CHAPTER 5

Subsurface System Design Issues and Approaches

5.1 Scope and Approach: EGS vs. Hydrothermal Reservoirs

Geothermal electric power and heat production from hydrothermal resources has been commercialized since 1904, leading to a large body of experience on what constitutes a good hot-water resource. In terms of thermal energy, a kilogram of hot water at temperatures of 150°C to 300°C has a low energy content compared to a kilogram of hydrocarbon liquid. This occurs because only the sensible and latent enthalpy of the geofluid can be used, rather than the stored chemical energy released during combustion of a hydrocarbon fuel. Therefore, for a producing geothermal well to be comparable in energy content to an oil well, high mass flow rates of hot water are needed. Typically, 50 to 150 kg/s or more per production well, depending on its temperature, are required to make a geothermal project economical. Resource temperature and flow per well are the primary factors in defining the economics of a geothermal resource. The increasing cost of drilling deeper wells trades off against the increased thermodynamic efficiency of higher temperature. Eventually, an Enhanced Geothermal System (EGS) will reach an optimum depth after which drilling deeper wells will not be more economical. However, studies by Tester and Herzog (1991) have shown that the optimal depth for minimum costs is on a fairly flat cost-versus-depth surface for most geothermal gradients. The insensitivity of project cost to depth, in the neighborhood of the optimal point, permits a range of economically acceptable depths.

Hydrothermal projects are based on resources with naturally high well productivity and high temperatures. They rely on having high flow per well to compensate for the capital cost of drilling and completing the system at depth, and they need very high permeability to meet required production and injection flow rates. Typically, in a successful hydrothermal reservoir, wells produce 5 MW or more of net electric power through a combination of temperature and flow rate (see Chapter 7). For instance, a well in a shallow hydrothermal reservoir producing water at 150°C would need to flow at about 125 kg/s (2,000 gpm) to generate about 4.7 MW of net electric power to the grid. Thus, as a starting target for EGS, we assume that the fluid temperature and production flow-rate ranges will need to emulate those in existing hydrothermal systems.

5.2 Formation Characteristics – Porosity, Permeability, Fracture Distribution, Density and Orientation, and Connectivity

A number of resource-related properties – temperature gradient, natural porosity and permeability of the rock, rock physical properties, stresses in the rock, water stored in the rock, and susceptibility to seismicity – control the amount of the heat resource in the earth's crust that can be extracted. These factors, taken together, not only control the physical process of extracting the heat, but also ultimately play a major role in determining the economics of producing energy (see Chapter 9 for details).

In the example above, to determine the economics of the hydrothermal project, the well depth, the temperature, and the flow rate need to be defined. While it is clear that the flow rate of the fluid and its temperature control the rate of energy produced, it is not evident what controls the reservoir production rate. In a natural system, wells flow due to pressure drop at the well, caused either by density changes due to boiling or by downhole pumping. The amount of possible pressure drop is controlled by the natural permeability and other properties of the rock that make up the reservoir. The permeability, or ability to conduct water to the well, may result from cracks in the rock or from connected pore spaces; but, from whatever cause, in a hydrothermal system the permeability is high. While permeability is a property of the rock only (related to the interconnectedness and size of cracks or pores), the transmissivity, which includes the cross-sectional area that the fluid flows through on its way to the well, can be influenced by well design. Measured transmissivities in geothermal systems are very high (greater than 100 darcy-meters is common), compared to oil and gas reservoirs with transmissivities often around 100 millidarcy-meters.

In an EGS system, the natural permeability is enhanced – or created when none exists – through stimulation. Stimulation can be hydraulic, through injecting fluids with or without controlling the viscosity at higher or lower rates and pressures; or chemical, by injecting acids or other chemicals that will remove the rock or the material filling the fractures. The stresses on the rocks and the elastic and thermal properties of the rocks in the potential reservoir, along with the design of the stimulation, control the extent of the enhanced or created fractures and their ultimate transmissivity. The natural rock properties and stresses on the rocks then become metrics for the formation of an EGS reservoir.

The economics of hydrothermal systems let us know that we need to target very high flow rates. High flow rates are only possible if the reservoir has high transmissivity. However, high transmissivity can come from a single fracture with a large aperture, or from a large number of fractures with small apertures. We could have both high flow rates and low pressure drop, if a large number of fractures with small fracture apertures gave high transmissivity.

We need to understand how the type of rocks, the stresses on those rocks, and the design of the stimulation interact to develop a connected fracture system. Rocks that are critically stressed to the point where they will fail, shear, and movement during stimulation should produce fractures that will stay open and allow for fluid circulation. Rocks with at least some connected permeability through either fractures or pore spaces are more likely to result in a connected circulation system after stimulation. If there is some significant porosity in the rocks before stimulation, there will be some water stored in the reservoir for future production. Taken together, all of these metrics define the outcome of stimulation and, thus, the economics of the project.

The fracture system not only needs to be connected and have high transmissivity, but it also must allow injected cool water to have sufficient residence time to contact the hot rock, so that it will be produced from the production wells at or close to the formation temperature. The amount of temperature drop in the production fluid that can be tolerated by different power plant equipment then will determine the life of that part of the reservoir for a particular conversion technology. Under given flow conditions, the longer the life of the reservoir, the better the economics.

At the best sites for developing a reservoir, the rocks will be stressed so that when they are stimulated, open fractures will be created. However, if there is too much pre-existing permeability or if the stimulation produces a preferred pathway of very open cracks that the injected fluid can take to the production wells, the created or enhanced fractures may allow water to move too quickly, or short circuit, from the injection wells to the production wells without heating up enough to be economic.

While permeability of a fractured reservoir can be improved by increasing the injection pressure, there are two negative effects of increasing the throughput in this way: (i) fractures at higher pressures may be "jacked" open, allowing a few paths to dominate and short circuits to occur, and (ii) the critical pressure beyond which fracture growth occurs may be exceeded, extending the reservoir, allowing water to be lost to noncirculating parts of the reservoir and reducing the proportion of effective heat-transfer area.

At Fenton Hill, high-injection pressures were used to maintain open fractures and improve permeability (Brown, 1988) However, the fractured volume continued to grow, water was lost from the circulating system, and new fractured volume was created that was not accessed by the wells. At Rosemanowes, trying to improve fracture permeability by increasing injection pressures resulted in growth of the fracture system but away from the inter-well region, exacerbating the water loss without improving the connectivity (see Figure 5.1).

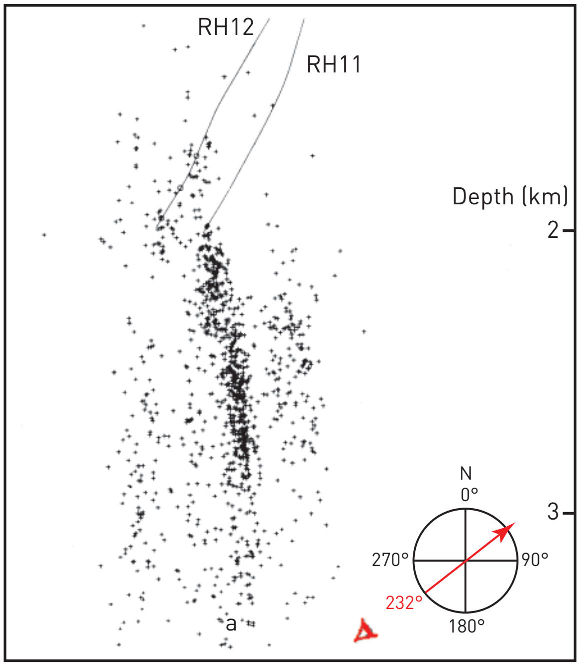

Figure 5.1 Vertical section viewed from the southwest showing downward growth of fractures (microseismic events) at Rosemanowes (Pine and Batchelor, 1983).

5.3 Rock-Fluid Interactions

One of the big risk areas in the long-term operation of an EGS system is the potential change in the permeability and connectivity of the stimulated reservoir with time. The fluid injected may be a combination of water from surface or shallow ground water and water naturally occurring in the geothermal reservoir. It will be cooled by the energy conversion system. As a result, the circulated water will not be in equilibrium with the minerals in the rock. With time, these minerals may dissolve or minerals dissolved in the water may precipitate, changing the permeability of the rock over time. In enhanced oil-recovery projects, rock-fluid interactions have been of great importance over the life of the project in determining the project economics and the ultimate amount of oil that can be recovered. On the other hand, hydrothermal geothermal projects have dealt with some of the most severe geochemical conditions on Earth and found economic methods to control scale and corrosion.

Because geothermal companies are trying to operate a complex power-generation plant attached to an even more complex natural system – while solving ongoing problems – there are few data available in the literature about their efforts to deal with the geochemistry of geothermal fluids under production. Furthermore, in the competitive marketplace, solutions to such problems are usually deemed proprietary.

Government-sponsored research in this area has quickly been absorbed by the private sector and commercialized. For instance, calcium carbonate scale in geothermal production wells, surface equipment, and in the injection wells has been controlled very successfully by use of scale inhibitors such as polymaleic acid in very small quantities. Silica scale has been more difficult to deal with. Despite research leading to several potential silica-scale inhibitors, the least expensive method of controlling silica scale has been modification of pH. Acidification of the spent brine has worked to some extent, but it causes corrosion in surface equipment that then needs to be dealt with. Lowering pH probably also impacts the subsurface, but there is not much research on how the acidified fluid reacts with the rock in hydrothermal reservoirs. In some situations, high silica acidified fluids appear to reduce permeability of sedimentary geothermal reservoirs, perhaps by changing the cementation of the grains. In other projects using pH lowering to control silica scale, injectivity appears to have improved over time in wells receiving the acidified fluid.

At Hijiori, during the long-term flow test, boiling in the wellbore and in the reservoir caused high-pressure drop in the production wells that led to scale deposition and required that the wells be cleaned. At Rosemanowes, long-term circulation appeared to improve permeability in one fracture set, but it decreased heat-transfer area and residence time so that a short circuit might have developed.

Circulating fluid that is not in geochemical equilibrium with the rock forming the heat exchange system will have long-term impacts, both on the properties of the reservoir and on the economics of the project. Models exist to predict some aspects of rock-fluid interaction. However, no EGS system has operated long enough yet to test whether the predicted behavior is observed. This is one of the areas with greatest uncertainty for EGS feasibility. Ongoing laboratory studies should help shed light on this issue, but long-term testing will be needed in several different real reservoirs to verify laboratory-scale results.

5.4 Temperature Variation with Depth

The temperature gradient determines the depth of wells needed to reach specific temperatures (see also Chapter 2). Knowledge of the temperature is essential to determining the amount of heat in place and the conversion efficiency with which it can be used to generate power. The depth to the resource is a primary factor in determining the cost of the wells. To some extent, the extra cost of drilling deeper wells trades off against the benefit of reaching higher temperatures because higher temperatures result in higher conversion efficiency. Well-field cost in hydrothermal power projects generally accounts for about 25%-50% of the total project capital cost. EGS projects are associated with somewhat lower flow rates, lower conversion efficiencies (because of lower temperatures), and greater depths (required to encounter economic temperatures). These factors often bring the well-field cost up to more than 50% of the total cost of the project, at least in the early stages of project development.

5.5 Geology

Other factors affecting well cost include lithology, grain or crystal size, and degree of weathering. These influence the rate of penetration and the life of the drill bit, as well as the mechanical and thermal properties of the rock and, thus, the results of the stimulation. Other geologic factors influence hole stability, ease of maintaining directional control, and drilling fluid circulation loss.

However, drilling cost is not the only cost element of the EGS affected by rock properties. Rock, in general, does not make a very good heat exchanger. While rocks have a high heat capacity and can, therefore, store a large amount of thermal energy per unit of volume, they do not have very high thermal conductivities. This means that water we inject into our enhanced or created reservoir must reside in the fractures or pore spaces long enough to heat up, and that only the rock surface area close to the fluid flow path will give up its heat to the fluid.

There are two ways to increase the residence time of the water in the rock: (i) increase the path length and (ii) slow the flow rate. The second method seems in direct contrast to our goal of having very high flow rates per well. However, we can slow the flow rate in a given fracture or part of the porous system by exposing the fluid to more fractures or a larger porous matrix contact area. This conforms to our other option of increasing the path length, because a longer path length will also allow more contact area. A larger number of fractures in combination with larger well spacing and a more complex fracture or porous pathway should accomplish the goal of a longer residence time for the fluid, and should also result in higher transmissivity.

To accomplish the two goals of long residence time and high transmissivity, a large number of complex fractures – none of them with very large apertures – would work the best. If the natural fractures in place are closely spaced, stimulating them to produce more connected and more conductive pathways should yield an ideal EGS reservoir. However, if fractures are fewer and widely separated, then a much larger well spacing will be needed.

5.6 Water Availability

Creation and operation of an EGS require that water be available at the site for a reasonable cost. In the absence of a nearby river, major lake, or the sea as a cooling source, the most efficient power-generation systems require evaporative cooling, which means that an average of about 15% of the water requirements for the cooling system are lost to evaporation and need to be replaced. During creation of an extensive and connected fractured system, large quantities of water are needed for stimulation and growth of the reservoir. While most systems probably can be maintained without adding much water through management of pressure in the reservoir, some water will need to be replaced in the reservoir. The size of the reservoir may need to be expanded periodically to maintain the heat-exchange area, requiring the addition of more water. A site with water available in large quantities, in close proximity, will improve project economics.

5.7 Susceptibility to Induced Seismicity

One of the other aspects of project economics and of project feasibility is the potential of the site for induced acoustic emissions (Batchelor et al., 1983). At the best potential EGS sites, rocks are critically stressed for shear failure, so there is always the potential for induced seismicity that may be sufficiently intense to be felt on the surface. With current technology, it appears feasible that the number and magnitude of these induced events can be managed. In fact, based on substantial evidence collected so far, the probability of a damaging seismic event is low, and the issue – though real – is often one more of public perception. Nonetheless, there is some risk that, particularly in seismically quiet areas, operation of an EGS reservoir under pressure for sustained periods may trigger a felt earthquake. As a result, the potential for seismicity becomes an environmental factor for determining the economics of EGS project development. This and other environmental factors that would control siting of potential EGS projects are discussed in Chapter 8.

5.8 Remaining Issues for Successful Stimulation

At our current level of understanding and with the technology available for stimulating potential geothermal reservoirs, pre-existing fractures with some connectivity in the far field are needed to develop a connected system that can be circulated. The fractures need to be oriented with respect to the stress field in such a way that they will fail in shear; this is the case over a wide range of geologic and tectonic conditions. We can stimulate connected fractures and improve permeability.

5.8.1 Site selection

Exploration methods that can effectively tell us the stress field *at depth* from the surface are not currently available. We can use GPS and satellite imaging to locate and map more regional stress regimes, but it is very difficult to predict the downhole stress patterns and how they will vary with depth. Few wells have been drilled to deep depths in the areas of highest heat flow. Those wells that have been drilled to deep depths are generally oil and gas wells, and the stress data are proprietary for the most part.

The heat flow data we have are limited and not very detailed. Unless an area has been extensively explored for geothermal energy, the detailed temperature-with-depth information that we need for siting EGS exploratory wells is not available. While oil and gas wells are often logged for temperature as part of the normal assessment process, these data are again proprietary and not available.

5.8.2 Instrumentation

Evaluation of the geothermal system requires drilling, stimulation, mapping of the stimulated area, and then drilling into the stimulated area. Borehole imaging prior to and post stimulation is a necessity for understanding and assessing the potential system, and for design of the stimulation. Once we have drilled a well, if the rock temperature is above 225°C, the use of borehole imaging tools for characterizing natural fractures and the stress regime will require precooling of the borehole. Instrumentation for borehole imaging is difficult to protect from borehole temperatures because data pass-throughs permit too much heat gain from the hot borehole environment. High-temperature electronics that would extend the temperature range for all kinds of instrumentation for use in geothermal situations need to be developed and applied to downhole logging tools and drilling information systems as well as to seismic-monitoring tools. There is a strong need for high-temperature instrumentation in other technologies such as internal combustion engine monitoring, generators and power generation systems, nuclear power generation monitoring, and high-temperature oil and gas well drilling and logging. These industries can support some of the developments to extend the temperature range for these components. However, geothermal temperatures can far exceed the highest temperatures in oil and gas wells. So, while we can piggyback to some extent on the oil and gas industry, there is still a need for a focused geothermal instrumentation program.

5.8.3 Downhole pumps

Experience has shown that downhole pumping of the production well is essential for long-term production management of the EGS reservoir system. However, only line-shaft pumps are currently capable of long-term operation in temperatures above 175°C. Line-shaft pumps are of limited usefulness for EGS development, because they cannot be set at depths greater than about 600 m. In principle, there is no limitation on the setting depth of electric submersible pumps; but these are not widely used in the geothermal industry.

5.8.4 High-temperature packers or other well-interval isolation systems

We know from experience that when we pump from the surface, we preferentially stimulate those fractures that accepted fluid before the stimulation. If we want to stimulate pre-existing fractures that do not accept fluid or create fractures where none exist, we would need to isolate sections of the borehole for separate stimulation. At present, we do not have packers that will accomplish this reliably. Most packers use elastomer elements that are limited in temperature to about 225°C. All-metal packers have been developed, but because there is not much demand for packers that function at high temperatures, these have not been tested widely or made routinely available. There is the potential for setting cemented strings of expanded casing with sealable sections in the open-hole section of the well, but this has not been tested either. Inflatable cement packers have been used in certain oil-field applications. They were tried at Fenton Hill unsuccessfully but later implemented successfully at Soultz using cement inflatable aluminum packers. In general, they have not yet been used in hydrothermal wells.

5.8.5 Short-circuit prevention and repair

Short circuiting, the development of preferred pathways in stimulated reservoirs, is one of the major problems for EGS economics. Short circuits may develop as part of the initial fracturing process, or during long-term circulation. Either way, we need a suite of methods to repair the situation, or be forced to abandon large sections of the stimulated volume.

5.8.6 Fracture design models

Credible hydraulic-fracturing simulation models capable of addressing the propagation of clusters of shear fractures in crystalline rock are not available. Developments must include incorporating dynamic (pressure, time, and temperature) poroelastic and thermoelastic effects in the formations penetrated by the fractures and in the regions of the fracture perimeter – as well as consideration of using explosive and intermediate strain rate stimulation methods.

5.8.7 Rock property quantification

Although some data are available (Batchelor, 1984), and some logging/coring analysis methods and numerical models have been developed, we still need better methods for quantifying formation properties pertinent to hydraulic fracturing and post-frac circulation. Methods are needed that include not just the near-wellbore region, but extend out as far as possible from the wells. The methods developed need to be cost-effective as well as reliable. We also need to use data, gathered both in the laboratory and in the field, to validate numerical models for fluid/rock geochemical interaction. The results from current models can vary immensely.

5.8.8 Fracturing fluid loss

The behavior of the reservoir during fracturing fluid injection and during circulation – and its relationship to fluid loss – is not well understood. The nature of dynamic fluid loss, and the effects of both poroelastic and thermoelastic behavior remain as issues. Specifically, it is largely unknown how thermal contraction caused by local cooling of the rock at and near fracture channels affects fluid losses and dynamic fracture propagation.

5.8.9 Fracture mapping methods

While microseismic event monitoring gives us 3-D, time-resolved pictures of event location and magnitude from which we infer the fractured rock volume, we do not have a quantitative understanding of how the event map relates to the flow paths that define the extent of the underground heat exchanger. More credible methods for mapping tensile fracture and shear fracture cluster geometry resulting from hydraulic stimulation are needed. Also, it may be possible to use the focal mechanisms for the events to determine which events are correlated with fluid flow.

5.8.10 Reservoir connectivity

While the fractured volume may be mapped using microearthquake data, there are still issues with ensuring that production wells connect adequately with injectors through the fractured volume. Some portions of the volume may be isolated from the injector. Boundaries due to pre-existing faults, fractures, and lithology changes may prevent connection or make too strong a connection with parts of the reservoir. It may be possible to improve reservoir connectivity through pressure-management methods such as producing one well while injecting into another or injecting into two wells simultaneously.

5.8.11 Rock-fluid interactions

Geochemistry at low temperatures can be a benign factor, but as the salinity and temperature increase, it may pose difficult engineering challenges. Considerable effort is now going into the numerical modeling of coupled geochemical processes, but generally there is still a lack of data to support the verification of the models. Dissolution and precipitation problems in very high-temperature EGS fields are not well understood. Conventional means of overcoming these problems by controlling pH, pressure, temperature, and the use of additives are widely known from experience at hydrothermal fields. Some laboratory studies may shed light on the processes involved; however, solutions to specific geochemical problems will have to be devised when the first commercial fields come into operation.

5.9 Approach for Targeting EGS Reservoirs

Exploring for hydrothermal geothermal systems is a high-risk proposition. Not only must the resource have a high temperature at a drillable depth, it must also be very permeable with fluid in place and sufficient recharge available to sustain long-term operation. With EGS resources, the exploration effort is not as demanding because, ultimately, only high temperature at drillable depth is really necessary. The temperature-at-depth maps of Chapter 2 provide us with the basic information we need to assess a project site. However, the economics of the project can be greatly improved by selecting a site with the right geological characteristics.

The criteria that make one site more economical to develop than another are fairly obvious. Most will be discussed in detail in the chapter on economics (Chapter 9). Here, we will address the resource characteristics that improve the project economics and reduce project risk.

Proximity to load centers. Where possible, sites relatively close to a load center with existing infrastructure (roads, power lines, water supply, etc.) are preferred.

Temperature gradient. Depth, number of wells, etc., will be set by the required temperature and by economic optimization. Obviously, higher-temperature gradients allow high-temperature rock to be reached at shallower depths, which reduces drilling costs.

Structural information. Because EGS reservoir depths are likely to exceed 3,000 m (10,000 ft), structural information on the target formations is likely to be limited. Geophysical techniques should be considered with a view to identifying fault zones, major fractures, and possible convection cells.

Regional stress regime. Some regional stress data are available, but we do not have the ability to estimate stress regimes at depths of interest (see 5.8.1). The type of stress regime is largely unimportant; successful reservoir stimulation usually can be achieved if there is some existing and/or historical differential stress of any kind. The first well should be directionally drilled to maximize the intersection with critically oriented joints in the target region.

Large rock volume. A site with a large volume of fairly homogeneous rock is preferred, which allows extension of information from the first wells to the rest of the area and reduces risk.

Thick sedimentary cover. A thick sedimentary cover, but without overpressure, above basement rock can insulate the crystalline rock, resulting in higher average temperature gradients, thereby reducing drilling cost.

Water availability and storage. Sites in sedimentary rock have the advantage of having water stored in place and will probably exhibit permeability. The matrix porosity may allow for better heat exchange. Sedimentary formations, however, may allow leak-off of injected fluids outside the stimulated reservoir volume.

Microseismic monitoring network wells. For early systems, a microseismic monitoring network will be required (Cornet, 1997). Its design will depend on the nature of the superficial formations and the depth and geometry of the target reservoir zone. Wells drilled for exploration, for oil and gas production, or for mining, can be used to install microseismic monitoring equipment. Sites that already have these holes can save money on installing the equipment. A site where such a monitoring system is already in place would provide baseline background data as well as reduce cost.

Understanding of lithology and pre-existing fractures. Data on lithology from other exploration efforts, such as oil and gas or an existing well of opportunity, can greatly reduce the risk of the project. The well should be logged and tested to obtain as much information as possible about the undisturbed fracture network. Vertical seismic profiling (VSP) or resistivity surveys may be helpful in identifying major structures.

5.10 Diagnostics for EGS Reservoir Characterization

Compared to typical oil and gas field data, there is scant information pertinent to geothermal prospects in crystalline rock. Information collection and diagnostic programs are essential to enhancing understanding, insight and knowledge of the behavior of geothermal granites. Although such programs can be costly, the oil and gas industry learned that the cost of ignorance far exceeds the cost of knowledge when trying to develop low-permeability gas formations. Hence, information collection and diagnostic programs are strongly recommended to accelerate the economical development of EGS. Appendix A.5.3 describes, in detail, the tests recommended to be conducted on the first well to be drilled into a prospective EGS reservoir.

5.11 Reservoir Stimulation Methods

In developing a methodology for creating EGS reservoirs, the primary goal of R&D in field testing is to improve the repeatability and reliability of stimulation methods. Because the cost of drilling the wells and generating the fractured volume is high, correcting problems such as short circuiting and high near-wellbore pressure drop should be a primary goal of any research efforts.

There are two general methods for creating a geothermal reservoir: (i) hydraulic fracturing through successive isolation and stimulation of sections of the wellbore (for details see Gidley et al., 1989), and (ii) stimulation of pre-existing fractures at pressures just high enough to cause shear failure.

The original concept developed in the 1970s of improving the residual permeability of the *in situ* rock mass at depth by injecting fluid under high pressure in successive sections of the wellbore has not yet been tested adequately because of technical difficulties. To overcome the problem of thermal drawdown, the concept of parallel stimulations evolved to enhance the total stimulated rock volume (Parker, 1989). Supporting this concept are the following ideas:

i. Stronger planned growth of microseismicity following stimulation of short packed-off zones.
ii. The apparent lack of microseismic overlap and the limited hydraulic connection between neighboring stimulated segments.

iii. The belief that a large open-hole length improves the chance of good connections to natural hydraulic features, which could be enhanced further by bulk stimulation with little development of the rest of the potential EGS reservoir.

iv. Increased engineering confidence in an ability to satisfactorily conduct stimulations of small zones with near planar spread of stimulated regions. The observed pressure/microseismic response of each small stimulation might be used to tailor the stimulation for each zone to the requirements of a uniform reservoir.

For example, at Rosemanowes, U.K., it was found that the impedance to flow between wells was too high, that the reservoir volume was too low, and that this had resulted in significant thermal drawdown. The use of gels with varying degrees of viscosity was tested to overcome the impedance problem by jacking the joints apart farther into the reservoir. However, it is probable that these methods resulted in the development of some fracture paths with much higher permeability short-circuiting to the other wells.

Attempts to fracture successive parts of the wellbore at Fenton Hill ran into problems with setting packers in deep, high-temperature rocks. Although some packers held, and hydraulic fracturing was attempted with the packer in place, it is likely that fracturing around the packer occurred. A segment of casing cemented in place was an effective way to place a seal and isolate the section of the wellbore for treatment. However, this is costly, decreases the size of the wellbore, and must be planned carefully to avoid the need to go back in different segments or shut off potentially productive zones.

The multisegment concept is an attractive one; however, it may be difficult to engineer because each reservoir segment has to be progressively stimulated, circulated, and tested in isolation, without causing a cross-flow. The concept has not been tried, and achieving hydraulic separation between reservoir segments may represent a difficult engineering feat. Otherwise, certain paths (short circuits) could dominate, thus reducing the overall sustainable life of the reservoir. The separate stimulation of isolated zones at great depth and temperature also may need extensive engineering development to occur. However, with a drillable inflatable packer now available for high-temperature use, the concept of successively fracturing different zones should be revisited.

Hydraulic stimulation has been effective in overcoming local difficulties of fulfilling economic reservoir creation targets. Reservoir development at the current state of the art will need to target rock with existing fractures and a stress state that promotes fractures to shear. A large volume of rock with similar conditions should be found for a large-scale project to be possible. Generally speaking, from experience to-date and in conjunction with previous developments from other projects, the basic steps for reservoir creation can be described as follows:

1. Drill the first deep well (injection) with the casing set at appropriate depth to give the required mean reservoir temperature.
2. Obtain basic fundamental properties of the underground such as stress field, joint characteristics, *in situ* fluid characteristics, mechanical properties of the rock mass, and the identification of flowing /open zones where appropriate.
3. Having established the best positions for the sensors of the microseismic sensor array, install an appropriate instrumentation system to yield the best possible quality of microseismic event locations, not only during the first stimulations but for all events likely during the reservoir's lifetime.

4. Conduct stepped flow-rate injections until the pressure for each injection step becomes steady. The maximum injection pressure should exceed the minimum formation stress at the point of injection.
5. Maintain high flow-rate injection until the seismicity migrates to the distance necessary for targeting the second well.
6. Depending on the relationship of the *in situ* stress and the density of *in situ* fluid, it may be possible to influence the vertical direction of reservoir growth by selecting an appropriate density of the stimulation fluid.
7. Perform a shut-in test to assess the size of the reservoir.
8. Carry out flow logs in the injection well to identify the main flowing zones.
9. Let the reservoir deflate and then make injection tests at lower flow rates to assess the permanent residual enhancement of permeability i.e., flow against injection pressure.
10. Target the second well (production) into the periphery of the seismically activated structure, with the separation of the wells appropriate to suit economic targets. At the same time, ensure that the well has a downhole pumping chamber incorporated in its completion plan.
11. Stimulate the second well in a stepped manner as described above to improve access to the previous stimulated zone and eventually permit the recovery of the mobile *in situ* fluid (carry out diagnostic technique as in steps 3 and 8).
12. Conduct short-circulation tests to assess the connectivity between the injector and the producer.
13. Perform tracer tests to evaluate reservoir flow-through volume, to characterize the residence time distribution, and to identify any short-circuit paths.
14. Repeat steps 10 to 14 for the third well, i.e., the second production well, and for a fourth and even fifth, if the system warrants this.

This process can then be repeated to create a large enough system to support a commercial power generation or heat and power installation. Although the steps described above are very rudimentary and perhaps oversimplify the overall approach, the general trend remains and the procedure fits with our understanding of the reservoir creation process. Each area or region will have its own specific properties and these will have to be taken into account in the general reservoir stimulation concept described.

Channeling or short circuiting of circulation fluids has been a nemesis in conductive heat transfer efforts. The feasibility of altering injection/producing patterns may be worth further investigation.

5.11.1 Geologic case studies

To demonstrate how this process might work in specific areas, and how costs might vary for different geologic conditions, some specific geologic cases were chosen (Table 5.1). These sites cover a wide geographical area and represent a diverse set of geological characteristics that are appropriate for a nationwide deployment of EGS technology.

i. *Winnie, Texas*

A deep, overpressured sedimentary basin with moderate geothermal gradient on the Gulf of Mexico. The area is actively producing oil and gas from both shallow and deep depths. The target formation for an EGS would be the Cotton Valley Formation, a tight sand encountered at between 4.6 km (15,000 ft) and 5.2 km (17,000 ft). In this area, temperature gradients are about 40°C/km, and the temperature at the completion depth of 5.75 km (18,900 ft) is 200°C. Rates of penetration (ROP) for this area are high except for soft shales at shallow depths. However, well costs are affected by overpressure encountered in some formations, so extra casing strings may be needed.

ii. *Nampa, Idaho*

This location in southwest Idaho is in the Snake River Plain with basalt to a depth of about 1.5 km and granitic basement below that. Basalt is hard and abrasive with fractures and loss zones. The temperature gradient is 43°C/km on average, but is higher below the basalt, so that the completion temperature at the target depth of 5.5 km is 265°C.

iii. *Three Sisters, Oregon*

The area immediately around the Three Sisters volcanoes is a national park and is, therefore, off-limits for drilling. However, a large caldera complex with high heat flow extends to the east toward Bend. Faults trending northeast-southwest, possibly tensional, pass through the caldera area and make this a potential target. Volcanics with potentially large lost circulation zones overlie granitic basement. The target temperature is 250°C at 4.6 km, due to a geothermal gradient of about 50°C/km. However, shallow groundwater circulation may obscure a much higher gradient, and no deep well data are available to determine this.

iv. *Poplar, Montana*

Plentiful data and ongoing oil and gas production from the Poplar Dome oil field in the Madison limestone make this site of interest. There are two targets: (i) the shallow, known-temperature oil field with temperatures of about 135°C at 2.2 km and (ii) the deep, granitic basement at 250°C at 6.5 km or possibly shallower. There has been little deep exploration in this area because production in the upper zones has been sufficient. However, as production has declined, deeper wells have been drilled in neighboring fields. Unfortunately, few temperature data are publicly available. The example addressed below is completed at shallow depth and low temperature in the Madison limestone because there are available data on this resource. The area generally is normally pressured. The location on a Sioux reservation with a casino, development, and increasing demand for power make this site somewhat more attractive.

v. *Kelseyville, California*

The Clear Lake volcanic field has very high temperature gradients and a great deal of data from both mining and geothermal exploration. Although tailings piles from mercury mining drain into the lake in some areas, making the environmental aspects of this site challenging, the location was chosen away from old mines but outside the city of Kelseyville. The target temperature is 415°C at a depth of 6 km. The high temperature warrants the deep depth. Altered and potentially unstable meta-sedimentary rocks overlie granite, which starts at variable depth of around 3-4 km.

vi. *Conway, New Hampshire*

This site is in the East, with a somewhat elevated temperature gradient (for the East Coast) of 24°C/km. The completion depth is 7 km to reach 200°C, with drilling through granite to total depth. The stress regime in this area is not well known, but is likely to be strike slip.

Table 5.1 Example of site-fracturing information.

	E. Texas Basin	Nampa	Sisters Area	Poplar Dome	Clear Lake	Conway Granite
Average temperature gradient to 250°C , °C/km	40	43	50	37	76	24
Depth to 250°C, km	5.75	5.5	4.6	6.5	3	10
Completion temperature, °C	200	265	250	135	415	200
Depth to top of granite, km	5	4.5	3.5	4	3	0
Completion depth, km	5	5	5	2.2	6	7
Stress type	Tension	Tension	Tension	Strike slip	Tension	Strike slip
Completion formation (bedrock)	Sandstone, silicified	Granite	Granite	Madison limestone	Granite	Granite
Overlying formations	Soft grading to harder cements	Basalt to about 1.5km	Tuffs, andesite/ basaltic lavas, andesite	Sandstone/ limestone/ shale	Rhyolite/ hydro-thermally altered meta-sediments	None

The sites with crystalline basement will be similar to many of the EGS sites studied so far for research purposes. All of these sites have significant stress histories that should have produced pre-existing fractures. The two sites in sedimentary basins are routinely fractured for oil and gas production and resemble the situation at Horstberg. Water is available from oil and gas production for fracturing and for circulation makeup. Water costs for the other sites assumed purchase from the local water utility, although the New Hampshire site is very close to a river, and there should be ample water available in the long term for cooling and makeup, as well as fracturing, because the run of the river water law is followed in the east.

Cost estimates were based on the assumption that commercial fracturing service companies would perform the hydraulic-fracture stimulation. Portions (some significant) of the above costs depend on: (i) equipment mileage from the nearest pumping service company office to the site, and (ii) service company on-site personnel time charges.

For these cases, the results from two hydraulic-fracturing models, Perkins Kern Nordgren (PKN) and Geertsama de Klerk (GDK), were used for volume, pumping power, and pumping time requirements. The PKN and GDK models yield close, but not exact, results for these. Because no direct link between cost and any property of the reservoir could be found, an average of the results from each was used in the analysis.

All cases were for a vertically oriented fracture (or shear fracture cluster), penetrating radially outward and downward as well as up, (centered at the casing shoe), with a fracture radius of 900 m to provide $5x10^6$ m^2 of fracture face exposure. The *in situ* stresses in the fracture regions were based on a stress gradient of 0.136 MPa/m. The injection fracturing pipe string was consistent with the drilling-casing programs for the site for calculating surface injection power requirements.

The effective rock mechanical properties (elastic moduli and Poisson's ratios), and fluid efficiency parameters for the designs, were based on relative percentages of granite to non-granite formation penetrated by the fracture (shear fracture cluster).

The costs for all project wells include tailing (placing) in relatively small, but sufficient, proppant quantities to mitigate high-pressure drop (skin) effects in the near wellbore vicinity. Table 5.2 shows the estimated cost for two average injection rates. Detailed step rate injection histories were not used for this analysis.

It was assumed that each well would need two fracture treatments. Experience would determine whether this is the best strategy or whether one longer fracture treatment would be more effective, so that in out years, the cost might be cut in half. These costs can be lowered further for later stimulations – once the project is determined to be feasible – by using purchased pumps that would be used for long-term site operations. For large-scale projects, there would be on-site fracturing pumps, designed for long-term operation, to stimulate new reservoirs without a service company. This represents a cost benefit in developing a large volume of relatively uniform rock.

Table 5.2 Cost estimates for wells at example sites, for two average injection rates.

Project site	Percentage of fracture in granite	Hydraulic fracturing costs, $	
		@ 93 kg/s	@ 180 kg/s
Winnie, TX	0%	145,000	171,000
Nampa, ID	39%	260,000	356,000
Sisters, OR	83%	348,000	450,000
Poplar, MT	0%	152,000	179,000
Kelseyville, CA	56%	450,000	491,000
Conway, NH	100%	502,000	580,000

5.12 Long-term Reservoir Management

Because no resource of commercial size has been tested for more than a few months, there are few data to make conclusions about the long-term management of an EGS resource. Flow rate per production well, temperature, and pressure drop through the reservoir and wells govern the energy that can be extracted from a well system. The nature of the fractured reservoir controls the reservoir life and the amount of heat that can ultimately be recovered from the rock volume. The pressure drop and wellhead temperature are both controlled by the nature of the fracture system, the surface area that the fluid is in contact with, and the fracture aperture and path length. While a long path length is desirable for a long reservoir life, a long path length would be likely to result in higher pressure drop. On the other hand, if there are many paths for the fluid to take, high flow rates and high fracture surface area can both be achieved with lower pressure drop, better heat exchange, and higher total heat recovered from the rock volume.

The amount of temperature drop in the active reservoir that can be tolerated by any given system is largely a matter of project economics. If there is no temperature decline, then the heat is not being efficiently removed from the rock. If there is too much temperature decline, either the reservoir must be replaced by drilling and fracturing new rock volume, or the efficiency of the surface equipment will be reduced and project economics will suffer. The amount of decline in circulating fluid temperature that power-generation equipment can tolerate is a matter of economics. While a given plant may be able to run with temperatures as much as 50% lower than the initial design temperature (in degrees Celsius), the net power output may fall below zero if there is not enough power to operate the pumps for the circulation system. With current technology, there are a number of options for operating the reservoir that might work to manage the reservoir long term. For the purpose of economics, a 10% drop in temperature means that the system can still operate without too extreme a reduction in efficiency, while extracting heat from the rock and maintaining some rock temperature for future heat mining. Sanyal and Butler (2005) use a drop of 15% in their analysis of recoverable heat from EGS systems, so a 10% drop is probably conservative. The temperature drop at East Mesa exceeded 10% in some parts of the field, and changes to the wellfield system were able to restore some of this without huge expense. This amount of temperature drop would be significant enough to trigger some intervention.

Long-term reservoir management demands that models predicting long-term temperature, pressure, and fluid chemistry behavior be validated with data collected from operating the reservoir (for example, see Dash et al., 1989). These models can be used to predict the reservoir behavior prior to operation and then make changes in well pressures, flow rates, and in the reservoir fractured volume to maintain the produced fluid temperature.

The circulation system consists of injection pumps, production pumps, the surface conversion system, the wells, the fractured reservoir, and the piping to move the fluid around. Each of these elements involves frictional pressure drop, which needs to be accounted for in the economics of the project because it represents an energy loss to the system. The wellbore size must be planned to accommodate the lowest pressure drop, while also controlling the cost of the well. The production wells most likely will be pumped using downhole pumps and so must be designed to accommodate the pump diameter needed for the pumps and motors – usually about 24 cm (9.5") – and maintain a sufficient-diameter downhole to reduce pressure drop for the high flow rates.

Buoyancy effects due to the density difference between the hot production and colder injection wells work to reduce the pumping work required for fluid circulation. Given that many EGS systems will involve deep reservoirs, this effect can have a significant impact on overall system performance. Buoyancy causes a pressure gain which, in principle, can be large enough to cause the system to "self-pump" as a result of a thermal siphon effect. For example, for a 250°C reservoir at 6 km, the net buoyancy gain could be as large as 10 MPa (1450 psi). Therefore, if the pressure drop in the circulating system – due to frictional losses in the wells and impedance within the fractured formation – was less than 10 MPa, the system would self-pump.

The life of the reservoir is largely controlled by the effective surface area and the total volume of rock that the circulating fluid accesses. However, other factors affecting the lifetime of the system include the amount of short circuiting of fluid between injection and production wells, the quantity of water permanently lost to the surrounding rock, and the amount and severity of seismic activity generated during reservoir operation (if any). The development of preferred pathways in the reservoir through which fluids can bypass portions of the fracture rock mass (termed "short circuiting") is one of the major challenges facing EGS system development. To measure short circuiting, tracer testing with numerical modeling will probably yield the best metric, but more research work needs to be done in this area. The metric adopted here is the ratio of the volume of tracer-doped water before breakthrough to a producer to the total reservoir effective volume. The larger this ratio is, and the closer it is to the reservoir porosity (usually 1% to 7% for fractured hard rocks), the less the short circuiting.

Loss of fluid to the reservoir determines how much cold fluid must be added as the system is produced. Because makeup water may be expensive, low fluid loss is desirable. Minimal loss is also desirable from other considerations. Fluid that has circulated repeatedly through the reservoir will eventually come to chemical equilibrium with the reservoir rocks, neither dissolving nor depositing minerals. Also, makeup water will be colder than water injected directly from the surface plant, so addition of large amounts of makeup water will hasten the cooling of the rock volume.

5.13 Conclusions – Stimulation Technologies and Estimated Costs

The analysis presented in Chapter 2 indicates that the heat stored in the earth to depths that are accessible with today's technology is truly vast. However, the fraction of this resource base that can be economically recovered is dependent on increased understanding of reservoir behavior and, therefore, is directly connected to current research and testing of EGS. Here, we present some of the pressing needs to advance the state of the art in EGS reservoir technology.

- ***Assessing the size of the stimulated volume and heat-transfer area.*** Being able to determine the heat-exchange area and the volume of the fractured rock in an EGS reservoir is an important part of stimulation design and operation. Conservative tracers, thermally and chemically reactive tracers, natural fluid tracers, microseismic monitoring, active seismic measurement, and advanced forms of reservoir tomography such as muon tomography are areas with potential for determining the size of the resource accessed, and for targeting and drilling further production and injection wells.

- ***Development of high-temperature downhole tools.*** While downhole tools have been developed that can be used to measure temperature, pressure, flow, and natural gamma emissions on a short-term basis, these instruments cannot be left in the well for long-term monitoring. In addition, tools for microearthquake monitoring are limited to temperatures below 120°C. New generation downhole tools need to withstand temperatures of more than 200°C for extended time periods to be useful for monitoring over the lifetime of the reservoir.

- ***Better understanding of rock/water interactions.*** One important area of ongoing research is prediction and monitoring of rock/water interactions (for example, see Moller et al., 2006). Although our understanding of the chemistry of rock/water systems has improved, we are still working on predictive models of long-term behavior in an EGS operation. Past EGS field experiments have yielded only scant information on rock/water interaction because of their limited duration. Data are available from deep petroleum industry wells, but these data have not been collected and analyzed for their relevance to EGS development. Control of scale formation and rock dissolution in the reservoir are areas for technology enhancement through research. Whereas scale and corrosion in wells and surface equipment can be controlled using methods developed by the hydrothermal industry, this has not been attempted in the reservoir itself.

- ***Methods for coping with flow short circuits.*** An important area for engineering research is the development of methods for dealing with flow short circuits that may develop during operation of the EGS reservoir. A better understanding of this will allow fluids to be directed to specified parts of the reservoir, and will prevent excessive water loss. The oil and gas industry uses fluids with controlled viscosity to accomplish some of this. Currently, the temperature limit for fluid additives to control rheology is about 175°C (350°F), well below the target temperature of 200°C for high-grade EGS projects. Increasing oil prices have resulted in renewed interest in extending the temperature limits for these fluid additives as higher-temperature oil and gas fields become economical to produce. As a result, maximum temperatures for fluid additives have been increased through research by the petroleum industry. There may be other areas of research that can result in reduced risk of short circuiting, or in managing sections of the wellbore to shut off preferred pathways. Pressure management of the reservoir may be useful for long-term control of both fluid loss and too-short fluid pathways causing excessive cooling.

- ***Strategy for dealing with formation temperature decline.*** The current strategy for coping with temperature drop in the system is to replace the cooled fracture volume with new fractured rock. This can be accomplished by drilling new wells into previously unfractured rock or by drilling legs from existing wells into rock previously fractured but not accessed by circulation. In large-scale, commercial systems, the well spacing and pattern would be designed to take advantage of as much of the created or enhanced reservoir as possible, so that no upfront fracturing cost would be wasted. However, there is bound to be some volume that is not swept on the edges of the system, which could be accessed either by redrilling wells, or by drilling new wells. The ongoing reservoir maintenance of a commercial-size system with many well groups and circulation cells would require adding new reservoir fracture area at regular intervals to maintain temperature and flow rate to the plant. This becomes part of the cost of maintaining the reservoir.

- ***Methods to control growth of fractured volume.*** It is clear from experiences at Soultz and other EGS sites that reservoirs can continue to grow during circulation, unless pressures are controlled and balanced to avoid expansion. Strategies for controlling operating pressures could be developed empirically by tracking the reservoir growth with seismic monitoring equipment. New wells, or new legs to existing wells, could then be drilled to access this new portion of the reservoir. This type of reservoir management would require validated numerical models that accurately predict reservoir behavior. Thermal hydraulic models currently can handle heat transfer, but they do not quantitatively predict changes in fracture surface area or permeability with pressure and temperature. Geochemically induced changes in permeability may be modeled in the future, but presently are not included in most models.

- ***Improved reservoir modeling.*** The future of EGS is extremely dependent on our understanding of the natural, unstimulated rock fracture system and on our ability to predict how the reservoir will behave under stimulation and production (for example, see DuTeaux et al., 1996). So far, we have not operated a commercial-sized EGS reservoir long enough to be able to use the data to validate a model. Until we do this, it is difficult to estimate the actual operating cost of one of these systems. At this early stage, we have based estimated EGS stimulation costs on variations of oil and gas field practice (see Chapter 9 for details). As more data become available, these costs will be refined.

To sum up, a robust R&D program will be needed to realize the ultimate potential of EGS. More specifically, to extend the predictive capabilities of reservoir performance modeling will require validation with extensive flow testing at a number of EGS field sites (e.g. see Figure 5.2).

Figure 5.2 Flow tests at Cooper Basin EGS site, Australia (Geodynamics, 2005).

References

Batchelor, A. S. 1984. “Mechanical properties of the Carnmenellis granite.” Internal Report 2-46, Camborne School of Mines Geothermal Energy Project, UK, Group III, Part 3, Volume 1.

Batchelor, A. S., R. Baria, and K. Hearn. 1983. “Monitoring the effects of hydraulic stimulation by microseismic event locations: A case study.” *SPE Paper 12109, Presented at the SPE 58th ATCE*, San Francisco, Calif.

Brown, D. W. 1988. “Anomalous earth stress measurements during a six-year sequence of pumping tests at Fenton Hill, New Mexico.” Los Alamos National Laboratory report, LA-UR-88-3985.

Cornet, F. H. 1997. “Proceedings of the 1st workshop on the development of a multiborehole observatory at the Gulf of Corinth.” *International Continental Drilling Program*, Athens.

Dash, Z. V., R. G. Aguilar, B. R. Dennis, D. S. Dreesen, M. C. Fehler, R. H. Hendron, L. S. House, H. Ito, S. M. Kelkar, M. V. Malzahn, J. R. Miller, H. D. Murphy, W. S. Phillips, S. B. Restine, P. M. Roberts, B. A. Robinson, and W. R. Romero. 1989. “ICFT: An initial closed-loop flow test of the Fenton Hill Phase III HDR reservoir.” Los Alamos National Laboratory report, LA-11498-HDR, DE89007286.

DuTeaux R., D. Swenson, and B. Hardeman. 1996. “Insight from modeling discrete fractures with GEOCRACK, a geothermal reservoir model,” *Proceedings Twenty-First Workshop on Geothermal Reservoir Engineering*, Stanford University, Calif.

Geodynamics. 2005. “Quarterly Report, Period ending 30 June 2005,” Geodynamics, Ltd., Milton, Queensland, Australia.

Gidley, J. L., S. A. Holditch, D. E. Nierode, and R. W. Veatch Jr. 1989. “Recent advances in hydraulic fracturing.” *Soc. Petr. Eng. Monograph*, 12.

Mansure, A. J. and L. J. Westmoreland. 2000. "Plugging lost-circulation zones with polyurethane: Controlling the process.” *Geothermal Resources Council Transactions*, 24.

Moller, N., C. Christov, and J. Weare. 2006. “Thermodynamic models of aluminum silicate mineral solubility for application to enhanced geothermal systems.” *Proceedings of the 31st Stanford Workshop on Geothermal Reservoir Engineering*, Calif.

Parker, R. H. (Ed). 1989. *Hot Dry Rock Geothermal Energy, Phase 2B Final report of the Camborne School of Mines Project*, Two Volumes, Pub Pergamon Press, ISBN 0-08-037929-X.

Pine, R.J. and A. S. Batchelor. 1983. “Downward growth of hydraulic stimulation by shearing in jointed rock.” Submitted to the international *Journal of Rock Mechanics and Mining Sciences*.

Sanyal, S. K. and S. J. Butler. 2005. “An analysis of power generation prospects from enhanced geothermal systems.” *Proceedings Geothermal Resources Council 2005*.

Sarian, S. and A. Gibson. 2005. “Wireline technology in HPHT wells.” *SPEE Paper 97571, Presented at the SPE High Pressure High Temperature Sour Well Design Applied Technology Workshop*, The Woodlands, TX.

Tester, J. W. and H. J. Herzog. 1991. “The economics of heat mining: an analysis of design options and performance requirements for hot dry rock (HDR) geothermal power systems.” *Energy Systems and Policy*, 25:33-63.

Appendices

A.5.1 Current State of Technology

A.5.1.1 Logging tools

Temperature, pressure, spinner, and gamma tools are available for use on logging cable for up to about 300°C. For temperatures exceeding this, the tools should be used as memory tools run on slick line. Resistivity, sonic, gamma, and density neutron tools are available for use at or above 260°C and 20 MPa pressures (Sarian and Gibson, 2005). Borehole imaging can be done by cooling the hole and using Formation Micro-imaging (micro resistivity) or by using a high-temperature (225°C limit) ultrasonic borehole televiewer.

A.5.1.2 Downhole mechanical tools

Downhole mechanical tools (packers, etc.) can be equipped for reliable service up to about 250°C. However, open-hole packers that can be set and released reliably are not readily available for these temperatures. Sandia (Mansure and Westmoreland, 2000) has contributed to the development of a drillable inflatable packer by Weatherford that can be used at high temperatures. Although the packer is not retrievable, it is drillable after the stimulation is finished. Similar noncommercial packers have been used successfully at Soultz.

A.5.1.3 Hydraulic-fracturing materials

Propping agents: Manufactured chemically stable proppants can provide acceptable long-term fracture conductivities at 8,000+ meters and temperatures of 250°C.

Fracturing fluids: Although water is the fluid of choice from an economic standpoint, there are alternatives that can provide adequate proppant transport rheology for periods of 72 hours at temperatures of 220°C. However, viscosity begins to decrease at about 175°C for most high-temperature fluids. Planning for this is necessary, if alternative fluids are to be used.

A.5.1.4 Downhole electric submersible pumps

Downhole electric submersible pumps are available for temperatures up to 175°C. High-volume flow rates of up to about 125 l/s can be produced at this temperature, but there is little testing at temperatures higher than this. Line-shaft pumps can produce fluids at higher temperatures, but these cannot be set at depths greater than about 600 m. They also require the use of oil lubrication of the rotating driveshaft. This oil leaks to the reservoir and is injected, causing long-term environmental risk and possible clogging or fouling of the heat exchangers in binary plants.

A.5.1.5 Numerical models

Numerical models are available for flow in fractures with heat exchange and changing pressure. However, the effect of thermal and pressure changes on permeability in fractures along with heat exchange has not been adequately modeled in such a way that fracture growth can be predicted. Fully coupled models that take geochemical effects into account are far from being perfected. Much more work is needed on the correlations required for these models, if they are to be used successfully.

A.5.2 Oil and Gas Developments Relevant to EGS

The oil and gas industry continues its pursuit of technology and tools applicable to high-pressure, high-temperature conditions. The temperatures that are currently being encountered for oil and gas development generally are on the lower end of the geothermal temperature spectrum. However, as the price of oil and gas increases, the search for new U.S.-based reserves will extend into deeper formations with higher temperatures and pressures.

Capability limits (both temperature and pressure) have increased significantly during the past decade for oil and gas wire-line logging equipment, downhole mechanical tools, and hydraulic-fracturing materials. These limits are expected to continue increasing to serve the needs of the oil and gas explorers and producers as they progress into more severe environments. As a result, the technology and tools that will emerge in the oil and gas industry also will be useful for developing geothermal applications.

A.5.3 Tests for the First Well in an EGS Project

The following lists specific tests and logs that are recommended for EGS wells:

1. Collection of full-hole, oriented core samples (one core barrel) at 100 m intervals throughout the prospective portion of the formation where fracture penetration is expected.

2. Comprehensive laboratory core analysis to ascertain:
   - Rock properties (via both mechanical and acoustical tests) for elastic modulii, Poisson's ratios, compressive and tensile and shear strengths, directional attributes, point-load behavior, densities, thermoelastic properties, etc.
   - Mineralogical compositions
   - Descriptive formation structure – fracture, fissure, joint, fault patterns

3. Comprehensive wire-line log suites, including:
   - Radioactive – Gamma ray, neutron
   - Acoustic wave train – Compression/shear wave
   - Resistivity – micro, intermediate, deep
   - Wellbore caliper
   - Wellbore image

4. Tests at selected points or intervals in the wellbore, in accordance with analyses of core and log information:
   - Micro-frac *in situ* stress breakdown
   - Mini-frac shut-in/pressure decline (for fluid leak-off)
   - Tri-axial borehole seismic in concert with mini-frac tests made during drilling each interval
   - Fluid injectivity/pressure fall-off (for both virgin, and induced fracture intervals)

5. Comprehensive mapping of the fracture or shear fracture cluster during hydraulic fracturing through monitoring of microearthquakes. This requires installation of a network of three-component seismometers in boreholes drilled into fairly solid rock and, if possible, into the basement rock.

Prior to drilling the second well in the prospect, the above collection of information should be thoroughly analyzed. Tests that obviously do not yield worthwhile information should be discarded. Test procedures that yield questionable information should be revised. In cases where information requirements emerge by virtue of the existing test results, additional test procedures should be developed to obtain such information. A test program should then be developed for the second prospective well. This process should be repeated for subsequent wells in the project. Once a deep well is completed, geophysical logs will be required to quantify the temperature profile, joint network data, *in situ* stress profile, sonic log, etc. In a high-temperature environment, the well may need to be circulated and cooled before these logs (except for a temperature log) can be carried out. The only useful temperature information obtained during drilling, or just after drilling, is the bottom-hole temperature, as the temperature profile higher in the well will be affected by the cooling caused by the drilling. Even the bottom-hole temperature may have some cooling if there is permeability on the bottom. It may take up to three months after the drilling is completed for the temperature to reach the natural equilibrium.

Following the assessment of the *in situ* conditions from geophysical logs, small-scale injection tests (as seen at Cooper Basin in Figure 5.2) will be required to assess undisturbed hydraulic properties of the open section of the well. The quantity of water and the pressure required will depend on the state of existing flowing joints and tightness of the formation. Estimation will be made on the requirement of the water for these tests. The following tests are appropriate for evaluating the natural state of the reservoir for permeability/transmissivity and other hydrologic properties:

i. *Slug test*

A slug test involves an impulse excitation, such as a sudden withdrawal/injection of a weighted float, or a rapid injection of a small volume of water. The response of a well-aquifer to that change in water level is then measured. The slug test will also give information required to design the subsequent low-rate injection test. The total amount of water used is negligible i.e., in the range of 2-5 m^3.

ii. *Production test*

Producing formation fluid will yield important information for the future heat exchanger about the P–T conditions in the reservoir. Furthermore, the fluid chemistry and the gas content are important parameters in designing the pilot plant to minimize scaling and corrosion. These are two good reasons to perform a production test at a time when the fluid surrounding the well is not yet disturbed by a major injection. A well can be produced by using a buoyancy effect or a down-hole pump. It is preferable to use a down-hole submersible pump where possible. A submersible pump can be deployed at a depth of about 100-150 m. Depending on the outcome of the slug test, it is probable that the well could produce nearly 1 m^3/hr, which may be sufficient to get several wellbore volumes of fluid in a reasonable time of a few weeks. Additionally, a down-hole pressure gauge, gas sampling (or gas trap) at the wellhead, and a surface flow meter, would add further information on the draw-down characteristic of the well.

iii. *Low-rate injection tests*

The main objective of the low-rate injection test is to determine the hydraulic properties of the unstimulated open-hole section of the well. The derived values will be used as inputs for numeric models, planning of the stimulation (pressure required for a stimulation), and subsequently for the assessment of the stimulation and identification of predominant flowing zones using a temperature or flow log.

iv. *Pre-stimulation test*

This test consists of injecting nearly 400-600 m^3 of fluid at a constant flow rate of about 5-7 kg/s. Fresh water, or saturated brine, can be used. Saturated brine can be very useful in helping stimulation near the bottom of the well, but this depends on the state of the *in situ* stress. After the pre-stimulation test, the wellhead is shut in to see how the pressure declines. This will give some indication of the natural transmissivity, leak-off, or far-field connectivity.

v. *Main stimulation of the first well*

During the main stimulation, fresh water is injected in steps with increasing flow rates. Three to four flow-rate steps are normally used. The flow-rate steps may vary depending on the leak-off, and on whether it is a closed system or open system. Flow-rate steps of about 30, 40, 50, and maybe 70 kg/s are not unreasonable. Normally, the selected step of injected flow rate is continued until the wellhead or downhole pressure reaches an asymptote showing that the far-field leak-off is balanced by the injected flow. This is feasible in a relatively open system, but most observed EGS systems have poor far-field connectivity and, therefore, the wellhead pressure is likely to continue increasing. In this case, injection may be carried out at 30 kg/s for 24-30 hrs, 40 kg/s for 24-30 hrs, 50 kg/s for 24-30 hrs, and 70 kg/s for 3 days. The injected volume may vary between 28,000 m^3 to 31,000 m^3, depending on the flow and the injection period.

vi. *Post-stimulation test*

A post-stimulation test is conducted to evaluate the enhancement in the permeability obtained during the main stimulation of the reservoir. Possible injection flow rates would be around 7, 30, 40 and 50 kg/s for about 12, 12, 24 and 12 hrs. The apparent reduction in the injection pressure, compared to the injection pressure required pre-stimulation for the same flow rate, will give quantitative indication of the improvement in the permeability of the stimulated rock mass. The total volume of water used for this test would be about 7,200 m^3.

vii. *Drilling of the second well and follow-on testing*

Results of the testing of the first well and the stimulated reservoir are used to target the drilling of the second well. Following drilling of the second well, the same wellbore characterization diagnostics recommended for the first well should be run on the second well. A suite of flow tests (similar to those for the first well) also should be carried out, but this time the goal of the testing is to establish the connection between the first and second well. If the connection is not good or needs improvement, the second well may need to be stimulated one or more times.

viii. *Short-term circulation test between the first and second wells*

Once a hydraulic link between the two wells has been established, a small-scale circulation loop between the wells will need to be established. Wells with a separation of 600 m and a good hydraulic link between the wells would show a breakthrough time for a tracer of about 4 to 6 days. The storage volume of the reservoir may increase to accommodate increased injection rates through the system. An initial starting step of 20 kg/s is considered reasonable and, if possible, the rate should be stepped up until the microseismicity suggests reservoir growth is taking place – which would suggest that about 2,600 m^3 will be required to initiate a circulation test. Taking a worst-case scenario of losing 10% in the formation via leak-off, this will bring the figure up to 3,600 m^3 for a three-week circulation test. A separator, a heat exchanger, a heat load, and water-storage facility will be required to implement this test.

ix. *Evaluate and refracture or stimulate near wellbore*

If the wellbore has skin damage (high-pressure drop near the wellbore), the near-wellbore area is very susceptible to improvement. Acidizing, emplacing proppants, short high-pressure stimulation, or other methods can help eliminate near-wellbore pressure drop.

x. *Long-term test circulation at or near commercial scale (about 50-100 kg/s)*

No one has reached flow rates in the region of 70-100 kg/s. This stage will depend on the result of the earlier circulation test. Evaluating the reservoir using pressure and temperature response, tracers, and microseismic data will help analysts understand what is happening in the reservoir and its surroundings.

About 4,000 m^3 would be required to charge the system. An acceptable worst-case scenario for water loss during circulation is 10%, which brings the figure up to 13,000 m^3 for a three-week test.