the end of the twentieth century. These issues included the manufacture and use of refractory and potentially carcinogenic PCBs (polychlorinated biphenyl compounds) as transformer fluids prior to 1970, fears about the health effects of electromagnetic fields (emf) generated near transmission lines, and safety concerns about the bare wires and overhead transmission lines, as well as distaste for their negative visual impact. Alternatives to existing AC and DC aboveground transmission systems do exist. For example, superconducting and conventional transmission carried out underground alleviate most of the major environmental and health concerns cited here.

Conventional underground transmission In urban or highly populated regions, underground power transmission is usually required due to both public safety concerns and the general lack of accessible, open space. Unfortunately, underground systems are more costly than overhead systems. Copper or aluminum cables placed underground need to be insulated to avoid charge transfer to the earth. This decreases their power-carrying capacity to below 1,000 MW_e and operating distances to about 100 km (60 mi) due to heat buildup resulting from Ohmic losses, dielectric losses, and capacitance effects. Improved insulation using gas blankets or active cooling with water or refrigerants can increase capacity at the expense of increased capital investment and somewhat higher operating and maintenance costs. Underground DC lines have lower resistive losses, but the need to rectify to AC introduces additional losses that often outweigh their Ohmic efficiency advantage. Similar technologies are also applied for underwater power transmission.

Superconducting transmission Superconducting transmission is a developmental area with great promise. As operating temperatures in a material approach its superconducting temperature limit, resistivity goes rapidly to zero, which virtually eliminates Ohmic losses and increases power capacity. The discovery of new compounds with superconducting properties near the normal boiling point of liquid nitrogen (77 K or –196°C) fueled much research and development work to manufacture practical superconducting wires and to integrate them into a complete transmission system that would be reliable and cost competitive. As of 2011, much remains to be done to achieve this goal.

17.5 Energy Distribution Systems

17.5.1 General characteristics of central versus distributed systems

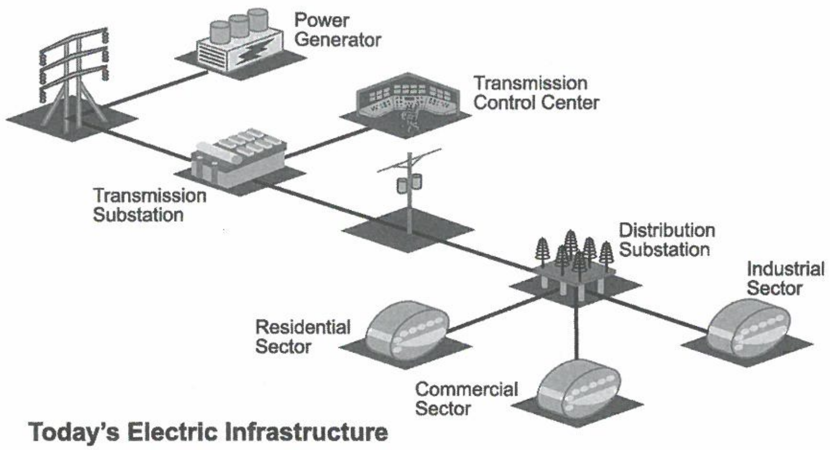
Electric power in developed countries is usually produced by large central generating stations, and then transmitted along high-voltage lines to local distribution systems that carry it to final consumers. Distributed generation (DG) and distributed energy resources (DER) concepts offer an alternative that has some attractive features. (Table 17.5 and figure 17.12 compare the generation and distribution networks for central station and distributed generation systems.) As a practical matter, it is useful to define DG and DER as small-scale generation located near and connected to a load being served with or without grid interconnection. Both nonrenewable and renewable energy resources could be involved, and there could be integration of electric power generation with heating and cooling loads.

Distributed networks are distinguished from central station power systems by two key features: the shorter distances between the power generators and end users, and the smaller scale of the generation plants within the system. Distributed generation technologies include internal combustion engines, small gas turbines, fuel cells, and photovoltaic and wind generation systems (see table 17.6 and figure 17.13). DG/DER can provide all or part of an individual's own needs, as well as produce excess power for sale. Excess power can be transmitted to a local distribution substation or distribution network.

DG systems are already in use in many countries, particularly for power-quality or high-reliability applications, to provide emergency capacity or to avoid

Table 17.5
Comparison of Central Station and Distributed Generation Systems

Characteristic	Distributed Generation	Central Station
Proximity	Variable, but typically < 100 mi	Large cities: 10–100 mi All others: 10–1,000 mi
Scale	1 kW_e–100+ MW_e	100–2,000 MW_e
Energy form	Electricity or combined heat and power (CHP)	Electricity only
Fuel or energy source	Fossil, renewable (solar, wind, geothermal, biomass), or hybrid	Gas or coal, hydro, and possibly concentrating solar or geothermal
Grid connection	Optional	Required



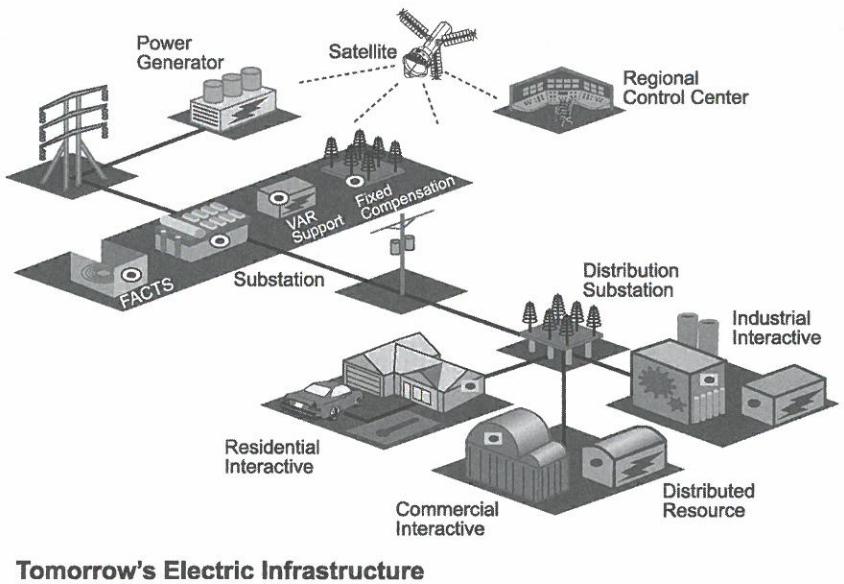


Figure 17.12
Systems for electricity generation and distribution: (a) baseload central station versus (b) distributed electricity generation. Source: EPRI (2001).

Table 17.6
Typical Ranges of Distributed Generator Unit Sizes

Type	Power Range
Internal combustion engines (ICEs)	1 kW–10+ MW
Fuel cells	1 kW–1 MW
Advanced CCGT	1+ MW–200+ MW
Microturbines	1 kW–1+ MW
Renewables	
Wind	10 kW–1MW
Solar PV	1–10 kW
Solar CSP	10 kW–50+ MW
Geothermal	1–100 MW
Biomass	10 kW–100 MW

Source: R. DeBlasio, National Renewable Energy Laboratories, Golden, CO, personal communication, 2003.
Note: CCGT = combined-cycle gas turbine–Rankine cycle; CHP = combined heat and power/cogeneration; CSP = concentrating solar power system; PV = photovoltaics.

expansion of local transmission and distribution systems. Following the tragic events of September 11, 2001, the security of energy supplies and infrastructures received increased attention from local and national governments. DG/DER systems would delocalize and diversify how we generate and distribute energy, which should result in more secure energy services.

Occasionally we are poignantly reminded of the vulnerability of centralized and interconnected grid systems. At 4:10 pm (EDT) on August 14, 2003, the US experienced its worst power outage when over 50 million customers lost power. Apparently, a large surge or outage developed somewhere in Ohio and quickly propagated to the remainder of the interconnected system in New York, Michigan, and parts of Connecticut and Vermont, as well as into the province of Ontario in Canada. For over 40 years, experts have warned of the weaknesses of the power grid system in North America. (An excellent reference that documents the vulnerability of the US power grid is Amory Lovins's 1982 book *Brittle Power*.)

Having additional spinning reserve capacity to meet peak demands on the hottest and coldest days of the year helps to reduce risks for outages. But fundamentally, a more robust control system with rapid diagnostics and response modes is needed to prevent a recurrence of blackouts on the scale of the 2003 event. Even with such improvements, centralized large grids inherently have vulnerabilities as a result of being regionally interconnected. A more distributed grid would avoid these systemic problems.

Advanced equipment to manage power flows throughout all parts of the electric grid will be an essential part of future management systems for electrical energy. NRC (2009) outlines the need for the following advances:

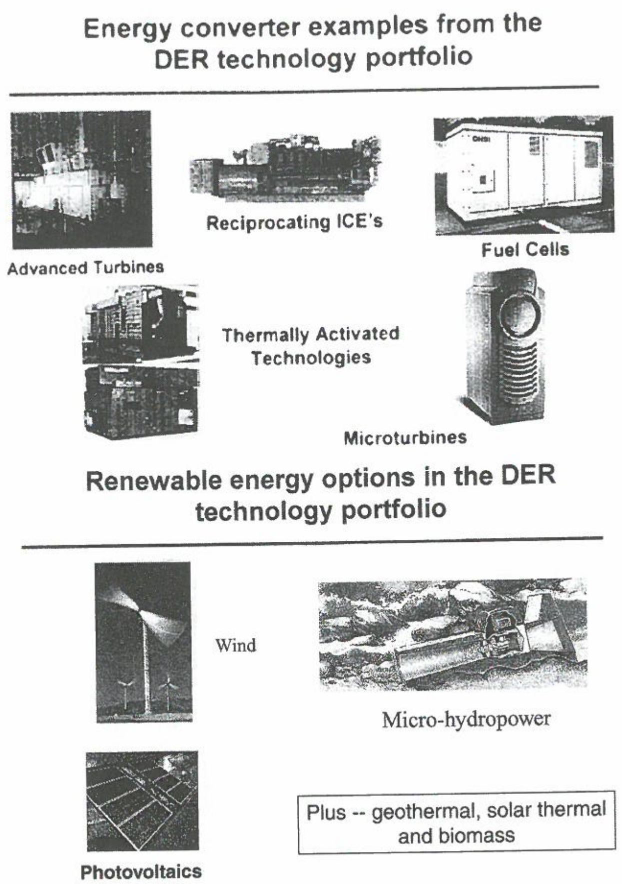


Figure 17.13
Examples of distributed energy technologies. Source: R. DeBlasio, National Renewable Energy Laboratories, Golden, CO, personal communication, 2003.

- power electronics (augmenting or replacing slower existing electromechanical devices) to manage both real and reactive power flows along transmission corridors, enhancing self-healing capabilities and improving both security and reliability of the grid;
- upgrading transmission lines and substations by using advanced materials to improve performance and robustness, and with HVDC for major corridors and for linking large remote generation and storage resources via underground cables;
- new wireless technologies and other applications;

- integration of measurement, communication, and control systems (both hardware and software) to monitor and control the full spectrum of grid elements. Such systems can also facilitate smart billing and other mechanisms to encourage consumer efficiency in energy use and behavior modification to ease peak system loading.

Additional details on the above technologies and related issues of integrated planning to establish consistent national goals and policies, the importance of research and development investments, development of a modern workforce, and other topics important to the future of the electric grid are discussed extensively in MIT (2011).

A recent example of innovation is the efficient transfer of practical quantities of electricity over distances of several feet *without wires*, as demonstrated by Kurs et al. (2007). In this approach, electric power is transmitted by strong resonant coupling of two oscillating magnetic field resonators. Electricity creates a magnetic field by exciting one magnetic resonator (the emitter), which in turn induces an oscillating magnetic field of the same frequency in a second resonator—the receiver. Electricity is then extracted from the receiver to power real-world devices and equipment (even at 2 kW_e in 2010). The emitter and receiver are each designed to oscillate naturally at one particular frequency, typically in the range of 0.3–10 MHz. Two oscillators, e.g., two vibrating springs (or electrical circuits, or magnetic coils, etc.), are resonance coupled (Feynman, Leighton, and Sands, 1963) if both vibrate at the same frequency *and* they interact strongly with each other but only weakly with their surroundings. To maximize the efficiency of wireless electric power transfer, this approach exploits resonance and designs the emitter and receiver to operate in the *strong* resonance coupling regime, i.e., so that the energy transfer rate from the emitter to the receiver is greater than the energy dissipation rate within these two devices. The power transfer is efficient even when the region between the emitter and receiver is completely obstructed. The coupling is essentially nonradiative, and thus the power being transmitted undergoes little dilution owing to radiation into all regions of space (as occurs with the energy in electromagnetic signals broadcast from conventional radio towers). Very importantly, the power transmission efficiency is high over distances that are large compared to the size of the emitter and receiver. This sharply contrasts with power transmission by conventional magnetic induction—the mechanism in electrical transformers, where the primary and secondary windings (the "emitter" and "receiver" of the transformer) must be very close to each other. This technology is now being commercialized for diverse consumer and industrial applications (see http://www.witricity.com/).

Analogous modes of energy transmission—as well as totally new mechanisms resulting from quantum effects—exist in the coupling of quantum mechanical oscillators (Hamam et al., 2009). There are likely to be many more new discoveries, some of which will develop with new end uses in communications, control systems, information management systems, and other applications that don't yet exist.

17.5.2 Combined heat and power opportunities

Most power distribution systems in developed countries are limited to providing electricity, not hot water or steam. Given that about 30–40% of a country's total energy load is utilized in buildings or industrial processes as thermal energy or heat at temperatures below 250°C, it is unfortunate that we do not generally have thermal energy available from utilities for purchase. A few notable exceptions exist in European cities, in Reykjavik, Iceland, and in New York City, where both electricity and thermal energy can be obtained from a utility company. As pointed out in section 17.2, the combined use of heat and electric power (CHP) can result in substantial gains in efficiency. Thus, from a resource utilization perspective, CHP systems are more sustainable. Since distributed energy resources are close to end users, the infrastructure needed to install a CHP system is not as extensive as that needed for centrally supplied grid power. Therefore, the capital investment needed to deploy CHP systems is more achievable for DG/DER applications.

17.5.3 Applications to renewable energy systems and hybrids

Given the smaller scale of DG/DER installations, their use of renewable energy resources (which tend to be more dispersed and less dense in terms of energy or power) is appropriate. Furthermore, given their localized characteristic with respect to resource grade, renewable energy is even more attractive here. Because solar and wind energy are inherently intermittent on both daily and seasonal time scales, hybridized DG/DER systems that use stored fossil or biomass energy to provide dispatchable power are being considered for a range of remote off-grid, as well as some grid-connected, systems. The tradeoff here is a reduction in energy storage and a smaller renewable system for capture and generation versus having two separate energy generators.

17.6 Ways of Organizing the Electric Economy

The electric industry has traditionally been organized as a regulated monopoly. In this system, state-level public utilities commissions were empowered to determine whether new capital facilities would be built and to set electricity prices such that investors would receive adequate returns in order to attract future investments. Today, utilities are organized in different countries on scales ranging from municipal to national, and with different mixes of public and state ownership and oversight.

As efficiencies were seen to improve through the deregulation of other industries (e.g., airlines, telecommunications, water, and gas utilities), an international experiment began in the UK in 1990 with privatization of the nationally owned Central Electricity Generating Board. Many other countries have followed the UK's lead. The results have been mixed, depending on the details of how the new markets are designed and regulated. Some successes have been achieved, increasing competitive markets for electrical generation (e.g., in the US and Australia), but, in the areas of deregulating retail customer prices and specifying allowable contracts, such markets have not worked well. Much difficulty seems to arise from the inability to store electricity and the reluctance of the political system to permit voters to be exposed to the risk of potentially high prices. However, the success of electricity deregulation is important to the future of electricity—in terms of the technologies used, the prices paid, and the practices of consumers.

17.6.1 Demand-side management (DSM) and distributed generation

As electricity use grew rapidly over the last half-century, the problems of meeting peak demands grew more challenging and expensive for the utility companies. Most companies instituted a variety of programs to reduce peak demands:

- offering much cheaper electricity to customers who were willing to be shut off during times of peak demand;
- providing services to consumers to encourage more efficient electricity use (insulating buildings, energy-efficient lighting, high-efficiency appliances, smarter management of time of use, etc.);
- encouraging investment in distributed generation sources that would reduce peak demands.

Under deregulation, many of the demand-side management (DSM) programs were dropped as the generation sector became separated from direct interaction in providing consumer electrical services. New generation companies focused on producing electricity at the most competitive rates. Meeting supply and demand became a secondary interest since the main responsibility for providing continuous service lay elsewhere. In a competitive environment, DSM programs were easily eliminated from the investment portfolio. The ISOs were struggling with matching supply and demand across the complex grid system, and the consumer service providers were not profitable enough to make investments in such programs.

If customers could install some local power generation to meet a portion of their demand, the need for transmission and distribution capacity would be reduced, especially if there were a match between times of peak demand and the output of the local supply. Customers could pay about twice the operating costs for the distributed generation and still break even (since they would be avoiding the transmission and distribution costs). Some of the renewable generation technologies (as discussed in chapters 10–15) are well suited for distributed power generation. For example, where air-conditioning peak loads are the problem, installation of photovoltaic panels might be an effective way to relieve the peak, since periods of hot sun and periods of hot weather tend to coincide. Other distributed technologies, such as local wind farms, natural-gas-fed fuel cells, or solar thermal water heaters, could be used to reduce overall electricity demand. If some energy storage capacity is provided, intermittent sources like solar and wind energy can also be employed, with the storage used to even out the supply and demand patterns on a daily basis. (A more detailed discussion of distributed technologies is provided in the last section of this chapter.)

17.6.2 Electricity transmission and distribution and economic deregulation

The system for electricity transmission is a set of high-current, high-voltage wires and associated hardware (e.g., transformers and circuit breakers) used for long-distance (hundreds of kilometers to 2,000 km or more) transport of bulk electricity. This system feeds energy to a more locally arranged (around 100 km or less) distribution network of wires operating at low voltage and current. Together, they constitute the grid, linking generating units to electrical loads. The central problem in designing and operating the grid is balancing generation and loads such that the individual grid components do not become overloaded and fail. Failures can cascade via subsequent dependent failures, and large regions can lose electrical service. (As mentioned earlier, this happened in the northeast and central US on August 14, 2003, the latest of an international succession of blackouts on approximately a decadal frequency.) Distribution failures are much more common. They are often caused by overloading a distribution transformer (e.g., caused by electrocution of a trespassing animal) or by tree limbs falling onto distribution lines. As deregulation of electricity sales has become more common over the past 12 years, the range of load and generation combinations has also become much greater, with a corresponding increase in the frequency of grid failures. Finally, weather-related grid failures occur regularly, particularly those associated with ice storms and high winds.

The infrastructure of the grid is land-intensive (although the land used may simultaneously be employed for agricultural or recreational purposes) and may be considered aesthetically intrusive. For these reasons, in wealthy countries opposition to new power lines has become so common that it has become very difficult to build new ones. As demands have grown, the result has been greater stress on the existing grid.

Concerns have also arisen that the electromagnetic fields associated with the grid's operation may cause diseases, particularly cancer. So far these fears appear

to be unfounded, but their persistence may reflect the discomfort that many people have with large-scale technologies. In the absence of particular benefits for those living near power lines, these factors have often been sufficient to motivate strong opposition to new facilities. This resistance has made it difficult to improve the grid in order to keep pace with growing demands and operating conditions.

Higher-voltage transmission lines, some perhaps utilizing superconductivity to reduce energy losses, may make longer-distance power transmission more attractive in the future. Smarter control systems and systems to facilitate real-time pricing of power may ease the inefficiencies associated with trying to match different supply and demand characteristics. Though the transmission and distribution grids have not yet been deregulated, many experts are trying to construct a new paradigm for the entire chain, from supply to the end-use customer, in which pricing is not based on electricity delivered, but on the electrical services (or even total energy services) delivered. The concept has many attractive attributes, but the reality of its implementation is daunting. The evolution of the present system into tomorrow's system will likely entail a number of successful and unsuccessful experiments and a gradual learning path to a more sustainable future for the electric industry. Part of this challenge will involve the comparison of electricity and hydrogen as energy carriers and a resolution of the drawbacks and benefits of each for the spectrum of energy services that will be needed in the future.

17.6.3 An example of electric industry planning using multiattribute assessment tools

The preceding sections outline the complexity of choices facing a variety of participants in the electric industry, as well as their customers and regulators. With deregulation, choices become even more challenging. An ideal market operates efficiently to select the most cost-effective products and production processes among competitors. But the electric market is far from ideal. We do not know how to properly price things that are of common societal benefit, except through a variety of market interventions, such as taxes, fees, subsidies, and regulations. Where these are imperfect or do not exist, the societal benefits may not be addressed responsibly. Some of the major issues facing the electrical sector include:

- assuring reliability of service,
- reducing GHG emissions,
- providing affordable basic energy services to the poor,
- siting facilities to reduce adverse land-use impacts.

Such issues are of concern to the industry and to society. But the industry is fragmented and competitive, with various customers and regulatory groups involved, as well as special interest groups that advocate for environmental responsibility and consumer rights. How can such a complex group of players help the electrical industry to evolve to a more sustainable state under the present ground rules?

Electrical services are provided by a multidimensional, complex system with many competing attributes and participants. Productive decision-modeling through assessments of the benefits to each of the participants becomes impossible. Utilities dispatch power in real time using real-time algorithms that consider the spot prices of various fuels as well as the operating costs and conditions of available generating units. These factors make equilibrium system models inappropriate.

Researchers with the Analysis Group for Regional Electricity Alternatives (Connors, 1991) evolved the concept of modifying a real utility dispatch model to include the various attributes of potential interest to a broad group of stakeholders (e.g., the utilities, the regulators, the consumers, and various interested nongovernmental organizations [NGOs]). They started with a diverse set of knowledgeable representatives from the major local and regional stakeholder groups in New England who each agreed to participate in an interactive team effort to develop the model and guide analysis of options through a set of scenarios. Stakeholders included representatives from regulatory groups, electric industry experts, ISOs, electricity consumers, and others who otherwise would not assemble for a discussion of a common future. In this project, the developers of the system model functioned as a technical support team to enable the work of the stakeholder steering group. Support for the project was initially provided by a group of utilities in the northeastern US.

The initial multi-stakeholder group suggested scenarios that they were interested in exploring. For instance, they asked what would happen if any of the following occurred:

- the proportion of renewable energy in the system doubles,
- grandfathered coal plants are phased out on a 10-year schedule,
- certain nuclear plants are decommissioned,
- primary energy prices vary over wide ranges,
- aggressive DSM programs are pursued,
- more or less electricity is imported from Canada,
- emissions regulations are tightened further.

The basic methodology enabling the analysis follows the lines shown in figure 17.14. The attributes (A^i, A^j, etc.) are chosen so that less is better—for example, lower

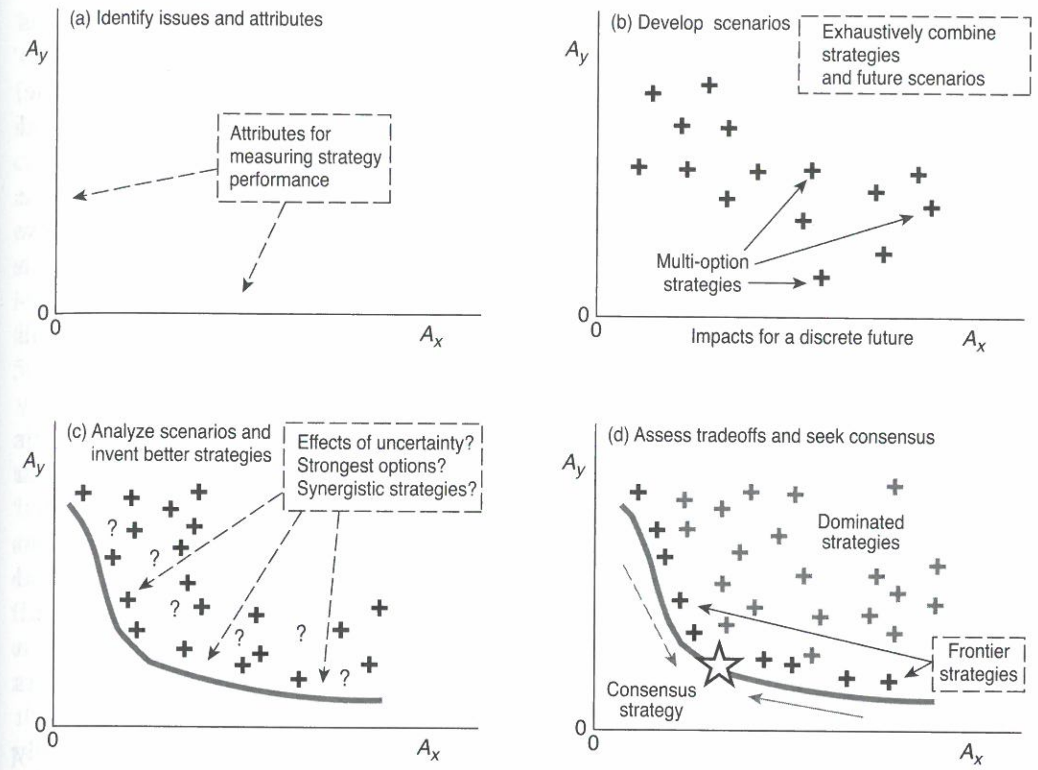


Figure 17.14
Basic elements in performing multiattribute tradeoff analysis in a multi-stakeholder policy debate. Source: Connors (1991).

costs or lower emissions. The group then decides on various options that they wish to explore relating to how the system will operate over the next 20 years. Options may include the types of new generation that are installed, the variability in primary fuel prices, and the DSM programs promoted. All the feasible combinations and permutations of options are identified as individual scenarios, and the model computes the attributes of interest for each scenario.

In step (b) of figure 17.14, the scenarios are plotted for two selected attributes. Similar plots can be made for other pairs of attributes as desired. There is a frontier of options that are cheaper and cleaner (in the case of a cost versus emissions plot), because they dominate other options that provide the same level of emissions at a higher cost or lower emissions at the same cost. As these frontier scenarios are identified in step (c), the steering group discusses their attributes and gains ideas for new options or for synergistic strategies. With multiple attributes of interest, the group examines whether the best strategies for one set of attributes also provides good results for the other attributes of interest. When a final set of dominant strategies is identified, the group considers where they wish to be along the frontier line, which presents, in the case discussed here, costs for different levels of environmental performance.

The method is particularly powerful in getting a group to understand the positions and interests of the other stakeholder participants, in creating new ideas for options that may not have been identified initially, and in building a consensus among the participants. Participants can carry their new understandings back to their individual organizations and raise awareness among all stakeholders.

The Analysis Group for Regional Electricity Alternatives (AGREA) started by identifying the attributes of electricity generation that were of interest to some or all of the group members. Costs and emissions were of prime interest, although other attributes, such as system reliability, were included in other studies. In initial runs with the model, participants matched the model results with their own experiences—in some cases finding ways the model needed improvement and sometimes finding that their own understanding of the system behavior was flawed. As they built confidence in the reliability of the model, they were also able to learn and teach each other about some of the complexities of the system. Regulators learned that tightening emissions regulations on new plants would probably result in increased usage of the older coal plants that were grandfathered, thus actually worsening total emissions. Utilities were able to better understand how their dispatch protocols could be improved to provide better environmental performance at essentially no additional cost (Connors, 1991). Some utilities were surprised to find that they were using gas turbines installed for peaking purposes as baseload power when gas prices were low. The basic techniques used have now been applied to many different scenarios and locations, including Switzerland (Connors, 1996) and Shandong province in China (Connors et al., 2002).

Connors (1996) concludes with the following challenge:

> While the multiattribute framework can be used to evaluate the performance and risks associated with resource choice, a question must be asked. If the development and broad-based application of learning tools like multiattribute tradeoff analysis did not occur in a vertically integrated utility industry, who—if anyone—will promote their development and use once the planning function has become decentralized? [This question becomes even more complex if additional environmental impacts (water, land, habitats, etc.) are added to the evaluation.] While a somewhat rhetorical comment, it raises doubts about who will be responsible for longer-term issues of market coordination, and identifies the need to develop an institutional niche in the restructured electric industry where balanced policies—which give wind and other resources their due—can be evaluated and implemented.

17.6.4 The need for more dynamic utilization of transmission and distribution capacity

Today's electric transmission and distribution systems have very low utilization factors. That is, the ratio of the average power flow to the maximum power flow (at its thermal limit) is about 0.3, which indicates that most of the time the transmission capacity is not fully utilized. Such underutilization is in part the result of rigid reliability requirements. In addition to the thermal limitation on capacity (related to expansion and excessive sagging of the line), these include the need for voltage stability and transient stability. Thermal expansion is the limiting factor in the longest lines (>150 miles between substations); voltage stability is limiting in lines from about 50 to 150 miles; and transient stability is limiting in lines shorter than 50 miles.

Since it is difficult to identify the critical technical problems that impact reliability, much less to understand possible corrective actions to assure high reliability, today's operating practices are based on a simplified deterministic assessment of "worst-case" scenarios. On this basis, the so-called "(N – 1) reliability criteria" evaluates systematically the consequences of failure of any one major component of a system with N major components. This is the key guideline for planning sufficient system capacity, requiring both generation and transmission reserves sufficient to ensure that electricity users are not affected for at least 30 minutes following any large equipment failure.

In practice, the required reserve capacity is determined without including the possibility of additional capacity from adjustments of other resources in the system. The result is underutilization of assets as well as inefficient scheduling of the least expensive and cleanest resources, just in case something fails. This paradigm was useful in earlier T&D systems, before growth in demand began to strain system capacity. Today, with more sophisticated sensors and communication devices deployed for better situational awareness, it is possible to use these measurements for more timely and efficient utilization of both transmission and generation. The US Federal Energy Regulatory Commission (FERC) has estimated that between 10–20% of O&M generation cost could be saved by resorting to more timely decisions as system conditions vary. This, however, requires more sophisticated software for advising system operators of the proximity of hard-to-manage conditions, as well as of the key decisions they could and should take to avoid them.

As society changes its supply mix for electricity generation to include many more intermittent resources (e.g., solar, wind) deployed at large scale, it is going to be difficult enough to balance the system when these resources fail to produce, and practically impossible to identify the worst-case scenarios for the (N – 1) reliability criteria. A shift of paradigm is needed toward software-supported dynamic monitoring and decision systems to sense imbalances in near real time and to adjust other controllable equipment. Since many portions of the US transmission and distribution system are limited in voltage and/or stability, instead of thermally limited (as assumed in the old paradigm), significant improvements of transfer capability are possible when the controllable T&D equipment is continually adjusted as real power is dispatched.

Historically, for equipment such as shunt capacitor banks (CBs), on-load tap-changing transformers (OLTCs), and phase-angle regulators (PARs), in particular, the set points for their local control have been able to maintain the actual voltage magnitudes of CBs and OLTCs as desired by the system operator. However, the communications and automated control of such T&D controllable equipment were not utilized for system management until recently. This advance opens a tremendous potential to adjust the most congested transmission paths by adjusting the critical voltages and line flows of controllable T&D equipment on-line. In order to identify the key equipment and appropriate amounts of set point adjustments, system operators need software that is currently not used by the control centers.

While methods exist for scheduling real power, subject to the transfer limits for real power, optimization of voltage support is not in place. This, in turn, leaves decisions to the system operator, who generally cannot implement the most efficient energy transactions because the voltage support is not optimized. It has recently been shown that opportunities to manage the existing T&D system by adjusting its controllable equipment, so as to enable the most desired energy transactions, could defer major investments in new transmission and distribution infrastructure and, at the same time, enable more efficient utilization of the existing resources.

In the interim, optimizing the existing mechanically controlled T&D equipment can greatly contribute to eliminating voltage-related problems. Implementation is possible at present, and only the right incentives are needed in order to pursue such enhancements in operating the T&D system today. On the other hand, fast power electronically controlled T&D devices, generally known as flexible AC transmission systems (FACTS), could greatly contribute to eliminating critical stability problems as they arise and could enhance the delivery of efficient and clean power. Breakthroughs are needed for making FACTS devices more compact and, ultimately, less expensive. The US Advanced Research Projects Agency–Energy (ARPA-E; see http://arpa-e.energy.gov) has a major program with the aim of making such improvements. Other technologies like voltage compensation devices at substations and phasor measurement units (PMUs) can support voltage and transient stability. A future sustainable electric grid will need wide-area measurement systems (WAMS) to collect and evaluate data from diverse and distributed sensors. Nevertheless, as the transmission and distribution networks are expanded and modernized, new operational algorithms will be important to facilitate system management (MIT, 2011).

The communications, sensing, and coordinated control of FACTS devices, needed for the rapid and large-scale modernization of present T&D systems, are major research and development challenges, as are the operational algorithms. More generally, there are complex tradeoffs between making the T&D system more robust and efficient by investing in new, high-cost infrastructure, on the one hand, or by investing in smarter, software-enabled utilization of the existing infrastructure on the other. The solutions will probably involve both strategies and a shift of operating and planning practice toward coordinating just-in-time (JIT) and just-in-place (JIP) paradigms. This is particularly important as T&D becomes an important enabler of sustainable electricity service (Ilic et al., 2011a; Ilic et al., 2011b).

17.7 Energy Market Impacts on Electricity Generation Options

The low cost of coal has made it the backbone of the electric power industry. However, in the past, costs of coal-fired generation increased because of strict emissions regulations. Also, demand growth slowed, so that the major capital costs associated with large coal plants were hard to justify. Adding smaller and cheaper gas-fired units became the industry's new capacity choice.

The major source of uncertainty in the COE from natural-gas-fired electric power plants is fuel costs. Assuming stable coal prices, a $4+/MMBtu gas price is an approximate threshold above which coal-based generation is economically favored. An understanding of natural gas markets, and in particular of gas deliverability at various prices, is important to gauging the profitability and sustainability of power generation options and of projects to supply new gas. Utilitarian analysis of prospective energy markets is challenging, owing in part to appreciable uncertainty regarding future economic progress, social and political behavior, and advances in technology. Nevertheless, careful exegesis of publicly accessible data can provide valuable insight into short- and long-run planning.

Demand behavior From 1980 to 1993, there was a significant excess of gas in the US. This "gas bubble" had several causes. Wellhead price controls were removed, creating a competitive market that was more responsive to prices than to demand. Anticipated growth in demand was delayed by repowering of coal-fired electric-generating stations and fewer shutdowns of nuclear power plants than expected. In recent years, several forces conspired to eradicate this surplus and to push demand and prices upward. A major driver has been increasing demand from electric power generators spurred on by economic expansion and population growth, especially in California. Cold winters and higher than normal drawdowns of hydro reservoirs in the Pacific Northwest exacerbated the situation (M. C. Lynch, WEFA, personal communication, 2001). Despite the US economic slowdown, electric-sector demand for gas will likely continue to grow, because gas-fired plants offer electricity generators lower capital costs as well as the option of staging capacity expansions in smaller increments, reducing the risk of overbuilding. Further, there is considerable consumer and political pressure to correct for the underbuilding of electric generating capacity in the 1990s.

In 2010, natural gas prices ranged from $6–8/MMBtu; coal prices were in the $2–2.50/MMBtu range, and electricity demand growth had dwindled due to an economic recession. Happily, North American gas reserves are plentiful—about 2,000 trillion cubic feet (tcf), or about 80 years supply at recent production rates—and economic production from plentiful oil gas shales is also expanding. Canadian domestic use will grow, but this will still leave ample stocks for export (see below). But how much gas will be available in the lower 48 states, when, and at what price? The answers will be determined by complex interactions among various forces that govern what Jensen (2001) describes as a "new North American natural gas economy." Jensen argues that fresh thinking about the behavior of the natural gas market under competition provides a more consistent understanding of prospective gas availability and the profit potential of long-term gas supply projects.

Short-run market behavior—coupling with oil prices Real-world, short-term gas supply and demand relationships are far more complex than the behavior implicit in the simple "X-like" supply/demand curves found in introductory economics textbooks. Jensen (2001) argues that it is not the absolute price of gas but rather the gas-to-oil price ratio (GOPR) that is important in determining gas demand. Under gas surpluses, gas prices become decoupled from oil prices and there can be gas-to-gas competition, as occurred in the US for much of the 1990s. Gas prices then decline substantially. However, when there is oil-to-gas competition, price buffering is provided by the electricity generators' ability to replace gas with petroleum-derived fuels. In 2010, with the US importing a substantial amount of petroleum to fuel the transportation sector, it is unlikely that there will be much more new oil-fired electric generation.

To expand gas production rates, reserve additions must increase, which means discovery rates must accelerate. However, between about 1985 and 2000, surplus gas in the US and Canada provided little incentive for intense exploration. Today, both countries seem to have left their days of excess gas behind. The US gas bubble has ended. After 1985, Canada began working off its large inventory of gas development prospects. Between 1978 and 1985, production from these wells had been stultified by export limits and domestic set-asides. The US and Canada may even be approaching "technical" limits on deliverability (yearly production rate as a percentage of proved reserves), which are set by geology and technology. Economics will provide an ultimate limit on deliverability (i.e., when sales from incremental production of gas can no longer provide acceptable rates of return on the cost to produce that gas). Canada has also started to use some remote natural

gas as a heating source to produce tar sand petroleum for conversion to automotive fuel. The US is now starting to use its shale gas reserves.

Jensen (2001) believes that, due to environmental concerns, neither nuclear nor coal-based electric power generation will significantly moderate the US electric sector's demand for natural gas. This contrasts with Japan, where coal and nuclear are combined to confine expensive LNG imports to about a 30% market share, largely intermediate load dispatch. Others, including Ellerman (2001, and personal communication, February 7, 2001), envisage a greater market share for coal in baseload US electricity generation and, thus, in tempering at least some of the demand growth for natural gas in this sector. Interestingly, the fear or reality of sustained upward movement of gas prices may have begun to challenge the long-run stability of coal prices. Ellerman (2001) points out that recent increases in the prices of coal from major US coal provinces show a strong correlation with high gas prices in the regions serviced by that coal. For example, Powder River Basin coal, which serves Texas, Oklahoma, and Arkansas, has tripled in price, and southern Appalachian coal has doubled. Prices of northern Appalachian coal, which serves regions in less competition with gas-fired electric power production, have gone up only 50%.

When gas is not in surplus, short-run prices can be buffered by electricity generators' substituting residual fuel oil or middle distillate oil (MDO) for gas when gas prices (per MMBtu) rise to about 90% and 140%, respectively, of refiners' acquisition cost (RAC) for crude oil (140% of RAC corresponds to $6.00/MMBtu gas for $25/bbl oil). With increases in oil prices to $60–90/bbl, natural gas is a competitive fuel. At higher gas price levels, incentives are spurring development of the extensive US reserves of shale gas; these new supplies have stabilized gas prices as of 2011. To avoid service interruptions and unpopular rate increases, gas-dependent wholesalers and retailers of electricity must understand the gas markets in the lower 48 US states. A diverse national and regional portfolio of electricity supply options will hedge against vicissitudes in fuel markets and public acceptance, while the US would retain its ability to provide affordable electricity to all consumers. Central hydro, nuclear, coal, and gas will contribute, as will distributed generation sources and various renewables, when economical. However, possible future intervention in these markets to reduce CO_2 emissions will have major implications for market competition among fuels. Until the possibility and nature of such policies are clarified, investors will be reluctant to make major new capital investments in electric power generation capacity. Some of the new technologies needed are not yet commercial, and the government, along with private investors, is supporting some of the RD&D needed to advance the state of development or to subsidize early deployment. In the meantime, the electric power industry will be operating under additional risks and uncertainties.

17.8 Sustainability Attributes

17.8.1 Improved resource utilization

Because energy storage generally increases system reliability and the ability to meet varying demands, one usually gets higher levels of resource utilization with well-designed storage in place. In particular, access to storage enables intermittent renewable technologies like wind, solar, and hydro to be more effective and can lead to higher efficiency in energy capture and utilization. For example, coupling thermal storage with a solar system can avoid the use of backup systems to provide energy when demand is high at night or on a cloudy day. In another setting, having a flywheel, supercapacitor, or battery system installed on a hybrid vehicle reduces the size, fuel consumption, and emissions of the primary engine. As we have seen, the ability to use CHP systems with distributed energy generation can have an enormous positive impact on overall efficiency.

17.8.2 Environmental, safety, and health concerns

Energy storage, transmission, and distribution systems are part of the overall infrastructure; as such, they have an impact on the environment. Impacts can be associated with land use, as in the need to build a pumped hydropower storage installation or the right of way required for an oil or gas pipeline or for a high-voltage electric transmission line. Impacts also come with the actual process of transporting the energy itself. One need only remember the fate of the *Exxon Valdez* in Prince William Sound in 1989 to understand the environmental risks associated with having millions of barrels of crude oil at sea in a large fleet of oceangoing supertankers.

A number of other potential hazards are associated with the storage and transmission of natural gas and other energy forms. For instance, explosive mixtures of natural gas and air occur on a regular basis throughout the world. Given the potency of the methane molecule as a greenhouse gas—it is about 50 times greater than carbon dioxide—leaks from a natural gas pipeline and distribution system could have a significant impact that would offset its favorable hydrogen-to-carbon ratio over coal.

There are significant concerns about the environmental, safety, and potential health risks of high-voltage overhead transmission of electric power. Some US experts have suggested that it may be easier from a regulatory or permitting standpoint to site a smaller-scale, fossil-fired generation plant than it would be to build a new aboveground transmission line. This trend favors the development of distributed generation as a means to achieve capacity expansion on existing grids. Distributed systems also provide a more robust infrastructure that would be more secure against natural disasters or acts of sabotage. Furthermore, linkages between

natural gas and electricity infrastructures allow better utilization of both systems when the peak period for one coincides with a low-usage period for the other.

Increased use of biofuels for transportation (chapters 10 and 18) may require new T&D infrastructure if the fuel of choice is incompatible with the present distribution infrastructures for gasoline and diesel fuel. An example is ethanol in concentrations above about 10–20% in gasoline. Because of its affinity for water and the phase separation characteristics at higher concentrations in gasoline mixtures, ethanol appears incompatible with existing petroleum distribution systems. An option is to convert biomass to a synfuel that is compatible with systems designed for petroleum. With present technologies, this option appears less efficient and more costly than ethanol production from biomass feedstocks, but rapid advances in technology may change these tradeoffs in the future.

If hydrogen is widely used as an energy carrier for transportation fuel in the future (chapter 18), the challenge of distributing this fuel will arise. Hydrogen could be delivered either by large transmission networks from central hydrogen-generating plants or by distribution systems associated with smaller distributed facilities for hydrogen production. Should production emanate from natural gas, there will be impacts on present natural gas distribution systems. Likewise, if electrolysis of water is involved, impacts and interconnections will occur with existing electric power systems and water systems. These infrastructures will be an important part of successful widespread development—and life-cycle issues of land use, economics, and safety will need serious attention.

Another evolving storage and transmission system is associated with the increasing interest in using carbon capture and storage technologies as a way to continue using fossil fuels with lower CO_2 emissions to the atmosphere (chapter 8). Coal (and perhaps natural gas) power plants can be designed or possibly retrofitted to separate CO_2 from the gases discharged to the atmosphere; the CO_2 can then be disposed of by injection into secure formations deep underground, such as saline aquifers, or sent to oil fields, where it could be used for enhanced oil recovery. Since coal power plants and suitable disposal sites are widely distributed throughout the US, such a CO_2-disposal system would differ from national energy T&D networks in that regional pipelines would gather CO_2 from power plants and other industrial sources for disposal at sites within a few hundred miles.

17.8.3 Economic and operational attributes

The capital costs for some storage systems can be high, particularly for advanced flywheels, pumped hydro, compressed-air energy storage (CAES), and superconducting magnetic energy storage (SMES). These costs need to be weighed against the benefits of the overall investment, which can be significant. For example, electricity and thermal energy storage provide several positive attributes that affect the economics of an electrical utility system. These include both capacity and operating benefits. By adding storage, expansions to existing generation and transmission systems can be avoided. As described in a review by Schoenung et al. (1996), adding capacity as gas-fired generation would involve \$500–600/kW$_e$ and adding transmission lines about \$200/kW$_e$ or more. Thus, the investment required in the energy storage system has a built-in avoided cost that significantly improves the economics of the investment. Furthermore, there are other operational benefits that indirectly affect the economics (see Schoenung et al., 1996, for more details). They include:

1. Load following during dynamic shifts in power distribution that occur on the electrical grid;
2. Spinning reserve that can supply needed generation capacity if sudden outages occur;
3. Power-quality improvements;
4. Lower operating and maintenance costs;
5. Reduced emissions by operating existing generation equipment at or near their peak performance conditions.

17.9 Opportunities for Advancement of Sustainable Energy Infrastructures

The value of having workable energy storage systems is clear. Because they improve the utilization of natural resources and overall system efficiency, the development of storage technologies should be encouraged from a sustainability standpoint. However, storage is not often viewed as a focus area for R&D within compartmentalized scientific bureaucracies, and it suffers from a lack of support. One could make the case that storage should receive accelerated support because of its cross-cutting effects on the performance of energy systems. R&D programs need to be balanced among both small (e.g., batteries, flywheels) and large (e.g., pumped hydropower, CAES, SMES) storage technologies.

This chapter documents the necessity of being able to deliver energy reliably to customers with an operating transmission and distribution network for a variety of energy types. Without integrated, secure, and reliable infrastructures, the usefulness of all energy technologies would be severely compromised. In industrialized countries, these infrastructures are highly developed as a result of significant capital investment and governmental oversight.

From a sustainability perspective, it may be necessary to change existing infrastructures or to develop completely new ones to achieve higher levels of performance. For example, if the US restructured its electricity supply system to a more distributed network of generation and transmission systems, it would facilitate the capture and storage of renewable energy, the development of hybrid systems, and an expansion of combined heat and power applications for residential buildings and industrial processes.

However, there is considerable inertia in many current systems with their focus on electricity only and on central-station generation. For example, North Dakota is a sparsely populated state with an extremely high-quality wind resource. In addition, since the major industry in the state is farming, there is much open land available for siting wind turbines and an attractive social and economic climate that would embrace the development of wind power as another exportable product. In fact, the estimated wind-power generation capacity is in the range of 100,000 MW$_e$ or more with acceptable capital investments of about \$400–800/kW$_e$. However, North Dakota has few electric power transmission lines available for bringing power to large load centers located in other states. Adding storage systems would greatly improve the attractiveness of wind as a substantial baseload contributor to meet the nation's demand for electricity. Thus, to deploy wind at a level in North Dakota that would make a difference for the country would require policies and capital investments at a national level to develop the needed infrastructure.

The North Dakota example is easily transferred to other areas of the US and to other countries with established infrastructures. In developing countries, although there is no existing system to change, enlightened policies and approaches are still needed to reach a more sustainable outcome. A strong force in making decisions today is the desire to have the initial capital cost, not the full life-cycle cost, as low as possible. Such attitudes usually do not favor developing energy storage technologies or the use of more distributed energy systems.

Finally, practitioners of energy sustainability must remember that investments in new technologies and in new infrastructure will inevitably increase the price of energy to consumers and will encourage more efficient use of energy. The most sustainable use of energy is "energy use avoided"! The recent National Academies report *America's Energy Future* (NRC, 2009) suggests that efficiency improvements in the end-use sectors that are discussed in chapters 18 through 20 could save about one-third of present energy use with no or only modest cost increases.

Problems

17.1 You have been asked to design a rotating mechanical flywheel to supply 1 MW$_e$ of power for one minute. You have two choices for materials—steel and a proprietary composite (Rx-2002). The properties of both materials are given below. Key parameters to specify in your design are the volume and area (radius), mass, and maximum rotational speed. Discuss the issues that led to your final design. Are there other factors that need to be considered before your flywheel is practical?

Density: steel = 7.8 g/cm^3; Rx-2002 = 2.0 g/cm^3
Maximum tensile strength: steel = 550 MPa; Rx-2002 = 2,100 MPa

17.2 A large pumped hydropower energy storage system is being considered for a site in Colorado near Denver where peak demand can be high at times. The plan calls for 1,000 MW$_e$ of dispatchable power for up to six hours. The proposed design would have two reservoirs, one located at Denver's mile-high elevation of 5,280 ft and the other in the foothills of the Front Range of the Rocky Mountains at an elevation of 8,000 ft. Estimate the minimum required volume of water that would need to be stored (state and justify all assumptions made). Assuming a margin of safety of 50% and an average water depth of 20 ft in both reservoirs, how large an area does this system impact? Are there other issues that may be important in assessing the sustainability attributes of this proposal?

17.3 Compressed-air energy storage (CAES) is being considered as a means for storing energy during off-peak periods and for generating electric power during peak demand periods. The Alabama Electric Cooperative has adopted a novel scheme that pumps air underground into a huge cavern created deep in a solid salt deposit. The cavern is a cylinder about 300 m tall by 80 m in diameter and has an internal volume of about 1.5 $\times 10^6$ m^3. Maximum storage pressures of 100 bar are possible using multistage compressors/turbine units that operate with equivalent efficiencies of $\eta_{compressor} = \eta_{turbine} = 0.85$. The ambient air temperature is 25°C, while the salt cavern's natural temperature is about 300°C as a result of prevailing geologic conditions. To keep the cavern from collapsing, a minimum pressurization level of 2 bar is required. Note that the thermal conductivity of the salt is high, and the thickness (radial and lateral extent) of the salt deposit is large relative to the dimensions of the cavity.

In the first part of the cycle, excess electrical power being produced during an off-peak period is used to operate the compressor to inject air into the cavern to pressurize it to 100 bar. In the final part of the cycle, power is produced during a peak demand period by expanding the cavern's pressurized air in a turbine (which is actually the compressor operating in reverse) to generate electric power.

Provide an expression for the net work produced during a single full cycle of energy storage and recovery and describe how you would estimate the net work produced. Please list all assumptions and simplifications used in your analysis. Your answer may be expressed as an integral equation involving the following variables: $\kappa\ (\equiv C_p/C_v)$, cavern volume ($\underline{V}_{cavern}$), T_{cavern}, $T_{ambient}$, $P_{cavern,\,max}$, $P_{cavern,\,min}$, $\eta_{compressor}$, $\eta_{turbine}$.

17.4 Electra and Caty Jones have a great idea that they feel will "revolutionize" the way electricity is produced by "avoiding the shortcomings of existing heat-to-power concepts that are constrained by the Second Law of Thermodynamics." In today's thermal cycles, fossil fuels are combusted in air to produce heat that is supplied to a practical power cycle to generate electricity. Typical fossil-fuel-fired power cycles include steam Rankine, gas turbine (Brayton type), or combined gas turbine–steam Rankine.

As an alternative to these cycles, Electra and Caty have invented an advanced fuel cell, which they call Electrocat, that isothermally converts natural gas, CH_4 (a common household fuel), directly to electricity using electrocatalyzed oxidation reactions in a proprietary electrolyte. Special proprietary catalysts promote the following redox reactions:

anode:	$CH_4 + 2H_2O \rightarrow CO_2 + 8e^- + 8H^+$
cathode:	$8H^+ + 8e^- + 2O_2 \rightarrow 4H_2O$
total reaction:	$CH_4 + 2O_2 \rightarrow CO_2 + 2\,H_2O$

According to their claims, the Electrocat's efficiency approaches 100% in recent tests using the conventional definition of cycle efficiency given in chapter 3.

In these same tests, the Electrocat produced 0.75 MW$_e$ of power continuously with a feed rate of 1 mole of CH_4 per second.

Given the promise of obtaining electric power directly from this fuel cell, MITY Industries is considering making a large investment in Electrocat technology. However, a few of MITY's top executives are skeptical of the Electrocat, and they need your help to answer a few basic questions. In order to fully understand your answers, they have requested that you state and justify any assumptions you make.

a. What is the maximum power-producing potential of the Electrocat for a feed rate of 1 mole per second of CH_4 at ambient temperatures (25°C)?
b. What is the utilization efficiency (η_u) of the Electrocat?
c. Is their claim that η_{cycle} approaches 100% thermodynamically possible? Could η_{cycle} exceed 100%? Explain.
d. What are possible sources of loss of work producing potential in the Electrocat?
e. By making a First and/or Second Law analysis, determine whether it is possible to use the Electrocat for process cooling or heating as well as electric power production.

Property data for CH_4, CO_2, H_2O, and other compounds and ions are given below:
For pure water (H_2O): $\Delta G_{vaporization} = 8.58$ kJ/mol and $\Delta H_{vaporization} = 44.0$ kJ/mol.
Standard Gibbs energies and enthalpies of formation and average ideal-gas state heat capacities at 298 K and 1 bar:

Compound	ΔG_f^o kJ/mol	ΔH_f^o kJ/mol	ΔS_f^o J/mol K	$\langle C_p^o \rangle$ J/mol K
$CO_2(g)$	–394.6	–393.8	2.68	36.8
$CO(g)$	–137.4	–110.6	89.93	29.3
$CH_4(g)$	–50.9	–74.9	–80.54	51.8
$N_2(g)$	0	0	0	29.3
$O_2(g)$	0	0	0	29.3
$H_2(g)$	0	0	0	22.15
$H_2O(g)$	–228.8	–242.0	–44.30	36.8
$H_2O(l)$	–237.1	–286.0	–164.09	75.3
$H^+_{(aq)}$	1517.0	–143.6	–5.57	–
$OH^-_{(aq)}$	–138.7	1536.2	5.62	–

17.5 Cornell University is considering a plan to utilize the cold temperatures available near the bottom of Lake Cayuga. The campus is located about 490 ft (150 m) above the surface of the lake. The average depth of the lake is about 210 ft (65 m). The Cornell plan would utilize the cool lake temperatures to assist central air-conditioning needs on campus. You have been asked to evaluate a critical step in the proposed process. At a steady flow of 20 kg/s, warm water is discharged to the lake at about 60°F and cooler water at 40°F is pumped back to the central air-conditioning plant on campus. Right now the warm water is released to the lake through an insulated expansion valve. You are to investigate the possibility of generating work to help offset the pumping power requirements. Consider using a hydraulic turbine to recover some of the PE from the elevation drop. MITY Industries has an adequate supply of turbines and pumps available with efficiencies of 90%, i.e.,

$$(\eta_P \eta_t = 0.90 \text{ and } \dot{W}_{pump} = \dot{W}_{ideal} / \eta_p \text{ and } \dot{W}_{turbine} = \eta_t \dot{W}_{ideal})$$

where $\dot{W}_{ideal}$ refers to reversible, isothermal operation. All sizes of ultra-high-efficiency reversible Carnot heat engines are also available. Is it possible to operate this system without external power? Explain your answer. In your analysis you can assume that the heat capacity and density of liquid water are constant, at 4,200 J/kgK and 1,000 kg/m, respectively.

17.6 Storage batteries that have small volumes and masses and high energy storage densities are in demand for both electric and hybrid vehicle applications. Based on your assessment of evolving technologies for advanced electrochemical batteries, estimate the smallest volume and weight battery system that might be available in the foreseeable future to provide full vehicle power for one hour of urban commuting in a family-sized five-passenger sedan. You can assume that minimum power levels for such a vehicle are 20 hp at average speeds and 80 hp at peak acceleration. A dynamic flywheel or super-capacitor storage system integrated with a regenerative braking device can also be assumed to be on board to offset the peak loads by 50% or so.

17.7 Estimate the amount of coal delivered daily to the 1,500 MW_e electric power plant in Nevada through the Black Mesa coal-water slurry pipeline. How many rail cars per day is this equivalent to, assuming each car has a capacity of 100 dry tons of coal? How much water is pumped and consumed each day? Does this pose a sustainability issue for this location? State and justify all other assumptions made.

17.8 Estimate the resistive losses over a 100-mile-long, 100 MW_e, DC transmission line constructed of two lines of copper conductor wire with an effective diameter of 2 cm at both the 100 kV and 250 kV levels. The electrical resistivity of copper is about 1.7 microhm-cm and its density is 0.321 lb/in^3.

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