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11 Geothermal Energy

Even now, in some places, nearly molten rock resides as little as 2–5 miles below the surface.
—http://yellowstone.net/geysers

11.1 Characterization of Geothermal Resource Types

11.1.1 Definition in general

In general terms, geothermal energy consists of the thermal energy stored in the earth's crust.[1] Practically speaking, the exact specification of a geothermal resource depends in part on the specific application or energy service that is provided. Thermal energy in the earth is distributed between the constituent host rock and the natural fluids that are contained in fractures and pores at temperatures above some specified reference temperature which is often selected at ambient levels. These fluids are mostly water with varying amounts of dissolved salts. Typically, in their natural *in situ* state, they are present as a liquid or supercritical fluid phase but sometimes may consist of a saturated or superheated steam vapor phase. Most geothermal resources presently used for electric power generation result from the intrusion of magma (molten rock) from great depths (>30 km) into the earth's crust at or near tectonic plate boundaries, while others are associated with recent volcanism.

Geothermal fluids of natural origin have been used for cooking and bathing since before the beginning of recorded history, but it was not until the early nineteenth century that geothermal energy was harnessed for industrial purposes. One of the first cases was the use of geothermal steam for heating evaporating ponds at the boric acid works near Larderello, Italy. In 1902, electricity was first produced using geothermal steam at Larderello. Since then, other developments, such as the steam field at The Geysers, California, and the hot-water systems in Wairakei, New Zealand, Cerro Prieto, Mexico, Reykjavik, Iceland, and in Indonesia and the Philippines have led to an installed world electric-generating capacity in 2011 of about

1 Much of what is included in this chapter updates earlier review articles and books coauthored with other colleagues. In that context, we want to acknowledge their contributions, in particular: *Geothermal Energy* by H. C. H. Armstead (1983); *Heat Mining* by H. C. H. Armstead and J. W. Tester (1987); "Geothermal Energy" (1982), a chapter in *Encyclopedia of Chemical Technology*, by J. W. Tester and C. O. Grigsby (1997); chapter 4 in IPCC (2011); a review article by Mock, Tester, and Wright (1997); and a recent summary of direct use by Lund, Freeston, and Boyd (2010). The MIT report *The Future of Geothermal Energy* (MIT, 2006) contains more extensive discussions of technologies as well as updated assessments of US resources, economic analyses, and projections for future large-scale deployment in the US to 2050.

11,000 MW_e and a direct-use, nonelectric capacity of more than 100,000 MW_{th} (thermal megawatts of power). Rapid growth in geothermal electric and direct-use capacity is expected in the coming decades, given that many high-grade, underutilized resources have been identified globally.

The source and transport mechanisms of geothermal heat are unique to this energy source. Heat flows through the crust of the earth at an average rate of 0.65 W/m^2 under the continents and 0.101 W/m^2 through the ocean floor. The result is a global terrestrial heat flow rate of approximately 1,400 EJ/y. With the continents covering about 30% of the earth's surface, the total terrestrial heat flow under continents is estimated at 315 EJ/y (Stefansson, 2005). The resulting average geothermal temperature gradient ranges from 25° to 30°C per km.

The intrusion of large masses of molten rock can increase heat flow and gradients locally, but, for most of the continental crust, the heat flow is due to upward convection and conduction of heat from the hot mantle and core of the earth and from heat generated by the decay of radioactive elements in the crust, particularly isotopes of potassium, uranium, and thorium. Local and regional geologic and tectonic phenomena play a major role in determining the location (depth and position) and quality (fluid chemistry and temperature) of a particular resource. For example, regions of higher-than-normal heat flow are associated with tectonic plate boundaries and with areas of geologically recent volcanic events (more recent than about one million years in the case of large magmatic intrusions of 10–100 km^3). This is why people frequently associate geothermal energy with specific places such as Iceland, New Zealand, or Japan (plate boundaries) or with Yellowstone National Park or the Larderello field in Italy (recent volcanism), while they neglect to consider geothermal energy opportunities in other regions.

In all cases, certain conditions must be met before one has a viable geothermal resource. The first requirement is accessibility. This is usually achieved by drilling to depths of interest—frequently using conventional methods similar to those used to extract oil and gas from underground reservoirs. The second requirement is sufficient reservoir productivity, which depends on the type of geothermal system that is being exploited. For indigenous resources, one normally needs to have sufficient quantities of hot, pressurized natural fluid contained in a confined aquifer with high rock permeability and porosity to insure long-term production at economically acceptable levels. In other situations, one only needs to have a sufficiently hot rock reservoir that can be artificially stimulated to produce a system for extracting energy at acceptable rates.

Geothermal energy has been regarded as a renewable resource, yet it is clearly different from solar, wind, and biomass. Stored thermal energy is extracted from the active reservoir at rates that are significantly higher than the natural heat flow, creating locally cooler regions. Effectively, heat has been "mined" from these zones. But, in contrast to fossil mineral resources which are finite and spatially restricted, stored thermal energy in the earth is ubiquitous, and as a result the depleted zones immediately begin to recover. These cooler and lower-pressure depleted zones lead to gradients that result in continuous recharge by conduction from hotter rock and by convection and advection of fluid from surrounding hotter regions. The time scales for thermal and pressure recovery have been found to be similar to those for energy production in operating geothermal systems, particularly within a porous hydrothermal reservoir where convection of natural fluids from hotter regions is important (Stefansson, 2000). Even in conduction-dominated reservoirs, sustainable operation is possible, as shown by modeling of thermal transients in representative systems (Fox, Sutter, and Tester, 2011). Other modeling studies (Pritchett, 1998) have shown that this geothermal resource exploitation can be economically feasible and still be renewable on a timescale useful to society, when nonproductive recovery periods are considered. Geothermal energy is evaluated in detail in a recent comprehensive special report on renewable energy sources and climate change mitigation (IPCC, 2011).

In developing geothermal energy resources, "hot" is a relative term, as it depends on the specific application. The geothermal resource actually spans a continuum in at least three dimensions: temperature, depth, and permeability/porosity (see figure 11.1). Low-grade systems involve temperatures from just above ambient to about

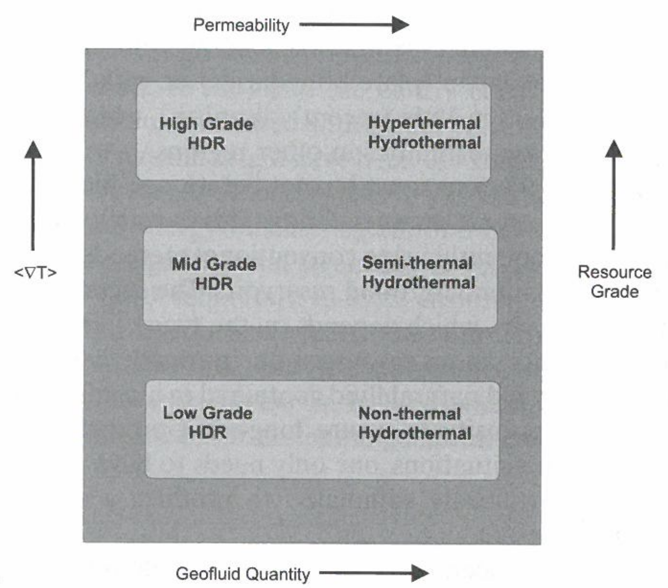

Figure 11.1
The geothermal continuum characterizes the resource in three dimensions: temperature gradient (∇T), geofluid quantity, and permeability/porosity.

150°C, which may or may not contain natural fluids. The geothermal gradient $\nabla T \equiv \partial T/\partial Z$ quantitatively establishes the relationship between temperature (T) and depth (Z). Generally, low-grade systems have lower gradients and are located deeper in the crust. If fluids are not present, then *in situ* permeabilities and porosities are intrinsically low or the reservoir system is located above the natural water table. The converse is true if natural fluids are available for heat extraction. High-grade resources are at the other end of the continuum, characterized by hot fluids contained in high-permeability and high-porosity host rock and at relatively shallow depths (typically less than 3 km). Geochemistry also plays a role. Reservoirs that spontaneously produce fluids of low salinity under artesian pressure and low concentrations of dissolved noncondensable gases are easier to exploit. If such systems are formed with high temperatures (>250°C) at shallow depths, then the resource grade is at its highest condition.

Thermal energy is extracted from the reservoir either by coupled transport processes, such as convective heat transfer in porous and/or fractured regions of rock, or by conduction through the rock itself. If the physical extent and heat content of a deposit are large enough and the deposit is near the surface, a heat-extraction scheme must be designed based upon the hydrologic and geologic situation, including the *in situ* rock properties. After such a scheme is successfully implemented, hot water or steam is normally produced at the surface and converted into a marketable product (e.g., electricity, process heat, or space heat). Also, spent fluids are normally reinjected to avoid surface discharges that could have environmental impacts. Many aspects of geothermal heat extraction are similar to those found in the oil, gas, coal, and mining industries. Because of these similarities, equipment, techniques, and terminology have been borrowed or adapted for use in geothermal development, a fact that has accelerated the development of geothermal resources.

Commercial utilization of the resources requires that the process be economically competitive. Consequently, the commercial geothermal systems developed to date have been limited to a relatively few, accessible, high-grade deposits scattered throughout the world. Improvements in extraction technology to lower production costs or increases in the prices for conventional fuels would make lower-grade geothermal resources commercially feasible.

There are two basic types of geothermal systems: those that spontaneously produce hot fluid (steam or water) from a reservoir and those that do not. Systems that produce fluid spontaneously are obviously easier to exploit. However, these natural hydrothermal systems are not always located near a user. For example, of the 11 most promising new geothermal areas in the US, six are within about 400 km of Los Angeles, California. The other five are all more than 400 km from any city with a population greater than 300,000. Furthermore, nine of the ten most populous cities in the US are more than 800 km from any known high-temperature, natural geothermal system. Economic utilization of these remote hydrothermal systems necessarily involves the generation and transmission of electricity rather than direct use of the geothermal fluid for space or process heating. A system of the second type, one lacking sufficient quantities of hot fluids, presents somewhat different challenges with respect to heat extraction, but because of the broader-based location of such resources, the problem of remoteness is partially alleviated.

Geothermal resources are commonly divided into four categories: hydrothermal, geopressured, hot dry rock, and magma. The characteristics of each are discussed in the sections that follow. Hydrothermal systems are commercially in use today, geopressured systems are being explored for limited future use, and hot dry rock appears to offer future promise through application of enhanced or engineered geothermal systems (EGS). The US geothermal energy potential is assessed in three recent studies (MIT, 2006; NRC, 2009a; NRC, 2009b).

11.1.2 Natural hydrothermal systems

Systems that spontaneously produce hot fluids are called *hydrothermal* or *convection-dominated*. Hydrothermal systems require a source of heat (usually a magmatic intrusion at depth), formations with enough permeability to allow fluid mobility, an adequate supply of indigenous fluid (water or steam), sufficient contact surface, time for the fluid to be heated, and a return path to the surface (see figure 11.2). These systems are frequently located in or near zones of recent volcanism and tectonism (mountain building) that are associated with the boundaries of crustal plates (Muffler, 1993; Healy, 1975; White, 1973; Tamrazyan, 1970). In addition to providing sources of heat, crustal plate margins are areas where tectonic forces have caused considerable fracturing of rock and high local permeability. Indeed, it is believed that the contributions of faults and joints to *in situ* permeability are far more important than those from intergranular (matrix) permeability.

Water or steam in hydrothermal systems is usually of meteoric origin, typically located at depths of 1–4 km at temperatures up to 350°C (Mock, Tester, and Wright, 1997; Kavlakoglu, 1970; Craig, 1963). Water falls as rain or snow and percolates downward through sediments or fissures until it comes to a heat source. There, it is heated and buoyantly rises toward the surface where it usually appears as geysers, hot springs, fumaroles, or solfataras.

If the pressure on the fluid in the reservoir is insufficient to prevent boiling, a vapor phase forms in the upper portion of the reservoir. This vapor phase consists of steam (often superheated or dry) and noncondensable gases that separate from the liquid phase. Most of the dissolved minerals concentrate in the liquid phase, leaving the vapor relatively free of dissolved solids. Hydrothermal systems that produce superheated steam are called vapor-dominated. These systems are the

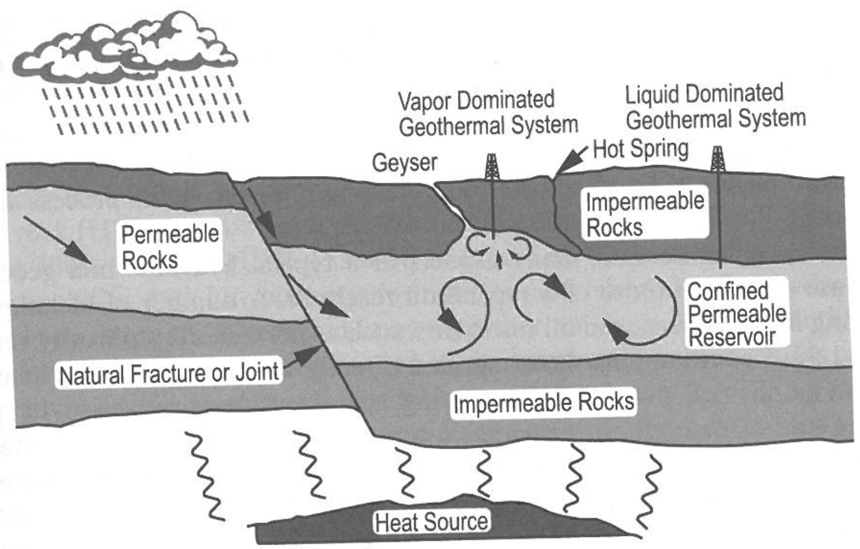

Figure 11.2
Typical features of a natural hydrothermal geothermal reservoir system. Adapted from Mock, Tester, and Wright (1997). Reprinted with permission of *Annual Review of Energy and the Environment*.

easiest and most efficient to exploit for electricity generation because the steam can be transported to low-pressure steam turbines and expanded directly with little risk of scaling or turbine blade damage. High-grade, vapor-dominated systems occur rarely, and several have been developed for baseload electricity generation. The major ones are the Geysers field in California, the Larderello field in Italy, and the Matsukawa field in Japan.

Systems that are pressurized above the vapor pressure do not form a vapor cap, and production from these types of fields consists of hot water or a mixture of hot water and steam. Such liquid-dominated resources are common and widely distributed. Because dissolved solids remain in the liquid phase, liquid-dominated systems can pose serious scaling and corrosion problems in surface piping systems and in production and injection wells. If the fluids are not reinjected, they can pose a waste disposal problem. Usually, the fluid in liquid-dominated systems is flashed (or subjected to a pressure drop that allows a separate vapor phase to form) and separated so that the vapor phase can be piped directly to the turbine generator. The liquid may be flashed more than once (multistage flashing), but ultimately a significant fraction of the hot water and minerals remains to be disposed of by release to surface waters, reinjection, evaporation, or some alternative use, such as process or space heating.

High-quality liquid-dominated fields containing relatively low-salinity water under pressure at temperatures up to 350°C have been identified in many regions, including the western US, New Zealand, Iceland, Indonesia, the Philippines, Italy, Turkey, and several countries in eastern Africa. Liquid-dominated resources with fluid temperatures ranging from about 80° to 300°C are being used commercially throughout the world for generating electricity and for providing process and residential heat.

As shown in figure 11.2, many aspects of a typical hydrothermal geothermal system are similar to those of a typical oil reservoir. A number of techniques for measuring field properties in oil reservoirs, such as permeability, porosity, reservoir size, and fluid content, have been applied directly to hydrothermal systems with success. Geophysical prospecting involving heat flow, electrical resistivity, gravity mapping, and other methods provide exploration data for inferring the extent and depth of a thermal anomaly (Wright, 1995; Rowley, 1982). Geochemical techniques, including geothermometry, stable isotope geochemistry, analysis of dissolved gases, and ratios of major elements in hot springs, are also used to locate and define geothermal fields.

11.1.3 Geopressured systems

Large sediment-filled reservoirs containing pore fluids under confining pressures much greater than the hydrostatic head are called geopressured basins. The sediments usually consist of sandstones and shales along with other sedimentary rock types that are more or less interbedded. Generally, the fluid contained in massive sandstone sediments is under near-hydrostatic pressure and is mobile, owing to relatively high permeability. The fluids contained in sandstone-shale and massive shale facies are generally overpressured by up to 60 MPa (600 bar) at temperatures of 150–180°C. These higher temperatures are caused, at least partially, by the low thermal conductivity of shale, which gives an apparent high-geothermal gradient. The heat flow is actually near normal. Pressures in the Texas and Louisiana geopressured reservoirs are expected to approach lithostatic pressure. The lithostatic pressure gradient in this Gulf Coast region is about 23 kPa/m (1 psi/ft).

In addition to hot water under pressure, geopressured reservoirs usually contain methane in solution. For the purposes of estimating the geopressured resource, the geofluids are usually assumed to be saturated with methane with (6.9–8.9) $\times 10^3$ m^3 CH_4/kg water (about 40–50 SCF of CH_4/bbl water). Field tests of a geopressured well in southern Louisiana indicate this may be the case. The relatively high salinity (100,000 ppm total dissolved solids or TDS) and expected subsidence effects of geopressured resources may seriously restrict their utilization.

11.1.4 Hot dry rock (enhanced geothermal systems)

Throughout most of the world, one or more of the necessary components of a hydrothermal reservoir is missing. In particular, the reservoir rock is often hot enough (≥200°C) but produces insufficient fluid for commercial heat extraction because of either low formation permeability or the absence of naturally contained fluids. Such formations constitute a part of the geothermal resource referred to as hot dry rock (HDR) or enhanced geothermal systems (EGS). From the early 1970s to about 2000, the term HDR was used to represent both conduction-dominated, low-permeability and low-porosity formations, and unproductive hydrothermal systems at the margins of or within known geothermal fields. More recently the US DOE has adopted the EGS classification to more rationally represent this resource.

In principle, EGS systems are available everywhere just by drilling to depths sufficiently deep to produce rock temperature useful for heat extraction—usually taken to be >150°C for producing electricity and >50–100°C for direct-heat use. Therefore, for baseload electric power generation in low-grade, low-gradient regions (20–40°C/km), depths of 4–8 km are required, while for high-grade, high-gradient systems (60°C/km), 2–5 km depths are sufficient. EGS resources have the potential to provide a high quantity of primary energy with a resource base in excess of 10^6 quads, and, if developed economically, could provide an alternative to fossil and nuclear fuels.

Techniques for the extraction of heat from low-permeability EGS have been under investigation in a number of laboratories worldwide (Sato, Ishibashi, and Yamaguchi, 1995; Sato and Ishibashi, 1994; Parker, 1989; Armstead and Tester, 1987; Kappelmeyer et al., 1991; Batchelor, 1984). For low-permeability formations, the basic concept is simple: drill a well to sufficient depth to reach a useful temperature, create large heat-transfer surface areas by hydraulically fracturing the rock, and intercept the fracture(s) with a second well. By circulating water from one well to the other through the fractured region, heat can be extracted from the rock (as depicted in figure 11.3).

While the concept is simple, many questions remain to be answered before it can be considered economically feasible. Through field tests of an EGS reservoir in low-permeability crystalline rock, significant progress has been made in understanding reservoir characteristics, including fracture initiation and propagation, the specific details of fracture geometry (area, aperture distribution, connectivity, etc.), its thermal drawdown, water loss rates, flow impedance, fluid mixing, and fluid geochemistry (Armstead and Tester, 1987). In addition to hydraulic fracturing, permeability and surface area can be created by explosive fracturing, chemical leaching, and thermal stress cracking (Armstead and Tester, 1987). Studies of explosive fracturing were conducted in the UK (Batchelor, 1984, 1987) and in the USSR (Diadkin and Pariisky, 1975; Aladiev et al., 1975).

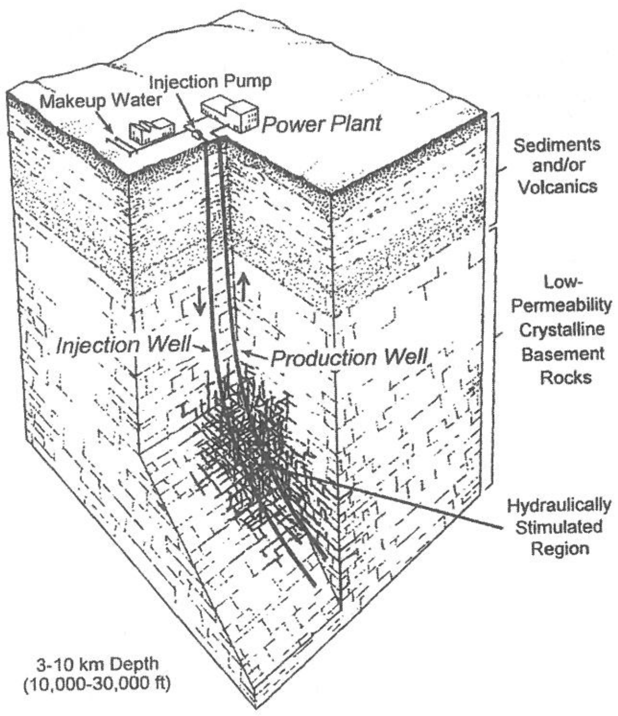

Figure 11.3
Hot dry rock reservoir concept for low-permeability formations. Source: Mock, Tester, and Wright (1997). Reprinted with permission of *Annual Review of Energy and the Environment.*

If rock of sufficient natural permeability exists in a confined geometry, techniques similar to waterflooding or steam drive employed for oil recovery might be used to advantage (Tester and Smith, 1977; Bodvarsson and Hanson, 1977). Other techniques for heat extraction, such as downhole heat exchangers, downhole pumps, or alternative methods of operation, such as injection-recovery (huff-puff), have also been proposed.

Because many of these methods involve the creation of permeability in rock, EGS systems are not limited to particular tectonic settings. Until the heat-extraction technology is suitably developed and the economics are demonstrated on a large scale, the first commercial EGS systems will most likely be confined to regions of high geothermal gradient (>50°C/km) to reduce drilling costs.

11.1.5 Magma

The magma resource consists of rock that is partially or completely molten, encountered at accessible depths. Considerable development of drilling and heat-extraction

concepts and technology must be accomplished before heat can be extracted usefully from magma. Central to the problem of extracting heat is the ability to find a body of magma at drillable depths. Unfortunately, many suitable magma systems are located within the boundaries of protected regions such as Yellowstone National Park in Wyoming. Drilling into magma requires the development of equipment, lubricants, and cements that can operate at temperatures of 700–1,000°C and depths to about 7 km. While this depth is substantial, it is not beyond the capability of commercial drilling today.

Magma's high temperatures, normally greater than 650°C, make this resource particularly attractive for efficient generation of electricity or for heat application in high-temperature industrial processes.

11.1.6 Ultra-low-grade systems

Direct use of low-grade geothermal energy usually manifests itself as a thermal energy source or sink for heat pump applications or for agricultural uses such as greenhouse heating or fish farming. Geothermal heat pumps (GHPs) normally operate at shallow depths (2–4 m) where the earth's temperature is relatively constant. The coefficient of performance (COP) of a typical GHP is about 4 or more, meaning that 4 units of thermal energy are transferred for every 1 unit of electrical work (see Bloomquist, 1981; Keller, 1977; and see section 11.3.3 for more details). Thus, the efficiency of electrical energy utilization is increased more than fourfold using a GHP in such combined heat and power applications.

11.1.7 Markets for geothermal energy

Although the natural hydrothermal, magma, and geopressured systems have reasonably large resource bases and will be exploited when technical and economic conditions are favorable, their distribution worldwide is controlled by prevailing natural geologic conditions. Figure 11.4 illustrates the relationship between resource base and reserve for a hypothetical 40°C/km geothermal system. In terms of total energy use, electric power generation is now and will continue for the immediate future to be the predominant end use for geothermal resources. Essentially all generated electricity is baseload and goes to the transmission grid. To date, only high-grade hydrothermal systems have been developed for commercial electric power generation and district heating applications. Especially for electricity generation, the production temperature strongly influences the thermal efficiency of the power plant. Hydrothermal resources have been utilized most effectively when resource location and user demand coincide. Such is the case in developing countries like Indonesia and the Philippines, in parts of Central America, and in the western US.

Although geopressured and magma resources have substantial potential, in order for geothermal energy to become a major player in supplying energy worldwide in

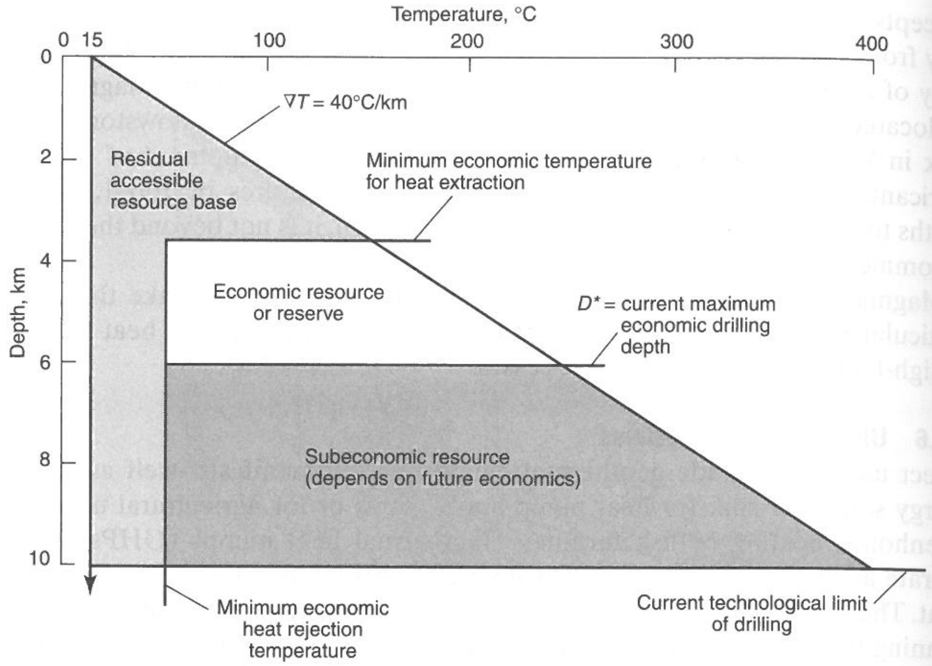

Figure 11.4
Idealized depth-versus-temperature profile for a hypothetical 40°C/km geothermal resource. The resource base and economic resource or reserve regions are shaded in different tones to illustrate the factors limiting the portion of the total resource base that can be economically produced with a specified set of technologies and economic factors. Adapted from Tester and Grigsby (1980). Reprinted with permission of John Wiley & Sons.

the next decade, EGS resources must be utilized. Fortunately, EGS is by far the largest, most widely distributed resource, but appropriate heat mining technology has not become commercially available. Competitive universal heat mining requires the development of advanced heat-extraction techniques for EGS to stimulate production and improved drilling methods that would reduce development costs so that even low-gradient regions can be economically developed.

Since geothermal energy occurs in the form of hot water or steam, direct-heat applications were developed long before electricity was first generated from geothermal steam in 1902 in the Larderello field. Low-temperature geofluids, wherever they are available, have seen widespread use for heating, cooling, and bathing for centuries (Armstead, 1983). More recently, even the thermal capacity of the earth at shallow depths is being utilized in operating GHPs. In fact, a fairly aggressive deployment program in the US in the 1990s increased the adoption of GHPs in residential and commercial buildings from 40,000 units per year in 1994 to 50,000

units per year by 2008. US statistics reported that 700,000 units had been installed by 2008, with a total of around 1.5 million units installed worldwide (NRC, 2009a). Large reductions in fossil energy use would be possible with the development of district heating infrastructure that would use lower-enthalpy geothermal resources for heating and cooling in residential and commercial buildings. Iceland's extensive district heating network is an outstanding example of what could be replicated in many parts of the US and other countries with aggressive policies and incentives.

Given the remoteness of many high-grade hydrothermal fields, electricity is mostly generated at the field site and tied into an existing grid system at an acceptable cost. Geothermal power plants have smaller capacities (about 50–100 MW) than nuclear and fossil-fuel plants and consequently can be used as baseload units in systems with much larger total generating capacity. Of the 4.2 million GW_eh of electric-generating capacity in the US in 2007, only 14,800 GW_eh was provided by geothermal sources (NRC, 2009a). With cost-effective, reliable geothermal systems available, a substantial market exists for both new and replacement generating capacity during the twenty-first century.

Reistad (1975) discusses energy usage as a function of utilization temperature and concludes that about 40% of our annual fossil energy consumption is severely degraded thermodynamically. Typically, fossil combustion temperatures of 1,000–2,000°C are used to produce space and process heat at temperatures below 250°C. Importantly, a very significant fraction of fossil energy is consumed to produce domestic hot water and for space heating at temperatures well below 100°C. Recently, Fox, Sutter, and Tester (2011) analyzed energy use as a function of utilization temperature in the US by reviewing data reported by the EIA since 1968, as illustrated in figure 11.5. A wide variety of applications are contained in the 32 EJ (30 quads) of energy used below 250°C that would be compatible with a geothermal energy supply system.

In contrast to the generation of baseload electricity from geothermal, which can be tied into an electric transmission and distribution system, the situation with the nonelectric market is different. Utilizing geothermal space and process heat systems may require some retrofitting by the consumer. For example, a fuel-oil or natural-gas furnace usually is designed with in-house storage or is attached to an existing distribution network. The use of geothermal hot water or steam would require a completely new fluid-distribution system within the community. Heat pumps are the exception, as the geothermal part is developed at each building site.

Direct-heat supply temperatures are typically close to actual process temperatures in district heating systems, which range from approximately 60–120°C. In 2009 the main types (and relative percentages) of direct applications in annual energy use were space heating of buildings (63%), bathing and balneology (25%), horticulture (greenhouses and soil heating) (5%), industrial process heat and

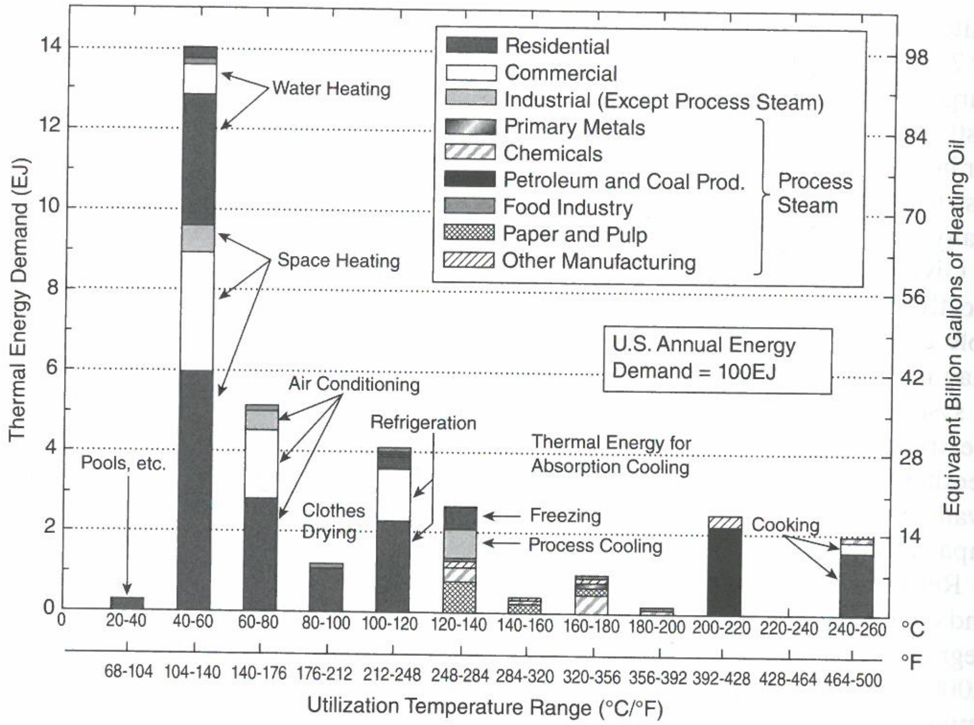

Figure 11.5
Temperature distribution of thermal energy use from 0° to 260°C with electrical system energy losses (ESEL). The end uses with the largest contributions are annotated. Note: Based on EIA data from 1968 to 2008. The total thermal energy demand from 0° to 260°C in 2008 was 33.5 EJ (31.7 quads). Source: Fox, Sutter, and Tester (2011). Reprinted with permission of the Royal Society of Chemistry.

agricultural drying (3%), aquaculture (fish farming) (3%), and snow melting (1%) (Lund, Freeston, and Boyd, 2010). When the resource temperature is too low for other direct uses, it is possible to use ground source or geothermal heat pumps. GHPs contributed 70% (35.2 GW_{th}) of the worldwide installed direct-use capacity, and have had the fastest growth of all geothermal direct uses since 1995 (Rybach, 2005; Lund, Freeston, and Boyd, 2010). Further details regarding direct use and heat pumps are found in section 11.3.3.

11.2 Geothermal Resource Size and Distribution

11.2.1 Overall framework and terminology

Geothermal resources are commonly considered as mineral resources, like oil, gas, and coal. However, because they contain water and their production can affect

groundwater flows, geothermal resources may be classified as a particular type of water resource. In addition, there is considerable nonuniformity in the terminology used to describe geothermal resources. For example, the geothermal resource base has been defined several ways: (1) all stored heat above 15°C to 10 km depths (White and Williams, 1975); (2) the potentially useful heat in the earth's crust at temperatures greater than 80°C and depths less than 6 km (Armstead, 1983); or (3) the total heat contained in subsurface rocks and fluids to a depth of 3 km and at temperatures above 15°C (EPRI, 1978). The most widely accepted terminology for geothermal resources is that proposed by Muffler and Guffanti (1979), described below:

- *Resource base*: All of the thermal energy contained in the earth's crust, whether its existence is known or unknown and regardless of cost considerations.
- *Accessible resource base*: All of the thermal energy between the earth's surface and a specific depth in the crust beneath a specified area and referenced to a mean annual temperature.
- *Resource*: Thermal energy that could be extracted at costs competitive with other forms of energy at a foreseeable time, under reasonable assumptions of technological improvement and economic favorability.
- *Reserve*: That part of the geothermal resource that is identified and also can be extracted at a cost competitive with that of other commercial energy sources at present.

It would be misleading to imply that this or any terminology is accepted throughout the geothermal industry. Indeed, these definitions are somewhat simplistic compared to the definitions applied to the same terms in the oil, gas, or mining industry (see figure 11.4 for a slightly modified version). For example, in the US in 2010, an oil reserve can secure a bank loan, but a geothermal reserve cannot. Currently, there are simply not enough cases of economic exploitation of geothermal energy for it to be considered a good financial risk. Nonetheless, at certain high-grade sites in the US, Europe, and Asia, investments in commercial developments have been significant.

11.2.2 Quality issues

Investment in the extraction of mineral resources usually proceeds when the likelihood of return on invested capital is high. Consequently, the quality of the resource needs to be carefully characterized. For geothermal resources, quality is determined by factors including depth to the reservoir or average geothermal gradient, rock type, fluid composition and production rates, and the energy content of the reservoir. Typically, mineral deposits or ore bodies are evaluated according to the grade and accessibility of the deposit, processing costs, and distance to the nearest market. Based on the evaluation approach, a deposit might be classified as a reserve or a resource. A similar body of terminology is under development in the geothermal energy field; thus far, as mentioned earlier, geothermal terminology has borrowed heavily from the other mineral-related fields.

Gaining access to the fluids or hot rock is key to assessing the quality of any geothermal resource. Usually depth is the critical parameter, for drilling costs typically scale exponentially with depth. Rock hardness and formation stability or integrity are also critical as they determine the ease of drilling through the formation.

The chemistry of natural geothermal fluids can pose significant challenges to utilization. For instance, the salinity content of a liquid-dominated, hydrothermal reservoir fluid can vary from a few hundred ppm total solids (drinking water quality; 100 ppm = 0.01% by weight) to a concentrated brine (>30% by weight solids). The fact that hydrothermal reservoir fluids are hot and under pressure contributes to difficulties in processing, particularly if they contain large amounts of noncondensable gases such as CO_2. The presence of dissolved gases, such as H_2S and NH_3, usually requires special abatement procedures to meet air emission standards.

11.2.3 Resource base and reserve estimates

As a measure of the resource base, we will first consider the heat content of a mass of rock at a specific depth that could potentially be extracted as primary energy. Then, we will discuss how much stored thermal energy can be removed by either extracting a portion of the hydrothermal fluids contained in a natural reservoir or by extracting energy from a suitably engineered artificial reservoir in EGS.

Accessible geothermal resource base Estimates of all or part of the accessible geothermal resource base are numerous, and each estimate is based on slightly different assumptions. If the definition of "accessible resource base" as given above is strictly followed, the total amount of heat Q contained in rock beneath the earth's surface to a depth Z is expressed by

$$Q = \sum A_i \left[\int_o^z (\Phi \rho_f C_{p,f} + (1-\Phi)\rho_r C_{p,r})(\nabla T_i \cdot Z + T^* - T_{ref}) dZ \right] \tag{11.1}$$

where Z = depth, km; T = rock temperature, °C; A_i = surface area having a characteristic regional gradient of ∇T_i; T^* = ambient surface crustal temperature, about 15°C; Φ = porosity of rock; ρ_f = fluid density, kg/m^3; ρ_r = rock density, kg/m^3; $C_{p,f}$ = fluid heat capacity, J/(kgK); $C_{p,r}$ = rock heat capacity, J/(kgK); ∇T_i = geothermal gradient, °C/km; and T_{ref} = reference temperature, °C.

Integrating equation (11.1) for each unit of area A_i, assuming a constant geothermal gradient and taking $T^* = T_{ref} = 15$°C, yields:

$$Q_i = A_i[\Phi \rho_f C_{p,f} + (1-\Phi)\rho_r C_{p,r}]\nabla T_i \frac{Z^2}{2}. \tag{11.2}$$

Below about 3 km, Φ approaches 0, and equation (11.2) can be simplified to give:

$$Q_i = A_i(\rho_r C_{p,r})\nabla T_i \frac{Z^2}{2}. \tag{11.3}$$

Given regional distributions of land areas overlying each range of geothermal gradient, the resource base to a given depth can be calculated. Likewise, given the heat contained per unit area to a given depth, one can extrapolate to another depth to find the accessible resource base by simply substituting the new depth in equation (11.2). Estimates of the worldwide accessible resource base commonly are referenced to a specific mean annual surface temperature and a specific maximum depth. For example, the Electric Power Research Institute (EPRI, 1978) uses 15°C and a depth of 3 km, assuming (1) a normal gradient of 25°C/km for all nongeothermal areas, (2) a gradient of 40°C/km for 90% of the area of a country that lies inside a geothermal belt, and (3) a gradient of 90°C/km for the remaining 10% of the area within a geothermal belt. Typical values for rock (r) and fluid (f) properties used in these calculations are: ρ_r = 2,000 – 2,800 kg/m^3; $C_{p,r}$ = 800 – 1,200 J/kgK; λ_r = 2.5 – 3.0 W/mK; ρ_f = 800 – 1,000 kg/m^3; $C_{p,f}$ = 4,000 – 4,200 J/kgK.

Comparisons of accessible resource base estimates are given in table 11.1 for the world and the US from several sources, all referenced to a mean annual temperature of 15°C and a maximum depth of 10 km. Two important conclusions can be drawn from these estimates. First, the amount of energy is enormous. In 2010, the total US primary energy consumption was about 111 EJ/yr (about 100 quads/yr). If only 0.1% of the accessible geothermal resource base can be economically extracted, it could supply the complete energy needs of the US at its current rate of increase for almost 170 years. Second, probably 97% of the energy contained in the upper 10 km of the earth's surface is contained in the rock itself as a conduction-dominated resource and, therefore, requires an EGS extraction scheme. Conventional geothermal resources in the US are shown on a map in plate 9 in terms of the distribution of heat flow per unit area at the surface. Plate 10 shows the potential for EGS development by displaying the subsurface temperature distributions at depths of 3.5, 6.5, and 10 km (MIT, 2006).

Geothermal reserves Several factors limit the amount of energy that can be economically extracted from the earth. Some of these are now and always will be fixed; figure 11.4 shows a depth-versus-temperature profile for a resource having an average gradient of 40°C/km. The resource base is depicted by the large triangle

Table 11.1
Geothermal Worldwide Resource Base Estimates: Total Thermal Energy Content in Place (Q)

Resource Type	Total Q in 10^3 quads[a] US	World
Hydrothermal (vapor- and liquid-dominated)	2.4–9.6	130
Geopressured[b]	71–170	540
Magma[c]	500–1,000	5,000
Hot dry rock[d]	14,000	105,000
Moderate- to high-grade ($\nabla T > 40°C/km$)	2,500	26,500
Low-grade ($\nabla T \le 40°C/km$)	11,500	78,500

Sources: MIT (2006); Mock, Tester, and Wright (1997); Armstead (1983); Armstead and Tester (1987); Duchane (1994); Rowley (1982); US figures from MIT (2006) are based in part on work by Dr. David Blackwell's group at SMU and on USGS estimates (Muffler and Guffanti, 1979; Sass, 1996; Sass et al., 1993).
[a] Q = 1 quad ≡ 10^{15} BTU ≈ 10^{18}J with 2010 worldwide commercial energy demand = 440 quads and 2010 US commercial energy demand = 100 quads.
[b] To depths of 10 km and initial rock temperatures >85°C.
[c] To depths of 10 km and initial rock temperatures >650°C.
[d] Includes hydraulic and methane energy content.

enclosed by lines extending from 15°C at 0 km to 400°C at 10 km depth. The economic resource or reserve is contained within the resource base by imposed minimum temperature and maximum drilling depth constraints. The first major limitation to the estimates of the amount of heat that can be economically extracted is the effective geothermal gradient. This largely determines the potential for a given area. If the gradient is small, the depth to the minimum acceptable initial rock temperature is large. A minimum initial rock temperature (T_{ref}) of 150°C is assumed to provide reasonable thermodynamic conversion efficiencies (see section 11.3.3). A normal gradient (25°C/km) requires drilling to at least 5.4 km to reach 150°C. If the gradient is 40°C/km, as depicted in figure 11.4, holes that are only 3.4 km deep are needed. Another major limitation is the maximum economic drilling depth D^*. For an assumed maximum drilling depth of 6 km, only gradients above about 40°C/km represent substantial amounts of stored energy. The final limitation is imposed by heat rejection conditions for the geothermal fluid in the power plant (taken here to be 50°C). Imposing these limitations on an area of 1 km^2 with a gradient of 40°C/km, the total geothermal resource to 6 km (assuming average values of $C_{p,r}$ = 772 J/(kgK) and ρ_r = 2,500 kg/m^3) is

$$\left[\frac{Q_i}{A_i}\right] = \rho_r C_{p,r}\left[\frac{\nabla T_i Z^2}{2} + (T^* - T_{ref})Z\right]_{3.4\text{km}}^{6\text{km}}. \qquad (11.4)$$

The total energy available to the economic depth D^* = 6 km is 0.81 EJ/km^2 or 0.77 quads/km^2. The fraction of this amount that can be extracted economically will

depend on the prices for other forms of energy and the degree of success in developing commercial-sized systems.

Estimating the economic resource or reserve for a particular type of geothermal resource shares much in common with estimating reserves for oil and gas and other mineral stocks. Technological improvements to reduce the cost of producing geothermal heat or electricity will increase reserves, while lower energy prices for fossil and fissile fuels will decrease reserves. At this stage of development, we can only say that the geothermal resource base is huge and warrants R&D expenditures to increase the fraction of the resource base that can be produced in competitive world energy markets.

11.3 Practical Operation and Equipment for Recovering Energy

11.3.1 Drilling and field development

The first step in developing a geothermal field involves thorough evaluation of potential sites using all available lithologic, hydrologic, geophysical, and geochemical data. Locating and evaluating a reservoir can be difficult and expensive, particularly in regions that have not been drilled extensively or where surface manifestations of geothermal activity are not present. Once a site has been located, it must be purchased or leased for its geothermal rights before exploratory and production drilling can begin.

Drilling and completing wells for geothermal energy applications involve methods similar to those used in drilling for oil or gas. However, geothermal wells are generally more difficult and expensive to construct because subsurface formation temperatures are higher and the rock itself is typically harder to drill, with many fractures, lost circulation regions, or more abrasive mineral matter. In fact, drilling-related costs are usually the single largest cost component in any geothermal development. Drilling is inherently risky, including as much "art" as science (not to mention sophisticated engineering and an extraordinary infrastructure of specialized disciplines). Given this situation, one might expect the cost of drilling and completing a well to a specified depth would be highly variable. While this is certainly true to some degree, there are general trends.

Average costs for drilling tend to scale exponentially with depth, whether they are conventional oil and gas wells or geothermal wells. Tester and Herzog (1991) and Armstead and Tester (1987) examined a substantial set of drilling cost data to provide guidelines for estimating costs. Figure 11.6 provides a summary of recent individual well cost data for geothermal, oil, and gas wells, along with several correlations (MIT, 2006). On the semilogarithmic coordinates of figure 11.6, a straight line results for the average cost of gas and oil wells versus their depth. Also shown are the predictions of costs for geothermal wells, using the Wellcost Lite model,

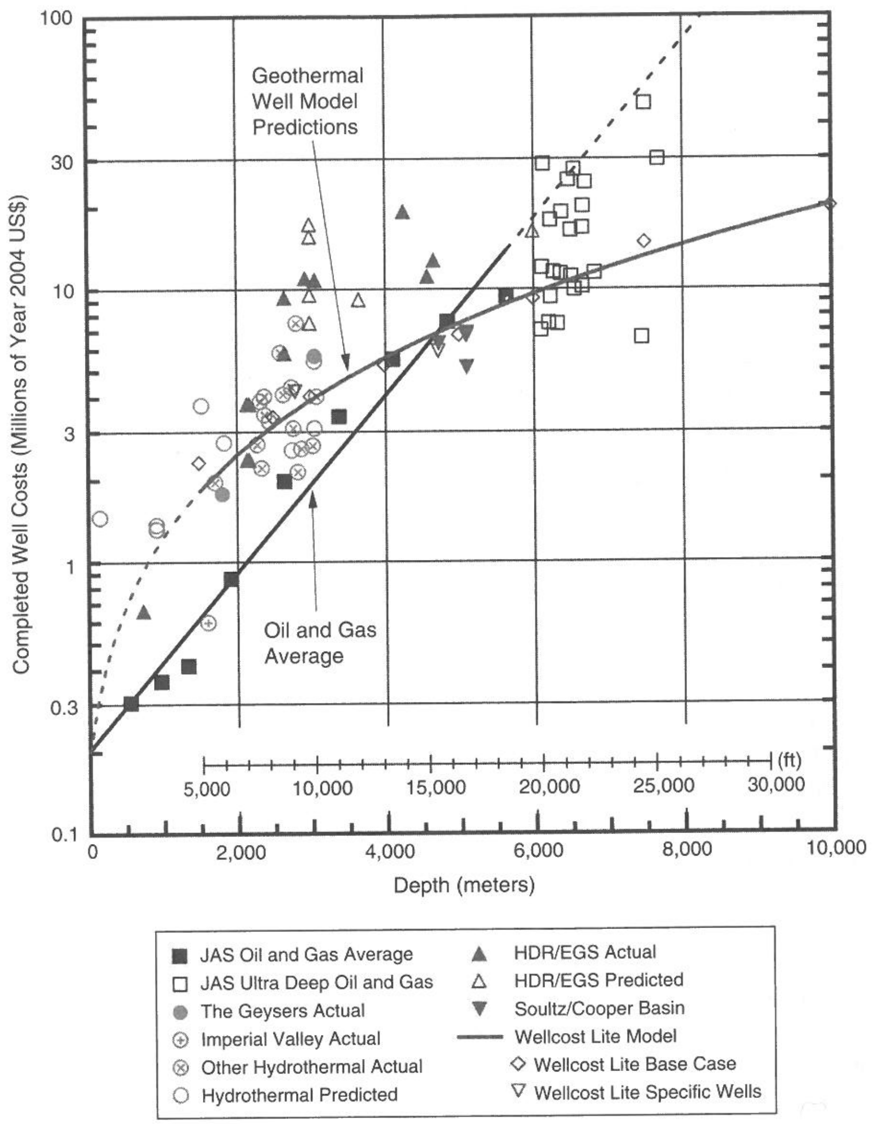

Figure 11.6
Completed geothermal, oil, and gas well costs as a function of depth in 2004US$, including estimated costs from Wellcost Lite model. Source: MIT (2006).

which uses actual geothermal well data and drilling experience to predict well cost as a function of depth (Pierce, Livesay, and Finger, 1996).

Figure 11.6 demonstrates that, for depths less than 5 km, all hydrothermal and EGS well costs are higher than the cost of a typical oil or gas well drilled to the same depth. The line for the "oil and gas average" is based on costs for hundreds of wells compiled by the Joint Association Survey (JAS, 1976–2000).

Completed well diameters for geothermal wells range from 8 to 12 inches (20–30 cm), which is somewhat larger than found for oil and gas wells. Larger diameters increase costs, as do the slower penetration rates often encountered in geothermal drilling (see Armstead and Tester, 1987). For depths between 1 and 5 km, geothermal wells are about 2–4 times as expensive as a comparable oil or gas well. At larger depths, we expect geothermal well costs to approach those for oil and gas wells because ultradeep oil and gas drilling frequently encounters a similar set of problems as geothermal drilling, including hole collapse, hard rock, and higher temperatures and pressures. As we can see from the ultradeep JAS data, the range of costs gets large for wells deeper than 6 km, with the most expensive wells about a factor of 10 more costly than the least expensive ones.

11.3.2 Reservoir fluid production

To justify the cost of developing a geothermal field, estimates must be made of the total amount of extractable energy and the production rate. Typically, computer models are used to simulate performance for a given set of reservoir properties. Two general categories of reservoir models, one involving matrix and one fracture-dominated flow, are usually encountered. The first type applies to high-matrix permeability hydrothermal formations and the second to fractured, low-permeability media common in EGS reservoirs. A simple example of each case with schematic thermal history curves is shown in figure 11.7.

Porous and permeable reservoir Extraction of heat from hydrothermal systems now in operation is straightforward. Because the reservoirs are pressurized, the fluid passes directly to the surface under artesian flow when the reservoir is penetrated. Productivity of the wells may occasionally be enhanced by stimulation at the wellbore or downhole pumping, but this is often unnecessary. Efficient production of a pressurized field is largely a matter of well spacing for a specified set of *in situ* properties. When the pressure of such a field drops to the point where it is insufficient to produce hot fluid, stimulation techniques are used. For example, water is injected to repressurize the system and literally force fluid to move through the porous rock to be heated as it flows toward the production well. Such water-drive flooding methods are commonly used to enhance oil recovery as well. Because reinjection of fluid is required in geothermal applications today, water-drive methods can be used throughout the life of the field. Also, in pressurized geothermal systems,

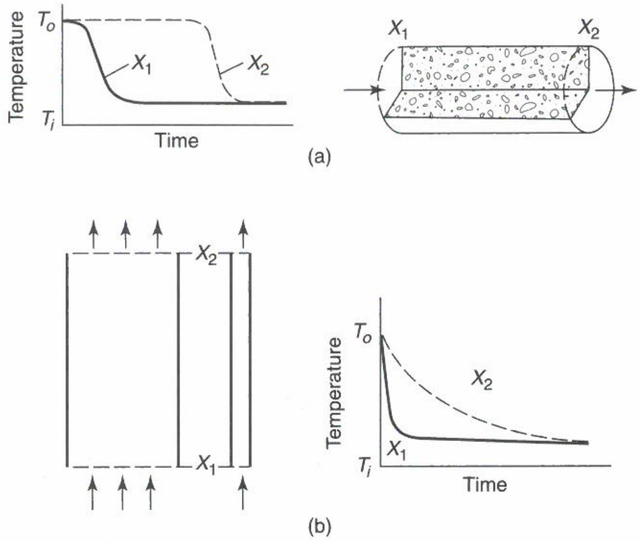

Figure 11.7
Limiting idealized cases used in modeling the thermal drawdown of geothermal reservoir: (a) isotropic porous media; (b) flat fracture with a rectangular aperture. Adapted from Tester and Grigsby (1980). Reprinted with permission of John Wiley & Sons.

most of the thermal energy is contained in the rock and not the pore fluids, so enhancement methods can greatly extend the lifetime of a field.

Discretely fractured, low-permeability reservoirs Many hydrothermal systems and most EGS reservoirs consist of widely spaced open fractures between sections of low-permeability and low-porosity rock. The efficiency of electric power production over the 20- to 40-year lifetime of an EGS power plant depends primarily on the temperature and composition of the geothermal fluid produced. Knowledge of the anticipated thermal drawdown and of fluid chemistry is crucial in developing optimal plant designs and reservoir management strategies. The predicted lifetime and the rate at which energy can be extracted from a single fracture depend on several major factors: (1) thermal properties of the rock, (2) accessible surface area of the fracture, and (3) distribution of and impedance to fluid flow across the fracture surface. Because rock has an inherently low thermal conductivity, conduction through the formation to the circulating fluid contained in the fracture controls the rate of heat extraction.

A simplified approach to estimating reservoir performance assumes that a certain fraction of the recoverable power, η, corresponding to uniform flow across the face of a circular fracture, could be extracted. Assuming only conduction of heat toward the fracture face and no thermal-stress cracking enhancement, the recoverable

thermal power $P(t)$ can be expressed analytically as (Armstead and Tester, 1987; McFarland and Murphy, 1976):

$$P(t) = \eta \dot{m}_w C_{p,w}(T - T_{min})\,\mathrm{erf}\left(\sqrt{\frac{(\lambda\rho C_p)_r}{t}} \cdot \frac{A}{\dot{m}_w C_{p,w}}\right) \tag{11.5}$$

where $A = \pi R^2$ = area of one face of the fracture, m^2 for a circular fracture or $A = L \times H$ for a rectangular fracture (see figure 11.7); $C_{p,w}$ = heat capacity of water, about 4.2 kJ/(kgK); $C_{p,r}$ = heat capacity of granite, about 1,000 J/kgK; $\dot{m}$ = water flow rate through the fracture, kg/s; t = time, s; T = mean rock temperature, °C; T_{min} = fluid reinjection temperature, °C; λ_r = thermal conductivity of granite, approximately 3 W/(mK); and ρ_r = density of granite, about 2.7 g/cm^3. Note that "erf" indicates the error function of the quantity contained in the large parentheses.

Equation (11.5) provides estimates of reservoir lifetime for an ideal fractured system with a specified area A and production rate. A few simple calculations reveal that large surface areas are required for low drawdown rates with wellbore flows in excess of 40 kg/s (see figure 11.8). For a given set of rock properties, the parameter $\dot{m}_w/A$ will determine the thermal drawdown rate. In designing systems, one can

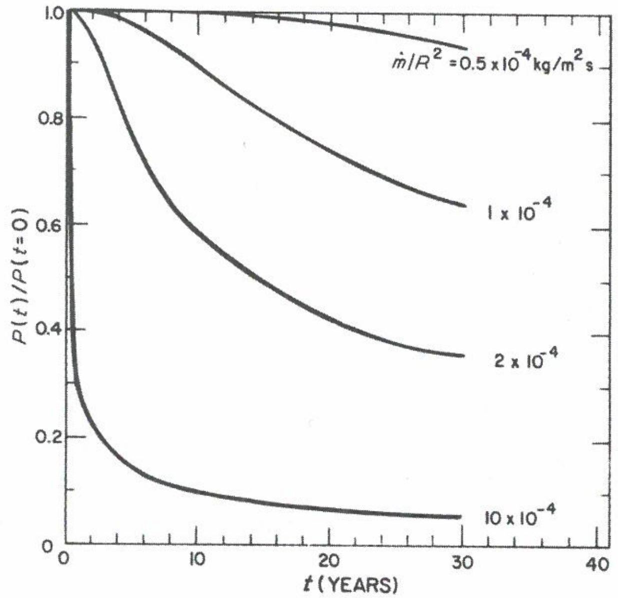

Figure 11.8
Parametric thermal power drawdown curves for a single idealized circular fracture of radius R. Adapted from Armstead and Tester (1987) and following equation (11.7). Reprinted with permission of Cengage Learning.

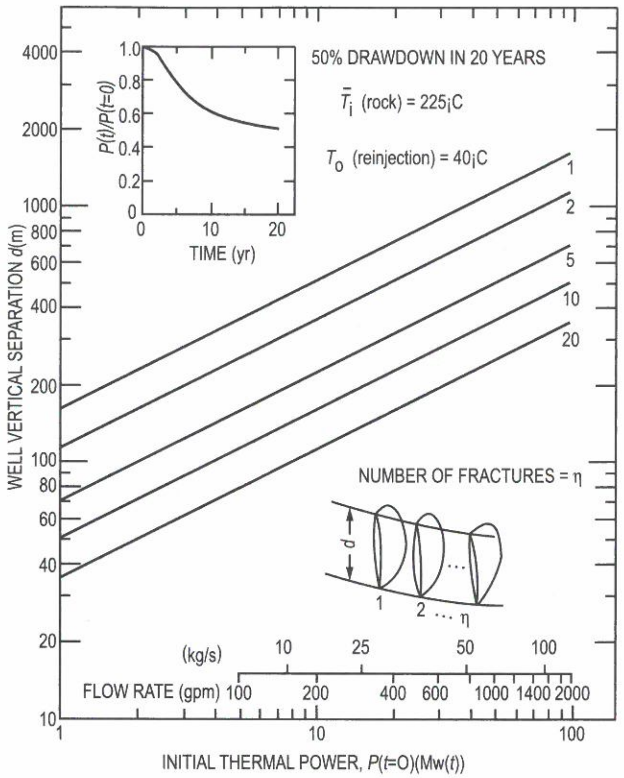

Figure 11.9
Conceptual design nomograph for low-permeability formations with a specified level of thermal drawdown (50% in 20 years of operation). Wellbore separation distances (d) that define single or multiple fracture sizes are shown as a function of initial thermal power level ($P(t = 0)$). Flow rates given in kg/s and in gal/min (gpm). Adapted from Armstead and Tester (1987). Reprinted with permission of Cengage Learning.

utilize single or multiple fracture concepts with specified drawdown rates at given initial power extraction levels. Figure 11.9 shows the required wellbore separation distance as a function of initial thermal power or mass flow rate and the number of fractures. In this case, 50% drawdown is achieved after 20 years of continuous operation with an overall $\dot{m}_w/R^2$ of approximately 2×10^{-4} kg/(m^{2}s). Because of the rock's low thermal conductivity, fractures separated horizontally by more than 50 m show negligible thermal interference over a 20-year period. Using simplified models to simulate reservoir thermal-hydraulic behavior, substantial enhancement of HDR reservoir performance might be possible by exploiting the effects of thermal stress cracking.

However, heat transfer and fluid flow behavior in discretely fractured rock systems with confining stresses are extremely complex in real systems, requiring more detailed geometric descriptions and assumptions to model thermal hydraulic performance. In addition, under certain conditions, induced thermal stresses may be large enough to cause secondary cracking, which may result in enhanced performance. Given the complexity of controlling mechanisms, performance predictions are uncertain even under well-defined laboratory conditions (for further discussion, see Tester, Murphy, et al., 1989; Harlow and Pracht, 1972).

If we neglect any possible enhancements due to secondary fracturing and rely only on conduction and convection from a fixed geometry reservoir, economically acceptable rates of energy extraction and lifetimes can be achieved in principle by proper well placement and flow management. For example, economically viable production rates and lifetimes are achievable in low-permeability HDR reservoirs by having circulating fluids contact large rock surface areas, equivalent to large single fractures (R, L, or $H \approx 1{,}000$ m), by using smaller multiple fractures in parallel. If thermal breakthrough occurs, redrilling and refracturing to generate new surface area in nondepleted regions of hot rock can be used to restore productivity.

11.3.3 Nonelectric, direct-heat utilization

Low-temperature, hydrothermal resources in the form of hot water or steam have been used in commercial direct-heating applications ranging from soil warming (10°C) to district heating (60–90°C) to power drying (200°C). Figure 11.10 illustrates three modes of utilization: for heating with extracted geofluids indirectly involving a heat exchanger and for both groundwater and ground source heat pumps.

District heating applications Internationally, geothermal district heating has been popular where there is proximity between a good hydrothermal resource and a reasonable load center. Reykjavik, Iceland; Paris, France; and many locations in Russia, Japan, and Hungary (Edwards et al., 1982) provide good examples of such developments. Iceland has been a leader in adopting widespread district heating. As of 2010, over 90% of Iceland's buildings are heated with hot fluids piped from its extensive geothermal fields. There is a very large geothermal district heating network serving over 200,000 homes in the Paris basin as well.

The oil price shocks of the 1970s catalyzed interest in nonelectric applications of geothermal energy in the US, with various federal and state tax credit programs adopted to incentivize the direct use of geothermal resources. By 1994, geothermal energy provided over 1.4×10^{16} J (13 trillion Btus) annually for direct-heat applications in the US, mainly in California, Oregon, Idaho, Nevada, Utah, New Mexico, Wyoming, South Dakota, Texas, and New York.

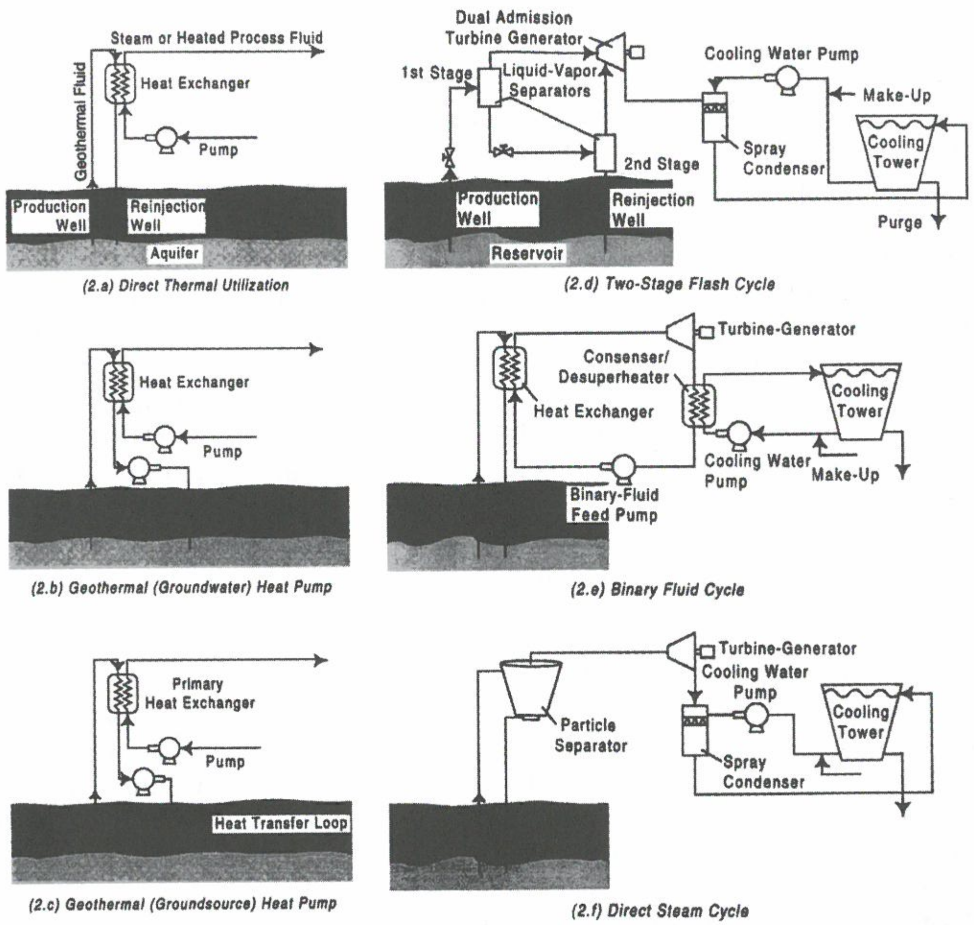

Figure 11.10
Energy utilization options for geothermal resources. Adapted from Mock, Tester, and Wright (1997). Reprinted with permission of *Annual Review of Energy and the Environment.*

Currently, there are 23 geothermal district heating systems in the US, including the nation's oldest in Boise, Idaho; the 65,000 m^2 (700,000 ft^2) system on the Oregon Institute of Technology campus; the municipal detention facility system in Yakima, Washington; and the nation's largest geothermal district heating system in San Bernardino, California. To assist communities and developers in evaluating the costs and benefits of such systems, Washington State University and the Geo-Heat Center have prepared comprehensive computer programs for geothermal direct-use cost evaluation (Rafferty, 1994).

The most recent compilation of low- and moderate-temperature geothermal resources in 10 western states contains information on 8,977 thermal wells and springs that are in the temperature range of 20–150°C. Data and maps are available for Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, and Washington. Resources with temperatures greater than 50°C and located within 8 km of a population center were identified for 271 cities and towns; 50 sites were judged high in priority for near-term comprehensive resource studies and development (Lienau, Ross, and Wright, 1995). Older data are available for the rest of the US (Reed, 1983).

Other direct-heating applications Industrial applications generally need moderate- to high-temperature geothermal resources. Industrial uses include enhanced oil recovery (90°C), ore or heap leaching operations using selective chemical dissolution to extract precious metals (110°C), dehydration of vegetables (130°C), mushroom growing (60°C), pulp and paper processing (200°C), hay drying (60°C), timber drying (90°C), and diatomaceous earth drying (182°C) (Lienau, Lund, and Culver, 1995). Industrial and other applications of geothermal heat are reviewed by Armstead (1983), Lindal (1973), and Lund, Freeston, and Boyd (2010).

Bathing, swimming, and balneology are globally widespread. In addition to the thermal energy, the chemicals dissolved in the geothermal fluid are used for treating various skin and health diseases. Greenhouses heated by geothermal energy and the heating of soil in outdoor agricultural fields have been developed in several countries. A variety of industrial processes utilize heat applications, including drying of forest products, food, and minerals in the US, Iceland, and New Zealand. Other applications are process heating, evaporation, distillation, sterilization, washing, and CO_2 and salt extraction. Aquaculture using geothermal heat allows better control of pond temperatures, with tilapia, salmon, and trout being the most common fish raised. Maintaining a controlled rearing temperature through the use of geothermal fluids can increase fish growth rates by 50–100%, significantly increasing the number of harvests per year. Some countries with colder climates use low-temperature geothermal water for melting snow or de-icing. In these cases, some city streets, sidewalks, and parking lots are equipped with buried piping systems carrying hot geothermal water (Lund, Freeston, and Boyd, 2010).

The first modern industrial use of geothermal heat in the US was at a vegetable dehydration plant in Fernley, Nevada. When the plant was built in 1978 to process onions, the geothermal fluid was used only to supply heat for the dehydration process. However, the advantages of using the fluid in the wet-preparation stage quickly became apparent. Because of its oxygen-free and essentially bacteria-free nature, the geothermal fluid maintains a bacterial count well below prescribed health standards. Advantages of using geothermal fluids include significantly increased production rates, elimination of the potential fire hazards of other fuels, and no degradation of the products through scorching.

Geothermal heat pumps The term "geothermal heat pump" (GHP) is generic for all heat pumps that utilize the earth's thermal capacity as an energy source (for heating) or energy sink (for cooling). At shallow depths greater than about 1–2 m (3–6 ft), the earth maintains a relatively constant temperature, warmer on average than the air above it in winter and cooler in summer, making possible typical GHP COPs of 4.0 or better. Such high efficiency can reduce energy consumption by 23–44% over air-source heat pumps and by 63–72% over electric resistance heating and standard air-conditioning equipment (L'Ecuyer, Zoi, and Hoffman, 1993).

The earth's thermal capacity can be utilized directly or indirectly. An example of its indirect utilization is the use of groundwater as an intermediary heat-transfer agent. The concept of GHPs is occasionally expanded to encompass the relatively few heat pumps that utilize lake or river water. Rafferty (1996) classifies GHPs in three groups: ground-coupled (direct thermal), groundwater, and hybrid (ground source; see figure 11.9). In the first type, a closed loop of pipe is buried horizontally beneath the frost zone, or vertically 30–120 m (100–400 feet) deep, and filled with a water-based antifreeze solution that extracts heat in a closed circulating loop from buildings during the summer, depositing it in the earth. In the winter, the system is reversed, extracting heat from the earth and carrying it into the building. Waste heat from a GHP during summer cooling periods can provide domestic hot water as an additional benefit.

The second type of GHP, first used in the US in the 1930s and, until recently, the most widely used approach, is the system in which groundwater is delivered to a heat exchanger installed in the heat pump loop, and then disposed on the surface or in an injection well (Pratsch, 1995). These systems have dropped in popularity as increased environmental regulations designed to prevent contamination of surface waters or aquifers have favored the adoption of the totally enclosed ground-coupled system.

The third type, the hybrid system, combines a ground-coupled system with a cooling tower, and is used primarily in commercial buildings. Due to the high cost in meeting peak cooling loads, hybrids incorporate a cooling tower, allowing the

designer to size the ground loop for normal heating loads and to use the tower to help meet the much larger peak cooling loads occurring during the summer.

To help mitigate the perceived energy crisis in the early 1970s, the US government initiated activities to assist the commercialization of GHPs. Several large projects were supported, including the 1982 installation of a 300-ton (note: 1 ton = 3,517 W = 200 Btu/min) heat pump in the county courthouse in Ephrata, Washington. Previously, the annual bill for operating the oil-fired boiler had been $14,000–22,000, depending on the severity of the winter. After GHP installation, costs fell to approximately $2,400 per year (Painter, 1984). Other demonstration projects included the 37,200 m^2 (400,000 ft^2) climate-controlled Oklahoma state capitol, using 277 independently controlled GHPs, and New Jersey's Stockton State College, home of the largest school GHP system (1,600 tons).

Until the mid-1990s, the US lagged behind other countries in taking advantage of geothermal heat-pump technology. In 1994, to accelerate commercialization of GHPs, the government (mainly the US DOE and EPA), public/private organizations (including Edison Electric Institute, National Rural Electric Cooperative Association, Electric Power Research Institute, and Consortium for Energy Efficiency), and the electric power industry (with more than 70 electric utilities and over 50 trade allies) established the Geothermal Heat Pump Consortium (GHPC), which initiated a $100 million, six-year program. Specific goals of the program were to reduce greenhouse gas emissions, improve energy efficiency, reduce heating and cooling costs, and increase annual GHP sales in the US from 40,000 units per year in 1994, with a total of 400,000 units to be installed by the year 2000. This goal was not met because of the high installation costs and the logistics that make retrofitting existing buildings difficult unless a clear adjoining land area is available. By 2007, US sales had reached 50,000 units per year, with over 700,000 units operating in the US and 1.5 million worldwide (NRC, 2009a). Clearly there are significant opportunities for reducing the primary energy needs of buildings by using GHPs as part of an integrated design, if barriers can be reduced.

11.3.4 Electric power generation

Most geothermal, nonconcentrating solar thermal and ocean thermal resources share the common disadvantage of having inherently low resource temperatures. One technique for increasing their quality, as well as their transportability, is to convert their available energy into electric power. In practical terms, the efficiency of such conversion processes is limited by resource temperatures and prevailing ambient conditions for heat rejection. Efficiencies for converting geothermal resources at temperatures below 200°C to electricity are substantially lower than those of fossil-fuel-fired or nuclear-powered plants, typically 5–20% versus 35–60% in terms of the ratio of work produced to heat supplied (Carnot, Second Law

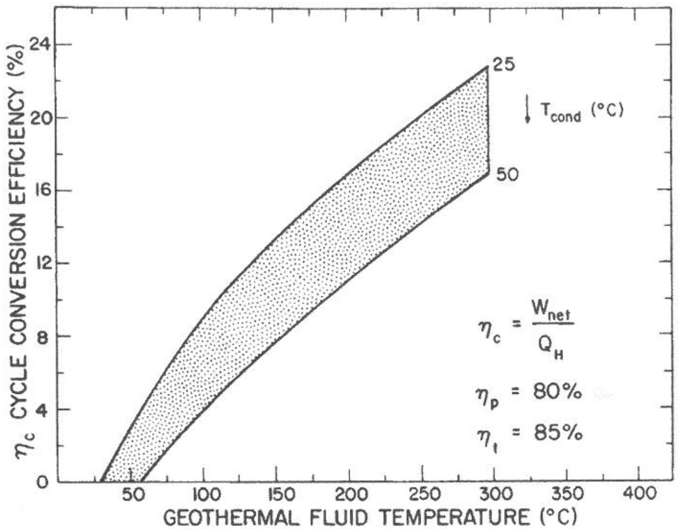

Figure 11.11
Typical range of anticipated cycle efficiencies for geothermal power plants. Adapted from Tester (1982).

efficiency). New technologies have been improving the practical efficiency of power production toward ideal thermodynamic limits to provide an economical process. For example, for a number of these low-temperature alternative energy sources, several hydrocarbons and their halogenated derivatives have been proposed as working fluids in Rankine cycles rather than the conventional choice of water/steam (Milora and Tester, 1976; Tester, 1982).

Figure 11.11 shows the typical range of cycle efficiencies expected for geothermal power plants. The Second Law of Thermodynamics imposes a real limitation on the production of electricity from low-temperature geothermal heat sources. The total maximum work that can be produced by cooling a condensed geofluid from its wellhead condition T_{gf} to the so-called dead state, or ambient condition T_o, is given by the thermodynamic availability B. The maximum work per unit mass of geofluid is then given by

$$\Delta B = [\Delta H - T_o \Delta S]_{T_o}^{T_{gf}} = W_{max} / m_{gf} = P_{max} / \dot{m}_{gf} \qquad (11.6)$$

where $\dot{m}_{gf}$ is the geothermal fluid flow rate, ΔH is the enthalpy difference, and ΔS is the entropy difference between states for the geofluid on a per unit mass basis. This maximum work quantity, W_{max}, or maximum power, P_{max}, can then be compared to the actual amount of work produced by any real power conversion process, W_{net}.

Comparisons of this type are usually achieved by defining a cycle efficiency η_{cycle}, which represents the net useful work W_{net} obtained from the system divided by the amount of heat transferred from the geothermal fluid Q_H:

$$\eta_{cycle} = \frac{W_{net}}{Q_H}. \qquad (11.7)$$

As the cycle efficiency decreases, the amount of heat rejected to the environment increases. For an ultimate sink at 25°C with a geothermal fluid heat source at 50°C, cycle efficiencies would be less than 5%, with 95% of the extracted geothermal energy rejected to the environment as heat. As a source temperature rises, the efficiency increases, as shown in figure 11.11.

An alternative approach to using cycle efficiency would be to compare directly the real work to the maximum possible work by defining utilization efficiency, η_u, as

$$\eta_u \equiv \frac{W_{net}}{W_{max}} = \frac{P}{\dot{m}_{gf} \Delta B} \qquad (11.8)$$

where P = net power extracted, ΔB = availability per unit mass, and $\dot{m}_{gf}$ = geothermal fluid-flow rate. Then, η_u is a direct measure of the effectiveness of resource utilization, because at a fixed T_{gf}, higher values of η_u correspond to lower well-flow rates for a given power output. In contrast, the cycle efficiency, η_{cycle}, is a measure of how efficiently the transferred geothermal heat is converted to work. The utilization efficiency concept is particularly useful in comparing different power conversion options for the same resource conditions. Ideally, η_u should be as high as possible, but there are limitations in the efficiency of work-producing machinery (turbines and pumps), as well as in the size of heat-transfer systems associated with generating power.

System options Figure 11.10 illustrates several utilization schemes for electric power production and direct use. Typically, a Rankine cycle of some type is employed. In the multistage flash system shown, the pressure of the produced geofluid is reduced to generate saturated vapor and liquid phases. The vapor fraction is then expanded in a condensing steam turbine/generator to produce electric power. The liquid fraction is flashed again to a lower pressure with the generated vapor expanded in the turbine from a lower starting pressure. Although the process can be repeated for multiple stages, two-stage systems are usually the best choice economically.

For vapor-dominated resources, such as those at the Geysers field in California, a direct-steam turbine condensing cycle is used. Particulate matter is removed from the steam before it enters a low-pressure turbine that employs conventional materials and designs.

When natural geofluids contain significant amounts of noncondensable gases, a direct-steam or flashing cycle is not a good choice. Indirect binary-fluid or two-phase-expander cycles (Tester, 1982) are more efficient for these applications. Binary-fluid cycles are closed-loop Rankine cycles that involve a primary heat-exchange step in which a secondary working fluid is vaporized, expanded through a turbine/generator, and condensed (as shown in figure 11.10). Binary-fluid systems tend to operate at somewhat higher work-to-heat rate efficiencies for geothermal fluid temperatures below 200°C. They are particularly well suited to take advantage of lower ambient temperatures (25°C or less) for cooling, and are relatively insensitive to the presence of noncondensables. Furthermore, because these nonaqueous secondary working fluids have low-temperature vapor densities considerably greater than steam, much smaller and less expensive turbines would be required for the same power output. Flashing cycles are, of course, simpler in that they do not require a primary heat exchanger or secondary fluid feed pump, but flashing can cause difficult scaling problems.

If the geothermal fluid contains large amounts of dissolved material that may corrode or deposit on heat-exchange surfaces, a combined multistage flash and organic binary cycle may offer a reasonable solution. This system can be designed in a number of ways. For example, a two-stage flash unit could be used to produce steam for fluid vaporization in an organic Rankine cycle. Other designs may involve a dual-cycle system where the flashed steam fraction drives a turbogenerator, and a binary cycle operates using a remaining liquid fraction to vaporize the secondary working fluid. Organic binary systems are state-of-the-art technology requiring some development, including the design of larger-capacity hydrocarbon units, control and valving systems, turbine seals for hydrocarbon vapors, and improved resistance to corrosion, erosion, and scaling of certain components.

Working fluid selection Accurate values of the thermodynamic properties of proposed working fluids are required to calculate electric power-cycle performance. Heat capacity at constant pressure in the ideal gas state C_p^*, saturation vapor pressure P^{sat}, pressure-volume-temperature (PVT) behavior, enthalpy and entropy changes, and liquid density at saturation ρ_l^{sat} can be expressed with semiempirical equations. Many hydrocarbons, fluorocarbons, and other organic working fluids have been examined for use as a replacement for water in low-temperature power conversion cycles. For example, R-600a (isobutane, i-C_4H_{10}), R-32 (CH_2F_2), R-717 (ammonia, NH_3), RC-318 (C_4F_8), R-114 ($C_2Cl_2F_4$), and R-115 (C_2ClF_5) were studied to provide a range of properties including molecular weight and critical temperature and pressure (Milora and Tester, 1976). All of these compounds have relatively high vapor densities at heat rejection temperatures as low as 20°C and would result in very compact turbines in comparison to steam turbines of similar capacity.

Factors other than desirable thermodynamic properties frequently determine practical working fluids. These include the fluid's thermal and chemical stability, flammability, toxicity, material compatibility (e.g., resistance to corrosion), and cost. The major disadvantage of hydrocarbons such as propane, pentane, and isobutane is their flammability, which requires costly explosion-proof equipment and ventilating systems. The situation with fluorocarbons is more complex, but thermal instability is an important issue.

Engineering design criteria Any real process for generating electricity or heat has inefficiencies or irreversible steps that result in a net work less than W_{max} given in equation (11.6). Efficient use of the resource may be necessary for commercial feasibility if reservoir development costs are high. Efficient utilization requires the following conditions:

1. Most of the heat is extracted from the geothermal fluid before disposal or reinjection.
2. Temperature differentials across heat-transfer surfaces are maintained at minimum practical levels.
3. Turbines and feed pumps are carefully designed for optimum efficiency.
4. Heat is rejected from the thermodynamic cycle at a temperature near the minimum ambient temperature T_o.

Whether or not these conditions can be met depends on the choice of thermodynamic cycle and fluid working medium, the geothermal fluid temperature, and the temperature of the coolant (water or air) to which the power plant rejects waste heat. For example, if waste heat is to be rejected from the thermodynamic cycle at a constant temperature by a condensing vapor (as in condition 4 above), then the working medium's critical temperature must be greater than the temperature of the power-plant coolant. Fulfillment of conditions 1 and 2 suggests the use of supercritical Rankine cycles. Thus, the critical temperature of the working fluid should also be below the maximum geothermal fluid temperature.

11.3.5 Equipment

Heat exchange and prime-mover fluid production As illustrated in figure 11.10, a geothermal electric or heating system may require a variety of heat-transfer steps to produce a suitable prime-mover fluid. For example, for binary-fluid cycles, a primary heat exchanger operating as a combined preheater, boiler, and superheater at subcritical pressures or as a vaporizer at supercritical pressures will be required to remove heat from the geothermal fluid and generate the organic vapor for injection into the turbine. In a flashing cycle, prime-mover steam is produced by reducing the pressure of the fluid in one or more steps. In both cases, the design and component sizing of the heat exchanger or flashing unit require specification of the appropriate duty factor for each unit (J/h, or kg steam generated/h) and of temperature and pressure differences.

Because power conversion efficiencies are low, the amount of heat transferred may be 5 to 15 times the power produced. Large heat exchangers are required at significant cost. For example, a 100 MW geothermal plant with a 12% cycle efficiency requires about 60,000 m^2 (650,000 ft^2) of heat-exchange surface area. Thus, multiple, parallel units of 1,900–5,500 m^2 (20,000–60,000 ft^2) would be utilized.

For a primary heat exchanger in a binary cycle, the overall heat-exchange surface area, A, can be expressed as a function of the heat load, $\dot{Q}$, an appropriate mean $\overline{\Delta T} = \langle T_{hot} - T_{cold} \rangle$, and an effective overall heat-transfer coefficient U:

$$A = \frac{\dot{Q}}{U\overline{\Delta T}}. \tag{11.9}$$

Practical ΔT should be selected to keep the heat exchanger cost at a reasonable level. In some cases, the exchanger might reach a pinched condition where ΔT approaches zero at one or more locations. Then, a minimum ΔT would have to be specified for any potential pinch points, consistent with practical heat-exchange area requirements.

To estimate the surface area of any exchanger, realistic values may be required for heat transfer coefficients of both fluids, wall resistance, and fouling factors. Since many different geothermal brine compositions and working fluids operating in subcritical and supercritical modes are under consideration, no single optimum design can be proposed.

Because the chemical compositions and temperatures of geothermal fluids vary widely from site to site, it is difficult to estimate accurately the extent of a potential scaling or fouling problem for primary heat exchangers without field testing. For example, the 300,000 ppm total dissolved solids (TDS) and 370°C temperatures of Salton Sea geothermal brines in the Imperial Valley in California present a more challenging problem than the brines at Cerro Prieto, which have <20,000 ppm TDS and 300°C temperatures. HDR systems introduce another factor, in that the circulating water is not indigenous to the reservoir. Dissolution products build up in the circulating fluid and might present scaling problems, particularly at higher reservoir temperatures (>250°C).

Only certain types of heat exchanger designs are appropriate for geothermal applications. These include shell-and-tube exchangers, fluidized-bed exchangers, and direct-contact exchangers. Direct-contact and fluidized-bed systems may be the only usable candidates when scale deposition rates are high.

When steam produced by flashing is the prime-mover fluid and is used directly in a condensing turbine, no primary heat-exchange step is required. In its place,

pressure reduction is used to produce a saturated vapor fraction. In a typical installation, the first stage of flashing is done at the wellhead. The two-phase mixture produced is piped to a separator system—frequently a cyclone unit—where the steam and liquid brine are separated. The steam fraction is transmitted to the turbine-generator unit located in a central area, and the liquid fraction is reinjected, discarded, or flashed to a lower pressure to produce additional steam for turbine expansion. This process can be continued as many times as are economically feasible. A two-stage flash system may produce 20–30% more power than a single-stage unit at the same total geothermal fluid-flow rate. But the improved performance of multistage systems must be balanced against the additional complexity and cost of utilizing the secondary steam (Eskesen, 1980).

Turbines In selecting nonaqueous working fluids for power-cycle applications, turbine sizes should be small to reduce costs and offset the additional heat-exchange surface area required for binary-fluid cycles. It is important to operate geothermal turbines at high efficiency whether they use steam or organic binary fluids. A similarity analysis of performance shows that turbine efficiency is essentially controlled by two dimensionless numbers involving four parameters: blade pitch diameter, rotational speed, stage enthalpy drop, and volumetric gas-flow rate (Baljé, 1962). Maximum turbine efficiency requires a specified relationship among these parameters. Therefore, turbine sizes, operating conditions, and, consequently, costs can be estimated. For fluid-screening purposes, a generalized figure of merit that relates directly to turbine size has been developed (Milora and Tester, 1976). Many organic fluids offer a significant reduction in turbine size. For example, a 100 MW_e capacity plant designed for a 150°C liquid-dominated resource would require numerous large turbine-exhaust ends with steam flashing. An ammonia binary cycle would require only a single exhaust end (Milora and Tester, 1976). Low-pressure steam turbines for geothermal operation with 50 MW capacities or greater have been commercially produced for a number of years. Organic binary cycles using geothermal energy have been placed in commercial operation, albeit at a smaller scale than flashing systems (Mock, Tester, and Wright, 1997).

Pumps Pumping requirements for geothermal systems are of four major types:

1. downhole pumps for fluid production,
2. fluid-reinjection pumps,
3. power-cycle feed pumps,
4. geothermal-fluid transport pumps.

According to a published survey and assessment of existing geothermal pumping equipment (Nichols and Malgieri, 1978), surface-mounted, conventional multistage centrifugal designs can be used for commercial-size applications for pumps of types

2–4 above. Reinjection pumps may present problems where highly corrosive and erosive geothermal brines are used. The most challenging problems are with downhole pumping, because of severe environmental and design constraints.

Several types of downhole pumping systems have been proposed. These include shaft-driven and submersible electric-motor-driven, multistage, vertical centrifugal designs that are commercially available and have been tested by a number of companies. There are complexities associated with downhole shaft pumps driven mechanically on the surface. For example, line-shaft bearings need to be effective for such high-temperature service. Electrically driven submersibles also experience serious problems at operating temperatures above 180°C because of the effects of heat, moisture, and brine on the motor. The other general pump types under development include organic-fluid- or steam-driven, downhole turbine pumps (Sperry Research, 1977), and hydraulically driven systems. In these cases, the problems of electric-motor- or shaft-driven units are replaced with a complex concentric wellbore-piping system.

Condensers and heat rejection Because conversion efficiencies are low, a large fraction of the extracted geothermal heat is ultimately rejected to the environment. For example, a geothermal plant operating with a cycle efficiency of 10% rejects about three to six times as much heat as a similar capacity fossil- or nuclear-fired unit. Consequently, the substantial costs associated with condenser-desuperheaters and cooling towers in geothermal systems strongly influence economic feasibility. Seasonal and diurnal variation of ambient dry-bulb temperatures can also significantly affect cycle performance. For dry cooling systems, condensing temperatures change seasonally, causing changes in the power output of the plant. Because of the size of geothermal units (≤100 MW_e), operating with a floating power output might be desirable.

The availability of water for cooling is also important. Fossil and nuclear plants are often located near abundant water supplies. Geothermal plants, of course, have to be located at the resource regardless of the water situation. Even so, if evaporative cooling is used, water consumption is high. For example, a 50 MW geothermal plant operating at 10% efficiency would consume cooling water at a rate of approximately 145 L/s (2,300 gal/min). In many existing plants, cooling water is provided by the geothermal fluid itself. For example, evaporative cooling at The Geysers in California consumes approximately 80% of the geothermal fluid, so that only 20% is reinjected (Holt and Ghormley, 1976). For liquid-dominated and geopressured reservoirs, total reinjection may be required to avoid subsidence or for other environmental or regulatory reasons. Furthermore, the brine may have to be treated before reinjection.

Design options for waste-heat rejection include direct-contact spray condensers, multipass water-cooled surface condensers, direct air-cooled condensers, spray

ponds, and wet, wet/dry, and dry cooling towers with forced-, induced-, or natural-draft design. For many power-cycle operations, evaporative cooling has been commonly used and will continue to be employed in future designs. However, when total reinjection is required and water is scarce or expensive, totally dry and wet/dry cooling are the only alternatives. Although high capital costs have prevented widespread use of completely dry systems in the US, many such systems have been operating successfully in Europe. The major disadvantage of dry systems, besides higher cost, is that performance of the power cycle depends on dry-bulb temperature fluctuations. If floating power capacity is an acceptable operating mode for small baseload units, then variations in power output would not be a serious detriment to using totally dry systems.

An alternative to totally dry systems is a wet/dry cooling tower, which combines advantages of both systems. Low condensing temperatures can be maintained during peak periods with high dry-bulb temperatures by using supplemental evaporative cooling, and water can be conserved during periods of low dry-bulb temperature. Fogging and drift are also better controlled. Wet/dry towers cost more, however, and are somewhat more difficult to operate and maintain.

11.3.6 Power-cycle performance

In principle, the utilization efficiency, η_u, can be somewhere between zero ($P = 0$) and unity ($P = \dot{m}_{gf} W_{max}$). Recall from equation (11.6) that W_{max} is a function only of the fluid's condition as produced at the wellhead temperature (T_{gf}) and the ambient or "dead state" temperature (T_o). In practice, its value is determined from economic considerations by balancing the cost of obtaining the heat (i.e., drilling and piping costs) against the cost of processing it (e.g., heat exchangers, turbines, pumps) to generate electricity in the power station. If η_u is small, then the resource is being utilized poorly, and a large investment in wells is required (cost per unit power goes to ∞ as η_u approaches 0). On the other hand, if we approach utilization of the full potential of the resource, then total well costs decrease but the required investment in highly efficient power-conversion equipment is high (cost per unit power goes to ∞ as η_u approaches 1.0). The economic optimum occurs when η_u assumes some intermediate value (e.g., at The Geysers, $\eta_u \approx 0.55$ with $T_o = 26.7°C$).

In a typical analysis of cycle performance, a set of equations is developed to describe the work and heat-flow rates to and from the chief plant components. After selecting a working fluid and a geothermal-fluid inlet temperature, the principal independent design variables are the maximum cycle-operating pressure, P_{max}, at the turbine inlet, the condensing temperature, and the heat exchanger's approach temperature.

For any given working fluid, there is an optimum set of operating conditions yielding a maximum η_u for particular geothermal-fluid and heat-rejection temperatures.

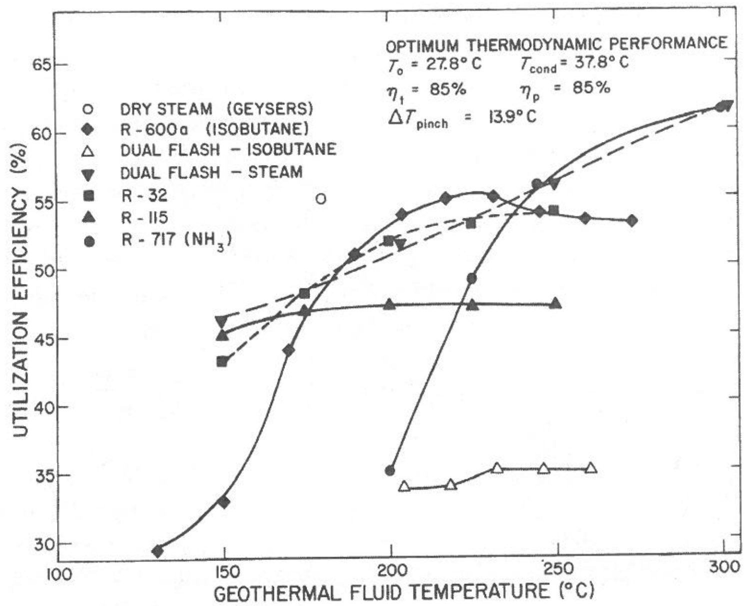

Figure 11.12
Comparison of maximum utilization efficiencies for different conversion methods as a function of geothermal fluid temperature. Optimum thermodynamic ΔT_{pinch} = 13.9°C. Adapted from Armstead and Tester (1987) and Tester (1982).

Computer optimizations for several different working fluids were conducted for geothermal fluid temperatures ranging from 100–300°C for a heat sink temperature of 16.7°C (Milora and Tester, 1976). At each point, cycle pressures were varied until an optimum was determined at that temperature. A characteristic maximum, of η_u, is observed at a resource temperature that is different for each fluid but is generally in the range of 55–65% efficiency. Figure 11.12 compares maximum utilization efficiencies for different conversion methods, including single- and dual-stage, flashing, binary, direct-steam injection, and dual flash-binary cycles, combining data from a number of sources (Holt and Ghormley, 1976; Milora and Tester, 1976). The output of a multistage steam-flashing cycle primarily depends on the following:

1. initial fluid temperature and composition,
2. flashing conditions of each stage (P_i^{sat}, T_i),
3. turbine efficiencies,
4. condensing temperature (Eskesen, 1980).

Generally, the work produced by a given flash stage is proportional to the amount of vapor created by the isenthalpic throttling step (see figure 11.10) and

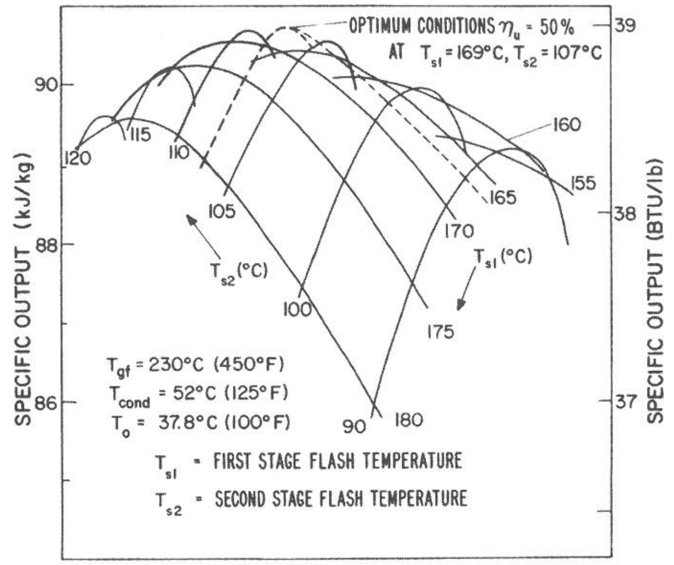

Figure 11.13
Effect of flashing conditions on the performance of a dual-flash/dual-admission steam turbine cycle operating on a 230°C, CO_2-free geothermal fluid. Performance shown for the following conditions: turbine efficiency η_t = 85%; feed pump efficiency η_p = 85%; brine containing 2.5 wt% NaCl T_{cond} = 52°C; T_o = 37.8°C; T_{s1} = first-stage flash temperature; T_{s2} = second-stage flash temperature. Adapted from Eskesen (1977, 1980).

the enthalpy difference that the vapor experiences when isentropically expanded in the turbine to the condensing pressure. If the temperature of the flashed fluid is only slightly below its wellhead temperature, then the fraction of vapor produced is small but the isentropic enthalpy difference is large. The opposite is true if the fluid is flashed to just above the condensing temperature. Optimal performance in terms of power output occurs at some intermediate flashing temperature. The performance of a two-stage flashing system is shown in figure 11.13, assuming an average turbine efficiency of 85%. Maximum output (η_u = 0.50) occurs when the first flashing stage is at 169°C (T_{s1}) and the second is at 107°C (T_{s2}).

11.4 Sustainability Attributes

11.4.1 Reservoir lifetime issues

Geothermal energy is considered by many to be the only renewable that does not depend directly or indirectly on sunlight. Some have argued that "it must be tapped slowly enough so as not to deplete the accessible reservoir of heat, and thus be truly renewable" (Brown, Flavin, and Postel, 1990). However, given the magnitude and distribution of the global geothermal resource, this restriction is neither practical nor necessary since the resource is large and improving technology will allow geothermal energy to contribute for centuries (see, for example, treatments by Wright, 1995; Armstead and Tester, 1987; and Rowley, 1982).

Whether or not a resource can be said to be renewable depends on the time frame under consideration. Kozloff and Dower (1993) suggest that a perspective of 300 years or more of continuous production is adequate for an energy fuel to be considered as renewable, since technical advances during that time will have rendered today's perspective obsolete. For geothermal resources, the renewability concept has a special connotation. In all practical situations, some degree of local depletion of geothermal energy within a specific reservoir occurs during production. But renewal of the thermal energy content will occur by natural processes of heat conduction from surrounding hot rock, by decay of indigenous radioisotopes, such as those of potassium, thorium, and uranium, and by convective heat transfer due to water recharge. With average rock thermal diffusivities of 10^{-6} m^2/s, heat conduction rates are slow enough to require a substantial time period to restore the thermal energy content of a locally depleted reservoir. Typically, within a period of time less than 10 times the production period, essentially complete recovery of original rock temperatures will occur (see Sutter et al., 2011, for a detailed analysis). Of course, for some hydrothermal systems, natural water recharge rates may be limiting unless artificially supplemented as was the case at the Geysers field in California.

We can also express the renewability of geothermal energy using the methodology introduced for biomass in section 10.1. In terms of that nomenclature, the dimensionless time constant, τ_r/τ_u, representing the ratio of time needed for resource generation to a characteristic societal utilization time, could range from about 10 to 1 depending on the specific characteristics of the geothermal field. For example, there are wells at the Larderello field in Italy that have been in full production for more than 70 years, while others have provided fluid at useful rates for only a few years.

Wright (1995) argues that the traditional geothermal project analysis underestimates the sustainability of production from a geothermal resource. Such analyses are usually done to demonstrate the financial viability of the project using constant and relatively high discount rates, and make pessimistic estimates of resource depletion. Field production is not only simulated in feasibility studies but carried out in practice in a conservative way. The geothermal field is said to be depleted when it will no longer sustain some chosen level of generation. Even at this point, however, significant quantities of heat remain in the rock-fluid reservoir system.

11.4.2 Environmental impacts

The main environmental concerns facing a geothermal development include land and water use, noise, seismic and subsidence risks, gaseous emissions, liquid effluents, and solid waste resulting from the development, production, and decommissioning of the geothermal field. In terms of minimizing point-source pollution, many operating geothermal plants have nearly emissions- and waste-free operation.

An important feature of the land and water use requirements for existing hydrothermal and future advanced systems is that the entire fuel cycle is located at the plant site. There are no strip mines, gas or oil pipelines, or waste repositories. Water consumption can be controlled by using total reinjection, nonevaporative cooling, and general pressure management in closed-loop recirculating cycles. Because the major elements of a geothermal system are underground, the surface footprint of a geothermal plant is relatively small. Typical requirements include structures to house the power-generating and heat-exchange equipment, land space for wellheads, and a pipe distribution system.

When geothermal energy is used to generate electricity, there is always waste heat rejected to the environment. Typically, the largest visible feature of a geothermal electric power plant is its battery of cooling towers or air-cooled condensers. Impacts of the waste heat on the local ecology and the means used to reject it need to be considered. Fortunately, individual plant sizes are usually limited to 50–100 MW$_e$, resulting in distributed waste heat rates that usually have small local environmental consequences. In addition, there is potential to utilize some of the waste heat for direct-use, low-temperature applications such as heating buildings, greenhouses, and soil and aquaculture/fish farming. These cogeneration activities are usually carried out on a small scale so that additional capital investments are marginal.

During field development, drilling operations, and plant construction, noise and disruption of normal activities are of concern. After the plant begins operation, noise levels are usually controlled by silencers and other active noise-abatement measures. At many geothermal sites, the surface land remains in service for residential, agricultural, recreational, and industrial uses. During stimulation of the reservoir by pressurization, the induced growth of small fractures to improve the permeability of the reservoir may generate low-intensity seismicity that may sometimes be felt at the surface. Obviously the reservoir site should be chosen well away from any existing fault lines, and the pressurization is done in stages to prevent unanticipated large effects.

Induced seismicity and subsidence due to geothermal fluid injection and extraction causing reservoir pressure changes are also possible. However, the magnitude of these environmental concerns is often tempered by the high natural seismic activity levels that are commonplace in most active hydrothermal regions. Typically, high frequencies and densities of small microseismic events occur within and at the margins of these fields. In fact, they are used to map the behavior of many systems, including the hydraulic stimulation of EGS reservoirs. Such small events relieve *in situ* stresses in a regular fashion and are not contributing to risks of massive fault movements or major earthquakes. Monitoring of seismic activity in geothermal areas is commonly employed to verify general background behavior, to measure the level of induced seismicity, and to assess risks. Current data suggest that seismic risks in geothermal developments are low when there is proper assessment and siting of geothermal developments away from major fault zones.

When large volumes of fluid are removed from underground reservoirs, the weight of the overburden can cause compaction of the underlying rock formation, leading to observed subsidence of the land surface. In vapor-dominated fields, stable formations with *in situ* subhydrostatic pressures are common, and subsidence is minimal and rare. However, in liquid-dominated fields with superhydrostatic fluid pressures, subsidence effects have been observed if replacement fluids are not injected to maintain reservoir pressures. Similar effects are observed in oil and gas fields, where water injection is routinely used to mitigate subsidence. In a geopressured reservoir, subsidence can also be a problem, as the reservoir itself is supporting a major portion of the lithostatic stress. Here, fluid injection is needed to replace fluids that are extracted to maintain formation pressures and formation stability and production rates. With EGS systems, closed-loop arrangements with total reinjection of fluids are envisioned, and thus both seismic and subsidence risks should be minimal.

Because all hydrothermal and geopressured systems contain steam and/or water phases with varying concentrations of dissolved gases (CO_2, H_2S, NH_3, etc.) and minerals (silicates, carbonates, metal sulfides and sulfates, etc.), depending on *in situ* conditions, there is a possibility of increased release rates of these substances. Nonetheless, technologies exist to separate and isolate most components in gaseous or liquid streams in order to control concentrations within regulated guidelines. For example, the Geysers field located in Lake County, California, has been able to operate well within California Clean Air Standards, which are currently the strictest in the US, by using appropriate H_2S abatement techniques. In addition, reinjection of spent brines or condensed vapor streams back into the formation is used to limit emissions and effluents and to keep the reservoir pressurized.

11.4.3 Dispatchable heat and power delivery

One of the attractive features of geothermal energy is that it can be applied for both baseload and peaking needs for electricity and process heating. Furthermore, the reservoir itself has built-in storage capacity in the hot fluid and rock that compose it.

For electrical applications, due to the inherently low conversion efficiency of geothermal systems (10–20%), multiple production and reinjection wells are used in installations to supply one power plant, typically with a generating capacity of 10–60 MW_e. Therefore, if the power plant is designed properly, it would be possible to lower the output by throttling down the flow in one or more production wells. In addition, for EGS applications, a periodic injection-production cycle can be used with the reservoir providing dynamic storage.

11.4.4 Suitability for developing countries

Given the typical range of sizes of geothermal field developments from a few MW_e to 100 MW_e or more, their application in distributed generation systems is attractive. In addition, the conversion technology associated with the power plant is relatively conventional and fully dispatchable, making geothermal plants attractive for new installations in developing countries or remote regions. Indeed, this has been the case in Indonesia, the Philippines, and Central America.

Admittedly, some infrastructure for exploration, drilling, reservoir stimulations, and power plant construction is needed to bring geothermal systems on line. Fortunately, many of the tasks involved can use existing labor forces, with on-site training provided by the developer. Power plant components can also be shipped to sites easily, as they are typically modular.

11.4.5 Potential for CO_2 reduction and pollution prevention

Dissolved CO_2 can be released by those geothermal systems that either employ flashed steam cycles or do not use total reinjection of fluids. The range of possible CO_2 emissions from plants utilizing hydrothermal resources in this manner is estimated to be 0.01–0.05 million metric tonnes (MMT) of carbon per quad of energy (10^{15} Btu or 10^{18} J). However, this is considerably less than the emissions for fossil-fuel alternatives (coal: 29 MMT/quad, oil: 21 MMT/quad; and natural gas: 15 MMT/quad) (Wright, 1995). Hydrothermal reservoirs also have very low emission levels of SO_x, no NO_x, and minimal particulates. For closed-loop HDR concepts, no CO_2, NO_x, SO_x, or particulates are emitted, assuming all captive plant power needs are provided by geothermal sources.

There are substantial opportunities for using geothermal energy to reduce greenhouse gas emissions and atmospheric pollution levels by displacing existing or planned fossil-fired electric power generation plants or fossil-fired boilers used for direct-heating applications. These stationary systems currently make up about 80% of worldwide total energy demand. The other 20% is in the transportation sector, which also requires a transportable and storable fuel. A few options exist for using geothermal energy to produce transportation fuels as well (e.g., electrolysis of water to generate hydrogen which could either be used directly or be used to process biomass to produce liquid hydrocarbon fuels that are CO_2 neutral). Currently, these are not economically attractive options, but concern about burning fossil fuels could change the balance in their favor.

11.5 Status of Geothermal Technology Today

11.5.1 Hydrothermal

International geothermal power industry Providing energy services with robust infrastructures drives social and economic development. Although many developing countries have more than quadrupled their energy usage since 1960, they still face energy shortages that decrease the efficiency of their industrial infrastructure and lead to economic loss. Geothermal power is particularly attractive for developing countries because it can provide uninterruptible, indigenous baseload electric power and heat for both on-grid and remote, off-grid applications. Furthermore, many developing countries are located in areas of active geologic processes—areas that contain high-grade geothermal resources. The Geothermal Energy Association (GEA, 1993) estimates that as much as 78,000 MW_e of geothermal electric power generation from hydrothermal resources are available for development from already known resource areas in some 50 developing countries. Realization of this amount of clean power generation would be of immeasurable value to the economies and environments of these countries. Table 11.2 and figure 11.14 show the

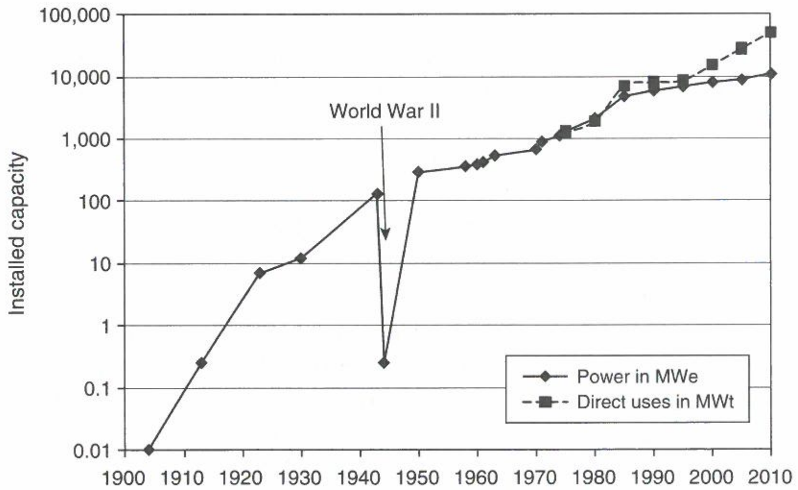

Figure 11.14
Historic development of geothermal installed capacity (power and direct uses) worldwide. There are no reliable data for direct uses before 1975. Data sources: Bertani (2010); Lund, Freeston, and Boyd (2010); Gawell and Greenberg (2007); Fridleifsson and Ragnarsson (2007).

Table 11.2
Current and projected deployment of geothermal energy by region.

	(2009)		2020		2030		2050	
REGION	Direct (GW_{th})	Electric (GW_e)	Direct (GW_{th})	Electric (GW_e)	Direct (GW_{th})	Electric (GW_e)	Direct (GW_{th})	Electric (GW_e)
OECD North America	8.443	3.998	50.0	9.5	120.0	15.0	230.0	42.0
Latin America	0.545	0.503	2.0	1.5	5.0	3.0	10.0	7.0
OECD Europe	10.959	1.550	62.0	3.0	150.0	5.5	300.0	28.0
Africa	1.520	0.169	4.0	0.5	11.0	1.5	18.0	9.5
Transition economies	1.064	0.110	3.0	0.5	5.0	1.0	10.0	5.0
Middle East	0.422	0	1.0	0.0	4.0	0.5	7.0	3.5
Developing Asia	0.478	3.094	5.0	6.5	10.0	14.0	20.0	31.0
India	0.203	0	2.0	0.0	5.0	1.0	10.0	3.0
China	3.687	0.024	20.0	1.0	50.0	4.0	125.0	17.0
OECD Pacific	1.257	1.105	6.0	2.5	15.0	4.5	85.0	14.0
TOTAL	28.578	10.553	155.0	25.0	375.0	50.0	815.0	160.0
EJ equivalent	0.279	0.256	1.589	0.639	3.843	1.34	8.353	4.541

Sources: Bertani (2010); Lund, Freeston, and Boyd (2010).
Note: "Direct" includes direct heating and cooling and geothermal heat pumps. "Electric" includes enhanced geothermal systems.

historical trends for geothermal energy utilization worldwide, with the exception of the period during World War II, when the Larderello field was out of service. With the exception of the World War II years, geothermal generating capacity has been exponentially increasing at about 8.5% per year since about 1920, as shown in figure 11.14.

As shown in figure 11.15, the most rapid development of geothermal energy for electric power production outside of the US is currently taking place in the Philippines and Indonesia. The Philippines have become the world's second largest producer of geothermally generated electricity, growing from a capacity of 890 MW_e in 1990, to 1,227 MW_e in 1995, to about 1,904 MW_e in 2009. Plans for the future include developing new fields, building new plants in collaboration with private industry, installing topping and bottoming cycles where feasible, and recovering waste heat for industrial uses (Huttrer, 1995).

Geothermal capacity has also grown rapidly in Indonesia, from 145 MW_e in 1990, to 310 MW_e in 1995, to 1,197 MW_e in 2009. The government of Indonesia has promulgated a series of regulations that will stimulate the geothermal industry by permitting private industry to develop steam fields and construct power plants and by significantly reducing the tax burden on such projects. As a further stimulus, the World Bank committed to funding large (20–55 MW_e), small (1–20 MW_e), and "mini" (35–1,000 kW_e) power projects at diverse sites in Indonesia (Huttrer, 1995). The growth in Indonesian capacity as shown in figure 11.15 reflects results of those and other initiatives.

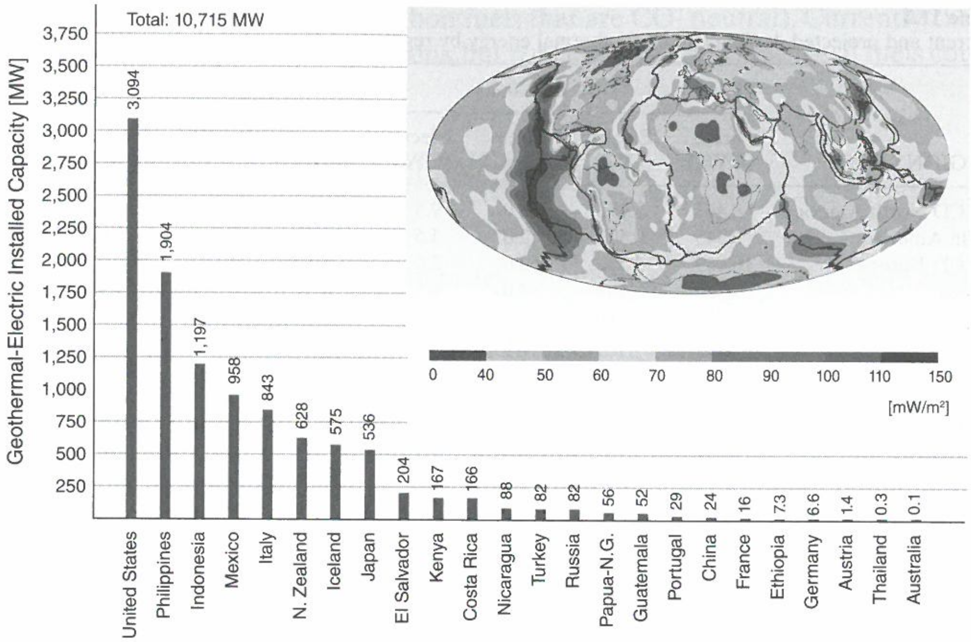

Figure 11.15
Geothermal electric installed capacity by country in 2009. Global map shows worldwide average heat flow in mW/m^2 and tectonic plate boundaries. Source: graph: Goldstein et al. (2011); inset map: IPCC (2011), figure 4.5.

In Japan, electric power produced from geothermal resources continues to increase with the construction of some new plants. At present, about 570 MW$_e$ of installed capacity have been built, and recent estimates of available (but still undeveloped) geothermal power indicate 5,820 MW$_e$ for 30 years for conventional steam generation, with an additional 14,720 megawatts for 30 years from binary generation (Ehara and Fujimitsu, 1995).

In many developing countries, electric power generation and sales are enterprises undertaken exclusively by their governments. However, before international investors can or will undertake investment in a country, they must be assured of a reasonable economic return, which depends on the existence of an appropriate business and financial, legal, and regulatory environment in the country, along with reasonable assurances that the facilities created by private investment will not later be nationalized without fair compensation, and that retroactive laws, taxes, or other unforeseen setbacks will not be put in place. Only then can the quality of a business investment be judged against other opportunities available to the same investor.

A key question is who will develop the geothermal reservoir field? Some developing countries prefer to use state-owned companies to develop their natural resources (e.g., petroleum, geothermal energy) and then sell fuel (steam) to the builder and operator of a power plant. The national utility or a direct customer purchases the electricity, and the power-plant developer recovers his investment from the income stream of the electricity sales. In other deregulated markets, completely private ownership is more common.

US geothermal power industry The US geothermal industry is composed of more than 50 companies. The major US field developers are Caithness Corporation, CalEnergy Company, Calpine Corporation, Constellation Energy, ESI Energy, Ormat International, Oxbow Power Services, and the geothermal division of Unocal Corporation. US utilities generating or purchasing geothermal power include Hawaiian Electric Company, Northern California Power Agency, PacifiCorp, Pacific Gas & Electric, Sierra Pacific Power, Southern California Edison, and Utah Municipal Power Agency. In 2009, the US geothermal power industry had about 3,090 MW$_e$ of generation capacity and produced about 15 billion kW$_e$h/year, primarily in four states: California, Hawaii, Nevada, and Utah. Geothermal energy is the second-largest grid-connected renewable electricity source, exceeded only by hydropower. In 2009, geothermal systems generated 5 times more electricity than solar energy and 2.5 times more than wind energy (see plate 6).

Nonetheless, hydrothermal geothermal resources must be managed properly or depletion rates can be large. The Geysers geothermal field, located about 120 km north of San Francisco, California, and the most productive geothermal field in the world, provides a useful example. Power generation there has been decreasing (7–8% per year) due to declining reservoir pressure since 1987. The problem appears to be that the natural recharge rate of fluids is inadequate to keep pace with the reservoir production rate. In contrast, the thermal energy content of the reservoir rock within the field is far from depleted—only 5% of the thermal energy has been consumed in almost 40 years of production. Recent joint research work by the industry and the US DOE has indicated that injection of supplemental water into the reservoir will help arrest the pressure decline and enable the reservoir to produce power for many more decades (see Voge et al., 1994; Enedy, Enedy, and Maney, 1991). However, studies by Enedy and others indicate that injection will have to be done with care to avoid adverse interference effects that could lead to short-circuiting of cooler fluids into nearby production wells. Construction of a 46-km-long, 51-cm-diameter wastewater pipeline from the Lake County Sanitation District to the southeast part of the Geysers field was completed in 1998 (see Dellinger, 1996, for details). This pipeline brings 29.5 million liters (7.8 million gallons) per day of wastewater to the geothermal field to help maintain reservoir pressure while at the same time disposing of the wastewater in an environmentally advantageous way. Reservoir engineers anticipate that the project will increase generation at the Geysers field by at least 70 MW_e. With the successful start of that project, the city of Santa Rosa planned a project to determine the feasibility of building a pipeline from their wastewater treatment plants to bring additional water for recharging the central part of the Geysers geothermal field. As of 2011, there were 15 operating power plants at The Geysers with a net generating capacity of about 725 MW_e.

Potential for geothermal power in the US Moderate- and high-temperature hydrothermal resources, in the range of 105–350°C, are located at accessible depths mainly in the western third of the continental US as well as in Alaska and Hawaii. At present, there are about 3,100 MW_e of installed generating capacity in the US, enough to serve the domestic needs of about 4 million people. Thus, geothermal energy has moved beyond the experimental stage. Approximately 5% of California's electricity and about 10% of Hawaii's electricity comes from hydrothermal resources. Both those states have renewable energy standards that mandate additional growth. There is substantial expansion and new geothermal development potential in these states, and there is potential for developing power plants in the near term in Alaska, New Mexico, Idaho, Washington, and Oregon. The rate of expansion of geothermal power in the US will depend on many factors, including availability of high-grade resources, economics, and policy incentives.

Comprehensive, well-documented assessments of the potentially recoverable hydrothermal resources in the US are few in number and often make limiting assumptions regarding energy markets where geothermal resources are competitive. Brook et al. (1979) gave the estimate of 95,000–150,000 MW_e from known and undiscovered hydrothermal reservoirs having a projected 30-year lifetime, but most people now believe this number is too high. Wright (1995) gave a rough estimate of 4,800 MW_e of electric power available for development by 2015, from high-grade hydrothermal systems in the contiguous 48 states. More recently, Bertani (2010) estimates that US generating capacity could grow to 5,400 MW_e by 2015, while the GEA (2010) provides a range from about 7,600 to 11,000 MW_e. Most of the disparity between these estimates is tied to the uncertainty of the magnitude of undiscovered hydrothermal resources, especially in the low to moderate temperature range. This uncertainty affects real and perceived risks, particularly at the early exploratory drilling phase of a project Therefore resulting projections are inherently quite speculative, with their accuracy dependent more on prevailing energy prices and the availability of financing than on specific technology.

11.5.2 Advanced systems

Geopressured Geopressured geothermal brines are hot, pressurized waters that contain dissolved methane and lie under the earth's crust at depths ranging from 12,000 to more than 20,000 feet (3,600–6,000 m). Brine temperatures range from 50 to 260°C; pressures from 560 to 1,380 bar (7,500–20,000 psi); dissolved salts from 20,000 to 300,000 ppm; and gas content from 0.65 to 2.85 SCM (standard m^3 [23–100 standard ft^3]) per barrel of brine. Geopressured resources occur worldwide. In North America, such resources are found in Alaska, in the Rocky Mountain regions, in California, and along the coast of the Gulf of Mexico (Beeland, 1986; Negus-de Wys, 1992). The northern Gulf of Mexico sedimentary basin contains a deep sequence of relatively permeable sandstone layers interbedded with relatively impermeable shales. Both formations are relatively porous and contain large quantities of hot brine with dissolved methane under abnormally high pressures.

Geopressured resources contain three forms of stored energy: thermal (hot brine), chemical (natural gas), and mechanical (hydraulic). It is possible to exploit each form singly or in combination to satisfy a variety of energy needs. In 1974, the federal government established a program to determine whether the geopressured aquifers along the Gulf Coast could be exploited technically and economically as a major source of domestic energy. The USGS has estimated that the northern Gulf of Mexico basin contains approximately 170,000 quads of energy (107,000 quads thermal at temperatures 100°C, and 63,000 quads from combustion of the dissolved natural gas) (Muffler and Guffanti, 1979; Wallace et al., 1979).

The geopressured R&D program supported by the US DOE successfully identified geopressured fairways in the onshore Gulf Coast areas of Texas and Louisiana, with an estimated 5,700 quads of methane in the sandstone reservoirs. In addition, the program established the feasibility of locating geopressured reservoirs using active seismic data and borehole petrophysical logs (or just well logs) from previously drilled petroleum wells, and demonstrated the feasibility of adapting the US petroleum industry's drilling and production technology to geopressured systems, proving it possible to extract the gas from the brine by simple and economical gravity separation techniques. The program also verified that geopressured pressure gradients range to more than twice the normal hydrostatic gradient, over temperatures ranging from 50° to 260°C. Further, the solubility of methane in geopressured brines was shown to decrease with increasing salinity. New technologies for assessing and using the resource were demonstrated, establishing that brine can be produced at rates of up to 40,000 barrels per day from a single well (note that 1 barrel equals 42 gallons US) and can be reinjected into shallow aquifers without affecting the surface and near-surface water and without causing subsidence or associated seismic activity.

The research program also characterized two large sandstone aquifers, each estimated to contain in excess of several billion barrels of brine. Technology was developed for successfully controlling the formation of calcium carbonate scale in well bores using phosphonate scale inhibitors. Electronic data bases were created using data from thousands of geophysical logs in Gulf Coast oil and gas wells and with technical bibliographic material at the University of Texas, Louisiana State University, and at the USGS facility at Bay St. Louis.

The technical feasibility of geopressured resource utilization was demonstrated in the late 1980s with a hybrid power system at Pleasant Bayou in Brazoria County, Texas, which supplied about 3,500 MW_eh to the Houston Power & Light Company's grid over a one-year period (Campbell and Hattar, 1991). In a collaborative effort sponsored by the US DOE and EPRI, the Ben Holt Company designed and constructed a 1 MW_e hybrid-cycle system in which gas was burned in an engine to generate electricity directly. Exhaust heat from the engine was then combined with heat from the brine to generate additional electricity in a binary cycle. Heat from the gas engine was available at high temperature, markedly improving the efficiency of the binary portion of the hybrid cycle and resulting in 30% more power than stand-alone geothermal and fossil-fuel-fired plants operating on the same energy resources.

At this point, it is difficult to estimate whether research and demonstration of geopressured systems will continue, as there are still significant risks that need to be addressed. A key area of concern is whether sustained production is possible from highly pressurized geopressured reservoirs to justify the investment costs for drilling and constructing power plants.

Magma Some researchers feel that recovery of energy from hot magma bodies is a goal worth pursuing because it would open up possibilities for both high-efficiency electricity generation and high-temperature chemical or metallurgical processing that is not possible with any other geothermal resource. Magma bodies are localized regions of immensely concentrated thermal energy consisting of molten or near-molten material at temperatures in excess of 650°C. To be classified as a geothermal resource, they need be located no deeper than 10 km (30,000 ft), at depths that are accessible with conventional drilling methods. In rare cases, magma bodies are found near or at the surface, such as at or near the sites of active volcanoes. Scientific teams from the US, the former USSR, and Japan have focused on developing engineering technologies for extracting heat. In particular, during the 1980s and 1990s scientists at Sandia National Laboratories experimented in the field with different methods at two sites in the US: at the Kilauea Iki lava lake in Hawaii, where actual heat-extraction tests were conducted, and in California at the Long Valley Caldera, where exploratory drilling was carried out (Colp, 1982; Gerlach, 1982). Other potential sites in the US include the Valles Caldera in north-central New Mexico and 12 active volcanoes of the Cascade range in the Pacific Northwest.

The possible use of magma for carrying out high-temperature chemical reactions to produce transportable fuels, such as methane and hydrogen, has been proposed by Gerlach (1982). In one concept, particularly suited for magmas rich in iron oxides, one could carry out the thermochemical reaction of ferrous oxide (FeO) and water to produce ferric oxide (Fe_2O_3) and hydrogen. In another concept, biomass would be gasified to produce methane (CH_4) at moderate temperatures and then synthesis gas, a mixture of hydrogen and carbon monoxide (CO), by further reaction of CH_4 with CO_2 at higher temperatures.

Modeling efforts at Sandia, based on preliminary field testing in Hawaii, suggest that a single well drilled into a magma body at 1,000°C could generate 30 MW_e. Another estimate of power generation costs by Crewdson et al. (1991) for Long Valley predicts that commercially competitive busbar costs of 5.6¢/kWh may be possible. Although these are estimates for high-grade magma resources located near the surface, drilling and its associated costs may not be the limiting factor. Of more importance is engineering a heat-extraction system that will work for extended periods at high rates of thermal power production. Critical issues include maintaining high heat-transfer rates when solidification of magma occurs during extraction, finding economic materials that can withstand the temperatures and chemistry of molten rock (including drilling hardware, well casing and cements, and tubular goods involved with heat extraction), and finding ways to insure that the reservoir itself remains stable and safe during drilling and production. Meeting these challenges will require an active R&D effort (which was under way with US DOE sponsorship until recently). Unfortunately, current R&D levels for magma are now at a low level, and it is too early in the development of this resource to provide reasonable projections of costs for providing electricity or process heat. The closest real activity to utilizing magma is the Icelandic Deep Drilling Project (IDDP), which is attempting for the first time to reach reservoir conditions above the critical point of water (374°C and 220 bar). As of May 2010, the first experimental well was producing superheated steam for several months before being temporarily shut down for modifications (see http://iddp.is/2010/07/336/).

Enhanced geothermal systems Hot dry rock (HDR) systems now are widely described in more scientific terms as "enhanced geothermal systems" (EGSs). The greatest potential source of geothermal energy is contained in hot rock formations at technically accessible depths (currently 10 km [30,000 ft]) in the earth's crust that do not contain sufficient fluids and/or permeability and porosity to permit heat extraction at commercially viable rates. Figure 11.3 illustrates the heat-mining concept being pursued to stimulate production in low-permeability formations in competent rock by creating an open network of fractures that emulate many features of existing hydrothermal reservoirs. The primary technique for engineering these EGSs utilizes fluid pressure to open and propagate fractures from wells placed in a region of rock at temperatures ranging typically from 150° to 300°C. The main idea is to enhance natural permeability hydraulically by opening old fractures and/or creating new ones and connecting them to a set of injection and production wells. Energy would be extracted by circulating pressurized water in a closed loop from the surface plant down one well, through the fracture network where it is heated, and up the second well to return it to the plant. Engineering the reservoir to allow adequate flow and heat transfer performance while minimizing water losses at its periphery is a major challenge. Within the plant, thermal energy could be used directly for residential or process applications or to generate electricity in a power cycle similar to the ones employed for hydrothermal resources. With this closed-loop design, emissions and effluents from EGSs are practically nonexistent. Of course, the impacts of waste-heat rejection, water and land use, and potential seismic risk are still present.

Because EGSs do not require contained hot fluids or *in situ* permeability, their resource base is much larger and more widely distributed—practically speaking, it is ubiquitous, varying only in grade. Table 11.1 provides estimates of the HDR (or EGS) resource base for low- and high-grade systems. Assuming that the rock formation is amenable to stimulation, its grade, in economic terms, is largely specified by the average geothermal gradient, as this determines drilling depths to reach certain temperature levels. The average baseline gradient for the world is about 25°C/km—this establishes the low-grade EGS resource, one that would have to be exploited if geothermal energy is to be universally available. Hyperthermal areas with gradients in excess of 60°C/km characterize the high-grade end of the resource. For example, in the western US, Iceland, and parts of Japan, generally higher heat flows and other desirable geologic conditions have led to large regions with gradients of 60–80°C/km and smaller areas with 100–200°C/km, such as in the Geysers–Clear Lake part of northern California.

The resource estimates for HDR (or EGS) given in table 11.1 are orders of magnitude larger than the sum total of all fossil and fissile resources. Although these estimates refer to the total usable thermal energy content of the geothermal resource that is accessible with current technology, even if only a small fraction can be economically extracted, the impact of EGS as a provider of sustainable, emissions-free energy would be far-reaching. In fact, it is this great potential of universal heat mining that has encouraged many to advocate pursuing EGS with national and international R&D efforts.

For about 25 years (1974–2000), the Los Alamos National Laboratory, with the sponsorship of the US DOE, led the research effort of developing EGS technology (Armstead and Tester, 1987; Tester, Brown, and Potter, 1989; Duchane, 1994). Most of the fieldwork was concentrated at the Fenton Hill site in north-central New

Mexico, which is in a high-gradient region on the western flank of an extinct volcano known as the Valles Caldera. For a period during the 1980s, the Federal Republic of Germany and the government of Japan supported a portion of the US effort at Fenton Hill under a collaborative agreement within the International Energy Agency (IEA). The Japanese, as reported by Sato and Ishibashi (1994) and Sato, Ishibashi, and Yamaguchi (1995), are now developing EGS technology on their own, and the Germans have joined forces with other members of the European Economic Community (EEC) to pursue EGS with modeling and field work at several sites in Europe. Duchane (1994) and Kappelmeyer et al. (1991) described European R&D on EGS. From about 1974 until 1992, the British were carrying out extensive field tests at the Rosemanowes site in Cornwall under sponsorship of the UK Energy Technology Support Unit at Harwell (for details, see Parker, 1989; Batchelor, 1984, 1987). Recently, they joined the EEC project in Europe and have suspended operations at Rosemanowes. There are other important R&D activities in other countries, including Russia (see Duchane, 1991) and Australia (MIT, 2006).

These field programs have made substantial progress in developing methods to drill, stimulate, map the structure, and characterize the performance of EGS reservoirs in a range of different geologic settings. Most of the field work has focused on creating EGS reservoirs in low-permeability formations that have little fluid content (i.e., low porosity), where the dominant features consist of sealed natural fractures or joints contained in otherwise competent rock of extremely low matrix permeability (10^3–10^7 times less permeable than a typical oil reservoir). In these cases, hydraulic fracturing methods employing the injection of pressurized water with or without special rheological additives have been used to create an open labyrinth of connected fractures. In other efforts, where open joint systems containing significant amounts of water or steam exist naturally (so-called hot wet rock), field development work concentrates on reservoir characterization to insure proper well placement to optimize the distribution of fluid flowing in the fractured system.

US, Australian, and Japanese testing has demonstrated that conventional drilling methods can be adapted for the harsh environments encountered in reaching zones of rock from 250° to 350°C, which are hot enough to be suitable for commercial power production in today's energy markets. Field testing has also verified that hydraulic pressurization methods can create permanently open networks of fractures in large volumes of rock. Experiments at Fenton Hill and Rosemanowes, for example, have extended open, connected fracture networks to kilometer dimensions, producing systems that are large enough for long-term commercial production. Techniques using chemical tracers, active and passive acoustic methods, and other geophysical logging techniques have been used to map out the geometric features of EGS reservoir systems to validate thermal hydraulic models of heat-extraction performance.

While this early work has demonstrated the technical feasibility of the EGS concept, none of the field testing to date has operated a commercial system. Two major issues remain as constraints to global commercialization: (1) the demonstration of sufficient reservoir productivity with low-impedance fracture systems of sufficient size and thermal lifetime to maintain economic fluid production rates of 50–100 kg/s per well pair at wellhead temperatures above 150°C, and (2) the high cost of drilling wells deep into hard rock. In certain geologic situations, controlling water losses is also important, as it can have negative economic and environmental impacts.

A key economic parameter is the cost of producing a unit of fluid at a specified temperature. This can be expressed in $ per kg/s of fluid produced or in $/kW of thermal power. High fluid-production temperatures, large sustained reservoir flow rates, and lower individual well drilling costs reduce the overall cost of EGS energy. On the other hand, higher flow rates through the reservoir lead to increased pumping power losses and accelerated rates of thermal drawdown, which lead to higher costs. The economic choice is to balance these effects.

This balance can be illustrated quantitatively by dividing the total installed cost of a geothermal development into major components associated with the field itself and its reservoir and with the power plant that converts the thermal energy into electricity. In mathematical terms, the total capital cost is

$$\Phi = \Phi_{geofluid} + \Phi_{powerplant} \tag{11.10}$$

where

$\Phi_{geofluid}$ = total field/reservoir development costs including those for geophysical exploration, well drilling, reservoir stimulation, and fluid transmission, collection, and distribution;

$\Phi_{powerplant}$ = installed capital costs of power conversion and electric generation equipment and switch gear for connecting to the grid.

The *geofluid* component can be represented roughly as

$$\Phi_{geofluid} = 2n_w A^*(\Phi_{well}) \tag{11.11}$$

where n_w is the number of production wells (the factor of 2 accounts for an equal number of reinjection wells), Φ_{well} is the individual completed well cost in $/well, and A^* is an empirical constant that includes costs for rig mobilization and demobilization, reservoir stimulation, and the geofluid collection and distribution system to the power plant. In turn, Φ_{well} is expressed as an exponential function of depth as depicted by a straight line in the shaded region of figure 11.16:

$$\Phi = C \exp(D\, Z) \tag{11.12}$$

where Z is the reservoir/well depth in meters = $(T_{gf}(t=0) - T_{surface})/\nabla T$; $T_{gf}(t=0)$ is the initial reservoir fluid production temperature in °C or K; $T_{surface}$ is the average ambient surface temperature at $Z = 0$ in °C or K; ∇T is the average geothermal temperature gradient in °C/km; and C and D are constants fit to the data presented in figure 11.17. The number of wells, n_w, is given by

$$n_w = \frac{P}{\eta_u \dot{m}_w \Delta B} \tag{11.13}$$

where P is the power capacity of the plant in kW, η_u is the utilization efficiency (that is, the fraction of thermodynamically limited power, typically 0.50–0.60), $\dot{m}_w$ is the geofluid mass flow rate per well in kg/s, and ΔB is the thermodynamic availability or maximum work-producing potential of the geofluid in kJ/kg. For a liquid-phase geofluid,

$$\Delta B \approx \langle C_p \rangle \left[T_{gf}(t) - T_o - T_o \ln(T_{gf}(t)/T_o)\right] \tag{11.14}$$

where $\langle C_p \rangle$ is the mean heat capacity of the geofluid in kJ/kg K, and T_o is the minimum thermal sink temperature in K. Plant capital costs typically decline as T_{gf} increases due to improved cycle efficiency and lower heat transfer area requirements. Empirically, we can represent this decline as a linear function,

$$\Phi_{powerplant} = \Phi^{o}_{powerplant} - ET_{gf}, \tag{11.15}$$

applicable for $150°\mathrm{C} \le T_{gf} \le 300°\mathrm{C}$ where $\Phi^{o}_{powerplant}$ and E are empirical constants (Tester and Herzog, 1990, 1991; Tester et al., 1994).

Ideally, to minimize costs, we need to find a minimum for certain choices of $\dot{m}_w$ and T_{gf}. Unfortunately, for a given-sized reservoir, these variables are connected in a nonlinear fashion and lead to certain economic tradeoffs. In real reservoirs, some decline in productivity is anticipated. This usually is expressed in terms of a reduction in T_{gf} over time. To optimally extract energy from an EGS reservoir, one must inject fluid at a sufficiently high rate ($\dot{m}$) to cause some thermal drawdown. But as T_{gf} decreases, so does ΔB from equation (11.14), and consequently, n_w (equation (11.13)) and $\Phi_{geofluid}$ (equation (11.11)) both tend to increase. To partly compensate for finite thermal drawdown, deeper, more costly wells (equation (11.12)) can be drilled. Hence, to reach an optimum for a given HDR resource, defined generically by specifying both ∇T and reservoir size, a tradeoff exists between pumping more fluid (higher $\dot{m}_w$) and drilling deeper. With reasonable values for equipment and drilling costs and acceptable levels of reservoir performance, initial reservoir temperatures of 250–300°C are favored when $T > 50$°C/km, while somewhat lower temperatures are better for lower ∇T.

Given these characteristics, how does EGS fit into the global energy picture? As we move further into the twenty-first century, we should be exploring means of meeting our future energy needs without increased use of fossil fuels. Key criteria for any new energy technology are that it should be relatively simple to implement and safe to operate, and have reasonable costs, high availability, and low environmental impact over its life cycle. In addition, the "scale" of the technology should be compatible with anticipated demand, and the resource should be adequately distributed to meet both baseload electricity and other distributed primary-energy needs. Although EGS concepts seem to meet all these criteria as well as or better than other alternatives, they have not been pursued as vigorously as other technologies. EGS and geothermal in general have much smaller constituencies, and, as a result, their positive attributes and the current state of development of geothermal energy systems are not as widely known to the public.

Commercialization of any new energy system depends critically on how well it competes with existing energy supplies. As with any developing technology, competitiveness and risk have real and perceived elements. EGS is unique in that certain elements, such as the surface power plants, have relatively low cost and performance uncertainty because they consist of commercially available components (e.g., pumps, heat exchangers, turbines, etc.). On the other hand, the underground reservoir systems, consisting of the wellbore-fracture network, carries much higher risk, partly because the technology is not yet fully mature and partly because drilling and reservoir stimulation are perceived to be speculative due to the natural parallels that are drawn to oil and gas production. One must remember, however, that exploration and production uncertainties for an EGS reservoir are intrinsically lower than those for a petroleum reservoir. In principle, all we require is sufficiently hot rock at accessible depths that is amenable to stimulation to create an open, connected fracture system.

The main technical obstacle for EGS is centered on the formation and connection of the fractured network to the injection and production well system. A key requirement is low impedance access to sufficiently large rock areas and volumes with acceptable water losses. For example, for an average geothermal gradient resource of 60°C/km, production flow rates of about 40–75 kg/s with water losses less than 5% and thermal drawdown rates of about 2% per year or less from an initial temperature of 250–300°C are required to achieve break-even electricity prices of 6–8¢/kWh (in 1996US$) (Armstead and Tester, 1987; Tester and Herzog, 1990, 1991; Tester et al., 1994). These estimates include the amortized capital costs of drilling and stimulating the wells and building the power plant, along with operating and maintenance costs of about 0.3–0.4¢/kWh.

Economic assessment studies conducted at Los Alamos, EPRI, MIT, US DOE, and elsewhere have been dissected to reformulate a generalized economic model

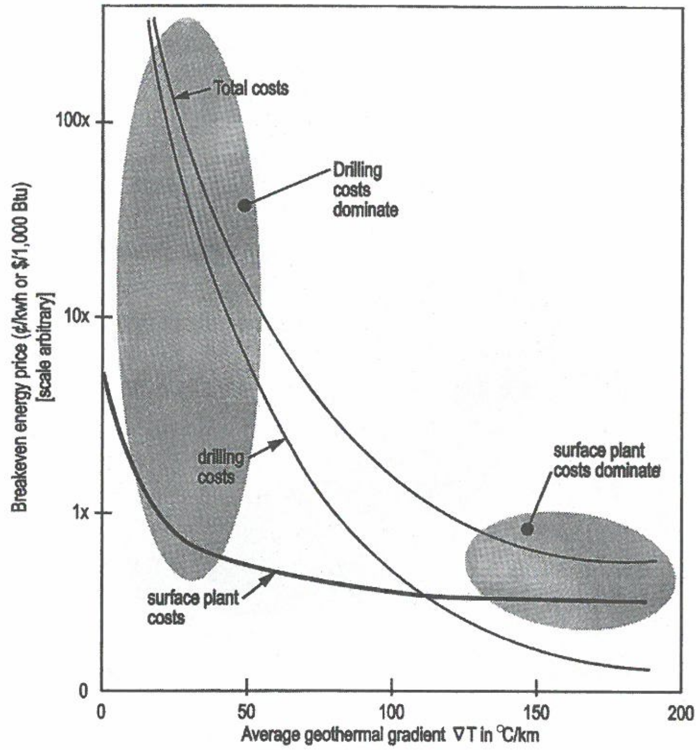

Figure 11.16
Effect of reservoir performance and resource grade on electricity or heat break-even prices. Adapted from Armstead and Tester (1987).

for HDR with revised cost components (Tester and Herzog, 1990, 1991). The main results of this comparative study are shown in figures 11.6, 11.16, and 11.17, where drilling costs and break-even heat and electricity prices are presented. In figure 11.6, one sees an exponential dependence of individual well cost on depth in general, and that geothermal wells, on average, are 2–3 times more expensive than oil or gas wells to the same depth. In figures 11.16 and 11.17, we see the strong dependence of projected break-even price on average gradient, which reflects the grade of an HDR reservoir. As gradients increase, the drilling cost component decreases relative to the surface plant cost. The bandwidth shown in figure 11.17 illustrates the effect of technological improvements on costs. In order to make HDR geothermal energy commercially competitive for low-grade resources with gradients of 20–30°C/km, revolutionary changes in the way in which wells are drilled are required to lower costs substantially. The linear drilling line illustrates a desirable limit for drilling costs (see also figure 11.6).

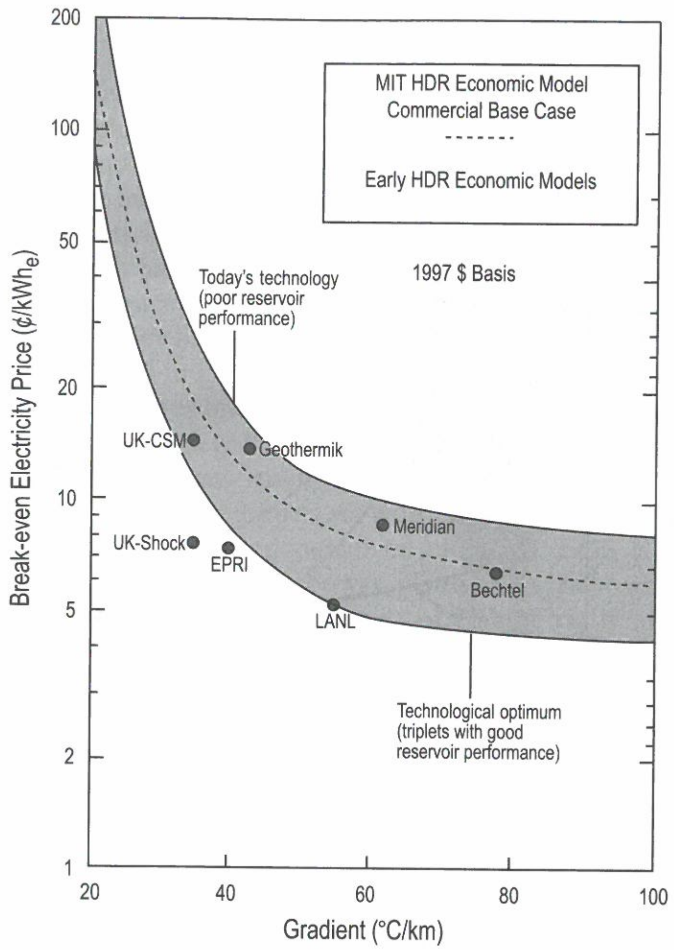

Figure 11.17
Estimated break-even busbar electricity prices as a function of the geothermal gradient for HDR/EGS systems. Adapted from Mock, Tester, and Wright (1997). Reprinted with permission of *Annual Review of Energy and the Environment.*

Economic assessments for EGSs assume reservoir productivities comparable to commercial hydrothermal systems. While field testing to date has not yet reached these productivity levels, a key problem is lowering flow impedance. Creating reservoirs of sufficient size is less of a problem, having already been achieved in tests at Fenton Hill, Rosemanowes, Cooper Basin, and elsewhere. The hydraulic connectivity between the wells and the fractured reservoir needs to be improved to reduce pumping losses due to high flow impedances (Fenton Hill) or to lower water loss rates (Rosemanowes). Iceland, one of the prime geothermal areas in the world, has an EGS project that will challenge technology for drilling into very hot rock bodies. The global community of EGS early developers is closely connected and shares lessons learned proactively. Not only are they focused on how to reduce production costs, but they also are learning characteristics of different geothermal HDR formations that affect the successful stimulation of productive reservoirs with minimization of water losses. Environmental issues such as induced seismicity and water quality impacts are also being evaluated to facilitate eventual sustainable production of EGS electricity and heat. Perhaps because these technologies still need considerable development before reaching large commercial use, the early projects are advancing the learning curve through collaboration. However, the EGS community serves as a model for other new technology initiatives to emulate.

Critics of EGS technology have argued that, with over $180 million invested from the mid-1970s to 2000 in the US alone, development toward a commercially viable system has been too slow. However, this criticism needs to be weighed against the R&D investments made in other energy technologies. For example, the total US investment in HDR/EGS over those 24 years is less than half of what we are currently spending annually on fission, fusion, or solar energy technologies. But interest is increasing in the viability of EGS.

HDR technology development in the US, at least up to 2000, seemed to lie solely with the reservoir testing at the Fenton Hill experimental site in New Mexico. Unfortunately, with growing concerns over the federal budget, support for advanced geothermal energy research and demonstration within the US DOE has been at risk for some time. Multiyear support for further testing of EGS in the field at several locations is needed to develop the potentially large HDR resources. The pioneering field efforts at Fenton Hill, Rosemanowes, Soultz, and Hijiori have provided the basis for developing economically viable stimulation and extraction technologies. Although some Advanced Research Projects Agency funds were directed toward EGS demonstration in the US, it is unclear whether a robust rejuvenation of R&D for advanced HDR/EGS technology will be supported in the coming decades. In 2009, the US DOE supported geothermal research, development, and demonstration projects with over $300 million of new funding as a result of the economic stimulus initiative (American Recovery and Reinvestment Act of 2009).

Several near-term conventional hydrothermal power and geothermal heat-pump demonstrations were supported, along with novel exploration and drilling technologies and a major EGS demonstration.

In the past few years there have been other encouraging signs, as many new global EGS projects such as those at Cooper Basin in Australia, Landau in Germany, and in the Cornish granites in the UK are under way or being announced.

11.6 Competing in Today's Energy Markets

Geothermal energy is already commercially competitive in many locations worldwide where high-grade hydrothermal resources are found, as shown in figure 11.15. In fact, by 2011, over 11,000 MW_e of generating capacity from geothermal resources had been achieved. Even more significant is the fact that subsidy-free geothermal power is frequently the least costly option for developing countries, such as Indonesia, the Philippines, and many countries in Central America. This is remarkable given the cost of coal and gas on international markets and the capital-intensive nature of a geothermal development where all the "fuel" costs are embedded in the initial capital investment in drilling wells and connecting the fluid production and reinjection piping.

In the US, geothermal electric power development has been increasing in the last few years but still much more slowly than it might, given the potential of its high-grade resources. Many states are continuing to restructure their electric utilities. Deregulation frequently focuses on the breakup of the vertically integrated utilities that constitute monopolies controlled primarily by state regulation. Generation, transmission, and distribution functions will be separated in an effort to increase competition in each area and to lower electricity prices for consumers without disrupting the excellent electrical energy services Americans enjoy. As a result, many utilities will opt to sell their generating capacity to become transmission companies (transcos) or distribution companies (distcos). Generation companies (gencos) will comprise companies spun off from utilities, large independent power producers (IPPs), and the myriad small IPPs currently operating under the Public Utilities Regulatory Policy Act of 1978 (PURPA), which created markets for renewable energy in general. Gencos may sell their power into a pool from which distcos would make purchases on a long-term or spot-market basis (or, more likely, a mixture of both), and transcos would wheel (transport) the power to distcos at an agreed transmission rate.

To preserve the benefits of clean, renewable energy supplies already in place, as well as to create a positive environment for further development, federal and state lawmakers are considering several options. For example, one option would be to require a specified amount of the overall electricity supply mix to be renewable

energy, such as geothermal energy—this is the so-called *renewable-energy portfolio standard*, or RPS. If the RPS percentage were to rise with time, such an option would steadily increase the amount of renewable electricity in the supply, ensuring a growth environment for geothermal power. Another option, perhaps in addition to the RPS, would be to allow and encourage distcos to market a certain amount of their power as "green," or derived from clean sources, and offer such power to their customers at a marginally higher price. (Such issues are being discussed in the US Congress and state legislatures as this volume goes to press, and we can anticipate that several years will be required before all aspects of deregulation and restructuring of the electricity industry will be ironed out.) This is both good and bad for geothermal development: good in the sense that this trend decentralizes utility decision-making and therefore provides a greater number of choices, and bad because geothermal electricity is capital-intensive and more risky than options using low-cost fossil fuel. For example, it is hard for renewable energy to compete with a 10–50 MW_e gas-fired, combined-cycle cogeneration plant with a long-term contract for purchasing inexpensive natural gas. Tables 11.3 and 11.4 summarize

Table 11.3
Estimated Busbar Electric-Generating Costs for New Baseload Capacity (in 2010US$)

Resource Type	Installed Plant Cost ($/kW)	Annualized Plant Cost[a] (¢/kWh)	O&M Costs (¢/kWh)	Annualized Well Drilling or Fuel Cost (¢/kWh)	Total Break-even Busbar Price (¢/kWh)
Oil[b]	800	2.0	0.3	8.5–17.0 ($20–50/bbl)	10.8–19.3
Coal	1,400	3.5	0.3	1.0–4.0 ($25–100/ton)	4.8–7.8
Gas[b]	600	1.5	0.3	2.4–6.1 ($3–5/MMBtu)	4.2–7.9
Nuclear[c]	3,000	7.4	0.4	1.0	8.8
Hydrothermal High-grade	1,500–2,000	3.6–5.1	0.3	3–4	6.9–9.4
Low-grade	2,000–2,500	5.1–6.3	0.4	6–12	11.5–18.7
Hot dry rock High-grade (≥ 60°C/km)	1,500–2,000	3.6–5.1	0.3	4–5	7.9–10.4
Low-grade (ca 30°C/km)	2,000–2,500	5.1–6.3	0.4	25–45	30.5–51.7

Sources: Armstead and Tester (1987); DiPippo (1980, 1995); Tester and Herzog (1990, 1991); Tester, Brown, and Potter (1989); Tester et al. (1994); Herzog, Tester, and Frank (1997); Deutch and Moniz (2003); EIA (2003); MIT (2006).

[a] Annual cost based on 17% fixed charge rate, 80% load factor for 50 MW (e or th) plant.

[b] Combined-cycle plant assumed for oil and gas.

[c] Nuclear fuel estimate includes allowance for decommissioning and for handling, treatment, and storage of waste; fission plants only.

Table 11.4
Estimated Busbar Heat Supply Costs for New Baseload Capacity (in 2010US$)

Resource Type	Annualized Plant Capital Cost ($/MMBtu)[a,b]	Heat Supply[c] Fuel Cost ($/MMBtu)	Annualized Heat Distribution Cost ($/MMBtu)	Total Break-even Price ($/MMBtu)
Oil[d]	0.50	11–22 ($50–100/bbl)	1.5	13–24
Coal	0.70	0.8–5.3 ($15–100/ton)	1.5	3.0–7.5
Gas[d]	0.40	3.6–5.9 ($3–5/MMBtu)	1.5	5.5–7.8
Nuclear[e]	1.6	0.8	2.0	4.4
Hydrothermal[f]				
High-grade	—	3–4	2.6	5.6–6.6
Low-grade	—	4–7	2.1	6.1–9.1
Hot dry rock[f]				
High-grade (>50°C/km)	—	3.0–4.0	2.6	5.6–6.6
Low-grade (ca 30°C/km)		5–11	2.0	7.0–13.0

Sources: Armstead and Tester (1987); DiPippo (1980, 1995); Tester and Herzog (1990, 1991); Tester, Brown and Potter (1989); Tester et al. (1994); Herzog, Tester, and Frank (1997); Deutch and Moniz (2003); EIA (2003); MIT (2006).
[a] Annual cost based on 17% fixed charge rate, 80% load factor for 50 MW (e or th) plant.
[b] 1 MMBtu = 10^6 Btu = 1.055×10^9 J.
[c] Heat supplied at 150°C as steam or pressurized hot water, not cogenerated.
[d] Combined-cycle plant assumed for oil and gas.
[e] Nuclear fuel estimate includes allowance for decommissioning and for handling, treatment, and storage of waste; fission plants only.
[f] Fuel cost includes all heat-exchange equipment and drilling costs.

levelized cost estimates for baseload electricity and process heat for fossil fuel, nuclear power, and a range of hydrothermal and EGS resource grades.

For the advanced technologies—EGS, magma, and geopressured—the competition is even tougher, as risk factors will initially be higher for investors. Higher risks will be partially offset for EGS systems by the increased flexibility in locating the system near a load center and the fact that *in situ* fluids and high-formation permeability are not required. Economic projections for EGS or for any precommercial technology must be considered as somewhat speculative, given the assumptions made regarding reservoir performance. For EGS specifically, we have divided the range into high- and low-grade resources. Both cases are assumed to meet baseline reservoir productivity and other performance parameters—including mass flows per well pair of about 75 kg/s (to generate 10 MW_e), effective heat transfer volumes and areas sufficient to support 10 years of production with 20% thermal drawdown or less, flow impedances (resistance to fluid flow) less than 0.1 GPa s/m^3 (an overall impedance of 1 GPa s/m^3 or less is a reasonable goal for a commercial EGS system), and water consumption rates less than 5% of the injected flow (Armstead and Tester, 1987). These baseline values are probably achievable with active R&D programs, as they more or less replicate the productivity levels already achieved for commercial liquid-dominated hydrothermal systems.

High-grade hydrothermal resources are competitive now for electric power generation, and high-grade EGS resources with proven stimulation would be competitive in some fraction of today's energy markets. But the low-grade resources of either will require higher prices for fossil fuels or lower development costs before they can compete in electricity markets. New interest in direct use for district heating and cooling and combined heat and power applications would create many new opportunities for lower-grade geothermal energy. And there are other forces—environmental, health-related, security-related—and general sustainable development concerns that could create a different economic situation.

11.7 Research and Development Advances Needed

The growth of geothermal energy development is not limited by resource availability. Rather, it is limited by inadequate technology. Only the highest-grade geothermal resources are commercially used today for the generation of electricity. Development of the vast majority of geothermal resources is not possible because, at most resource sites, drilling risks and power-generation costs are higher than those for competing fossil fuels, especially natural gas. With reasonable assumptions regarding discount rates, capital and drilling costs, and plant construction and field development periods, projected levelized costs for geothermal electricity range from 4¢ to 7¢ per kWh for new power development at high-grade geothermal resource sites, whereas new generation capacity from natural gas, where it is readily available, produces power at 2.6¢ to 6.2¢ per kWh. (Operation and maintenance costs at geothermal power plants whose capitalization has been paid may be as low as 0.3¢ per kWh.) Power-generation costs at the much more plentiful lower-grade geothermal resource sites are not able to compete today with natural-gas generation costs in the US. Core research, development, and demonstration programs aimed at improving existing technology and developing new, advanced technology are critical to enable the geothermal industry to compete in the domestic and global energy marketplaces. Given the high capital costs for demonstrations at commercial scale, multiyear government commitments are needed to achieve high deployment rates, particularly for mid- and low-grade resources. These commitments range from grants and loan guarantees for exploratory drilling, to multiyear production tax credits and feed-in tariffs, to cost-shared and fully supported government demonstration projects.

Drilling Drilling is one of the most expensive and risky activities in geothermal development. Any project requires drilling of production wells to bring geothermal fluid to the surface and drilling of injection wells to return the spent fluid to the reservoir. Because of the high temperatures and corrosive nature of some geothermal fluids, geothermal drilling, while technically feasible using conventional methods and rigs, requires some special equipment and procedures and tends to be more expensive than conventional oil and gas drilling. Geothermal wells are of larger diameter than oil and gas wells in order to support high flow rates, e.g., 50–150 kg/s. A typical cost is $1–3 million (see figure 11.6) for a typical geothermal well that will support 3–5 MW_e of dry-steam or flashed-steam electrical capacity. Drilling costs account for one-third to one-half of the total costs for a geothermal project. Improvement in existing drilling techniques and development of new, advanced drilling techniques would significantly lower the cost of electricity generated from geothermal resources.

Exploration and reservoir technology The major problem in exploration for geothermal reservoirs is how to identify and map producing regions deep in the subsurface so that drill holes can be sited and steered to intersect these producing zones. No two geothermal reservoirs are alike, and their permeabilities vary widely over short distances. Present surface exploration techniques have insufficient resolution, leading developers to drill too many dry wells and thus driving up development costs. Further, inadequate knowledge of the physical and chemical properties of the subsurface often makes it difficult to mine the heat in the most efficient way and to ensure the sustainability of geothermal reservoirs. Increased knowledge of rock mechanics is needed to provide improved techniques for creating new fractures and better well stimulation methods to open existing fractures and lower flow impedance. Better geochemical and geophysical techniques as well as improved computer methods for stimulating reservoirs and modeling heat extraction are needed. It is possible that geothermal development costs could be lowered by 10–40% and reservoir lifetimes extended significantly with improvements in earth science techniques.

Energy utilization and conversion The efficiency in conversion of geothermal steam into electricity in the power plant directly affects the cost of power generation. During the past decade, the efficiency of dry- and flash-steam geothermal power plants has been improved by 25%. Power plants installed at the Geysers geothermal field in California during the 1960s required 9 kg (20 lbs) of steam to produce 1 kWh of electricity (i.e., 2.5 kg/s of dry steam per MW_e, or 10–15 kg/s per 5 MW_e well). The newest plants at The Geysers, installed in the 1980s, required only 6.6 kg (14.5 lbs) of steam to produce that same kilowatt-hour of electricity (i.e., 1.8 kg/s of dry steam per MW_e or 9–11 kg/s per 5 MW_e well). The efficiency of geothermal power plants can probably be improved at least an additional 25% over the next decade with a modest investment in R&D.

11.8 Potential for the Long Term

The global resource base for geothermal energy is large and well distributed. Geothermal power, generated from these resources, has grown steadily since the early 1920s at an average rate of 8.5% per year.

Geothermal power plants offer several advantages. They are simple, safe, and modular (1–50 MW_e); they can be built rapidly (approximately one year for a 50 MW_e plant), and are capable of providing baseload, load following, or peaking capacity. Geothermal plants provide significant societal benefits, including indigenous energy for the long term with benign environmental attributes (e.g., negligible emissions of CO_2, SO_x, NO_x, and particulates, and modest land and water use). These features are compatible with sustainable development objectives at all levels, making geothermal energy an attractive option.

The growth in geothermal power capacity has been based exclusively on the use of high-temperature ($T > 150°C$), high-grade hydrothermal resources. If geothermal power is to become more universally available and have a significant impact on global energy supplies in the next century, then lower-temperature hydrothermal resources and other advanced concepts, including EGS, geopressured systems, and magma, must be vigorously pursued to make them economically competitive. This will require a robust advanced research program to reduce field development (especially drilling and stimulation) costs and to increase energy conversion efficiencies.

Lower-temperature hydrothermal resources ($T < 150°C$) provide an economical source of energy for geothermal heat pumps (GHPs) and for direct use in domestic, industrial, agricultural, aquacultural, and district heating applications. And depending on the price of electricity or the benefits of providing green power, even lower-enthalpy fluids could find use for electric power generation. The installation of GHPs in the US has been growing rapidly over the past decade, at a growth rate of over 15% per year. GHPs enable users to obtain an inexpensive source of space heating and cooling, along with domestic hot water, while offering utilities the benefits of reduced peak demands for power and the deferred need for additional plant capacity. New concepts are also appearing that would increase the application of geothermal energy. For example, the idea of using a 2.5 km borehole as a deep GHP heat exchanger for heating and cooling applications in large building complexes is being pursued in Germany (Fell, 2003).

Although the usable resource base of low- and moderate-temperature geothermal resources is large, development of direct-heat uses is proceeding slowly. The high capital costs needed for geothermal district heating systems presents a large barrier, and investment decisions are also affected by the availability of low-cost natural gas. In contrast to geothermal's wide use for electric power generation, most countries have no direct-heat geothermal industry or utility. Each direct-heat system requires a separate design, and few consultants or contractors are trained and experienced in the direct use of geothermal resources (see Geo-Heat Center, 1988).

Nonetheless, there have been some hopeful signs of the increased deployment of direct use. In the past 15 years, with rising interest in adopting carbon-free sustainable energy resources, geothermal direct use worldwide has grown almost sixfold to over 50,000 MW_{th} (Lund, Freeston, and Boyd, 2010). In 2008 alone, over 120 TWh (0.44EJ) of thermal energy was provided by geothermal sources and spread across a range of uses in 78 countries, with an annual average capacity factor of 27.5%.

Given the growing global interest in transforming our energy supply system, it is clear that the technical potential of direct-use applications for heating and cooling buildings with geothermal energy is vast and could make a huge difference in reducing gas and oil consumption. Geothermal heat pumps are becoming very attractive as a means of lowering electrical demand, but district heating networks are needed in urban and congested suburban areas for a more complete transformation. Unless multiyear incentives and policies are adopted to offset needed capital investments for infrastructure, the large potential of lower-grade geothermal will continue to be largely unrealized on a global scale.

Research efforts continue in Europe, Japan, Russia, Iceland, the US, and elsewhere to improve EGS technology for heat mining in deep, hot formations of low permeability and to demonstrate the viability of operating systems at scale. Active collaborations among R&D programs in the US, Japan, Australia, and Europe would also accelerate the development of heat mining technology beyond that possible by single nations. If these efforts receive sufficient support, share learning, and are successful, they could make geothermal energy universally available within a decade or two.

Problems

11.1 Some argue that geothermal energy is a dilute, low-grade energy resource. Estimate the minimum mass of hot rock needed to produce 1,000 MW_eyr of electricity, assuming that the rock mass is solid granite with a density of 2,500 kg/cubic meter and a heat capacity of 1,000 J/kg K at an initial temperature of 250°C. An ambient temperature of 25°C can be assumed.

11.2 A good geothermal well produces 75 kg/s of hot water at 200°C. For the same amount of delivered energy, what would be the production rate from an oil well? How does this compare with a typical US oil well that produces about 100–1,000 bbl of oil per day? You can assume that the average heat capacity of the geothermal water is 4,200 J/kg K, that its minimum useful temperature is 50°C, and that crude oil has a heating value of about 5.5 million Btu per bbl.

11.3 In conventional air-to-air heat-pump systems, the atmosphere is used as a source of energy in the winter during heating season and as a sink for heat rejection in the summer during air-conditioning season. Geothermal ground-source heat pumps use an underground reservoir as a thermal heat source and sink. These reservoirs are usually 3–10 meters deep, below the depth where seasonal fluctuations occur (i.e., below the frost line). At these depths the temperature is about 15°C. A nonfreezing, noncorrosive fluid, such as an aqueous solution of potassium acetate, is circulated through a coil of pipe buried in the ground to transfer thermal energy to and from the ground. How would you expect a geothermal heat-pump system to perform in comparison to an air-to-air heat-pump system operating under the following conditions in North Dakota?

a. Summer day when the outside temperature is 100°F (37.8°C)

b. Winter day when the outside temperature is –30°F (–34.4°C)

People in North Dakota like to keep their homes at a constant 70°F (21.1°C) year round. Comparisons should be made on an ideal basis for a fully reversible system and should be expressed in terms of units of heat (or cooling) transferred per unit of electrical work consumed, which is called the coefficient of performance (COP). What factors will limit the performance of practical heat pumps below their ideal limit?

11.4 What is the maximum amount of electric power that could be generated from a 250°C geothermal fluid flowing at 40 kg/s in Reykjavik, Iceland? The average ocean temperature off the coast of Iceland is about 5°C.

11.5 Imagine a situation in the future where HDR/EGS technology has succeeded to a point that it could provide one-half of the US electrical capacity (which was about 750,000 MW_e in 2003). How many wells would have to be drilled to make this possible, and what would their average depth be? What would the total capital investment need to be to achieve such a level of penetration? Some argue that this change would drastically alter our electricity transmission and distribution (T&D) infrastructure, which might in turn lead to a more distributed system for supplying combined heat and power. Do you agree or disagree with that statement? Explain. Be sure to state all the assumptions you made in making your estimates.

11.6 Two-stage flashing systems are commonly employed for generating power from hydrothermal resources that contain only minor amounts of noncondensable gases (see figure 11.10 and the discussion in the text). Here we see that a key design variable is the selection of the pressure or steam saturation temperature for each stage. Develop a simplified analysis to estimate the optimal flash temperatures for each stage. Compare your results with those shown in figure 11.13 for a geofluid production temperature of 230°C with the same condensing (T_c) and dead state (T_o) conditions.