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The Future of Geothermal Energy

Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century

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Idaho National Laboratory
Idaho Falls, Idaho 83415

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Contents

CHAPTER 3

Recoverable EGS Resource Estimates

CHAPTER 4

Review of EGS and Related Technology – Status and Achievements

CHAPTER 5

Subsurface System Design Issues and Approaches

CHAPTER 6

Drilling Technology and Costs

CHAPTER 7

Energy Conversion Systems – Options and Issues

CHAPTER 8

Environmental Impacts, Attributes, and Feasibility Criteria

CHAPTER 9

Energy-Sector Fundamentals: Economic Analysis, Projections, and Supply Curves

Preface

Recent national focus on the value of increasing our supply of indigenous, renewable energy underscores the need for reevaluating all alternatives, particularly those that are large and well-distributed nationally. This analysis will help determine how we can enlarge and diversify the portfolio of options we should be vigorously pursuing. One such option that is often ignored is geothermal energy, produced from both conventional hydrothermal and Enhanced (or engineered) Geothermal Systems (EGS). An 18-member assessment panel was assembled in September 2005 to evaluate the technical and economic feasibility of EGS becoming a major supplier of primary energy for U.S. base-load generation capacity by 2050. This report documents the work of the panel at three separate levels of detail. The first is a Synopsis, which provides a brief overview of the scope, motivation, approach, major findings, and recommendations of the panel. At the second level, an Executive Summary reviews each component of the study, providing major results and findings. The third level provides full documentation in eight chapters, with each detailing the scope, approach, and results of the analysis and modeling conducted in each area.

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CHAPTER 1
Synopsis and Executive Summary

Synopsis

Scope: A comprehensive assessment of enhanced, or engineered, geothermal systems was carried out by an 18-member panel assembled by the Massachusetts Institute of Technology (MIT) to evaluate the potential of geothermal energy becoming a major energy source for the United States. Geothermal resources span a wide range of heat sources from the Earth, including not only the more easily developed, currently economic hydrothermal resources; but also the Earth's deeper, stored thermal energy, which is present anywhere. Although conventional hydrothermal resources are used effectively for both electric and nonelectric applications in the United States, they are somewhat limited in their location and ultimate potential for supplying electricity. Beyond these conventional resources are EGS resources with enormous potential for primary energy recovery using heat-mining technology, which is designed to extract and utilize the earth's stored thermal energy. In between these two extremes are other unconventional geothermal resources such as coproduced water and geopressured geothermal resources. EGS methods have been tested at a number of sites around the world and have been improving steadily. Because EGS resources have such a large potential for the long term, we focused our efforts on evaluating what it would take for EGS and other unconventional geothermal resources to provide 100,000 MW_e of base-load electric-generating capacity by 2050.

Although somewhat simplistic, the geothermal resource can be viewed as a continuum in several dimensions. The grade of a specific geothermal resource would depend on its temperature-depth relationship (i.e., geothermal gradient), the reservoir rock's permeability and porosity, and the amount of fluid saturation. High-grade hydrothermal resources have high average thermal gradients, high rock permeability and porosity, sufficient fluids in place, and an adequate reservoir recharge of fluids – all EGS resources lack at least one of these. For example, reservoir rock may be hot enough but not produce sufficient fluid for viable heat extraction, either because of low formation permeability/connectivity and insufficient reservoir volume, and/or the absence of naturally contained fluids.

Three main components were considered in the analysis:

1. *Resource* – estimating the magnitude and distribution of the U.S. EGS resource.
2. *Technology* – establishing requirements for extracting and utilizing energy from EGS reservoirs including drilling, reservoir design and stimulation, and thermal energy conversion to electricity.
3. *Economics* – estimating costs for EGS-supplied electricity on a national scale using newly developed methods for mining heat from the earth. Developing levelized energy costs and supply curves as a function of invested R&D and deployment levels in evolving U.S. energy markets.

Motivation: There are several compelling reasons why the United States should be concerned about the security of its energy supply for the long term. They include growth in demand, as a result of an increasing U.S. population, along with increased electrification of our society. According to the Energy Information Administration (EIA, 2006), U.S. nameplate generating capacity has increased more than 40% in the past 10 years and is now more than 1 TWe. Most of this increase resulted from adding gas-fired combined-cycle generation plants. In addition, the electricity supply system is threatened with losing existing capacity in the near term, as a result of retirement of existing nuclear and coal-fired generating plants (EIA, 2006). It is likely that 50 GW_e or more of coal-fired capacity will need to be retired in the next 15 to 25 years because of environmental concerns. In addition, during that period, 40 GW_e or more of nuclear capacity will be beyond even the most generous relicensing procedures and will have to be decommissioned.

The current nonrenewable options for replacing this anticipated loss of U.S. base-load generating capacity are coal-fired thermal, nuclear, and combined-cycle gas-combustion turbines. While these are clearly practical options, there are some concerns. First, demand and prices for cleaner natural gas will escalate substantially during the next 25 years, making it difficult to reach gas-fired capacity. Large increases in imported gas will be needed to meet growing demand – further compromising U.S. energy security beyond just importing the majority of our oil for meeting transportation needs. Second, local, regional, and global environmental impacts associated with increased coal use will most likely require a transition to clean-coal power generation, possibly with sequestration of carbon dioxide. The costs and uncertainties associated with such a transition are daunting. Also, adopting this approach would accelerate our consumption of coal significantly, compromising its use as a source of liquid transportation fuel for the long term. It is also uncertain whether the American public is ready to embrace increasing nuclear power capacity, which would require siting and constructing many new reactor systems.

On the renewable side, there is considerable opportunity for capacity expansion of U.S. hydropower potential using existing dams and impoundments. But outside of a few pumped storage projects, hydropower growth has been hampered by reductions in capacity imposed by the Federal Energy Regulatory Commission (FERC), as a result of environmental concerns. Concentrating solar power (CSP) provides an option for increased base-load capacity in the Southwest where demand is growing. Although renewable solar and wind energy also have significant potential for the United States and are likely to be deployed in increasing amounts, it is unlikely that they alone can meet the entire demand. Furthermore, solar and wind energy are inherently intermittent and cannot provide 24-hour-a-day base load without mega-sized energy storage systems, which traditionally have not been easy to site and are costly to deploy. Biomass also can be used as a renewable fuel to provide electricity using existing heat-to-power technology, but its value to the United States as a feedstock for biofuels for transportation may be much higher, given the current goals of reducing U.S. demand for imported oil.

Clearly, we need to increase energy efficiency in all end-use sectors; but even aggressive efforts cannot eliminate the substantial replacement and new capacity additions that will be needed to avoid severe reductions in the services that energy provides to all Americans.

Pursuing the geothermal option: Could U.S.-based geothermal energy provide a viable option for providing large amounts of generating capacity when it is needed? This is exactly the question we are addressing in our assessment of EGS.

Although geothermal energy has provided commercial base-load electricity around the world for more than a century, it is often ignored in national projections of evolving U.S. energy supply. This could be a result of the widespread perception that the total geothermal resource is often associated with identified high-grade, hydrothermal systems that are too few and too limited in their distribution in the United States to make a long-term, major impact at a national level. This perception has led to undervaluing the long-term potential of geothermal energy by missing an opportunity to develop technologies for sustainable heat mining from large volumes of accessible hot rock anywhere in the United States. In fact, many attributes of geothermal energy, namely its widespread distribution, base-load dispatchability without storage, small footprint, and low emissions, are desirable for reaching a sustainable energy future for the United States.

Expanding our energy supply portfolio to include more indigenous and renewable resources is a sound approach that will increase energy security in a manner that parallels the diversification ideals that have

made America strong. Geothermal energy provides a robust, long-lasting option with attributes that would complement other important contributions from clean coal, nuclear, solar, wind, hydropower, and biomass.

Approach: The composition of the panel was designed to provide in-depth expertise in specific technology areas relevant to EGS development, such as resource characterization and assessment, drilling, reservoir stimulation, and economic analysis. Recognizing the potential that some bias might emerge from a panel of knowledgeable experts who, to varying degrees, are advocates for geothermal energy, panel membership was expanded to include experts on energy technologies and economics, and environmental systems. The panel took a completely new look at the geothermal potential of the United States. This was partly in response to short- and long-term needs for a reliable low-cost electric power and heat supply for the nation. Equally important was a need to review and evaluate international progress in the development of EGS and related extractive technologies that followed the very active period of U.S. fieldwork conducted by Los Alamos National Laboratory during the 1970s and 1980s at the Fenton Hill site in New Mexico.

The assessment team was assembled in August 2005 and began work in September, following a series of discussions and workshops sponsored by the Department of Energy (DOE) to map out future pathways for developing EGS technology.

The first phase of the assessment considered the geothermal resource in detail. Earlier projections from studies in 1975 and 1978 by the U.S. Geological Survey (USGS Circulars 726 and 790) were amplified by ongoing research and analysis being conducted by U.S. heat-flow researchers and analyzed by David Blackwell's group at Southern Methodist University (SMU) and other researchers. In the second phase, EGS technology was evaluated in three distinct parts: drilling to gain access to the system, reservoir design and stimulation, and energy conversion and utilization. Previous and current field experiences in the United States, Europe, Japan, and Australia were thoroughly reviewed. Finally, the general economic picture and anticipated costs for EGS were analyzed in the context of projected demand for base-load electric power in the United States.

Findings: Geothermal energy from EGS represents a large, indigenous resource that can provide base-load electric power and heat at a level that can have a major impact on the United States, while incurring minimal environmental impacts. With a reasonable investment in R&D, EGS could provide 100 GW_e or more of cost-competitive generating capacity in the next 50 years. Further, EGS provides a secure source of power for the long term that would help protect America against economic instabilities resulting from fuel price fluctuations or supply disruptions. Most of the key technical requirements to make EGS work economically over a wide area of the country are in effect, with remaining goals easily within reach. This achievement could provide performance verification at a commercial scale within a 10- to 15-year period nationwide.

In spite of its enormous potential, the geothermal option for the United States has been largely ignored. In the short term, R&D funding levels and government policies and incentives have not favored growth of U.S. geothermal capacity from conventional, high-grade hydrothermal resources. Because of limited R&D support of EGS in the United States, field testing and supporting applied geoscience and engineering research has been lacking for more than a decade. Because of this lack of support, EGS technology development and demonstration recently has advanced only outside the United States with accompanying limited technology transfer. This has led to the perception that

insurmountable technical problems or limitations exist for EGS. However, in our detailed review of international field-testing data so far, the panel did not uncover any major barriers or limitations to the technology. In fact, we found that significant progress has been achieved in recent tests carried out at Soultz, France, under European Union (EU) sponsorship; and in Australia, under largely private sponsorship. For example, at Soultz, a connected reservoir-well system with an active volume of more than 2 km^3 at depths from 4 to 5 km has been created and tested at fluid production rates within a factor of 2 to 3 of initial commercial goals. Such progress leads us to be optimistic about achieving commercial viability in the United States in a next phase of testing, if a national-scale program is supported properly. Specific findings include:

1. EGS is one of the few renewable energy resources that can provide continuous base-load power with minimal visual and other environmental impacts. Geothermal systems have a small footprint and virtually no emissions, including carbon dioxide. Geothermal energy has significant base-load potential, requires no storage, and, thus, it complements other renewables – solar (CSP and PV), wind, hydropower – in a lower-carbon energy future. In the shorter term, having a significant portion of our base load supplied by geothermal sources would provide a buffer against the instabilities of gas price fluctuations and supply disruptions, as well as nuclear plant retirements.

2. The accessible geothermal resource, based on existing extractive technology, is large and contained in a continuum of grades ranging from today's hydrothermal, convective systems through high- and mid-grade EGS resources (located primarily in the western United States) to the very large, conduction-dominated contributions in the deep basement and sedimentary rock formations throughout the country. By evaluating an extensive database of bottom-hole temperature and regional geologic data (rock types, stress levels, surface temperatures, etc.), we have estimated the total EGS resource base to be more than 13 million exajoules (EJ). Using reasonable assumptions regarding how heat would be mined from stimulated EGS reservoirs, we also estimated the extractable portion to exceed 200,000 EJ or about 2,000 times the annual consumption of primary energy in the United States in 2005. With technology improvements, the economically extractable amount of useful energy could increase by a factor of 10 or more, thus making EGS sustainable for centuries.

3. Ongoing work on both hydrothermal and EGS resource development complement each other. Improvements to drilling and power conversion technologies, as well as better understanding of fractured rock structure and flow properties, benefit all geothermal energy development scenarios. Geothermal operators now routinely view their projects as heat mining and plan for managed injection to ensure long reservoir life. While stimulating geothermal wells in hydrothermal developments are now routine, the understanding of why some techniques work on some wells and not on others can only come from careful research.

4. EGS technology has advanced since its infancy in the 1970s at Fenton Hill. Field studies conducted worldwide for more than 30 years have shown that EGS is technically feasible in terms of producing net thermal energy by circulating water through stimulated regions of rock at depths ranging from 3 to 5 km. We can now stimulate large rock volumes (more than 2 km^3), drill into these stimulated regions to establish connected reservoirs, generate connectivity in a controlled way if needed, circulate fluid without large pressure losses at near commercial rates, and generate power using the thermal energy produced at the surface from the created EGS system. Initial concerns regarding five key issues – flow short circuiting, a need for high injection pressures, water losses, geochemical impacts, and induced seismicity – appear to be either fully resolved or manageable with proper monitoring and operational changes.

5. At this point, the main constraint is creating sufficient connectivity within the injection and production well system in the stimulated region of the EGS reservoir to allow for high per-well production rates without reducing reservoir life by rapid cooling. U.S. field demonstrations have been constrained by many external issues, which have limited further stimulation and development efforts and circulation testing times – and, as a result, risks and uncertainties have not been reduced to a point where private investments would completely support the commercial deployment of EGS in the United States. In Europe and Australia, where government policy creates a more favorable climate, the situation is different for EGS. There are now seven companies in Australia actively pursuing EGS projects and two commercial projects in Europe.

6. Research, Development, and Demonstration (RD&D) in certain critical areas could greatly enhance the overall competitiveness of geothermal in two ways. First, it would lead to generally lower development costs for all grade systems, which would increase the attractiveness of EGS projects for private investment. Second, it could substantially lower power plant, drilling, and stimulation costs, which increases accessibility to lower-grade EGS areas at depths of 6 km or more. In a manner similar to the technologies developed for oil and gas and mineral extraction, the investments made in research to develop extractive technology for EGS would follow a natural learning curve that lowers development costs and increases reserves along a continuum of geothermal resource grades.

   Examples of impacts that would result from research-driven improvements are presented in three areas:

   - *Drilling technology* – both evolutionary improvements building on conventional approaches to drilling such as more robust drill bits, innovative casing methods, better cementing techniques for high temperatures, improved sensors, and electronics capable of operating at higher temperature in downhole tools; and revolutionary improvements utilizing new methods of rock penetration will lower production costs. These improvements will enable access to deeper, hotter regions in high-grade formations or to economically acceptable temperatures in lower-grade formations.
   - *Power conversion technology* – improving heat-transfer performance for lower-temperature fluids, and developing plant designs for higher resource temperatures to the supercritical water region would lead to an order of magnitude (or more) gain in both reservoir performance and heat-to-power conversion efficiency.
   - *Reservoir technology* – increasing production flow rates by targeting specific zones for stimulation and improving downhole lift systems for higher temperatures, and increasing swept areas and volumes to improve heat-removal efficiencies in fractured rock systems, will lead to immediate cost reductions by increasing output per well and extending reservoir lifetimes. For the longer term, using CO_2 as a reservoir heat-transfer fluid for EGS could lead to improved reservoir performance as a result of its low viscosity and high density at supercritical conditions. In addition, using CO_2 in EGS may provide an alternative means to sequester large amounts of carbon in stable formations.

7. EGS systems are versatile, inherently modular, and scalable from 1 to 50 MW_e for distributed applications to large "power parks," which could provide thousands of MW_e of base-load capacity. Of course, for most direct-heating and heat pump applications, effective use of shallow geothermal energy has been demonstrated at a scale of a few kilowatts-thermal (kWt) for individual buildings or homes. For these applications, stimulating deeper reservoirs using EGS technology is not relevant. However, EGS also can be easily deployed in larger-scale district heating and combined heat and power (cogeneration) applications to service both electric power and heating and cooling for buildings without a need for storage on-site. For other renewable options such as wind, hydropower, and solar PV, these applications are not possible.

8. Using coproduced hot water, available in large quantities at temperatures up to 100°C or more from existing oil and gas operations, it is possible to generate up to 11,000 MW_e of new generating capacity with standard binary-cycle technology, and increase hydrocarbon production by partially offsetting parasitic losses consumed during production.
9. A cumulative capacity of more than 100,000 MW_e from EGS can be achieved in the United States within 50 years with a modest, multiyear federal investment for RD&D in several field projects in the United States.

Because the field-demonstration program involves staged developments at different sites, committed support for an extended period will be needed to demonstrate the viability, robustness, and reproducibility of methods for stimulating viable, commercial-sized EGS reservoirs at several locations. Based on the economic analysis we conducted as part of our study, a $300 million to $400 million investment over 15 years will be needed to make early-generation EGS power plant installations competitive in evolving U.S. electricity supply markets.

These funds compensate for the higher capital and financing costs expected for early-generation EGS plants, which would be expected as a result of somewhat higher field development (drilling and stimulation) costs per unit of power initially produced. Higher generating costs, in turn, lead to higher perceived financial risk for investors with corresponding higher-debt interest rates and equity rates of return. In effect, the federal investment can be viewed as equivalent to an “absorbed cost” of deployment. In addition, investments in R&D will also be needed to reduce costs in future deployment of EGS plants.

To a great extent, energy markets and government policies will influence the private sector’s interest in developing EGS technology. In today’s economic climate, there is reluctance for private industry to invest its funds without strong guarantees. Thus, initially, it is likely that government will have to fully support EGS fieldwork and supporting R&D. Later, as field sites are established and proven, the private sector will assume a greater role in cofunding projects – especially with government incentives accelerating the transition to independently financed EGS projects in the private sector. Our analysis indicates that, after a few EGS plants at several sites are built and operating, the technology will improve to a point where development costs and risks would diminish significantly, allowing the levelized cost of producing EGS electricity in the United States to be at or below market prices.

Given these issues and growing concerns over long-term energy security, the federal government will need to provide funds directly or introduce other incentives in support of EGS as a long-term “public good,” similar to early federal investments in large hydropower dam projects and nuclear power reactors.

Based on growing markets in the United States for clean, base-load capacity, the panel thinks that with a combined public/private investment of about $800 million to $1 billion over a 15-year period, EGS technology could be deployed commercially on a timescale that would produce more than 100,000 MW_e or 100 GW_e of new capacity by 2050. This amount is approximately equivalent to the total R&D investment made in the past 30 years to EGS internationally, which is still less than the cost of a single, new-generation, clean-coal power plant.

The panel thinks that making such an investment now is appropriate and prudent, given the enormous potential of EGS and the technical progress that has been achieved so far in the field. Having EGS as an option will strengthen America’s energy security for the long term in a manner that complements other renewables, clean fossil, and next-generation nuclear.

Major recommendations: Because prototype commercial-scale EGS will take a few years to develop and field-test, the time for action is now. Supporting the EGS program now will move us along the learning curve to a point where the design and engineering of well-connected EGS reservoir systems is technically reliable and reproducible.

We believe that the benefit-to-cost ratio is more than sufficient to warrant such a modest investment in EGS technology. By enabling 100 GW_e of new base-load capacity, the payoff for EGS is large, especially in light of how much will have to be spent for deployment of conventional gas, nuclear, or coal-fired systems to meet replacement of retiring plants and capacity increases, as there are no other options with sufficient scale on the horizon.

The panel specifically recommends that:

1. There should be a federal commitment to supporting EGS resource characterization and assessment. An aggressive, sufficiently supported, multiyear national program with USGS and DOE and other agency participation is needed to further quantify and refine the EGS resource as extraction and conversion technologies improve.
2. High-grade EGS resources should be developed first at targets of opportunity on the margins of existing hydrothermal systems and in areas with sufficient natural recharge, or in oil fields with high-temperature water and abundant data, followed by field efforts at sites with above-average temperature gradients. Representative sites in high-grade areas, where field development and demonstration costs would be lower, should be selected initially to prove that EGS technology will work at a commercial scale. These near-term targets of opportunity include EGS sites that are currently under consideration at Desert Peak (Nevada), and Coso and Clear Lake (both in California), as well as others that would demonstrate that reservoir-stimulation methods can work in other geologic settings, such as the deep, high-temperature sedimentary basins in Louisiana, Texas, and Oklahoma. Such efforts would provide essential reservoir stimulation and operational information and would provide working "field laboratories" to train the next generation of scientists and engineers who will be needed to develop and deploy EGS on a national scale.
3. In the first 15 years of the program, a number of sites in different regions of the country should be under development. Demonstration of the repeatability and universality of EGS technologies in different geologic environments is needed to reduce risk and uncertainties, resulting in lower development costs.
4. Like all new energy-supply technologies, for EGS to enter and compete in evolving U.S. electricity markets, positive policies at the state and federal levels will be required. These policies must be similar to those that oil and gas and other mineral-extraction operations have received in the past – including provisions for accelerated permitting and licensing, loan guarantees, depletion allowances, intangible drilling write-offs, and accelerated depreciations, as well as those policies associated with cleaner and renewable energies such as production tax credits, renewable credits and portfolio standards, etc. The success of this approach would parallel the development of the U.S. coal-bed methane industry.
5. Given the significant leveraging of supporting research that will occur, we recommend that the United States actively participate in ongoing international field projects such as the EU project at Soultz, France, and the Cooper Basin project in Australia.
6. A commitment should be made to continue to update economic analyses as EGS technology improves with field testing, and EGS should be included in the National Energy Modeling System (NEMS) portfolio of evolving energy options.

Executive Summary

1.1 Motivation and Scope

The goal of this assessment is to provide an evaluation of geothermal energy as a major supplier of energy in the United States. An 18-member assessment panel with broad experience and expertise was formed to conduct the study beginning in September 2005. The work evaluated three major areas of Enhanced Geothermal Systems (EGS):

1. Magnitude and distribution of the EGS resource
2. Status and remaining requirements of EGS technology needed to demonstrate feasibility at a commercial-scale
3. Economic projections of impact of EGS on U.S. energy supply to 2050

Although there have been earlier assessments of EGS technology and economics, none has been as comprehensive as this one – ranging from providing a detailed evaluation of the geothermal resource to analyzing evolving energy markets for EGS. Our group was able to review technical contributions and progress, spanning more than 30 years of field testing, as well as several earlier economic and resource estimates.

Substantial progress has been made in developing and demonstrating certain components of EGS technology in the United States, Europe, Australia, and Japan, but further work is needed to establish the commercial viability of EGS for electrical power generation, cogeneration, and direct heat supply.

Based on the analysis of experienced researchers, it is important to emphasize that while further advances are needed, none of the known technical and economic barriers limiting widespread development of EGS as a domestic energy source are considered to be insurmountable.

Our assessment evaluates the status of EGS technology, details lessons-learned, and prioritizes R&D needs for EGS. It will inform the ongoing debate of how to provide a more sustainable and secure energy supply for Americans for the long term, without compromising our economic capacity and political and social stability, and while minimizing environmental impacts. Therefore, energy researchers and developers, utility analysts and executives, and government policy makers should find our report useful.

The study addresses two critical questions facing the future of EGS:
1. Can EGS have a major impact on national energy supply?
2. How much investment in R&D is needed to realize that impact?

One means of illustrating the potential of any alternative energy technology is to predict how a supply curve of energy costs vs. energy supply capacity would evolve as a result of moving down a learning curve and lowering capital costs. These positive economic effects reflect both R&D improvements to individual technology components, as well as lower risks and uncertainties in investments to deploy EGS by repeating the process at several field locations. In addition, given that the grade of the EGS resource varies widely in the United States, the supply curve analysis also indicates a gradual transition from deployment of higher- to lower-grade resources.

The panel has defined the impact threshold for EGS technology as being able to provide 100,000 MW of additional electrical capacity competitively by 2050. While we recognize that this specific goal is not part of the current DOE program, a 10% impact is a reasonable goal for EGS to become a major player as a domestic energy supply. Our assessment deals directly with the technical and economic feasibility of having EGS achieve this goal, emphasizing the quantitative requirements of both science and engineering in subsurface environments. We develop supply curves for EGS and lay out a rationale that specifies what technology and learning improvements will be needed to reduce risks and lower costs to a point where EGS could have a major impact on the U.S. energy supply. A key aspect of our work is to evaluate whether the costs of the additional R&D needed to demonstrate the technology at a commercial scale are low enough, and the potential energy security benefits high enough, to justify federal and private investment in EGS.

This first chapter of our report summarizes our overall approach, as well as the main findings in the three focus areas. Included in this chapter are recommendations for research and development, regulatory and governmental policies, and evolving energy markets for EGS that would achieve this high level of impact on the U.S. energy supply.

1.2 Defining EGS

In general terms, geothermal energy consists of the thermal energy stored in the Earth's crust. Thermal energy in the earth is distributed between the constituent host rock and the natural fluid that is contained in its fractures and pores at temperatures above 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 phase but sometimes may consist of a saturated, liquid-vapor mixture or superheated steam vapor phase. The amounts of hot rock and contained fluids are substantially larger and more widely distributed in comparison to hydrocarbon (oil and gas) fluids contained in sedimentary rock formations underlying the United States.

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 20th century that geothermal energy was harnessed for industrial and commercial purposes. In 1904, electricity was first produced using geothermal steam at the vapor-dominated field in Larderello, Italy. Since that time, other hydrothermal developments, such as the steam field at The Geysers, California; and the hot-water systems at Wairakei, New Zealand; Cerro Prieto, Mexico; and Reykjavik, Iceland; and in Indonesia and the Philippines, have led to an installed world electrical generating capacity of nearly 10,000 MW_e and a direct-use, nonelectric capacity of more than 100,000 MWt (thermal megawatts of power) at the beginning of the 21st century.

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 almost 59 mW/m^2 [1.9×10^{-2} $Btu/h/ft^2$]. The intrusion of large masses of molten rock can increase this normal heat flow locally; but for most of the continental crust, the heat flow is due to two primary processes:

1. Upward convection and conduction of heat from the Earth's mantle and core, and
2. Heat generated by the decay of radioactive elements in the crust, particularly isotopes of uranium, thorium, and potassium.

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 igneous activity and/or volcanic events (younger than about 1 million years). This is why people frequently associate geothermal energy only with places where such conditions are found – such as Iceland, New Zealand, or Japan (plate boundaries), or with Yellowstone National Park (recent volcanism) – and 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. For hydrothermal systems, one normally needs to have large amounts of hot, natural fluids contained in an aquifer with high natural rock permeability and porosity to ensure long-term production at economically acceptable levels. When sufficient natural recharge to the hydrothermal system does not occur, which is often the case, a reinjection scheme is necessary to ensure production rates will be maintained.

Thermal energy is extracted from the reservoir by coupled transport processes (convective heat transfer in porous and/or fractured regions of rock and conduction through the rock itself). The heat-extraction process must be designed with the constraints imposed by prevailing *in situ* hydrologic, lithologic, and geologic conditions. Typically, hot water or steam is produced and its energy is converted into a marketable product (electricity, process heat, or space heat). Any waste products must be properly treated and safely disposed of to complete the process. 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, to some degree, accelerated the development of geothermal resources. Nonetheless, there are inherent differences that have limited development such as higher well-flow requirements and temperature limitations to drilling and logging operations (see Chapters 4 and 6 for details).

The U.S. Department of Energy has broadly defined Enhanced (or engineered) Geothermal Systems (EGS) as engineered reservoirs that have been created to extract economical amounts of heat from low permeability and/or porosity geothermal resources. For this assessment, we have adapted this definition to include all geothermal resources that are currently not in commercial production and require stimulation or enhancement. EGS would exclude high-grade hydrothermal but include conduction-dominated, low-permeability resources in sedimentary and basement formations, as well as geopressured, magma, and low-grade, unproductive hydrothermal resources. In addition, we have added coproduced hot water from oil and gas production as an unconventional EGS resource type that could be developed in the short term and possibly provide a first step to more classical EGS exploitation.

EGS concepts would recover thermal energy contained in subsurface rocks by creating or accessing a system of open, connected fractures through which water can be circulated down injection wells, heated by contact with the rocks, and returned to the surface in production wells to form a closed loop (Figure 1.1). The idea itself is a simple extrapolation that emulates naturally occurring hydrothermal circulation systems – those now producing electricity and heat for direct application commercially in some 71 countries worldwide.

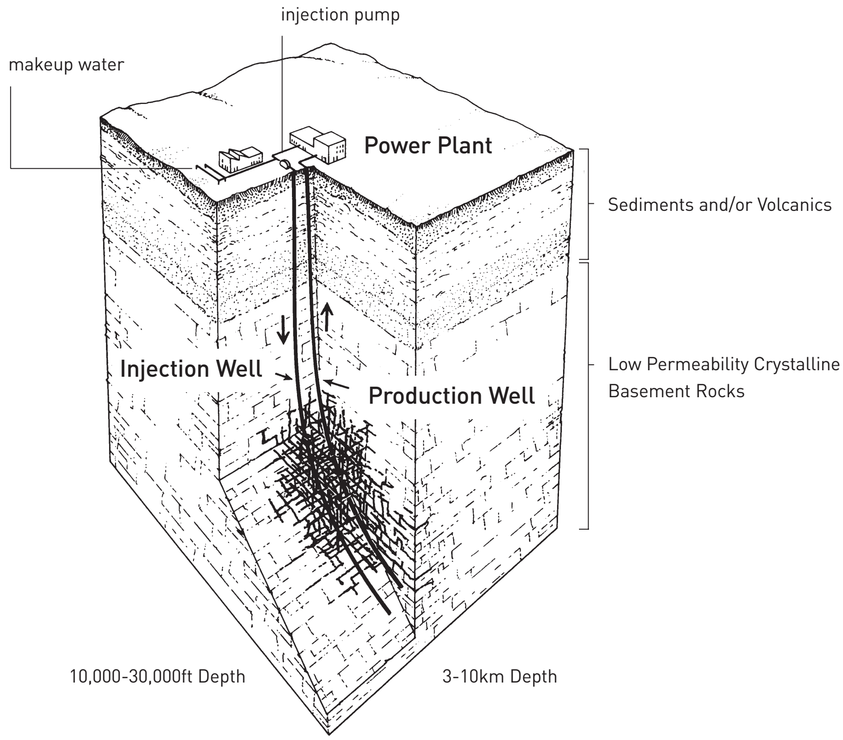


Figure 1.1 Schematic of a conceptual two-well Enhanced Geothermal System in hot rock in a low-permeability crystalline basement formation.

In principle, conduction-dominated EGS systems in low-permeability sediments and basement rock are available all across the United States. The first step would be exploration to identify and characterize the best candidate sites for exploitation. Holes then would be drilled deep enough to encounter useful rock temperature to further verify and quantify the specific resource at relevant depths for exploitation. If low-permeability rock is encountered, it would be stimulated hydraulically to produce a large-volume reservoir for heat extraction and suitably connected to an injection-production well system. If rock of sufficient natural permeability is encountered in a confined geometry, techniques similar to water-flooding or steam-drive employed for oil recovery might be used effectively for heat mining (Tester and Smith, 1977; Bodvarsson and Hanson, 1977). Other approaches for heat extraction employing downhole heat exchangers or pumps, or alternating injection and production (huff-puff) methods, have also been proposed.

1.3 U.S. Geothermal Resource Base

The last published comprehensive study of geothermal energy by the U.S. Geological Survey appeared in 1979 (USGS Circular 790). As a result, we have relied on published data and projections that have appeared since 1979 to update and refine the earlier USGS estimates.

We have not tried to improve on USGS estimates of the hydrothermal resources, as they represent a high-grade component of the geothermal resource that is already undergoing commercial development in the United States. For this assessment, we have divided the EGS resource into categories as shown in Table 1.1. (For information on energy conversion factors, see Appendix A.) In addition to the conduction-dominated portions of the EGS resource in sediments and basement rock formations, we added three categories: geopressured, volcanic, and coproduced fluids. Resource base estimates for geopressured and supercritical volcanic systems were taken directly from the USGS Circulars 726 and 790. Coproduced fluids is a new category of EGS that was also included in our assessment. It represents heated water that is produced as an integral part of oil and gas production. Estimates in this category were based on ongoing work in Blackwell's group (McKenna et al., 2005, in Chapter 2).

Table 1.1 Estimated U.S. geothermal resource base to 10 km depth by category.

Category of Resource	Thermal Energy, in Exajoules (1EJ = 10^{18}J)	Reference
Conduction-dominated EGS		
Sedimentary rock formations	100,000	This study
Crystalline basement rock formations	13,300,000	This study
Supercritical Volcanic EGS*	74,100	USGS Circular 790
Hydrothermal	2,400 – 9,600	USGS Circulars 726 and 790
Coproduced fluids	0.0944 – 0.4510	McKenna, et al. (2005)
Geopressured systems	71,000 – 170,000**	USGS Circulars 726 and 790

* Excludes Yellowstone National Park and Hawaii

** Includes methane content

While this report uses SI units with energy expressed in exajoules (EJ), these are relatively unfamiliar to most people. Table A.1 provides energy equivalents for other unit systems.

Today's hydrothermal systems rarely require drilling deeper than 3 km (10,000 ft), while the technical limit for today's drilling technology is to depths greater than 10 km (30,000 ft). Consistent with earlier USGS assessments, we adopted a 10 km limiting depth to define the total geothermal resource base. We assumed that resources at depths of less than 3 km are contained in hydrothermal resource base or are associated with hydrothermal temperature anomalies. Consequently, a minimum depth of 3 km was used for EGS resources in this study. The recoverable resource associated with identified hydrothermal resources has been separately estimated by the USGS and others.

Without question, the largest part of the EGS resource base resides in the form of thermal energy stored in sedimentary and basement rock formations, which are dominated by heat conduction and radiogenic processes. These are reasonably quantifiable on a regional basis in terms of rock temperatures at depth, densities, and heat capacities. Southern Methodist University has developed a quantitative model for refining estimates of the EGS resource in sedimentary and basement rocks. While Chapter 2 details their methodology and calculations, here we present only salient results regarding the magnitude and distribution of the U.S. EGS resource.

Figure 1.2 shows the heat flow of the conterminous United States where one easily sees that the western region of the country has higher heat flow than the eastern part. This fact leads to substantial regional differences in rock temperature as a function of depth. Figures 1.3-1.5 illustrate this by showing temperatures at depths of 3.5, 6.5, and 10 km, respectively. The resource base for the sedimentary and basement sections of EGS resources were computed by first subdividing the subsurface into 1 km-thick, horizontal slices of rock. Using the temperature versus depth information from the SMU database, the amount of stored thermal energy for a given location (specified by longitude and latitude coordinates within the United States) could easily be determined for each slice (see Figure 2.3 and the corresponding discussion). Figure 1.6 shows the amount of energy in each slice as a function of temperature at depths to 10 km for the entire United States. This histogram provides a rough estimate of the energy potentially available for each EGS resource grade (given by initial rock temperature and the depth). Higher grades would correspond to hotter, shallower resources.

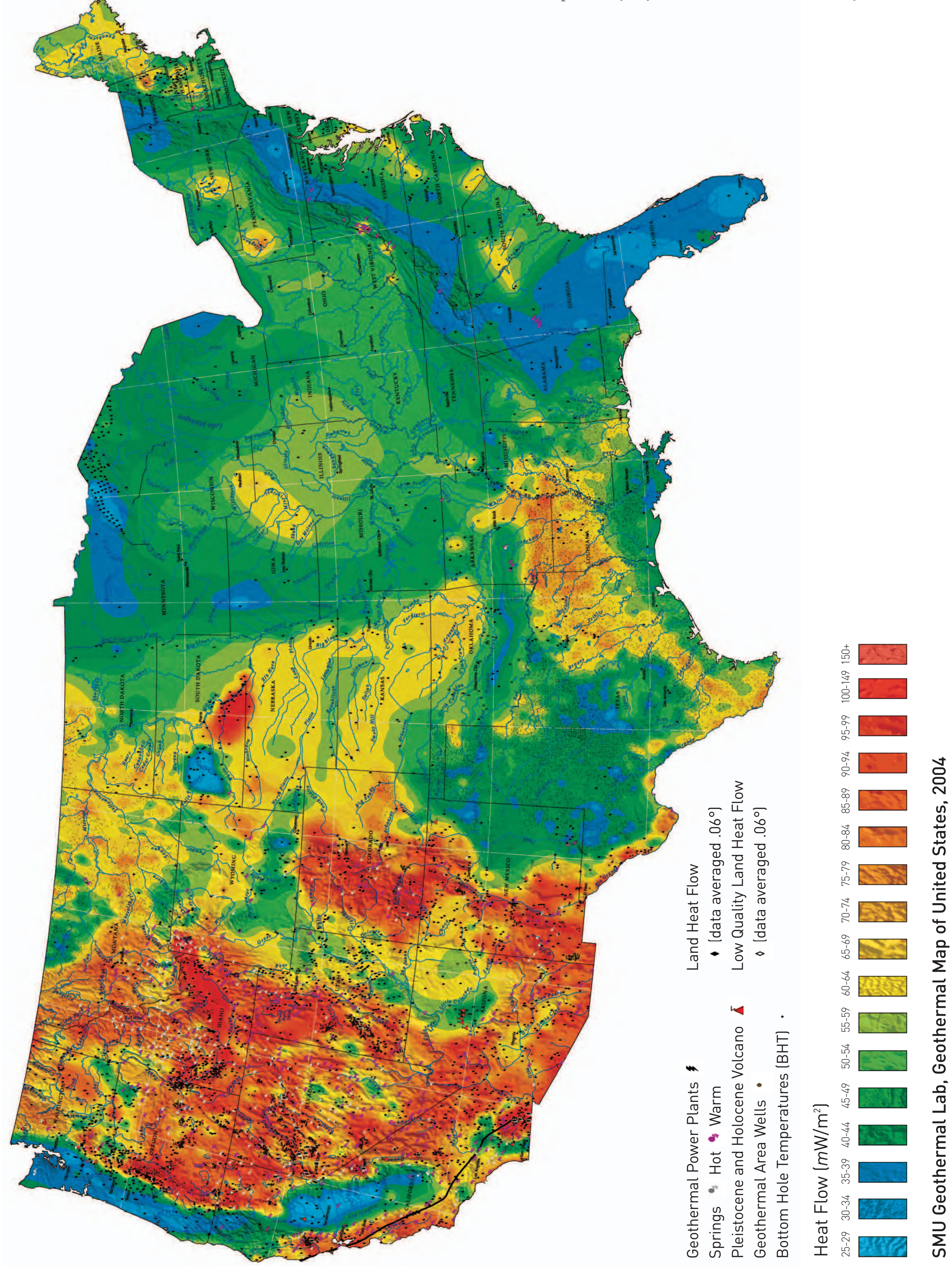


Figure 1.2 Heat-flow map of the conterminous United States – a subset of the geothermal map of North America (Blackwell and Richards, 2004)

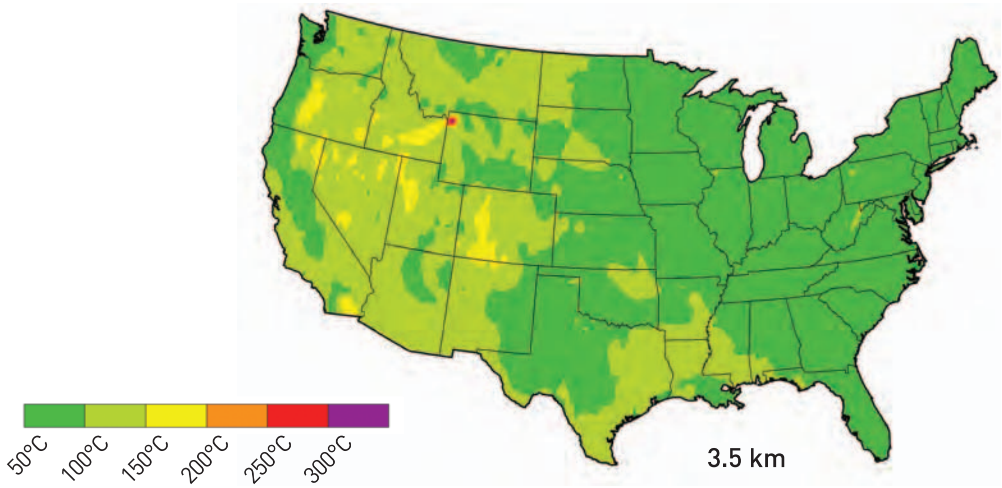


Figure 1.3 Temperatures at a depth of 3.5 km.

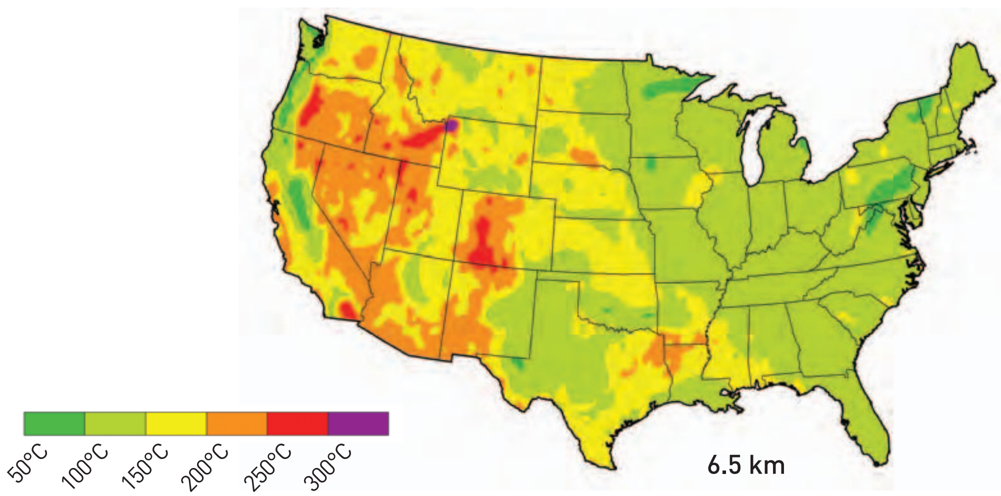


Figure 1.4 Temperatures at a depth of 6.5 km.

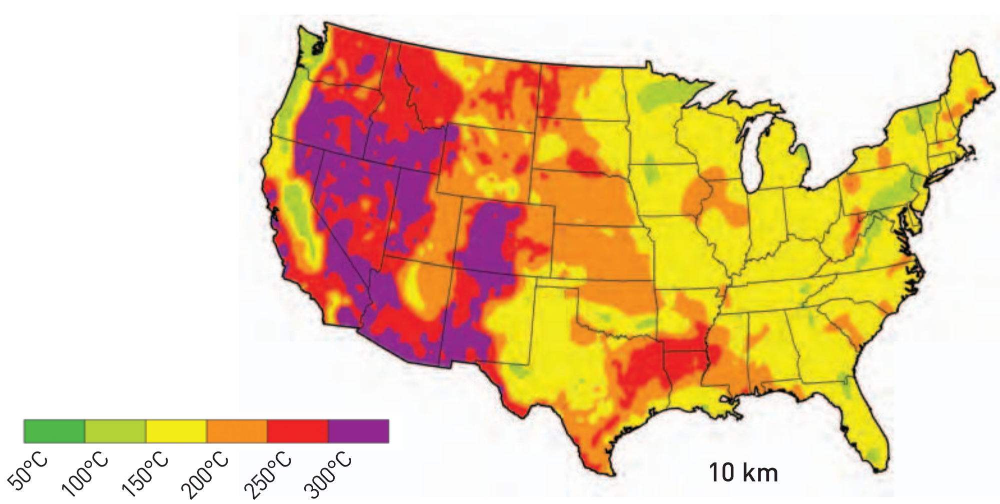


Figure 1.5 Temperatures at a depth of 10 km.

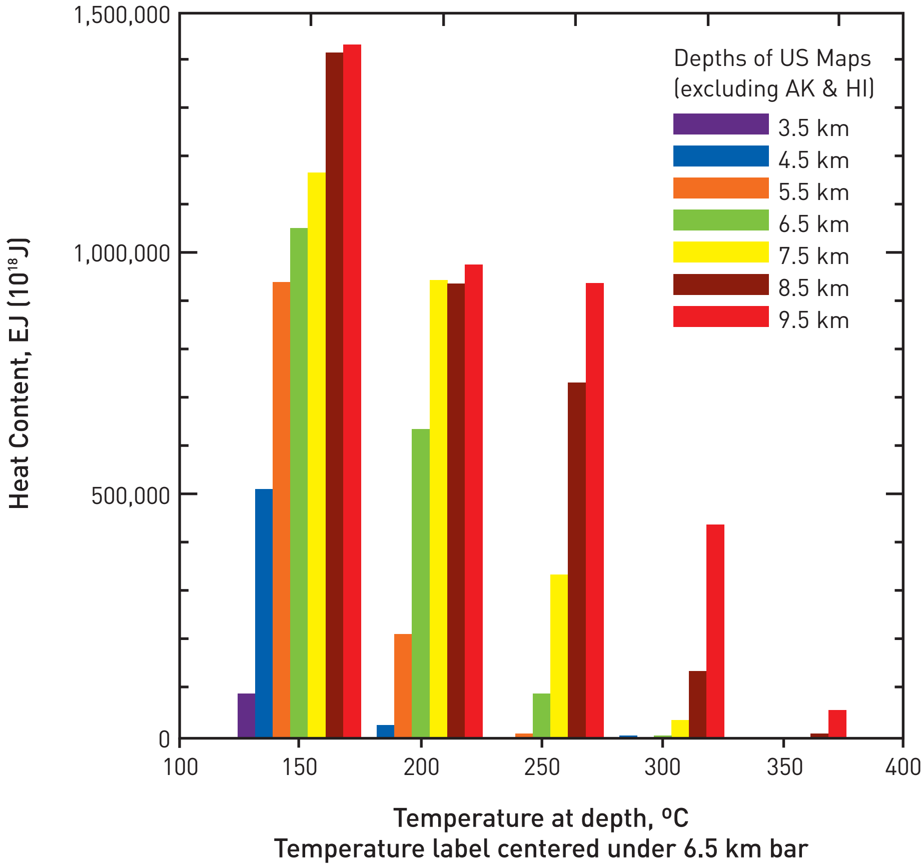


Figure 1.6 Histograms of heat content as thermal energy, as a function of depth for 1 km slices. For each temperature indicated, the total thermal energy content contained in a 1 km-thick slice over the entire U.S. area is plotted.

The total resource base to a depth of 10 km can also be estimated. Values are tabulated in Table 1.1. By almost any criteria, the accessible U.S. EGS resource base is enormous – greater than 13 million quads or 130,000 times the current annual consumption of primary energy in the United States. Of course, the economically recoverable reserve for EGS will be much lower, subject to many technical and economic constraints that are evaluated throughout this report.

We can easily see that, in terms of energy content, the sedimentary and basement EGS resources are by far the largest and, for the long term, represent the main target for development. However, in the shorter term, it makes sense to develop higher-grade EGS resources. For example, very high thermal gradients often exist at the margins of hydrothermal fields. Because wells there would be shallower (< 4km) and hotter (>200°C) with infrastructure for power generation and transmission often in place, such high-grade regions could easily be viewed as initial targets of opportunity.

To extract thermal energy economically, one must drill to depths where the rock temperatures are sufficiently high to justify investment in the heat-mining project. For generating electricity, this will normally mean drilling to rock temperatures in excess of 150°C to 200°C; for many space or process heating applications, much lower temperatures would be acceptable, such as 100°C to 150°C.

Although beyond the scope of this assessment, it is important to point out that even at temperatures below 50°C, geothermal energy can have a significant impact. Geothermal heat pumps provide an important example of how low-grade thermal energy, available at shallow depths from 2 to 200 m, leads to substantial energy savings in the heating and cooling of buildings. For example, with a practical coefficient of performance (COP) of 4 or better year-round in the U.S. Midwest, it is often

possible to achieve more than 75% savings in electrical energy consumption per unit of heating or cooling delivered to the building. Because the use of geothermal heat pumps is often treated as an energy efficiency measure rather than as energy supply – and because they are readily available commercially – more than 1 million units had been installed in the United States by the end of 2005.

For a geothermal resource to be viable, in addition to having sufficiently high temperature, *in situ* hydrologic and lithologic conditions need to be favorable. In existing vapor- and liquid-dominated hydrothermal systems, this amounts to having a rock system (reservoir) that has high permeability and high porosity filled with steam or water under pressure. If such conditions do not exist naturally, then the rock system must be stimulated to generate or modify a reservoir to make it sufficiently productive. This is the essence of EGS, where the reservoir is engineered to have it emulate the productivity of a viable hydrothermal system. A range of lithologic and geologic properties are important for determining EGS stimulation approaches. Most important, the state of stress at depths of interest must be known. In addition, other features of the rock mass that influence the probability of creating suitable inter-well connectivity include natural fracture spacing, rock strength, and competence.

1.4 Estimating the Recoverable Portion of EGS

Estimating the recoverable fraction of any underground resource is inherently speculative, whether it is for oil or gas, geothermal energy, or a specific mineral. Typically, some type of reservoir simulation model is used to estimate how much can be extracted. To reduce errors, predicted results are validated with field data when available. This type of "history matching" is commonly used in reservoir analysis.

Sanyal and Butler (2005) have modeled flow in fractured reservoirs using specified geometries to determine the sensitivity of the calculated recoverable heat fraction to rock temperature, fractured volume, fracture spacing, fluid circulation rate, well configuration, and post-stimulation porosity and permeability. They used a 3-dimensional finite difference model and calculated the fraction of the thermal energy in place that could be mined for a specified set of reservoir properties and geometry. Interestingly, for a range of fracture spacings, well geometries, and fracture permeabilities, the percentage of recoverable thermal energy from a stimulated volume of at least 1×10^8 m^3 (0.1 km^3) under economic production conditions is nearly constant at about 40 ± 7% (see Figure 3.1). Furthermore, this recovery factor is independent of well arrangements, fracture spacing, and permeability, as long as the stimulated volume exceeds 1×10^8 m^3 – a value significantly below what has been already achieved in several field projects.

The Sanyal-Butler model was used as a starting point to make a conservative estimate for EGS resource recovery. Channeling, short circuiting, and other reservoir-flow problems sometimes have been seen in early field testing, which would require remediation or they would limit capacity. Furthermore, multiple EGS reservoirs would have a specified spacing between them in any developed field, which reduces the reservoir volume at depth per unit surface area. Given the early stage of EGS technology, Sanyal-Butler estimated 40% recovery factor was lowered to 20% and 2% to account for these effects, and reservoir spacings of 1 km at depth were specified to provide a more conservative range for EGS.

With a reservoir recovery factor specified, another conservative feature was introduced by limiting the thermal drawdown of a region where heat mining is occurring. The resource base figures given in Table 1.1 use the surface temperature as the reference temperature to calculate the total thermal energy content. A much smaller interval was selected to limit the amount of energy extracted by specifying a reservoir abandonment temperature just 10°C below the initial rock temperature at depth.

Finally, the recoverable heat in kJ or kW-s in a given 1 km slice per unit of surface area was then determined from the total energy in place at that depth, i.e., the resource-base amount (results are shown in Figure 1.7). A final limiting factor was introduced to account for the fact that only a portion of the land area in the United States is accessible for EGS development. Areas within national parks and monuments, wilderness areas, etc., would be off-limits to EGS, as well as some locations near and within large urban areas or utility and transportation corridors.

In addition to estimating the recoverable fraction of energy that can be extracted from the total EGS resource, it is important to also estimate the amount of surface-land area and subsurface rock volume required for an EGS plant. For scaling purposes, we have based an analysis of above-ground requirements on those needed for existing hydrothermal systems (see Chapters 7 and 8), while below-ground requirements were based on the amount of rock volume needed to sustain plant operations for a 20-year period. These are tabulated for a range of plant sizes on a per MW_e basis for the surface plant and auxiliaries, and for the subsurface reservoir in Table 1.2.

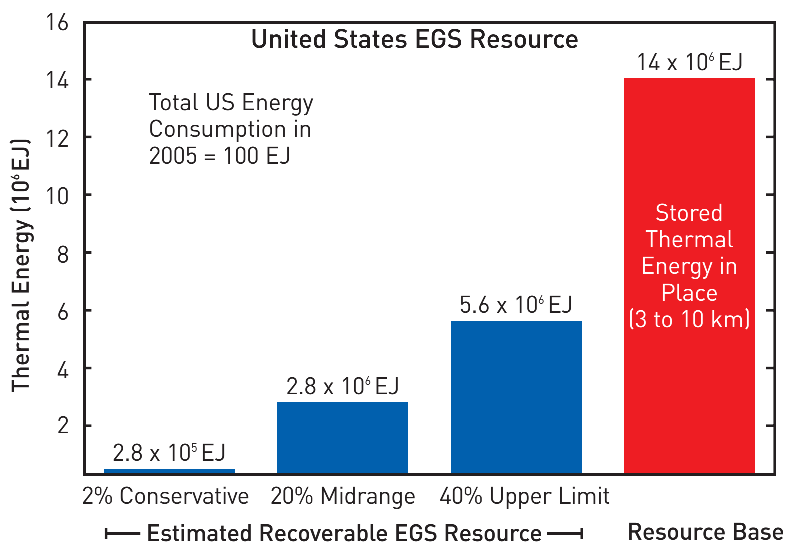


Figure 1.7 Estimated total geothermal resource base and recoverable resource given in EJ or 10^{18} Joules. Note: Other energy equivalent units can be obtained using conversion factors given in Appendix A.

Table 1.2 Estimated land area and subsurface reservoir volumes needed for EGS development. Note: Above 100 MW_e, reservoir size scaling should be linear.

Plant size in MW_e	Surface area for power plant and auxiliaries in km^2	Subsurface reservoir volume in km^3
25	1	1.5
50	1.4	2.7
75	1.8	3.9
100	2.1	5.0

1. Assuming 10% heat to electric-power efficiency, typical of binary plants.

2. Introduces a factor of 4 to surface area and volumes to deal with redrilling of reservoir at 5-year intervals over a 20-year projected lifetime.

1.5 Geothermal Drilling Technology and Costs

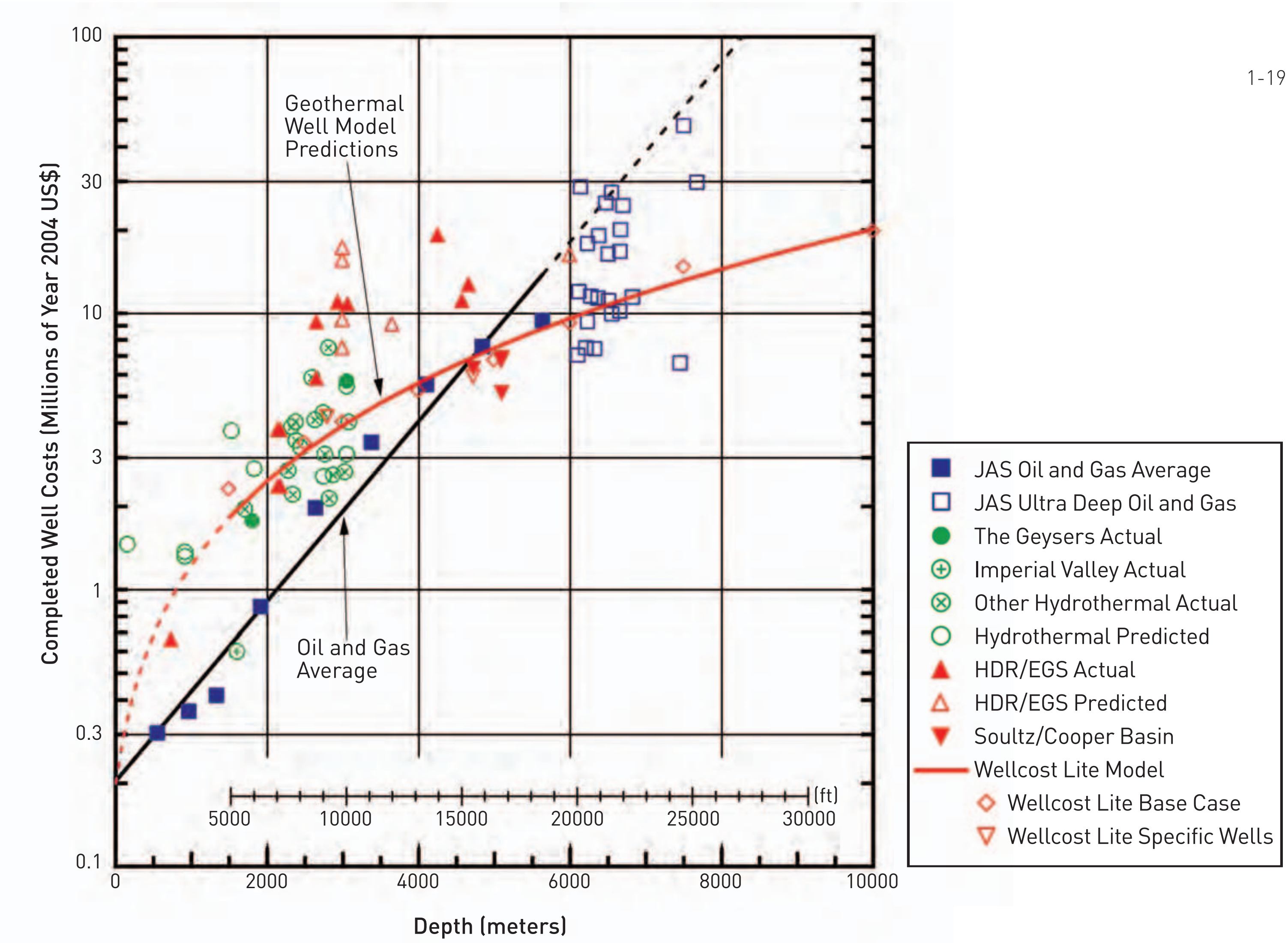
Well costs are a significant economic component of any geothermal development project. For lower-grade EGS, the cost of the well field can account for 60% or more of the total capital investment. For making economic projections, estimates of well drilling and completion costs to depths of 10,000 m (30,000 ft) are needed for all grades of EGS resources. Drill-site specifics, stimulation approaches, well diameters and depths, and well production interval lengths and diameters are just some of the parameters that need to be considered. Drilling records for geothermal wells do not exist in sufficient quantity or detail for making such projections. In recent years, there have been fewer than 100 geothermal wells drilled per year in the United States and very few of them are deeper than 2,800 m (9,000 ft), which provides no direct measure of well costs for deeper EGS targets for the long term.

Insight into geothermal well costs is gained by examining trends from experience in the oil and gas well-drilling industry. Thousands of oil and gas wells are drilled each year in the United States, and data on their costs are available on a yearly basis from the American Petroleum Institute's Joint Association Survey (JAS) (see API, 2006). Additionally, the similarity between oil and gas wells and geothermal wells makes it possible to develop a drilling cost index that can be used to normalize any geothermal well cost from the past three decades to present current values, so that the well costs can be compared on a common dollar basis.

Because of the limited data available for geothermal drilling, our analysis employed the Wellcost Lite model, developed by Bill Livesay and coworkers at Sandia National Laboratories during the past 20 years, to estimate the cost of EGS wells. The model can accommodate expected ranges in a multitude of parameters (well diameter, bit life, penetration rate, casing design, geologic formation conditions, etc.). Improvements in drilling technology can also be incorporated into the model, as well as directional drilling with multilateral completion legs. Wells in the depth ranges from 1,500 m (4,920 ft) to 10,000 m (32,800 ft) were modeled in three categories: shallow wells (1,500-3,000 m), mid-range wells (4,000-5,000 m), and deep wells (6,000-10,000 m).

EGS well costs are significantly influenced by the number of casing strings used. For example, two 5,000 m-deep wells were modeled, one with four casing intervals and another with five casing intervals. Whereas the former requires fewer casing intervals, the increased lengths of individual sections may raise concerns about wellbore stability. This is less of a risk if more casing strings are used, but costs will be adversely affected by an increase in the diameter of the upper casing strings, the size of the rig required, and a number of other parameters. The 6,000 m well was modeled with both five- and six-casing intervals. Costs for the 7,500 m and 10,000 m wells were estimated using six casing intervals.

Shallow wells at depths of 1,500, 2,500, and 3,000 m are representative of current hydrothermal practice. Predicted costs from the Wellcost Lite model were compared to actual EGS and hydrothermal well drilling-cost records, where available. Figure 1.8 shows the actual costs of geothermal wells, including some EGS wells. The costs predicted by the Wellcost Lite model show adequate agreement with actual geothermal well costs, within the normal ranges of expected variation for all depths.



1. JAS = Joint Association Survey on Drilling Costs.
2. Well costs updated to US$ (yr. 2004) using index made from 3-year moving average for each depth interval listed in JAS (1976-2004) for onshore, completed US oil and gas wells. A 17% inflation rate was assumed for years pre-1976.
3. Ultra deep well data points for depths greater than 6 km are either individual wells or averages from a small number of wells listed in JAS (1994-2000).
4. "Other Hydrothermal Actual" data include some non-US wells (Source: Mansure 2004).

Figure 1.8 Completed oil, gas, and geothermal well costs as a function of depth in 2004 U.S.$, including estimated costs from the Wellcost Lite model. The red line provides average well costs for the base case used in the assessment.

Nonetheless, given the scarcity of the geothermal well cost data compared to oil and gas wells, estimating statistically meaningful well costs at particular depths was not possible, so average costs were based on model predictions with a large degree of inherent uncertainty. Well-design concepts and predictions for the deeper categories – 6,000 m, 7,500 m, and 10,000 m (19,680 ft, 24,600 ft, and 32,800 ft) – are obviously even more speculative, as there have been only two or three wells drilled close to depths of 10,000 m in the United States. Because of this, a conservative well design was used to reflect this higher uncertainty.

Emerging technologies, which have yet to be demonstrated in geothermal applications and are still going through development and commercialization, can be expected to significantly reduce the cost of these wells, especially those at 4,000 m and deeper. One technology that will potentially reduce the cost of the well construction (casing and cementing) is expandable tubular casing, a patented invention by Shell Oil (Lohbeck, 1993). The concept has been licensed to two commercial firms. There are still concerns about the effect of thermal expansion and the depth of reliable application of the expanded casing when in place.

Drilling-with-casing is another new technology that has the potential to reduce cost. This approach may permit longer casing intervals, leading to fewer strings and, therefore, reduced costs. Research is needed to improve our understanding of cementing practices that apply to the drilling-with-casing technique.

Well-design changes, particularly involving the use of smaller increments in casing diameters with depth, are likely to significantly reduce EGS well costs. This well-design approach requires detailed analysis to resolve concerns about pressure drops during cementing. It may be limited to cemented liners.

Being able to increase borehole diameter by under-reaming is a key enabling technology for almost all of the EGS drilling applications, including current and future drilling technologies. The development of an under-reamer that is reliable and can penetrate at the same rate as the lead bit is a necessity. Current work at Sandia on small-element drag cutters in geothermal formations may enable drag-cutter under-reamers (the standard for oil and gas applications) to be a viable tool for geothermal application.

Rate-of-penetration (ROP) issues can significantly affect drilling costs in crystalline formations. ROP problems can cause well-cost increases by as much as 15% to 20% above those for more easily drilled basin and range formations.

Casing diameters that decrease with depth are commonplace in conventional casing designs for the hydrothermal, and oil and gas industries. Unfortunately, geothermal wells currently require larger-diameter casings than oil/gas wells. However, this simply means that EGS wells will benefit even more from the use of successful evolving technologies, which have the potential to reduce the cost of the deep wells by as much as $2.5 million to $3 million per well.

In the longer term, particularly when lower-grade EGS resources are being developed, more revolutionary approaches could have a large impact on lowering EGS drilling costs, in that they could increase both ROP and bit lifetime as well as facilitate under-reaming. For example, such approaches would reduce the number of times the drill string would have to be removed from the hole to change drill bits. Three revolutionary drilling technology examples include hydrothermal flame spallation and fusion drilling (Potter and Tester, 1998), chemically enhanced drilling (Polizotti, 2003), and metal shot abrasive-assisted drilling (Curlett and Geddes, 2006). Each of these methods augments or avoids the traditional method of penetration based on crushing and grinding rock with a hardened material in the drill bit itself, thereby reducing the tendency of the system to wear or fail.

1.6 EGS Reservoir Stimulation – Status of International Field Testing and Design Issues

Creating an Enhanced Geothermal System requires improving the natural permeability of hot rock. Rocks are naturally porous by virtue of minute fractures and pore spaces between mineral grains.

When some of this porosity is interconnected so that fluids (water, steam, natural gas, crude oil) can flow through the rock, such interconnected porosity is called permeability.

Rock permeability extends in a continuum over several orders of magnitude, from rocks that are highly permeable and whose contained fluids can be produced by merely drilling wells (e.g., oil and gas wells, water wells, hydrothermal systems), to those that are almost completely impermeable (e.g., tight gas sands, hot dry rock). Extensive drilling for petroleum, geothermal, and mineral resources during the past century has demonstrated that the largest heat resource in the Earth's crust, by far, is contained in rocks of low natural permeability. Recovery of heat from such rocks at commercial rates and competitive costs is the object of the EGS program.

This EGS assessment draws heavily on research funded by the DOE and ongoing EGS work around the world. The knowledge gained from this research in the United States and elsewhere, reviewed below, forms a robust basis for the future enhancements of this growing knowledge base.

Since the 1970s, research projects aimed at developing techniques for the creation of geothermal reservoirs in areas that are considered noncommercial for conventional hydrothermal power generation have been – and are being – conducted around the world. These include the following:

- United States: Fenton Hill, Coso, Desert Peak, Glass Mountain, and The Geysers/Clear Lake
- United Kingdom: Rosemanowes
- France: Soultz, Le Mayet de Montagne
- Japan: Hijiori and Ogachi
- Australia: Cooper Basin, Hunter Valley, and others
- Sweden: Fjallbacka
- Germany: Falkenberg, Horstberg, and Bad Urach
- Switzerland: Basel and Geneva

Techniques for extracting heat from low-permeability, hot dry rock (HDR) began at the Los Alamos National Laboratory in 1974 (Armstead and Tester, 1987). For low-permeability formations, the initial concept is quite straightforward: drill a well to sufficient depth to reach a useful temperature, create a large heat-transfer surface area by hydraulically fracturing the rock, and intercept those fractures with a second well. By circulating water from one well to the other through the stimulated region, heat can be extracted from the rock. Fundamentally, this early approach – as well as all later refined methods – requires that good hydraulic conductivity be created between injection and production wells through a large enough volume of rock to sustain economically acceptable energy-extraction rates and reservoir lifetimes. Ultimately, field testing will need to produce a commercial-sized reservoir that can support electricity generation or cogeneration of electrical power and heat for a variety of applications such as heat for industrial processes and local district heating.

As expected in the early development of any new technology, many lessons have been learned from 30 years of EGS field research in the eight countries listed above. For example, the initial concept of producing discrete hydraulic fractures has largely been replaced by stimulating the natural fracture system. Although the goal of operating a commercial-sized EGS reservoir has not been achieved yet,

field testing has successfully demonstrated that reservoirs of sufficient size with nearly sufficient connectivity to produce fluids at commercial rates can be established.

Through field tests in low-permeability crystalline rock, researchers have made significant progress in understanding reservoir characteristics, including fracture initiation, dilation and propagation, thermal drawdown, water loss rates, flow impedance, fluid mixing, and fluid geochemistry. In addition to using hydraulic stimulation methods to establish connectivity in the far field, it is feasible to create permeability near injection or production wellbores by explosive fracturing, chemical leaching, and thermal stress cracking (Armstead and Tester, 1987; Tester et al., 1989).

Included among the milestones that have been achieved are:

- Drilling deep directionally oriented wells to specific targets.
- Creation of contained fracture systems in large volumes of rock of 1 km^3 or more.
- Improved understanding of the thermal-hydraulic mechanisms controlling the opening of fracture apertures.
- Improved methods for sequencing the drilling of wells, stimulating reservoirs, and managing fluid flow and other hydraulic characteristics.
- Circulation of fluid at well-flow rates of up to 25 kg/s on a continuous basis.
- Methods to monitor and manage induced microseismicity during stimulation and circulation.
- Extraction of heat from well-defined regions of hot fractured rock without excessive thermal drawdown.
- Generation of electrical power in small pilot plants.

Nonetheless, there are outstanding issues that must be resolved before EGS can be considered commercial. In general, these are all connected to enhancing the connectivity of the stimulated reservoir to the injection and production well network. Notably, they are incremental in their scope, representing extending current knowledge and practical field methods. There are no anticipated “showstoppers” or fundamental constraints that will require new technologies to be discovered and implemented to achieve success. The remaining priority issue is demonstrating commercial levels of fluid production from several engineered EGS reservoirs over acceptable production periods. Specific research and field-testing goals can be placed into two categories:

1. Primary goals for commercial feasibility:

- Develop and validate methods to achieve a twofold to fourfold increase in production well-flow rate from current levels, while maintaining sufficient contact with the rock within the reservoir and ensuring sufficient reservoir lifetime.
- Validate long-term operability of achieving commercial rates of heat production from EGS reservoirs for sustained periods of time at several U.S. sites.

2. Secondary goals connected to EGS technology improvement:

- Develop better methods of determining the distribution, density, and orientation of pre-existing and stimulated fractures to optimize overall hydraulic connectivity within the stimulated reservoir.

- Improve methods to repair or remedy any flow short circuits that may develop.
- Understand the role of major, pre-existing faults in constraining or facilitating the flow in the reservoir.
- Develop robust downhole tools to measure temperature, pressure, flow rate, and natural gamma emissions, capable of surviving in a well at temperatures of 200°C or higher for long-term monitoring.
- Predict scaling or deposition through better understanding of the rock-fluid geochemistry.

The advancement of EGS greatly depends on our understanding of the pre-existing, unstimulated, rock-fracture system – and on our ability to predict how the reservoir will behave under stimulation and production. So far, no EGS reservoir has been operated long enough to provide the data needed to validate a simulation model. A reliable reservoir-simulation model will allow us to better estimate the operating and maintenance costs of an EGS energy facility.

As we demonstrate in Chapter 2, the heat stored in the earth beneath the United States – at a depth accessible with today's drilling technology – is truly vast. However, the fraction of this resource base that can be economically recovered is dependent on improving the technology to map, penetrate, fracture, and maintain productive EGS reservoirs – and on improving our understanding of reservoir behavior under long-term energy extraction. These improvements, in turn, are directly connected to the level of research, development, testing, and demonstration of EGS.

While support of research will pay rapid dividends in providing measurable improvements to these important components of EGS technology – as well as technologies for drilling and power conversion mentioned earlier – there is also an opportunity for developing more revolutionary, potentially groundbreaking technologies in the longer term that could make EGS even more useful and universally accessible. For example, in Section 1.5, we mentioned three revolutionary drilling methods that could, if perfected, provide increased economic access to EGS by dramatically lowering costs, particularly for low-grade, low-gradient resources. In the reservoir area, there are possibilities as well. One such possibility involves the proposed use of carbon dioxide (in a supercritical state) as a fluid for heat extraction within an EGS reservoir (Brown, 2000). Recently, Pruess and Azaroual (2006) estimated reservoir performance using supercritical carbon dioxide in place of water. Early modeling results suggest improvements in heat-extraction efficiency, as well as the ability to store and sequester carbon dioxide within the confined EGS reservoir for carbon management.

With a fully supported federal R&D program and anticipated market price increases for electric power, the technology developed in this program could be implemented in a relatively short period of time in high- and mid-grade areas in the Western United States. The knowledge and momentum generated during this early deployment would enable EGS methods to be applied widely across the United States, including lower-grade areas of the Midwest and the East, which have not had any hydrothermal geothermal development yet.

1.7 Geothermal Energy Conversion Technology

There are several options for utilizing the thermal energy produced from geothermal systems. The most common is base-load electric power generation, followed by direct use in process and space-heating applications. In addition, combined heat and power in cogeneration and hybrid systems, and as a heat source and sink for heat pump applications, are options that offer improved energy savings.

Today, with nearly 10,000 MW_e of electricity generated by geothermal worldwide, there are several energy conversion technologies commercially available at various stages of maturity. These include direct steam expansion, single- and multistage steam flashing, organic binary Rankine cycles, and two-phase flow expanders. Figure 1.9 shows several representative flow sheets of conversion options applicable for a range of EGS resource grades. Direct-use and heat pump applications are also having an increasing impact, with a combined, estimated market penetration of about 100,000 MWt worldwide.

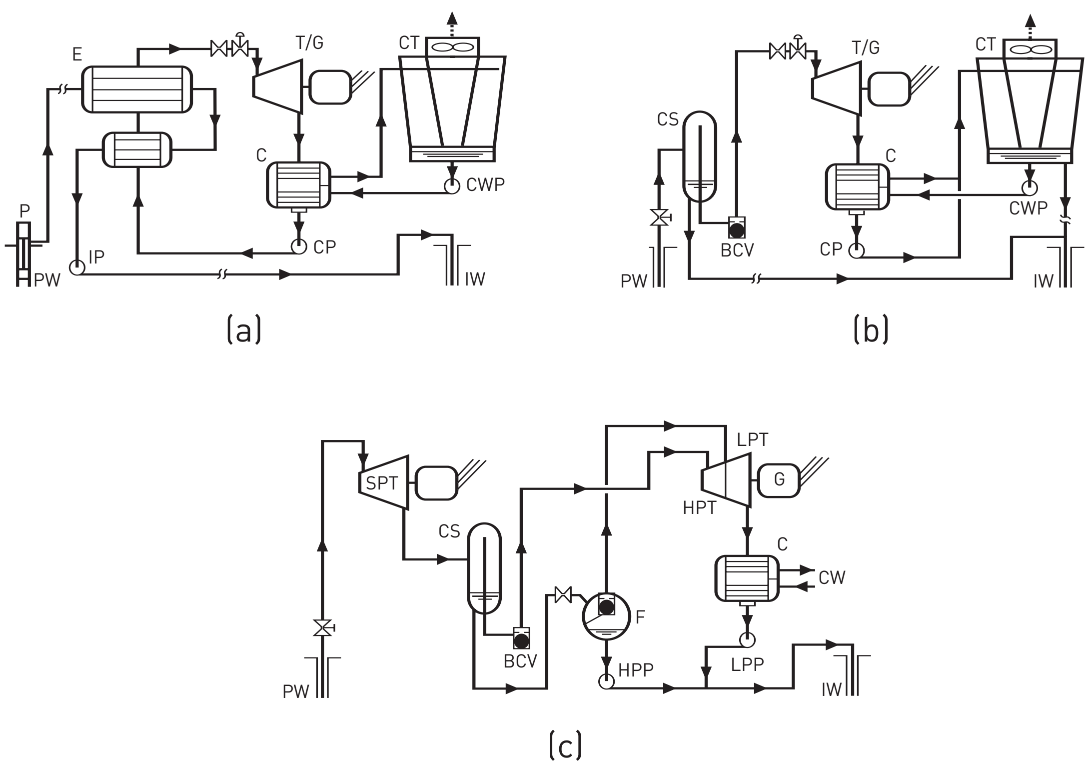


Figure 1.9 Schematics of EGS power conversion systems: (a) a basic binary power plant; (b) a single-flash power plant; (c) a triple-expansion power plant for supercritical EGS fluids.

There are inherent limitations on converting geothermal energy to electricity, because of the lower temperature of geothermal fluids in comparison to much higher combustion temperatures for fossil fuels. Lower energy source temperatures result in lower maximum work-producing potential in terms of the fluid's availability or exergy; and in lower heat-to-power efficiencies as a consequence of the Second Law of thermodynamics. The value of the availability determines the maximum amount of electrical power that could be produced for a given flow rate of produced geofluid, given a specified temperature and density or pressure. Figure 1.10 illustrates how the availability of the geofluid (taken as pure water) varies as a function of temperature and pressure. It shows that increasing pressure and increasing temperature have a nonlinear effect on the maximum work-producing potential. For example, an aqueous geofluid at supercritical conditions with a temperature of 400°C and pressure of 250 bar has more than five times the power-producing potential than a hydrothermal liquid water geofluid at 225°C. Ultimately, this performance enhancement provides an incentive for developing supercritical EGS reservoirs.

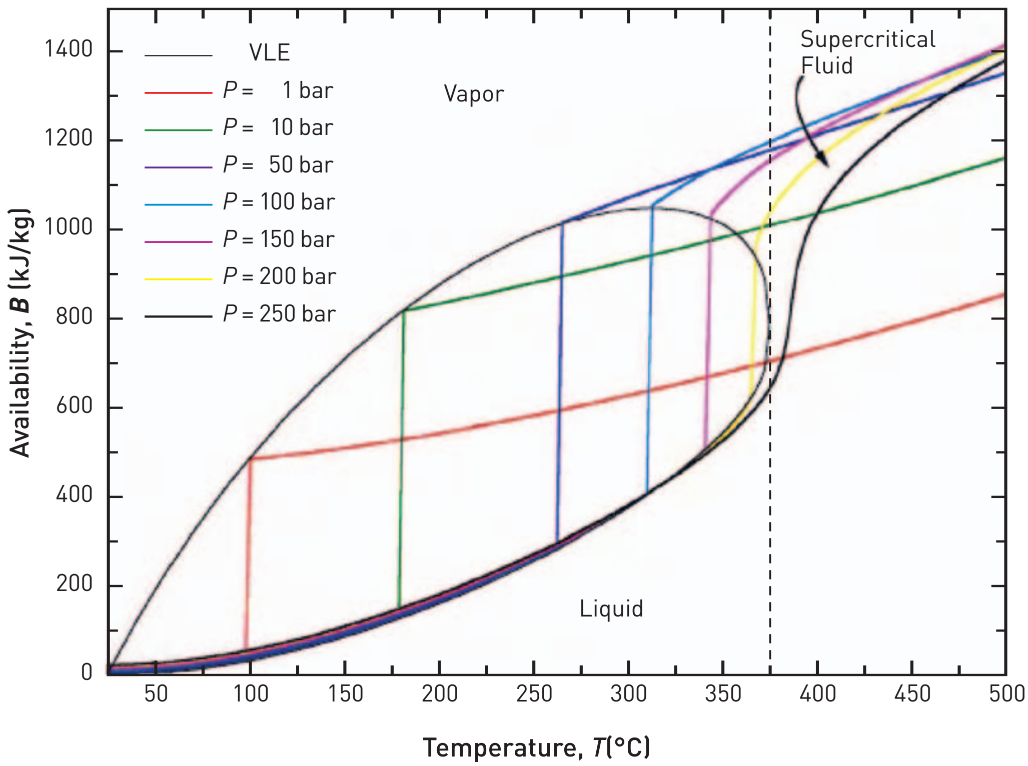


Figure 1.10 Availability diagram for water. The magnitude of the availability is a direct measure of the maximum electrical work- or power-producing potential of aqueous-produced geofluid at specific-state conditions of temperature and pressure.

The large capital investment that is contained in the well-field/reservoir portion of the system places a premium on achieving as high an efficiency as possible for a given geothermal resource, so it is worth putting considerable effort into mitigating these thermodynamic limitations. A utilization efficiency, defined as the ratio of actual net power to maximum possible power, provides a measure of how close the conversion system comes to ideal, reversible operation. Current practice for geothermal conversion systems shows utilization efficiencies typically range from 25% to 50%. Future engineering practice would like to increase these to 60% or more, which requires further investments in R&D to improve heat-transfer steps by minimizing temperature differences and increasing heat-transfer coefficients, and by improving mechanical efficiencies of converters such as turbines, turbo-expanders, and pumps.

Keeping these issues in mind, the panel considered specific cases for a range of EGS resource types and applications:

1. Electricity generation using EGS geofluids from sedimentary and basement rock formations and similar reservoirs, ranging in temperature from 100°C to 400°C, including one case at supercritical conditions;
2. Electricity generation from coproduced oil and gas operations using organic binary power plant designs over resource temperatures ranging from 100°C to 180°C;
3. Combined heat and power – cogeneration of electricity and thermal energy where the conditions at the MIT COGEN plant (nominally 20 MW_e and 140,000 lb/h steam) were used as a model system.

Each case in (1)-(3) involved the following steps, using standard methods of engineering design and analysis:

a) identification of the most appropriate conversion system;

b) calculation of the net power per unit mass flow of geofluid;

c) calculation of mass flow required for 1, 10, and 50 MW plants;

d) estimation of capital and installed plant costs

Our analysis of surface-conversion systems shows the following:

- Practical, commercial-scale energy conversion systems exist for all EGS geofluid types from low-temperature liquid water at 100°C to supercritical water at 400°C.
- 6,000 to 11,000 MW_e of generating capacity exists in coproduced hot waters associated with land-based domestic oil and gas production operations.
- Installed capital costs for surface conversion plants ranged from $2,300/kWe for 100°C resource temperatures to $1,500/kWe for 400°C resource temperature.

General EGS system properties were treated in one part of the analysis to provide design equations and costs, while several near-term targets of opportunity were also evaluated in somewhat more detail. Chapter 7 describes the technologies analyzed, along with plant-flow sheets and layouts for specific cases.

1.8 Environmental Attributes of EGS

When examining the full life cycle of geothermal energy developments, their overall environmental impacts are markedly lower than conventional fossil-fired and nuclear power plants. In addition, they may have lower impacts in comparison to other renewables such as solar, biomass, and wind on an equivalent energy-output basis. This is primarily because a geothermal energy source is contained underground, and the surface energy conversion equipment is relatively compact, making the overall footprint of the entire system small. EGS geothermal power plants operating with closed-loop circulation also provide environmental benefits by having minimal greenhouse gas and other emissions. Being an indigenous resource, geothermal – like other renewable resources – can reduce our dependence on imported fossil fuels. As it provides dispatchable base-load capacity, geothermal – even at high levels of penetration – would have no storage or backup-power requirements.

With geothermal energy, there is no need to physically mine materials from a subsurface resource, or to modify the earth's surface to a significant degree as, for example, in strip mining of coal or uranium. Unlike fossil and biomass fuels, geothermal energy is not processed and transported over great distances (an energy-consuming and potentially environmentally damaging process), there are minimal discharges of nitrogen or sulfur oxides or particulate matter resulting from its use, and there is no need to dispose of radioactive materials. However, there still are impacts that must be considered and managed if this energy resource is to be developed as part of a more environmentally sound, sustainable energy portfolio for the future.

The major environmental issues for EGS are associated with ground-water use and contamination, with related concerns about induced seismicity or subsidence as a result of water injection and production. Issues of noise, safety, visual impacts, and land use associated with drilling and production operations are also important but fully manageable.

As geothermal technology moves away from hydrothermal and more toward larger EGS developments, it is likely that environmental impacts and risks will be further reduced relative to those associated with hydrothermal systems. For example, EGS plants should only rarely have a need for abatement of hydrogen sulfide (H_2S), ammonia (NH_3), and other chemical emissions.

1.9 Economic Feasibility Issues for EGS

This section highlights the role that EGS can play in supplying base-load and distributed electricity in evolving U.S. energy markets. Important factors that favor having EGS as an option will be discussed, including projected demand growth, retirement of existing conventional capacity, transmission access, fuel supply limitation, environmental, and other constraints on expanding fossil and nuclear supply.

Major components affecting risk in geothermal-based electricity and thermal energy production are discussed in Section 9.7.

Geothermal energy, which is transformed into delivered energy (electricity or direct heat), is an extremely capital-intensive and technology-dependent industry. Capital investment can be divided into three distinct phases:

1. Exploration, and drilling of test and production wells
2. Construction of power conversion facilities
3. Discounted future redrilling and well stimulation.

Estimated levelized costs were used as a basis for comparing EGS projections to existing and new energy-supply technologies. The methodology used for the supply curves was analyzed in detail to show how access to potential growth in EGS generation capacity would be available in the United States as a result of the diversity, large size, and distribution of the EGS resource.

Two different economic models – Geothermal Electric Technology Evaluation Model (GETEM) and MIT EGS – were updated and modified to estimate levelized electricity prices for EGS technology over a range of conditions. Starting with specified base-case values that represent financial parameters (debt interest, equity rate of return, etc.), system performance (thermal drawdown rate or reservoir lifetime, well flow rate, number of production and injection wells, etc.), capital costs (site exploration, drilling and redrilling, reservoir stimulation, and surface plant facilities), and operating and maintenance costs, we calculated and validated predicted costs for EGS at targeted, representative sites using both models (see Table 1.3), and explored the effects of sensitivity to uncertain parameters, as shown in Figures 1.11 and 1.12.

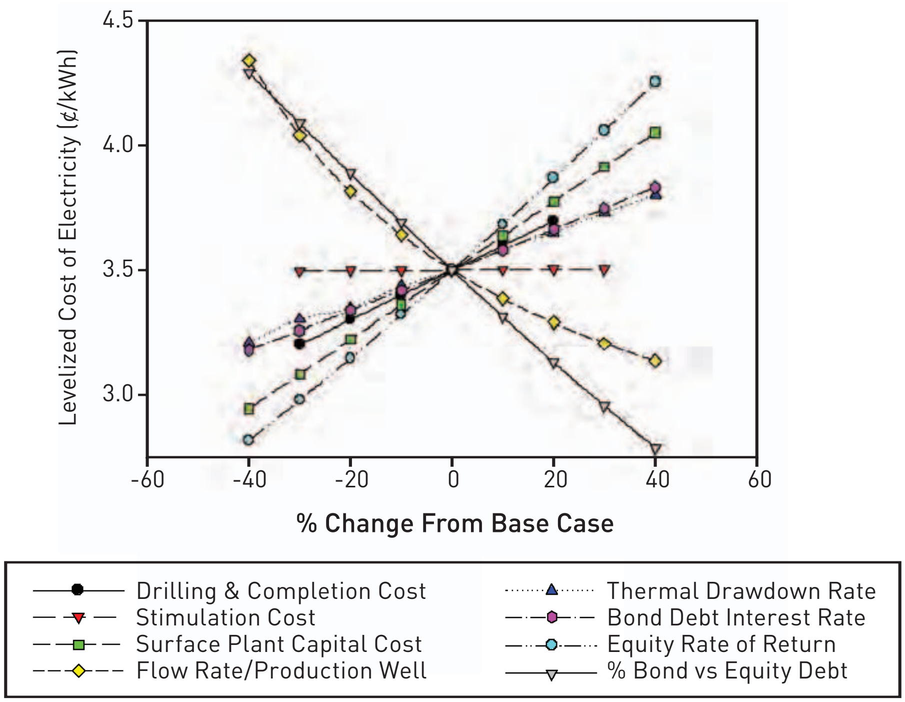


Figure 1.11 Sensitivity for mature technology at a representative high-grade EGS site: 80 kg/s flow rate per production well in a quartet configuration (1 injector : 3 producers) for the Clear Lake (Kelseyville, Calif.) scenario showing levelized cost of electricity. (MIT EGS economic model results shown.)

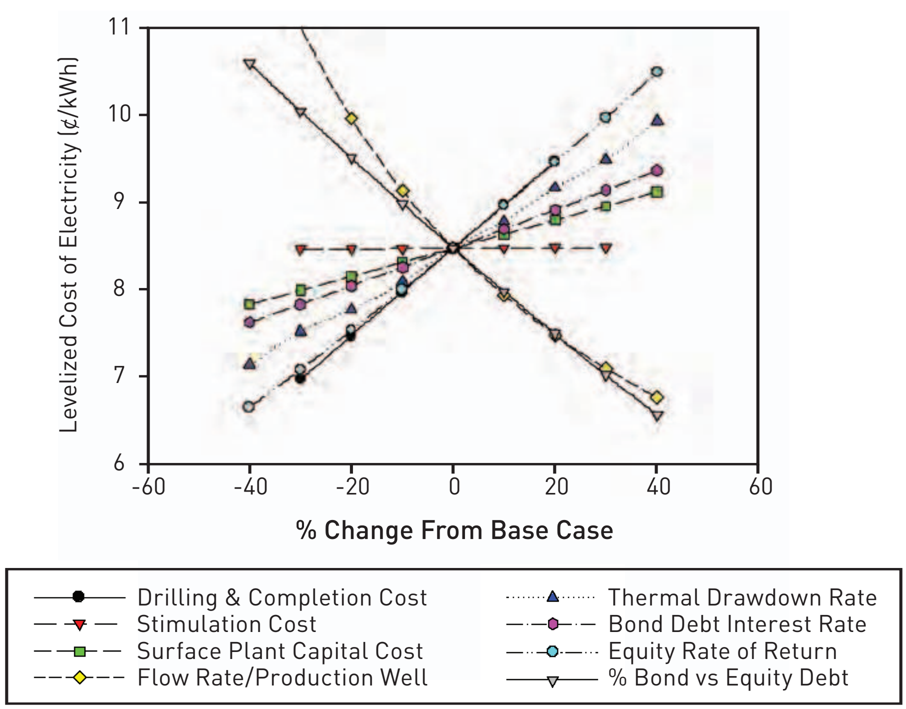


Figure 1.12 Sensitivity for mature technology at a representative low-grade EGS site: 80 kg/s flow rate per production well in a quartet configuration (1 injector : 3 producers) for the Conway, N.H., scenario showing levelized cost of electricity. (MIT EGS economic model results shown.)

We assumed a six-year nominal lifetime period for each stimulated reservoir, which led to a complete redrilling and restimulation of the system in six-year intervals for the lifetime of the surface plant facilities, typically 20 to 30 years. Other important factors affecting the levelized energy cost (LEC) include equity and debt interest rates for invested capital, well-drilling costs, surface plant costs, and reservoir flow rate per production well. Table 1.3 gives estimated values for six representative EGS sites for the United States, showing the dramatic effect that reservoir fluid flow rate has on LEC, going from an initial value of 20 kg/s per well to 80 kg/s per well for the two base cases shown.

Table 1.3 Levelized energy cost (LEC) for six selected EGS sites for development.

Site Name	Average gradient $\partial T/\partial z$ (°C/km) to well depth	Depth to Granite (km)	Well Depth (km)	Base Case Initial Values 20 kg/s production rate LEC (¢/kWh)		Base Case Mature Technology 80 kg/s production rate LEC (¢/kWh)		
				MIT EGS	GETEM	MIT EGS	GETEM	Depth (km)
E. Texas Basin, TX	40	5	5	29.5	21.7	6.2	5.8	7.1
Nampa, ID	43	4.5	5	24.5	19.5	5.9	5.5	6.6
Sisters Area, OR	50	3.5	5	17.5	15.7	5.2	4.9	5.1
Poplar Dome a, MT	55	4	2.2	74.7	104.9	5.9	4.1	4.0
Poplar Dome b, MT	37	4	6.5	26.9	22.3	5.9	4.1	4.0
Clear Lake, CA	76	3	5	10.3	12.7	3.6	4.1	5.1
Conway Granite, NH	24	0	7	68.0	34.0	9.2	8.3	10‡

‡10 km limit put on drilling depth – MIT EGS LEC reaches 7.3¢/kWh at 12.7 km and 350°C geofluid temperature.

Figure 1.13 illustrates a predicted aggregate supply curve for the U.S. EGS resource, regardless of region and not described by a particular depth or stored thermal energy content, using the variable rate of return (VRR) MIT EGS costing model. As expected for any new technology, costs at low levels of penetration are higher than existing markets for electric power, but rapidly decline. When EGS increases above 100 MW_e of capacity, which amounts to only a few EGS projects, costs begin to become competitive. The segmented structure of the supply curve is a reflection of dividing the EGS resource into 1 km-thick segments (see Figure 1.6). The slight increase in break-even price that occurs at higher levels of penetration (above 5,000 MW_e) is due to extraction of heat from somewhat lower-grade EGS resources (with lower average gradient and heat flow) that require deeper, more costly drilling. However, by the time these levels are reached, it is expected that competitive electricity prices will be equal to or greater than the EGS values, so that further deployment will not be constrained.

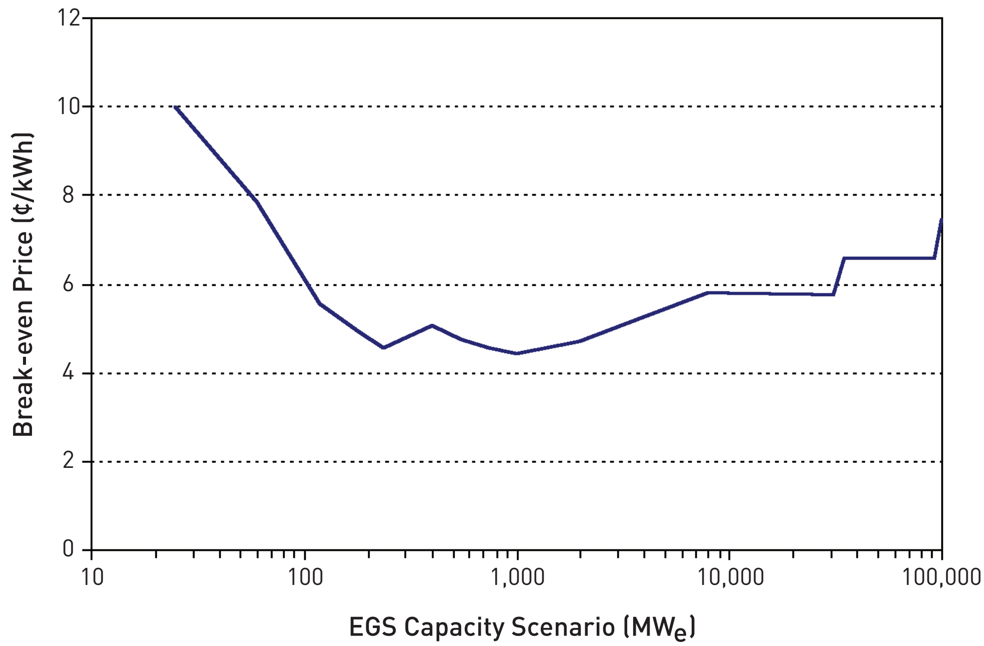


Figure 1.13 Aggregate supply using MIT EGS, variable rate of return (VRR) model with quartet well configurations and a maximum flow per well of 80 kg/s.

Next, we analyzed the effects of experience. Learning curves were developed to reflect cost reductions resulting from improvements in drilling, reservoir stimulation, and surface plant technologies. These stem from the combination of R&D investments that lower costs, and experience gained by repeating the deployment of EGS plants at different U.S. sites as part of a focused national initiative. Figures 1.14 to 1.16 illustrate these supply curves using both GETEM and MIT EGS models over a range of assumed conditions. When the EGS break-even prices are greater than competitive market prices for electricity, additional institutional investment is needed. For example, on Figure 1.14, this corresponds to the period from 0 to about 12 years. The total amount of investment required is proportional to the area between the EGS price curve and the market price curve. weighted by the amount of EGS capacity online.

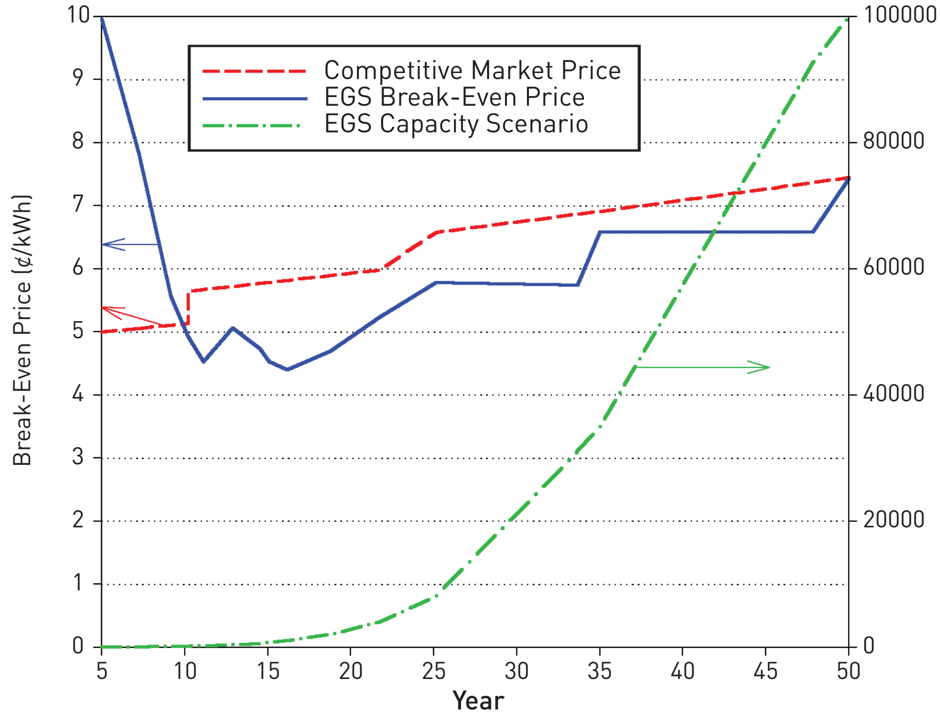


Figure 1.14 Levelized break-even COE using the MIT EGS model for the 100,000 MW — 50-year scenario and variable debt and equity rates (VRR). Flow rate per production well (in a quartet configuration — 1 injector, 3 producers) follows the 80 kg/s learning curve. Thermal drawdown is 3%/yr resulting in complete redrilling and restimulation of the system, with a vertical spacing between stacked reservoirs of 1 km after ~6 years of operation. Resulting absorbed technology deployment costs are $216 million (U.S. 2004).

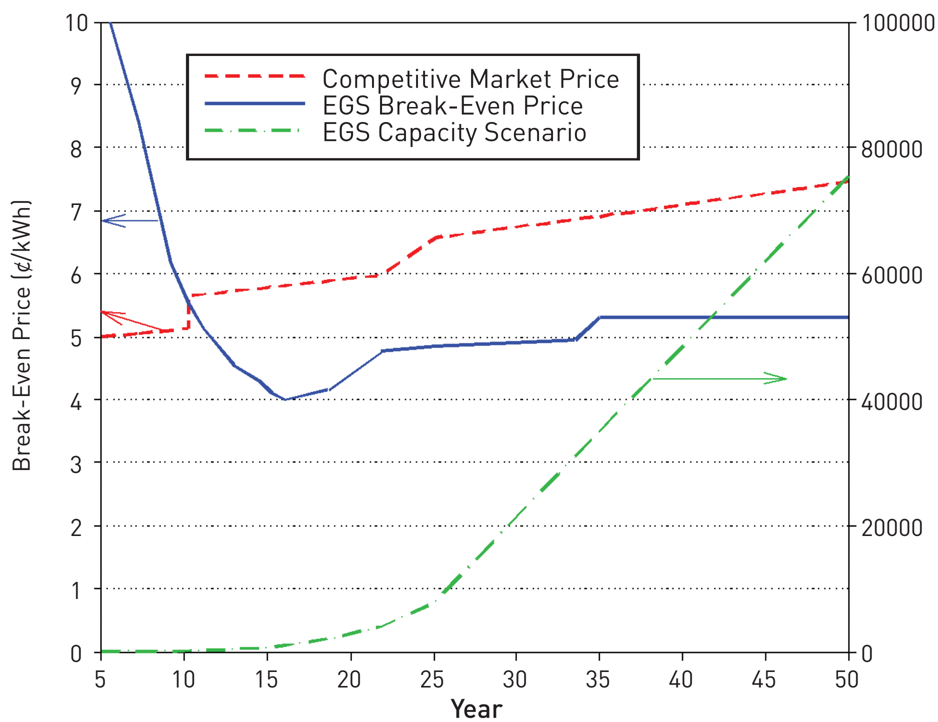


Figure 1.15 Levelized break-even COE using the MIT EGS model for the 100,000 MW – 50-year scenario and a fixed-charge rate of 12.8% per the NEMS model. Flow rate per production well (in a quartet configuration – 1 injector, 3 producers) follows the 80 kg/s learning curve. Thermal drawdown is 3%/yr resulting in complete redrilling and restimulation of the system, with a vertical spacing between stacked reservoirs of 1 km after ~6 years of operation. Resulting absorbed technology deployment costs are $262 million (U.S. 2004).

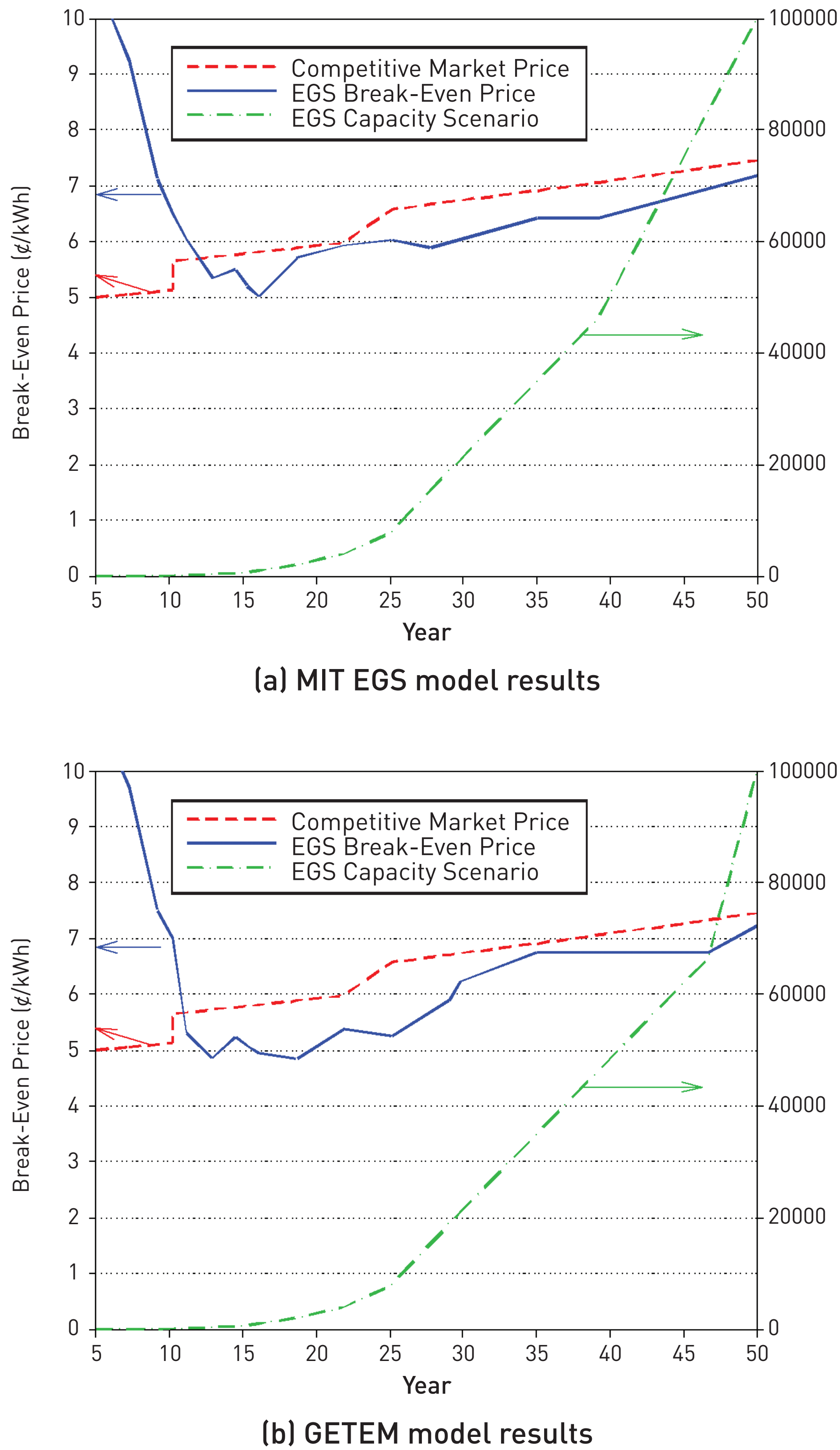


Figure 1.16 Levelized break-even COE using (a) MIT EGS and (b) GETEM for the 100,000 MW – 50-year scenario using a fixed-charge rate of 12.8% per the NEMS model. Flow rate per production well (in a triplet configuration – 1 injector, 2 producers) follows the 60 kg/s learning curve. Thermal drawdown is 3%/yr resulting in complete redrilling and restimulation of the system, with a vertical spacing between stacked reservoirs of 1 km after ~6 years of operation. Resulting absorbed technology deployment costs are (a) $368 million and (b) $394 million (U.S. 2004).

As a result of technology improvements from research and learning curve effects, we have found a strong positive correlation between the early deployment of new EGS facilities and the significant decline in the levelized cost of delivered electricity. This finding reflects not only the economies from new techniques and access to higher-value resources, but also the inevitable changes in availability and increased cost of conventional energy sources. For example, for hydroelectric power, reduced capacity occurs as a result of changed weather patterns and lower resource flows to existing facilities, as well as competition for the resource for alternate uses such as fish and wildlife, recreation, flood control, and capacity losses in dammed areas. In the case of coal-fired electricity, increased bus-bar costs are predicted as result of three effects occurring over time: (i) fuel cost increases, (ii) higher capital costs of new facilities to satisfy higher efficiency and environmental quality goals, including capture and sequestration of CO_2, and (iii) retirement of a significant number of low-cost units in the existing fleet due to their age or failure to comply with stiffer environmental standards. In the case of nuclear facilities, we anticipate a shortfall in nuclear supplies through the forecast period, reflecting retirement of the existing power reactors and difficulties in siting and developing new facilities. Without corresponding base-load replacements to meet existing and increased demand, the energy security of the United States will be compromised. It would seem prudent to invest now in developing a portfolio of options that could meet this need.

To sum up, based on our technical and economic analysis, a reasonable investment in R&D and a proactive level of deployment in the next 10 years could make EGS a major player in supplying 10% of U.S. base-load electricity by 2050. Further, the analysis shows that the development of new EGS resources will not be limited by the size and location of the resource in the United States, and it will occur at a critical time when grid stabilization with both replacement and new base-load power will be needed. Adding the EGS option to the U.S. portfolio will reduce growth in natural gas consumption and slow the need for adding expensive natural gas facilities to handle imported liquefied natural gas (LNG).

Although EGS-produced commercial power currently lacks a demonstration of its capability, this can be realized in the short term with a proven application of R&D support. The potential of EGS in evolving U.S. energy markets is large and warrants a comprehensive research and demonstration effort to move this technology to commercial viability, especially as the country approaches a period when gap between demand for and generation of electricity will most affect the existing system capacity.

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CHAPTER 2

Geothermal Resource-Base Assessment

2.1 Introduction

Previous analyses have suggested that the amount of thermal energy available for Enhanced Geothermal System (EGS) development is enormous (Armstead and Tester, 1987; Rowley, 1982; Mock et al., 1997; Tester et al., 1994; Sass, 1993). However, these earlier works did not use detailed geologic information – and, as a result, the methodologies employed and resulting resource estimates were, by necessity, somewhat simplified. This study utilizes published geologic and geophysical data for the United States to calculate the stored thermal energy (or "heat in place") on both a national and state level, at depths from 3 to 10 km. The methodology, resource types considered, and the resource-base calculations are included in this chapter. Recoverability, or useful energy, is discussed in Chapter 3 of this report. A depth of 3 km was selected as a cutoff for upper depth because, outside of the periphery of active magmatic and hydrothermal systems, temperatures in excess of 150°C at less than that depth are rare.

Several classes of geothermal resources are discussed in this chapter (Table 2.1). In earlier analyses – USGS Circular 726 (White and Williams, 1975), USGS Circular 790 (Muffler and Guffanti, 1979), and USGS Circular 1249 (Duffield and Sass, 2003) – the geothermal resource was divided into four major categories: hydrothermal, geopressured, magma, and conduction-dominated (Enhanced Geothermal Systems or Hot Dry Rock). The resource classes that are discussed in this report include 1) sedimentary Enhanced Geothermal Systems (EGS), 2) basement EGS, 3) geopressured-geothermal systems, and 4) coproduced fluids (hot aqueous fluids that are produced during oil and gas production). Brief mention is also made of supercritical/volcano (i.e., igneous) geothermal systems. There is overlap of some of these categories, which will be explained in the discussion that follows.

Table 2.1 Geothermal resource categories.

Category of Resource	Reference
Conduction-dominated EGS	
Sedimentary EGS	This study, basins > 4 km
Basement EGS	This study
Volcano Geothermal Systems	USGS Circular 790 + new data
Hydrothermal	USGS Circulars 726 and 790
Coproduced fluids	McKenna et al. (2005)
Geopressured systems	USGS Circulars 726 and 790

Conventional hydrothermal resources, presumed to exist at depths of 3 km or less, are specifically excluded. A team at the United States Geological Survey (USGS) (Williams, 2005) is currently reevaluating these resources. Also not included, because of their relatively small geographic size, are EGS resources on the periphery of hydrothermal systems in the Western United States. While these types of resources are certainly of high grade and can be viewed as near-term targets of opportunity, they are so small in area and site-specific that a regional study of this scale cannot quantitatively assess them. They are, in general, extensions of the hydrothermal resource and will be identified as part of

the ongoing assessment of hydrothermal geothermal resources being conducted by the USGS. However, some larger basement EGS resource areas that might, in some sense, be considered marginal to hydrothermal systems – such as The Geysers/Clear Lake area in California and the High Cascades Range in Oregon – are included in this discussion (see Section 2.3.5).

The data set used to produce the *Geothermal Map of North America*, published by the American Association of Petroleum Geologists (AAPG) (Blackwell and Richards, 2004a), is the basic thermal data set used in developing the resource assessment. The conterminous U.S. portion of the map is shown in Figure 2.1. In order to expand coverage from the earlier GSA-DNAG map (Blackwell and Steele, 1992; Blackwell et al., 1991) and early versions of this type of resource evaluation (Blackwell et al., 1993; Blackwell et al., 1994), extensive industry-oriented thermal data sets were used, as well as published heat flow data from research groups. To that end, a western heat-flow data set was developed, based on thermal gradient exploration data collected by the geothermal industry during the 1970s and 1980s (Blackwell and Richards, 2004c; Kehle, 1970; Kehle et al., 1970).

The basic information in this data set consists of temperature-depth/gradient information. However, thermal conductivity and heat flow were also determined for as many of the sites as possible, based on thermal conductivity estimates from geologic logs (where available), and geologic maps for other sites where there were no well logs. About 4,000 points were used in the preparation of the map (of the 6,000 sites in the database). The focused nature of the drilling is shown by the clumps of data on Figure 2.2, especially in western Nevada and southwestern Utah.

A second industry data set consisting of about 20,000 point bottom-hole temperature (BHT) measurements, compiled in the early 1970s and published in digital form (AAPG CD-ROM, 1994), was also utilized. The AAPG BHT data set was augmented in Nevada by BHT data digitized from hydrocarbon exploration well logs in the files of the Nevada Bureau of Mines and Geology. Use of the BHT data required extensive analysis of the error associated with the determination of *in situ* equilibrium temperatures from these nonequilibrium data. That process is described briefly in Section 2.2.2 and, in more detail, by Blackwell and Richards (2004b, c).

The heat flow varies from less than 20 mW/m^2 in areas of low heat flow to more than 150 mW/m^2 in areas of high heat flow. The causes of the variations and the distribution of heat flow in the conterminous United States are discussed in detail by Roy et al. (1968, 1972), Sass et al. (1971), Lachenbruch and Sass (1977), Reiter et al. (1986), Morgan and Gosnold (1989), Blackwell et al. (1991), and others. The value of surface heat flow is the building block for the temperature-at-depth calculation (see Figure 2.3). Individual sites have thermal conductivity (rock columns) that varies with depth and, thus, the average thermal gradient depends on the depth interval studied – whereas, heat flow does not. In this study, contours of measured heat flow are combined with regionally specific, depth-averaged thermal conductivity models to more accurately represent the larger-scale thermal regime (i.e., average gradients and temperatures as a function of depth).

To summarize, the values of heat flow used to produce the contours for the United States shown in Figure 2.1 were compiled from the following data sets: the SMU compiled Western Geothermal database (includes the USGS Great Basin database http://wrgis.wr.usgs.gov/open-file/of99-425/webmaps/home.html); the SMU-compiled U.S. Regional Heat Flow database (approximately 2,000 points, see www.smu.edu/geothermal); and the AAPG BHT database (AAPG 1994). The various data site locations are shown in Figure 2.2 by data category. In addition, for completeness, hot and warm spring locations, and Pleistocene and Holocene volcanoes, were shown on the Geothermal Map of North America and on Figure 2.1.

2.2 EGS Resource-Base Calculation – Temperature-at-Depth Maps

Several data components are needed to calculate temperature at depth. The heat flow (Q) map is the starting point for the calculations. The thermal conductivity (K) and the geothermal gradient (∇T, $\partial T/\partial z$) complete the trio of quantities directly involved (see Figure 2.3). In addition to the thermal conductivity as a function of depth, the radioactivity of the crustal rocks (A), the thickness of the radioactivity layer (r), the regional heat flow (i.e., the heat flow from below the radioactive layer, Q_m) (Roy et al., 1972), and the average surface temperature (T_o) must be available at each point in the grid. The components of the analysis used are briefly described below.

The resource maps were prepared at a gridding interval of 5 minutes (5' = 5 minutes = 0.08333°) of latitude/longitude. This grid interval corresponds to points with an average spacing of about 8 km representing an area of about 64 km^2. A typical 250 MW$_e$ EGS plant might require about 5-10 km^2 of reservoir planar area to accommodate the thermal resource needed, assuming that heat removal occurs in a 1 km-thick region of hot rock at depth. Power plant operations, of course, would be confined to a much smaller area, 3 km^2 or less. Thus, at the field level, focused exploration and evaluation will be necessary to select optimum sites in a given region, because the grid size used in the analysis is bigger than a reasonable field size.

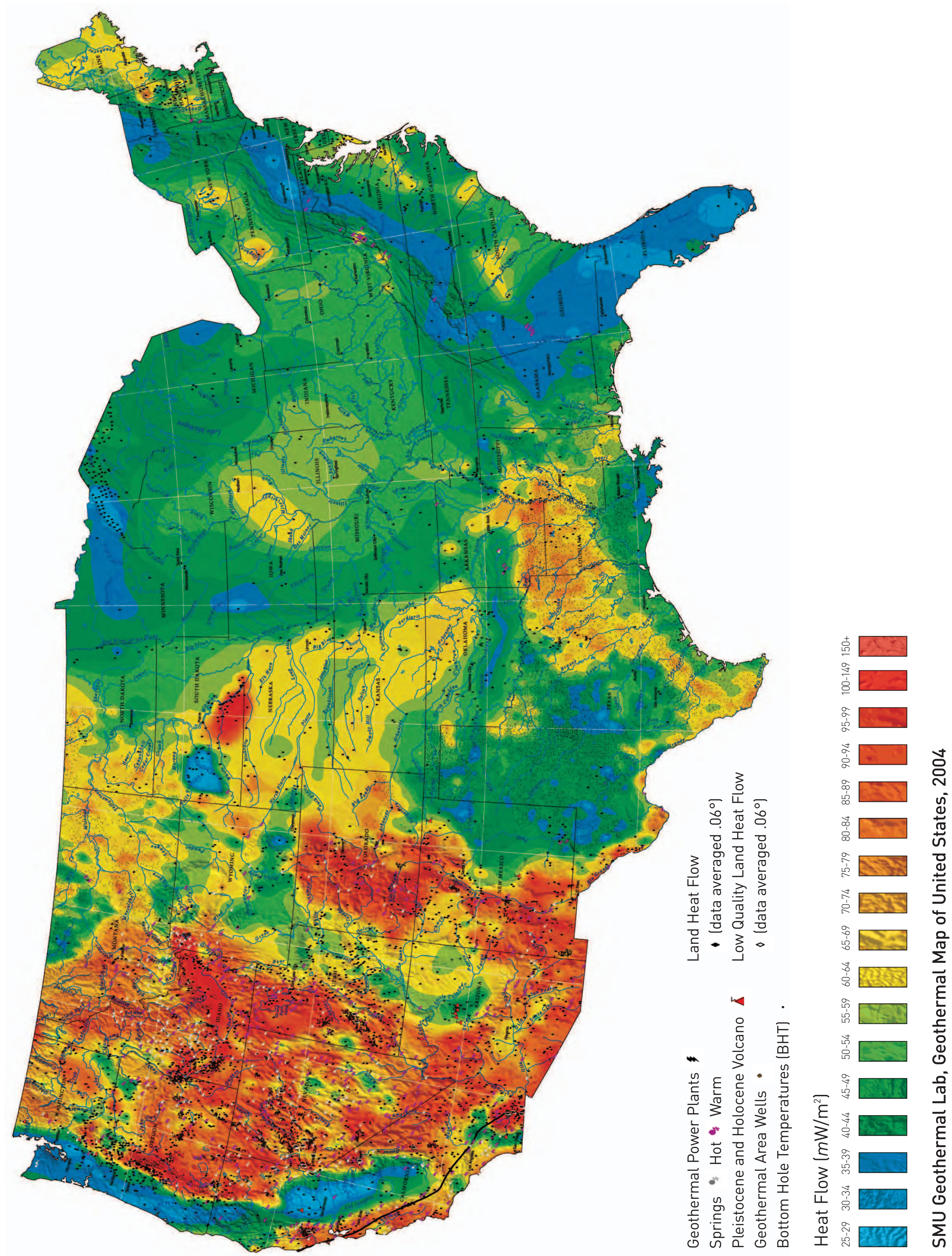


Figure 2.1 Heat-flow map of the conterminous United States – a subset of the geothermal map of North America (Blackwell and Richards, 2004)

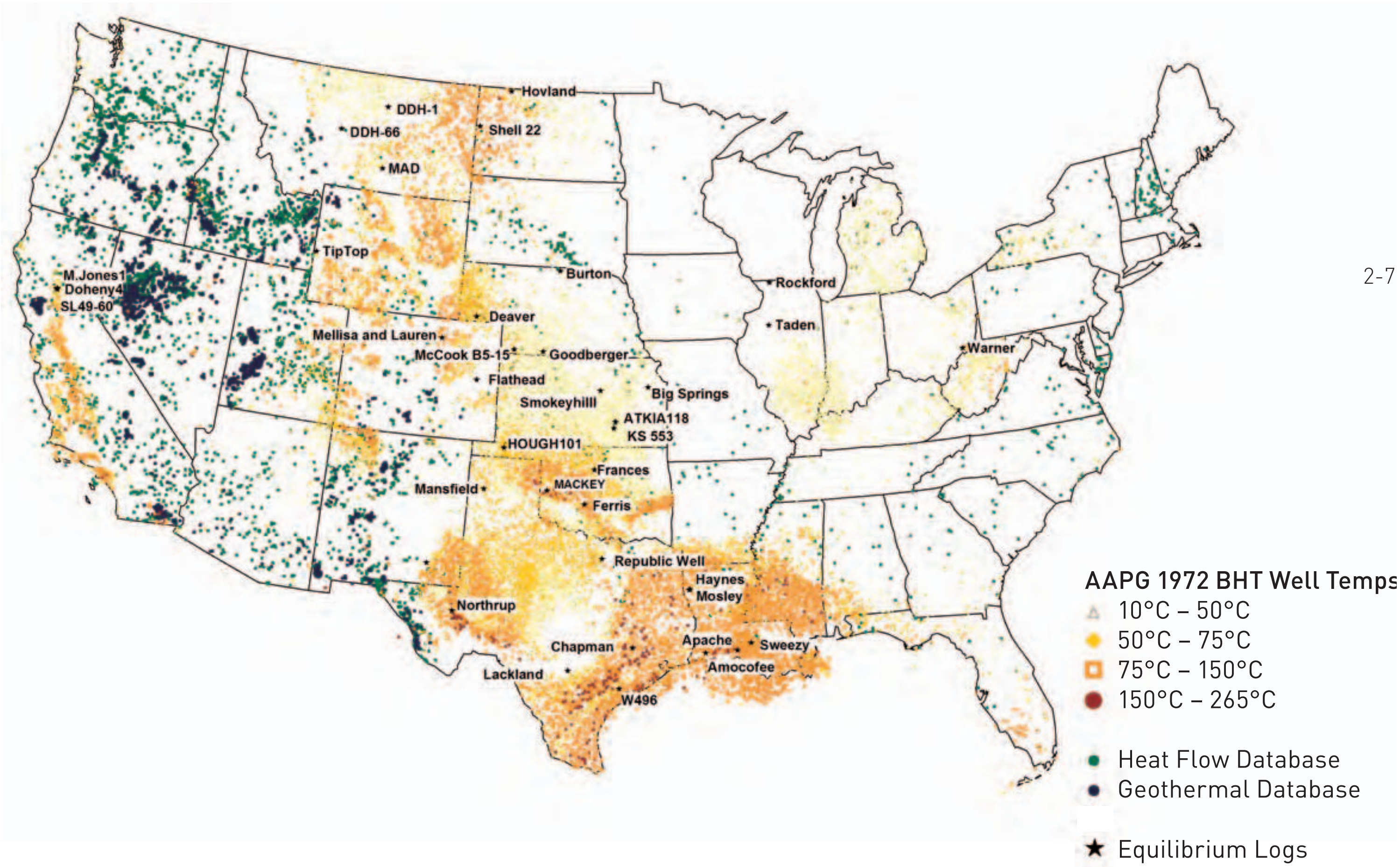


Figure 2.2 All BHT sites in the conterminous United States in the AAPG database. BHT symbols are based on depth and temperature (heat flow is not available for all of the sites, so some were not used for preparation of the Geothermal Map of North America). The named wells are the calibration points. The regional heat flow and geothermal database sites are also shown.

2.2.1 Heat flow

Before calculation of the heat-flow grid values, individual data points were ranked for quality, based on the uncertainty of the data points (see Blackwell et al., 1991, for a discussion of quality ranking). Hydrothermal system-influenced data (very high values, i.e., generally greater than 120 mW/m^2) were excluded from the contouring. All of the heat-flow values obtained from the regional data sets were then merged and contoured using a gridding interval of 5' (0.08333°) of latitude/longitude (about 8 km point spacing) with a minimum curvature algorithm. The resulting heat-flow grid (see Figure 2.1) is the starting point for all of the calculations described in this chapter.

Figure 2.2 illustrates that, at the present stage of the analysis, there are still large geographic areas that are under-sampled with respect to the 8 km grid interval, such that the contours are not well constrained in places where the data are sparse. For example, Kentucky and Wisconsin have no conventional heat-flow data at all (although there are some BHT data points), and there are large gaps in several other areas, especially the eastern part of the United States. Areas in the Appalachian basin may have low thermal conductivity and high heat flow (as is the case in northwestern Pennsylvania), but data are limited in this region. Heat flow for AAPG database BHT points in the eastern United States was not calculated, due to the small and generally scattered nature of the drilling there and limited thermal conductivity information. The deeper wells were used in the preparation of the temperature maps, however.

Although there are BHT data in some areas to depths of 6,000 m, the maximum depth used for the correction was 4,000 m, due to limited information on the drilling effect for deeper wells, and a lack of calibration wells at those depths. Generalized thermal conductivity models for specific geographic areas of the various sedimentary basins were used to compute the heat flow associated with the BHT gradients. The results were checked against conventional heat-flow measurements in the same regions for general agreement.

Data from the Western Geothermal Database were also used to prepare the contour map. These are heat-flow measurements derived from thermal gradient exploration wells drilled primarily for geothermal resources exploration in the western United States, generally during the late 1970s and 1980s. The majority of these wells are 150 m or less in depth. The raw data were processed to calculate heat flow where there was sufficient information. There are site-/well-specific thermal conductivity data for about 50% of the sites. In the Basin and Range, most of the sites are in the valley fill. Thermal conductivity was assumed for these wells based on lithology logs or, in the absence of even this data, on well-site geology maps.

The flow of the temperature-at-depth calculations is shown in Figure 2.3. There are discussions of each of the main parameters used in the following sections. The important parameters are the measured heat flow (this section), the thermal conductivity distribution (Section 2.2.3 and 2.2.4), the surface temperature (Section 2.2.5), and the distribution of heat due to radioactive elements in the crust (U, Th, K) (Section 2.2.6). In the calculations, Q_o is the measured heat flow, K is the thermal conductivity, Q_m is the mantle or tectonic component of heat flow (Section 2.2.6), A is the radioactive heat generation, r is the scaled depth of the radioactivity effect (10 km in these calculations, see Section 2.2.6), X is the depth of the temperature calculation, the subscript s indicates the sediment section, and the subscript b indicates the basement section of the calculation.

2.2.2 Geothermal gradients

The mean thermal gradient in the sedimentary section can be found by dividing the heat flow by the thermal conductivity (see Figure 2.3). The variation in the mean gradient is from less than 15°C/km to more than 50°C/km on a regional basis. Within an individual well, the geothermal gradient can vary by up to a factor of 5 or more, depending on the lithology in a particular depth interval. However, the whole sedimentary section is averaged in the approach used here.

Unlike thermal gradient maps produced from direct observations from individual wells (Kron and Stix, 1982; Nathenson and Guffanti, 1980; DeFord and Kehle, 1976), the gradients produced as described in this section and the subsequent temperature-at-depth calculations are not biased by the part of the sedimentary section in which the measurements were made. Thus, the geothermal gradient distribution used here is smoother and more regionally characteristic of the average geothermal gradient to depths below where direct measurements exist. This smoothing process produces a somewhat different temperature-at-depth result than would be obtained from extrapolation of existing gradient compilations that do not include thermal conductivity and heat-flow analyses.

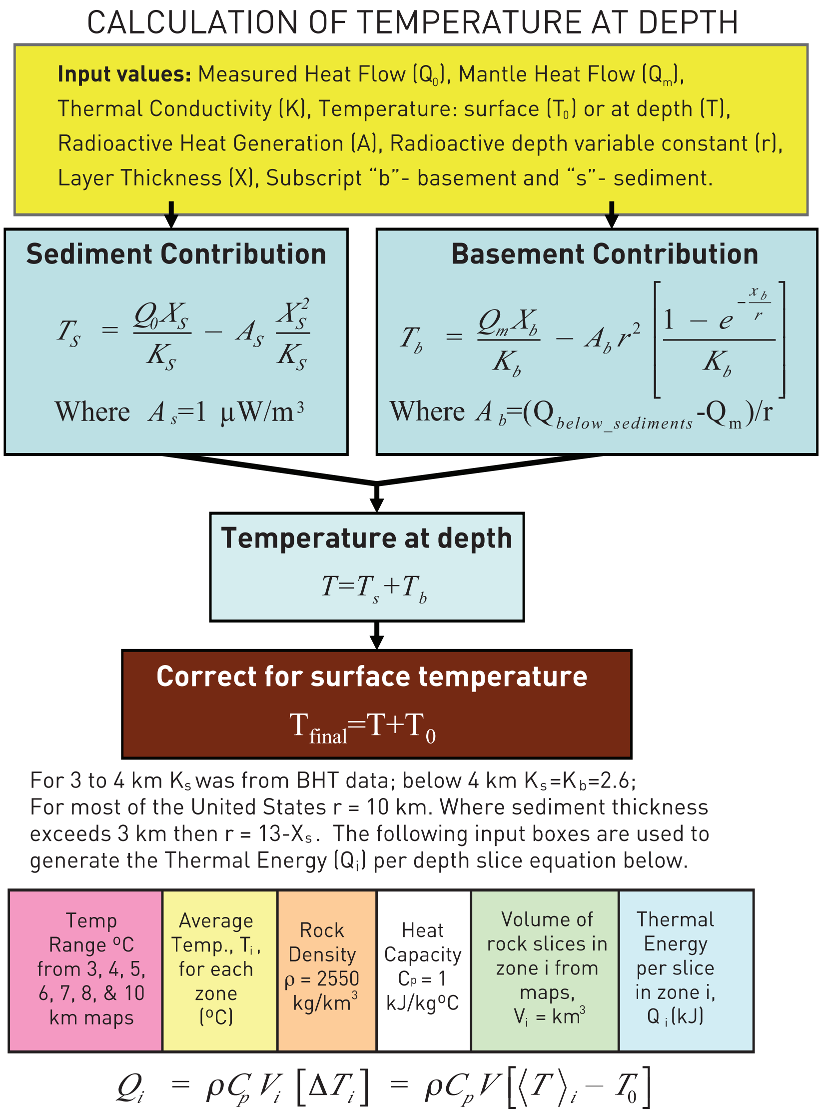


Figure 2.3 Flow chart for calculation of temperature and heat content at depth.
Note: 1 kW-sec = 1 kJ and angle brackets denote depth-averaging.

Use of the extensive BHT data set is a new feature of the heat-flow map and this temperature-at-depth analysis used in previous studies. The BHT data were calibrated by comparison to a series of precision temperature measurements made in hydrocarbon wells in thermal equilibrium, and a BHT error was thus established (Blackwell and Richards, 2004b; Blackwell et al., 1999). Data up to a maximum depth of 3,000 m were used (4,000 m in southern Louisiana). The basic correction was similar to the AAPG BHT correction, with modifications as proposed by Harrison et al. (1983). A secondary correction that is a function of the gradient was applied, so that a bias associated with average geothermal gradient in the well was removed. This correction was checked against the approximately 30 sites in the United States with accurate thermal logs (Figure 2.2). We contend the correction for the average gradient of a group of wells is accurate to about ± 10°C at 200°C, based on the direct comparisons described by Blackwell and Richards (2004b).

With the inclusion of the BHT data, there is a higher confidence level in the interpreted temperatures at depth. For geothermal resource potential purposes, the corrected BHT data can be used directly in

many places, because many of these measurements are at 4 to 6 km depths. This additional data improves the definition of areas that qualify for further EGS evaluation.

2.2.3 Thermal conductivity

For the calculations of temperature at depth, the vertical thermal conductivity is sorted by depth into either one or two layers. The two-layer model for some of the areas is based on the effect of reduction of porosity and mineralogical changes in low-conductivity shale and in volcanic rock at temperatures above 60-80°C. A value of thermal conductivity of 2.6 W/m/K was assumed for the basement rocks. This value was based on the median of the values for basement rocks from the regional heat-flow database. For some of the sedimentary basins, an upper layer of lower thermal conductivity is assumed to overlie the 2.6 W/m/K value used for the deeper sedimentary rocks and the underlying basement.

A histogram of thermal conductivity for the wells in the regional heat-flow data set is shown in Figure 2.4. There is a peak in the distribution of thermal conductivity values at about 1.4 W/m/K. These low-conductivity values are characteristic of lithologies such as volcanic rock, shale, and unconsolidated valley fill. A value of 1.4 W/m/K was assumed for the Basin and Range valley fill and other high-porosity rocks where no measurements were available. There is another smaller peak in the distribution between 2.0-3.0 W/m/K. Rocks in the > 2.2 W/m/K category are generally low-porosity sedimentary rocks and basement lithologies (granite, metamorphic rocks, carbonates, sandstone, etc.). The value of 2.6 W/m/K was used as the crustal value – instead of the 2.8-3.0 W/m/K peak – to partly take into account the effect of temperature on thermal conductivity, which ranges from 5% to 10% per 100°C change in temperature.

Regional values of thermal conductivity in the upper 2 to 4 km are based on generalized rock distributions. The peak at 1.4 W/m/K is related to the thermal conductivity of Late Cenozoic basin fill in the Great Basin. Parts of the Pacific Northwest and the Great Basin were assigned values of thermal conductivity of 2.0 W/m/K to a depth of 2 km, to approximate a mean of basement, volcanic, and Cenozoic rift basin lithologies. In the areas of the Salton Sea/Imperial Valley and the Los Angeles Basin, the upper 2 km of section was also assigned a thermal conductivity value of 2.0 W/m/K. Thus, the vertical thermal-conductivity distribution in sedimentary and volcanic sections is considered only on a semiregional scale.

There are lateral variations of almost 100% in the mean thermal conductivity within the sedimentary section. Therefore, detailed studies are necessary to identify the most favorable locations from the point of view of temperature and lithology. The highest thermal-conductivity values (> 3.4 W/m/K for relatively thick intervals on a regional basis) are associated with areas where Paleozoic carbonates and evaporates dominate the section such as in the Michigan, Illinois, Anadarko, and Delaware Basin regions. These areas were assigned the 2.6 W/m/K value starting at zero depth. Lower thermal conductivity values (< 2.0 W/m/K on a regional basis) are in areas where a significant part of the upper section is shale, such as in the Great Plains (Williston Basin, Cretaceous shales, Anadarko Basin, Paleozoic shales) and possibly in the northern Allegheny area (Paleozoic shales). Typical thermal-conductivity values for the different lithologies, based on measurements in the Midcontinent region, are given by Blackwell and Steele (1989), Gallardo and Blackwell (1999), Carter et al. (1998), Gosnold (1990), and Speece et al. (1985), for example.

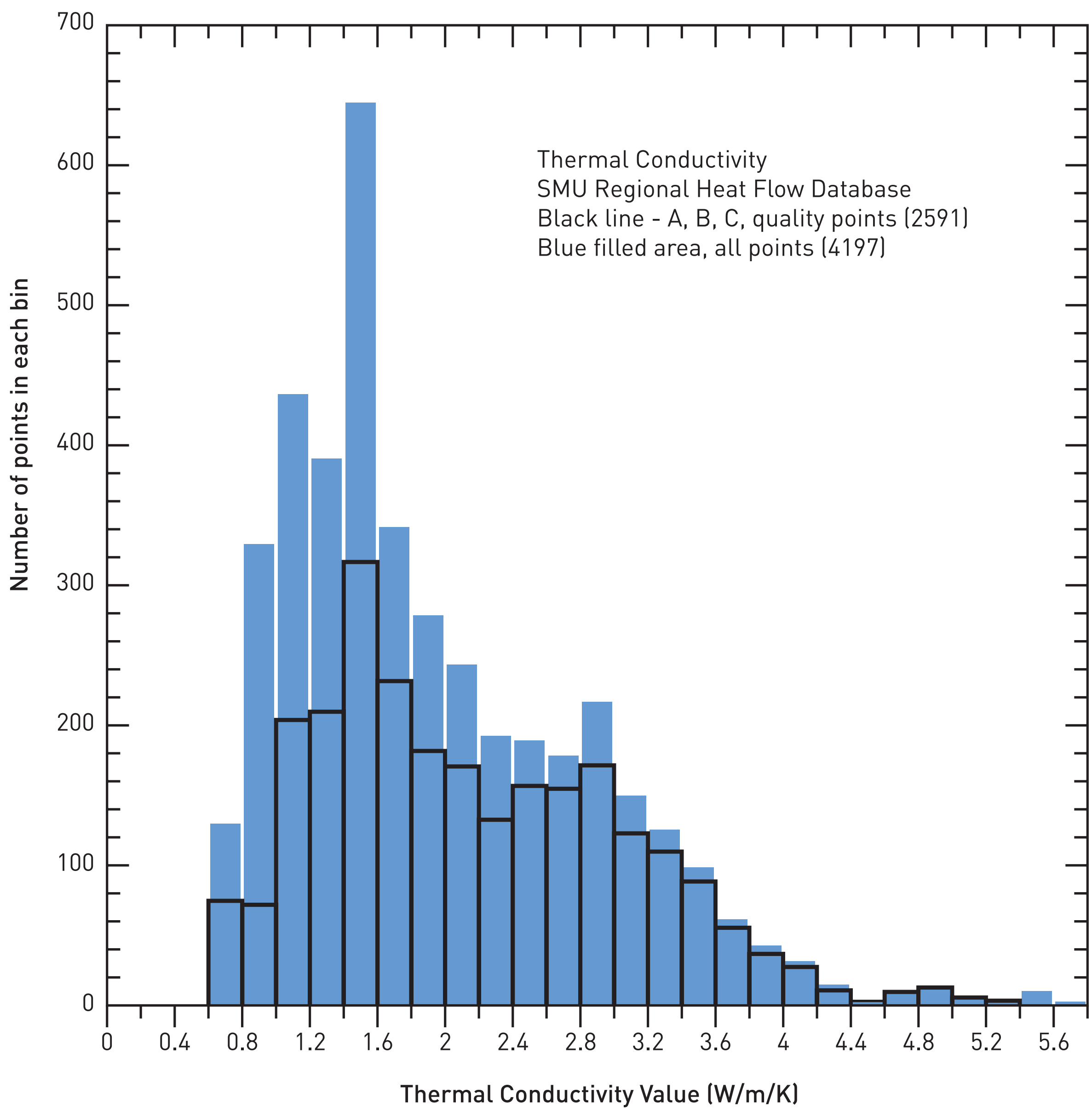


Figure 2.4 Histogram of *in situ* thermal conductivity, *K*, in the regional heat-flow database. Source: SMU Regional Heat Flow database at www.smu.edu/geothermal.

2.2.4 Sediment thickness

A map of the thickness of sedimentary cover was prepared by digitizing the Elevation of Basement Map published by the AAPG (1978). The basement elevation was converted to thickness by subtracting its value from the digital topography, resulting in the map shown in Figure 2.5. Sediment thickness is highly variable from place to place in the tectonic regions in the western United States (west of the Great Plains); and, for this reason, most of the areas of deformation in the western United States do not have basement contours on the AAPG map. Because of the complexity and lack of data, the sediment/basement division in the western United States is not shown, with the exception of the Colorado Plateau (eastern Utah and western Colorado), the Middle Rocky Mountains (Wyoming), and

the Great Valley of California. The area of most uncertainty is the Northern Rocky Mountain/Sevier thrust belt of the Cordillera – in that area, basement thermal conductivity was assumed. Local late extensional basins such as those in the Basin and Range and the Western Snake River Basin, are also not specifically represented on the sediment thickness map and were assigned a thickness of 2,000 m.

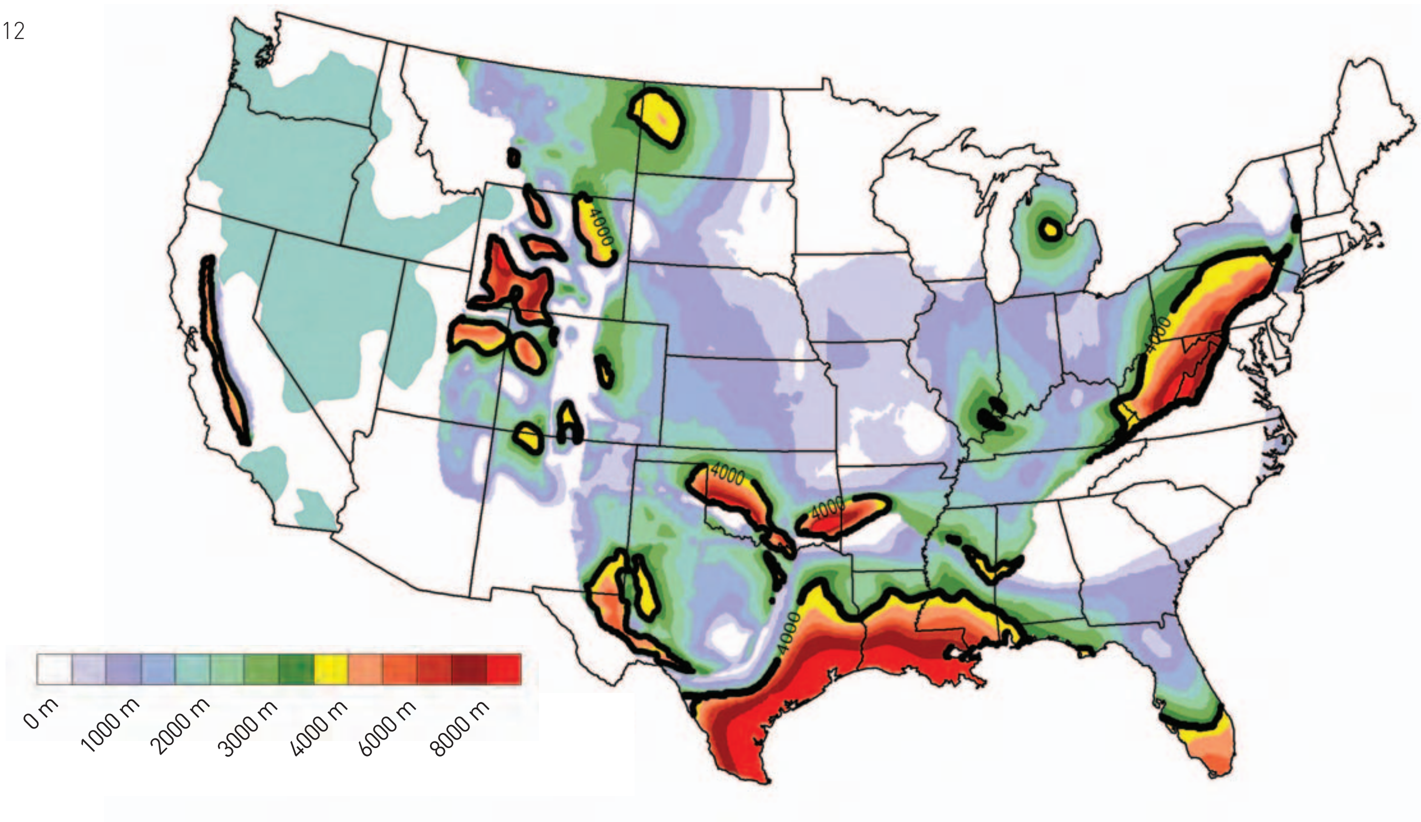


Figure 2.5 Sediment thickness map (in meters, modified from AAPG Basement Map of North America, 1978). The 4 km depth contour is outlined with a bold black line. The low-conductivity regions in the western United States are in blue/green.

In the Basin and Range and the Southern and Middle Rocky Mountains, there are smaller – but sometimes very deep – basins filled with low thermal-conductivity material. The scale of this study is such that these areas are not examined in detail, and considerable variations are possible in those regions, both hotter and colder than predicted.

The map in Figure 2.5 indicates areas that might be of interest for EGS development in the sediment section (the areas inside the 4 km sediment thickness contour), and areas of interest for basement EGS. With the exception of the Anadarko basin, the Gulf Coast, and the eastern edge of the Allegheny basin, sedimentary thickness does not exceed 4 km, except in very localized regions in the area east of the Rocky Mountains. Thus, outside the areas identified by the heavy lines on Figure 2.5, development would have to be in basement settings (east of the Rocky Mountains).

2.2.5 Ground surface temperature

The ground surface temperature is shown in Figure 2.6. This temperature represents the lowest value of the average heat rejection temperature possible for any energy-conversion scheme. The values are from measurements of temperature in shallow groundwater wells (Gass, 1982). These temperatures can be used as shown in Figure 2.3 to calculate maximum attainable temperature differences, which can then be used to calculate the thermal energy content of a rock volume for any U.S. region (difference of the rock temperature at depth and the average surface temperature).

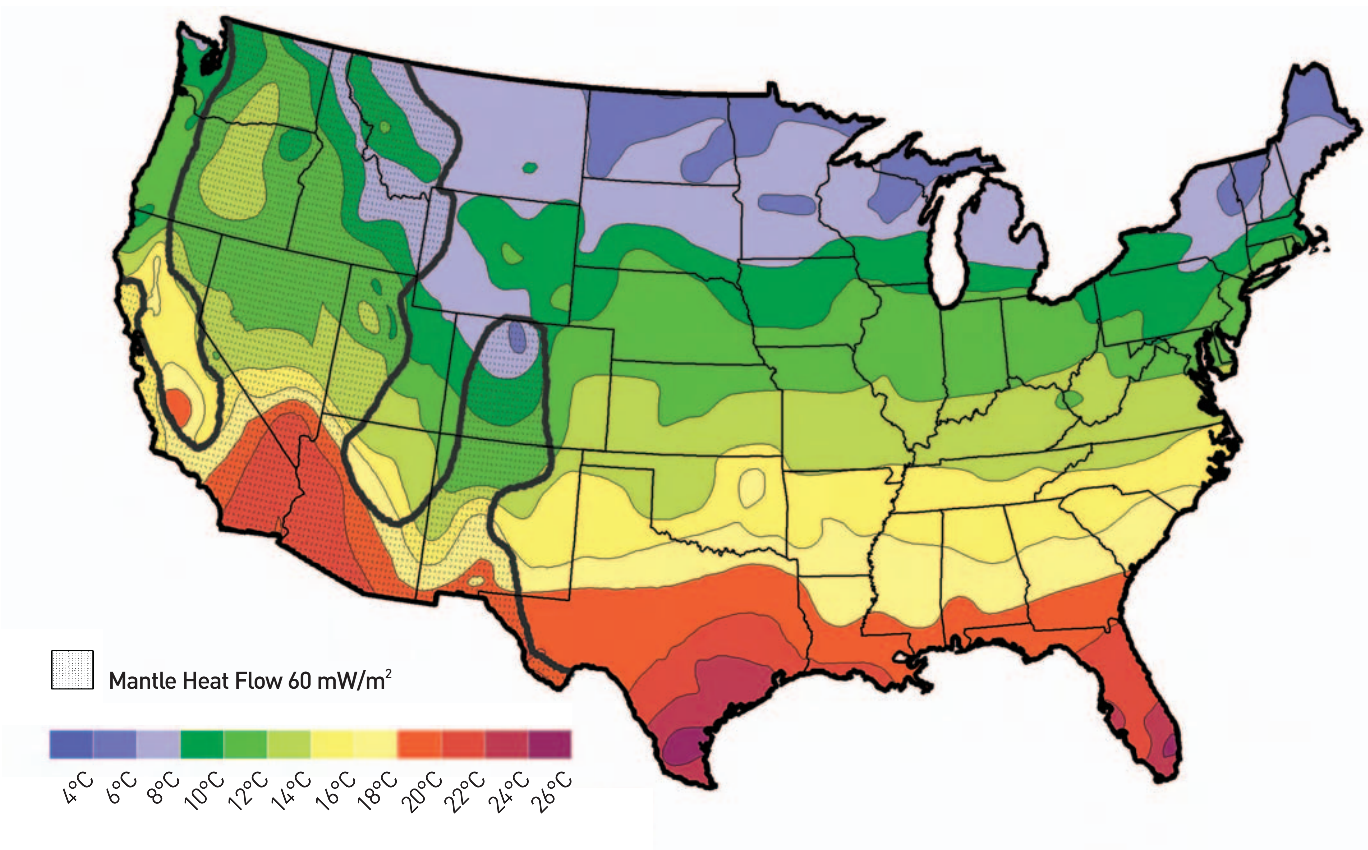


Figure 2.6 Map of surface temperature (colors, Gass, 1982) and generalized mantle heat flow for the conterminous United States (dotted area inside heavy black line is greater than 60 mW/m^2, the remainder of the area is 30 mWm^2).

2.2.6 Tectonic and radioactive components of heat flow

The heat flow at the surface is composed of two main components that may, of course, be perturbed by local effects, i.e., the heat generated by radioactive elements in the crust and the tectonic component of heat flow that comes from the interior of the Earth (referred to here as the mantle heat flow). The radioactive component varies from 0 to more than 100 mW/m^2, with a typical value of about 25 mW/m^2. The characteristic depth of the radioelements (U, Th, and K) in the crust averages about 10 km (Roy et al., 1972), so that most of the variation in heat flow from radioactivity is above that depth. This component can be large and is locally variable, and, thus, there can be areas of high heat flow even in areas that are considered stable continent. For example, in the White Mountains in New Hampshire, the heat flow is as high as 100 mW/m^2, because of the extreme natural radioactivity of the granite (Birch

et al., 1968). In contrast, in parts of the nearby Adirondack Mountains, the heat flow is only 30 mW/m^2, because the upper crustal rocks have very small radioelement content.

In the analysis of temperatures to 10 km, the heat flow from below the layer of radioactive elements providing a heat source in the continental crust must be known, because the depth-scale of the radiogenic contribution is similar to the depth of calculation. For the majority of the area covered by the analysis, two different "mantle" heat flow values were used: 60 mW/m^2 for the high heat-flow regions in the west and 30 mW/m^2 for most of the rest of the map area. The region of high mantle heat flow is shown as the dotted area inside the heavy black line in Figure 2.6. The high mantle heat flow is a result of the plate tectonic activity (subduction) that has occurred along the west coast of North America during the past 100 million years, and the hot spot activity along the Yellowstone/Snake River Plain track (Blackwell, 1989). Part of the Cascade Range in the Pacific Northwest (active volcanic arc) and part of the Snake River Plain (hot spot track) were assigned mantle heat flow values of 80 mW/m^2, because they are associated directly with geologically young volcanism. Finally, part of the Great Valley/Sierra Nevada Mountains areas were given a mantle heat flow of 20 mW/m^2 compatible with the outer arc tectonic setting in those areas (see Morgan and Gosnold, 1989; Blackwell et al., 1991). Transitions in heat flow between these different areas are generally sharp on the scale of the map, but are hard to recognize in some locations, because of the variable heat flow due to the upper crustal effects. Nonetheless, as deeper depths are considered, this regional factor becomes dominant.

2.3 EGS Resource Maps and Resource-Base Estimates – Lower 48 States

2.3.1 Heat (thermal energy) content

The results of the analysis described in the previous section are presented as temperature-at-depth maps and as thermal energy (or "heat") in place. The temperatures were calculated from the depths of 3 to 10 km at every km. The mean values at 0.5 km intervals were used in the recoverable resource analysis in subsequent chapters. Maps of the temperature at 3.5 km, 4.5 km, 5.5 km, 6.5 km, 7.5 km, and 10 km are shown in Figure 2.7. Heat-in-place was calculated and is listed in Table A.2.1 for 1 km x 1 km x 1 km blocks centered at depths of 3.5, 4.5, 5.5, 6.5, 7.5, 8.5, and 9.5 km using the assumptions and equations shown in Figure 2.3. The values listed in Table A.2.1, and shown in the histogram in Figure 2.8, represent the geothermal resource base and not the power that can be generated. For demonstration purposes, the values are shown in terms of stored thermal energy, namely, exajoules (EJ = 10^{18} J). The only area excluded from the calculation is Yellowstone National Park (8,980 km^2). It represents a large area of high temperature, and so its exclusion affects the resource-base calculation of areas at high temperature at shallow depths. The histogram in Figure 2.8 shows that there is a tremendous resource base of approximately 13 million EJ, between the depths of 3.5 to 7.5 km in the temperature range of 150°C to 250°C. Even if only 2% of the resource were to be developed, the thermal energy recovered would be 260,000 EJ. This amount is roughly 2,600 times the annual consumption of primary energy in the United States in 2006.

To understand the magnitude of the thermal energy or heat content of the rock, it is useful to consider the following "thought experiment." Imagine a 14 km long x 14 km wide x 1 km thick slice of rock below the ground surface, which is at an initial temperature of 250°C. Reasonable average values are 2,550

kg/m^3 and 1,000 J/kg°C, for the density (Ú) and heat capacity (C_p) of the rock, respectively. If this mass of rock is cooled through a temperature difference of 200°C to a final temperature of 50°C, then the heat removed is given by

$$Q = \rho C_p V \Delta T = (2550\text{kg/m}^3)(1000\text{J/kg}^\circ\text{C})(14\text{km} \times 14\text{km} \times 1\text{km})(250^\circ\text{C} - 50^\circ\text{C})$$
$$= 100 \times 10^{18}\text{J} \approx 100 \text{ quads.}$$

This quantity of thermal energy, which could potentially be released from a 200 km^2 area of rock, is equivalent to the total amount of energy consumed annually in the United States, which has a total land area close to 10 million km^2. This illustration demonstrates the substantial size of the U.S. geothermal resource. Of course, the size of the accessible resource is much smaller than implied by this simplistic analysis. Details relating to the development scenarios are described elsewhere in this report, including Chapter 3.

The validity of the calculations of temperature at depth is important. In the areas of hydrocarbon development, there are wells that have been drilled to 3 to 6 km (10,000 to 19,000 ft) depths, so that the predicted temperatures can be checked against measurements in deep wells. In the case of the areas represented in the AAPG BHT database, this has been done and the agreement is within ± 20°C in the 3 to 6 km depth range. In the areas of geothermal drilling, there is some information outside of the immediate influence of geothermal systems, and there are a few research wells that serve as data points at depth. This information has been compared to the calculated values with similar results to the BHT comparison.

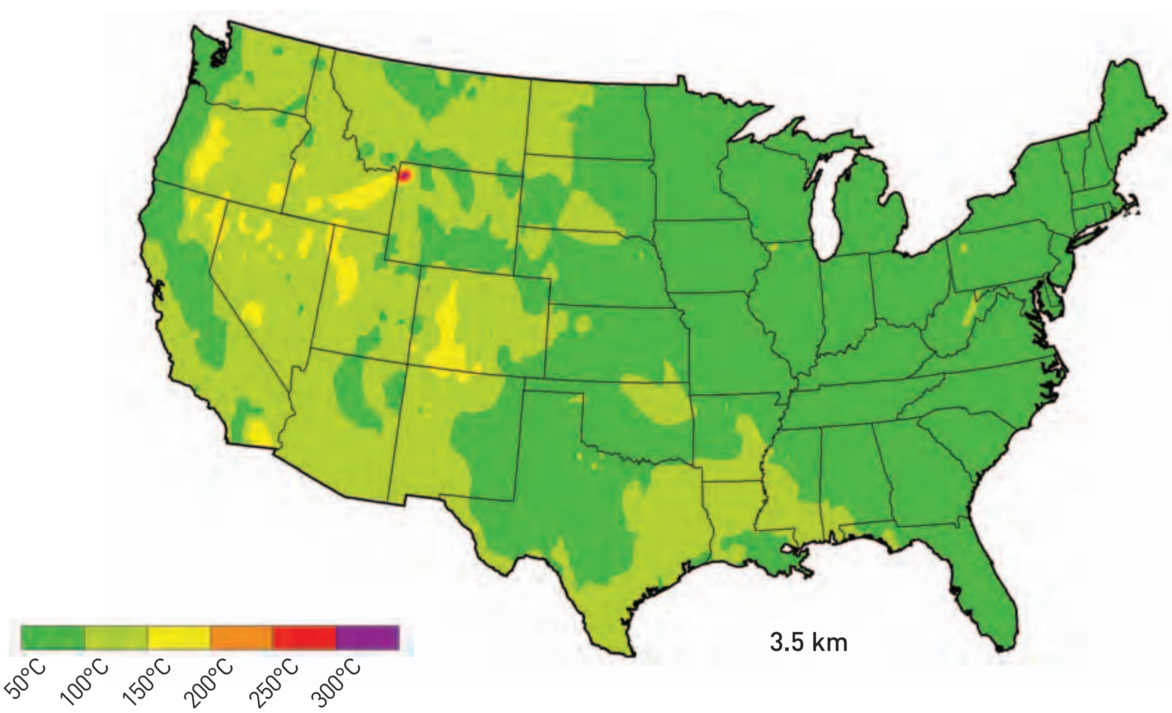


Figure 2.7a Average temperature at 3.5 km.

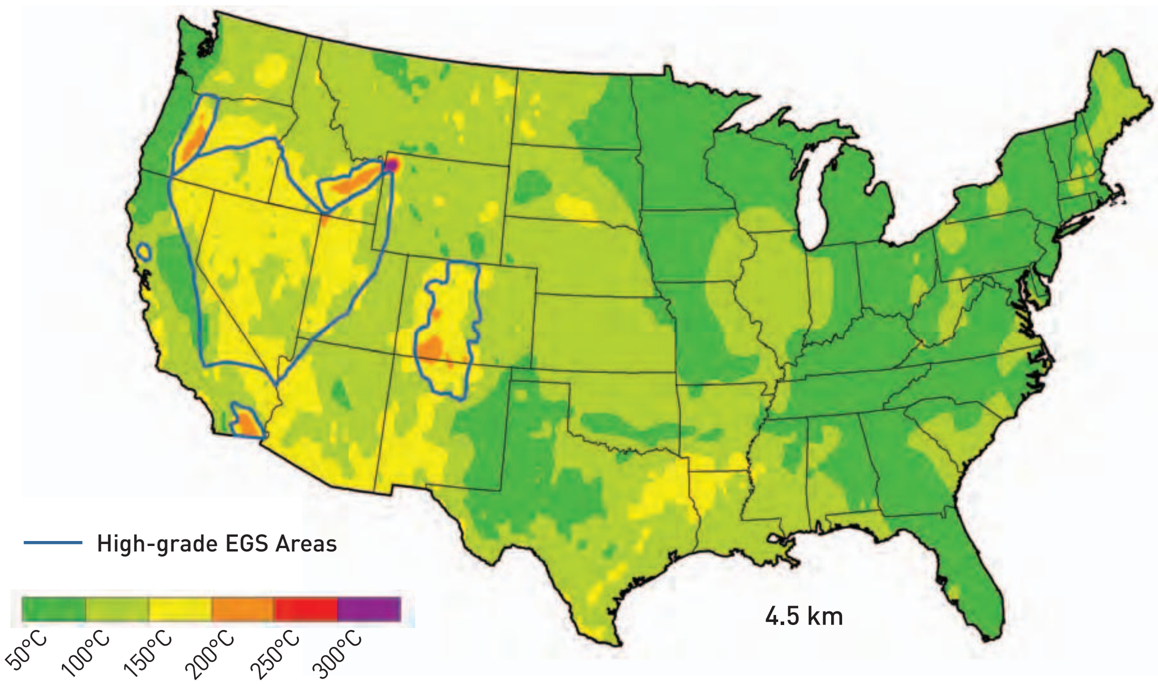


Figure 2.7b Average temperature at 4.5 km. Includes areas of special EGS interest outlined in blue and identified in Table 2.2.

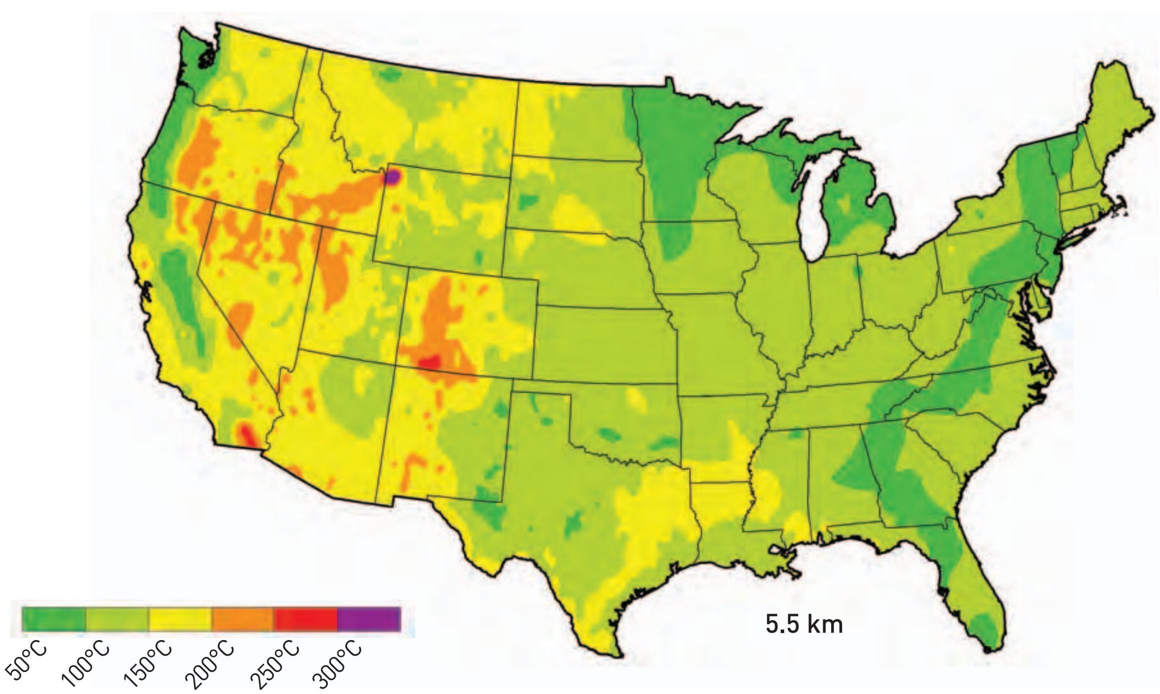


Figure 2.7c Average temperature at 5.5 km.

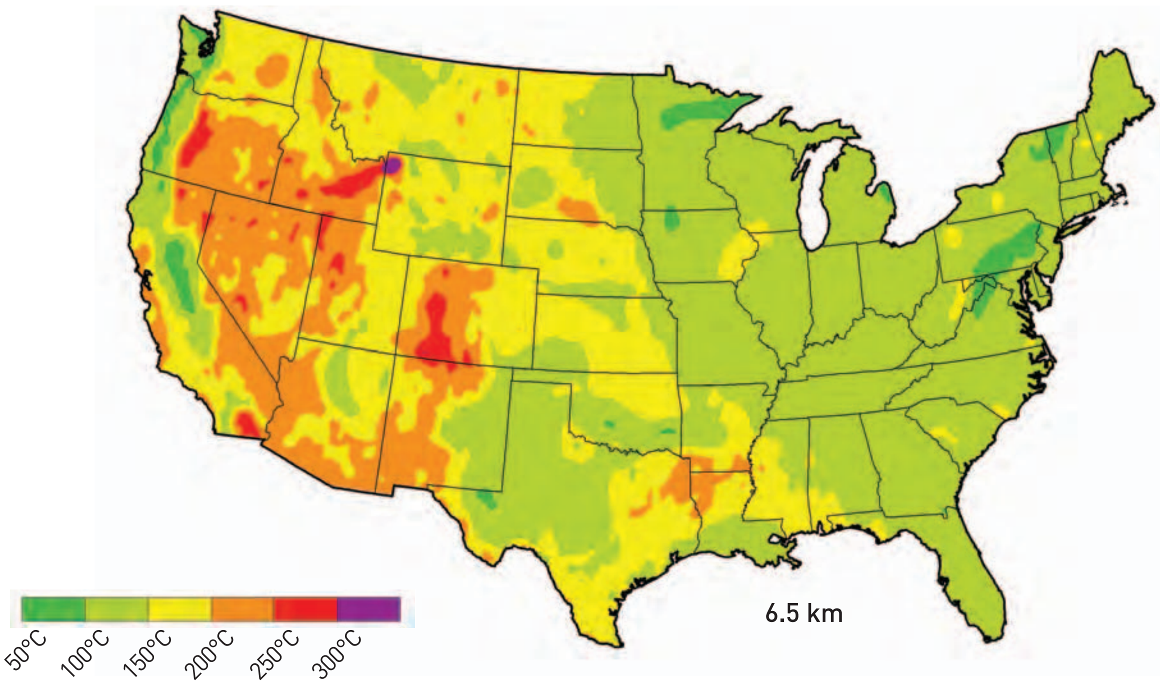


Figure 2.7d Average temperature at 6.5 km.

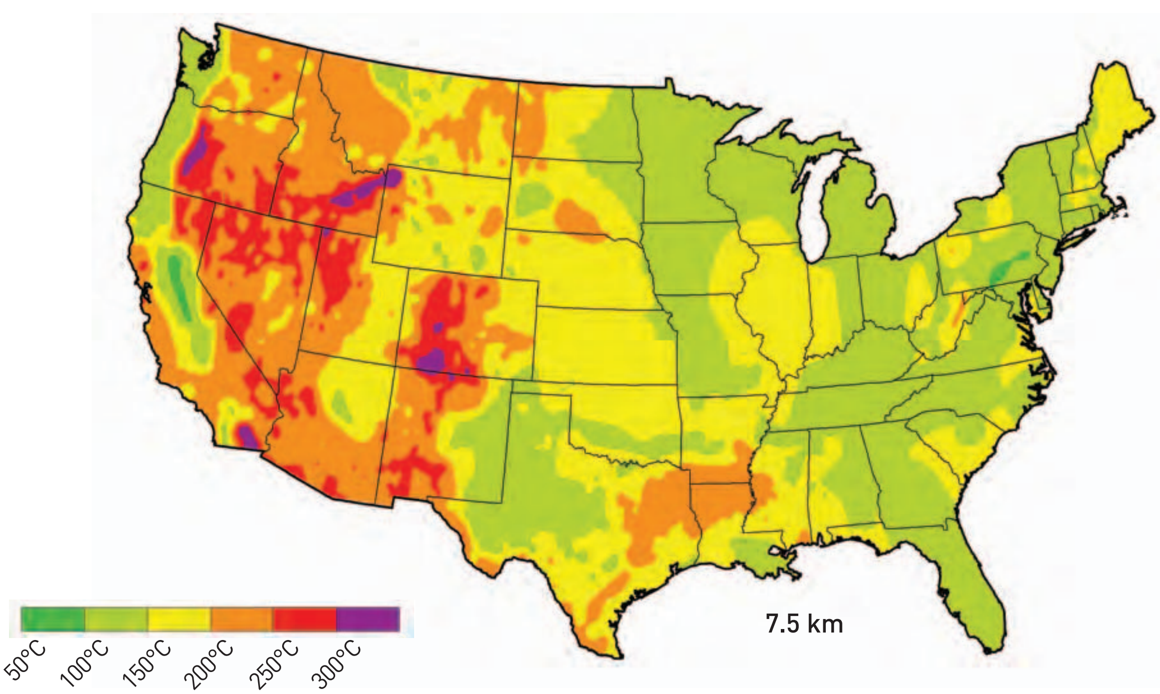


Figure 2.7e Average temperature at 7.5 km.

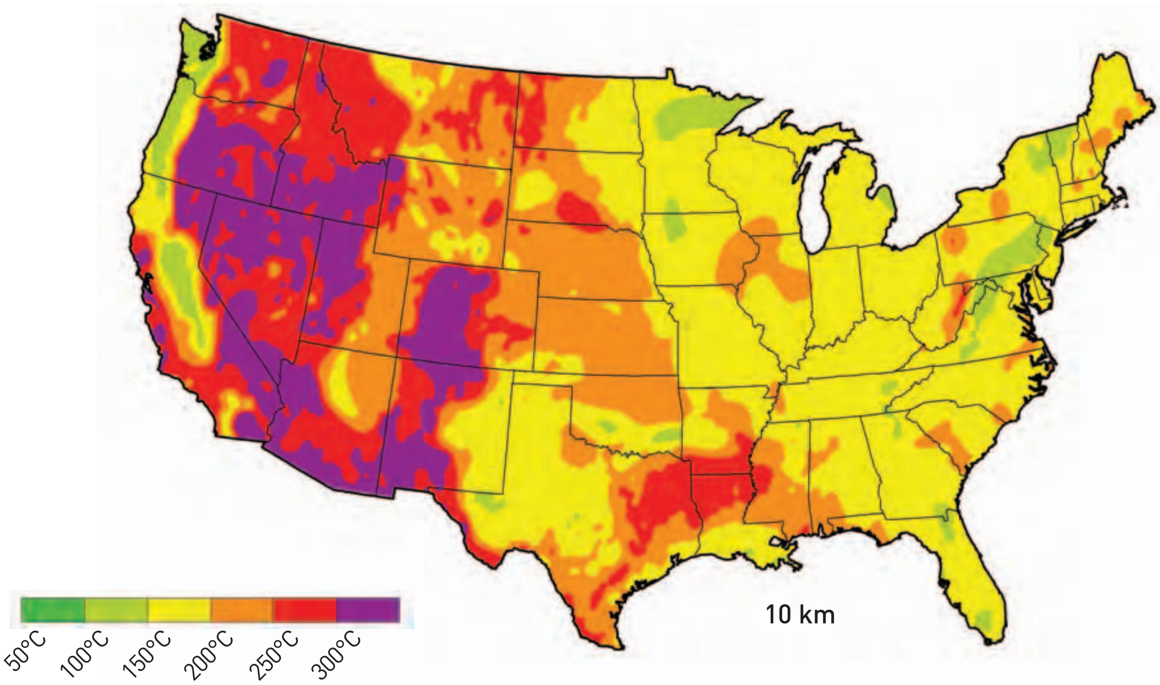


Figure 2.7f Average temperature at 10.0 km.

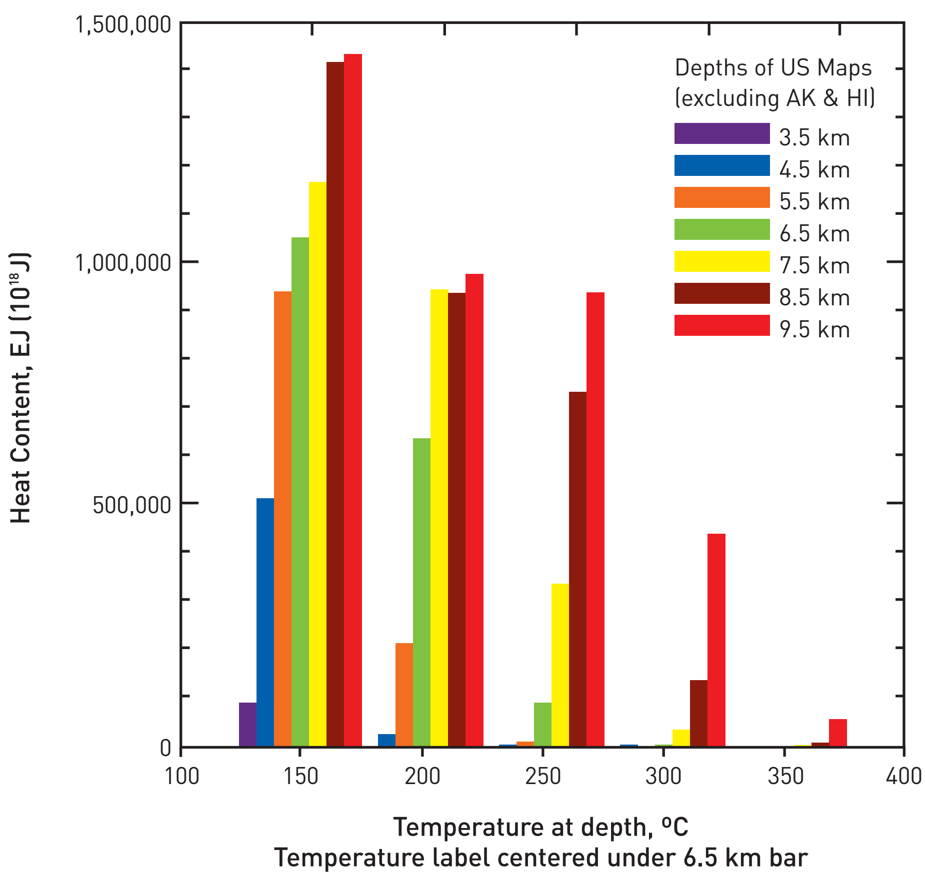


Figure 2.8a Histograms of heat content in EJ, as a function of depth for 1 km slices.

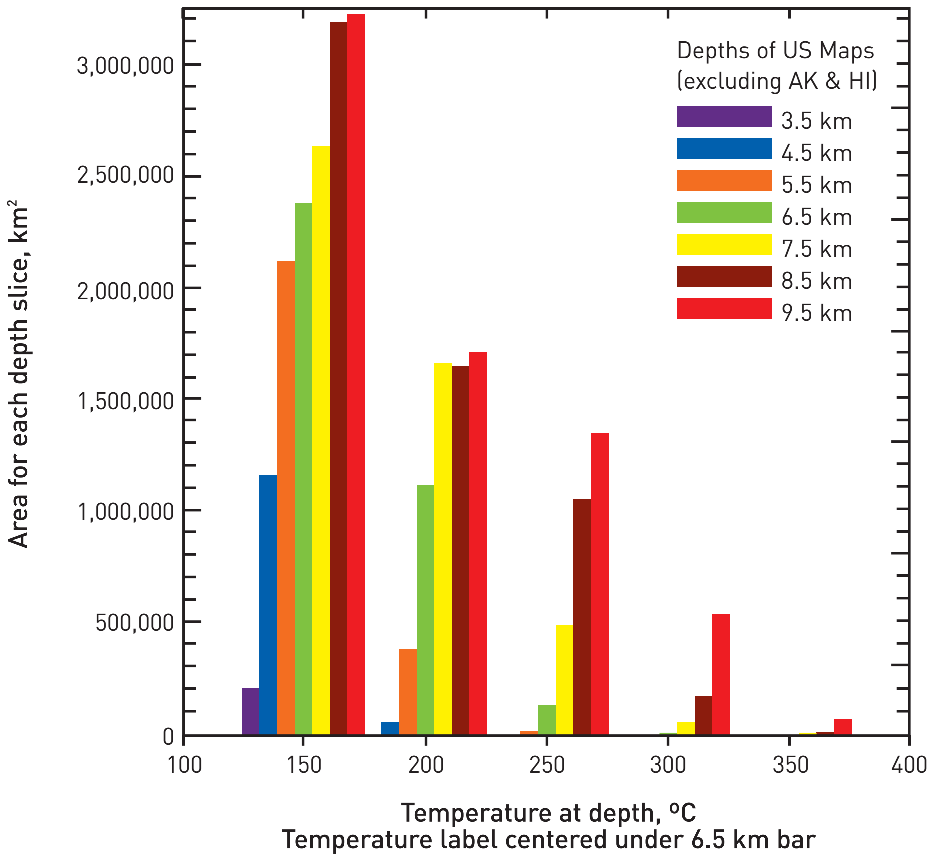


Figure 2.8b Histograms of United States area at a given temperature, as a function of depth for 1 km slices.

Although the EGS resource base is huge, it is not evenly distributed. Temperatures of more than 150°C at depths of less than 6 km are more common in the active tectonic regions of the western conterminous United States, but by no means are confined to those areas. The highest temperature regions represent areas of favorable configurations of high heat flow, low thermal conductivity, plus favorable local situations. For example, there are high heat-flow areas in the eastern United States where the crustal radioactivity is high, such as the White Mountains in New Hampshire (Birch et al., 1968) and northern Illinois (Roy et al., 1989). However, the thermal conductivity in these areas is also high, so the crustal temperatures are not as high as areas with the same heat flow and low thermal conductivity, such as coastal plain areas or a Cenozoic basin in Nevada. The most favorable resource areas (e.g., the Southern Rocky Mountains) have a high tectonic component of heat flow, high crustal radioactivity (Decker et al., 1988), areas of low thermal conductivity (as in young sedimentary basins), and other favorable circumstances such as young volcanic activity.

There are also areas of low average gradient in both the eastern and western United States. In the tectonically active western United States, the areas of active or young subduction have generally low heat flow and low gradients. For example, areas in the western Sierra Nevada foothills and in the eastern part of the Great Valley of California are as cold as any area on the continent (Blackwell et al., 1991).

2.3.2 Crustal stress

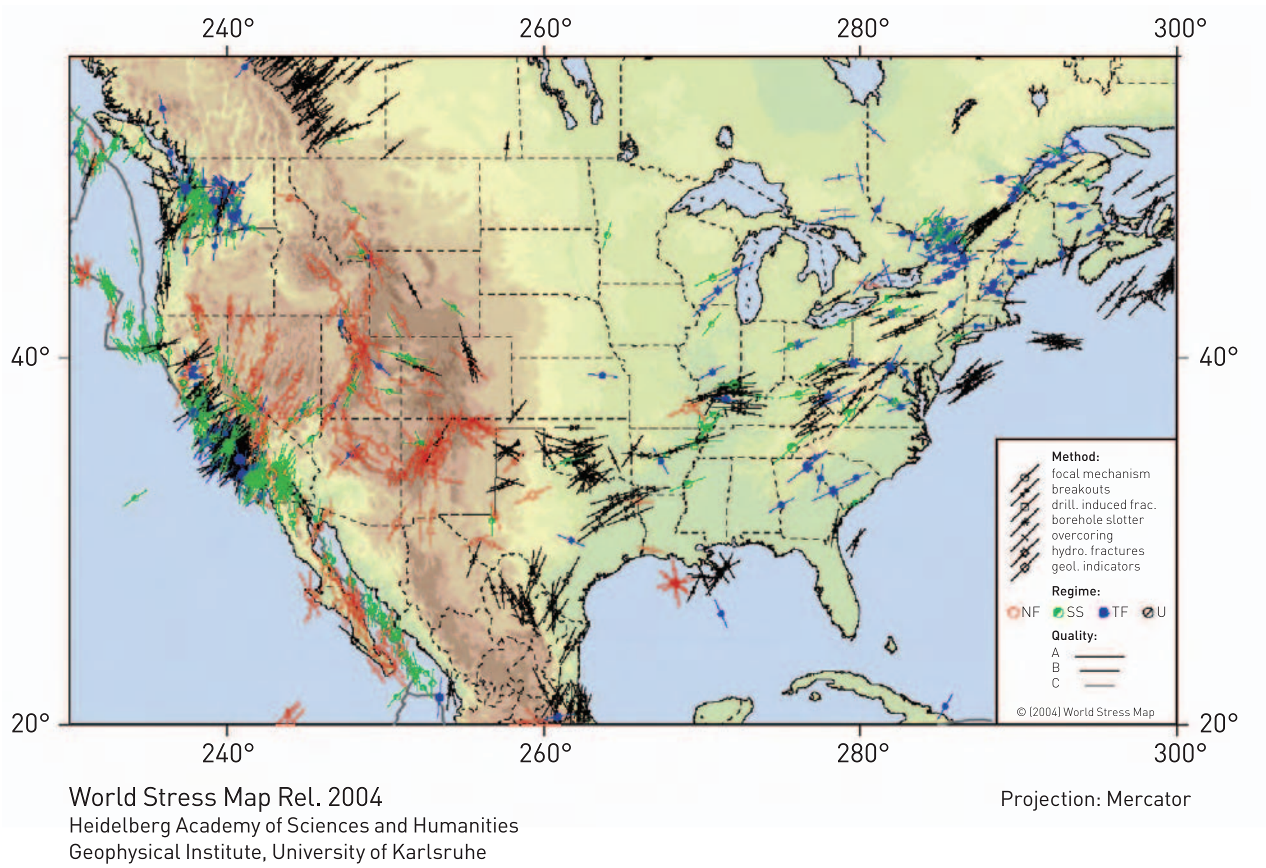
Data on the state of stress are shown in Figure 2.9 (Zoback and Zoback, 1991; Zoback et al., 1991). All stress regimes are represented in the conterminous United States. The stress regime is extensional in areas such as the Basin and Range and the Gulf Coast; and compressional in parts of the eastern United States and locally in the state of Washington. Strike-slip stresses are also typical of large areas such as along the transform plate in California. However, there are still large areas that are not well-characterized; detailed resource evaluation in these areas will have to include stress studies.

There is not enough information to determine the optimum stress regime for EGS geothermal development. In Australia, the planned development in the Cooper Basin is in a highly compressive regime with geopressured conditions (Wyborn et al., 2005); while, at the Soultz area in Europe, the stress regime is extensional (Elsass et al., 1995). Because the stress regime determines drilling strategies (see Chapter 6); and because, in opening fractures, the most favorable ones are along the direction of maximum shearing stress, it is important to have information on regional stress direction and magnitude in the planning of EGS geothermal development.

2.3.3 EGS geology

Much of the thermal energy resides in “basement” rocks below the sedimentary section. Because basement is usually defined as areas of metamorphic or igneous rocks, the composition and lithology of “basement” is actually extremely variable. The basement lithology below the sedimentary cover, where present, is as complicated as the surface exposures. While the generic description “granite” is used in this report, the lithology is not exactly specified. Quantification of the most favorable rock composition and structure for EGS development remains to be done. Most of the experimental EGS sites have been in granite (in a strict geologic sense), because of the expected homogeneity of the rock type. In fact, there may be situations where layered rocks might be equally or more favorable because the orientations of fractures might be easier to predict and the rock types may be more extensively fractured. From a more practical point of view, the lithology also affects the heat flow in the form of its radioactive content and the resulting heat flow. As has already been described above, areas of high radioactivity will have higher heat flow and so may have higher temperatures, all other factors being similar.

Some of the EGS resource resides in the sedimentary section, however. In general, as depth and temperature increase, the permeability and porosity of the rocks decreases. So, at depths of 3+ km and temperatures of 150+°C, the rocks are similar to basement in permeability and porosity. In many areas of the country, there is extensive drilling for gas at depths where temperatures are well within the EGS range because the gas deadline is on the order of 200+°C. In many of these areas, the rocks are “tight” and must be fractured to produce commercial quantities of gas (Holditch, 2006). In fact, much of the gas resource remaining in the United States is related to these types of formations. Examples are the Cretaceous sandstones in the Pieance Basin, Colorado (Mesa Verde and Wasatch Formations), and the East Texas Jurassic section (Bossier, etc.). These sandstones are “granitic” in bulk composition but still have some intrinsic porosity and permeability. Modeling by Nalla and Shook (2004) indicated that even a small amount of intrinsic porosity and permeability increases the efficiency of heat extraction, so that these types of rocks may be better EGS hosts than true granite. Thus, there is a natural progression path from the deep hot gas reservoir stimulation and production to EGS reservoir development in both technology and location. It seems likely that these areas might be developed early in the EGS history, because of the lower reservoir risk than in unknown or poorly known basement settings.



Maximum Horizontal Stress Orientation
Inferred from:

- Focal mechanism
- Wellbore breakouts
- Fault slip data
- Volcanic alignments
- Hydraulic fracturing
- Overcoring

Red data – Normal faulting stress regime: $S_v > S_{Hmax} > S_{hmin}$
Green data – Strike-slip faulting stress regime: $S_{Hmax} > S_v > S_{hmin}$
Purple data – Thrust faulting stress regime: $S_{Hmax} > S_{hmin} > S_v$
Black data – Stress regime unknown

Figure 2.9 Subset of the Stress Map of North America (Zoback et al., 1991, World Stress Map, 2004).

2.3.4 Crustal permeability

Crustal permeability is a difficult parameter to characterize. Permeability may be in the form of pore space in a sedimentary rock, such as in a sand, or as fractures in any type of rock strong enough to fracture. In general, permeability will decrease with depth. In sedimentary rocks, there is typically a relatively regular decrease due to compaction and diagenesis as depth and temperature increase. In basement rocks and deep sedimentary rocks, the primary permeability and porosity are related to the fracture and stress regime. General controls on and permeability of the crust have been discussed by Brace (1984), Davis (1981), Black (1987), among others. Ingebritsen and Manning (1999) have summarized a generalized distribution of crustal permeability as shown in Figure 2.10a. In the upper part of the crust, there is more than 8 orders of magnitude of permeability variation. However, by depths of 5 km, the variation is down to about 5 orders; and by 10 km, the range is closer to 2 orders of magnitude. Modeling of large-scale crustal fluid flow indicates a significant regime change over the permeability range of 10^{-17} to 10^{-15} m^2. At the smaller value, the crust is basically impermeable; while, at the larger value, large-scale fluid flow is possible with significant reconfiguration of the heat transfer and crustal temperatures (Wisian and Blackwell, 2004). Apparently, general large-scale crustal permeabilities are less than 10^{-16} m^2 in most areas, as evidenced by the lack of hot springs over large areas of the United States. Permeability vs. depth plots for the Pierre Shale of the mid-continent, and clastic sediments in the Uinta Basin are shown in Figure 2.10b (Bredehoeft et al., 1994). These measurements show that the Pierre Shale is essentially impermeable. In the case of the clastic sediments of the Uinta Basin, a “tight gas sand” area, the variation is from low to moderate permeability.

As a result of the range of variation and the uncertain controls on the type and nature of permeability, it is generally thought that most deep, hot regions of the crust away from tectonic activity will require extensive characterization and subsequent engineering of a reservoir to be produced. Existing and past studies of such situations are summarized in Chapter 4. This need to understand the rock characteristics and conditions is a major reason that areas of deep drilling for gas production may be the least expensive locations for initial EGS development.

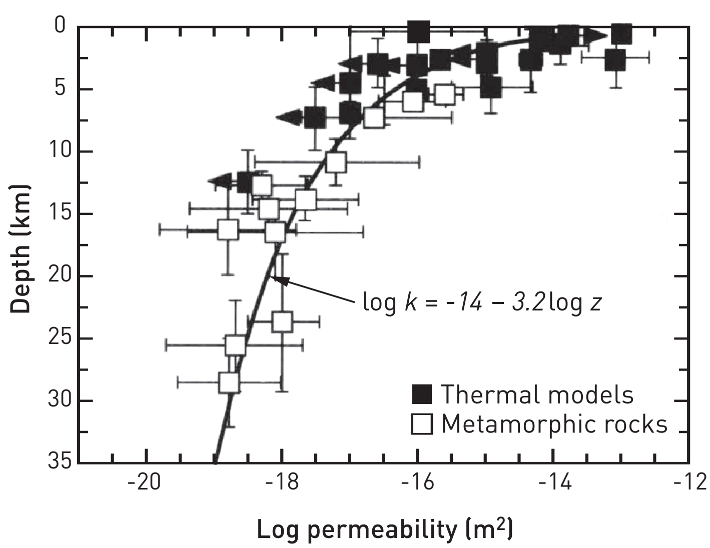


Figure 2.10a Permeability as a function of depth in continental crust (Ingebritsen and Manning, 1999).

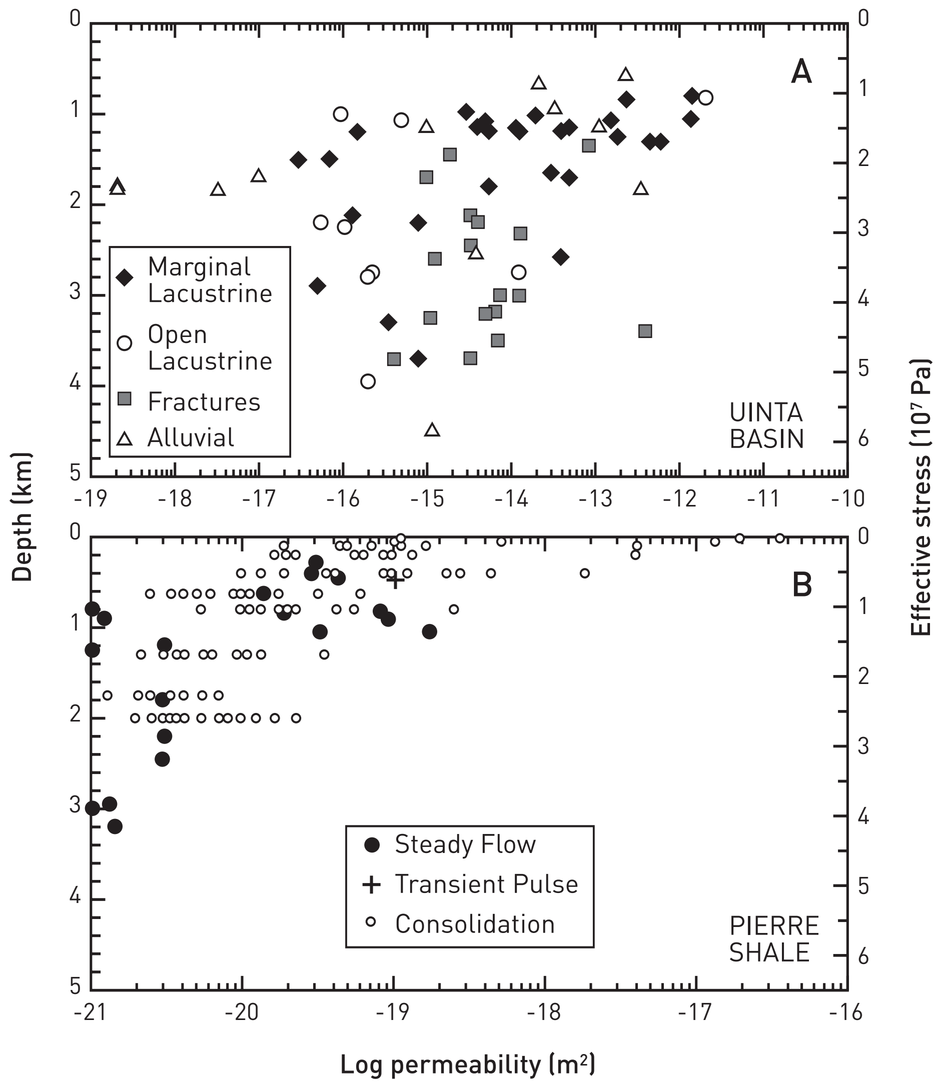


Figure 2.10b Permeability determined by direct hydraulic testing, as function of depth or effective stress in upper (<5km) crust (Bredehoeft et al., 1994). Results of drill-stem tests in sedimentary facies in Uinta Basin are shown in A; results of tests on core from Pierre Shale are shown in B.

2.3.5 High-grade EGS – targets for the near term (> 200°C at depths of about 4 km)

There are some large areas that have high temperatures at relatively shallow depths (3-5 km) that deserve special mention as near-term EGS development candidates. These are generally in the western United States, but are not confined to the areas that are presently developed as conventional hydrothermal geothermal systems. The most prominent of these areas are listed in Table 2.2. They include the Great Basin (Sass, 2001), the Snake River Plain, the Oregon Cascade Range, the Southern Rocky Mountains, the Salton Sea, and The Geysers/Clear Lake areas (see Figure 2.7b). In all these areas, detailed site studies could locate temperatures of more than 200°C at less than 4 km.

Table 2.2. High-grade EGS areas (>200°C at depths of about 4 km).

Region	Characteristics
Great Basin	30% of the 500 km x 500 km area is at temperatures > 200°C. Highly variable geologic and thermal conditions with some drilling confirming deep conditions. Large-scale fluid flow both laterally and horizontally so extensive fracturing at depth in many areas. The stress regime is extensional. Rocks are highly variable with depths of 4-10 km, mostly sedimentary with some granite and other basement rock types.
Snake River Plain and margins	75% of the 75 km x 500 km area is at temperatures > 200°C. Details of the geology at depths of 3-10 km unknown, probably volcanics and sediments overlaying granitic basement at 3-5 km, low permeability. The stress regime is unknown, existing fracturing may be limited.
Oregon Cascade Range	25% of the 50 km x 200 km area is at high, uniform temperatures and with similar geology (volcanic and intrusive rocks dominate). The margins of the area are accessible. The stratovolcanoes are excluded from the analysis. Conditions are more variable in California and Washington, but some high-grade resources probably exist there as well.
Southern Rocky Mountains	25% of the 100 km x 300 km area is at temperatures > 200°C. Geology is variable. Area includes the northern Rio Grande Rift and the Valles Caldera. Can have sediments over basement, generally thermal conditions in basement are unknown. Both high crustal radioactivity and high mantle heat flow contribute to surface heat flow. Probably highest basement EGS potential on a large scale.
Salton Sea	75% of the 25 km x 50 km area is at temperatures > 200°C. Young sedimentary basin with very high heat flow, young metamorphosed sedimentary rocks at depth. There is extensive drilling in the existing geothermal systems and limited background data available from hydrocarbon exploration.
Clear Lake Volcanic Field	50% of the 30 x 30 km area is at temperatures > 200°C (steam reservoir is 5 km x 10 km). Low-permeability Franciscan sediments, may find granite at deeper depths. Possible access problems. Significant deep drilling with temperatures of 200°C at 2 km over a large area.

One area that has received some previous study is The Geysers/Clear Lake region in California (Stone, 1992). While The Geysers steam field is part of the area, exploration for other steam deposits has identified a large area that is hot at shallow depth, but does not have enough permeability for conventional hydrothermal systems. An interpretation of the temperatures at depth in the area is shown in Figure 2.11 (Erkan et al., 2005). Temperature maps at 2, 3, 4, and 5 km are shown, based on the interpretation of more than 600 drill sites. The actual area of steam development (Stone, 1992) is shown as the cross-hatched area in the first panel. Even outside this area and away from its periphery, temperatures are interpreted to exceed 200°C at 3 km over an area about 30 by 40 km. There may be an area almost as large, with temperatures of more than 350°C at 5 km. In this area, supercritical geothermal conditions might also exist.

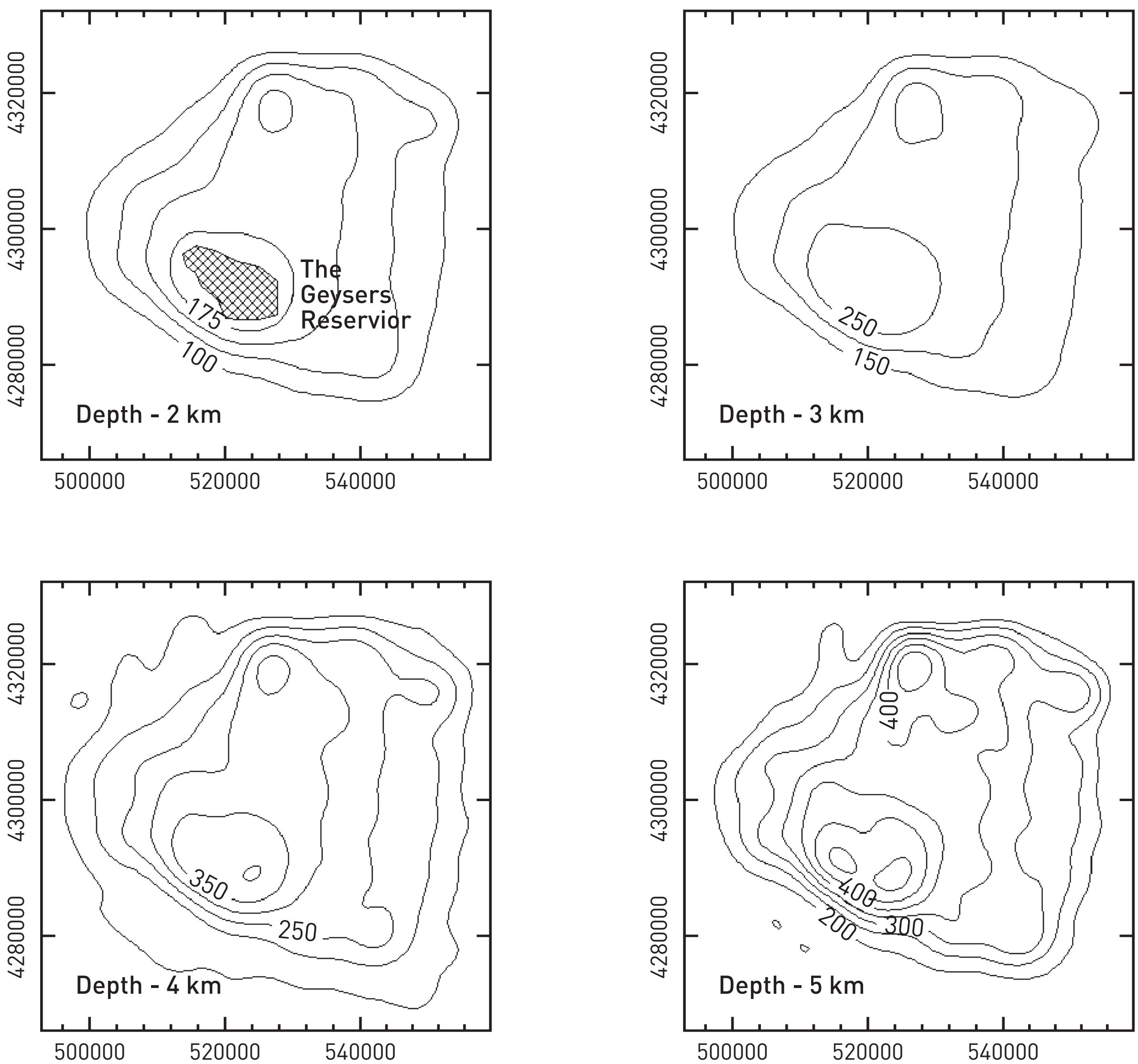


Figure 2.11 Temperatures at depths of 2 to 5 km in The Geysers/Clear Lake thermal area (Erkan et al., 2005).

2.4 EGS Potential of Alaska

There are all varieties of geothermal resources in Alaska. However, there is almost no information on the thermal regime except in very localized areas. Also, there is only a need for electrical generation development in localized areas, so for Alaska the questions are, first, how closely collocated are the resources with the demand; and, second, are there resources large enough to trigger new local development. The limited data available are shown in Figure 2.12 as a contour map of heat flow. Also included on the plot are the locations of volcanoes and hot springs. The EGS resource was estimated as in the case of the conterminous U.S. area described above. A thermal conductivity of 2.7 W/m/K was assumed everywhere, and the surface temperature was assumed to be 0°C. The heat content is shown in Table A.2.1 under column AK. This heat has not been added to the other U.S. values, however. The assessment of temperature at depth is diagrammatic only, because of the lack of data and the lack of collocation of information and electrical power need. There are possible conventional geothermal developments at several of the warm springs in central Alaska because of collocation situations. There is an active project at Chena Hot Springs near Fairbanks to develop 500 kW of power from a 165°F resource using binary power-generation equipment (Brasz and Holdmann, 2005). The first 250 kW unit went online in August 2006.

Coproduced fluids in the Cook Inlet gas developments (Shurr and Ridgley, 2002) are a possible future development scenario, but this area is part of the outer arc low heat-flow regime, and temperatures there are not particularly high.

2.4.1 Volcano systems

Electricity prices are high in Alaska, particularly in remote areas with only diesel-generating systems, typically greater than 25¢/kWh. In the longer term, electricity prices will depend partly on the future of oil and gas development on the North Slope, and on the location of a gas pipeline, if one is built. As a result of these and other factors, any long-term geothermal development scenario at this time is speculative. However, more than 40 volcanoes have been historically active, indicating there must be significant heat in a number of areas in Alaska. There are several of these volcanic centers relatively near the population center of Anchorage. Mt. Spurr and Mt. Dedoubt are close enough that geothermal power developed there might be transmitted to the load centers near Anchorage. The Wrangle Mountains are a huge volcanic complex almost certainly with associated geothermal systems. However, as a national park, geothermal energy recovery may not be possible, even if viable resources exist.

Smith and Shaw (1979) evaluated the igneous systems in Alaska for the 1978 resource assessment. They examined 27 volcanoes and estimated a resource base of about 2.5 x 10^{12} MWh for that set of sites. This estimate is certainly minimal, because there are more than 70 volcanoes that have erupted in the past 10,000 years along the Aleutian chain (www.UnivAlaska.edu). This is recent enough that there is a significant possibility that there is still heat associated with these areas.

Very high-grade EGS involving reservoir temperatures and pressures in the supercritical region (T > 374°C and P > 220 bar) are possible in Alaska, because of the many active volcanoes that are present along the Aleutian Island arc. If each one had a supercritical system associated with it, the resource could be quite large. The viability of such geothermal development has not been proven, but is under active research in Iceland (Valgardur, 2000; and Fridleifsson and Elders, 2004). The power

from such systems in Alaska could be developed in the remote areas and converted to hydrogen for transport to load centers in future energy scenarios. Under the appropriate economic conditions, it is possible that several tens of thousands of megawatts could be developed. Efforts to initiate development are ongoing at the volcanoes Matushkin, on Unalaska, (Reeder, 1992; Sifford and Bloomquist, 2000); and Akutan, on the island of Akutan (Starkey Wilson, personal communication, 2005).

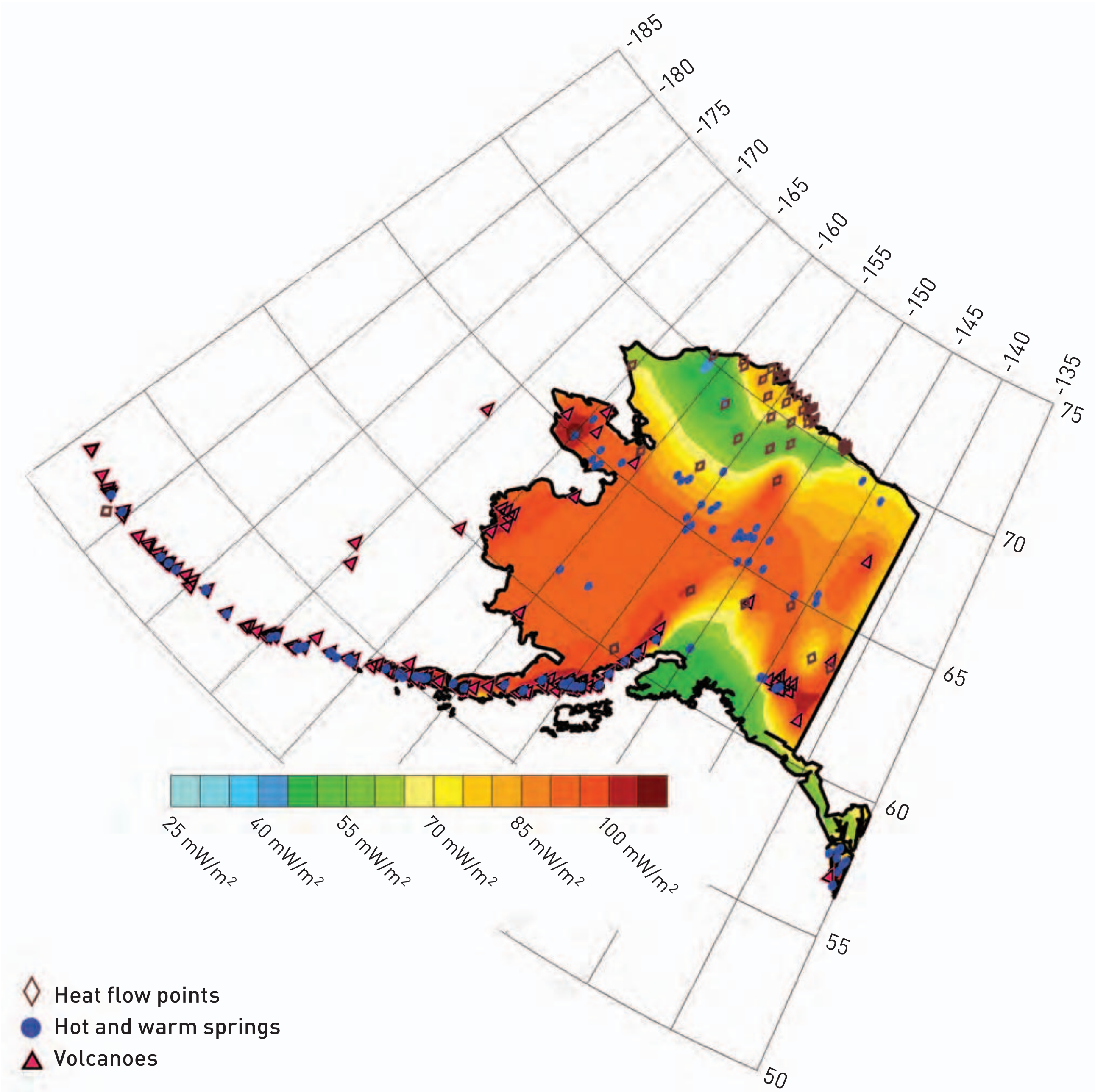


Figure 2.12 Heat-flow map of Alaska (from Blackwell and Richards, 2004).

2.5 EGS Potential of Hawaii

There is an existing power plant on the island of Hawaii along the east rift of the Kilauea volcano (Sifford and Bloomquist, 2000). The temperatures are high in this system of basaltic rift activity. There may be other resources in this area, but these are conventional hydrothermal resources. There is little subsurface information available outside of this area. The deepest drill hole on the Island of Hawaii, near Hilo (DePaolo et al., 2001), has a gradient of about 40°C/km below a depth of about 1.9 km and a BHT at 2.9 km of 42°C (Buttner and Huenges, 2003). There might be geothermal resources on Maui; but, on the other islands, geoelectric grade resources are not likely, due to the older age of volcanic activity there. There is little direct thermal information for these areas though, and the possibility of EGS development has not been ruled out. In a recent analysis of the geothermal potential of Hawaii, Lovekin et al. (2006) calculated resource estimates of 1,396 MW for the island of Hawaii (80% related to Kilauea volcano) and 139 MW for the island of Maui.

The island of Hawaii has the best possibility for the development of supercritical geothermal resources, if the viability of such development becomes feasible. Extensive interest in such development exists in Iceland, where drilling into such systems is planned in the near future (Fridleifsson and Elders, 2004).

2.6 Unconventional EGS Associated with Coproduced Fluids and Geopressured Fluids

2.6.1 Introduction

There are areas identified in the resource maps (Figure 2.7) where high temperatures are routinely being encountered in sedimentary rock during drilling for hydrocarbons. These temperatures typically reach 150°C (330°F) to more than 200°C (400°F). In some of these areas, significant porosity and permeability exists at depths of 3 to 6 km, and there is potential for large amounts of hot water either with or without stimulation of the reservoirs. In some of these cases, there may be the opportunity to stimulate fluid flows high enough to produce significant quantities of geothermal energy without having to create a new reservoir, or with relatively minor modifications of an existing oil or gas reservoir. So the distinction between an EGS system and a natural hydrothermal system are somewhat blurred. In these areas, there is also a developed infrastructure and an existing energy industry presence. Therefore, it seems possible that EGS or hybrid geothermal systems might be developed before the transition is made to pure, "start-from-scratch" EGS systems (McKenna et al., 2005). For the purpose of this report, these situations are divided into two categories: Coproduced Fluids and Geopressured Fluids. Thus, we have added coproduced hot water from oil and gas production as an unconventional EGS resource type, because it could be developed in the short term and provide a first step to more classical EGS exploitation.

2.6.2 Coproduced fluids: "conventional" geothermal development in hydrocarbon fields

Some areas of oil and gas development have relatively high temperatures at routinely drilled depths for hydrocarbon production. For example, parts of east and south Texas and northwest Louisiana are characterized by temperatures in excess of 150°C (300°F) at depths of 4 to 6 km (13,123 ft to 19,684 ft) (McKenna and Blackwell, 2005; McKenna et al., 2005) (see Figure 2.7). Data from BHT and high-resolution log segments in wells in south Texas indicate temperatures of more than 200°C (400°F) at 5 km (16,000 ft). In east Texas, temperatures are more than 150°C in the depth range of 3.5 to 4 km (11,000 to 13,000 ft). And, in northwest Louisiana, BHTs and equilibrium temperature logs document temperatures of 120-160°C at only 3 km (10,000 ft). Because *in situ* thermal conditions have been verified in these specific areas, the substantial areal extent of potential geothermal resources shown in Figure 2.7 is valid.

In addition to temperature requirements, a geothermal development requires large-volume flows of water, on the order of 1,000 GPM per MW (depending on the temperature). There are two typical types of existing situations associated with hydrocarbon development that are very favorable for geothermal development. The first might be considered "conventional" hydrothermal development, in that high volumes of water are produced in some fields as a byproduct of hydrocarbon production. This situation exists, for example, in massive water-flood secondary recovery fields (Table 2.3). Curtice and Dalrymple (2004) show that coproduced water in the conterminous United States amounts to at least 40 billion barrels per year, primarily concentrated in a handful of states (Figure 2.13). In most mature hydrocarbon fields, the disposal of this coproduced water is an expensive problem (Veil et al., 2004).

Table 2.3 Equivalent geothermal power from coproduced hot water associated with existing hydrocarbon production in selected states (a complete listing is given in Appendix A.2.2).

State	Total Water Produced Annually, in 1,000 kbbl	Total Water Production Rate, kGPM	Equivalent Power, MW @ 100°C	Equivalent Power, MW @ 140°C	Equivalent Power, MW @ 180°C
Alabama	203,223	18	18	47	88
Arkansas	258,095	23	23	59	112
California	5,080,065	459	462	1,169	2,205
Florida	160,412	15	15	37	70
Louisiana	2,136,573	193	194	492	928
Mississippi	592,518	54	54	136	257
Oklahoma	12,423,264	1,124	1,129	2,860	5,393
Texas	12,097,990	1,094	1,099	2,785	5,252
TOTALS	32,952,141	2,980	2,994	7,585	14,305

The factors required for successful geothermal electrical power generation are sufficiently high fluid flow rates for a well or a group of wells in relatively close proximity to each other, at temperatures in excess of 100°C (212°F). Opportunities can be found in most of the basins in the continental United States. For example, Figure 2.13 shows the average total produced water as a byproduct of hydrocarbon

production by state for 31 states (Curtice and Dalrymple, 2004). Oklahoma and Texas alone produce more than 24 billion barrels of water per year. In certain water-flood fields in the Gulf Coast region – particularly in northeastern Texas, southwestern Arkansas, and coastal Alabama/Mississippi – more than 50,000 barrels/day of fluid are produced, and paid for (in terms of pumping and disposal costs) by existing operations. Collecting and passing the fluid through a binary system electrical power plant could be a relatively straightforward process; because, in some cases, the produced fluid already is passed to a central collection facility for hydrocarbon separation and water disposal. Hence, piggy-backing on existing infrastructure should eliminate most of the need for expensive drilling and hydrofracturing operations, thereby reducing the risk and the majority of the upfront cost of geothermal electrical power production. There is not actual information available for the temperature of the waters available, so example calculations are shown for extreme cases of temperature. If the produced water is exploited for electric power production, the resulting power potential from contemporary binary plants is substantial as shown in Table 2.3. Chapter 7 discusses this subject in more detail.

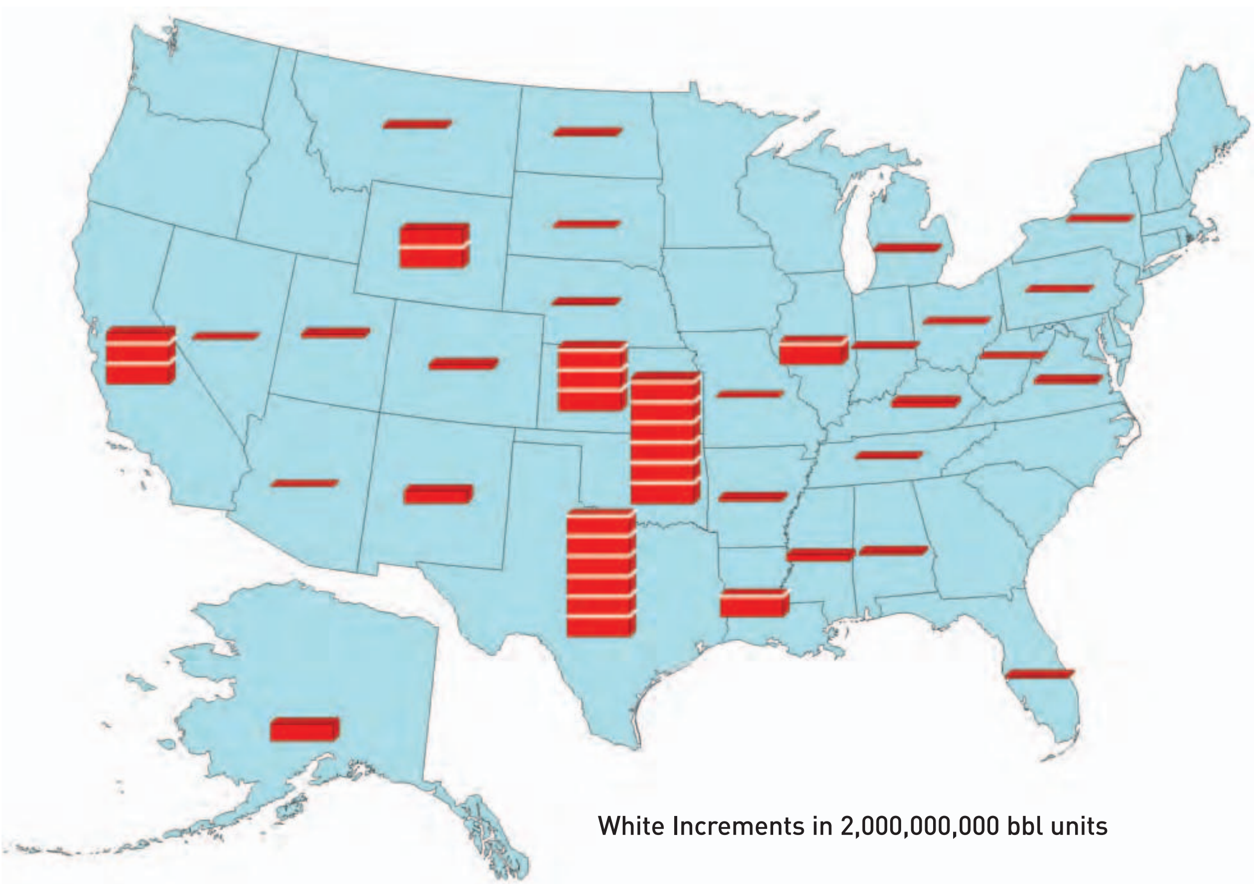


Figure 2.13 Water production from oil and gas wells (Curtice and Dalrymple, 2004).

Some of the fluid is produced from dispersed sites and may not be appropriate for use. However, these figures do give an idea of the absolute minimum of fluid that can be easily produced; and, if collected, could be a feedstock for existing reservoirs or new EGS types of applications. Its use in this way would also mitigate the environmental problems associated with disposal, by introducing a beneficial use of the waste product and ultimately lowering the cost of some forms of hydrocarbon

extraction. The figures for equivalent power in Table 2.3 represent an upper limit for electricial power generation that could be brought online with relatively low invested cost using all coproduced fluids (see also Chapter 9). The primary unknowns and, hence, limiting factors in these areas are the magnitude of the combined flow rates and the actual temperatures of the produced fluid in these existing hydrocarbon fields. In the case of two fields in Alabama, the temperatures appear to be more than 120°C (250°F), well within the range of binary generation capability.

2.6.3 Geopressured geothermal resources

The second category of systems in sedimentary rock is represented by the geopressured areas of deep basins where wells produce at pressures much higher than hydrostatic. The largest areas are in the young Gulf Coast sedimentary basin, but other basins also have geopressured conditions. The geothermal potential of geopressured zones in the northern Gulf of Mexico basin was evaluated in some detail by Papadopulos et al. (1975) and by Wallace et al. (1979). Papadopulos et al. (1975) noted, "Unlike other geothermal areas that are being considered for the development of energy, the energy potential of the waters in the geopressured-geothermal areas of the northern Gulf of Mexico is not limited to thermal energy. The abnormally high fluid pressures that have resulted from the compartmentalization of the sand and shale beds that contain these hot waters are a potential source for the development of mechanical (hydraulic) energy. In addition, dissolved natural gas, primarily methane, contributes significantly to the energy potential of these waters." So the development of this type of geothermal resource will also result in the recovery of significant amounts of natural gas that would otherwise be uneconomic.

Papadopulos et al. (1975) assessed the resource potential of geopressured-geothermal reservoirs within the onshore part of Tertiary sediments, under an area of more than 145,000 km^2 along the Texas and Louisiana Gulf Coast – this represents about half of the total area with geopressured conditions (see Figure 2.14). The assessment included only the pore fluids of sediments that lie in the interval between the top of the geopressured zones and the maximum depth of well control in 1975, i.e., a depth of 6 km in Texas and 7 km in Louisiana. They did not include the resource potential of geopressured reservoirs within (i) onshore Tertiary sediments in the interval between the depth of maximum well control and 10 km, (ii) offshore Tertiary sediments, and (iii) Cretaceous sediments. They did estimate that the potential of these additional geopressured reservoirs is about 1.5 to 2.5 times what was assessed in their study.

In contrast to geothermal areas of the western United States, subsurface information is abundant for the geopressured-geothermal area of the northern Gulf of Mexico basin. The area has been actively explored for oil and gas, and hundreds of thousands of wells have been drilled in search of petroleum deposits in the Texas and Louisiana Gulf Coast. The data presented by Papadopulos et al. (1975) represent general conditions in the various regions outlined. They believed that their information on geologic structure, sand thickness, temperature, and pressure were adequate for the purpose of their study. On the other hand, they noted a lack of sufficient data on porosity, permeability, and salinity. The basis on which various data presented were determined, calculated, or assumed was discussed in the "Appendix" to their report (White and Williams, 1975).

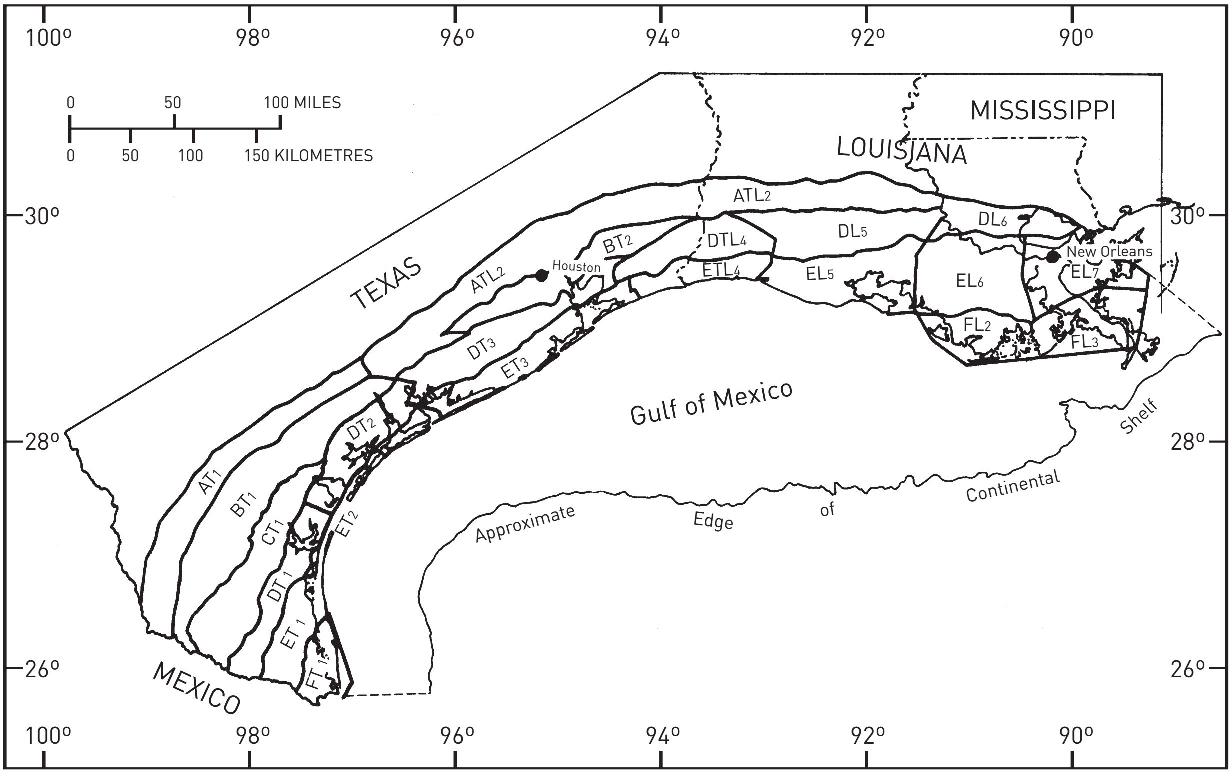


Figure 2.14 Location map showing the extent of the assessed geopressured zones and their division into subareas (AT1, BT1, etc.) (USGS Circular 726, 1975.)

The results of the assessment by Papadopulos et al. (1979) were incorporated into the final conclusions of the overall geothermal resource assessment of Circular 726 (White and Williams, 1975). Based on their analysis, they assessed the thermal resource base to be 46,000 EJ and the methane volume to be 23,700 x 10^{12} SCF, with a thermal equivalent of 25,000 EJ. The resource base, according to their calculations, is then about 1,000 MW for a century. Even their most conservative estimate of development was 46,000 EJ, excluding the chemical energy in the dissolved gas.

The Wallace et al. (1979) assessment extended the study to Cretaceous rocks north of, and beneath, the Tertiary sediments studied by the 1975 project for a total area of more than 278,500 km^2 (including offshore areas). The area they accessed extended from the Rio Grande in Texas northeastward to the vicinity of the mouth of the Pearl River in Louisiana; and from the landward boundary of Eocene growth faulting southeastward to the edge of the Continental Shelf, including unmapped Cretaceous sediments underlying the Tertiary sediments, extending farther inland. They assumed a depth limit of 6.86 km (22,500 ft) for development and a lower limit of temperature of 150°C (300°F). As was the case for Papadopulos et al. (1975), they did not include the dissolved methane in their calculations. They estimated that the accessible resource was 110,000 EJ of dissolved methane, which was later reported by Wallace et al. (1979) to be about 59,000 x 10^{12} SCF or only about 60,000 EJ (see Table 2.5).

These numbers may be compared with the calculated thermal resource base for the Gulf Coast states calculated above. This value for the states of Louisiana, Mississippi, and Texas is 1.5 x 10^6 EJ. This number does not include the offshore areas of the Gulf of Mexico. The amount calculated by Wallace et al. (1979) was 110,000 EJ. This value includes the stored thermal energy in both the on- and offshore geopressure areas, but does not include the energy stored in dissolved methane or the hydraulic energy resulting from the naturally high pressures of geopressured fluids.

In considering these estimates, it is important to note that the EGS values in this report include the entire states of Texas, Louisiana, and Mississippi, and not just the geopressure areas. The Wallace et al. (1979) value for the specific geopressure value could be considered to *add* to the baseline EGS figures from the analysis of stored thermal energy reported in Table A.2.1. This is because of the characteristics of the sedimentary basin resource. Wallace et al. (1979) used a value of approximately 20% for the porosity of the sediments. Because the heat capacity of water is about five times larger than that of rock, the stored thermal energy is approximately twice what would be present in the rock mass with zero porosity as assumed in the analysis summarized in Table A.2.1. The ability to extract the methane for energy from these areas is also an additional resource.

Subsequent to these assessments, technologies for recovering geopressured energy were extensively studied by the U.S. DOE between 1979 and 1990. From late 1989 until early 1990, a 1 MW_e plant was operated on the Pleasant Bayou well in the Texas Gulf Coast near Houston, which produced hot water and natural gas. About half of the power was generated by a binary cycle plant running on the thermal energy of the water, and about half generated by burning the gas in a reciprocating-engine-operated electric generator (Campbell and Hattar, 1990). The economics of the power generation at that time were not favorable, due to the low price of natural gas and oil, and the test was discontinued after the 6-month trial run. The well had been flow tested for a period of about 5 years with limited drawdown, so the geologic system seemed to be a success, and the reservoir sufficiently large to sustain production for many years (Shook, 1992). With today's higher gas costs and increasing demand for natural gas, geopressured systems deserve to be reconsidered, because their economics in today's energy markets will be much more favorable as pointed out in a recent study (Griggs, 2005).

2.6.4 EGS in sedimentary basins beneath hydrocarbon-bearing fields

Another scenario exists for geothermal development in many of the areas exploited for deep oil and gas production, especially in the Gulf Coast and mountain states regions. In these areas, EGS development in the deep, high-temperature part of the sedimentary section might be more cost-effective than basement EGS systems. Table 2.4 shows a comparison of needs for EGS-type development costs vs. reality in existing hydrocarbon fields. It is clear that many of the upfront reservoir costs have been reduced, and that the existing infrastructure can be readily adapted to geothermal electrical power production.

Table 2.4 Comparison of cost components for "EGS" development (previous model for geothermal development vs. reality in oil patch situations).

Components of Direct EGS Development Cost	• Drill wells that reach hot temperatures.>150°C (>300°F), • Fracture and/or horizontally drill wells to develop high water flow and/or acquire make-up water, • Install infrastructure, roads, piping, and power line routing, • Build power stations
Actual Field Conditions	• Many wells with BHTs of more than 150°C (300°F) at 4,570 m (15,000 ft) or less, • Wells fractured or horizontally drilled in many cases, • Water available from the well or adjoining wells in fields or as externally supplied disposal water (paid for by disposer), • In-place infrastructure of power lines, roads, pipelines, • Continued production of gas and oil in otherwise marginally economic wells.
Direct Costs to Develop a Gulf Coast EGS System	• Build power station, • Recomplete wells, in some cases, and test flow system, • Minor surface infrastructure upgrades (i.e., insulating collection pipes, etc.)

Future work must be performed on the suitability of some of the wells/fields now being developed as deep, hot, tight, sandstone gas reservoirs; but, overall, it appears that large areas of the United States are suitable for future geothermal exploitation in the near term that have not been considered in the past. Many of these areas are hot, and most are being artificially stimulated (fractured), or horizontally drilled, or both. These areas are clearly "EGS" types of systems but with known drilling and development costs and abundant water. Because of the thousands of wells drilled, the costs may be in some cases one-half to one-third of those for hard rock drilling and fracturing. A failed well in oil and gas exploration often means too much associated water production. In some areas, such as the Wilcox trend in south Texas, there are massive, high-porosity sands filled with water at high temperature. These situations make a natural segue way into large-scale EGS development.

Theoretical modeling suggests that stimulations in sedimentary settings, where there is some intrinsic porosity and permeability, are more favorable than a fractured basement rock setting (Nalla and Shook, 2004). Production data from the hydrocarbon industry indicate that most of the hydrocarbon-bearing basins and Gulf Coast Plain in Texas, Louisiana, Mississippi, and Alabama host elevated temperatures and the potential for significant water flow (Erdlac and Swift, 2004). Currently, the oil and gas industry feels this is more of a problem than an asset. As an indication of the possibilities, research into the suitability of such basin-hosted geothermal resources has begun in the north German Basin (Zimmermann et al., 2005). In this area, low-formation permeability requires stimulating potential sandstone reservoirs, and/or significant lateral drilling. But those conditions have not deterred initial research.

The detailed size of this resource has not been calculated separately from the general EGS resource, which is mostly in basement rocks. The areas that are in this EGS category are the areas of sedimentary section deeper than 4 km. The deep sections of sediments are present over many areas of the United States (see Figure 2.5). Especially promising large areas are found in the Gulf Coast, the Appalachian Basin, the southern Midcontinent, and the Rocky Mountains. As described above, the thermal energy in such areas is at least equal to that in the geopressure-geothermal resource estimated for the Gulf Coast. Therefore, a very conservative figure of 100,000 EJ is listed in Table 2.5 for Sedimentary EGS systems. While this number may be a few percent of the total EGS value (10^5 quads, about 1% as listed in Table 2.5), the accessible fraction of the energy in a 10- to 25-year time frame may be equal to or greater than the basement EGS value (see Chapter 3). Thus, the main reason for emphasizing this aspect of the EGS resource is its likelihood of earlier development compared to basement EGS, and the thermal advantages pointed out by the heat-extraction modeling of Nalla and Shook (2004).

2.7 Concluding Remarks

Table 2.5 provides a summary of resource-base estimates for all components of the geothermal resource. By far, the conduction-dominated components of EGS represent the largest component of the U.S. resource. Nonetheless, the hydrothermal, coproduced resources, and geopressured resources are large and significant targets for short-and intermediate-term development.

The question of sustainability is not addressed in this chapter. However, the geothermal resource is large and is ubiquitous. The temperature of the cooled part of the EGS reservoir will recover about 90% of the temperature drop, after a rest period of about 3 times the time required to lower it to the point where power production ceased (Pritchett, 1998). So development of an area 3 to 5 times the area required for the desired power output could allow cycling of the field and more than 100 years of operation. In areas where there are already large numbers of wells, this type of scenario might be practical and economical. Thus, in some scenarios of development, the geothermal resource is sustainable.

Although the EGS resource base is huge, it is not evenly distributed. Temperatures of more than 150°C at depths of less than 6 km are more common in the active tectonic regions of the western conterminous United States, but by no means are confined to those areas. While the analysis in this chapter gives a regional picture of the location and grade of the resource, there will be areas within every geological region where conditions are more favorable than in others – and indeed more

favorable than implied by the map contours. In the western United States, where the resource is almost ubiquitous, the local variations may not be as significant. In the central and eastern United States, however, there will be areas of moderate to small size that are much higher grade than the maps in Figure 2.7 imply; these areas would obviously be the initial targets of development.

The highest temperature regions represent areas of favorable configurations of high heat flow, low thermal conductivity, plus favorable local situations. For example, there are lateral variations of almost 100% in the mean thermal conductivity within the sedimentary section. In addition, there are high heat flow areas in the eastern United States, due to the high crustal radioactivity, such as the White Mountains in New Hampshire (Birch et al., 1968) and northern Illinois (Roy et al., 1989). The most favorable resource areas in the eastern United States will have high crustal radioactivity, low average thermal conductivity, and other favorable circumstances (such as aquifer effects). Detailed exploration studies are necessary to identify the highest temperature locations, because the data density is lowest in the eastern United States, where smaller targets require a higher density of data points.

Table 2.5 Summary of nonhydrothermal U.S. geothermal resource-base estimates.

Source and Category		Thermal Energy, in 10^{18}J = EJ	Volume of Methane, x 10^{12} SCF*	Total Gas + Thermal Energy, in 10^{18}J = EJ
Geopressured (Papadopulos et al.,1975).		46,000	23,700	71,000
Geopressured (Wallace et al.,1979).		110,000	59,000	170,000
Coproduced Resources		0.0944 – 0.451 (depends on water temperature)		
EGS				
- Sedimentary EGS (lower 48 states)		100,000		
- Basement EGS (lower 48 states)		13,300,000		
- Volcanic EGS	Excluding Yellowstone and Alaska	65,000 (high)		
	Alaska – 26 systems	9,000 (low)		
	Hawaii – 2 systems	1,535 MW		
- Alaska – all EGS		3,200,000		
- Hawaii		N/A		

* SCF = standard cubic feet of methane (ideal gas conditions) at 1 atm, 60°F.

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Appendix A

A.2.1 Geothermal Resource-Base Data

Table A.2.1 Geothermal resource base (in exajoules = 10^{18}J) for selected states, and the total conterminous United States. Some northeastern states are combined at the end of the table.

Depth	AK[1]	AL	AR	AZ	CA[2]	CO	FL	GA
3.5 km								
150°C	0	0	0	499	10,950	17,845	0	0
200					316			
250					414			
300					275			
4.5 km								
150°C	39,588	34	6,361	49,886	53,068	45,890	0	0
200					4,734	8,413		
250					407			
300					796			
5.5 km								
150°C	387,597	1,046	16,077	82,432	79,100	55,161	1,032	0
200		8	125	8,960	23,029	36,890		
250					3,332	5,033		
300								
6.5 km								
150°C	361,688	9,148	20,725	52,335	54,243	54,667	4,339	95
200	187,722	60	6,373	74,305	70,941	51,170	2	
250				473	9,186	24,029		
300					176	1,077		
7.5 km								
150°C	139,800	20,603	33,674	38,005	35,806	37,983	7,535	9,827
200	503,829	150	16,045	85,611	85,336	52,511	14	
250	4,556		115	26,972	36,940	47,984		
300					5,204	10,517		
350								
8.5 km								
150°C	66,880	32,605	38,944	28,284	37,742	19,225	10,324	15,797
200	218,770	2,038	21,847	45,502	57,201	55,299	1,205	
250	471,901		1,196	95,001	84,389	53,729		
300				1,363	11,419	34,801		
350					3,627	4,269		
9.5 km								
150°C	14,408	39,537	32,749	13,959	36,234	6,260	31,540	32,705
200	175,463	10,425	20,115	36,486	36,780	54,748	4,503	
250	576,921		14,743	94,872	91,626	46,846		
300	54,703			42,529	48,111	55,326		
350					7,079	18,765		
Total	**3,203,825**	**115,655**	**229,089**	**777,471**	**888,460**	**798,437**	**60,494**	**58,424**

Depth	IA	ID	IL	IN	KS	KY	LA	ME
3.5 km								
150°C	0	15,845	0	0	0	0	0	0
200		138						
250								
300								
4.5 km								
150°C	0	36,008	0	0	0	0	11,455	0
200		7,218						
250		112						
300								
5.5 km								
150°C	0	61,467	0	0	266	0	19,920	0
200		31,035						
250		415						
300		90						
6.5 km								
150°C	10,729	35,257	2,005	0	57,556	0	15,280	785
200		53,875					11,028	
250		19,510						
300		359						
7.5 km								
150°C	17,070	4,770	60,518	20,997	85,427	2,728	16,380	30,136
200		71,735					23,859	
250		36,102						
300		11,323						
350		303						
8.5 km								
150°C	40,477	0	61,118	35,957	86,027	42,443	18,265	33,809
200		33,742	381		7,233		24,313	
250		75,531					4,171	
300		28,026						
350		771						
9.5 km								
150°C	43,724	0	59,015	39,003	32,540	42,930	20,828	32,849
200	14,099	5,812	3,086		76,639		12,123	1,547
250		82,886					23,396	
300		44,226						
350		17,411						
Total	**126,100**	**673,966**	**186,123**	**95,956**	**345,689**	**88,100**	**201,019**	**99,126**

Depth	MI	MN	MO	MS	MT	NC	ND	NE
3.5 km								
150°C	0	0	0	0	13	0	0	0
200								
250								
300								
4.5 km								
150°C	0	0	0	1,512	8,373	0	3,845	848
200								
250								
300								
5.5 km								
150°C	0	0	0	17,227	107,436	150	25,288	6,705
200				65	150		96	
250								
300								
6.5 km								
150°C	0	0	84	31,807	123,860	2,036	36,938	60,446
200				1,158	13,265		2,534	1,018
250					25			
300								
7.5 km								
150°C	0	0	25,081	31,467	62,006	7,728	31,332	77,730
200				10,863	109,931	74	22,289	4,053
250				58	114		27	
300					5			
350								
8.5 km								
150°C	4,581	3,331	75,279	24,382	35,340	22,597	39,481	70,168
200				30,334	143,166	181	38,193	17,414
250				3	18,204		183	136
300					136			
350								
9.5 km								
150°C	40,271	32,458	76,217	18,161	25,945	36,425	36,731	16,489
200			22	37,958	90,470	2,247	40,190	85,119
250				4,534	101,691		12,630	1,809
300				0	109			
350					74			
Total	**44,852**	**35,789**	**176,684**	**209,528**	**840,312**	**71,437**	**289,756**	**341,935**

Depth	NH	NM	NV	NY	OH	OK	OR	PA
3.5 km								
150°C	0	2,229	15,906	0	0	0	14,395	0
200								
250								
300								
4.5 km								
150°C	0	48,980	85,462	0	0	0	54,781	0
200		1,037	262				5,548	
250								
300								
5.5 km								
150°C	59	67,955	85,749	0	0	2,896	54,155	564
200		15,416	43,121				29,064	
250								
300								
6.5 km								
150°C	1,050	34,334	34,897	1,860	0	31,793	22,500	3,134
200		68,390	106,889				63,830	
250		3,447	9,585				15,248	
300								
7.5 km								
150°C	4,431	21,924	8,662	6,805	10,306	53,052	8,174	11,688
200		69,124	91,850			32	57,547	420
250		35,654	69,176				39,841	
300		1,126	18				8,110	
350								
8.5 km								
150°C	7,811	29,305	6	17,423	41,481	48,164	4,305	23,057
200	115	34,911	40,609			20,869	28,063	1,924
250		84,705	132,887				74,882	
300		5,884	14,815				21,944	
350								
9.5 km								
150°C	7,940	41,058	0	29,872	44,285	38,271	7,119	25,800
200	1,251	19,195	10,640	3,270		41,271	10,212	5,838
250		71,993	104,280			0	66,719	
300		52,671	91,908				47,698	
350		1,674	17				12,264	
Total	**22,657**	**711,011**	**946,738**	**59,230**	**96,071**	**236,347**	**646,397**	**72,424**

Depth	SC	SD	TN	TX	UT	VA	WA	WI
3.5 km								
150°C	0	0	0	74	10,371	0	24	0
200								
250								
300								
4.5 km								
150°C	0	8,051	0	32,528	36,521	0	9,796	0
200				14	1,160			
250								
300								
5.5 km								
150°C	0	18,442	0	83,934	52,362	0	41,967	0
200				354	20,480		185	
250								
300								
6.5 km								
150°C	2,712	32,029	431	117,096	50,085	991	44,388	1,733
200		8,979		21,659	44,178		13,290	
250					8,626			
300								
7.5 km								
150°C	18,126	44,780	4,212	120,075	35,496	7,876	17,087	9,177
200		17,494		80,165	46,958		47,972	
250				668	32,160		2,395	
300					1,369			
350								
8.5 km								
150°C	28,101	58,298	19,938	152,725	13,841	16,758	3,831	31,652
200		26,030		111,793	50,315		56,655	
250		2,711		13,340	49,693		15,087	
300					16,700			
350								
9.5 km								
150°C	30,597	45,838	39,322	159,675	2,540	23,827	3,728	56,882
200	3,020	39,180	398	114,015	47,367	1,344	22,915	2,711
250		14,239		59,693	48,600		56,683	
300				409	41,421		2,320	
350					1,956			
Total	**82,556**	**316,072**	**64,302**	**1,068,217**	**612,202**	**50,796**	**338,324**	**102,155**

Depth	WV	WY[3]	MA_CT_RI_VT	MD_NJ_DE	Continental USA[4]
3.5 km					
150°C	0	106	0	0	91,760
200					653
250					558
300					283
4.5 km					
150°C	0	6,795	0	0	518,041
200		203			29,930
250		8			734
300					965
5.5 km					
150°C	703	34,380	0	35	947,166
200		1,319			218,922
250		287			8,745
300					458
6.5 km					
150°C	3,367	68,411	183	468	1,062,065
200		7,132			641,638
250		334			94,405
300		177			1,854
7.5 km					
150°C	9,833	73,849	3,559	2,576	1,177,632
200	1,738	27,546		332	954,271
250		1,551			342,032
300		265			38,242
350		94			397
8.5 km					
150°C	19,425	51,926	15,198	6,760	1,426,245
200	3,834	58,148		538	944,568
250		8,809			739,995
300		445			140,961
350					8,673
9.5 km					
150°C	16,561	27,358	18,343	11,624	1,440,428
200	7,131	82,408	136	668	984,067
250	1,033	18,542		33	946,675
300		1,642			444,280
350		64			61,446
Total	**63,626**	**471,799**	**37,419**	**23,033**	**13,267,370**

1. Alaska does not include the Aleutians.
2. California had the addition of the Clear Lake and Salton Sea areas for 3.5 and 4.5 km.
3. Wyoming does not include Yellowstone National Park (8987 km^2).
4. Continental U.S. - not including Alaska or Hawaii, or Yellowstone National Park. It does include the addition of Clear Lake and the Salton Sea areas of California at depths of 3.5 and 4.5 km.

A.2.2 Coprocessed Water Associated with Oil and Gas Production

Table A.2.2 Water production (Curtice and Dalrymple, 2004) and potential power generation from oil and gas operations for selected states.

State	State	Total Processed Water, 2004, (bbl)	Water Production Rate, kGPM	Water Production Rate kg/s	Power, MW @ 100°C	Power, MW @ 140°C	Power, MW @ 150°C	Power, MW @ 180°C
AL	Alabama	203,223,404	18	1,026	18	47	64	88
AK	Alaska	1,688,215,358	153	8,522	153	389	528	733
AZ	Arizona	293,478	0.0265	1.4814	0.0267	0.0676	0.0918	0.1274
AR	Arkansas	258,095,372	23	1,303	23	59	81	112
CA	California	5,080,065,058	459	25,643	462	1,169	1,590	2,205
CO	Colorado	487,330,554	44	2,460	44	112	153	212
FL	Florida	160,412,148	15	810	15	37	50	70
IL	Illinois	2,197,080,000	199	11,090	200	506	688	954
IN	Indiana	72,335,588	7	365	7	17	23	31
KS	Kansas	6,326,174,700	572	31,933	575	1,456	1,980	2,746
KY	Kentucky	447,231,960	40	2,257	41	103	140	194
LA	Louisiana	2,136,572,640	193	10,785	194	492	669	927
MI	Michigan	188,540,866	17	952	17	43	59	82
MS	Mississippi	592,517,602	54	2,991	54	136	185	257
MO	Missouri	17,082,000	2	86	2	4	5	7
MT	Montana	180,898,616	16	913	16	42	57	79
NE	Nebraska	102,005,344	9	515	9	23	32	44
NV	Nevada	13,650,274	1	69	1	3	4	6
NM	New Mexico	1,214,796,712	110	6,132	110	280	380	527
NY	New York	1,226,924	0.1110	6.1931	0.1115	0.2824	0.3840	0.5326
ND	North Dakota	182,441,238	16	921	17	42	57	79
OH	Ohio	12,772,916	1	64	1	3	4	6
OK	Oklahoma	12,423,264,300	1,124	62,709	1,129	2,860	3,888	5,393
PA	Pennsylvania	18,571,428	2	94	2	4	6	8
SD	South Dakota	6,724,894	1	34	1	2	2	3
TN	Tennessee	62,339,760	6	315	6	14	20	27
TX	Texas	12,097,990,120	1,094	61,067	1,099	2,785	3,786	5,252
UT	Utah	290,427,704	26	1,466	26	67	91	126
WV	Virginia	2,235,240	0.2022	11.2828	0.2031	0.5145	0.6995	0.9703
VA	West Virginia	252,180,000	23	1,273	23	58	79	109
WY	Wyoming	3,809,086,632	344	19,227	346	877	1,192	1,654

CHAPTER 3

Recoverable EGS Resource Estimates

3.1 Scope and Approach

This chapter provides a rationale and methodology for estimating the amount of useful energy that could be recovered from Enhanced Geothermal Systems (EGS) over the range of accessible depths and temperatures that exist in the United States. As discussed in Chapter 2, the EGS resource base is defined as the total thermal energy in place in the Earth's crust to the depth that we can reach with current technology. Thus, the estimated resource base for EGS presented in Chapter 2 is a measure of the total contained energy. Here, we want to estimate what fraction of this amount is recoverable.

If we limit our calculation of stored thermal energy in place to a depth of 10 km beneath the land area of the United States, then the amount of thermal energy in the crust is so large (about 14 million quads) that we can view it as sustainable (see Chapter 2, Table A.2.1). Even if we were to use it to provide all the primary energy consumed in the United States, we still would be depleting only a tiny fraction of it.

The depletion aspect requires additional exploration and detail. Geothermal is often classified as a renewable resource, but the time scale for its renewablilty is certainly longer than for solar, wind, or biomass energy, which have daily and annual cycles. For instance, a fractured EGS reservoir is cooled significantly during heat-mining operations over its normal project life of about 20 to 30 years, as a result of heat-mining operations. If the reservoir was abandoned at that point, the rock would recover to its initial temperature in 100 years or less (Armstead and Tester, 1987; and Elsworth, 1989 and 1990). With the time for full recovery of a former active reservoir approaching a century, one might not categorize geothermal heat mining as a sustainable energy resource. However, as long as the fraction of stored heat that is being mined in any year is a small fraction (<10%) of the total assessable resource base, geothermal can be treated as fully renewable and, therefore, a sustainable resource. Given that the U.S. geothermal resource base is about 14 million EJ, we would always be utilizing much less than 10% annually of the total thermal energy, even if all of our primary energy came from geothermal resources.

Chapter 2 characterized the EGS resource primarily by depth and temperature. In some regions, the EGS resource is available at high temperatures at shallow depths making energy recovery easier and less costly than other lower-grade regions, where deeper drilling is needed to reach useful rock temperatures. Another positive attribute of EGS for the long term will be the ability to locate heat-mining operations near end users. For example, an EGS site being developed in Switzerland is within the city limits of Basel. However, a significant portion of the resource will be inaccessible from the surface, due to its location under state and national parks, wilderness, military sites, or very high elevations. In addition, developed areas will not be suitable for EGS development, including major roads and utility corridors, airports, urban areas, and others. As it turns out, these inaccessible areas amount to only a small fraction of the total, leaving a significant amount of the stored thermal energy contained in accessible regions available for capture and utilization on the surface.

As discussed in Chapter 7, there are several factors that control the amount of the resource that can be recovered as heat or converted into electricity. These include the initial rock temperature and the maximum temperature drop that can be tolerated by the heat/power plant (i.e., the reservoir abandonment temperature), the volume of rock that can be accessed and stimulated, the active or effective heat-exchange area (controlled by the length, width, and spacing of the existing and stimulated fractures), and the flow rate of the water through the connected fractures (controlled by the permeability and the pattern of the injectors and producers) (Armstead and Tester, 1987; Ellsworth, 1989; and Sanyal and Butler, 2005).

Recoverable thermal energy was estimated, assuming an abandonment temperature 10°C below the average initial rock temperature in the reservoir. Numerical modeling studies by Sanyal and Butler (2005) have indicated that the recoverable fraction of stored thermal energy referenced to a specified reservoir abandonment temperature was about 40%, assuming an idealized, well-defined hydrothermal reservoir with homogeneous properties. To be conservative for EGS systems, the analysis applied the Sanyal and Butler model with lower recovery factors, namely, 20% and 2% to represent an appropriate range of values that might be deliverable in practice. Recovered thermal energy was calculated from the initial amount contained in specified 1 km-thick, horizontal rock slices at initial temperatures given in Chapter 2 and for a specified abandonment temperature that was 10°C below the initial temperature. The temperature-depth maps (Figure 2.7) were used for estimates of the total stored thermal energy. The recovered thermal energy was then converted to electric energy, using an overall heat-to-power cycle efficiency as discussed in Chapter 7 for binary and flash-steam cycles.

To get a better idea of the potential power supply available in the near future, the EGS resource was divided into two parts: 1) a portion associated with hydrothermal systems at depths shallower than 3 km, and 2) the remaining resource at depths between 3 and 10 km as estimated in Chapter 2. Cost of generated power was calculated for each of these two types of EGS resource, using the GETEM code developed for geothermal power costing for the U.S. DOE Geothermal Technologies Program (see Chapter 9, section 9.10.1 for more details).

3.2 Resource Base vs. Reserves

It will be helpful to review the way reserves are treated by the oil and gas industry before addressing this subject for EGS. In the energy industry, the estimated amount of oil or gas available with current technology at today's energy prices is often referred to as the reserve. Reserves clearly are much smaller than the resource base; but, in general, reserve estimates will increase as extractive technology improves and/or energy prices increase. For instance, in most deep sedimentary rock, there is some methane dissolved in the water found in the pores of the reservoir rock. This dissolved gas can be considered part of the natural gas resource base. If we calculated all of it contained in subsurface rock, a large amount of energy would be contained in this resource. Today, dissolved methane is usually not included in natural gas reserve estimates, because it is too dilute and/or too expensive to extract.

An excellent example is U.S. geopressured resources that contain a substantial amount of methane as part of their resource base (see Section 2.6.3). If technology were to improve so that dissolved methane could more easily be extracted, the methane contained in geothermal fluids, in general, could be included in reserves estimates. Similar analogies can be drawn using methane trapped in gas hydrates found in permafrost and marine sediments, or regarding the uranium dissolved in seawater as part of the uranium resource base.

U.S. oil and gas reserves correspond to economically extractable resources as specified by the Securities and Exchange Commission (SEC) Staff Accounting Bulletin, Topic 12 (2006). Given that oil and gas prices fluctuate on the commodity market, the competitive price levels are subject to change. When the price of oil was low a few years ago, thousands of small "stripper" wells in the United States were shut in. The oil and gas contained underground, which is connected to these wells, is still regarded as part of the reserves and included in estimates of what would be available but was not economic to produce at the market price at that time.

Reserve estimates made by the oil and gas industry are further categorized as proven, probable, and possible. The methods for accounting for these reserves are governed by the rules of the SEC (2006). Proven reserves exist where there is a sufficient body of supporting data from geology, geophysics, well tests, and field production to estimate the extent of the oil or gas contained in the body of rock. They are deemed, "commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations." Proven reserves can be developed or undeveloped. Probable reserves are unproven reserves, but geological and engineering data suggest that they are more likely than not to be recoverable. Statistical methods are often used in the calculation of probable reserves, and the deciding criterion is usually that there should be at least a 50% probability that the quantities actually recovered will "equal or exceed the sum of estimated proved plus probable reserves." Probable reserves can be in areas adjoining proven or developed fields or isolated from developed fields, but with drilling and testing data that indicates they are economic with current technology. Possible reserves are unproved reserves that are less likely to be recoverable than probable reserves, based on geological and engineering data analysis. Statistically, they are defined as reserves that, if recovered, have – at most – a 10% probability of equaling or exceeding the sum of the estimated proven, probable, and possible reserves. Possible reserves have few, if any, wells drilled; and the reservoir has not been produced, or even tested. However, the reservoir displays favorable geology and geophysics, and its size is estimated by statistical analysis. Possible reserves can also be in areas with good data to indicate that oil and gas are present, but they may not be commercially developable, or the technology to develop them may not exist (but such technology improvements can reasonably be expected in the future). Although this sounds very speculative, there is such a long history of oil and gas production that these estimates are regarded with a fair degree of confidence.

With regard to hydrothermal geothermal resources, some fields have been drilled and produced, so there are supporting data to make assessments of proven, probable, and possible reserves. Of course, even here there is some degree of speculation because no hydrothermal fields have been depleted of heat down to the point where they are uneconomic to produce. However, because EGS is an emerging technology that has not been produced commercially, the level of speculation and uncertainty is even higher – too high, in fact, to regard any of the EGS resource base as economic reserves at this time. EGS should to be classified as a "possible" future reserve.

Obviously, there are no commercial EGS reservoirs and no past production history on which to base recovery calculations. Even hydrothermal reservoirs have not been produced to the point where the amount of heat recovered from the rock volume can be accurately calculated. Nonetheless, we have attempted, as a part of our assessment of EGS, to develop a rationale and methodology for making such an estimate. To do this, we used a combination of the experience from hydrothermal power production projects, numerical modeling, and reasonable constraints regarding how we expect the system to operate for determining what fraction of the total EGS resource might be recovered.

3.3 Metrics that Influence the Recoverable Resource

The EGS resource base heat-in-place estimates developed in Chapter 2 are made by assuming a volume of rock with an average rock density, heat capacity, and a minimum reference temperature. For this assessment, the average surface temperature was used to define the minimum reference temperature. To determine the amount of that heat that can be mined, it is also necessary to include several other important parameters. The initial temperature of the rock at depth determines not only how much thermal energy is in place, but also the rate at which it can be recovered. In addition, a final useful production temperature must be specified for that application. This temperature is referred to as the "abandonment temperature" and represents the average temperature of the active reservoir rock volume at the time heat-extraction operations cease.

The volume of rock that can be fractured and the average spacing between the fractures, along with their length and width, will control the effective heat-exchange area of the reservoir. These, in turn, will determine the rate of energy output and the life of the reservoir. Reservoir volume and the effective surface area available for heat transfer will also affect the fraction of the thermal energy stored in the reservoir that can be extracted over time. The rate at which water – the heat transfer medium – is circulated through the system is a critical parameter. The flow pattern of water between injection and production wells controls how much of the fractured volume is actually swept by the circulating fluid. The permeability and porosity of the fractured volume determine the amount of water stored in the rock, as well as how fast it can move through the rock and with what amount of pressure drop. The circulating water exists at a representative temperature that is taken to be the average temperature of the rock. Also important, the actual flow pattern of fluid in the reservoir is influenced by the spatial distribution of permeability and porosity, as well as the relative positions of the production and injection wells.

3.3.1 Temperature

The resource base figures in Chapter 2 represent the total stored thermal energy in place, relative to the ambient regional surface temperature, T_o. We can define the recoverable fraction of that thermal energy, F_r, as a function of several independent or specified variables, such that:

$$F_r \equiv \frac{Q_{rec}}{Q_{total}} = f[V_{active}, V_{total}, C_r, T_{r,i}, T_{r,a}, T_o] \tag{3-1}$$

$$F_r = \frac{\rho V_{active} C_r (T_{r,i} - T_{r,a})}{\rho V_{total} C_r (T_{r,i} - T_o)}$$

$$F_r = \phi_v \frac{(T_{r,i} - T_{r,a})}{(T_{r,i} - T_o)}$$

where

Q_{rec} = recoverable thermal energy content of the reservoir

Q_{total} = total thermal energy content of the reservoir

ϕ_v = active reservoir volume/total reservoir volume

ρ = rock density (kg/m^3)

V_{total} = total reservoir volume (m^3)

V_{active} = active or effective reservoir volume (m^3)

C_r = rock specific heat (J/kg °C)

$T_{r,i}$ = mean initial reservoir rock temperature (°C)

T_o = mean ambient surface temperature (°C)

$T_{r,a}$ = mean rock temperature at which reservoir is abandoned (°C).

The rate of heat extraction from the rock depends on the difference between the temperature of the rock and the temperature of the circulating water at any point within the reservoir. The larger this difference, the more quickly heat will move from the rock into the water and, in the end, the more heat that can be extracted from the rock. On the one hand, if the cool injected water reaches the production well without being sufficiently heated, the total amount of heat mined from the rock will be less than expected, and the project will not achieve its design conditions. On the other hand, if there is no decline in produced fluid temperature over time, then the flow rate is not high enough to efficiently mine the heat contained in the rock. And, again, the project will not be economically optimized because less total thermal energy will be recovered.

Ideally, we want to maximize the total amount of useful energy extracted from the reservoir. The total energy extracted is given by the time integral over the production period of the instantaneous rate of heat extraction from the rock. For an EGS reservoir, the heat extraction rate is equal to the product of the mass flow rate and the specific enthalpy difference between the produced and reinjected fluid. If we increase the mass flow rate too much, the produced fluid temperature and its specific enthalpy will both decline, offsetting a potential increase in heat extraction rate. At some mass flow rate, an optimal balance is achieved between heat extraction rate and thermal drawdown rate.

In addition, there are issues concerning the efficiency of converting the extracted thermal energy to electrical energy. If we had a completely flexible power-conversion system that could use any temperature of fluid to generate electric power or extract usable heat – although at varying efficiency – we could cool the rock significantly and continue to use the same surface equipment. Real electric-generating power plants, heat pumps, or heat exchangers are designed for a specific set of conditions. The larger the difference between design conditions and actual operating conditions, the less efficient the equipment will become. This places a practical lower limit on the circulating fluid temperature, and consequently a lower limit on the average temperature of the rock in contact with the fluid. We call this latter temperature the “reservoir abandonment temperature,” $T_{r,a}$.

The thermal drawdown that occurs in a reservoir will be confined to a localized rock volume defined, in part, by the positions of the injector and producer wells in the stimulated region. The approach for restoring plant output when the thermal drawdown becomes too large will be to drill new infill wells

into parts of the field that have not been exploited. This strategy has worked for hydrothermal systems and should work for EGS as well. There will come a time when old wells will be abandoned or redrilled, or new wells added.

Assuming that an EGS reservoir consists of discretely fractured flow paths with average spacings of 100 m or less, then some simplications can be made. Because of the low thermal diffusivity of rock (of order 10^{-6} m^2/s), most of the temperature drop in the reservoir occurs near the injection well and adjacent to the fracture faces in contact with the flowing fluid. If the reservoir rock temperature drops only 10°C on average, there would be ample energy left in the reservoir for future use with equipment designed to operate at lower temperatures, which would increase the sustainability of the resource for the longer term. For instance, a cube of rock 1 km on a side at 200°C would contain 4×10^{14} kJ of thermal energy relative to the ambient surface temperature. However, if the average reservoir rock temperature is dropped only 10°C, the heat recovered from that mass of rock would be 2.5×10^{13} kJ, leaving about 95% of the original energy in place for later exploitation.

As discussed earlier in this chapter, following active heat-mining operations, production flow and heat removal would cease, allowing rock temperatures to fully recover by conduction in less than 100 years (Elsworth, 1989). This would permit EGS energy recovery to operate sustainably into the future. To be conservative, we specified an abandonment temperature of only 10°C lower than the initial rock temperature in estimating the recoverable energy fraction.

3.3.2 Fractured rock volume

While solid rock is excellent for storing heat, the rate of heat removal by conduction is slow, as a result of its low thermal conductivity. Only that fraction of the rock volume made accessible by the stimulation process can be considered part of the active reservoir where heat extraction occurs. The basic idea is to create permeability and porosity by hydraulic stimulation to open up channels for fluid to circulate through the rock, thereby shortening the rock conduction path. The transfer of heat in such a porous/fractured rock reservoir is a complex process that is not easy to model analytically. Sanyal and Butler (2005) have done sensitivity studies of the impact of various reservoir properties such as fractured volume, fracture spacing, permeability, porosity, and well configuration on the recovery fraction of heat-in-place using 3-dimensional finite element modeling. They varied the permeability, flow rate, fracture spacing, well spacing, injector-to-producer pattern, and fractured volume. They found that the single most important parameter affecting how much of the thermal energy that could be recovered is the fractured volume. In fact, perhaps the most important finding of their study is that the net electrical power that can be achieved from a volume of fractured rock is roughly 0.026 W_e/m^3 (26 MW_e/km^3). This factor applies to a wide variety of production-injection well arrangements (doublets, triplets, five-spots), fracture spacings (3-30 m), and permeability (10-100 mD). The factor seems to hold constant to within about 5%. It also includes reasonable estimates for parasitic power requirements for circulating the fluid through the reservoir.

Based on early field testing of EGS concepts, the geometric arrangement of the production and injection wells, to a large degree, influences the amount of rock that can be stimulated, and the accessible volume of rock that the circulating fluid contacts. EGS wells could be configured in a variety of ways: e.g., with one producer for every injector (a doublet), two producers to each injector (a triplet), or four producers to each injector (the classic five-spot pattern used in enhanced oil recovery operations). The stress regime in the rock volume will determine the fracture pattern and direction, and this will influence the optimal arrangement of injectors and producers. However, having more

than one producer for each injector reduces the amount of "dead" fractured volume, in which the rock is fractured but the fluid doesn't circulate. See Chapter 5 for more details.

3.3.3 Fracture spacing

Earlier researchers cited the importance of reservoir geometric structure on heat-removal effectiveness (see Kruger and Otte, 1972; and Armstead and Tester, 1987). Later, Sanyal and Butler (2005) found that, while the fractured volume had the largest effect on recovery factor of the parameters they studied, fracture spacing also had a measurable impact because it is part of determining the active reservoir volume. They investigated fracture spacings between 3 and 300 m. For reasonable fracture spacings of 3 to 30 m that might be realistically accomplished, there is little or no thermal interference, and the fracture spacing is largely irrelevant compared to the total fractured volume in determining how much of the heat-in-place will be recovered. However, for very large fracture spacings (~300 m) and a maximum possible flow rate determined by pump and pressure limitations, the recovery factor using a five-spot pattern with four producers per injector was 2.2%. A smaller fracture spacing of 30.5 m (again using a five-spot pattern and the same flow rate) yielded a 29.4% recovery factor. Lowering the flow rate from 500 kg/s to 126 kg/s per producer (with 30.5 m fracture spacing) increased the recovery factor from 24% to 42.5%, and maintained the reservoir life while still producing economic power output.

Many researchers, typified by the work of Sanyal and Butler, identify fractured rock volume as the single most important parameter affecting thermal recovery. To reach this conclusion, they have implicitly assumed that the rock mass has been homogeneously fractured, which will certainly not be the case in practice. While large surface area and fractured volumes are needed to ensure long-term heat extraction at acceptable rates, their mere existence alone does not guarantee performance. Sufficient fracture density and size are needed and fluid must sweep across the fractured surface area reasonably efficiently for long-term performance to be realized. This has been one of the biggest engineering challenges for EGS, and will be discussed extensively in Chapters 4 and 5.

3.3.4 Fracture surface area

The geothermal reservoir operates like an underground heat exchanger. Injected water is circulated through the reservoir and is exposed to the surfaces of hot rock allowing it to remove heat. The rate of heat transfer – and, consequently, the final temperature that the fluid achieves – is related to the mass flow rate of fluid and the surface area the fluid contacts. The heat-transfer system can be thought of as similar to a series of flat plates with gaps (the fractures) between them and a semi-infinite conduction heat source surrounding each fracture. Heat is transferred by conduction through the rock, perpendicular to the surfaces of the fractures. Then heat is transferred by convection at the rock-fluid interface to the fluid contained in the fracture. The larger that surface area is relative to the flow rate, the faster heat can be transferred to the fluid and still have its outlet temperature approach the original rock temperature with minimal thermal drawdown. (For more details concerning these coupled transport processes, see Armstead and Tester, 1987.) There are several parameters that affect this heat-transfer area:

- Well spacing – This is the distance between the wells in the active part of the reservoir. The well spacing controls the length of the fracture that is actively involved with fluid circulation.
- Fracture spacing – The average distance between fractures that are open and accepting fluid. These are assumed to be connected to the production wells through the fractured rock volume. In reality, these may not act as separate discrete fractures, but as an overall fractured rock mass.

- Fracture length and width – The fracture length is related to, but not necessarily the same as, the well spacing between producer and injector. The fracture is not likely to be a flat plane, but will take a tortuous path through the rock. The path length will, thus, be longer than the well spacing in most cases. The fracture width is the lateral distance that the fracture extends and has active circulation.
- Well configuration – The arrangement of the production wells in relation to the injector. The actively circulated fracture width is controlled, to some extent, by the geometry of the well configuration.

To produce 50 kg/s from a 200°C body of rock, with no more than 10°C temperature drop in the produced fluid over a project life of 30 years, a large rock surface area relative to the mass flow rate of fluid is needed (see Armstead and Tester, 1987). For instance, with eight fractures being used for heat extraction, each must have a length and width sufficient to produce 125,000 m^2 of surface area. If these fractures are 100 m apart, then 700 m or more of wellbore at the 200°C average reservoir temperature is required. To maintain the temperature for a longer life, we would need a longer fracture path length, larger fractures, or more fractures in the wellbore. Real fractures are certainly not the discrete, rectangular channels or circular discs assumed in this simple model. In real situations, fractures often have a greater surface area and path length than the distance between the wells would suggest. At Soultz, for example, in GPK3, about nine open fractures occur in the 540 m open-hole section. However, one fracture at 4,760 m takes 70% of the total fluid flow. This channeling, if left uncontrolled, will effectively reduce the useful recovered thermal energy of the entire reservoir, because heat removal in the fracture that is accepting the higher flow rate is much higher than can be sustained by transient thermal conduction through the surrounding rock.

3.4 Determining the Recoverable Fraction

As discussed above, Sanyal and Butler (2005) have modeled flow in fractured systems to determine the sensitivity of the recoverable heat fraction to several important parameters: rock temperature, fractured volume, fracture spacing, fluid-circulation rate, well configuration, and post-stimulation porosity and permeability. They used a 3-dimensional finite difference model and calculated the fraction of the heat-in-place that could be mined as these important parameters were changed. They found that for a variety of fracture spacings, well geometries, and fracture permeabilities, the percentage of heat recoverable from a stimulated volume of at least 1 x 10^8 m^3 under economic production conditions is nearly constant at about 40%, with a range between 34% and 47% (see Figure 3.1). This recovery factor is independent of well arrangements, fracture spacing, and permeability, as long as the stimulated volume exceeds 1 x 10^8 m^3. This roughly corresponds to a block of rock approximately 500 m x 500 m x 500 m. Because Phase II of the Fenton Hill project, the Rosemanowes project, the Soultz project (both the shallow and deep stimulated volumes), and the Cooper Basin project have achieved fractured volumes based on acoustic emissions mapping of equal to or greater than or greater than 10 x 10^8 m^3 (or 1 km^3), this threshold has already been exceeded in practice.

Because in the early stages of EGS technology development, short circuiting and other reservoir management problems will require extra fractured volume to counter too-rapid temperature drop, it was assumed that two to three times the volume would be needed to guarantee a useful reservoir life. This provides sufficient volume of hot rock for extended development in the event of an irreparable short circuit. However, the excess rock volume effectively halves the recovery factor. The Sanyal and Butler (2005) study found recovery factors that ranged from 2.5% to 90%, with a typical recovery

factor of about 45%. Very high recovery factors could only be achieved with uneconomic flow rates or other conditions that resulted in a short reservoir life. Recovery factors from 2% to 40% were therefore used in the calculation of potentially recoverable resources for this study. A recovery factor of 20% was used for Table 3.2 and the supply curves developed in Chapter 9. A 2% recovery factor was used for Table 3.3.

With a recovery factor and an abandonment temperature specified, the recoverable heat can be determined from the total energy in place, i.e., the resource-base amount:

$$Q_{rec} = F_r \, \rho \, V_{total} \, C_r \, (T_{r,i} - T_o). \tag{3-2}$$

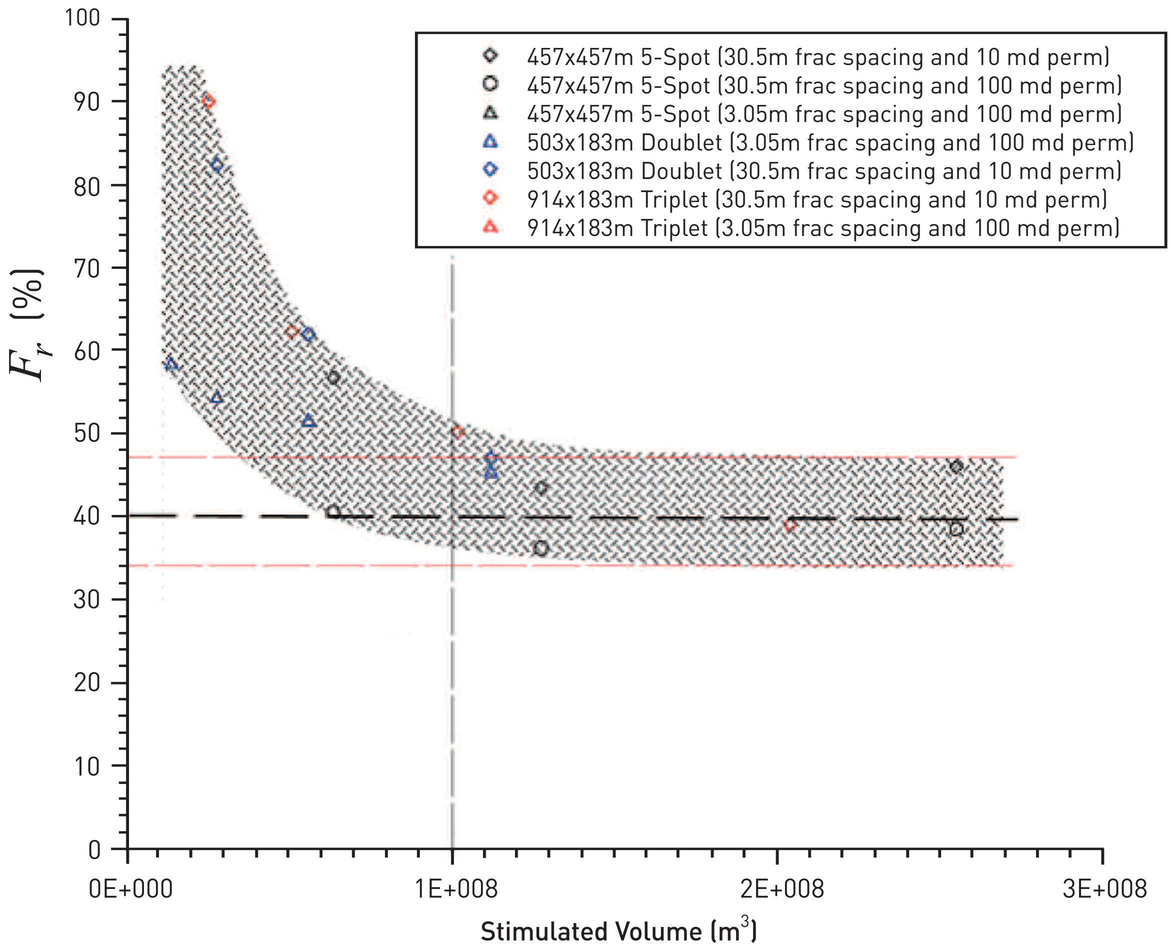

Figure 3.1 Recovery factor vs. stimulated volume for a range of well geometries, fracture spacing, and permeability. (Sanyal and Butler, 2005).

The recovery factor should improve with time as EGS extraction and energy conversion technology matures. The study by Sanyal and Butler (2005) suggests that recoverable energy fractions as high as 45% can be expected with economic flow rates and energy outputs. The analysis assumed an abandonment temperature that corresponds to only a 10°C temperature drop in the rock. There is evidence from 30 years of field testing that strongly suggests that hydrothermal systems achieve recovery amounts for total heat as high as or higher than 45%.

Regarding these estimated recovery factors, it is important to note that they depend strongly on how one defines accessible reservoir volume and characterizes flow through it.

Our ability to create large stimulated rock volumes has certainly improved dramatically. We can now stimulate volumes of 1 km^3 or more. Figure 3.2 shows the stimulated volume for past EGS experimental sites. By developing technology to control flow short circuits and methods to reduce impedances to flow when needed, the fraction of recoverable thermal energy will certainly increase as well.

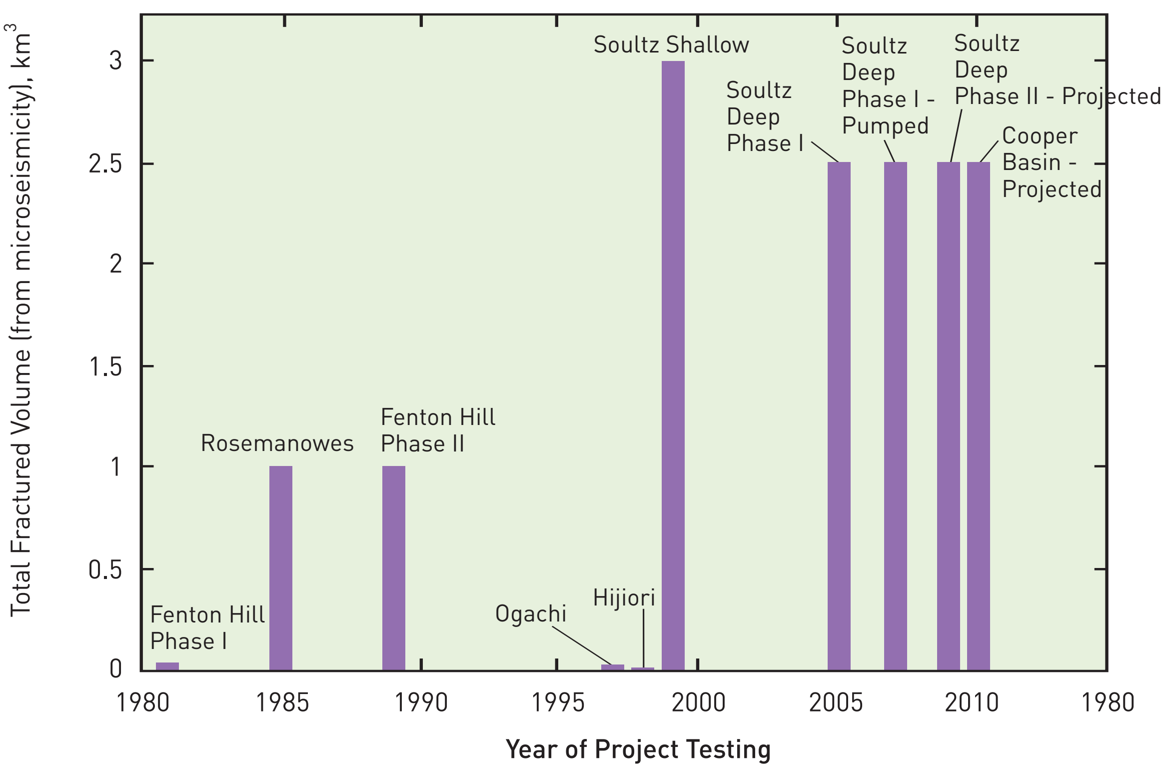

Figure 3.2 Total fractured or stimulated reservoir volume, as determined from microseismic data for representative EGS/hot dry rock (HDR) projects.

3.5 Usable Energy – Converting Heat to Power

Once the amount of recoverable heat from the reservoir has been estimated, it needs to be converted to usable energy, which we assume for this exercise is electricity. Field experience with EGS testing led us to believe that we can extract the heat from the rock for extended periods, with minimal thermal drawdown, if we design and operate the system carefully. As a first approximation, we assume that the production temperature of the fluid at the surface is the average temperature of the rock volume. It is important to note that we are not neglecting the thermal decline within the reservoir that certainly occurs – we are just restricting it to correspond to a specified decline in the average rock temperature at a given depth. Recovered amounts are then estimated from the resource base figures given in Chapter 2 (Figure 2.6) for the conterminous United States.

The power cycle employed, and the ambient surface temperatures along with the fluid temperature, determine the energy conversion efficiency. Chapter 7 discusses power cycles in general, including the conversion efficiency, temperature drop through the system, and other aspects of the conversion of the recoverable heat into electricity. The percentage of heat that can be converted to electricity is quantitatively represented by the thermal efficiency, i.e., the fraction of the total heat delivered to the power cycle by the circulating geofluid that is converted to electrical energy. Thermal efficiencies are based on Figure 7.2 for binary plants at resource temperatures under 200°C, and on the discussion in Section 7.2.2 for flash plants at temperatures above 200°C. The effects of ambient temperature, cooling method, and the power-conversion cycle itself are included. Using the net cycle efficiency allows us to convert the recoverable thermal energy for different temperature resources to electric energy. Table 3.1 shows the utilization efficiencies from Chapter 7 used for this conversion.

Table 3.1 Cycle thermal efficiencies used for energy conversion (see Chapter 7).

Temperature, °C	Cycle Thermal Efficiency η_{th}, %
150	11
200	14
250	16
300	18
350	22

To relate electrical energy to a potential electric-generating capacity, this energy will need to be converted to electric power (power is energy transfer per unit of time). In order to convert electrical energy to electrical power, we need to consider the time over which the energy will be produced. One option is to look at the resource from a project lifetime standpoint. This is the approach used by the United States Geological Survey (USGS) in Circular 790 (Muffler and Guffanti, 1978), where they assumed a project life of 20 years and divided the recoverable energy reserves by the number of seconds in 20 years. Since the time of that report, several geothermal projects have been operated for as long as 30 years, and most project planning for future geothermal projects assumes that each plant will last at least 30 years. Assuming this is the case, the average MW_e of capacity that would result is given by:

$$MW_e = \eta_{th} Q_{rec} \times 1MJ/1000kJ \times 1/t \qquad (3\text{-}3)$$

where

Q_{rec} = recoverable thermal energy (heat) in kWs (or kJ)

η_{th} = net cycle thermal efficiency (fraction)
t = seconds in 30 years = 30 yr x 365 days/yr x 24 hrs/day x 3600 s/hr. = 9.46 x 10^8 s

Specifying a recovery factor is arbitrary – however, by assuming a range that spans an order of magnitude and is always lower than the estimates by Sanyal and Butler, we have sufficiently captured the inherent uncertainty in this prediction. The exploitable amount of thermal energy was further reduced by assuming that only a small fraction is actually removed during the period of production to generate electric power. This additional reduction was implemented by specifying a mean temperature of the reservoir at the end of production. This is the abandonment temperature [$T_{r,a}$ in Eq. (3-1)] and had a value of 10°C below the initial rock temperature, $T_{r,i}$.

Table 3.2 shows the recoverable heat as electric power for the United States, assuming a 30-year project life for each depth and average temperature, and a 20% recovery factor. Table 3.3 shows the recoverable heat as electric power using a 2% recovery factor. At only 2% recovery, we note that the 4-5 km deep section of the EGS resource on its own represents an increase of about a factor of 25 over today's U.S. electricity production from geothermal energy. As we go deeper, or increase the recovery factor above 2%, the recoverable electrical power increases proportionally. Going forward, we expect both enhancements to occur as a result of EGS technology improvements from invested R&D and learning curve cost reductions (see Chapter 9 for more details).

Table 3.2 Total recoverable energy in net MW_e for 30 years, with 20% recoverable fraction of thermal energy from the reservoir.

Depth of Slice, km	Power available for slice, MW_e	Amount at 150°C, MW_e	Amount at 200°C, MW_e	Amount at 250°C, MW_e	Amount at 300°C, MW_e	Amount at 350°C, MW_e
3 to 4	122,000	120,000	800	700	400	
4 to 5	719,000	678,000	39,000	900	1,200	
5 to 6	1,536,000	1,241,000	284,000	11,000	600	
6 to 7	2,340,000	1,391,000	832,000	114,000	2,800	
7 to 8	3,245,000	1,543,000	1,238,000	415,000	48,000	1,200
8 to 10	4,524,000	1,875,000	1,195,000	1,100,000	302,000	54,000
TOTAL	12,486,000					

(a) See Table 3.1 for values of the cycle thermal efficiency used.
(b) $T_{a,i} = T_{r,i}$ – 10°C, i.e., 10°C below the initial rock temperature [see Eq. (3-1)].

Table 3.3 Total recoverable energy in net MW_e for 30 years, with 2% recoverable fraction of thermal energy from the reservoir.

Depth of Slice, km	Power available for slice, MW_e	Amount at 150°C, MW_e	Amount at 200°C, MW_e	Amount at 250°C, MW_e	Amount at 300°C, MW_e	Amount at 350°C, MW_e
3 to 4	12,000	12,000	80	70	40	
4 to 5	72,000	68,000	4,000	90	120	
5 to 6	154,000	124,000	28,000	1,100	60	
6 to 7	234,000	139,000	83,000	11,000	300	
7 to 8	324,000	154,000	124,000	41,000	5,000	120
8 to 10	452,000	187,000	119,000	110,000	30,000	5,000
TOTAL	1,249,000					

(a) See Table 3.1 for values of the cycle thermal efficiency used.

(b) $T_{a,i} = T_{r,i} - 10°C$, that is 10ºC below the initial rock temperature [see Eq. (3-1)].

3.6 Access to the EGS Resource

Only a portion of the total EGS resource will be accessible for development. Urban areas, major roads and utility corridors, as well as national and state parks, recreation areas, wilderness areas, and national monuments will be off-limits for development. Military bases, while possibly accessible for EGS development, are currently treated in a different way from other federal lands – development is severely restricted and royalty structure is different from public or private lands. The panel recommends that these restricted areas should not be considered as part of the EGS resource base. At this point in the evaluation of EGS feasibility, these off-limit areas have not been mapped and have been excluded from the EGS resource – the one exception was the Yellowstone National Park region, which is not included in the U.S. total or in Wyoming, Montana, or Idaho. Quantifying these restricted areas is an important aspect of resource assessment that should be considered in the future.

For this study, we simplified the analysis. The portion of the EGS resource that was not accessible for development was estimated by taking the total fraction of the land in each state – and for the United States as a whole – that was contained in state and national parks, recreation areas, wilderness, national monuments, and military lands. This fraction was assumed to be the fraction of the EGS resource that was inaccessible for development, and it was subtracted from the total recoverable resource:

$$\text{Accessible } MW_e = MW_e(1 - IF) \tag{3-4}$$

where

IF = fraction of the total state or U.S. land area that is inaccessible, as described above, due to being located under a park, wilderness or nature preserve, or military base

MW_e = Calculated electric power capacity accessible if all land area was available for development

The amount of power that could then be considered recoverable and accessible is calculated using Eq. (3-1) to (3-4). For states such as Washington, New York, or California, with a large fraction of the total land contained in national and state parks, recreation areas, wilderness and military lands, the fraction of the resource that is considered inaccessible is more than 5%. For states in the Midwest or Gulf Coast, the fraction is much lower, closer to 1%.

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