Impact of enhanced geothermal systems on US energy supply in the twenty-first century

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Recent national focus on the value of increasing US supplies of indigenous renewable energy underscores the need for re-evaluating all alternatives, particularly those that are large and well distributed nationally. A panel was assembled in September 2005 to evaluate the technical and economic feasibility of geothermal becoming a major supplier of primary energy for US base-load generation capacity by 2050. Primary energy produced from both conventional hydrothermal and enhanced (or engineered) geothermal systems (EGS) was considered on a national scale. This paper summarizes the work of the panel which appears in complete form in a 2006 MIT report, 'The future of geothermal energy' parts 1 and 2.

In the analysis, a comprehensive national assessment of US geothermal resources, evaluation of drilling and reservoir technologies and economic modelling was carried out. The methodologies employed to estimate geologic heat flow for a range of geothermal resources were utilized to provide detailed quantitative projections of the EGS resource base for the USA. Thirty years of field testing worldwide was evaluated to identify the remaining technology needs with respect to drilling and completing wells, stimulating EGS reservoirs and converting geothermal heat to electricity in surface power and energy recovery systems. Economic modelling was used to develop long-term projections of EGS in the USA for supplying electricity and thermal energy. Sensitivities to capital costs for drilling, stimulation and power plant construction, and financial factors, learning curve estimates, and uncertainties and risks were considered.

**Keywords: geothermal energy; hot dry rock; heat mining; EGS;
engineered geothermal systems; enhanced geothermal systems**

1. 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 US population, along with increased electrification of our society. According to the Energy Information Administration

(EIA 2006), US 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 GWe or more of coal-fired capacity will need to be retired in the next 15–25 years owing to environmental concerns. In addition, during that period, 40 GWe or more of nuclear capacity will be beyond even the most generous relicensing procedures and will have to be decommissioned.

The current non-renewable options for replacing this anticipated loss of US 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 US 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 probably 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. In addition, 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 measurable opportunity for capacity expansion of US 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, 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-hours-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 US 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.

2. Scope

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 non-electric applications in the United States, they are somewhat limited in their location and ultimate potential for supplying electricity. Beyond these conventional resources are enhanced geothermal systems (EGS) resources with enormous potential for primary energy recovery using heat-mining technology, which is designed to extract and use 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. Since 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 MWe 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 may not produce sufficient fluid for viable heat extraction, either owing to low formation permeability/connectivity and insufficient reservoir volume, and/or the absence of naturally contained fluids.

Three main components were considered in the analysis.

  (i) *Resource.* Mapping the magnitude and distribution of the US EGS resource.
 (ii) *Technology.* Establishing requirements for extracting and utilizing energy from EGS reservoirs including drilling, reservoir design and stimulation, and thermal energy conversion to electricity.
(iii) *Economics.* Estimating costs for EGS-supplied electricity on a national scale using newly developed methods for mining heat from the Earth, as well as developing levelized energy costs (LECs) and supply curves as a function of invested R&D and deployment levels in evolving US energy markets.

The goal of this assessment was 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 study was structured to address two critical questions facing the future of EGS.

  (i) Can EGS have a major impact on national energy supply?
 (ii) How much investment in R&D is needed to realize that impact?

Although there have been earlier assessments of EGS technology and economics, none were fully comprehensive—from providing a detailed evaluation of the magnitude and distribution of the geothermal resource to analysing evolving energy

markets for EGS. Our assessment evaluates the status of EGS technology, details the lessons learned and prioritizes R&D needs for EGS. Our group was able to review technical contributions and progress, spanning more than 30 years of field testing in the United States, Europe, Australia and Japan, as well as several earlier economic and resource estimates. Although substantial progress has been made in developing and demonstrating certain components of EGS technology, further work is needed to establish the viability of using EGS for commercial-scale electrical power generation, cogeneration and direct heat supply.

One means of illustrating the potential of any alternative energy technology is to predict how a supply curve of energy costs versus 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 defined the impact threshold for EGS technology as being able to provide 100 000 MW of additional cost-competitive electrical capacity by 2050 for the USA. While we recognize that this specific goal is not part of the current Department of Energy (DOE) programme, a 10% impact by 2050 (based on today's generation capacity) is a reasonable objective for EGS to become a major player as a domestic energy supplier. 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. A key objective of the study was to develop supply curves for EGS and to 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 US energy supply. We evaluated 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 further federal and private investment in EGS.

3. Pursuing the geothermal option

Could US-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 US 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 highly limited in their distribution in the United States to make a major long-term 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.

4. 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 US 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 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 US Geological Survey (USGS Circulars 726 and 790) were amplified by ongoing research and analysis being conducted by US heat-flow researchers and analysed 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 analysed in the context of projected demand for base-load electric power in the United States.

5. 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 fluids that are 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–vapour mixture or superheated steam vapour phase. The amounts of hot rock and contained fluids are substantially larger and more widely distributed in comparison with 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 twentieth century that geothermal energy was harnessed for industrial and commercial purposes. In 1904, electricity was first produced using geothermal steam at the vapour-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 MWe and a direct-use, non-electric capacity of more than 100 000 MW (thermal megawatts of power) at the beginning of the twenty-first 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^{-1} 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:

(i) upward convection and conduction of heat from the Earth's mantle and core and
(ii) 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 *ca* 1 Myr). 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
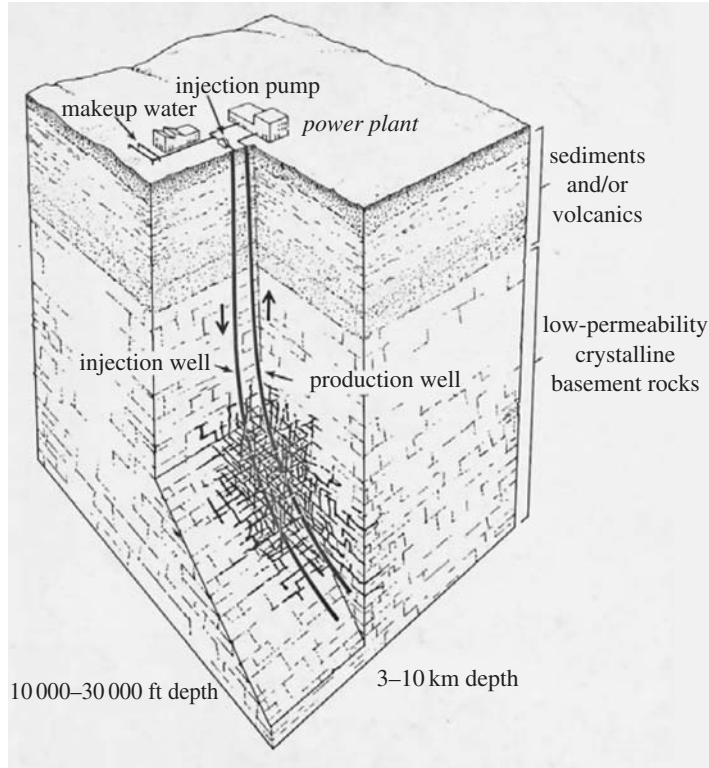
Figure 1. Schematic of a conceptual two-well enhanced geothermal system in hot rock, in a low-permeability crystalline basement formation.

Table 1. Estimated US geothermal resource base to 10 km depth by category.

category of resource	thermal energy, in exajoules (1 EJ=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[a]	74 100	USGS circular 790
hydrothermal	2400–9600	USGS circulars 726 and 790
coproduced fluids	0.0944–0.4510	McKenna *et al.* (2005)
geopressured systems	71 000–170 000[b]	USGS circulars 726 and 790

[a]Excludes Yellowstone National Park and Hawaii. [b]Includes methane content.

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 product 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. Owing to 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.
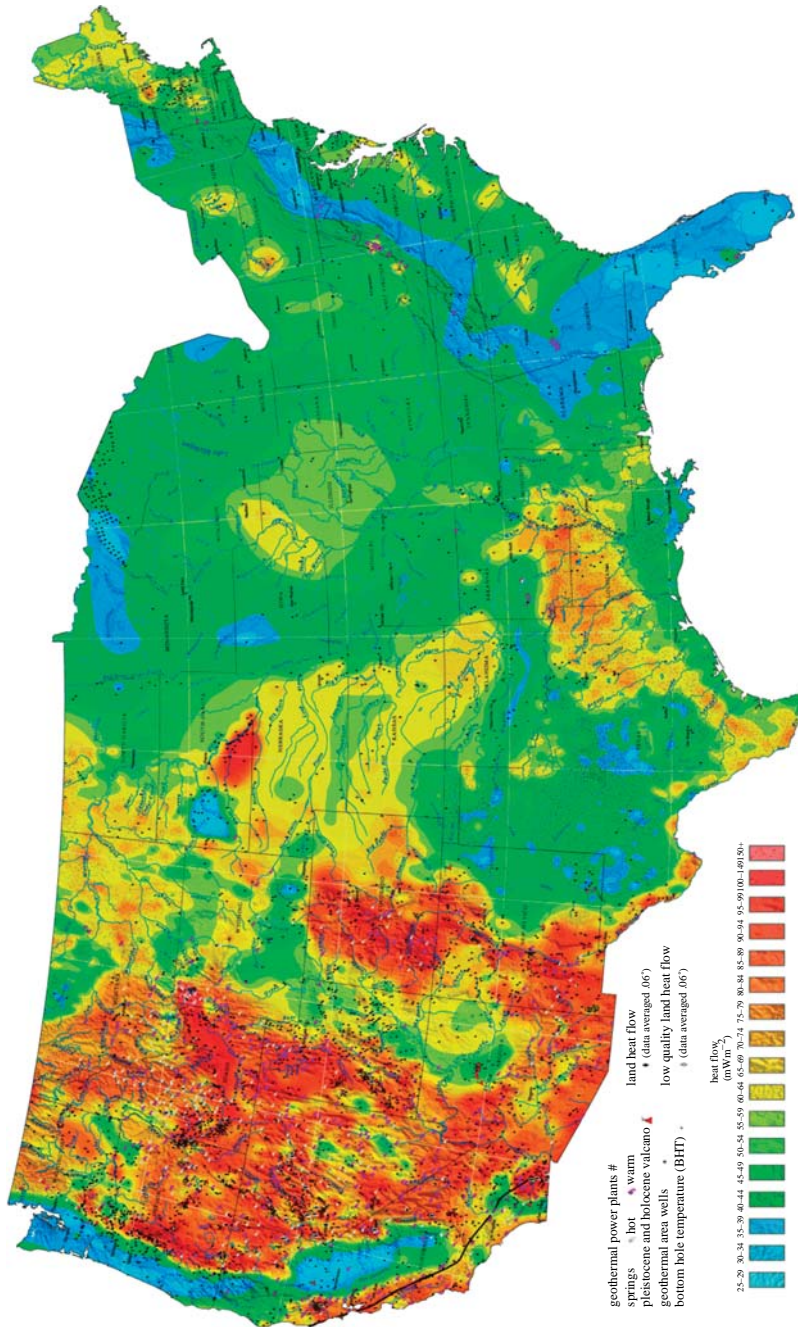
Figure 2. Regional heat-flow map of the conterminous United States, a subset of the geothermal map of North America (Blackwell & Richards 2004). The coloured scale ranges from 25 (blue) to 150+ (red) mW m^{-2} heat-flow units.
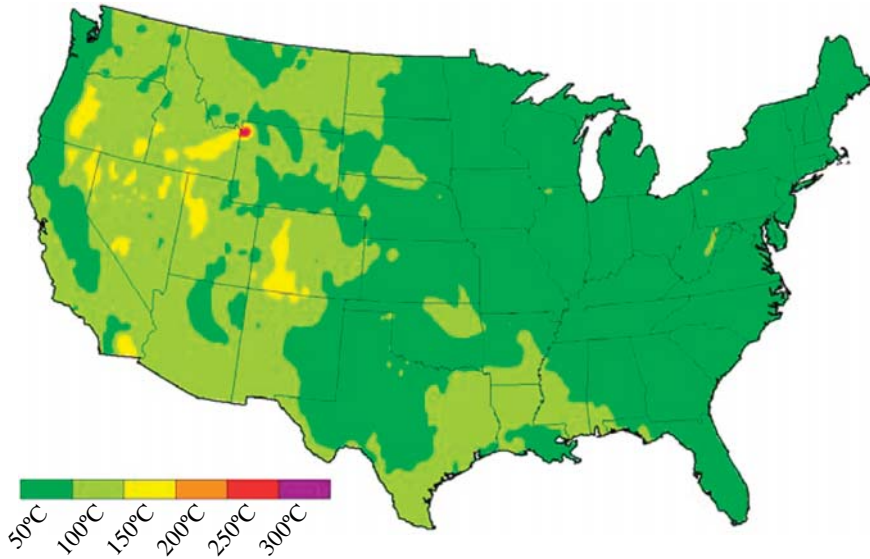
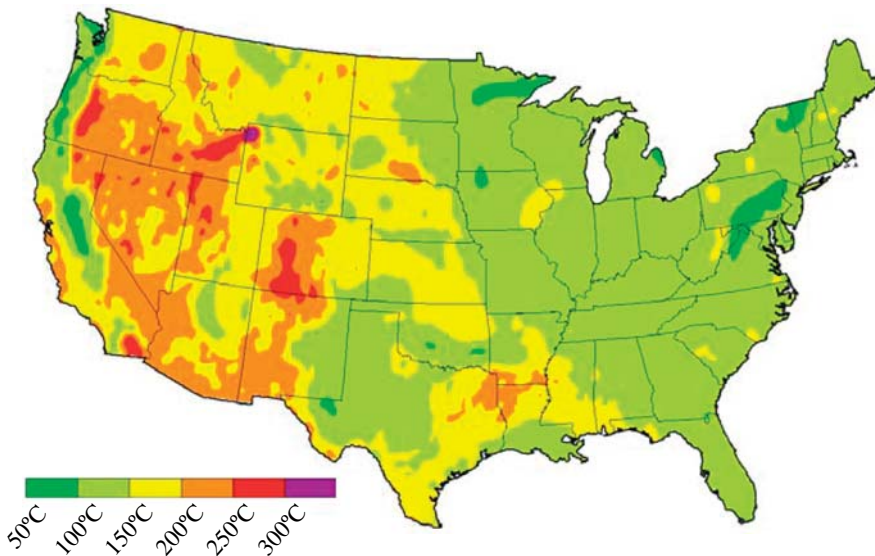Figure 3. Temperatures at a depth of 3.5 km.

Figure 4. Temperatures at a depth of 6.5 km.

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 of Tester *et al.* (2006) for details).

The US DOE 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). 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.

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 (Bodvarsson & Hanson 1977; Tester & Smith 1977). Other approaches for heat extraction employing downhole heat exchangers or pumps, or alternating injection and production (huff–puff) methods, have also been proposed.

6. US geothermal resource base

The last published comprehensive study of geothermal energy by the US 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 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 (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).

While this paper uses SI units with energy expressed in exajoules (EJs), these are relatively unfamiliar to most people. Appendix A 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 the hydrothermal resource base or 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. SMU has developed a quantitative model for refining estimates of the EGS resource in sedimentary and basement rocks. While the full report (Tester *et al.* 2006) details their methodology and calculations in Chapter 2, here we present only salient results regarding the magnitude and distribution of the US EGS resource.

Figure 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 3–5 show 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 3 and the corresponding discussion). Figure 6 shows the amount of energy in each slice as a function of temperature at depths up 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 the initial rock temperature and the depth). Higher grades would correspond to hotter, shallower resources.

The total resource base to a depth of 10 km can also be estimated. Values are tabulated in table 1. By almost any criterion, the accessible US 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 resources. For example, very high thermal gradients often exist at the margins of hydrothermal fields. Since wells there would be shallower (less than 4 km) and hotter (greater than 200°C) with infrastructure for power
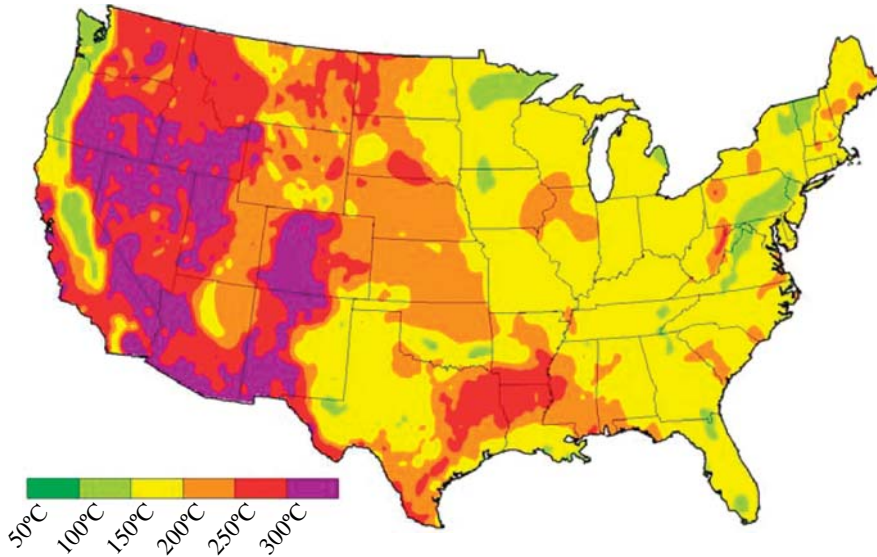
Figure 5. Temperatures at a depth of 10 km.

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 150–200°C; for many space or process-heating applications, much lower temperatures would be acceptable, such as 100–150°C.

Although beyond the scope of this assessment, it is important to point out that even at temperatures below 50°C, the 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 US 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. 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 favourable. In the existing vapour- 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
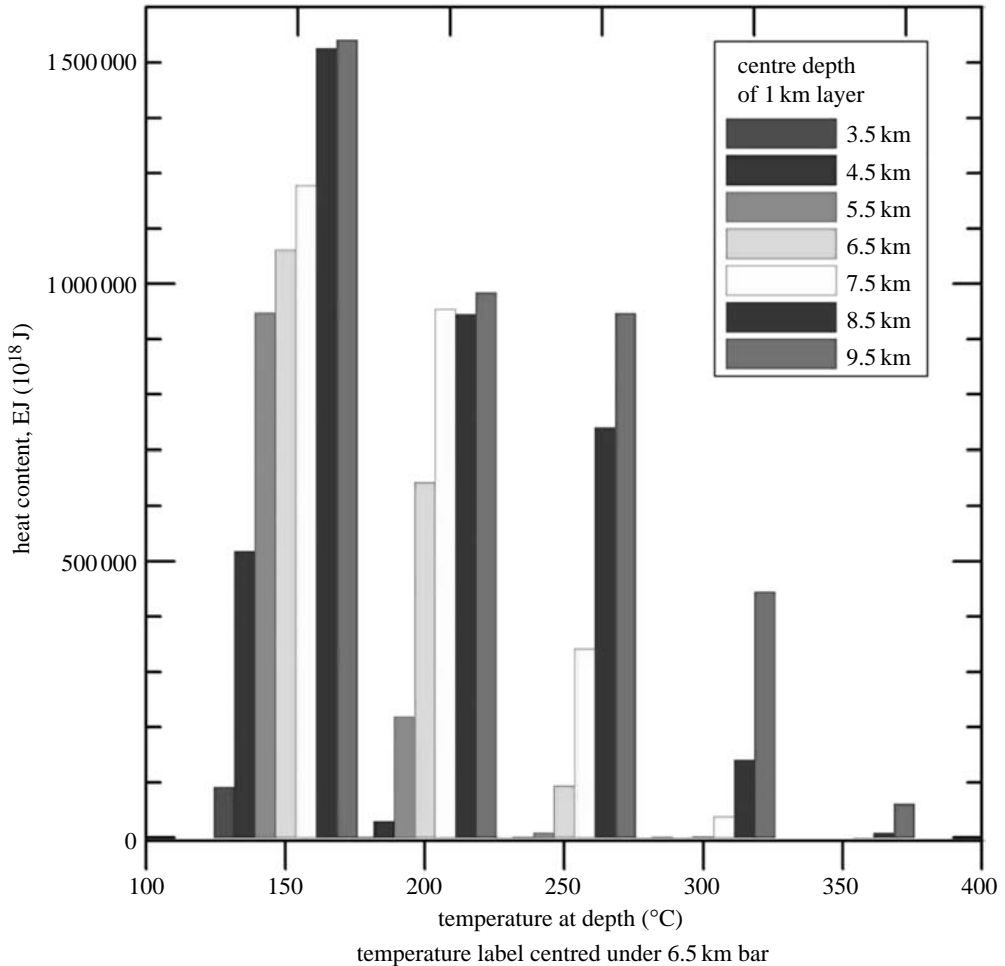
Figure 6. Histograms of heat content as thermal energy, as a function of depth for 1 km slices. For each temperature indicated, the total thermal energy content contained in a 1 km thick slice over the entire US area is plotted.

that influence the probability of creating suitable inter-well connectivity include natural fracture spacing, rock strength and competence.

7. 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 energy 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 modelled flow in fractured reservoirs using specified geometries to determine the sensitivity of the calculated recoverable heat
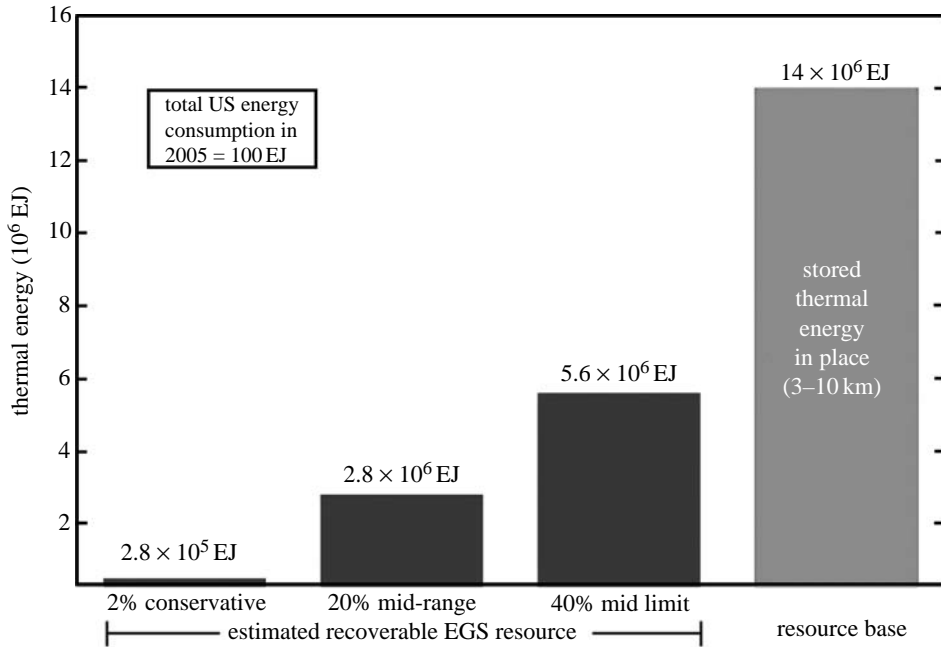
Figure 7. Estimated total geothermal resource base and recoverable resource given in EJ or 10^{18} J. Note: other energy equivalent units can be obtained using conversion factors given in appendix A.

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 $1 \times 10^8 \, \text{m}^3$ (0.1 km^3) under economic production conditions is nearly constant at approximately $40 \pm 7\%$. Furthermore, this recovery factor is independent of well arrangements, fracture spacing and permeability, as long as the stimulated volume exceeds $1 \times 10^8 \, \text{m}^3$, a value significantly below what has been already achieved in several field projects.

The Sanyal–Butler model was used as a starting point to estimate EGS resource recovery. Channelling, 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, the 40% recovery factor estimated by Sanyal and Butler was lowered to 20 and 2% to account for these effects, and reservoir spacings 1 km deep 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 use the surface temperature as the reference temperature to calculate the total thermal energy content. A much smaller

Table 2. Estimated land area and subsurface reservoir volumes needed for EGS development. (Note: above 100 MWe, reservoir size scaling should be linear.)

plant size in MWe[a]	surface area for power plant[b] 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

[a]Assuming 10% heat to electric-power efficiency, typical of binary plants. [b]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.

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 kWs in a given 1 km slice per unit 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 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, 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 MWe basis for the surface plant and auxiliaries, and for the subsurface reservoir in table 2.

8. 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 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 2800 m (9000 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 (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.

Owing to the limited data available for geothermal drilling, our analysis employed the Wellcost Lite model, developed by Bill Livesay and co-workers 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 1500 m (4920 ft) to 10 000 m (32 800 ft) were modelled in three categories: shallow wells (1500–3000 m); mid-range wells (4000–5000 m); and deep wells (6000–10 000 m).

EGS well costs are significantly influenced by the number of casing strings used. For example, two 5000 m deep wells were modelled, 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 6000 m well was modelled with both five and six casing intervals. Costs for the 7500 and 10 000 m wells were estimated using six casing intervals.

Shallow wells at depths of 1500, 2500 and 3000 m are representative of the current hydrothermal practice. Predicted costs from the Wellcost Lite model were compared with actual EGS and hydrothermal well-drilling cost records, where available. Figure 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.

Nonetheless, given the scarcity of the geothermal well cost data when compared with oil and gas wells, estimating statistically meaningful well costs at particular depths was not possible, hence average costs were based on model predictions with a large degree of inherent uncertainty. Well-design concepts and predictions for the deeper categories—6000, 7500 and 10 000 m (19 680, 24 600 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. Owing to 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 4000 m and deeper. One technology that will potentially reduce the cost of the well
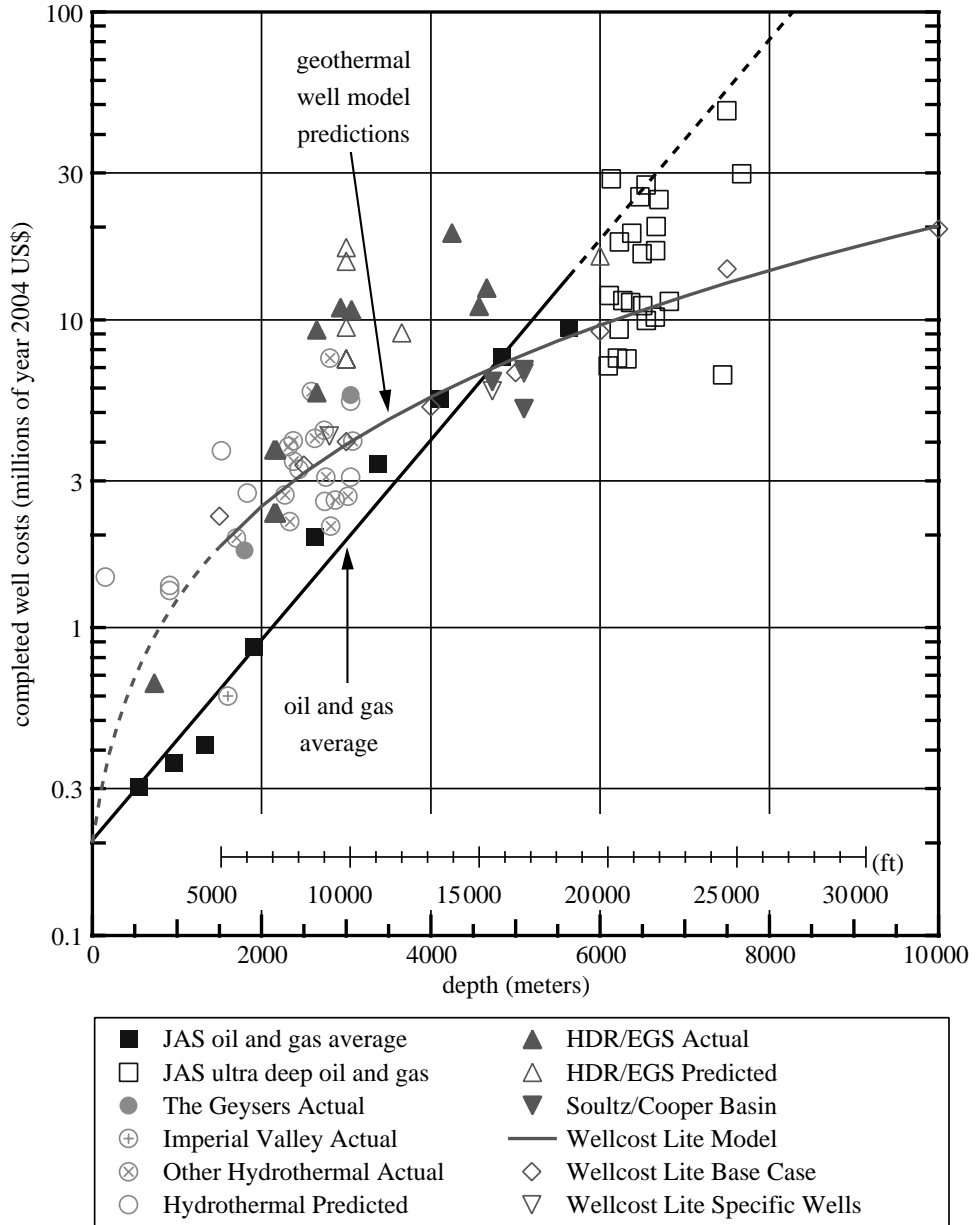
Figure 8. Completed oil, gas and geothermal well costs as a function of depth in 2004 US$, including estimated costs from the Wellcost Lite model. The grey line provides average well costs for the base case used in the assessment.

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 15–20% 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–$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 & Tester 1998), chemically enhanced drilling (Polizzotti *et al.* 2003) and metal shot abrasive-assisted drilling (Curlett & 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.

9. EGS reservoir stimulation—status of international field-testing and design issues

Creating an EGS 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 and 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 or HDR). 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 programme.

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 non-commercial 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, HDR began at the Los Alamos National Laboratory in 1974 (Armstead & Tester 1987). For low-permeability formations, the initial concept is rather 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 & 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^{-1} 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, and
— 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.

(i) Primary goals for commercial feasibility.
    — Develop and validate methods to achieve a two- 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 US sites.
(ii) 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.

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 behaviour 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, earlier 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 & Azaroual (2006) estimated reservoir performance using supercritical carbon dioxide in place of water. Early modelling 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 programme and anticipated market price increases for electric power, the technology developed in this programme 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.
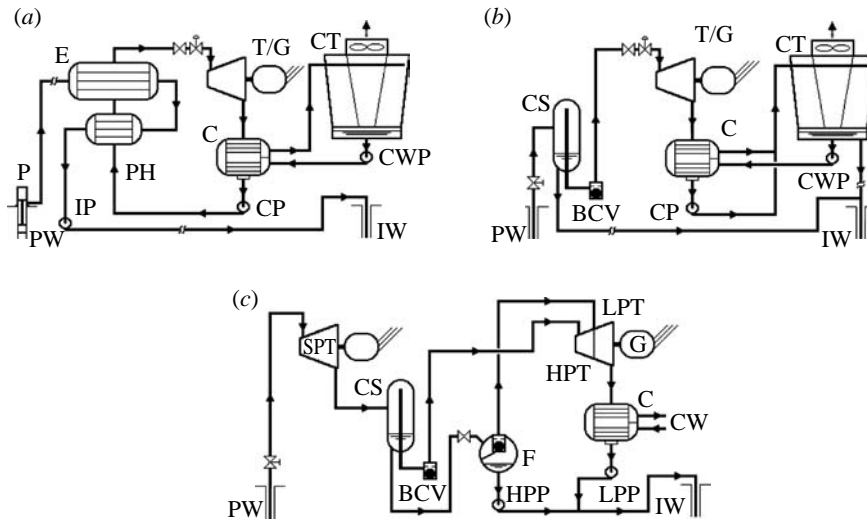
Figure 9. Schematics of EGS power-conversion systems: (*a*) a basic binary power plant; (*b*) a single-flash power plant; (*c*) a triple-expansion power plant for supercritical EGS fluids. Abbreviations: BCV, ball check valve; C, condenser; CP, condensate pump; CS, cyclone separator; CT, cooling tower; CW, cooling water; CWP, cooling water pump; E, evaporator; F, flash vessel; G, generator; HPP, high-pressure pump; HPT, high-pressure turbine; IW, injection well; LPP, low-pressure pump; LPT, low-pressure turbine; P, pump; PH, preheater; PW, production well; SPT, super-pressure turbine; T/G, turbine/generator.

10. 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 MWe 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 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 approximately 100 000 MW worldwide.

There are inherent limitations on converting geothermal energy to electricity, owing to the lower temperature of geothermal fluids in comparison with 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 magnitude of the availability determines the maximum amount of electrical power that could be produced for a given flow
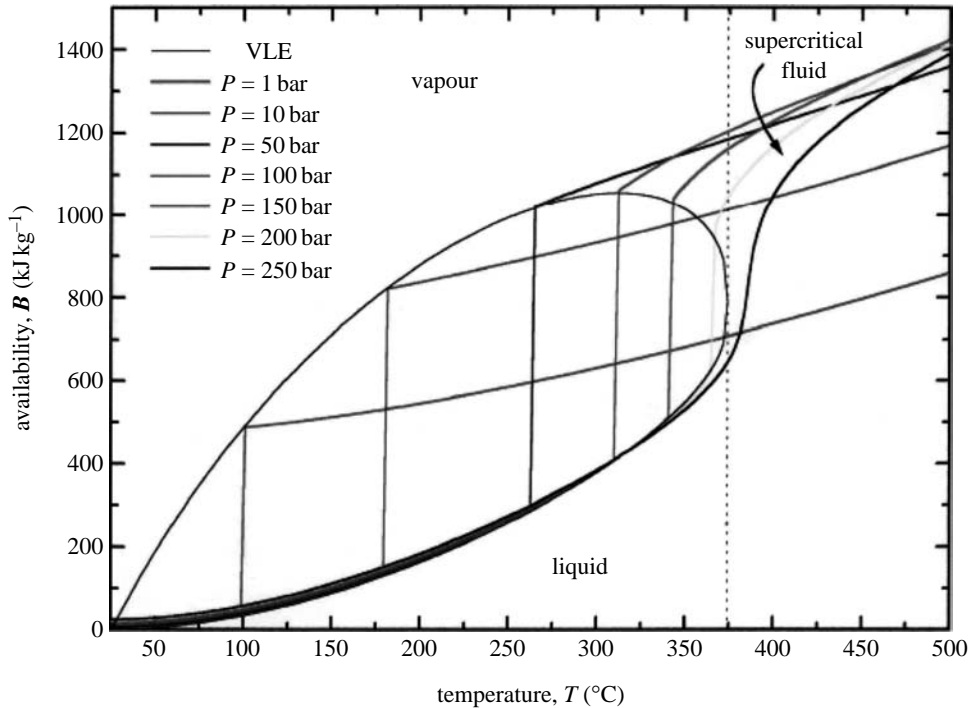
Figure 10. Availability diagram for water. The magnitude of the availability is a direct measure of the maximum electrical work- or power-producing potential of aqueous-produced geofluid at specific-state conditions of temperature and pressure.

rate of produced geofluid, given a specified temperature and density or pressure. Figure 10 shows 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.

The large capital investment 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.

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

Each case in (i)–(iii) involved the following steps, using standard methods of engineering design and analysis:

(i) identification of the most appropriate conversion system,
(ii) calculation of the net power per unit mass flow of geofluid,
(iii) calculation of mass flow required for 1, 10, and 50 MW plants, and
(iv) 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.
— 6000–11 000 MWe 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 $2300 kWe^{-1} for 100°C resource temperatures to $1500 kWe^{-1} 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.

11. Environmental attributes of EGS

When examining the complete 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 with 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 sulphur oxides or particulate matter resulting from its use, and there is no need to dispose of radioactive materials. However, still there 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 towards 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 sulphide (H_2S), ammonia (NH_3) and other chemical emissions.

12. Economic feasibility issues for EGS

This section highlights the role that EGS can play in supplying base-load and distributed electricity in evolving US energy markets. Important factors that favour 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.

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:

  (i) exploration, and drilling of test and production wells,
 (ii) construction of power-conversion facilities, and
(iii) discounted future redrilling and well stimulation.

Estimated levelized costs (LEC) or break-even prices were used as a basis for comparing EGS projections to existing and new energy-supply technologies. The methodology used for the supply curves was analysed 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.

Table 3. Levelized electricity cost (LEC) for six selected EGS sites for development.

site name	average gradient $\partial T/\partial z$ (°C km^{-1}) to well depth	depth to granite (km)	well depth (km)	hydraulic stimulation costs ($K) for fluid injection rates		base-case initial values 20 kg s^{-1} production rate LEC (¢ kWh^{-1})		base-case mature technology 80 kg s^{-1} production rate LEC (¢ kWh^{-1})		
				93 L s^{-1}	180 L s^{-1}	MIT EGS	GETEM	MIT EGS	GETEM	depth (km)
E. Texas Basin, TX	40	5	5	145	171	29.5	21.7	6.2	5.8	7.1
Nampa, ID	43	4.5	5	260	356	24.5	19.5	5.9	5.5	6.6
Sisters area, OR	50	3.5	5	348	450	17.5	15.7	5.2	4.9	5.1
Poplar Dome a, MT	55	4	2.2	152	179	74.7	104.9	5.9	4.1	4.0
Poplar Dome b, MT	37	4	6.5	152	179	26.9	22.3	5.9	4.1	4.0
Clear Lake, CA	76	3	5	450	491	10.3	12.7	3.5	4.1	5.1
Conway Granite, NH	24	0	7	502	580	68.0	34.0	8.5	8.3	10[a]

[a]10 km limit put on drilling depth—MIT EGS LEC reaches 7.3 ¢ kWh^{-1} at 12.7 km and 350°C geofluid temperature.
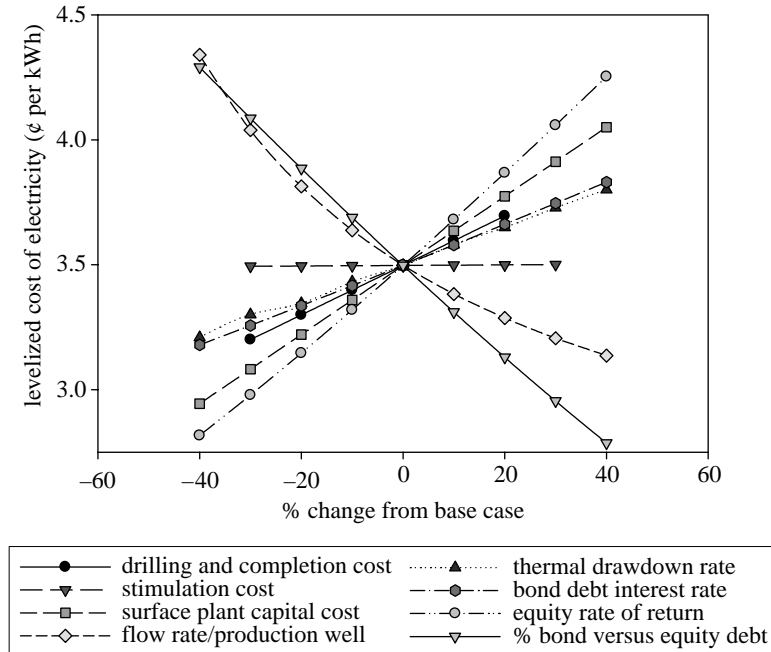
Figure 11. Sensitivity for mature technology at a representative high-grade EGS site: 80 kg s^{-1} flow rate per production well in a quartet configuration (one injector: three producers) for the Clear Lake (Kelseyville, CA) scenario showing levelized cost of electricity. (MIT EGS economic model results shown.)

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 the models (see table 3), and explored the effects of sensitivity to uncertain parameters, as shown in figures 11 and 12.

We assumed a 6-year nominal lifetime period for each stimulated reservoir, which led to a complete redrilling and restimulation of the system in 6-year intervals for the lifetime of the surface plant facilities, typically 20–30 years. Other important factors affecting the LEC include equity and debt interest rates for invested capital, well-drilling costs, surface plant costs and reservoir flow rate per production well. Table 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 20–80 kg s^{-1} per well for the two base cases shown.

Figure 13 shows a predicted aggregate supply curve for the US EGS resource, regardless of the 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
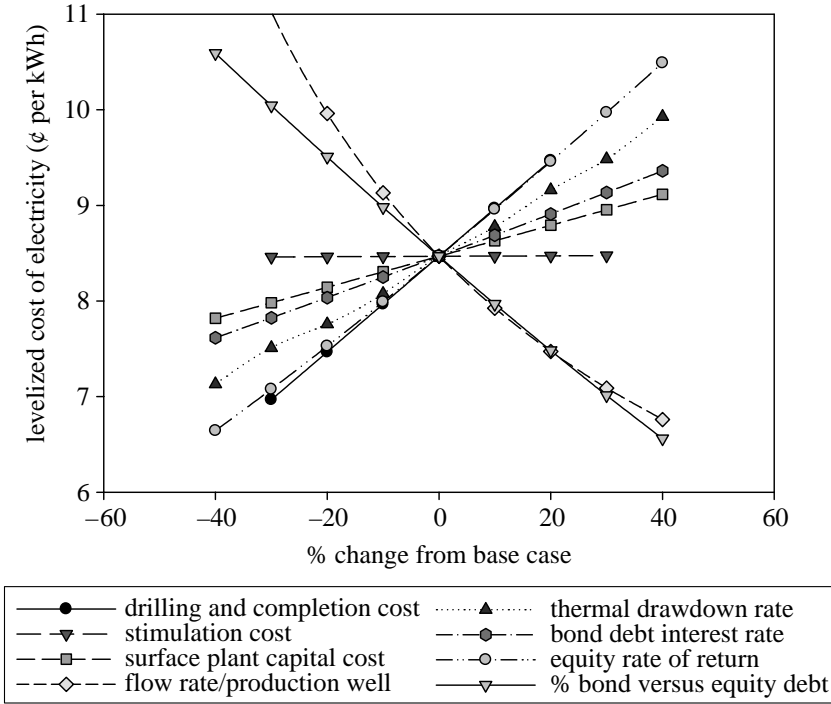
Figure 12. Sensitivity for mature technology at a representative low-grade EGS site: 80 kg s^{-1} flow rate per production well in a quartet configuration (one injector: three producers) for the Conway, NH, scenario showing levelized cost of electricity (LEC). (MIT EGS economic model results shown.)
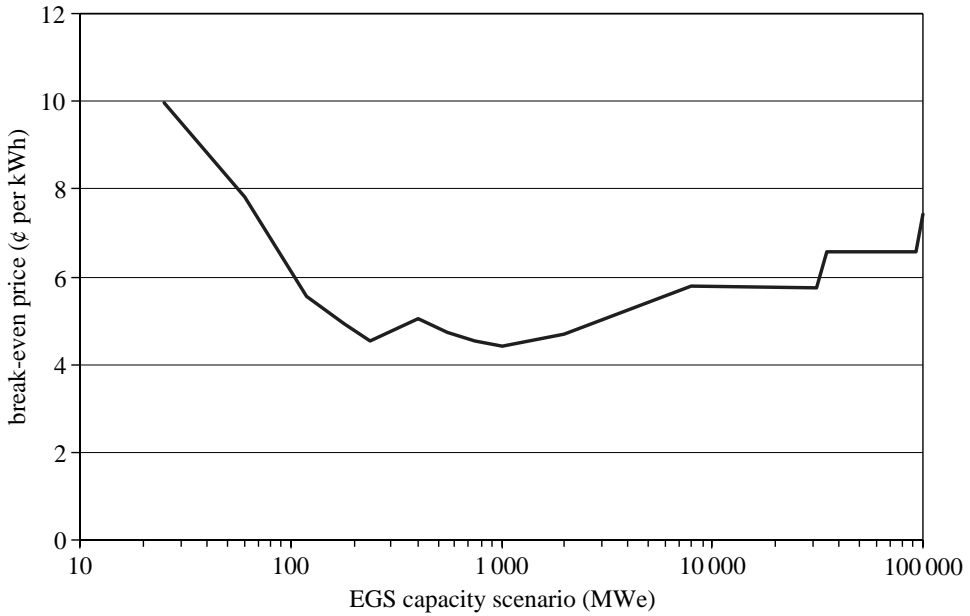

Figure 13. Aggregate supply using MIT EGS, variable rate of return (VRR) model with quartet well configurations and a maximum flow per well of 80 kg s^{-1}.
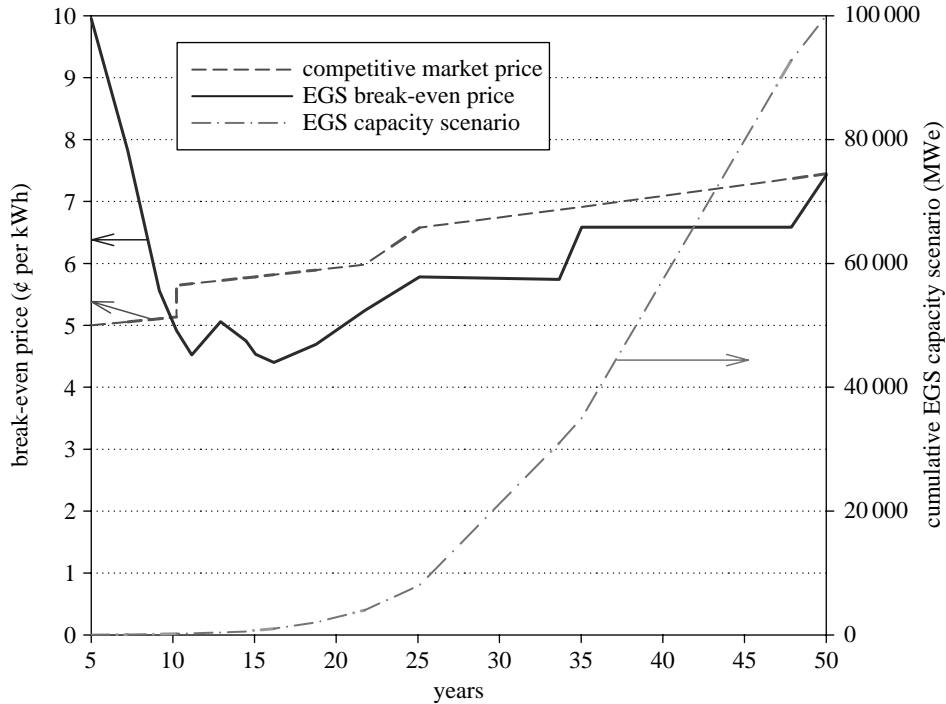
Figure 14. Levelized electricity costs (LEC) and capacity growth using the MIT EGS model for the 100 000 MW, 50-year scenario and variable debt and equity rates (VRR). Flow rate per production well (in a quartet configuration, one injector and three producers) follows the 80 kg s^{-1} learning curve. Thermal drawdown is 3% per year resulting in complete redrilling and restimulation of the system, with a vertical spacing between stacked reservoirs of 1 km after approximately 6 years of operation. Resulting absorbed technology deployment costs are \$216 million (US 2004).

EGS increases above 100 MWe 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 6). The slight increase in break-even price that occurs at higher levels of penetration (above 5000 MWe) 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.

Next, we analysed 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 US sites as part of a focused national initiative. Figures 14–16 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 14, this corresponds
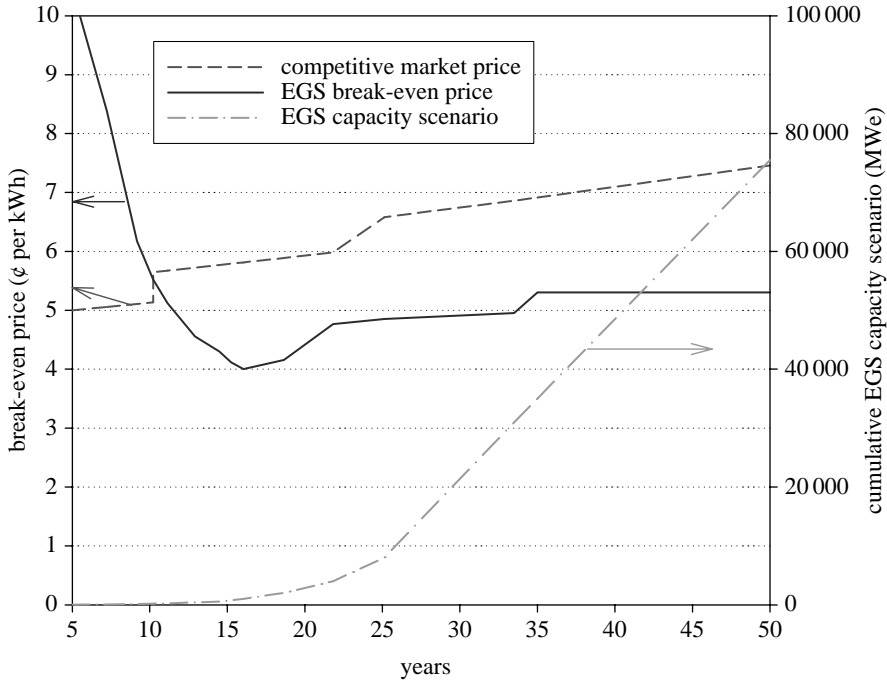
Figure 15. Levelized electricity costs (LEC) and capacity growth using the MIT EGS model for the
100 000 MW, 50-year scenario and a fixed-charge rate of 12.8% per the NEMS model. Flow rate per
production well (in a quartet configuration, one injector and three producers) follows the 80 kg s^{-1}
learning curve. Thermal drawdown is 3% per year resulting in complete redrilling and restimulation of
the system, with a vertical spacing between stacked reservoirs of 1 km after approximately 6 years of
operation. Resulting absorbed technology deployment costs are $262 million (US 2004).

to the period from 0 to approximately 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.

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, agricultural irrigation and capacity losses
in dammed areas. In the case of coal-fired electricity, increased bus-bar costs are
predicted as a 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
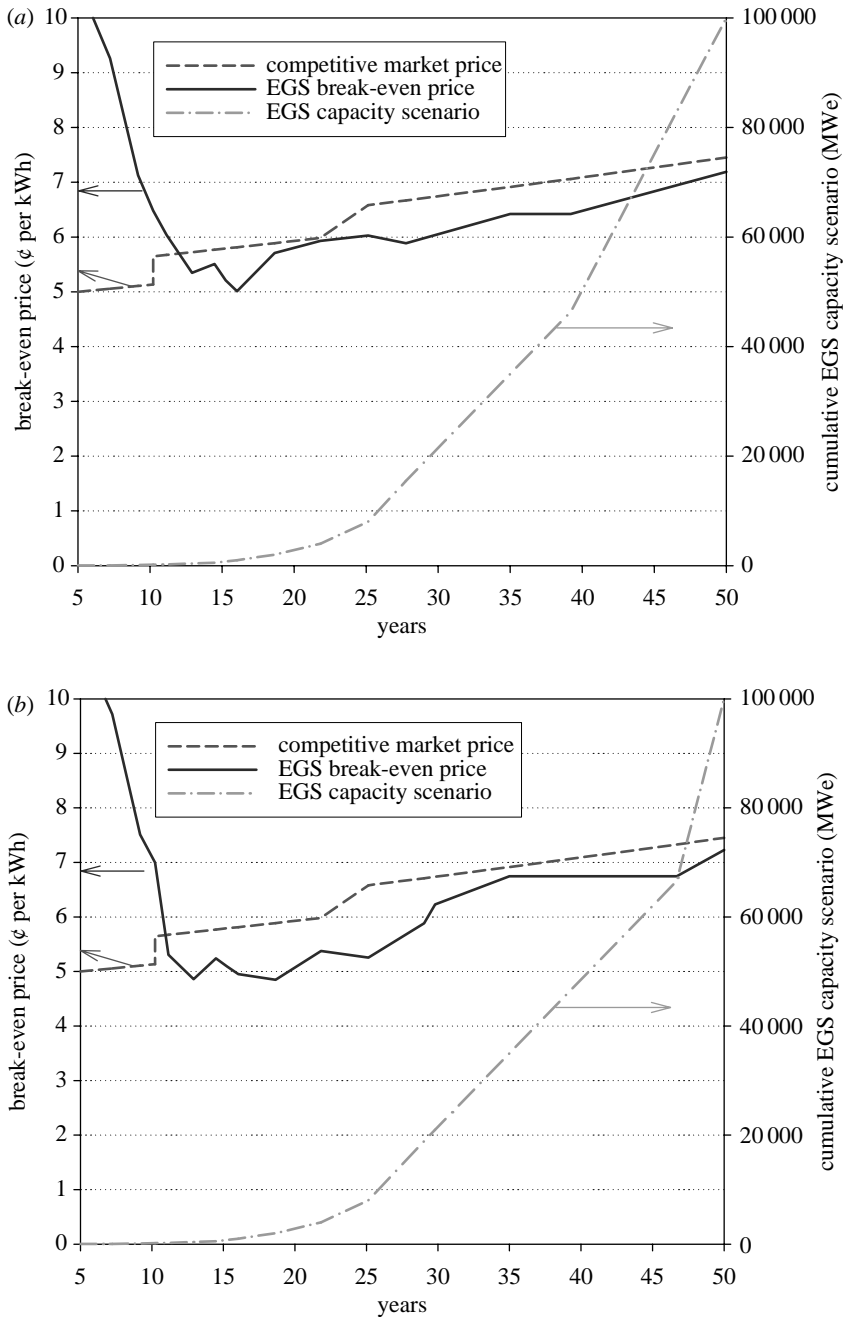retirement of the existing power reactors and difficulties in siting and developing

Figure 16. Levelized electricity costs (LEC) and capacity growth 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, one injector and two producers) follows the 60 kg s^{-1} learning curve. Thermal drawdown is 3% per year resulting in complete redrilling and restimulation of the system, with a vertical spacing between stacked reservoirs of 1 km after approximately 6 years of operation. Resulting absorbed technology deployment costs are (*a*) $368 million and (*b*) $394 million (US 2004).

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 US 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 US portfolio will reduce growth in natural gas consumption and slow the need for adding expensive natural gas facilities to handle imported liquefied natural gas.

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 US 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 the gap between demand for and generation of electricity will most affect the existing system capacity.

13. Conclusions

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 GWe 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 favoured the growth of US geothermal capacity from conventional high-grade hydrothermal resources. Owing to the 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. Owing to this lack of support, EGS technology development and demonstration has recently 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 barrier or limitation to the technology. In fact, we found that significant progress has been achieved in recent tests carried out at Soultz, France, under European Union 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 2–3 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 programme is supported properly. Specific findings include the following.

(i) 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 and hydropower, in a lower-carbon energy future. In the shorter term, having a significant portion of the US 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.

(ii) 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 2000 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.

(iii) 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.

(iv) 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.

(v) 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 production rates per well without reducing the reservoir life by rapid cooling. US 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 favourable climate, the situation is different for EGS. There are now seven companies in Australia actively pursuing EGS projects and two commercial projects in Europe.

(vi) 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 increase 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.

(vii) EGS systems are versatile, inherently modular and scalable from 1 to 50 MWe for distributed applications to large 'power parks', which could provide thousands of MWe 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.

(viii) 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 MWe of new generating capacity with standard binary-cycle technology, and increase hydrocarbon production by partially offsetting parasitic losses consumed during production.

(ix) A cumulative capacity of more than 100 000 MWe 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.

Since the field-demonstration programme 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–$400 million investment over 15 years will be needed to make early generation EGS power plant installations competitive in evolving US 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 approximately $800 million to $1 billion over a 15-year period, EGS technology could be deployed commercially on a time-scale that would produce more than 100 000 MWe or 100 GWe 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.

Table 4. Energy conversion factors. (Source: 'Sustainable energy: choosing among options', Massachusetts Institute of Technology (2005). Key: MWy, megawatt-year; bbls, barrels $=42$ US gallons; tonnes, metric tons $=1000$ kg $=2204.6$ lb; MCF, thousand cubic feet; EJ, exajoule $=10^{18}$ J. Nominal calorific values assumed for coal, oil and gas. Note: to convert from the first-column units to other units, multiply by the factors shown in the appropriate row (e.g. 1 Btu $=252$ cal).)

	Btus	quads	calories	kWh	MWy
Btus	1	10^{-15}	252	2.93×10^{-4}	3.35×10^{-11}
quads	10^{15}	1	2.52×10^{17}	2.93×10^{11}	3.35×10^{4}
calories	3.97×10^{-3}	3.97×10^{-18}	1	1.16×10^{-6}	1.33×10^{-13}
kWh	3412	3.41×10^{-12}	8.60×10^{5}	1	1.14×10^{-7}
MWy	2.99×10^{10}	2.99×10^{-5}	7.53×10^{12}	8.76×10^{6}	1
bbls oil	5.50×10^{6}	5.50×10^{-9}	1.38×10^{9}	1612	1.84×10^{-4}
tonnes oil	4.04×10^{7}	4.04×10^{-8}	1.02×10^{10}	1.18×10^{4}	1.35×10^{-3}
kg coal	2.78×10^{4}	2.78×10^{-11}	7×10^{6}	8.14	9.29×10^{-7}
tonnes coal	2.78×10^{7}	2.78×10^{-8}	7×10^{9}	8139	9.29×10^{-4}
MCF gas	10^{6}	10^{-9}	2.52×10^{8}	293	3.35×10^{-5}
joules	9.48×10^{-4}	9.48×10^{-19}	0.239	2.78×10^{-7}	3.17×10^{-14}
EJ	9.48×10^{14}	0.948	2.39×10^{17}	2.78×10^{11}	3.17×10^{4}

	bbls oil equiv.	tonnes oil equiv.	kg coal equiv.	tonnes coal equiv.	MCF gas equiv.	joules	EJ
Btus	1.82×10^{-7}	2.48×10^{-8}	3.6×10^{-5}	3.6×10^{-8}	10^{-6}	1055	1.06×10^{-15}
quads	1.82×10^{8}	2.48×10^{7}	3.6×10^{10}	3.6×10^{7}	10^{9}	1.06×10^{18}	1.06
calories	7.21×10^{-10}	9.82×10^{-11}	1.43×10^{-7}	1.43×10^{-10}	$3.97\ \text{x}10^{-9}$	4.19	4.19×10^{-18}
kWh	6.20×10^{-4}	8.45×10^{-5}	0.123	1.23×10^{-4}	3.41×10^{-3}	3.6×10^{6}	3.6×10^{-12}
MWy	5435	740	1.08×10^{6}	1076	2.99×10^{4}	3.15×10^{13}	3.15×10^{-5}
bbls oil	1	0.136	198	0.198	5.50	5.80×10^{9}	5.80×10^{-9}
tonnes oil	7.35	1	1455	1.45	40.4	4.26×10^{10}	4.26×10^{-8}
kg coal	5.05×10^{-3}	6.88×10^{-4}	1	0.001	0.0278	2.93×10^{7}	2.93×10^{-11}
tonnes coal	5.05	0.688	1000	1	27.8	2.93×10^{10}	2.93×10^{-8}
MCF gas	0.182	0.0248	36	0.036	1	1.06×10^{9}	1.06×10^{-9}
joules	1.72×10^{-10}	2.35×10^{-11}	3.41×10^{-8}	3.41×10^{-11}	9.48×10^{-10}	1	10^{-18}
EJ	1.72×10^{8}	2.35×10^{7}	3.41×10^{10}	3.41×10^{7}	9.48×10^{8}	10^{18}	1

Appendix A. Energy conversion factors

Table 4 summarizes some relevant energy conversion factors.

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