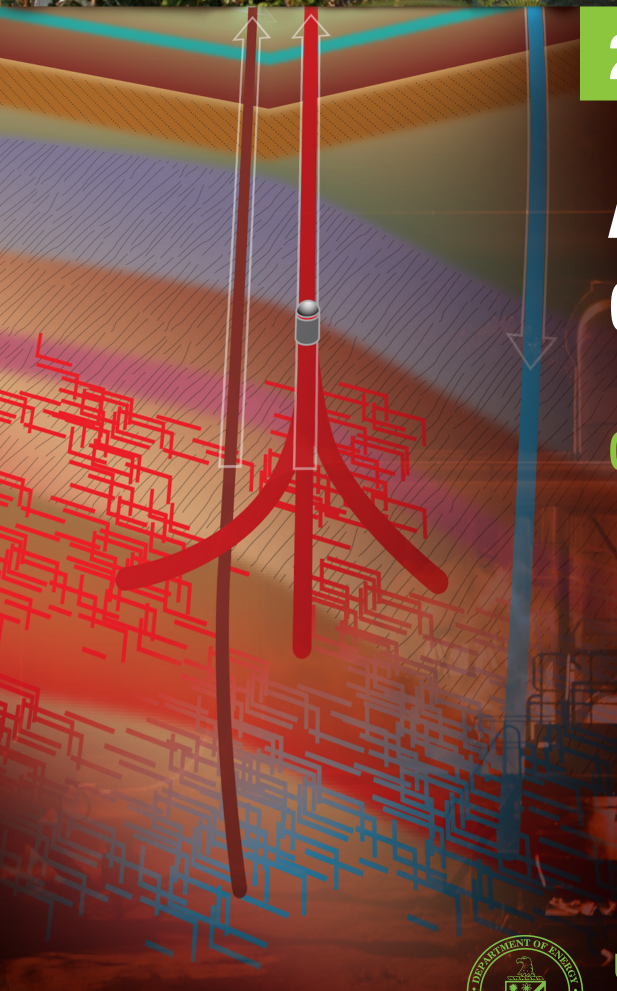

2008

An Evaluation of Enhanced Geothermal Systems Technology

Geothermal Technologies Program

U.S. Department of Energy
Energy Efficiency and Renewable Energy
Bringing you a prosperous future where energy is clean, abundant, reliable, and affordable

Foreword

This document presents the results of an eight-month study by the Department of Energy (DOE) and its support staff at the national laboratories concerning the technological requirements to commercialize a new geothermal technology, Enhanced Geothermal Systems (EGS). EGS have been proposed as a viable means of extracting the earth's vast geothermal resources. Those who contributed to the study and authored portions of the report include: Allan Jelacic, Raymond Fortuna, Raymond LaSala and Jay Nathwani (DOE); Gerald Nix (retired), Charles Visser, and Bruce Green (National Renewable Energy Laboratory); Joel Renner (Idaho National Laboratory); Douglas Blankenship (Sandia National Laboratories); Mack Kennedy (Lawrence Berkeley National Laboratory); and Carol Bruton (Lawrence Livermore National Laboratory). Richard Price (TMS Inc.) and Clifton Carwile (consultant) also made substantial contributions. Michael Reed, Jim McVeigh, Jihan Quail, and Christina Van Vleck (SENTECH, Inc.) and Raymond David (National Renewable Energy Laboratory) contributed to the design and production of this report.

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Executive Summary

A DOE-sponsored study, **The Future of Geothermal Energy**[1], by a panel of independent experts led by the Massachusetts Institute of Technology (MIT), examined the potential of geothermal energy to meet the future energy needs of the United States. The panel concluded that geothermal energy could provide 100,000 MWe or more in 50 years by using advanced technology known as Enhanced Geothermal Systems (EGS). EGS are fractured, hot-rock reservoirs that have been engineered to extract heat by the circulation of water between injection and production wells.

This report briefly reviews the assumptions and conclusions of the MIT study. On the whole, those assumptions were reasonable and within the bounds of a balanced systems analysis. Conclusions about the amounts of investment needed to achieve competitiveness and produce 100,000 MWe were not supported.

The report's primary purpose is to evaluate relevant technology from today's commercial geothermal industry and other related industries. Much of the information covered here was developed through workshops attended by experts from the geothermal industry and related industries.

The steps in EGS reservoir development involve identifying a suitable site, creating the reservoir, and operating and maintaining the reservoir. Each step requires implementation of technologies specialized for the uniquely challenging geothermal environment. Currently available technologies are identified and assessed relative to their ability to satisfy the needs of EGS reservoir development. The adequacy of technology has been determined for both near- and long-term applications.

To achieve the goals outlined in the MIT study of large scale (100,000 MWe) use of cost-competitive geothermal energy, significant advances are needed in site characterization, reservoir creation, wellfield development and completion, and system operation, as well as improvements in drilling and power conversion technologies. These technology improvements will also support ongoing development and expansion of the hydrothermal industry. To realize the promise of EGS as an economic national resource, we will have to create and sustain a reservoir over the economic life of the project. The DOE strategy is to leverage and build from current geothermal technologies and resources to develop the advanced technologies required for EGS, while at the same time generating benefits in the near-, mid-, and long-term. This will require a systematic, sustained research and development effort by the Federal government in strong partnership with industry and academia to ensure full development of EGS.

A broad knowledge base about reservoir creation and operation will be essential for the eventual commercialization of EGS on a scale envisioned by the MIT study. This knowledge can only be gained by experience from field demonstrations in a variety of geologic environments reflecting a range of reservoir conditions. Immediate technology improvements are needed in reservoir predictive models, zonal isolation tools, monitoring and logging tools, and submersible pumps. These improvements and others stemming from the evaluation are essential for reaching the long-term potential[2] of EGS.

[1] The Future of Geothermal Energy: Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century (Massachusetts Institute of Technology, 2006). http://www1.eere.energy.gov/geothermal/future_geothermal.html.

[2] Ibid. 14-19.

Purpose

1.

In January 2007, a comprehensive study, **The Future of Geothermal Energy**, was released by the Massachusetts Institute of Technology (MIT). The DOE-sponsored study, performed by a panel of independent experts, examined the potential of using the Earth's heat to help meet the future energy needs of the United States. The panel concluded that geothermal energy is capable of providing at least 100,000 MWe within 50 years by using advanced technology known as Enhanced Geothermal Systems (EGS). The MIT panel also concluded that: "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."[3]

This report examines the conclusions of the MIT study and the critical assumptions that led to those conclusions, and determines whether those conclusions are well-founded. The report also evaluates the state of technology available in today's commercial geothermal industry and other EGS-related industries. Technologies from those industries will be essential to meeting the 100,000 MWe goal envisioned by the study.

Technology is constantly evolving; improvements and new approaches are introduced as market conditions warrant or dictate. This report only considers the adequacy of technology available today to bring EGS projects to market. With the success of the first commercial projects, technology improvements beyond those envisioned here can be expected to meet future needs.

In developing information for this report, DOE sponsored four workshops at which experts from today's geothermal industry and representatives from allied industries, such as the oil and gas industry, were asked to give their candid opinion of EGS technology. These workshops provided the basis for many of the conclusions presented here. Summaries of the workshops are available at the DOE geothermal web site: http://www.eere.energy.gov/geothermal/development_workshops.html. The summaries contain additional discussion of relevant issues.

Geothermal Energy and the EGS Concept

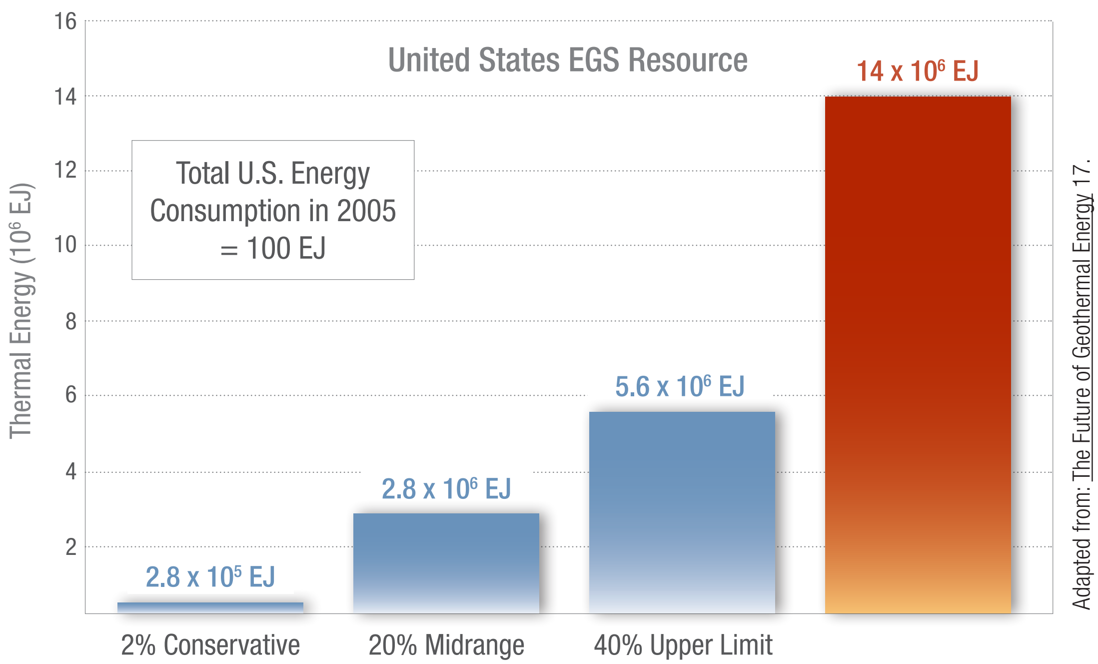
2.

Heat is naturally present everywhere in the earth. The MIT study calculated the prodigious amounts of heat at depths from 3 to 10 km (Figure 1). Given the current state of knowledge about the earth's thermal properties, this analysis is sound and was endorsed at the EGS workshops. For all intents and purposes, heat from the earth is inexhaustible.

Water is not nearly as ubiquitous in the earth as heat. Most aqueous fluids are derived from surface waters that have percolated into the earth along permeable pathways such as faults. Permeability is a measure of the ease of fluid flow through rock. The permeability of rock results from pores, fractures, joints, faults, and other openings which allow fluids to move. High permeability implies that fluids can flow rapidly through the rock. Permeability and, subsequently, the amount of fluids tend to decrease with depth as openings in the rocks compress from the weight of the overburden.

[3] Ibid. 1-3.

Figure 1. EGS Development Potential Shown



At shallow depths, typically less than 5 km, the coincidence of heat, water (usually with dissolved minerals and gases), and permeable rock can result in natural hot water reservoirs. These hydrothermal reservoirs have impermeable or low-flow boundaries such as structural discontinuities or other geological features that impede the migration of fluids. Often, hydrothermal reservoirs have an overlying layer or caprock that bounds the reservoir and also serves as a thermal insulator, allowing greater heat retention. If hydrothermal reservoirs contain sufficient fluids (water or steam) at high temperatures and pressures, those fluids can be produced through wells to generate electricity or, for process heat.

Today, the geothermal industry is a thriving commercial enterprise in the United States and throughout the world. The installed domestic capacity of geothermal power plants exceeds 2,800[4] MWe total in five western states, and the Geothermal Energy Association (GEA) predicts that generating capacity in the United States will double over the next five years, driven in large part by incentives such as the Production Tax Credit. These power plants use hot water and steam from hydrothermal reservoirs as their energy source.

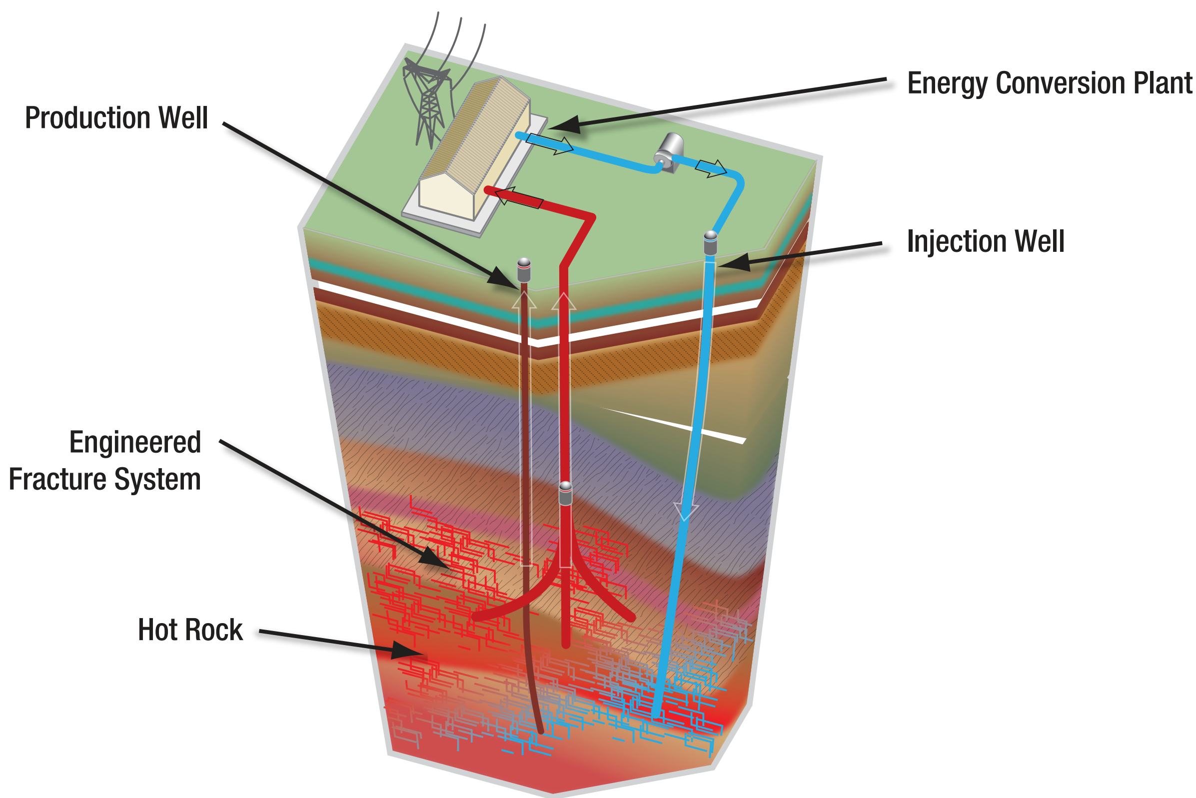
Beginning with national resource assessments by the U.S. Geological Survey (1975 and 1978[5]), various studies have estimated the developmental potential from identified hydrothermal resources to be in the range of tens of thousands of megawatts. After some 30 years of exploration, the estimated total potential has not increased significantly, leading some analysts to conclude that the occurrence of natural hydrothermal reservoirs is limited. The natural hydrothermal resource is ultimately dependent on the coincidence of substantial amounts of heat, fluids, and permeability in reservoirs, and the present state of knowledge suggests that this coincidence is not commonplace in the earth. An alternative to

[4] Geothermal Energy Association (GEA), "All About Geothermal Energy: Current Use," 6 Apr. 2008. http://geo-energy.org/aboutGE/currentUse.asp.

[5] L.J. Patrick Muffler, ed. Assessment of Geothermal Resources of the United States (1978). http://pubs.er.usgs.gov/usgspubs/cir/cir790.

dependence on naturally occurring hydrothermal reservoirs involves human intervention to engineer hydrothermal reservoirs in hot rocks for commercial use. This alternative is known as "Enhanced Geothermal Systems," or EGS. EGS reservoirs are made by drilling wells into hot rock and fracturing the rock sufficiently to enable a fluid (water) to flow between the wells. The fluid flows along permeable pathways, picking up *in situ* heat, and exits the reservoir via production wells. At the surface, the fluid passes through a power plant where electricity is generated. Upon leaving the power plant, the fluid is returned to the reservoir through injection wells to complete the circulation loop (Figure 2). If the plant uses a closed-loop binary cycle to generate electricity, none of the fluids vent to the atmosphere. The plant will have no greenhouse gas emissions[6] other than vapor from water that may be used for cooling.

Figure 2. EGS Cutaway Diagram



A complete geothermal system includes both surface and underground components, and the MIT study analyzed elements of both components. DOE has focused this technology evaluation on the underground component (i.e., the EGS reservoir), rather than the energy conversion surface component. The surface component represents a significant fraction of the overall cost of a commercial EGS and will be a major factor in ultimately determining economic viability. However, by far the greater knowledge gaps and technology uncertainties involve the reservoir.

6 Enex Binary Plants, "Benefits of the Enex Binary Plant," 6 Apr. 2008. http://www.enex.is/?PageID=191.

3. Assessment of Assumptions in the MIT Study

The DOE Geothermal Technologies Program (GTP) hosted four workshops, starting with a workshop on Enhanced Geothermal Systems on June 7-8, 2007, in Washington, DC, with invited experts from geothermal and related industries. Key individuals from the MIT panel described the study's assumptions and uncertainties, methods, and results to the participants. Summaries of the workshops are available at the DOE geothermal web site: http://www1.eere.energy.gov/geothermal/egs_technology.html.

The MIT study made a number of assumptions regarding geothermal resources, EGS technology, and the economics of EGS. The more critical of those assumptions (italicized) are examined below. Further discussion about the assumptions can be found in the workshop summaries.

3.1 Geothermal Resource

The study used the most current data available on subsurface temperatures across the United States to estimate heat in place at depths of 3 to 10 km. The analytic technique combined heat flow data, a general representation of geology, and thermal conductivities for the rock underlying the contiguous United States in a geographic information system (GIS) model to calculate the temperature at depth[7]. Oil, gas, and water well temperatures were used to validate the model's predictions, but those data are limited in depth and geographic extent.

Estimation of the resource required assumptions regarding *thermal gradient and conductivity of rock and the ability to extrapolate limited data to ensure complete coverage*. Because rock types at depth are uncertain for many locations, conductivity was estimated for most sites. The conductivities of common rock types at the depths of the study vary within a narrow range, and the impact on resource calculations is minimal.

Although few direct measurements of temperature exist at depths greater than 5 km in the United States, the estimates reported by the MIT study are sound and based on verifiable theory. The energy calculations are conservative in that the MIT panel discounted the considerable heat known to be present in the 0 to 3 km depth interval as well as the heat beneath certain dedicated lands such as national parks and wilderness areas.

3.2 Recoverable Resource

Literature estimates[8] of recoverability range as high as 90% of the heat in place (at uneconomic low flow rates) to a more credible 40%, given an optimal production strategy. The MIT study examined the recovery factor parametrically[9]. *The recovery factor of 2% is a conservative assumption* in the analysis. No geothermal reservoir has operated long enough to demonstrate an actual long-term recovery factor. Even at 2% recovery, the amount of resource in place is prodigious, well in excess of that needed to produce 100,000 MWe.

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[7] Petty, Susan and Gian Porro. 2007. *Updated US Geothermal Supply Characterization.* 22-24 Jan, at Stanford University, Stanford, California.

[8] Williams, Colin F. 2007. *Updated Methods for Estimating Recovery Factors for Geothermal Resources.* 22-24 Jan, at Stanford University, Stanford, California.

[9] Thorsteinsson, Hildigunnur, et al. 2008. *The Impacts of Drilling and Reservoir Technology Advances on EGS Exploitation.* 28-30 Jan, at Stanford University, Stanford, California.

While seemingly conservative for overall resource calculations, the choice of recovery factor is critical for EGS reservoir creation and operation and ultimately for economic viability. At the reservoir scale, the MIT panel apparently assumed *a local depletion factor for their economic analysis* based on modeled results by Sanyal and Butler[10]. Without long-term reservoir performance data, the choice of recovery factor remains somewhat arbitrary. Some reservoir engineers have calculated that at The Geysers geothermal field in northern California, the world's largest geothermal power complex, only about 10% of the heat in place has been recovered after nearly 50 years of production. Given the field's continued operation, albeit at a reduced production level, 10% might be taken as a conservative estimate.

3.3 EGS Well Drilling

Drilling is an essential operation in creating and sustaining EGS reservoirs. Today's oil and gas drilling technology can routinely reach depths of 4 to 5 km. The MIT study concludes that drilling costs rise exponentially for oil and gas wells while costs for geothermal wells remain linear. Estimates of drilling costs with depth were calculated by a parametric cost model using a rather limited data base from shallow wells[11]. The assumption of *linear well cost with depth* is not realistic beyond 5 km, given the rigors of the geothermal environment (temperature, pressure, hard crystalline rock, reactive fluids) and current state of technology. Hence, the projected well costs with depth are considered optimistic.

The MIT study modeled improvements in drilling based on an analysis of experience gained through case studies. This concept of experience driving improvements is termed the "learning effect." While there are uncertainties in the impact of learning, available studies tend to validate the assumption that learning reduces well costs, especially within a given field. Although a number of technological improvements are examined which would reduce cost, those improvements are correctly not included in the economic analysis. Ultimately, drilling costs will have to be reduced to produce 100,000 MWe from EGS.

3.4 Reservoir Creation

The MIT study assumed that *the principal means of EGS reservoir creation will be hydraulic stimulation* or the pumping of large volumes of fluids into the reservoir rock thereby fracturing the rock or opening pre-existing fractures. Hydraulic stimulation is a standard, mature technology[12], used in oil and gas fields to enhance production. This technology has been applied at all the EGS field projects to date with varied success. The MIT study contains an excellent summary of those stimulation experiments.

The key assumption associated with reservoir creation is that *sufficient volumes of rock can be stimulated with enough fracture surface area and permeability to enable the extraction of large quantities of heat*. This assumption is partially corroborated by EGS field experiments around the world, notably at Soultz-sous-Forêts, France. Rock volumes on the order of cubic

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[10] Sanyal, Subir K. and Steven J. Butler. 2005. *An Analysis of Power Generation Prospects from Enhanced Geothermal Systems.* 24-29 Apr, at World Geothermal Congress 2005, Antalya, Turkey.

[11] Augustine, Chad et al. 2006. *A Comparison of Geothermal with Oil and Gas Well Drilling Costs.* 30 Jan - 1 Feb, at Thirty-first Workshop on Geothermal Reservoir engineering, at Stanford University, Stanford, California. http://conferences-engine.brgm.fr/contributionListDisplay.py?confId=3.

[12] Fokker, Peter A. 2006. *Hydraulic Fracturing in the Hydrocarbon Industry.* 29 Jun - 1 Jul, at Enhanced Geothermal Innovative Network for Europe (ENGINE) Workshop 3, Zurich, Switzerland.

kilometers can be stimulated, assuming that observed microseismic events are indicators of shear fractures and hence, correlate with reservoir volume. However, the assumption that the reservoir volume will have adequate interconnectivity or permeability at commercial scales has not yet been proven. The results to date are based on pilot-scale experiments. An attempt to expand the reservoir at Soultz by connecting a third well to two others was largely unsuccessful, probably due to a previously unknown permeability barrier within the reservoir[13].

Assumptions about the ability to create EGS reservoirs of sufficient volume, surface area, permeability, and inter-well connectivity for commercial applications are reasonable, but optimistic, given the current state of knowledge. These assumptions have not been corroborated by large, well-documented field projects in a number of different geologic settings.

3.5 Reservoir Operation and Maintenance

The MIT study of reservoir performance under production conditions contains significant uncertainties that derive from reservoir geometry and permeability. The flow rate of circulating fluid in an EGS reservoir and the thermal drawdown associated with this flow rate are major unknowns. The analysis assumed *a flow rate of 80 kg/sec at 200°C from each production well*, equivalent to a commercial hydrothermal reservoir. This is a reasonable target, given that EGS reservoirs are intended to serve as enhanced or augmented hydrothermal reservoirs. At present there is no experimental evidence to verify that this level of productivity can be achieved. As pointed out in the analysis, the EGS project at Soultz, which is the best-performing project to date, has had a maximum well productivity of about 25 kg/s. Well productivity remains the greatest technological challenge for the commercialization of EGS.

Besides productivity, the analysis assumed that the fracture system will provide sufficient thermal stability for long-term production. This derives from the total effective surface area of the reservoir. The MIT study assumed *a conservative reservoir lifetime of six years, where lifetime is defined as a 10ºC decline in fluid production temperature*, after which the reservoir would have to be re-drilled and re-stimulated. This temperature decrement is conservative because greater amounts of cooling have been observed in commercially operating reservoirs. The reservoir lifetime and other parameter values for the base case EGS economic models are unknown in that no commercial-scale EGS plant has operated with sufficient thermal drawdown to establish reliable lifetime performance data.

The analysis assumed that *the system loses up to 2% of total injectate during reservoir operation*. For some systems, the cost of water could dominate stimulation costs. Water losses during operation are also a potentially important cost. Lacking knowledge about water consumption in various EGS environments, the assumption to limit water losses is optimistic if water must be accounted for in project costs.

For energy conversion, the assumption was that *the engineering systems would be the same as those used for liquid-dominated hydrothermal resources at similar temperatures (flash steam and binary power cycles)*. This is a reasonable assumption since differences between fluids

[13] Takatoshi, Ito. 2006. *Detection of Flow-pathway Structure upon Pore-pressure Distribution Estimated from Hydraulically Induced Micro-seismic Events and Applications to the Soultz HDR Field.* 29 Jun – 1 Jul, at Enhanced Geothermal Innovative Network for Europe (ENGINE) Workshop 3, Zurich, Switzerland.

produced from hydrothermal and EGS reservoirs should be minimal once chemical stability is attained during circulation. The thermodynamic analyses are based on well-understood and well-founded theory and data. Because energy conversion efficiencies have a linear influence on the calculated recoverable resource, errors in assumed energy conversion efficiencies may represent a minor source of error in resource calculations. The overall approach and the cost and performance results obtained are sound.

3.6 EGS Economics

Every element of the economic analysis has a different level of risk and different calculation requirements. Assumptions were made regarding many parameters for each EGS system element, including reservoir productivity, drilling, plant cost, resource depth, interest rates, and so forth. Interconnection with the power grid was assumed not to be an issue. Although stimulation and reservoir connectivity remain as major issues, reservoir creation efforts are assumed to be consistently effective. The technical parameters with the highest uncertainty and risk are flow rate per production well and thermal drawdown rate (i.e. reservoir lifetime.)

The analysis includes different learning curves for each technology element. *The learning curve for achieving 80 kg/sec flow rates was assumed to be a one-time*[14] *effect that is achieved fairly quickly*. The opinion of the experts in the workshops was that learning curves based on oil and gas experience may be optimistic for EGS well drilling[15]. The study uses an equity rate of return of 17%, which corresponds to a fairly risky venture. The drilling cost model uses a conservative contingency factor of 20% for trouble costs. For this type of economic modeling, the surface plant design is not specified in detail, so correlations must be used. Taken in total, the learning curve for plant costs is somewhat optimistic, and the long-term cost was based on the judgment of the MIT panel. Sensitivity analyses were performed to identify the variables most responsible for uncertainty and risk.

Some important assumptions were made regarding future baseload supply and demand. Of the 90 GWe of nuclear power in the existing power plant fleet, about half are assumed to be retired in the time frame of the study, and about 50 GWe of coal generation is also projected to be retired. This turnover in existing plant inventory provides an opportunity for replacement with EGS, concomitant with the development goal of 100 GWe.

The study assumed that *a carbon tax of $10/ton equivalent (equivalent to seven to eight mills/kWh) would be introduced beginning in year 10*. This tax was included on the expectation that policies would be adopted that would make thermal generation pay some externality cost (either through carbon capture and sequestration, or through a tax on CO_2 emissions). Without the carbon tax assumption, the predicted economic advantage of EGS over conventional electric generation is reduced and the rate of EGS penetration would be lessened.

3.7 Summation

The authors of the MIT study based their technical assumptions on results from available field tests, published reports, and well-established theory. On the whole, those assumptions were reasonable and within the bounds of a balanced systems analysis. The study's findings,

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[14] "Hydraulic Fracturing," Permian Basin Oil and Gas Magazine Apr. 2007:14-17. http://www.pbpa.info/newsletter/0704.pdf.

[15] Ibid.

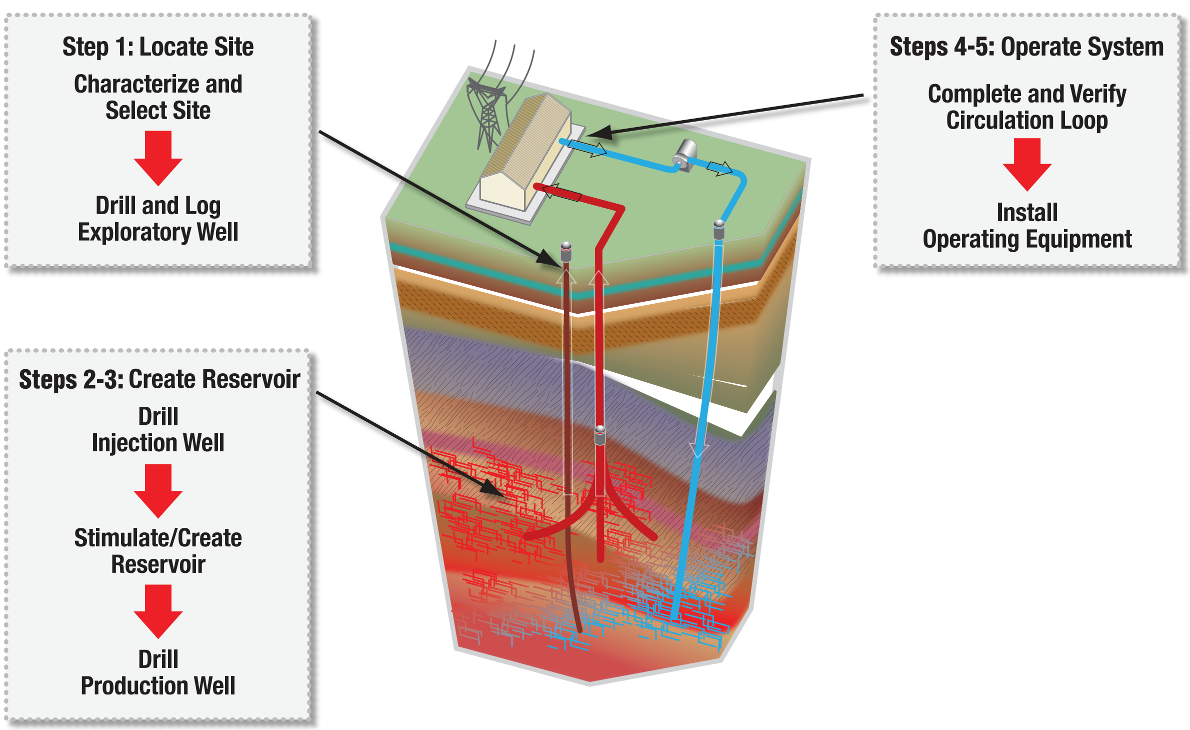
in particular that 100,000 MWe from EGS technology can be achieved within 50 years, are credible. But as the study points out, significant constraints exist in creating sufficient connectivity between wells to meet economic requirements for reservoir productivity and lifetime. Overcoming these constraints will require substantial reservoir testing in a number of different geothermal environments as well as research-driven improvements in technology. Consequently, the conclusion that a $300 million to $400 million investment over 15 years will be needed to make early-generation EGS power plants installations competitive is overly optimistic. This level of investment and the combined public/private investment of $800 million to $1 billion over 15 years to encourage sufficient deployment to produce 100,000 MWe are not supported by the analysis. Investments in excess of these amounts will probably be required.

4. Technology for EGS Reservoir Development

The MIT study provides a firm basis on which to consider how to bring the vision of commercialization of EGS technology to fruition. The remainder of this report evaluates available technologies from various fields and estimates their utility for EGS applications.

In conducting this technology evaluation, EGS reservoir development has been represented as a multi-step decision process. The process goal is to create an EGS reservoir that can operate economically. The logical steps that must be taken to complete an EGS economic reservoir project are: (1) finding a site; (2) creating the reservoir; and (3) operating the reservoir. The steps are illustrated in Figure 3, showing the tasks that must be performed. The decision process that should be followed to complete each step and task is illustrated in Appendix A.

Figure 3. EGS Development Sequence



At each step, a certain measure of performance must be achieved to allow the project to proceed to the next step. Those performance measures will usually depend on conditions at the site and the desired operational properties of the EGS reservoir. Ideally, they would be determined a priori by the model used to simulate the reservoir, but no such model yet exists at this level of detail. The MIT study used two independent models to consider EGS economics, but those models did not specify performance measures for each step of the development process. While lack of well-defined measures and a suitable reservoir model are drawbacks, the outcome of the technology evaluation should not be significantly affected at this level of analysis.

Results of the technology evaluation are presented here in Tables 1-5 which list the *Required Tasks* that must be performed to develop a commercial-scale reservoir, the *Available Technologies* to do the task, the current *Status* of those technologies, and the *Adequacy* of the technologies to complete the task satisfactorily. In the tables, *Near-Term* adequacy refers to the ability of available technology to complete the required task independent of cost at a few selected demonstration sites. *Long-Term* indicates the ability to commercialize EGS on a scale commensurate with the MIT study. (Note: Color coding in the table indicates the relative degree of adequacy /readiness for each technology, with green denoting most adequate and red denoting least adequate.) While some technologies are adequate for the job at hand in the near-term, they may not be suitable for large-scale EGS deployment because of performance limitations or cost. Where applicable, such deficiencies are identified.

4.1 Finding the Site – Site Characterization

The first step in creating an EGS reservoir is to find an appropriate site. At this time, lack of experience with EGS development presents a problem in defining what is "appropriate." Site characterization will draw on existing knowledge of the site and its surroundings to the extent data are available. Depending on the quality of the databases, substantial pre-development information may be obtained about a number of technical and non-technical properties. Adequate heat obviously must be present for the desired application, but the depth to the target temperature is important for economic reasons. Various site properties that should be known for successful creation of the reservoir include:

- Temperature gradient and heat flow
- Stress field
- Lithology and stratigraphy
- Structure and faulting
- *In situ* fluids and geochemistry
- Geologic history
- Seismic activity
- Proximity to transmission
- Land availability
- Demographics

The list is illustrative of the range of properties, rather than exhaustive. Some or all of these properties may already be known if wells have previously been drilled at the site and suitable data collected. Lacking such wells or data, prospective reservoir properties must be inferred from the surface. Additional information can be gathered by site analyses and surveys, such as seismic reflection and geologic mapping. Surface-based technologies are available that can provide information about many site characteristics, but that information becomes more problematic with depth. Remote technologies have proven successful in finding new hydrocarbon resources for companies involved with the oil and gas industry. However, these technologies have not yet been successfully applied to EGS, especially regarding expected reservoir properties. For example, the MIT study states that: "Exploration methods that can effectively tell us the stress field at depth from the surface are not currently available"[16]. There currently appears to be no known technological solution to remotely characterize important EGS reservoir properties with confidence.

Table 1 summarizes the information needs for site characterization and the technology available to meet those needs. The table and following commentary suggest potential areas of improvement in technology.

TABLE 1. Finding the Site – Site Characterization

■ = Most Adequate ■ = Some Degree of Adequacy ■ = Least Adequate

REQUIRED TASK	AVAILABLE TECHNOLOGIES	TECHNOLOGY STATUS	ADEQUACY	
			Near-Term	Long-Term
Determine temperature gradient and predict temperature at depth	Various temperature measurement tools in shallow boreholes	Commonly used throughout industry. Gaps are primarily data, not technology.	YES	YES
	Geothermometry (chemical and isotopic measurements)	Some interpretation of geothermometry requires sophisticated understanding of numerous interacting factors, such as shallow equilibration.	YES	NO
Determine stress field using surface-based technology	InSAR	The strength of Interferometric Synthetic Aperture Radar (InSAR) is its ability to provide observations of ground displacements with a precision of a few millimeters in images with 20-meter spatial resolution covering 100-km distances.	YES	YES
	Global Positioning System (GPS)	The GPS provides only regional coverage unless many instruments are used with close spacing. GPS may provide regional indication of stress.	YES	YES
Determine geologic characteristics and history (lithology and structure)	Geophysical surveys	Surveys are routinely used in mineral and petroleum exploration. Seismic interpretation is inadequate for many geothermal environments. Magnetotelluric surveys can be improved. Electrical resistivity surveys are technically acceptable, but equipment can be improved. Magnetic surveys are technically acceptable.	YES	NO
	Lithologic analysis	The science, methods, and equipment used for this analysis are mature.	YES	YES
	Geologic mapping	The science, methods, and equipment used for mapping are mature.	YES	YES

Table continued on following page

[16] The Future of Geothermal Energy 5-8.

REQUIRED TASK	AVAILABLE TECHNOLOGIES	TECHNOLOGY STATUS	ADEQUACY	
			Near-Term	Long-Term
Detect fluid-filled fractures	Self-potential; streaming potential	Self-potential is commonly used for shallow hydrothermal systems.	NO	NO
Evaluate background seismicity	Seismometers located in shallow surface holes	Surface seismometry is a mature technology.	YES	YES
Predict potential for stimulation	Geologic models from the oil and gas industry	Data and experience are inadequate for modeling of most projected EGS environments due to lack of sufficient measurements under geothermal conditions.	NO	NO

As Table 1 notes, current technology can be used to characterize potential EGS sites. As EGS commercialization grows, new technology will be needed that will enable site characterization to be done in a less costly manner and with greater confidence. The table indicates target areas of needed technological improvement:

- Better models of the appropriate geologic settings for EGS.
- Improved geophysical methods for finding fluid-filled fractures.

Geologic models are only as good as the quality and adequacy of the information used to construct them. Existing models are based on oil and gas field properties that cannot predict the potential for EGS. Models for most appropriate EGS geologic settings must be developed.

Significant research is required to develop and demonstrate surface-based technology with adequate resolution at reservoir depth. At present, remote determination of key EGS reservoir rock characteristics appears out of reach in the near-term.

4.2 Finding the Site – Exploratory Well and Reservoir Characterization

While remote techniques for determining in-situ reservoir properties give some first-order knowledge about the site, they do not confirm the site's suitability for development at the projected reservoir depth. This must be done with an exploratory well, which may be either a slim hole or a full-scale injection well. This well is intended to measure and/or confirm reservoir properties; it is not necessarily part of the final EGS reservoir. A slim hole has the advantage of lower cost, while a large diameter well may eventually be used for the final reservoir. The difference reflects the degree of confidence (and financing) the developer has in completing the project. The situation would be improved by the presence of a pre-existing well that can be reworked (i.e., deepened, diverted, or perforated) as an exploratory well.

Taking rock core and a suite of well logs is a vital element of drilling an exploratory well to fully characterize the reservoir rock. Because stress field azimuths guide the drilling program for the remainder of the wells in the field, a small hydraulically created fracture (a "mini-frac") is induced in the reservoir rock to determine the in-situ stress field. Flow tests of fluid between the rock and the wellbore should also be conducted as a means of determining reservoir productivity prior to stimulation.

The aforementioned techniques will probably be used in the first wells drilled at any project. Table 2 shows technology availability and adequacy for gaining knowledge of the subsurface that will be useful in planning the stimulation. The table indicates that adequate technology exists to characterize early EGS sites, but broad-scale improvements in technology will be required in the long-term.

TABLE 2. Finding the Site – Exploratory Well and Reservoir Characterization

■ = Most Adequate ■ = Some Degree of Adequacy ■ = Least Adequate

REQUIRED TASK	AVAILABLE TECHNOLOGIES	TECHNOLOGY STATUS	ADEQUACY	
			Near-Term	Long-Term
Characterize subsurface conditions	High-temperature logging and imaging tools Log interpretation methods	Some tools for one-time measurements of wellbore and system parameters are available, but they may be deficient at high temperatures. Geothermal log interpretation methods are derived from oil and gas experience.	YES	NO
	Stress measurement inferred from natural breaking of rocks in the wall of the wellbore and "mini-frac"	Principal stress direction and magnitude are estimated from limited testing capabilities. Imaging tools for breakouts currently require a heat shield.	YES	NO
	Core sampling and evaluation	Routinely used in mineral exploration. Interpretive techniques for geothermal applications are still evolving.	YES	NO
Isolate zones within the well for mini-fracs and flow testing	High-temperature packers	A prototype high-temperature packer for low-pressure applications is available, but little field work has been performed.	NO	NO
Conduct flow tests	Pressure, temperature, and fluid-flow measurement tools	Suitable downhole instrumentation for standard flow tests available up to 200ºC.	YES	NO
Perform stress measurements	Micro-fracs and borehole breakouts, core-based measurements	Suitable technology available for lower-temperature applications. Technology lacks zonal isolation capability.	YES	NO
Interpret data to plan stimulation	Models predicting the effect of stimulation on fracture formation and growth	Current models have not been effective in a geothermal environment.	YES	NO

The MIT study and Table 2 note that high-temperature instrumentation for borehole imaging and other purposes is a key technology deficiency. Though tools exist that can perform satisfactorily for short periods, instruments capable of collecting data in place for protracted periods (i.e., days to years) for well stimulation and, more importantly, for reservoir operation and management remain elusive. Until methods for reliable zonal isolation are available for high-temperature applications at high differential pressures, all stimulation attempts, including mini-fracs, will be limited to open-hole or low-temperature applications.

The procedures for drilling the exploratory well should not differ greatly from those used in drilling any moderate to deep well. If the well has an intended use as a production or injection well, precautionary steps should be taken in well completion (casing strings and cementing, open-hole section). The technologies, materials, and services needed to construct the well are available from commercial suppliers.

4.3. Creating the Reservoir – Injection Well

Once preliminary characterization activities have been completed, reservoir development can proceed with drilling of the initial injection well. Information about the reservoir rock (e.g., temperature, stress field, lithology, and structure) is valuable in planning the drilling campaign. As with the exploratory well, drilling technology is fully commercial, though long-term improvements can be made, especially by adapting equipment and tools to the high-temperature geothermal environment. Table 3 addresses the adequacy of current drilling technology for EGS applications.

TABLE 3. Creating the Reservoir – Injection Well

■ = Most Adequate ■ = Some Degree of Adequacy ■ = Least Adequate

REQUIRED TASK	AVAILABLE TECHNOLOGIES	TECHNOLOGY STATUS	ADEQUACY	
			Near-Term	Long-Term
Reduce rock	Drilling bits	Roller bits are used in hard rock. Advanced bits (e.g., PDC-based drag bits) are used in oil and gas, and they drill 60% of footage worldwide. Alternatives to mechanical methods (flame jet, etc.) are in experimental stages.	YES	NO
Steer the direction of wells	Advanced steering tools	Wireline based systems are used in geothermal. Commercial advanced steering tools allow control over well trajectories. Tools providing limited steering control are in use by one geothermal firm. Commercial tools are limited to ~150ºC.	YES	NO
	Logging while drilling/diagnostics while drilling	The technology is commonly used in the oil and gas industry. Commercial tools are limited to ~150ºC.	YES	NO
Complete wells	Metal casing in various diameters and production tubing (e.g., slotted liner)	Fully commercial systems to complete wells are available. Advanced technology, such as expandable tubulars and casing-while-drilling and low-clearance casing systems, is emerging in oil and gas applications. Underreamers work only in "soft" rock. Elastomers used in these systems fail at high temperatures.	YES	NO
	Design methods for selective cementing	Various high-temperature cement formulations are available from the drilling service industry. Design methods for selective cementing of casing exist for wells with small temperature fluctuations.	YES	NO
Isolate zones during drilling	Open and cased hole packers and expandable tubulars and screens	Elastomer and cement packers commonly used for low-temperature applications. Experimental versions of low-pressure packers developed for geothermal applications are not generally available. Retrievable packers for high pressure operations in high temperature (>150°C for extended operation) wells are not available.	NO	NO

Table continued on following page

REQUIRED TASK	AVAILABLE TECHNOLOGIES	TECHNOLOGY STATUS	ADEQUACY	
			Near-Term	Long-Term
Log well	Logging tools (e.g., tools to measure downhole pressure, flow, temperature, image fractures)	Logging tools and sensors are available for operation up to about 150°C. Higher temperature versions of some tools are available but have limited lifetimes or require heat shielding. Unshielded prototypes for pressure and temperature are experimental.	YES	NO
Monitor well parameters	Micro-fracs and borehole breakouts, core-based measurements	Suitable technology available for lower-temperature applications. Technology lacks zonal isolation capability.	YES	NO
Interpret data to plan stimulation	Monitoring tools, sensors (e.g., tools to measure downhole pressure, flow, temperature, and seismicity)	Monitoring tools and sensors are available commercially for sustained operation up to about 150°C. Tools capable of operation at >200°C are still experimental.	YES	NO

EGS well construction activities resemble those employed in the oil and gas industry, but there are substantive differences. Geothermal wells are typically drilled at higher temperatures with larger diameters in harder rock. These differences and the small size of the geothermal industry have retarded geothermal drilling technology relative to oil and gas technology. The geothermal industry has moved forward despite the disadvantages. For purposes of this evaluation, technologies associated with drilling and completing injection and production wells are taken to be the same, and this report does not differentiate between them.

The following commentary elaborates on points made in Table 3:

- PDC bits dominate drilling because of increased rate of penetration and longevity, but these bits have yet to be proven in geothermal environments. Roller cone bits are used in geothermal hard rock environments, a century-old technology that is robust but slow. Advancements in rock reduction technologies will probably be needed for EGS commercialization.
- High temperatures have hampered the introduction of oil and gas related technologies into geothermal well construction. The target operating temperatures of EGS wells (≧200°C) are greater than those of almost all oil and gas wells. Steering tools used at The Geysers geothermal field are primitive (i.e., first generation steering tools that use a cumbersome detachable wireline for power and communication), and attempts to use more advanced tools have failed. Operators have been able to achieve adequate results from old technologies, but better steering and logging while drilling (LWD) tools are desirable.
- Casing and cementing costs are responsible for roughly 30% of the cost of constructing a geothermal well. Reducing the amount of steel used is a goal for all drilling operations. "Lean" casing designs such as expandable tubulars, casing-while-drilling, and low-clearance casing systems (i.e., with a minimal annulus between casing strings) now emerging in the oil and gas industry offer additional advantages. These technologies increase options for dealing with difficult well conditions.

Transferring this technology to the geothermal environment to bridge rock strength and temperature issues will require hard-rock underreamers. Some casing schemes, such as expandable tubulars, employ elastomer sealing elements that are not suitable at geothermal temperatures.

- Geothermal wells are cemented to the surface to constrain casing and stabilize wellheads. Reducing the amount of cement used would simplify cementing and provide greater predictability in casing-rock interactions. Robust designs proposed by industry experts will let the casing float or expand and contract freely due to thermal fluctuations. Similar strategies would also benefit injection well designs.
- Zonal isolation is essential for many EGS reservoir development activities. Well control problems often require direct measures (e.g., cementing for lost circulation control) at specific zones of the wellbore. Open-hole zonal isolation tools include packers and alternative casing systems. Experimental packer systems developed for geothermal environments only operate at low pressure, or they are not retrievable and are not commercially available. Current best practices address wellbore problems during drilling, but alternatives that employ retrievable open-hole packers will be needed in the future.
- Logging tools for measuring temperature, pressure, flow, fracture imaging, and other formation characteristics require heat shielding and can only be used for brief periods. While the drilling industry works within these limitations, more robust tools capable of operating in >200°C environments are needed. Monitoring tools emplaced in the wellbore for long-term operations measure many of the same parameters recorded during transient logging activity, but can also include other reservoir monitoring sensors such as those for monitoring induced seismicity. Advances in components, battery technology, materials, and fabrication methods are desirable.
- Economic viability will require design and construction of wells and well fields that efficiently exploit the geothermal resource. The design space for EGS well construction should include options for highly deviated directional wells, multilateral completions, multiple completion zones, and so forth.

Current technology gaps will hamper, but not prevent, implementation of EGS demonstrations and supporting experimental projects. Economic development of EGS will require advances in a number of technologies and well construction schemes that maximize the effectiveness of stimulation, injection, and production of EGS reservoirs.

4.4 Creating the Reservoir - Stimulation

Once the first injection well has been drilled and completed, the reservoir rock can be stimulated. Stimulation usually requires an open-hole section through the targeted fracture zone, which has been determined from logs, core, and other information gathered during site characterization.

The tasks required to stimulate the reservoir as determined by the MIT study are shown in Figure 4 (see Tasks 1-9). Carrying out these tasks should create a large fractured volume of rock. The fracturing fluid must be pumped at high pressures and flow rates, and a high-fidelity seismic monitoring network is critical to the stimulation (Task 5).

Figure 4: MIT Study Reservoir Creation Process Tasks

1. Drill the first deep well (injection) with the casing set at appropriate depth to give 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 microsensor array, install an appropriate instrumentation system to yield the best possible quality of 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's 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 an the density of *in situ* fluid, it may be possible to influence the vertical direction of reservoir growth by selecting an appropriate stimulation fluid density.
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 well separation 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 about 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.

Adapted from: The Future of Geothermal Energy 12-14.

The knowledge base for stimulation of geothermal systems remains limited. Some experts believe that successful stimulation will require favorably oriented pre-existing fractures or zones of weakness. Furthermore, stimulation would be dominated by shearing rather than tensile fracturing. They advocate applying only enough hydraulic pressure to shear existing zones of weakness, rather than using higher pressures that would induce tensile fractures. Hydraulic stimulations in oil and gas fields, which are typically done at pressures well in excess of the rock strength, appear to include a combination of both shearing and tensile fracturing. For EGS to become a universal technology, stimulation must succeed in a variety of stress environments.

The technology is available to stimulate both petroleum and geothermal reservoirs, though stimulation is not commonly practiced by the geothermal industry. The ability to create a circulation system with both high productivity and thermal stability over time has not been demonstrated.

Table 4 identifies the adequacy of technologies needed to complete the stimulation successfully.

TABLE 4. Creating the Reservoir - Stimulation

■ = Most Adequate ■ = Some Degree of Adequacy ■ = Least Adequate

REQUIRED TASK	AVAILABLE TECHNOLOGIES	TECHNOLOGY STATUS	ADEQUACY	
			Near-Term	Long-Term
Plan and design stimulation (e.g., zones, pressures, volumes, fluids, proppants)	Stimulation models for oil and gas; basic numerical models for geothermal applications	Stimulation modeling techniques for geothermal systems are not a mature technology.	YES	NO
Imaging and mapping of fractures	Microseismicity, gravimetry, self-potential, tiltmeter arrays	Surface microseismic and gravity tools are adequate for most purposes, but the resolution may be insufficient for EGS. Self-potential is not proven for this purpose. Tiltmeter results are difficult to interpret in zones of multiple fractures.	YES	NO
Identification of flow paths during and post-stimulation	Microseismicity, gravimetry, SP, tiltmeter arrays	The utility of existing techniques for tracking fluid flow has not been demonstrated. Microseismic techniques are not hardened for downhole use.	NO	NO
Effective real-time decision-making capability for stimulation	Oil and gas industry stimulation modeling and control technology	The oil industry has modeling and control capability for petroleum environments, but experience in geothermal systems is lacking.	YES	NO
Zonal isolation for stimulation	Stimulation packers, slotted liners	Packers that can operate at stimulation pressures and temperatures are not available. Slotted liners and related technologies may not perform adequately for EGS	NO	NO
Create/enhance flow paths	Hydraulic stimulation; chemical stimulation; and rate controlled explosives	Geothermal stimulations for EGS use water or water weighted with dense chemicals such as barium sulfate salts. Chemical and other stimulation methods have been used in hydrothermal systems.	YES	NO
Keep flow paths open	Proppants for both near well bore and far field use scaling, dissolution, and permeability control	Proppants are typically used in oil and gas stimulations. Temperature-hardened proppants have not been evaluated in geothermal environments. Scaling and dissolution control technologies are available, but may not be adequate for EGS conditions.	YES	NO

The purpose of reservoir stimulation is to provide abundant fluid flow paths between the injection well(s) and the production well(s). These flow paths should have minimal impedance to reduce pumping power needs, but adequate residence time and surface area to sustain the production of hot fluids.

The following commentary elaborates on points made in Table 4:

- Stimulation design involves selecting zones of the wellbore to be targeted for stimulation as well as the rate, pressures, and volumes of injectate. The type(s) of stimulation fluids and use of proppants must also be considered. The oil and gas industry routinely employs application-specific design tools for its stimulations[17]. While design codes exist, robust tools that couple hydrological-thermal-mechanical-chemical phenomena are not available. Revised and/or new design tools will be required for commercial EGS development. Field experience and data are vital to developing such tools.
- Mapping the evolution or growth of fractures during stimulation is very important. Surface (or near-surface) seismic monitoring, gravimetry, and tilt measurements are generally considered adequate for fracture imaging. The utility of these measurements depends on the fracture population; for example, tilt measurements are most useful in tracking single, rather than multiple, fractures. Increased resolution and accuracy of these mapping techniques requires downhole tools that can withstand the temperatures associated with EGS.
- While remote sensing of fracture growth via microseismic analysis indicates possible fluid flow paths, the ability to directly map the flow through the created reservoir does not currently exist. Methods to track fluid flow should be investigated[18].
- The oil and gas industry has demonstrated that real-time control and adjustment of the stimulation process is vital to success. Development of intelligent control systems requires both theoretical understanding and practical knowledge obtained from multiple stimulations in a variety of situations.
- Zonal isolation is required for selective stimulation of target wellbores. For open-hole applications, zonal isolation tools include packers and alternative casing designs. While experimental packer systems have been developed for geothermal environments, they were either designed for low pressure applications (e.g., for lost circulation control) or were not retrievable. General purpose open hole packers do not exist for geothermal environments, with the primary barrier being the poor stability of elastomeric seals at high temperatures. Cased hole isolation tools suitable for high-temperature environments are emerging, and these tools have the advantage of metal-to-metal seals.
- The purpose of stimulation is to create well-to-well flow paths that minimize impedance but meet operational needs. As previously suggested, the stimulation method may be important in the development of an optimum fracture network. Variable fluid weights and viscosities for hydraulic stimulation may be needed.

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[17] Yoshioka, Keita et al. 2008. *Optimization of Geothermal Well Stimulation Design Using a Geomechanical Reservoir Simulator.* 28 – 30 Jan, at Thirty-Third Workshop on Geothermal Reservoir Engineering, at Stanford University, Stanford, California.

[18] Karner, Stephen L. 2006. *Correlating Laboratory Observations of Fracture Mechanical Properties to Hydraulically-Induced Microsensitivity in Geothermal Reservoirs.* 30 Jan – 1 Feb, at Stanford University, Stanford, California.

Chemical stimulation techniques may be needed to increase permeability near the wellbore and in far-field fractures. More novel techniques using deflagration methods could also be used to enhance the effective radius of the wellbore.

- The MIT study assumes that EGS should target geologic settings where fractures are critically stressed. By stimulating such zones, reductions in the normal stress across fractures will induce shear failure. If the rock's matrix strength is sufficient, this shearing will result in dilation and increased fracture aperture; the fracture effectively "self-props." In settings where the stress state and fracture characteristics are not optimum, proppants may have to be employed to prevent fractures from closing. In addition, it may be advantageous to create secondary fractures that link to the existing network, again requiring proppants. While proppants are used extensively in the oil and gas industry, they are not chemically stable for high-temperature applications. Temperature hardened proppants may be required.

Creation of the reservoir through stimulation is considered to be a critical aspect of EGS development. Technology needs, such as real-time control of the stimulation, are extensions of current petroleum industry capabilities. EGS-specific needs, those with general applicability, include understanding fluid flow paths through use of imaging techniques not currently available.

4.5 Completing the Well Field

Once the initial volume has been stimulated by either opening existing fractures, creating new fractures, or both, circulation can be established by drilling a production well. Care must be taken in drilling this well; directional drilling may be required to intersect the fractures created during stimulation of the initial well. Measurements of acoustic signals generated by the stimulation are used to delineate the zone of fracturing. At present, insufficient knowledge about fracture behavior is available to pinpoint the target zone. The current strategy seeks to penetrate the fringe of the acoustic signals or microseismic cloud, rather than the zone of highest event density, to maximize the inter-well distance.

The remaining tasks to complete the reservoir are described in the MIT study (see Figure 4, Tasks 10-14). These tasks are necessary to establish sufficient connectivity between wells. As suggested by Task 14, the number of wells drilled (both injection and production) will depend on the size of the reservoir, the productivity of the wells, and the development plan. In early stages, especially at a new site, the number will likely be in the range of three to six wells until working experience is gained.

Production wells will follow much the same drilling procedures as injection wells (see Table 3). Differences are likely in the extent of directional drilling, completion, and cementing to accommodate stresses due to thermal cycling. Temperature-hardened proppants may be required to maintain fluid flow between wells (see Table 4).

Technology issues related to completing the EGS reservoir with additional wells appear at this point to be minimal. The greatest concern is positioning additional wells to optimize energy production while minimizing opportunities for short circuiting (premature breakthrough of injected fluids in production wells.) The best tool to avoid such unwelcome consequences is a reliable reservoir model which can predict flow between wells.

4.6 Operating and Maintaining the Reservoir

The economics of EGS hinge on the ability to produce energy for extended periods without resorting to expensive remedial actions, such as unscheduled drilling of additional wells. Experience in operating and maintaining EGS reservoirs is limited, and currently there is no knowledge base from which to make decisions. Critical issues at this step of development include short circuiting, dissolution or precipitation of minerals altering the reservoir's plumbing, buildup of dissolved solids and gases in the circulating fluid, inefficient recovery of heat, induced seismicity, and fluid losses from the reservoir. The petroleum industry has dealt with some of these issues, albeit in non-geothermal environments. In the absence of working experience with EGS reservoirs, responses to these issues must largely be trial and error.

Operationally, EGS wells will have to function at high pressures and flow rates in both injection and production modes for years. Pumping of fluids is expected to be necessary to maintain adequate flow rates. Reliable high-temperature submersible pumps have been consistently mentioned by experts as a technology gap throughout this analysis. The adequacy of technology to meet the operational requirements of EGS reservoirs is indicated in Table 5.

TABLE 5. Operating the Reservoir

■ = Most Adequate ■ = Some Degree of Adequacy ■ = Least Adequate

REQUIRED TASK	AVAILABLE TECHNOLOGIES	TECHNOLOGY STATUS	ADEQUACY	
			Near-Term	Long-Term
Maintain acceptable flow rates and reduce or eliminate fluid loss	Submersible Electrical Pumps	SEPs have operating temperatures of 175ºC with power ratings of 1500 kW. Pump technology is not adequate for long-term high-temperature deep operation.	NO	NO
	Packers for fracture isolation	High temperature zonal isolation tools are not available to allow control of flow from multiple zones.	NO	NO
	Lineshaft pumps	Lineshaft pumps are a fully commercial technology, but depth-limited.	YES	NO
Maintain reservoir and track reservoir evolution	Monitoring tools, sensors (e.g., tools to measure pressure, flow, temperature, seismicity)	Monitoring tools and sensors are available for sustained operation up to about 150°C. Downhole monitoring tools capable of sustained operation at >200°C do not exist.	NO	NO
Monitor rock/fluid interactions	Geochemical analytical techniques; geochemical models	Geochemistry is understood for a large subset of relevant chemicals, but real-time detection technology has limited scope and poor accuracy. Geochemical models lack confirmatory field data.	YES	NO
Mitigate reservoir and surface problems (e.g., short circuiting, pressure drop)	Coupled modeling tools and simulators; cements; zonal isolation tools	Cements are routinely used in the hydrothermal industry for lost circulation. Zonal isolation tools that operate at high temperatures are not available.	YES	NO

Table continued on following page

REQUIRED TASK	AVAILABLE TECHNOLOGIES	TECHNOLOGY STATUS	ADEQUACY	
			Near-Term	Long-Term
Manage induced seismicity	Pressure control; rock mechanics models	Operation protocols that limit injection/ production pressures are considered a useful management tool. Rock mechanics models are available, but cannot predict seismicity.	YES	NO
Control scaling	Scale control technology	Chemical management technologies (e.g., additives for pH control) are used in the hydrothermal industry to mitigate well bore and near-field scaling. Technologies for hydrothermal systems may not be as effective for EGS which will operate in chemical disequilibrium.	YES	NO
Validate reservoir model using field data	Monitoring tools and sensors (e.g., tools to measure pressure, flow, temperature, seismicity); tracers	Few sensors can operate at high temperature for long periods. A temperature sensor is available, but it must be hardened for geothermal conditions. Tracer tests are an established method of validating reservoir models. Smart tracers have not been developed.	YES	NO
Design field expansion	Reservoir simulation models	Existing models are not fully coupled to enable planning of field expansion. Sufficient data to validate models is not available.	YES	NO
Generate electricity	Heat exchanger and power plant	Power conversion technology is relatively mature in the hydrothermal industry. Currently evaluating for EGS applications.	YES	TBD

The management goal for reservoir operation is to sustain rated output for the design lifetime. To meet this goal it is necessary to optimize the extraction of heat with respect to temperature drop, maintain the rate of fluid production, prevent subsurface fluid loss, and minimize parasitic power losses. As heat extraction proceeds, temperatures in the reservoir will decline. Successful EGS reservoir management will require careful monitoring and mitigation to control the impact on heat recovery and power plant efficiency.

At this stage, every barrier to successful management and operation of EGS facilities has probably not been identified. However, as shown in Table 5, several technological advancements will clearly be needed to ensure economic success:

- Submersible electrical pumps will control fluid loss and minimize parasitic losses associated with high injection pressures. To meet EGS needs associated with long-term, high-temperature, deep-well operation, technical advancements in pump connections, materials, seals and controllers are required. Submersible electric pumps with 1000-3000 horsepower motors must survive ~3 years at ≧200ºC.
- High-temperature packers and other zonal isolation tools will reduce or eliminate fluid loss, help identify and mitigate short circuiting of flow from injectors to producers, and target individual fractures or fracture networks for testing and validating reservoir models.

- Temperature-hardened tools for real-time down-hole monitoring of temperature, pressure, and flow, along with in-stream surface monitoring of fluid chemistry, would significantly enhance the ability to track the hydrologic and thermal evolution of the reservoir, monitor rock-fluid interactions, and provide the appropriate field data for validating and updating reservoir models and simulators.
- Operation of an EGS reservoir will require injection of fluids that are not at equilibrium with the reservoir rock mass. As a result, scaling and/or dissolution will likely occur in the wellbore or the reservoir. Treatments available today may not be adequate for long-term operation.
- Although research sponsored by DOE has significantly advanced the sophistication and use of tracers for characterizing hydrothermal systems, development of new "smart" tracers is warranted. For instance, reliable tracers that can measure and/or monitor the surface area responsible for rock-fluid heat and mass exchange do not exist, limiting the ability to quantify and predict heat extraction efficiencies.
- Induced seismicity is an issue with potential to halt if not end a project, as demonstrated in Soultz, France, and Basel, Switzerland. Studies of the issue, including one released under the auspices of the International Energy Agency, conclude that damaging earthquakes as a result of EGS reservoir operation are unlikely. Nevertheless, the issue could have strong negative consequences on the acceptability of EGS projects near population centers. Initial impact in the U.S. is believed to be low since many candidate sites for early development are in unpopulated areas. The current state of knowledge does not point to technological solutions. Protocols for operation of EGS facilities have been proposed, but they have not yet been generally adopted or proven to be effective.
- Reservoir management and operation relies heavily on models and simulators that can accurately predict reservoir behavior. For optimum EGS operation, fully coupled Hydrologic-Thermal-Mechanical-Chemical (H-T-M-C) models and simulators will be necessary to predict fluid flow, heat extraction, temperature drawdown, rock-mechanical processes, and chemical processes that will have either beneficial or deleterious impacts on reservoir performance and longevity.
- The technical advances for submersible pumps and high-temperature isolation tools are likely to be unique to EGS. Development of temperature hardened tools for real-time, down-hole monitoring will be readily transferable to conventional geothermal systems. Smart tracer technology and fully coupled H-T-M-C models and simulators are multi-use technologies that will have value beyond the EGS domain.

Specific technology requirements at this stage of EGS reservoir development remain uncertain due to limited operating experience. Operational experience is measured in months rather than years. The longest period of continuous performance was at Rosemanowes, U.K. Fluids were circulated at Rosemanowes for three years, during which production temperatures fell from 80°C to 55°C, suggesting to some experts a probable short circuit in the reservoir. Technology solutions to address short circuiting, like other concerns with long-term operation, will require a much larger and broader experience base.

Conclusions

The MIT study was comprehensive, the assumptions and models were properly addressed and applied, and the study is suitable as a starting point for identification and prioritization of technology improvements required to commercialize EGS. While there are uncertainties in the analysis and gaps in knowledge, the study presents the present understanding of the EGS opportunity in a realistic manner. EGS can contribute substantially to meet future U.S. energy needs.

There are three critical assumptions about EGS technology that require thorough evaluation and testing before the economic viability of EGS can be confirmed:

1. **Demonstration of commercial-scale reservoir –** This requires stimulation and maintenance of a large volume of rock (equivalent to several cubic kilometers) in order to minimize temperature decline in the reservoir. Actual stimulated volumes have not been reliably quantified in previous work.
2. **Sustained reservoir production –** The MIT study concludes that 200°C fluid flowing at 80 kg/sec (equivalent to about 5 MWe) is needed for economic viability. No EGS project to date has attained flow rates in excess of ~25 kg/sec.
3. **Replication of EGS reservoir performance –** EGS technology has not been proven to work at commercial scales over a range of sites with different geologic characteristics.

These assumptions can be tested with multiple EGS reservoir demonstrations using today's technologies. However, as this evaluation shows, Research and Development should be conducted in parallel with field projects to fill some long-term technology gaps. The key technology requirements for immediate development stemming from this evaluation include:

- Temperature-hardened submersible pumps
- Zonal isolation tools
- Smart tracers
- Monitoring and logging tools
- Coupled models to predict reservoir development and performance

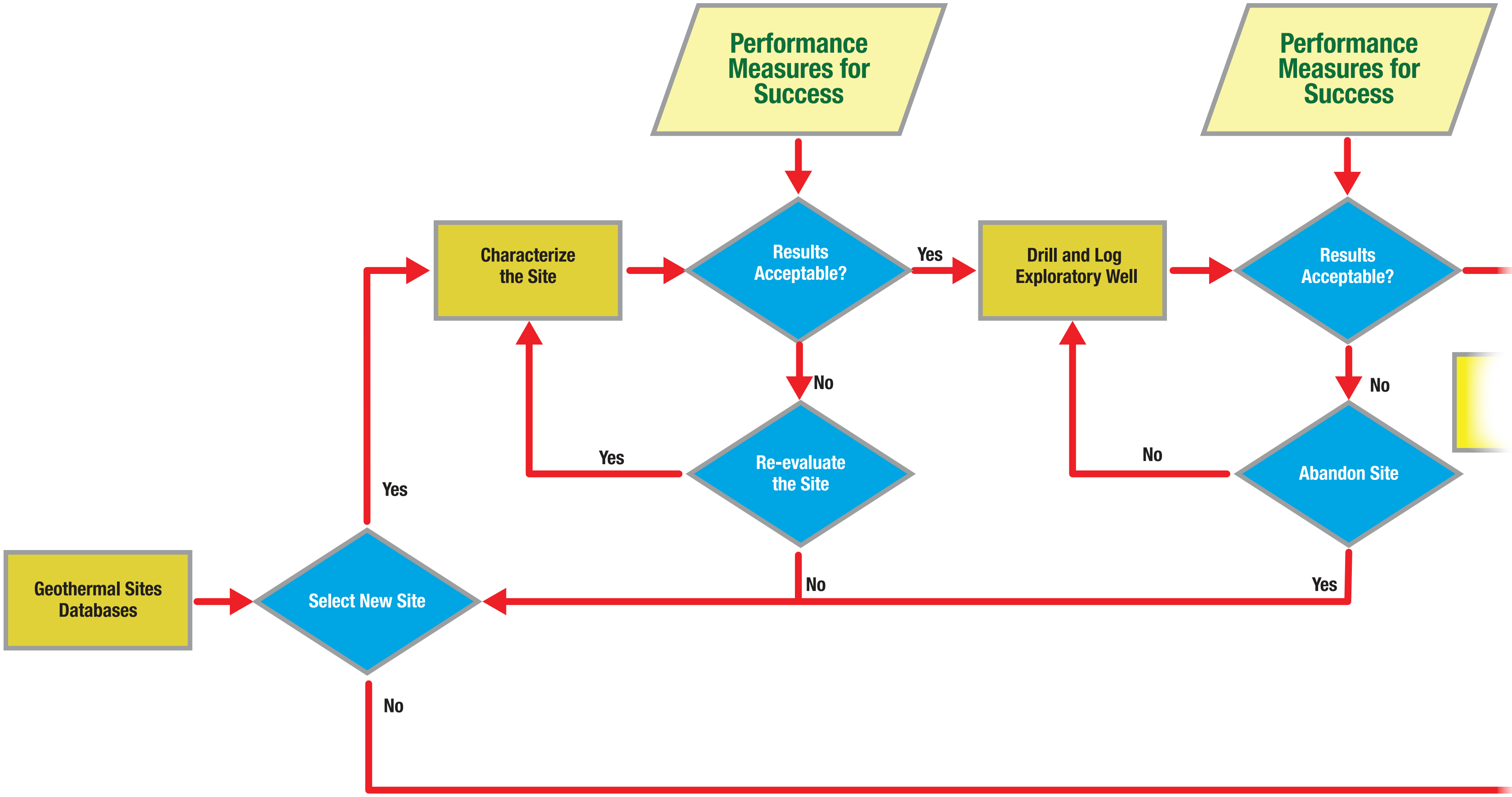
Experience from the conventional geothermal and petroleum industries provides a solid foundation from which to make technology improvements. In the long-term, significant reduction in drilling costs will be necessary to access deeper resources, and the cost of conversion of the energy into electricity must be reduced. These improvements will rapidly move EGS technology forward as an economically viable means of tapping the nation's geothermal resources.

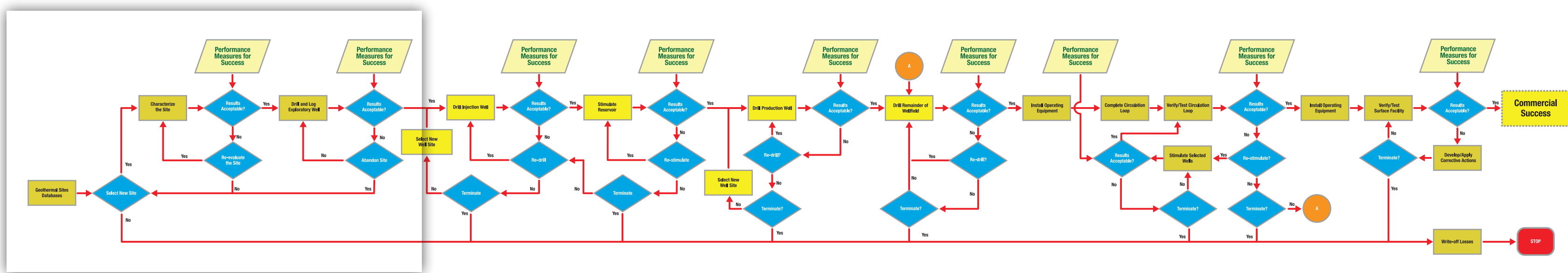
Appendix A:

Logic Process for Development of An Enhanced Geothermal System (EGS) Facility

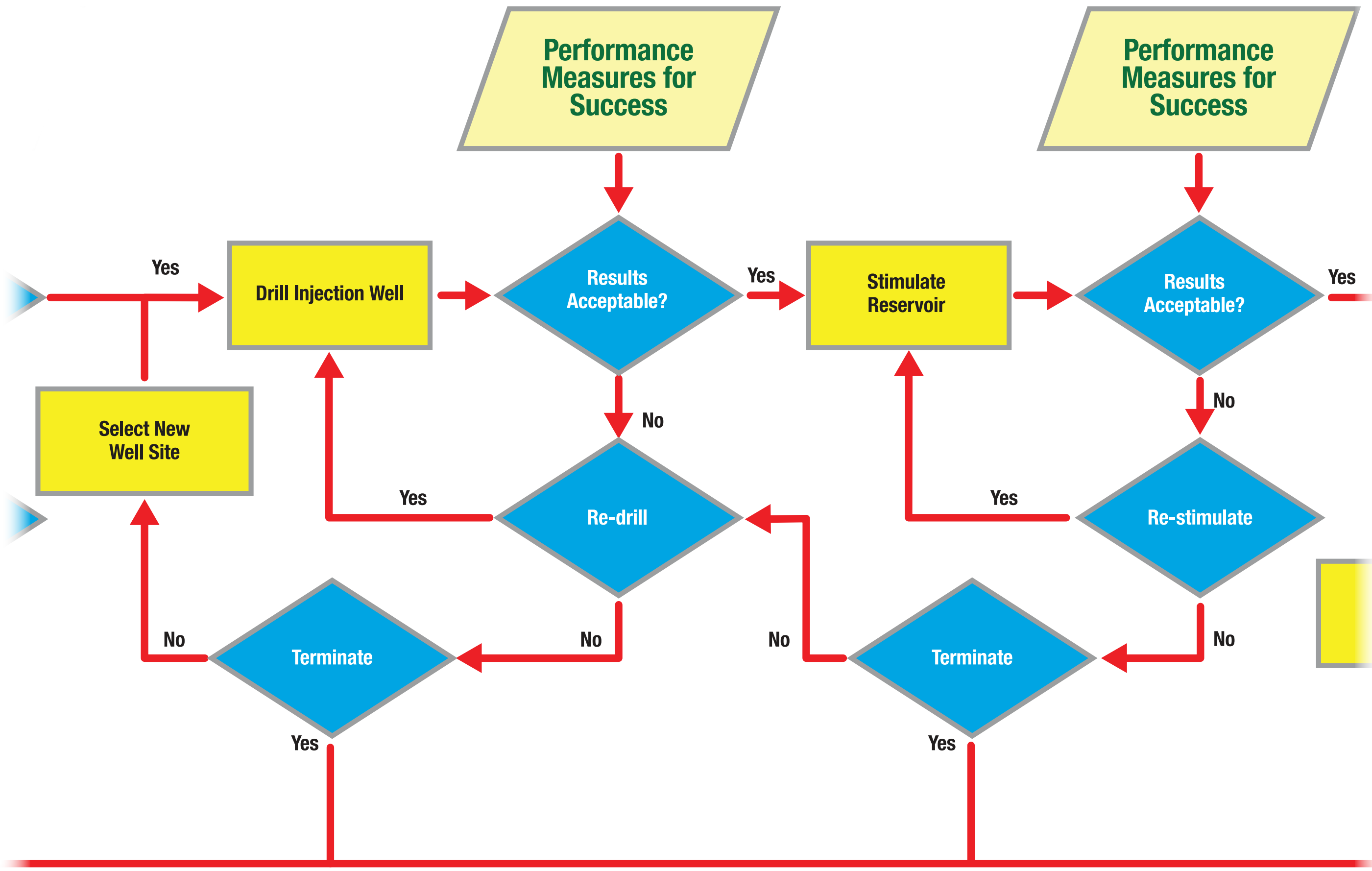
Appendix A: Logic Process for Development of An Enhanced Geothermal System (EGS) Facility

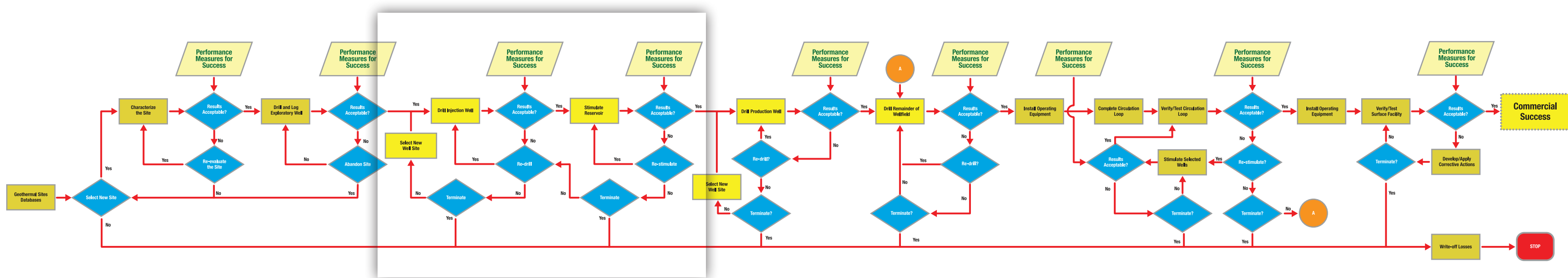
Step 1 - Finding a Site



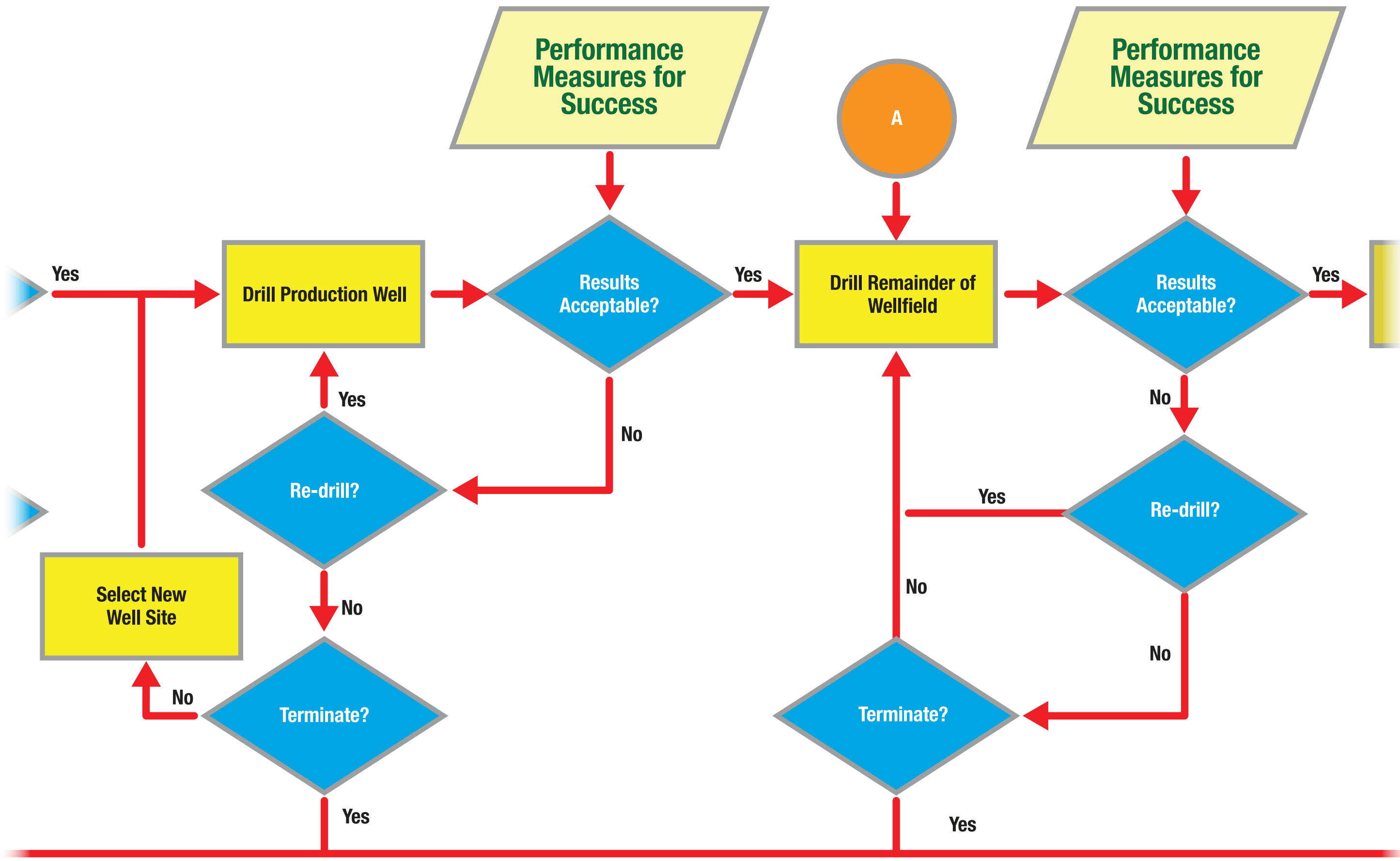


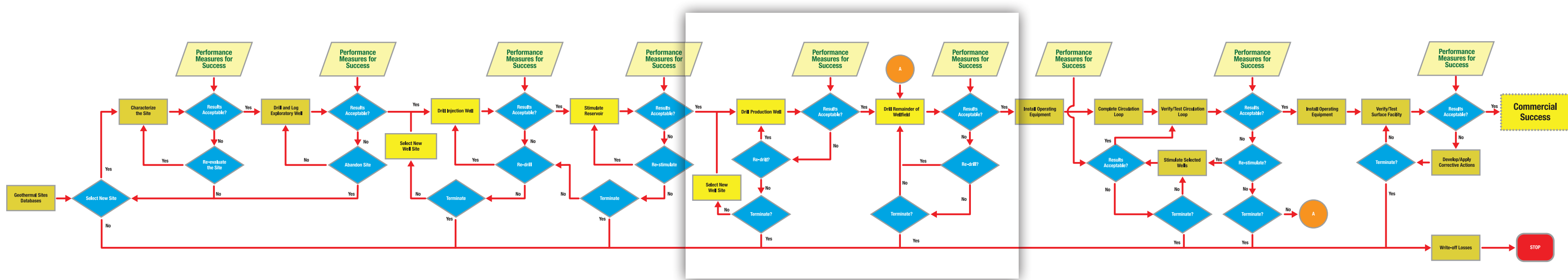
Step 2 - Creating Reservoir



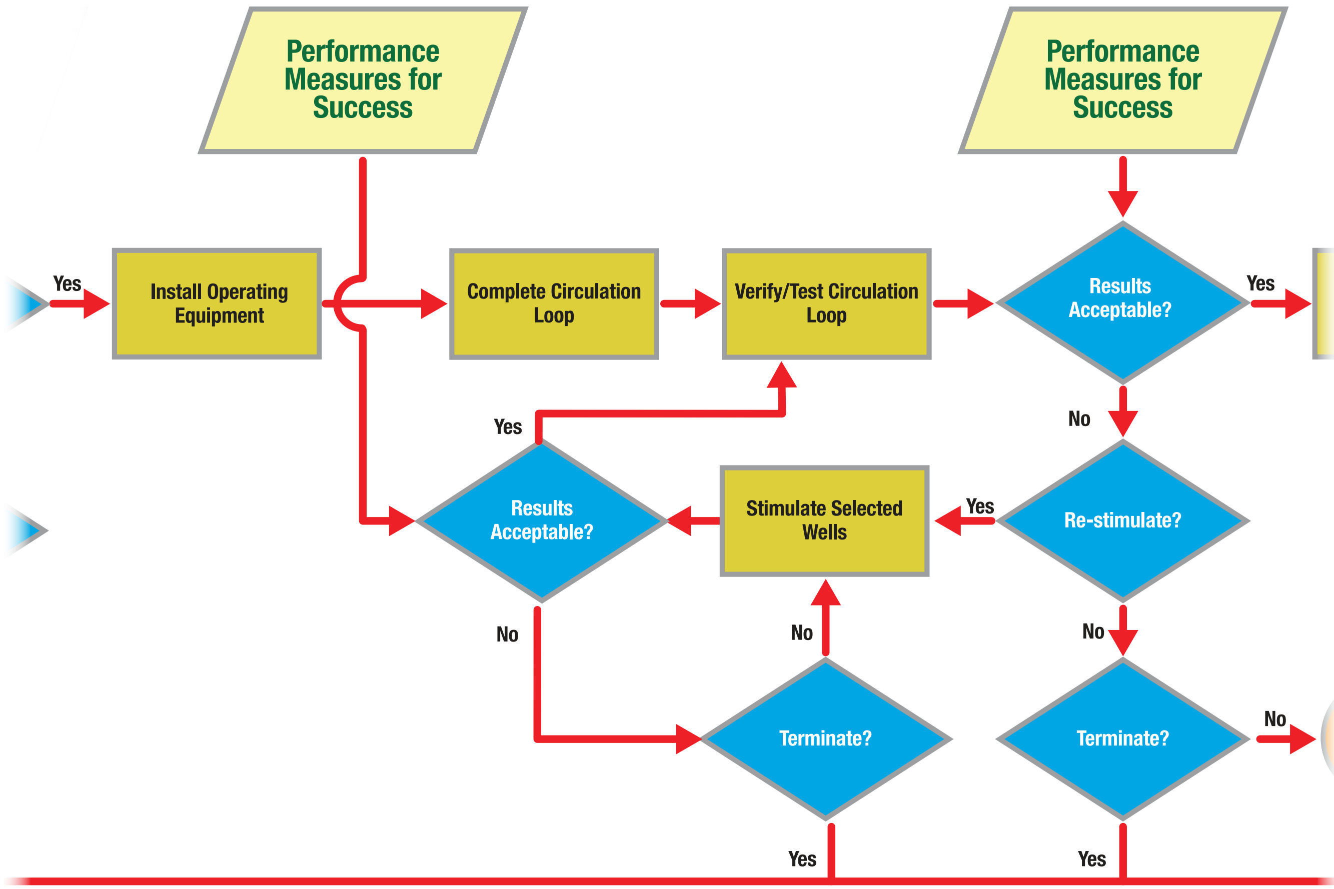


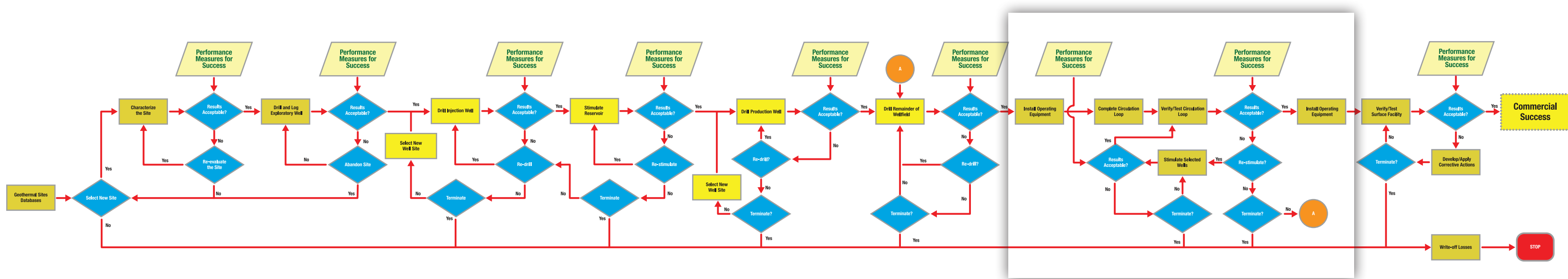
Step 3 - Completing Wellfield



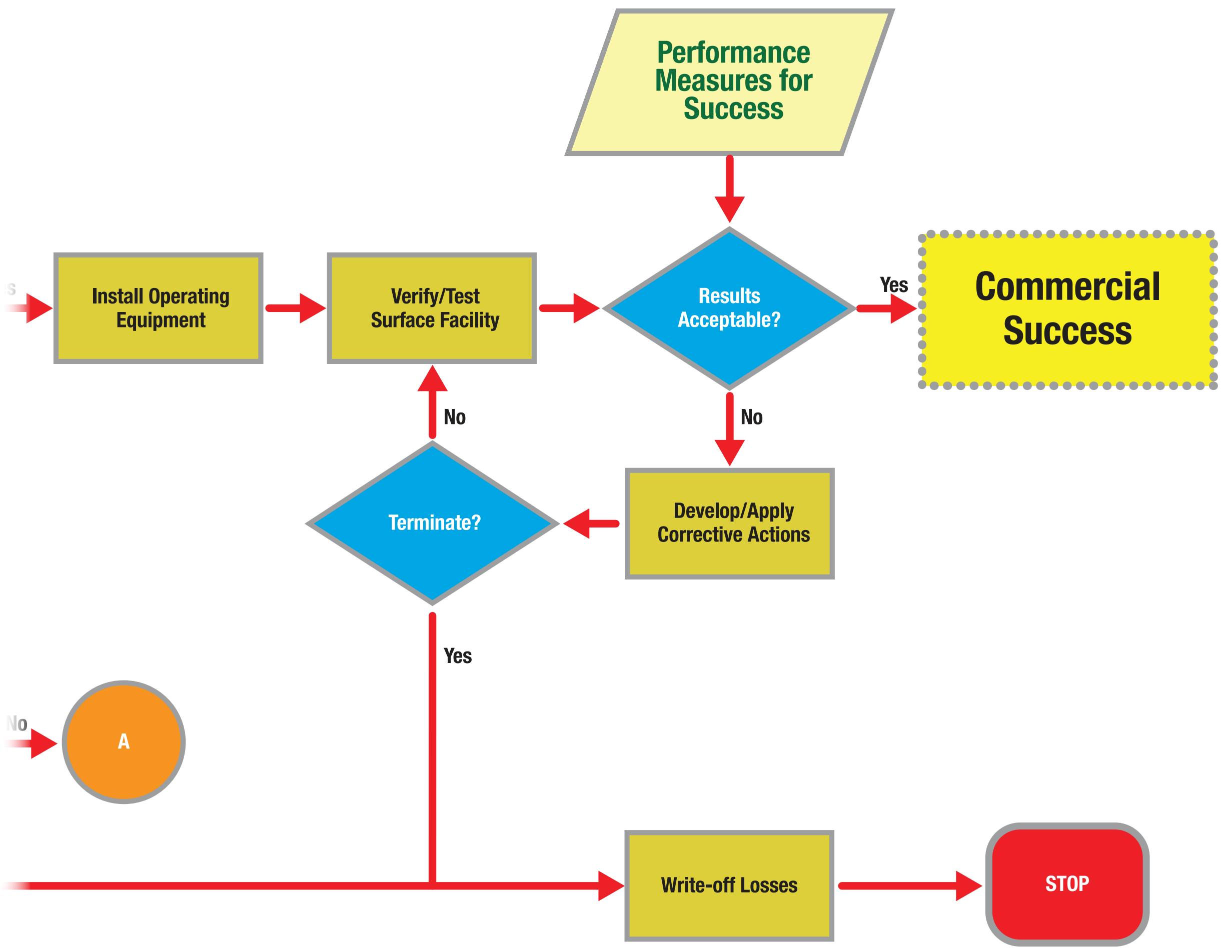


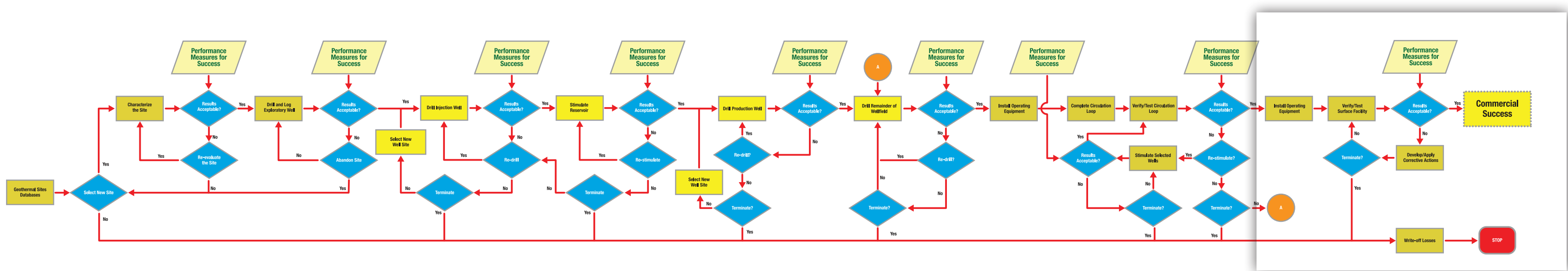
Step 4 - Operating Reservoir





Step 5 - Operating Facility





Glossary

Borehole Breakouts

Failure of the borehole wall which forms because of stress in the rock surrounding the borehole. The breakout is generally located symmetrically in the wellbore perpendicular to the direction of greatest horizontal stress on a vertical wellbore.

Binary Cycle

Binary geothermal systems use the extracted hot water or steam to heat a secondary fluid to drive the power turbine.

Casing

Pipe placed in a wellbore as a structural interface between the wellbore and the surrounding formation. It typically extends from the top of the well and is cemented in place to maintain the diameter of the wellbore and provide stability.

Core

A cylinder of rock recovered from the well by a special coring drill bit.

Depletion Factor

Annual percentage of the depletion of the thermal resource.

Drag Bit

Drilling bit that drills by scraping or shearing the rock with fixed hard surfaces, "cutters." See also *rotary cone bits* and *polycrystalline diamond compact bits*.

Enhanced Geothermal Systems (EGS)

Engineered reservoirs that can extract economic amounts of heat from geothermal resources.

Fault

A fracture in rock exhibiting relative movement between the adjoining surfaces.

Fracture

Natural or induced breaks in rock.

Fracturing Treatments

Fracturing treatments are performed by pumping fluid into the subsurface at pressures above the fracture pressure of the reservoir formation to create a highly conductive flow path between the reservoir and the wellbore.

Global Positioning System (GPS)

A navigational system using satellite signals to fix the location of a radio receiver on or above the earth's surface.

Geothermal Resources

The natural heat of the earth that can be used for beneficial purposes when the heat is collected and transported to the surface. See also *EGS* and *hydrothermal reservoir.*

Gravimetry

The use of precisely measured gravitational force to determine mass differences that can be correlated to subsurface geology.

Hydraulic Stimulation

A stimulation techniques performed using fluid. See *Stimulation.*

Hydrothermal

Pertaining to hot water.

Hydrothermal Reservoir

An aquifer, or subsurface water that has sufficient heat, permeability, and water to be exploited without stimulation or enhancement.

Induced Seismicity

Induced seismicity refers to typically minor earthquakes and tremors that are caused by human activity that alters the stresses and strains on the Earth's crust. Most induced seismicity is of an extremely low magnitude, and in many cases, human activity is merely the trigger for an earthquake that would have occurred naturally in any case.

Interferometric Synthetic Aperture Radar (InSar)

A remote sensing technique that uses radar satellite images to determine movement of the surface of the earth.

Line Shaft Pump

Fluid pump that has the pumping mechanism in the wellbore and that is driven by a shaft connected to a motor on the surface.

Liner

A casing string that does not extend to the top of wellbore, but instead is anchored or suspended from inside the bottom of the previous casing string.

Lithology

The study and description of rocks, in terms of their color, texture, and mineral composition.

Lost Circulation

Zones in a well that imbibe drilling fluid from the wellbore, thus causing a reduction in the flow of fluid returning to the surface. This loss causes drilled rock particles to build up in the well and can cause problems in cementing casing in place.

Magnetic Survey

Measurements of the earth's magnetic field that are then mapped and used to determine subsurface geology.

Magneto-telluric

An electromagnetic method of determining structures below the earth's surface using electrical currents and the magnetic field.

Matrix Treatments

Treatments performed below the reservoir fracture pressure, and generally are designed to restore the natural permeability of the reservoir following damage to the near-wellbore area. Matrix treatments typically use hydrochloric or hydrofluoric acids, to remove mineral material that reduces flow into the well.

Micro-seismicity

Small movements of the earth causing fracturing and movement of rocks. Such seismic activity does not release sufficient energy for the events to be recognized except with sensitive instrumentation. See also *seismicity*.

Mini-frac

A small fracturing treatment performed before the main hydraulic fracturing treatment to acquire stress data and to test pre-stimulation permeability.

Packer

Device that can be placed in the wellbore to block vertical fluid flow so as to isolate zones.

Permeability

The ability of a rock to transmit fluid through its pores or fractures when subjected to a difference in pressure. Typically measured in darcies or millidarcies.

Polycrystalline Diamond Compact Drilling Bit (PDC)

A drilling bit that uses polycrystalline diamond compact inserts on the drill bit to drill by means of rotational shear of the rock face. See *drag bits*.

Proppant

Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic stimulation.

Recovery Factor

The fraction of total resource that can be extracted for productive uses.

Resistivity Survey

The measurement of the ability of a material to resist or inhibit the flow of an electrical current, measured in ohm-meters. Resistivity is measured by the voltage between two electrodes while an electrical current is generated between two other electrodes. Resistivity surveys can be used to delineate the boundaries of geothermal fields.

Roller Cone Bit

Drill bit that drills by crushing the rock with studded rotating cones attached to the bit.

Resource Base

All of a given material in the Earth's crust, whether its existence is known or unknown, and regardless of cost considerations.

Seismic

Pertaining to, of the nature of, or caused by an earthquake or earth vibration, natural or man-made.

Seismicity

The phenomena of earth movements. Also the frequency, distribution and intensity of earthquakes. Syn. *seismic activity*.

Seismometer

Electrical device that is used on the surface and within wellbores to measure the magnitude and direction of seismic events.

Self-potential

Self-potential in geothermal systems measures currents induced in the subsurface because of the flow of fluids.

Spinner Survey

The use of a device with a small propeller that spins when fluid passes in order to measure fluid flow in a wellbore. The device is passed up and down the well continuously measuring flow to establish where and how much fluid enters or leaves the wellbore at various depths.

Slim Hole

Drill holes that have a nominal inside diameter less than about 6 inches.

Slotted Liner

Liner that has slots or holes in it to let fluid pass between the wellbore and surrounding rock.

Smart Tracer

Tracer that is useful in determining not only the flow path between a well injecting fluid into the subsurface and a well producing fluid from an adjacent well, but which can also be used to determine temperature along the flow path, the surface area contacted by the tracer, the volume of rock that the tracer interacts with, and the relative velocities of separate phases (gas, oil and water in petroleum fields; steam and liquid water in geothermal systems).

Stimulation

A treatment performed to restore or enhance the productivity of a well. Stimulation treatments fall into two main groups, hydraulic fracturing treatments and matrix treatments.

Stress

The forces acting on rock. In the subsurface the greatest force or stress is generally vertical caused by the weight of overlying rock.

Structural Discontinuity

A discontinuity of the rock fabric that can be a fracture, fault, intrusion, or differing adjacent rock type.

Submersible Sump

Pump with both the pumping mechanism and a driving electric motor suspended together at depth in the well.

Tiltmeter

Device able to measure extremely small changes in its rotation from horizontal. The "tilt" measured by an array of tiltmeters emplaced over a stimulation allow delineation of inflation and fracturing caused by the stimulation.

Thermal Gradient

The rate of increase in temperature as a function of depth into the earth's crust.

Thermal Drawdown

Decline in formation temperature due to geothermal production.

Tracer

A chemical injected into the flow stream of a production or injection well to determine fluid path and velocity.

Under Reamer

A drilling device that can enlarge a drill hole. The device is placed about the drill bit and can be opened to drill and then closed to be brought back up through smaller diameter hole or casing.

Well Log

Logging includes measurement of the diameter of the well and various electrical, mass, and nuclear properties of the rock which can be correlated with physical properties of the rock. The well log is a chart of the measurement relative to depth in the well.

Zonal Isolation

Various methods to selectively partition portions of the wellbore for stimulation, testing, flow restriction, or other purposes.

Energy Units[1]

Joule (J)

This is the basic energy unit of the metric system, or in a later more comprehensive formulation, the International System of Units (SI). It is ultimately defined in terms of the meter, kilogram, and second.

1 Exajoule (EJ) = 10^{18} J

British Thermal Unit (Btu)

This is a basic measure of thermal (heat) energy. A Btu is defined as the amount of energy required to increase the temperature of 1 pound of water by 1 degree Fahrenheit, at normal atmospheric pressure.

BTU is the English system analog of the calorie. For specific heat capacities to be the same, whether expressed in Btu/lb-°F or in cal/gm-°C:

1 Btu = 251.9958 cal.

1 Quadrillion Btu (Quad) = 10^{15} Btu = 1.055 EJ

Kilowatt-hour (kWh)

The kilowatt-hour is a standard unit of electricity production and consumption. By definition, noting that 1 kilowatt = 1000 watts:

1 kWh = 3.6 x 10^{6} J (exact).

The relationship between the kWh and the Btu depends upon which "Btu" is used. It is common, although not universal, to use the equivalence:

1 kWh = 3412 Btu.

This corresponds to the International Table Btu. [More precisely, 1 kWh = 3412.14 Btu (IT).]

1 Terawatt-year (Twyr) = 8.76 x 10^{12} kWh = 31.54 EJ = 29.89 quad.

[1] Units were taken from American Physical Society Web site, http://www.aps.org/policy/reports/popa-reports/energy/units.cfm.