Enhanced Geothermal Systems (EGS) R&D Program

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MONITORING EGS-RELATED RESEARCH

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INTRODUCTION

This report reviews technologies that could be applicable to Enhanced Geothermal Systems development. EGS covers the spectrum of geothermal resources from hydrothermal to hot dry rock. We monitored recent and ongoing research, as reported in the technical literature, that would be useful in expanding current and future geothermal fields. The literature review was supplemented by input obtained through contacts with researchers throughout the United States. Technologies are emerging that have exceptional promise for finding fractures in nonhomogeneous rock, especially during and after episodes of stimulation to enhance natural permeability.

BACKGROUND

Projects sponsored by the Office of Geothermal and Wind Technologies, in the Office of Power Technologies, U.S. Department of Energy (DOE), focus on the needs and concerns of the geothermal industry while promoting the public benefits of geothermal energy. Today, many geothermal sites in this country have not reached full economic potential because they lack adequate fluid production. The DOE Enhanced Geothermal Systems Program was created to develop the technology to allow geothermal energy to be extracted from the earth□s crust in areas with higher than average heat flow but where the natural permeability or fluid content is limited. Geothermal systems developed in these areas are defined as Enhanced Geothermal Systems (EGS).

The primary motivation of this review of current literature was to describe and publicize a number of technical thrusts where emerging technologies could be of value to improving the use of the moderate-quality hydrothermal reservoirs that will be the test beds for EGS in the U.S. These technologies are being developed in both the petroleum (oil and gas) industry and in research being sponsored by the U.S. Department of Energy's geothermal program, which will be reported to the International Energy Agency about U.S. reservoir-related technologies for Hot Dry Rock and other EGS-like geothermal reservoirs *[1]*.

In the most general terms, geothermal energy consists of the thermal energy stored at accessible depth in the earth□s crust. The total U.S. geothermal resource base, thermal energy to 10 km, has been estimated at 6,000,000 Quads (1 Quad = 10^{15} BTUs). For comparison, the total U.S. annual use of primary energy was 95 Quads in 1998 (EIA report, Annual Energy Outlook 2000, December 1999). Hydrothermal resources, as a subset of the overall geothermal resource base, are typically located at depths of 1-4 kilometers and contain steam or liquid water up to 350°C in a convectively active, permeable region of porous rock. The hydrothermal resource is estimated to be 9600 Quads *[2]*.

In a recent survey by Gawell et al., "Preliminary Report: Geothermal Energy, the Potential for Clean Power From the Earth" *[3]*, U.S. geothermal energy experts estimated that the USA geothermal potential for installed electrical capacity with today□s technology is 3,780 to 6,520 MWe (megawatts electric). Using "enhanced technology", which was not defined , the potential is 10,660 to 18,880 MWe. The survey was conducted in January and February 1999.
In comparison, the Energy Information Administration (EIA), at its National Energy Modeling System (NEMS) conference, March 21, 2000; projected, in its reference case, installed geothermal capacity to be 3,000 MWe in 2010 and 3,800 MWe in 2020. The EIA further stated that geothermal would provide 17 billion kilowatt hours in 2010 and 25 billion kilowatt hours in 2020. Multiplying the ratio of 18,800/3,800 by 25 billion kilowatt hours results in 125 billion kilowatt hours/year or about 1.3 Quads/year for the Gawell upper limit. Thus the potential as presented by Gawell is only a small portion of the hydrothermal resource base, because much of the 9,600 Quad base is currently non-economic to produce even with the postulated "enhanced technology".

It is clear that there is a tremendous challenge to the geothermal community to reduce costs in order for geothermal energy to meet and, hopefully, exceed the 18,880 MWe potential from known hydrothermal resources. Reducing the costs associated with finding and exploiting geothermal resources beyond currently economic hydrothermal resources will be necessary. This issue was recognized early in the DOE EGS Program and a workshop, "Dual-Use Technologies" for Hydrothermal and Advanced Geothermal Reservoirs *[4]*, was held at Berkeley, California, April 2, 1998 in conjunction with the DOE Geothermal Program Review. The workshop brought together geothermal researchers from around the world to discuss what research might be appropriate for both EGS and hydrothermal-based systems. This was followed by EGS Workshop 2 *[5]* in July 1998, in Salt Lake City, Utah, to define a strategic road map for EGS research and deployment.

EGS Workshop 3, August 17-18, 1999 in Berkeley, California, *[6]* provided a forum for developing inputs to tactical plans for research to enhance near-commercial geothermal systems in the U.S. About 20 of the country's foremost geothermal and geophysical scientists were convened to discuss the state of the art of understanding geothermal reservoirs, and how that might be advanced. Two key topical areas emerged:

1) improving permeability of hydrothermal systems, and
2) improving fluid contents of hydrothermal systems.

The term Enhanced Geothermal Systems (EGS) has been adopted to cover all engineered or enhanced geothermal resources beyond conventional hydrothermal systems and includes Hot Dry Rock (HDR). HDR is a term originally adopted by the Los Alamos National Laboratory (LANL) in the early 1970s to refer to low permeability, high-temperature rock masses which lack sufficient inplace fluid for heat extraction. The Europeans have also used the term HDR to refer to the geothermal reservoir at Soultz. However, the Soultz reservoir appears to be similar to the description given by Rose *[7]* for the Steamboat Hills (Nevada) reservoir; "The Steamboat Hills reservoir is similar to many other geothermal reservoirs in that the areal and volumetric extent of the system is poorly defined. No distinct boundary can be drawn between reservoir and non-reservoir. It is reasonable to assume; however, that there exists a region of brine-filled fractures wherein the flow processes are controlled to a large extent by the induced flow paths between the injection and production wells and to a lesser extent by naturally occurring convective processes."

In developing this status report on EGS-related technologies the general approach adopted was 1) to survey U.S. scientists and researchers in various fields, 2) to review the readily available U.S. literature in these fields and, 3) to organize the material by topic. The intent was to look for recent advances in a number of technical fields which could potentially reduce the cost of energy from geothermal resources and thereby increase the portion of the resource base that could produce energy competitively in the future.

The findings have been grouped into eight topical areas:

1) Exploration,
2) Drilling and Completion,
3) Instrumentation and Electronics,
4) Well Stimulation,
5) Fracture Detection,
6) Seismic Techniques,
7) Reservoir Definition and Operation, and
8) Numerical Simulation.

There is, as always, overlap between categories. Attempting to cover the whole field of geothermal development would be a daunting endeavor, far beyond the scope of this current task. Therefore, we limited the scope to an overview of technologies that offer significantly increased capability for geothermal frontier areas such as the high temperature, low permeability, highly fractured, or fluid-deficient margins of hydrothermal systems. We have avoided sweeping conclusions or attempts at assessing the "state-of-the-art". This current effort is not comprehensive, but is intended to be representative of the current state of the technologies reviewed. Based on extensive interviewing of key researchers, what is reported here does represent a working consensus about what research thrusts are proving to be interesting and have practical import.

Similarly, the concentration of the literature in a limited number of areas appears to be indicative of the level of activity and interest in those fields. For example, the major emphasis in U.S. oil fields is not necessarily on exploration, but going back in and attempting to exploit existing fields with new technology; thus the large amount of literature on seismic technology and new drilling techniques. In geothermal, there is little interest in exploration because, in many cases, it is not currently economic to develop geothermal energy sources even in most of the known reservoirs.

In addition to our independent search, a number of researchers provided references and papers for this report. Most of the text of this report is taken directly from the listed sources, usually with extensive paraphrasing.

TECHNOLOGIES

1. Exploration

Exploration is the first step in geothermal energy development - a step which consists of the location of reservoirs and the siting of wells for production of geothermal waters. Exploration entails the application of various methods and techniques from the fields of geology, geochemistry and geophysics. Exploration strategies have the purposes of minimizing risk of failure and optimizing the cost-effectiveness of the exploration *[8]*. In his paper, Wright provides a comprehensive overview of the status of geothermal exploration technology as of about 1990. Since then there have been significant advances in many areas which should reduce the risk and cost of finding and defining geothermal resources.

Wright provides an explanation of the various types of techniques is provided which forms a good introduction to geothermal exploration:

1) Geological Techniques
   - Geologic Mapping
   - Study of Drill Samples and Information
   - Stratigraphic Studies
   - Structural Analysis
   - Radioactive Age Dating of Rocks
2) Geochemistry
   - Overview of Geothermal Geochemistry
   - Chemistry of Geothermal Fluids
   - Geochemistry of Rocks
3) Geophysical Studies
   - Thermal Methods
   - Electrical Methods
   - The Seismic Methods
   - Magnetic Methods
   - Gravity Methods

An early step in the reconnaissance phase of exploration is the development and interpretation of a conceptual model of the subsurface using all available geological, geochemical, geophysical, and hydrological data. Applying this concept to EGS and including all known and suspected reservoirs might be a useful first step in expanding beyond the present hydrothermal systems.

Wright included drilling as an exploration tool and certainly it is the ultimate test. However, it is an expensive approach to exploration. An exception could be microdrilling with miniaturized logging instrumentation . The LANL microdrilling project is discussed under "Drilling and Completion" and "Instrumentation and Electronics".

In 1996, Huttrer *[9]* discussed the potential for cost cutting in the exploration phase of geothermal development. The paper discusses briefly the status in each technical area of exploration and provides cogent observations regarding the potential for cost reduction in exploration. Huttrer suggested relooking at satellite imagery (although he was referring specifically to the detection of heat, rather than synthetic aperture radar) and applauded efforts in seismic tomography for characterizing and mapping fracture patterns. He stated that the costs of exploration were unlikely to drop significantly. Although there isn't a great deal of classic geothermal exploration going on, advances in defining what is underground in oil and gas reservoirs appear to have promise in reducing the costs of developing a geothermal reservoir.

2. Drilling and Completion

In analyses of the costs of developing a geothermal reservoir, emphasis is most often placed upon drilling and completing wells with not much consideration given to costs incurred in other technology areas. This is understandable, because drilling and completion are often said to constitute as much as 50% of the total cost of a geothermal power system. In 1997, Glowka *[10]* stated the case for conducting geothermal drilling and completion research and development as follows. "Approximately 35-50% of the costs of a typical geothermal power project are the costs of drilling and completing the wells. Given this fact and the fact that a typical geothermal well costs two to three times that of a typical oil and gas well drilled to the same depth, it is logical to seek drilling cost reduction as a way of making geothermal power more cost competitive."

In 1993, the Geothermal Division of the Department of Energy (DOE) asked the National Research Council to establish a committee to examine opportunities for advances in drilling technologies. In its 1994 report *[11]*, the Committee stated that drilling is a key technology in several applications of strategic and societal significance, including exploration for and extraction of oil, gas, geothermal, and mineral resources. The Committee further recommended that advances be sought in:

1) Increasing rates of penetration and tool life through improvements in cutter technology and materials
2) Improving capabilities to sense conditions at and ahead of the tool in order to locate targets or avoid obstacles in the subsurface, and
3) Improving the ability to steer the bit and to drill directional, or horizontal holes to reach desired targets or target zones.

The Sandia geothermal program *[12]* has followed a two-pronged approach of 1) developing technologies to realize incremental reductions in drilling costs and 2) pursuing higher-risk, longer-term R&D on advanced concepts that will ultimately lead to significant reductions in cost. Similarly, the DOE Office of Fossil Energy (FE) has an extensive program in advanced drilling, completion and stimulation which is directed toward oil and gas recovery. The National Energy Technology Laboratory (NETL), which is a field laboratory of FE, has organized its activities into five areas; Conventional Drilling Efficiency, Under Balanced Drilling Systems, New Concept Drilling Systems/Components, Advanced Completion and Stimulation Systems, and Supporting Research. As the search for oil and gas encounters hotter and harder formations and the need for drilling cost reductions increases, applications in geothermal and oil and gas tend to overlap.

Smart drilling

A "smart drilling" system is a system capable of sensing and adapting to conditions around and ahead of the drill bit to reach desired targets. Such a system may be guided from the surface, or it may be self-guided, utilizing a remote guidance system that can modify the trajectory of the drill. A smart drilling system does not currently exist, but is presaged by recent advancements in directional drilling and in technologies of measurement while drilling *[11]*. Rapid innovation in microelectronics and other fields of computer science and miniaturization technology holds the prospect for greater improvements - even revolutionary breakthroughs - in these systems. The development of smart drilling systems has the potential to revolutionize drilling. Research in this area will have a significant impact on drilling success and overall cost reduction.

NETL and Sandia are developing building blocks for such a system. Novatek and NETL have engaged in a cooperative effort to develop an integrated, steerable drilling system *[13]*, which includes a mud-actuated hammer as a key element. The overall goal of this system is to provide significant cost reduction and technical advantage over current drilling practice, particularly in deep, medium-to-hard rock formations. Novatek describes several key subsystems of the integrated drilling system concept in some detail, including an advanced telemetry system, and a steerable drilling head that offers advanced sensing capabilities. Similarly, the composite drill pipe with data transmission integrated into the drill pipe being supported by FE is potentially a component of a "smart drilling" system. A key technical challenge will be to develop reliable electromagnetic connectors that can maintain reliable, high-speed data flow between the sections of drill pipe. The Sandia Diagnostics While Drilling (DWD) initiative, described below, for the DOE geothermal program is a precursor to a smart drilling system.

Sandia's "Advanced Drilling Systems Study" *[14]*, and the NADET "Workshop on Revolutionary Drilling and Sampling Technologies" *[15]* provide indepth discussions of the prospects for "revolutionary" drilling concepts as contrasted to smart drilling systems. Examples of these revolutionary concepts include the spark drill, rock melters and lasers.

Diagnostics-while-drilling

Diagnostics-while-drilling (DWD) is an initiative *[16]* of the Sandia geothermal program. The central concept is a closed information loop, carrying data up the well and control signals down. Upcoming data provides a real-time report on drilling conditions, bit and tool performance, and imminent problems. Sandia states that DWD will reduce costs, even in the short term, by improving drilling performance, increasing tool life, and avoiding trouble. Its longer-term potential includes making smart drilling systems feasible.

A DWD system faces four major technical challenges; the high-speed data link, development of drilling advisory software, surface-controllable downhole tools; and advanced downhole sensors. The data link should have a minimum transmission rate of 100 kbits/sec, which is four orders of magnitude above the data rate of mud-pulse telemetry used in conventional MWD (Measurements While Drilling) systems. The choice of data-link technology will be driven by the status of current industry development, Sandia in-house research and data rate requirements as derived from proof-of-concept testing. Prototype software for the driller's console does not exist, but will be based upon software being developed for circulation monitoring and based upon Sandia's experience with drill-rig instrumentation. As stated by Sandia, with an economical high-speed data link, a wide range of downhole tools that have not been feasible to date will become practical. There will also be a greater impetus to develop and upgrade downhole sensors.

Advanced composite drill pipe

Advanced Composite Products & Technology Inc. (ACPT), Huntington Beach, CA, will design and fabricate an advanced drill pipe made of a carbon fiber-epoxy resin *[17]*. Woven into the composite material will be high-speed data communications capabilities that will convey drilling information from the bottom of the wellbore to operators on the surface. Composite materials offer the potential of developing lightweight drill pipe that can reduce torque and drag, particularly in difficult drilling environments. This, in turn, can increase drilling speed and lower overall costs. ACPT and its team will develop a 5.5-inch diameter composite drill pipe. Traditionally, composites have been more expensive than steel, however, the company is proposing innovations that it believes can make the advanced drill pipe cost competitive.

Fiber-optic cable for data transmission

Sandia has tested optical fiber in flowing mud inside drill pipe, showing that fiber can withstand the drilling environment while transmitting data. With sponsorship by the Gas Research Institute, Sandia is currently working on methods to deploy optical fiber for MWD applications. DWD may create the market pull necessary to justify full development of optical fiber telemetry.

Polycrystalline diamond bits

Polycrystalline diamond bits have been under development in the DOE geothermal program for 20 years *[12]* and represent a unique success story for bringing on line a new drilling capability that greatly improved penetration rates and bit life in soft formations. Current work is addressing advanced synthetic diamond products for hard-rock drilling for geothermal applications. Combining these bits with DWD capability may make it feasible to use these bits in fractured hard-rock geothermal applications.

The FE program *[17]* is testing new hardening and diamond bonding technologies in the development of a high-strength thermally stable polycrystalline diamond (TSD) cutter design for advanced drag bits. Drilling demonstrations using these bits with a high-power slimhole mud motor have shown that they are more economical than conventional drag bits over a wide range of formation hardness.

A wide variety of PDC bits are being widely offered commercially. An example is provided in the Security DBS advertisement *[18]* where Security claimed that its PDC bit product lines are unmatched in drilling performance and durability and provide higher ROP without compromise, and directional application without surprises. Hycalog is another provider of PDC bits and has described *[19]* a combination of PDC technologies in a bit designed for high ROP in soft formations, but with the capability to drill hard interbedded formations or stringers. Hydraulics, bit face design, cutter size and usable diamond volume were optimized for soft formations. Localized cutter placement was optimized and an innovative low-friction gauge pad incorporated to increase stability and component lifetime in hard stringers.

Bit designs that are capable of dealing with multiple types of rock during a long bit run are especially valuable in geothermal operations, because it is not unusual to have hard rock interbedded with stretches of softer material, voids and fractures.

Microdrilling

A microdrilling technology *[17][20][21][22]* being pursued by LANL could fundamentally change oil and natural gas exploration. Microdrilling technology is based on the miniaturization of conventional coil tubing techniques that deploy a drill motor and bit on the end of tubing coiled around a spool. Drilling fluids are run through the tubing to turn the motor and drill bit. In September 1999, LANL drilled four, 2 3/8 inch diameter, microholes to a maximum depth of 500 ft in alluvium and lake sediment. The team is developing an even smaller motor and bit system that could allow drilling to 10,000 feet (3 km), which is deep enough to explore much of the world's potential oil and gas resources. Microholes are defined as wells drilled from the surface with bore sizes of roughly several inches in diameter. This technology, when developed for depths to 10,000 ft, could replace traditional deep drilling methods for gathering subsurface data. The ultimate goal is to demonstrate the feasibility of obtaining geotechnical information about the subsurface by combining miniaturized conventional drilling technologies with contemporary electronics and advanced sensors assembled in very small-diameter borehole instrumentation packages. This should result in a substantial reduction in the cost of deep earth exploration and increase the quantity and quality of subsurface data by using instruments specifically designed for data acquisition in microholes. While the current focus is on applications in the petroleum industry, microhole technology could also significantly impact geothermal energy development by providing important subsurface information at considerably reduced costs. If it can be shown that deep wells drilled can be drilled routinely with microhole dimensions, a very substantial reduction in the cost of obtaining subsurface information would result. A LANL cost study has indicated that microholes have the potential to be drilled for less than one-fifth the cost of conventional production holes.

Acoustic telemetry

Acoustic telemetry uses the steel drill pipe as a waveguide to transmit stress waves. It can transmit data at rates higher than mud-pulse telemetry. With repeaters, acoustic telemetry can transmit at rates sufficient for minimal DWD, refreshing at once per second. Sandia *[12]* has built and licensed a working acoustic telemetry system for production tubing in oil and gas wells. Current work focuses on practical downhole transmitters for MWD systems. These transmitters are piezoelectric devices that directly convert electrical energy into stress waves, eliminating the need for moving parts.

In 1996, Tochikawa et al *[23]* reported on an acoustic telemetry system based on the principle of elastic wave propagation and which used magnetostrictive technology for the oscillator in the transmitter. The authors believed that a magnetostrictive device would overcome the perceived limitations of piezoelectric materials which operate at several tens of kHz, are not suitable for use in the low frequency band and have a lower compressive strengths. The project focused on the development of the acoustic wave source and both laboratory and field tests were conducted to verify system operation. They were successful in transmitting an acoustic wave through the drill string from a depth of 1,914 meters to the surface.

Downhole mud hammer

FE has a project to develop an integrated steerable drilling system that would offer significant cost reduction in deep, medium to hard rock formations using a mud actuated hammer engine *[17]*. Key aspects of this R&D development focus on down-hole bit rotation, sensing and control, directional drilling and casing while drilling. Recognizing that several of these functions of a smart drilling system could be supplied by the down-hole mud actuated hammer, Novatek began a joint development effort in 1997 with NETL *[13]* to develop the mud hammer potential for improved rate of penetration (ROP) through creating an instantaneously high axial force, which in brittle formations causes high fracturing and in more ductile formations causes greater indentation of the cutters into the formation. Prototype hammers have undergone both laboratory and field testing and are robust enough to operate to 4 kilometers (13,100 feet) in inclined wells. Recent development efforts have focused on improving hammer performance particularly under deep well conditions. Novatek is also under contract to Sandia *[12]* to develop a drilling mud-actuated percussive hammer for geothermal drilling applications. Although the DOE geothermal program has funded very little of the project to date, Sandia's interest in geothermal applications remains strong.

Underbalanced drilling

As drilling proceeds, operators fill the advancing borehole with fluids. These fluids carry cuttings away from the bit. Additives such as barite are typically mixed into the drilling fluid to make it denser and capable of controlling high downhole pressures. In many environments, operators will overbalance to provide added safety. However, encountering porous and permeable zones while overbalanced can lead to stuck drill pipe and loss of drilling fluids into the formation. Both problems can add significantly to costs. Lost drilling fluids can also permanently damage the formation, reducing the productivity of the well. Some environments, such as established gas producing areas, pose limited downhole pressure risk. Technologies that allow drilling to proceed at or below reservoir pressure (underbalanced) can result in faster penetration and limited or no reservoir damage *[17]*.

Underbalanced drilling in oil and gas is now experiencing growth at a rate that rivals that of horizontal drilling in the mid-1980s. Reduced formation damage in horizontal wells has been the driving force behind this recent resurgence in interest. Current underbalanced drilling operations in low pressure or depleted reservoirs can be carried out using air, mist or foam. An environment of hard rocks where conventional drilling techniques produce slow penetration rates is no longer the only application for underbalanced drilling. Underbalanced drilling has been effective in many different types of reservoirs. The technology is not limited by depth, having been used successfully at depths up to 20,000 feet (6,000 m). The largest technical barriers to growth in underbalanced drilling are handling formation influxes, the inability to use conventional MWD with compressible lightweight fluids, and corrosion. Oil companies first began drilling wells with air in the late 1940s. Primary motivations to use air were to increase drilling penetrations through hard formations and to overcome severe lost-circulation problems. Many tight gas reservoirs in the United States are attractive targets for underbalanced drilling because they are located in hard-rock country where tight (low-permeability) formations are more susceptible to formation damage from invasion of conventional drilling fluids *[24]*.

It has been shown *[25]* that underbalanced drilling can reduce drilling costs through increased penetration rates and the elimination of differential sticking and lost circulation. Many oil and gas operators have also recorded spectacular production increases from reduced reservoir impairment. *[26]*. (This aspect should be of great interest to geothermal operators also.) Despite extra mobilization and operating costs for the additional underbalanced drilling equipment that is needed (such as rotating heads, compressors, separators, etc.), underbalanced drilling often makes economic sense in eliminating costs associated with lost circulation and stuck pipe, and from drilling cost savings that result from higher rates of penetration.

Recently, NETL has funded Maurer Engineering to develop new lightweight fluids for underbalanced drilling *[27]*. The approach uses hollow glass microspheres (HGS) to reduce the density of drilling fluids. The project consists of transferring the Russian technology to the U.S. and utilizing microspheres manufactured by 3M to reduce underbalanced drilling costs. The spheres are added in volumetric concentrations up to 50 percent This avoids the use of air. When a well is completed, the microspheres can be removed with conventional mud solids handling equipment and reused. The diameter of commercial spheres range from 8 to 125 microns. They are typically used as fillers in paints, glues and other materials to reduce manufacturing costs. Larger diameter spheres, 1 mm and larger, may also be used. One of the major advantages of underbalanced drilling is increased drilling rates and microspheres can significantly increase drilling rates by reducing wellbore pressures. Other advantages are that using microspheres maintains an "incompressible" fluid and there is no corrosion from the use of air. Subsequently it was reported *[28]*, that an HGS fluid was formulated in the field and used to drill two wells in Kern County, CA. Concentrations of microspheres up to 20% by volume were used to decrease the fluid density to 0.8 lb/gal less than normally used in the field. The field tests demonstrated that HGS drilling fluid can be easily and safely mixed under field conditions, is compatible with conventional drilling fluids and rig equipment, and can be circulated through conventional mud motors, bits and solids control equipment with little detrimental effect on either mud or equipment.

Horizontal drilling/rotary steerable systems

Horizontal drilling along with steerable downhole drilling systems are used extensively in oil and gas development. These two papers *[29][30]* illustrate the potential and provide a backdrop for application to geothermal. At the Wytch Farm development on the south coast of England, Amoco set an ERD (extended-reach-drilling) record in 1999 of 10,728 meters with a measured depth of 11,287 meters *[29]* during its project to access offshore reserves beginning in 1993. The average rate of penetration (ROP) over the life of the project was 75 m/d (9 ft/hr), including trips and problem time, but the best ROP was 165 m/d. Bit life and rotary-steerable-system (RSS) and tool performance contributed most to increased performance. Complex geosteering was required to keep the bit in the productive sands. Wytch Farm wells had to compete for funds on a cost/barrel basis with other projects. Workshops were set up to involve the team in finding ways to reduce costs to meet the aggressive cost/barrel hurdle. When combined with improved fracture diagnostics, it would appear that horizontal drilling along with RSS has a place in geothermal development.

Also intriguing is a Baker Hughes advertisement *[31]*, where it is stated that the AutoTrak rotary steerable system has drilled more than 1 million feet. Features include continuous rotation, downhole guidance, two-way communication and specially designed Hughes Christensen PDC bits. It is claimed that near-bit resistivity sensors and Triple Combo LWD make AutoTrak an extremely precise geosteering tool. It can routinely drill 7,500 ft (2,500 m) horizontal sections with tight geologic control. On one well, the system kept the lateral hole within 8 inches (0.2 m) of its target trajectory.

Sometimes, in reviewing the technical and commercial literature, there is apparent conflict between what is at the R&D stage and what is commercially available. Steerable systems are a good example. Sandia discusses its DWD proposal and FE is supporting the Novatek project, but Baker Hughes is offering AutoTrak as a commercial service. Additional effort would be required to define the actual state of the art.

The application of horizontal wells in oil and gas development has increased significantly over the last decade *[30]*. In 1997, The DOE National Petroleum Technology Office worked with a coalition of industry representatives to identify the target resource for horizontal-well technology and to evaluate its future recovery potential under several economic and technological scenarios. The analytical system used consisted of a comprehensive reservoir database (oil/gas), a screening model to select various candidates for horizontal wells, process predictive models (for each selected reservoir), and a detailed economic model. Results from the analyses indicated that more diverse, expanded application of horizontal well technology holds significant promise for additional economic oil recovery at $16-24 dollars a barrel from the analyzed resources in the United States.

A similar approach should be considered for geothermal resources and generalized to examine not only the potential of horizontal drilling but of other advances in exploration, drilling, logging, etc.

Measurements/logging while drilling

The MWD industry is divided into two segments, MWD and LWD. Traditional MWD (Measurements While Drilling) typically provides directional and lithologic information (usually gamma ray) to guide the drilling engineer to the target and allow optimized placement of the well. MWD tools may also include measurements such as weight-on-bit and torque to help optimize drilling and may include sensors such as downhole pressure measurements to enhance safety. Directional and gamma MWD services are used in all markets where the hole is drilled directionally or horizontally. LWD (Logging While Drilling) is a relatively new addition to the suite of measurements offered while drilling and refers generally to information useful to the geotechnical group (geologists, geoscientists and petrophysicists). Several important applications are 1) high angle and horizontal wells, 2) high cost wells, and 3) high risk wells. The report *[32]* examines the needs for improved MWD technology (except where noted, MWD and LWD are used interchangeably).

The project tasks, supported by the Gas Research Institute, were divided into three general categories:

1) Define the current state of the technology,
2) Analyze the needs not being met by the current MWD technology and
3) Define high-priority research areas which would provide the maximum benefit to the industry.

Drivers for MWD/LWD in the oil and gas industry are the need to drill faster, to place wells more accurately and to verify the presence of hydrocarbons. Sophisticated and reliable tools are needed to accomplish these successfully within economic constraints.

Significant barriers to the increased use of current MWD/LWD technology are:

1) High costs of the services,
2) Size availability and
3) Limitations in high temperature applications.

Among the high priority needs identified, those applicable to geothermal include;

1) High telemetry rates for logging data,
2) Telemetry for drilling with compressible fluids,
3) Better power sources,
4) Improved tool reliability,
5) Near bit and bit look-ahead systems, and
6) High temperature electronics.

There are several companies which specialize in the management and presentation of drilling data. One of the primary areas identified in which needs were not being met was in information management and presentation. Rig instrumentation providers have historically not incorporated MWD data in their presentations. Rather, they compile surface/rig data (torques, loads, flow rates, pressures, rig reactive forces, penetration rates, etc.) and present it to the user. The GRI report *[32]* provides a good overview of data transmission methods; mud pulse telemetry, electromagnetic telemetry, acoustic systems, and hardwire telemetry systems and provides an extensive discussion of commercially available MWD/LWD systems.

3. Instrumentation and Electronics

High temperature electronics

The high temperatures associated with geothermal reservoirs impose severe restrictions on the use of electronic packages downhole. There is therefore a significant incentive for improving the temperature rating of instruments. The availability of new integrated circuits based on aircraft gas turbine applications affords the opportunity to incorporate these circuits into designs suitable for geothermal wellbore deployment *[12]*.

In contrast, McDonald *[32]* reported on the real-world situation in oil and gas as follows. High temperature environments, 350°F (175°C) and above, are present in just a few regions (oil and gas) in the world. LWD is just over a decade old (in 1999) and commercial equipment designed for high temperature markets has not been developed because of the limited market. He stated that two factors will influence the move to higher temperature tools. First, operators are planning to drill deeper where temperatures can reach 400°F (204°C). Second, service companies' LWD products and services are maturing and they will have the resources to pursue smaller markets as they fill out their product lines.

One company reported that they use MWD on 100% of their wells in Thailand, but do not use LWD at all because of temperature limitations. When tools become available, they plan to switch from 100% wireline to 100% LWD. Most MWD systems are rated to 150°C (302 °F) or less with a few directional packages rated at 175°C (350°F). However, operators report that tools are generally not available and those that offer high-temperature capabilities often cannot deliver the performance and reliability advertised. The general consensus was that the quantity requirements for high-temperature drilling components are orders of magnitude smaller than those of the automotive and consumer markets. Thus, component manufacturers have generally not been responsive even to oil field needs where the quantities required are correspondingly orders of magnitude higher than for geothermal development. GRI and others are taking proactive approaches to developing alliances and establishing participation in consortiums that would bring the necessary improvements to make high-temperature MWD/LWD available to users.

A new set of integrated circuit components has been introduced to address problems of reliable high temperature (HT) operation *[33]*. These components were developed specifically for control applications on aircraft gas turbine engines. A database with more than two million device hours at the targeted maximum temperatures has been developed and failure analysis completed on failed components. A basic set of 15 integrated circuits has been developed specifically for reliable HT operations in downhole environments. The source integrated circuits have been used in aircraft turbine engines with lifetime requirements of 50,000 hours at temperatures as high as 300 °C. Introduction of these HT products combined with reliable HT passive components, circuit boards, and solders (also tested and available) promises to significantly increase the reliability of downhole data acquisition.

Fiber-optics for temperature measurement

Another application is the use of optical fiber to measure complete wellbore temperature profiles *[12]*. Optical fiber is placed within the wellbore and a laser pulse is fired down the wellbore fiber. This creates two small backscattered wavelengths of light known as Raman Stokes and anti-Stokes scattering. By time sampling the Raman intensities and taking the ratio of the two wavelengths, a point by point temperature measurement can be realized for the length of the fiber. A major problem is the degradation of the wellbore fiber after installation. Sandia is addressing this issue with the ultimate objective of extending fiber life to 10 years at 250 °C (482 °F).

Hurtig et al (1994) and Osato et al (1995) *[34]* have also described a similar fibre-optic temperature sensing technique using Raman light scattering analysis. The present temperature capability appears to be limited to about 250°C (482 °F), but Iglesias (1997) *[34]* is developing a system capable of operation up to 450°C (842 °F) and 50 MPa (7,250 psi).

Fiber optic sensors

A reliable downhole sensor network will dramatically improve reservoir management practices and enable the construction of "intelligent" downhole well completion and control systems *[35]*. Fiber optic technology will play a seminal role in the architecture of downhole imaging and control systems because of advantages of power, performance, and reliability over conventional electronics. Results from a field test of a fiber optic seismic borehole receiver prototype demonstrate that a multi-level, fiber optic hydrophone system can improve the economics of Vertical Seismic Profiling (VSP) and cross-well surveys. 3D VSP and cross-well imaging survey techniques, which use conventional receivers and a variety of surface and subsurface sources, can achieve the required subsurface resolution. However, the costs of using these tools generally restrict their application. Increasing the number of receiver levels is one solution to the cost issue. However, without an accompanying increase in component and system reliability, these larger recording systems will not be viable. Achieving the necessary performance, high channel-count and reliability for multi-level downhole receivers will be difficult and expensive to accomplish with conventional electronics. Fiber optic sensors demonstrate clear advantages in reliability, performance and lifetime costs.

Fiber optic sensors to measure temperature and pressure have been previously used in well-bores, but fiber optic acoustic sensors for downhole seismic have proven to be more difficult to build, principally because of the large dynamic range needed for seismic imaging. One sensor configuration that exhibits the necessary dynamic range is the Mach-Zehnder hydrophone interferometer. In this type of sensor, a coupler splits an entering coherent light bundle into two optical paths. One signal path passes through an isolated reference leg and the second signal path passes through optical fiber wound around an acoustically sensitive mandrel. The two signals are recombined at the output of the sensor. The mismatch results in an interference signal or phase change which maps into acoustic sound levels.

One advantage of the fiber optic acoustic system is that the remote sensors contain no electronics. Current temperature limits on the fiber optic sensors are constrained by the packaging materials, not by the fiber; 200°C (392 °F) sensors are not a stretch. A field test of a prototype fiber optic borehole system was conducted at Texaco's Kern River field in Bakersfield, California. These tests demonstrated that a borehole hydrophone cross-well system together with a powerful downhole seismic source can provide useful high resolution images *[35]*.

Under sponsorship of DOE National Petroleum Technology Office and in collaboration with Chevron Research and Technology Company, Virginia Tech is investigating optical technology for ruggedized sensors . The objective of the research program is to develop and evaluate sensors for downhole measurement of pressure, temperature, volumetric flow, and acoustic waves (for seismic applications) and to develop technology to enable survival of the sensors over extended periods of time. The paper *[36]* describes preliminary research in the development of a miniaturized fiber optic pressure sensor for downhole use. Using a new sensor configuration, designs for the measurement of pressure, temperature, flow and acoustic waves are being evaluated. This configuration combines features of both interferometric and intensity-based optical sensors, resulting in a sensor that demonstrates the high sensitivity of interferometry, together with the simple signal processing of intensity-based sensors. The sensor employs a structure known as a Fabry-Perot interferometer cavity, formed by aligning two polished fiber ends inside a capillary tube. Reflections within the cavity interfere and the intensity of the optical output of the sensor depends on the relative phase difference of the two reflections. This phenomenon has been applied in the development of a prototype pressure sensor to validate the concept. While the preliminary results validate the optical sensor and suggest a promising future for the application of the sensor in the oil industry, much work remains before the sensor is practical for downhole applications.

Microhole logging tools

As discussed under 'Drilling and completion', LANL *[20][21][22]* is pioneering the miniaturization of coiled-tubing drilling technology for the purpose of achieving a very substantial reduction in the cost of exploration drilling. Participants with LANL are Texaco, Halliburton, Chevron, Strata Production, LANL and the Lawrence Livermore National Laboratory (LLNL). LANL leads the project and is responsible for design and fabrication of the microhole logging tools. LANL will apply its expertise in developing radiation monitoring devices to the development of the micro-gamma tool. The LLNL contribution will be the design of telemetry subassemblies for the various packages under development. Halliburton, Texaco, Chevron, and Strata Production Company will provide overall technical guidance and assistance in the form of access to engineering personnel, nonproprietary existing designs, selective parts, test and calibration facilities, and logs from conventional-sized wells at locations where a microhole can be drilled and logged.

Initially, the project is concentrating on the prototyping of wireline tools, adaptable to a measurement-while-microdrilling system; to measure borehole trajectory, natural and spectral gamma, and resistivity. The tools will be patterned after non-proprietary designs of conventional tools obtained through the industrial participants and subcontractors. The tools will incorporate, where applicable, state-of-the-art technologies available at LANL and in the industrial sector. The resistivity tool will be designed to take advantage of the capability to drill underbalanced microholes with very low volume "designer" drilling fluids that would enhance the resistivity contrast of target formations. In following years, these tools will be incorporated into the microhole drilling bottomhole assemblies. Other conventional logging tools will be considered for miniaturization and prototyping. Environmental testing of the tools will occur in existing small pressure vessels and conventional wells. Field verification of the measurement performance of the logging tools will be conducted in microholes drilled in close proximity to wells for which conventional logs are available.

While it apears that rapid progress is being made in developing a microdrilling capability, the development of a basic suite of formation logs is just beginning. Hydrophones, accelerometers and a vertical geophone suitable for use in a 0.5 inch diameter instrumentation package have been tested. The sensors are specified for operation at 90°C (194 °F), but have been tested only at temperatures less than 60°C (140 °F) in wells. The ultimate combination of drilling microholes and using a new generation of logging tools should lead to a significant decrease in costs and a dramatic increase in the use of drilling for direct exploration for hydrocarbon reserves.

4. Well Stimulation

This can encompass a number of techniques, particularly for oil and gas, but for geothermal, the primary technique is hydrofracturing.

Hydraulic fracturing

Hydraulic stimulation entails the injection of fluid to raise the reservoir pressure sufficiently to reopen natural fractures that may have been partially or completely sealed by rock-water geochemical interaction products, or increasing the permeability of unsealed natural fractures by further dilating them by simple reduction of confining stress or by shear slippage, or even possibly creating new fractures in the reservoir rock *[34]*.

The original concept of engineering HDR systems by driving parallel hydrofractures between judiciously located boreholes has not proven to be practicable. The interaction between the propagating hydrofracture and the natural fracture system limits the distance to which hydraulic fractures can be propagated outwards into crystalline rock. However, hydrofracture methods serve as a potential mean of improving the linkage between the borehole and any natural fracture system *[34]*.

In 1999 Entingh reviewed U.S. experiments in well stimulation *[37]*. The DOE-funded experiments were done in late 1970's and early 1980's. Hydrofracturing was successful in one geothermal well in sedimentary formations, as expected from experience with petroleum wells. Four attempts to stimulate production wells in formations where the permeability was fracture-based resulted in little flow enhancement or less-than-commercial flow rates. These experiments convinced many geothermists in the U.S. that hydraulic stimulation of hydrothermal reservoirs was not commercially useful. That conclusion was somewhat ironic; however, in that neither of the fracture-based reservoirs where these experiments were done, Raft River, Idaho, and the Baca prospect at Valles Caldera, New Mexico, proved to have insufficient hot fluid to be commercially viable. We have been told that two hydrofractures done in the late 1990's at the Coso, California, hydrothermal field did improve flow in two injection wells.

Hydraulic fracture stimulation plays a critical role in a broad range of petroleum producing environments - from shallow oil reservoirs to the deepest gas reservoirs. Low permeability, moderate permeability, and now even the highest permeability formations can benefit from hydraulic fracture stimulation. Fracture stimulation is performed in hard rock, soft rock, naturally fractured rock, and unconsolidated rock *[38]*.

Advanced fracturing technologies

In 1994, NETL began a field-based project to investigate the application of 'new and novel' fracture stimulation technologies for gas storage wells. The paper *[39]* discusses the technologies and results of the gas storage project and how they might be applicable to marginal oil and gas wells. The approach utilized for the project was to test the new and novel fracture stimulation technologies in various geologic and reservoir settings across the U.S. Four different technologies were tested at nine field sites. The four technologies and the findings relevant to oil and gas wells were:

1) Tip-screenout fracturing: This hydraulic fracturing technique is ideal for creating highly conductive fractures in high permeability formations. However, relatively large volumes of aqueous-based fluids are required. Tip-screenout treatments are extremely effective at enhancing deliverability in high-permeability, high-pressure wells.

2) Hydraulic fracturing with liquid carbon dioxide and proppant: This technique utilizes a non-aqueous carrier fluid to completely avoid the fluid-damage issue, hence providing immediate stimulation benefits. Liquid carbon dioxide with proppant treatments provide immediate stimulation benefits. Fluid leakoff appears to be a problem. Application is probably limited to situations where pump rate can overcome fluid loss.

3) Extreme overbalance fracturing: This method involves exposing the target formation to a high-pressure pulse of nitrogen, thus creating fractures. Extreme overbalance treatments suffer from operational complexity, high cost and poor understanding.

4) High energy gas (propellant) fracturing: this method utilizes propellants which are ignited and burned to form a small volume of high-energy gas that fractures the formation. Multiple, radiating fractures are created. High energy gas fracturing is operationally simple and low in cost, but the fractures created, being unpropped, provide stimulation of uncertain durability.

Gas fracturing technology is also discussed in a recent paper *[40]* which concludes that gas fracturing can be a simpler and cheaper stimulation technology than hydraulic fracturing, at least in those instances where its characteristics are not limitations. The high pressure gas pulse produces multiple, short (5-20 feet long) fractures radiating from the wellbore. The technique has been applied in 3,000 cased holes in China with a maximum depth of more than 6 km (19,700 feet). The paper describes the theory and results, laboratory experiments and field application.

Surface tiltmeters

A collaboration between LLNL and Pinnacle Technologies *[38]*, began in 1995 with the goal of extending tiltmeter fracture mapping from 6,000 feet (1.8 km) to 10,000 feet (3 km). The LLNL efforts were funded by the DOE Oil and Gas Technology Partnership Program *[17]*.

Tiltmeters measure strain fields induced by hydraulic fracturing, but near-surface noise (pumps, traffic, wind, thermal expansion and contraction) masked tilt signals from fractures occurring at depths below 6,000 feet (1.8 km) using previous tiltmeter technology. During the hydrofracturing process, a fluid-driven tensile fracture propagates away from the borehole in the direction perpendicular to the least in-situ principal stress. Arrays of near-surface tiltmeters situated around the wellhead map the strike and dip of induced hydraulic fractures by measuring the 3-D strain field generated by the process. Surface tiltmeter fracture mapping is a fracture diagnostic technique in the oil and gas industry that provides a measurement of fracture orientation (azimuth and dip), fracture volume, complexity and approximate location.

A typical hydraulic fracture treatment at 7,000 ft (2.1 km) depth results in induced surface tilts of only about 10 nanoradians - or about 10 parts in a billion. The latest generation of high-resolution tiltmeters can detect tilts of less than one nanoradian. Resolution of fracture orientation is typically better than +/- 5 degrees at depths less than 5,000 ft (1.5 km), and can drop to +/- 10 degrees as depths approach 10,000 ft (3 km) *[38]*.

In another paper *[41]* on subsidence monitoring, there is also discussion of tiltmeter monitoring of fracturing from steam and waterflood operations. The subsidence part may or may not be applicable to geothermal, but the use of tiltmeters to detect fluid migration and growth of fractures appears to be relevant to geothermal operations.

Downhole tiltmeters

Downhole tiltmeter fracture mapping involves deploying wireline-conveyed tiltmeter arrays in offset wellbores to measure hydraulic fracture growth versus time. Creating a hydraulic fracture involves parting the rock and deforming the reservoir. Downhole tiltmeter mapping involves measuring the fracture-induced deformation in a nearby offset well(s) versus time and depth and inverting the data to obtain the created fracture dimensions. The principles are the same as for surface tiltmeter mapping, but the different array geometry make it very sensitive to fracture dimensions (height and length), but less sensitive to fracture orientation. The array is run on wireline with anywhere from six to ten tiltmeters coupled to the borehole with centralizer springs. The downhole array records tilt in a continuous fashion like surface arrays, but the array spans the same depth interval as the zone being fracture treated. Even if the downhole tiltmeters are located only a few fracture dimensions away from the fracture, downhole tilt mapping does not provide a precise outline of the fracture perimeter. Instead, it provides an estimate of the dimensions of an ellipsoid (or multiple ellipsoids) that best approximate the fracture perimeter. The upper temperature limit of the tiltmeter is currently 125 °C (257 °F)*[42]*.

Gamma ray detection

In June 1999, FE *[17]* announced it would provide funds to RealTimeZone, Inc. of Roswell, New Mexico, to develop a new way to transmit data from areas deep within a gas reservoir. The system should give operators on the surface virtually instantaneous readings on the progress of fracturing operations designed to free trapped natural gas. The team will be include the New Mexico Institute of Mining Technology, Sandia National Laboratories, and several petroleum companies. RealTimeZone's innovation should give operators a way to make changes in the fracturing process as problems occur, or to stop the job before a fracture penetrates outside the formation. The concept envisions injecting a low-level, gamma-ray emitting material into the formation along with the fracturing fluid. A battery-operated gamma ray detector would be positioned at the base of the injection well to monitor the movement of the tracer as it moves with the fracture into the formation.

Synthetic aperture radar

Synthetic aperture radar (SAR), just now entering commercial use, uses satellites to periodically measure ground distance from the satellite. SAR can measure large swaths of earth in a single pass and promises to be a useful monitoring technique. Several companies and government organizations are working to resolve problems relating to signal decorrelation (due to vegetation, rainfall, etc.) and spatial resolution *[41]*. SAR is good for large-scale reconnaissance, but tiltmeters are still needed for precise local measurements.

Satellite interferometric synthetic aperture radar was determined to be uniquely suited to monitoring year-to-year deformation of the entire Yellowstone caldera (about 3,000 square kilometers). The main advantage of satellite interferometric synthetic aperture radar (InSAR), in this application, was its ability, under favorable conditions, to measure deformation of the entire caldera floor and its surroundings. By measuring a surface of deformation rather than movement at isolated points, the researchers were able to locate and characterize deformation sources better than had been possible previously. The interferograms were made by taking the phase difference of pairs of SAR images, correcting for the topography using a digital elevation model (DEM) and then correcting for orbital errors. The depth of the larger body in the model was 8.5 + /- 4 km *[43]*. From the information presented in Figure 4, it appears that changes on the order of several millimeters in height were detectable.

In 1997, Massonnet, Holzer and Vadon reported *[44]* on the use of the interferometric combination of pairs of SAR images acquired by the ERS-1 satellite to map the deformation field (subsidence) associated with the activity of the East Mesa geothermal plant, located in southern California east of the town of El Centro. The field is a water-dominated hydrothermal system with primary production between 1,829 meters and 2,280 meters. Fluid is produced from medium-to fine-grained quartzose sandstones. SAR interferometry was applied to this flat area without the need of a digital terrain model. Several combinations were used to ascertain the nature of the phenomenon. Short term interferograms revealed surface phase changes on agricultural fields similar to what had been observed previously with SEASAT radar data. Long term (two year) interferograms allowed the study of land subsidence and improved prior knowledge of the displacement field, and agreed with existing, sparse levelling data. The satellite data were not selected purposely for the detection of surface deformation at the East Mesa geothermal field, but as general reconnaissance to search for possible impacts from agricultural activities on surface elevations. The maximum rates of subsidence from the 1991-1994 relevelings were about 18 mm/year which compares well with the 16 mm/year determined from the interferograms.

In-situ stress

Hickman et al have reported extensively, *[45][46][47]* on the relationship between fracture permeability and in situ stress in the Dixie Valley, Nevada, geothermal reservoir. The reader is referred to these papers for the research details, but the importance of their findings is probably best stated by Steve Hickman in a private communication *[48]* as follows: "A relationship between stress and fracture permeability has been demonstrated before, but Dixie Valley is the first time this was shown in a geothermal system. This is particularly significant in that fracture sealing and permeability reduction (that is ubiquitous in many geothermal systems) is expected to seal up fractures and destroy permeability; yet our results show that fault slip - in response to high shear stress - is sufficient to keep these fractures permeable and maintain high reservoir productivity. Thus, our results at Dixie Valley are critical in that they demonstrate how geothermal systems remain permeable even though they otherwise be expected to be tight. Given this, we were also able to show that knowledge of the in-situ stress field can be used to predict which fractures - and fault segments (for a fault-hosted geothermal system like Dixie Valley) - should be permeable and which should not be. This provides valuable guidance in deciding where to drill new wells (especially infill wells), if a □dry□ well should be redrilled and - if so - in which direction, and how one might best go about creating new permeability in an otherwise dry well through hydraulic fracturing or other means."

Field examples of efforts by Petrobas (the Mexican national oil company) in determining in-situ stresses with the Anelastic Strain Recovery Test (ASRT), breakout analysis and microfracturing are shown in a recent paper *[49]*. The ASRT technique is based on core strain relief after coring. Individual sand grains become stressed during burial and lithification of the sedimentary materials resulting in compression and distortion of the grains. When a rock stratum is cored, the sand grains attempt to expand elastically as soon as the original stresses are relieved, but they are held back by cement bonds. Many of these cement bonds will eventually be broken, forming a microcrack population preferentially aligned with the stress field. The main goals are to determine the principal in-situ stress direction and its magnitude. The strain direction is a reliable output since it does not depend on the rock strain absolute value. This is not true for stress magnitude.

Breakouts are caused by localized compressive shear fracturing of the borehole wall due to amplification of the regional tensor by the borehole itself. Small pieces of rock between failure-induced fractures are spalled or eroded and the borehole becomes elongated in the minimum horizontal stress direction. Such elongation and orientation of the long axes can be identified by logging tools. With appropriately located wells, breakouts can be used to map regional stress directions as well as local stress trajectories. Depending on the size of the area, 25 to 50 wells should be studied and each one should have breakout data over several thousand meters .

Hydraulic fracturing is considered the most popular method for computing the minimum horizontal in-situ stress magnitude, given by the fracture closure pressure. The fracture direction can be obtained by combining hydraulic fracturing results and other methods such as oriented coring, tiltmeter and acoustic emission. Minifracturing has been heavily utilized by Petrobas for optimizing hydraulic fracturing treatment starting in the late 1980s in the Campos Basin.

5. Fracture Detection

The previous section dealt with well stimulation, emphasizing hydraulic fracturing. The techniques discussed were used in real time to follow the fracture as it was developing. This section on fracture detection discusses the detection or diagnostics of naturally occurring or induced fractures.

Techniques

Although this first paper *[50]* by Cipolla and Wright covers both aspects, it is a good introduction to fracture detection. The paper details the state-of-the-art in applying both conventional and advanced technologies to better understand hydraulic fracturing and improve treatment designs. The initial portion describes the application and limitations of various tools and methods, including well testing, net pressure analysis (fracture modeling), techniques that employ open-hole and cased-hole logs, surface and downhole tilt fracture mapping, microseismic fracture mapping, and production data analysis. Case histories are included that illustrate the application of these various fracture diagnostic technologies. The case histories include examples of how several fracture diagnostic techniques can be used in concert to provide more reliable estimates of fracture dimensions and allow better economic decisions.
The authors discuss the techniques, capabilities, and limitations in three groups; Group 1- Direct Far Field Fracture Diagnostic Techniques; Group 2 - Direct Near-Wellbore Fracture Diagnostic Techniques and Group 3 - Indirect Fracture Diagnostic Techniques. Group 1 comprises two relatively new types of fracture diagnostics; tiltmeter fracture mapping and microseismic fracture mapping. These diagnostics are conducted from offset wellbores and/or from the earth's surface *during* the fracture treatment, and provide information about big picture far-field fractures *during* growth. A limitation of these techniques is that they map the total extent of hydraulic fracture growth, but provide no information about the effective propped fracture length or conductivity. Group 2 techniques are run inside the treatment wellbore *after* the fracture treatment by logging a physical property such as temperature or radioactivity in the near-wellbore region. The major limitation of these measurements is that they do not provide any information about the fracture further than about 1-2 feet away from the wellbore. Examples of these techniques are radioactive tracer technology, temperature logging, production logging, borehole image logging, downhole video and caliper logging. Group 3 techniques consist of analysis and numerical simulation approaches, using data from various sources, such as fracture modeling/net pressure analysis, pressure transient testing (well testing), and production data analysis.

Resistivity logging

The resistivity logging tool is one of the few tools that can operate at high temperature. It can be used to detect permeable fractures in hard rock. Several new types of resistivity measurement methods, which provide more information on fractures, have been developed. FMI (Formation

Micro Imager) is a resistivity log that give the resistivity distribution at the borehole wall. It is a powerful tool for detecting the presence and orientations of fractures, joints, and drilling-induced fractures in high-temperatures boreholes and has been widely used in HDR/HWR developments. An ULSEL (Ultra Long Spacing Electric Log) was tested at Hijiori in Japan. It can detect low-resistivity regions at distances up to several tens of meters from a borehole. However, data collected are unidirectional and have limited resolution. The HTPF (Hydraulic Tests on Preexisting Fractures) tool is a system for measuring resistivity distribution as a function of pressure. A straddle packer is used and the fracture is inflated while simultaneously measuring electrical resistivity distribution. This results in an image of a fracture trace along the borehole wall. The HTPF tool is effective for measuring crack-opening behavior and can be used for stress measurement *[34]* .

Borehole Televiewers

The acoustic borehole televiewer (BHTV) is useful for detecting and estimating the orientation of fractures and joints at the borehole wall. Signal processing has helped improve images obtained with the BHTV. Operating temperature is still limited, but high-temperature tools are being developed. A Doppler BHTV that can image the flow distribution in individual fractures at the borehole wall has been proposed, but a downhole tool that uses this method has not yet been developed *[34]*. Borehole televiewers were used by Scott Keys of the USGS to survey fractures in geothermal wells beginning in the late 1970s.

6. Seismic Techniques

Seismic techniques are primarily a means of detecting and defining the extent of fractures. However, the topic is sufficiently important, complex and diverse to warrant separate treatment. The intense interest in detecting potential new sources of natural gas is driving advances in surface detection of natural fracture systems. This has obvious application to hydrothermal geothermal systems, both known and, perhaps, undiscovered resources..

Geothermal reservoirs are predominantly fracture controlled. In order to efficiently exploit the resources, an accurate map of the productive fractures is important. Because of the natural heterogeneity, it is very difficult to map the fracture on the basic of surface geologic information and borehole data. In order to understand structure (lithology, faults, fractures) seismic imaging methods are being developed and applied. Both passive and active methods are being used. The active methods are 3-D surface reflection and vertical seismic profiling. Passive methods entail microearthquake monitoring. The overall goal of these studies, sponsored by the DOE geothermal program, is to evaluate, develop and apply seismic imaging to not only understand the static properties, but also derive knowledge regarding the dynamic nature of the reservoir; i.e., to map changes such as steam/fluid movement, active faulting fracture generation, or other properties relating to the production of the reservoir (taken from *[51])*.

Surface imaging

The goal of advanced fracture detection technologies in oil and gas operations is to observe subsurface fractures prior to drilling. Surface imaging consists of a surface seismic source and surface receivers and includes interpretation of the data. Detection technologies generally rely on advanced seismic collection and analysis techniques to reveal directional differences (anisotrophies) in the reservoir□s seismic response that may be related to fracturing. Carefully designed and controlled pulses of energy are sent into the earth and the reflected energy is collected and measured as it is progressively reflected back from deeper and deeper horizons. Seismic information can be collected along a line, providing a 2-dimensional, cross-sectional, view of the structures below the line. Recently, the acquisition of data in a grid, providing a 3-dimensional view of the subsurface, has become a standard tool in the development of many structurally or stratigraphically complex areas. Two types of returning seismic waves can be measured. Pressure waves (P-waves; individual particles oscillating in the direction the wave is moving) are the conventional data source. The changing timing, frequency, and amplitude of P-wave arrivals can give accurate representations of the subsurface structure of individual rock layers. Shear waves (S-waves; particles oscillating perpendicular to the direction of wave motion) are much more difficult and expensive to collect, but may provide more information on the varying properties of the rocks through which they travel *[17]*.

In the fall of 1999, FE announced *[17]* that it had selected three new research efforts that are intended to encourage gas companies to drill in a wider range of naturally-fractured, tight reservoirs that hold massive amounts of untapped natural gas. The vast amounts of natural gas in these tight gas reservoirs - an estimated 460 trillion cubic feet, or nearly three times the proved gas reserves in the United States - will become increasingly important to meet rapidly rising demands for clean-burning natural gas. Tight gas reservoirs are expected to account for 25% of all U.S. gas production in the next decade. If successful, the projects will show that advanced fracture detection technologies developed in the FE natural gas program can be applied in a greater number of geologic settings.

Previously, the effectiveness of the advanced tools in the three projects have been measured by comparing their projections with data from previously drilled fields. In the new efforts, the tools will be applied in fields before any wells are drilled. Much of the cost-sharing will be in the form of the costs for drilling wells to verify that a reservoir is actually fractured in the manner indicated by the advanced technologies. Participants will provide seismic data and conduct well logging, coring and pressure testing to confirm the presence of natural fractures.

Advanced Resources International, Inc., Arlington, Virginia, will demonstrate its geomechanical (subsurface rock deformation) model using 3-D seismic data and local/regional stress data to predict the location and character of natural fracture clusters. GeoSpectrum, Inc., Midland, Texas, will use a high-quality 3-D seismic data set specifically acquired to provide statistics related to natural fractures in the subsurface, and to determine areas of high-fracture density. GeoSpectrum will advance the current state-of-art by using powerful interpretation techniques and cost effective data processing systems needed to extract all the meaningful data for identifying fracture density. State University of New York (SUNY) at Buffalo, Buffalo, New York, will combine low-cost, innovative techniques that, when integrated, yield high-quality information to identify fractured reservoirs. The process uses relatively inexpensive data in an innovative manner and will evaluate an area of 760 square miles for a fraction of the cost of 3-D seismic.

Similar work is being done in a geothermal setting. The goal of the project described *[52]* is to test the ability of new seismic reflection data processing methods to map the subsurface location of permeable fractures, lithologic boundaries, and faults within the Dixie Valley, Nevada, geothermal field. The new seismic processing techniques used in this study, simulated annealing optimization and Kirchhoff pre-stack migration, were applied to 38.6 miles of previously acquired seismic reflection data from Dixie Valley. The results demonstrate that the new seismic processing techniques can contribute significantly to predicting the location and down-dip geometry of faults that bound geothermal fields and control permeability at depth.

4D seismic

4D seismic is the interpretation of time-lapse 3D seismic surveys to determine changes in a reservoir. The three papers *[53][54][55]* in this area discuss three applications of the concept in oil and gas production.

One of the reports *[55]* explains that changes during reservoir production in fluid saturation, pressure and temperature result in changes in density and seismic velocity. These changes result in impedance changes that, under favorable conditions, can be detected in seismic data. Ideally, an initial seismic survey is acquired before production or enhanced recovery to establish a baseline response. Later, a second survey is acquired and differences between the two surveys can be interpreted as dynamic reservoir changes. In principle, the technique can be applied in geothermal, such as at the Geysers to indicate areas of fluid depletion, to define reservoir boundaries, and to show the impact of injecting water brought in from outside.

Time-lapse or 4D-seismic has been applied successfully to monitor fluid changes in a reservoir during production *[53]*. Acoustic properties in the reservoir are affected by fluid changes because the bulk density and bulk modulus of the rock both change as the pore fluid is replaced. The seismic amplitude change as a result of water injection was large enough to be visible in the high porosity regions of the reservoir. Initially the reservoir contained 80% gas and 20% water. The time interval was 1,250 days after start of injection.

In 1996, Chevron Nigeria Ltd. acquired a repeat 3D-seismic survey over the Meren field, offshore Nigeria, for time-lapse reservoir-monitoring purposes *[54]*. By comparing the 1996 survey with a Chevron legacy 3D survey dating from 1987, the time-lapse images showed significant reservoir-fluid changes during the nine year interval. A detailed interpretation of one particular sand suggested that water from two injectors had very preferential channel-flow characteristics not previously discernible from well data. Also, the 4D seismic interpretation identified areas that may contain major amounts of bypassed oil reserves.

Two 3D seismic data sets from the Lena field, U.S. Gulf of Mexico, were analyzed for time lapse effects *[55]*. A preproduction 3D seismic survey was acquired in 1983 with a single source and a single streamer in an east/west direction. A regional dual-source and -streamer 3D survey covering the field was acquired in 1995. This latter survey was shot in a N58 ^{o}E direction. The time lapse differences for the reservoir were compared with production data, geologic models, flow simulation and forward seismic models. It was concluded that a time lapse, seismic-difference anomaly represented a region of gas invasion into the oil reservoir and areas bypassed by the injected gas were identified for infill drilling.

Downhole seismic

Over the past several years as part of the DOE NETL fractured-gas program, researchers have been developing and applying high resolution seismic methods to define and map the permeable pathways in naturally fractured gas reservoirs *[56]*. The work has focused on single and multiple component borehole sources in crosswell and single well configurations to record multicomponent data at frequencies from fifty hertz to several kilohertz. Work to date show that while surface methods provide broad characterization of fractures, borehole methods are necessary for providing the resolution necessary for inferring actual transport properties in fractured media. Due to limited bandwidth and resolution, few if any of the surface based techniques have been able to derive the resolution to map the fracture(s) actually responsible for the transport.

Theoretical work at the Lawrence Berkely National Laboratory *[56]* suggested that, by using higher resolution methods, it would be possible to image fracture properties beyond anisotropic effects and that crosswell and single well data acquisition configurations would be appropriate for gathering the data required to image fracture properties. LBNL performed several different scale experiments under controlled conditions at several different fractured sites. The main site was the Conoco borehole test facility near Newkirk, Oklahoma. Considering the data available on the facility, there was strong evidence for a fracture controlled transport system. Therefore, both crosswell and single well surveys were carried out in the wells before, during, and after air was injected to enhance seismic visibility over a fully saturated fracture.

From the crosswell data it was determined that there was a fracture somewhere between the two wells; and from single well data it was determined that the distance to the fracture was 17 meters. A slant well was drilled on the seismic data and a fracture was encountered at the predicted place. There were several significant results from this work;

1) Single well reflection surveys can provide useful information on vertical features a significant distance from the well and single well surveys hold great promise in characterizing fine scale reservoir heterogeneity;

2) Relatively small fractures can account for significant fluid flow. Using standard processing techniques, fracture zones were located which could be detected, but not located, by other means and,

3) Replacement of water with a gas (in this case air) produces large changes in the P-wave signal, even in such small features as a fracture with a width on the order of a millimeter.

Single-Well Seismology (SWS), Reverse Vertical Seismic Profiling (RVSP) and Cross-Well Seismology (CWS) are three new borehole seismic techniques. These techniques can provide much higher resolution images of oil and gas reservoirs than can be obtained with surface seismic techniques. Borehole seismology involves inserting the source and/or the seismic receivers in oil or gas wells. In the past, these methods have been limited to short distances between source and receivers in wells less than 10,000 ft (3 km) deep. This limitation of borehole seismology was due to the limitations of available downhole seismic sources, which were all impulsive and fluid coupled.

Borehole seismology can be used in management of both new and mature reservoirs and for improved location of in-fill drilling, or the completion of new wells. Borehole seismology can be also used for the determination of continuity of bedding, the direction of fractures, the determination of lithologies, mapping fluid saturation, and mapping of fault planes. In February 1997, P/GSI (Paulsson Geophysical Services Inc.) deployed a borehole seismic source and receiver system which was designed for long source-receiver spacing in deep wells *[57]*. The advanced downhole source is designed to operate to well depths of 20,000 feet at 400°F (204 °C). The borehole seismic data acquisition system consisted of a clamped vibratory source, a multi-level receiver string of clamped, three-component geophones and an acquisition system for Reverse VSPs. The receivers used fiber optic technology for low noise and fast data transmission from the well to the surface.

The analysis of a reverse vertical seismic profile (RVSP) acquired over a pinnacle reef in the northern Michigan reef trend is presented *[58]*. The survey exhibited two features of note: 1) a new, strong, downhole vertical vibrator, and 2) a random distribution of surface receiver locations. The high resolution of the image was largely due to the downhole source (see *[57]*), which generated a high powered signal at frequencies up to several hundred Hertz. RVSP has the potential to be less expensive and to provide better subsurface illumination than conventional VSP. With downhole shots, and by using surface receiver spreads similar to surface seismics, RVSP can produce a 3D data set in days or even hours once the receivers are in place.

While potentially useful in exploration ventures, the real promise of cross-well surveys lies in their ability to image producing horizons within existing fields, thereby enabling production and injection strategies to be optimized. However, the usual cross-well surveys suffer from high data acquisition costs. For cross well seismic to achieve its real potential, a major change in data-acquisition had to be found. INEEL under a CRADA with OYO Geospace Instruments is developing a large downhole seismic sensor array that can be scaled to greater than 100 sensor locations (3-axis using either geophones or accelerometers) and can be clamped, unclamped, and moved to a new borehole location *[59]*. The hardware is compatible with state-of-the art electronics and fiber-optic telemetry technologies. INEEL is funded to support development of prototype seismic sensor modules scalable to at least a 300-channel system. The final task in the project is the fabrication and testing of a fully integrated fieldable prototype system.

Downhole wave sources

Recognizing the need for a source capable of generating lower frequencies and clamping to the borehole wall, industry and government joined together in a CRADA to design and build a powerful, commercial quality, downhole, 3-component seismic vibrator. The CRADA members comprised Sandia, Raytheon Aircraft, GRI, Pelton, Chevron, Exxon, Amoco and Conoco. The project *[17][57]* was to develop a clamped, vibratory borehole seismic source to provide both P- and S-waves with high output energy over a broad frequency range. Crosswell seismic imaging holds great promise for providing improved description of oil reservoirs (and other geologic formations) in the region between wellbores. A primary reason why such imaging is not routinely used is the lack of borehole seismic sources and receivers which can satisfy the demands of downhole conditions.

Current seismic sources include both vibrating and impulsive types, but most suffer from one or more of the following limitations: 1) low output energy; 2) low frequency operation; 3) only one polarization output; 4) low temperature operation; or 5) difficult deployment. The advanced seismic source developed in this project addresses these limitations and is based on hydraulic actuator technology for high output power and utilizes Sandia expertise in high temperature electronics to achieve high temperature capability. The entire crosswell system, including seismic source, receiver array, fiber optic wirelines and trucks, uphole electronics and field data processing have all been integrated and checked out under field conditions. A new service company, Paulsson Geophysical Services Inc., was formed to provide surveys with this source. In February 1997, P/GSI deployed the new borehole seismic source and receiver system which was designed for long source-receiver spacing in deep wells. The advanced downhole source has generated reflections with source to receiver raypath length of 16,000 feet. The source is also designed to operate to well depths of 20,000 feet (6.1 km) at 400°F (204 °C). The first commercial survey for the downhole seismic vibrator was a cross well seismic survey in conjunction with a massive hydro fracture experiment. Both the source and the receivers operate on fiber optic wirelines.

In 1998, MIT/ERL, supported by the ERL Reservoir Delineation Consortium, set out to test the new downhole source. They stated *[58]* that the observed signals were strong and broadband, especially considering the 600 feet (183 meters) of glacial till at the test site. The high resolution of the image was largely due to the downhole source, which generated a high powered signal at frequencies up to several hundred Hz.

Microseismic monitoring

Microseismic fracture mapping can provide an image of a fracture through detecting microseisms or micro-earthquakes that are triggered by shear slippage on bedding planes or natural fractures adjacent to the hydraulic fracture. The location of these microseismic events is obtained using a downhole receiver array of accelerometers or geophones that are positioned at the depth of the hydraulic fracture in one or more offset wellbores. In the past, both wireline-conveyed and cemented-in receiver arrays have been used in field applications. The data is gathered and processed with a surface data acquisition system, and the microseismic events are located using techniques based on P- (compressional) and S (shear) -wave arrivals to provide time-dependent images of fracture growth and geometry *[60]*.

Microearthquakes induced by hydraulic fracturing have been studied by many investigators to characterize fracture systems created by the fracturing process and to better understand the locations of energy resources in the earth's subsurface *[61]*. The pattern of the locations often contains a great deal of information about the fracture system stimulated during the hydraulic fracturing. Seismic tomography has found applications in many areas for characterizing the subsurface of the earth. In addition, the evolution of the created fracture system can be inferred from the temporal changes in seismic velocity and the pattern of microearthquake locations. Seismic tomography has been used to infer the spatial location of a fracture system in a reservoir that was created by hydraulic fracturing. In the paper, the authors summarize, in general terms, the history of the technique and the state of the art as of about 1995.

Using specific applications, the next four papers *[62][63][64][65]* illustrate the progression in hardware, technique and understanding since the early work by Los Alamos at Fenton Hill, New Mexico. In 1991, microseismic logging was considered to be a new hydraulic fracture diagnostic method *[62]*. The "new" method of the paper was used to determine the fracture height and azimuth from data recorded in the cased treatment well. The height was determined from the vertical extent of a spatial anomaly in the waveforms. The anomaly was delineated by recording the data at discrete depths whose range extend beyond the fracture limits. The determination relies on identifying a change in the dominant direction of motion in the background data. Azimuth was determined from the initial particle motion polarization of the largest events of the microseismic event population. Microseismic logging differs from traditional microseismic monitoring because it was specifically developed to yield height and azimuth from the waveforms recorded in the treated well. With the capabilities of commercial technology available in 1991, microseismic logging required a single downhole data acquisition tool; a standard 7-conductor wireline and truck; data recording equipment. The downhole tool consisted of a three-component, VSP-type motion sensing sonde with hole lock mechanism and an orientation-indicating device.

Microseismic events or acoustic emissions associated with hydraulic fracturing were recorded with a borehole seismic tool in a deviated well during multirate injection, shut-in, and flowback *[63]*. The event locations indicated that the fracture orientation, length, and height were compatible with regional stress directions and estimates of the fracture size that were based on pressure decline. The acoustic-emission-mapping technique was developed for applications in fracturing crystalline rock and has a history of moderate success in hot dry rock geothermal fields. Acoustic emissions have been used with varying degrees of success to map hydraulic fractures in sedimentary formations, because the high attenuation of seismic waves in sedimentary rocks imposes limitations in the instrumentation and acquisition configurations that can "listen to fractures". Laboratory experiments show that these events arise from discrete ruptures on the fracture plane. If these microseismic events can be located, the strike and dip of the fracture can be determined. This would provide a characterization of the fracture far from the borehole that can be implemented in cased or nonvertical wells, even for nonvertical fractures.

The ideal situation would be to deploy several vertical arrays of three-components sensors near the expected fracture to get accurate locations of many events by triangulation. Unfortunately, few hydrocarbon-reservoir sites present this opportunity. In principle, however, locations can be determined with a single calibrated three-component sensor, either in the injection well itself or in a nearby observation well. Events were monitored throughout the four phases of the survey during the critical time intervals of injection and falloff. A total of 215 events were selected for analysis. The feasibility of the technique was demonstrated in the case of high-rate water injection in a sand/shale formation. The locations of the seismic events mapped out an inclined planar area near the borehole. The plane strikes N100°E, dips 74° to the north. The areal extent of the seismically active portion of the fracture is 164 ft high by 66 ft long The downhole equipment consisted of a modified slimhole seismic tool with a 2.125 in. OD and a 20,000 psi pressure rating. Data were recorded in analog form on four 240 minute videocassette tapes, and the downhole signals were monitored on an oscilloscope during the survey. The tool was run through 2.875 inch ID tubing and clamped in 7 inch casing at 6,282.8 ft from the rotary table, 24.6 feet below the bottom perforations adjacent to the target formation.

By collecting high-quality seismic data, microearthquakes can be mapped, potentially yielding extensive and high resolution information about the fracture system *[64]*. Fracture maps may be useful in planning infill and horizontal drilling and in designing and evaluating hydraulic stimulation and enhanced recovery operations in fracture-dominated oil and gas reservoirs. Borehole geophones at reservoirs depths provide the high-quality data needed to determine microearthquake location patterns. But when special observation wells must be drilled, microseismic studies can be expensive. To demonstrate that high-quality data could be collected inexpensively, geophones were deployed in existing wells and techniques developed for analyzing data from the resulting sparse array of instruments. The demonstration of inexpensive and effective methods should support the routine application of microearthquake techniques to study reservoir fracture systems.

Although less detailed than borehole surveys, less convenient than surface tiltmeter or seismic measurements, and less directly interpretable than coring studies, the microseismic technique provides a combination of resolution, coverage, and economy that is difficult with other methods. Downhole microseismic monitoring has been applied routinely to hydraulic-stimulation experiments in hot-dry rock geothermal reservoirs at Fenton Hill, New Mexico, in the United Kingdom, Japan and France. Tomography has been performed using these data, indicating low-velocity process zones in the seismic region.

Additional, more recent, data processing has defined planar features that represent individual joints that slipped*[64]* . These experiments took place in hard, crystalline rock, through which elastic waves propagate efficiently. Despite poorer wave-propagation properties, stimulation-related microearthquakes have been mapped successfully in sedimentary environments using downhole geophones or accelerometers. The paper describes remote well microseismic monitoring in the Austin chalk, Giddings field, Texas and in the 76 field, Clinton, Kentucky. The deployments began as reconnaissance experiments; however, the data were of sufficient quality to permit accurate mapping of the microearthquake data, yielding previously unknown details of the reservoir fracture systems. Microseismic data was collected using downhole, three-component geophone tools. A mechanical arm coupled the instruments to the borehole wall. The tools were equipped with 8- or 30-Hz geophones. Downhole amplification of the geophone outputs was 60 dB. At the surface, the signals were further amplified and antialias filtered before they were input to a digital, PC-based, event-detection system. Data were sampled at 5 kHz.

More than 480 and 770 stimulation-induced microearthquakes were recorded at two sites in the Austin chalk and more than 3,200 production-induced microearthquakes were recorded at Clinton County, Kentucky. Hodogram-inclination data caused Austin chalk events to locate out of zone, leading to the use of reflected phases for depth control. In Clinton County, dual-geophone deployment in a single well constrained event depths successfully. Combining shot and well-log data with a joint hypocenter-velocity inversion allowed calibration of seismic velocities and downhole geophone orientations and calculation of accurate microearthquake locations.

Two recently developed borehole seismic techniques have proved useful in characterizing fractured reservoirs for oil field development. Case histories *[65]* illustrate how these well seismic techniques can help to determine main fracture orientations and densities. One technique involves monitoring microseismic activity taking place in active fractures at the reservoir, the other an analysis of the birefringence effects that apply to shear wave energy when passing through the fracture medium.

Microseismic monitoring provides information on active, open fractures. Because of their relative low-cost, the sensors can be deployed permanently. In two major surveys in the North Sea the SST500 VSP tool was used to successfully record microseismic activity. In order to investigate compaction processes, seismic monitoring was carried out for 20 days using an observation well in the center of the field. This was done by deploying a downhole geophone array of six three component receivers. Initial event detection was conducted in-field using algorithms running on a computer networked to the recording system. This data was then shipped back to shore using helicopter flights from the platform.

In late 1997, seismic data was acquired during a major Reservoir Characterization Project (RCP) designed to monitor the effect of prolonged CO_2 injection over the Vacuum field in New Mexico *[65]*. The dataset was processed to provide information on the character of reservoir fracturing through analysis of shear waves. Observation of the splitting effects on the generated shear waves when propagating across a fractured reservoir (birefringence) lead to direct indications about the reservoir. Shear wave energy, traveling through a fractured volume, will naturally split into two separate wave-fields, each traveling at a different velocity from the other. The faster shear wave energy propagates with a particle motion parallel to the principal direction of fracture orientation. The slower shear wave energy propagates with a particle motion perpendicular to this principal direction. Analysis of the isolated fast and slow shear wave fields can be used to quantify the level of azimuthal anisotropy within the reservoir and consequently determine fracture orientations. In addition, the fast and slow shear waves provide information on the rock and fluid properties.

In May 1999; Malin and Shalev *[66]* reported on a DOE project to study fracture patterns and densities in the Geysers reservoir using microearthquake shear-wave splitting. The purpose of the DOE-supported geothermal project is to produce three-dimensional maps of crack density and crack orientation in fracture controlled geothermal or hydrocarbon reservoirs utilizing shear wave splitting. The objectives for 1998-1999 were:

1) Determination of fracture pattern and mapping the leading crack direction in two geothermal areas; the Geysers and Casa Diablo,
2) Conduct detailed three-dimensional tomography for crack-density and construct a crack-density map of the subsurface with 1 km resolution, and
3) Develop a shear wave splitting tomographic method to simultaneously invert for crack density and crack orientation.

The method may be employed in areas where the cracks are not aligned in the same direction. More than 2,000 split shear wave observations were obtained from both the Geysers and Casa Diablo. The polarization direction maps for both areas showed consistent direction for fast shear wave polarization which enables performed crack density inversion. Crack density maps show regions of high crack density that may be used as drilling targets.

Drill-bit seismics

Drill-bit seismics have been used on land and in shallow marine environments for many years. The technique uses acoustic energy radiated during drilling to provide time/depth and formation-velocity information at the well site. The paper *[67]* addresses deploying a vertically-oriented receiver cable in a marine environment, but the basic concept as described here would also be applicable to geothermal using an offset well. The drill bit replaced the usual wave source with the drill bit as the vibrator. A similar cross-correlation approach was used to obtain travel time information. Because the drill bit signal was unknown, it was monitored with accelerometers mounted on top of the drillstring. It is possible to process the drill-bit seismic data as a VSP to produce a corridor stack that may be compared with surface seismic data. Three limitations of the method were described:

1) Roller cone bits must be used, because PDC bits usually do not provide sufficient vertical pressure-wave energy or cause axial drillstring vibration,
2) Well deviation is limited to about 65 degrees maximum. At higher deviation angles, interaction between the drillstring and borehole attenuates the signal, and
3) The signal to noise ratio of the data is influenced by the type of formation, noise sources both on and off the rig, and drilling parameters.

Seismic signals while drilling a Hot Dry Rock geothermal well in Soultz-sous-Forets, France were detected by two downhole detectors in the granitic basement *[68]*. The technique provided a means for the real time detection of the drilling target. Although signal characteristics are highly dependent on the field and drill system, information about the structure of the earth can be recovered by appropriate signal processing. A combination of drill bit and downhole multicomponent detectors is one of the best means available for measurement of HDR reservoirs using the drill signal, because the signal is highly attenuated in the overburden and is reflected at overburden/basement boundary. The triaxial drill-bit VSP (vertical seismic profiling) method with a downhole multicomponent detector is under development and has resolved subsurface structures in test sites and geothermal fields. At the Soultz site, a well was drilled into basement and associated drill signals were detected by a multicomponent and two single component seismic detectors installed in the granitic basement. The signals were analyzed and a reflection image obtained which was consistent with logging, the distribution of microseismicity and results of the AE.

7. Reservoir Definition and Operation

Logging techniques such as temperature, resistivity, density and sonic log, BHTV and FMI are used in every stage of HDR/HWR development. They provide valuable information about the reservoir but generally provide information only near the wellbore and thus cannot provide complete diagnostics about the condition of the reservoir *[34]*.

Tracers

It appears that tracers are becoming a powerful tool in understanding geothermal reservoirs and providing information for optimum operation. This is the focus of this section.

With the increased use of reinjection in geothermal reservoirs, tracers have become an important tool in developing reservoir management strategies *[69]*. If injectors are positioned too close to producers, a risk of short circuiting develops, resulting in the possibility of premature thermal breakthrough. If injectors are placed too far away, the injected water will not provide sufficient pressure support to the reservoir. Since chemical breakthrough is more rapid than thermal breakthrough, a tracer test can provide important interwell flow data that can be used to optimize injection well placement and injection flow rates.

In view of the excellent detectability of the substituted polyaromatic sulfonates in conjunction with the excellent thermal stability of the aryl-sulfonyl bond, a study of the polyaromatic sulfonates was initiated *[70]* with the objective of identifying a class of compounds for use as tracers in hydrothermal environments having fluids hotter than 300°C (572 °F). A recently identified family of candidate fluorescent tracers, the polyaromatic sulfonates, was shown to be resistant to thermal decay under simulated geothermal reservoir conditions at 300°C (572 °F). Laboratory techniques have been identified for the simultaneous analysis of several compounds from this family by reverse-phase high-performance liquid chromatography (HPLC) in combination with ion pairing and fluorescence detection. One of the polyaromatic sulfonates, pyrene tetrasulfonate, was used in a tracer test at Dixie Valley, Nevada at 250°C (482 °F). It showed breakthrough in several productions wells with a detection limit of approximately 200 parts per trillion.

The uv-fluorescent polyaromatic sulfonates are excellent candidates for geothermal tracing applications because they are environmentally benign, very detectable by flouorescene spectroscopy, affordable, and thermally stable. Two compounds from this category, 1,5-naphthalene disulfonate and 1,3,6-naphthalene trisulfonate, have been investigated in the laboratory and in the field and have been shown to be suitable for both low-temperature and high temperature geothermal reservoirs *[71]*. The decay kinetics of the candidate tracer 1,3,6-naphthalene trisulfonate was studied under conditions that simulate a hydrothermal environment. It was shown to possess sufficient thermal stability to qualify for use in reservoirs as hot as

340°C (644 °F). In a series of field tests at Dixie Valley, Nevada; Ohaaki, New Zealand; and Awibengkok, Indonesia; 1,3,6-naphthalene trisulfonate and 1,5-naphthalene disulfonate were successfully used to trace injection-production flow patterns. These compounds were shown to have excellent detection limits of approximately 200 parts per trillion by standard HPLC (high-performance liquid chromatography) and fluorescence detection methods.

Geothermal operators have long desired a simple, efficient, reliable and cost effective method of online tracer detection. With the recent breakthroughs in laser fluorimetry, Raman spectroscopy, near-IR solid-state lasers, fiber optics, and CCD spectroscopy, such an online detection method may be possible *[72]*. The development of online detection will depend on a number of related tracer and hardware properties. Raman and absorption spectroscopy may provide an analytical tool that will allow for the use of a number of visible dyes that are available in bulk and which may be sufficiently thermally stable for use in geothermal systems. In addition, very efficient and affordable solid-state lasers are available that produce emission in the near-IR and that could be powered by batteries or solar panels in the field.

A new generation of environmentally benign vapor-phase tracers has been used in tracer tests to estimate the degree to which injectate is being recovered following a significant increase in injected volumes of water into the Southeast Geysers field since startup of the Southeast Geysers Effluent pipeline *[72]*. To assist in evaluating the effectiveness of the increased injection, the distribution of water into the reservoir needed to be defined using tracers. Naturally occurring tracers were considered, but chemical analysis of the pipeline water revealed no distinctive compounds nor would the steam derived from the water have an isotopic composition significantly different from that of the reservoir. Consequently, a project was proposed and accepted to conduct chemical-tracer tests. Two hydrofluorocarbons, R-134a (tetrafluoroethane) and R-23 (trifluoromethane) were chosen as potential replacements for the now environmentally unacceptable R-13. The injection tests also served as an evaluation of these new tracers. Six tracer tests were conducted. The tests provided information on the distribution of injectate in the reservoir. The new tracers were evaluated by calculating their recovery in the production steam, and by comparing these recoveries to that of tritiated water, which was injected along with the gas tracers in one test. The tracer tests were largely successful. Recoveries of the gas tracers ranged from 23 to 93%, demonstrating that thermal stability is not an issue for the new tracers in the normal Geysers reservoir. Sampling and analysis of the new tracers also proved effective; detection limits are now down to a million times lower than the peak concentrations of the tracer returns in this series of tests.

Tracer testing in geothermal reservoirs can yield valuable information concerning reservoir fluid volume and fluid exchange rate. The paper *[69]* reports the use of tracer testing to determine useful information about reservoir fluid volume and upper limits on fluid exchange rates. Using the numerical simulation code TETRAD, a greatly simplified 2-dimensional flow model of the geothermal reservoir at Beowawe was developed. The objective was to simulate a tracer test like the one conducted at Beowawe in 1994 in order to verify the approach that was used to estimate fluid volumes and fluid exchange rates. The researchers were able to also simulate a leaking reservoir. This indicates that the extended method of Rose and coworkers can be used to estimate the volume of a leaking reservoir. Rose et al determined that the volume of fluid contained within the reservoir is approximately 17 billion gallons. In addition, a simple two-dimensional numerical simulation model that verifies the analytical approach was developed. Similarly, Rose et al *[73]* conducted fluorescein and amino G tracer tests at Dixie Valley. The objective was to demonstrate the feasibility of using numerical simulation to model the flow of tracer throughout a geothermal reservoir.

Explicit-fracture tracer test

In a novel mix of fracture analysis and tracer-flow analysis, the report discussed an explicit-fracture tracer test that would serve to characterize tracer flow along distinct fracture sets between an injection well and the surrounding productions wells within a geothermal reservoir. Using PTS and borehole imaging data, the major fracture sets within an injection wellbore would be characterized. Downhole injection of distinct tracers at various depths within the wellbore will be used to test flow paths through various fracture domains. By measuring tracer production at the surrounding production wells, there will be enough information to distinguish various fracture flow paths. The interpreted information will then be used to further constrain the three-dimensional fracture map *[71]*.

Downhole fluid analyzer

APS Technology has a three-year project entitled "Downhole Fluid Analyzer," to develop a fluid analyzer tool that will measure fluid properties inside the well without interfering with production. The tool will provide real-time information to the natural gas well operator as it is analyzed underground. The tool will be developed so that it can be integrated into current completion system technologies. Field tests will be performed at sites to be determined *[17]*.

8. Numerical Simulation

This section on numerical simulation is abstracted from the GeothermEx, Inc. report *[74]*, "Assessment of the state-of-the-art of numerical simulation of Enhanced Geothermal Systems". Four HDR codes (FRACTure, GEOTH3D, FRACSIM-3D and Geocrack2D, four hydrothermal codes (TOUGH2, TETRAD, STAR AND FEHM) and 19 simulators used in nuclear was isolation applications were evaluated. GeothermEx considered and discussed the need for including desirable EGS features in the simulators and also made recommendations for improving the state-of-the-art relative to EGS simulation.

Considering that EGS development in the near term will occur in or near geothermal fields that have been developed for power generation, it is likely that an EGS simulator will have to have the basic capabilities required of a conventional hydrothermal reservoir simulator. These are the ability to handle multi-phase fluid flow, heat transfer and tracer transport in porous or fractured media in three dimensions. In addition, there are desirable special characteristics of an EGS reservoir simulator, including:

1) Explicit representation of fractures
2) The ability to change fracture opening as a function of effective stress
3) The ability to handle shear deformations and associated jacking of the fractures
4) A relationship between fracture aperture and fracture conductivity
5) Channeling of flow in fractures
6) The ability to handle certain thermo-elastic effects
7) The ability to handle mineral deposition and dissolution

While not all are needed for a given simulation effort, a complete simulation tool would have all of the above features. GeothermEx then discussed, in brief, how these features were or were not handled in the simulators reviewed.

Explicit representation of fractures

Nearly all of the simulators can be used to model fractures at some level. Two of the HDR simulators (FRACTure and Geocrack2D) can represent fractures discretely; FRACSIM-3D does so in simulating hydraulic fracturing operations only. Several of the nuclear-waste-isolation codes allow discrete fractures to be represented. Like all four hydrothermal codes, GEOTH3D uses a porous medium approach; FRACSIM-3D also uses this method to simulate normal production and injection (as opposed to stimulation).

All of the porous-medium simulators allow approximate representation of large-scale discrete fractures using long and narrow gridblocks with high porosity and permeability. At least one fracture mesh generator (Golder Associates' FracMan) has been adapted to two of the hydrothermal codes (TOUGH2 and FEHM), enabling them to represent fractures explicitly as a series of 2-D, triangular elements. This type of approach holds promise for easing the development of hydrothermal models with many discrete fractures.

Fracture opening as a function of effective stress

This feature enables a more accurate representation of reservoirs with low natural permeability or when permeability enhancements are being modeled. Three of the four HDR simulators and many of the nuclear-waste-isolation simulators include approximation of this, either through permeabilities that are a function of stress or by discrete-fracture modeling. None of the hydrothermal simulators have this feature because they do not incorporate deformation of the rock matrix, which is needed to calculate aperture changes.

Shear deformation and associated jacking of fractures

Of the HDR simulators, FRACTure and FRACSIM-3D include this feature, which is particularly important as fractures grow during stimulation operations. As in the case of fracture opening in response to changes in fluid pressure, none of the hydrothermal simulators can model this, nor can any of the nuclear-waste-isolation simulators.

Relationship between fracture aperture and conductivity

Three of the four HDR simulators and several of the nuclear-waste-isolation simulators use the cubic law to define the relationship between fracture aperture and conductivity. However, the cubic law cannot be used for two-phase flow. In multi-phase porous-flow models, ignoring capillary pressure, fluid flow in a fracture can be expressed as a modified (multi-phase) form of Darcy's Law.

Channeling in fractures

Only one HDR simulator (FRACTure) handles this feature, and does so approximately by manually adjusting fracture element properties. None of the hydrothermal simulators take account of channeling. In two nuclear-waste-isolation simulators (FracMan and HYDREF), channeling is accounted for by using pipe-like elements, often located at the intersection of two fractures. There are two difficulties associated with representing channel flow. First, one must define where channeling is occurring from field data. Although certain pressure transient analysis methods can indicate channel-like (one-dimensional) flow, the location and orientation of the channel can only be inferred. Second, the simulation mesh must be fine enough to capture the sharp gradients associated by flow in a small channel, and the inclusion of small, cylindrical elements with random orientations presents difficulties in regard to both designing the grid and accurately computing the results.

Thermo-elastic effects

All of the HDR simulators except GEOTH3D include this feature; FRACSIM-3D handles thermo-elastic effects using a global stress rather than a local elasticity solution. All of the conventional hydrothermal simulators can approximate this effect by varying bulk porosity and permeability with pressure and temperature. However, they cannot simulate, for example, the thermal contraction of impermeable rock, which changes the aperture (and therefore, possibly, the conductivity) of a fracture. Many of the nuclear-waste-isolation simulators handle thermo-elastic effects.

Mineral deposition and dissolution

Only one of the HDR simulators (FRACSIM-3D) includes a simple mineral deposition and dissolution with user-specified temperature-dependent reaction rate constants and saturation concentrations. One nuclear-waste-isolation simulator (PORFLOW W) has this capability also. Of the hydrothermal simulators, a reactive chemical transport model has been developed to work with TOUGH2. This augmented simulator (TOUGHREACT) permits a wide range of chemical processes to be modeled, including mineral deposition and dissolution.

The difficulty encountered in trying to solve chemical reactions within a numerical model of a geothermal system suggests that a de-couple approach would be preferable if such a feature is to be implemented. However, a lack of this feature is not a hindrance to EGS development. In fact, in more than 40 years of operating hydrothermal systems, which are much more likely to have scaling problems, scaling is an operational consideration but never a serious impediment to development.

Tracer module

All the reviewed simulators handle tracers fairly effectively.

Multi-phase flow

All the conventional hydrothermal simulators and a few of the nuclear-waste-isolation simulators provide multi-phase flow capability. None of the HDR simulators have this ability. This is likely to become a limitation if HDR simulators are to be considered for evaluating EGS projects adjacent to existing hydrothermal systems with extensive two-phase conditions.

Summary of findings

While each of the simulators evaluated had many of the capabilities listed above, none has all of them. Each simulator has its strengths and weaknesses. Furthermore, the ease of implementing new features varies with simulator type. Fortunately, a 'perfect' simulator that incorporates all of the above features is not needed for most EGS projects or at every state of a given project. Further development of existing simulators is more useful than developing a single, all-purpose simulator for EGS applications. This is particularly true considering that near-term EGS development in the U.S. is likely to take place in hot, low-permeability areas in or around existing hydrothermal fields. Here, a field operator will need to use numerical simulation to predict the effect of EGS development on conditions in the main field. Considering that nearly all reservoirs developed for geothermal power production have two-phase conditions, a conventional hydrothermal simulator must be used for the present.

In the longer term, a stand-alone EGS project might require a dedicated EGS simulator that combines the capabilities of HDR and hydrothermal simulators, and possibly some of the features of the more complex nuclear-waste-isolation simulators. As research into the identification and characterization of hydraulically active fractures continues, such simulator features will be become more important than they are now.

No EGS reservoir has operated for sufficient time to validate any numerical model, fracture-based or otherwise. Therefore, at the present time, the lack of any particular feature is not hindering the development of EGS. Developing an EGS simulation experience base should be a priority at this time. Meaningful modeling and simulator development cannot be done in the abstract. Only through interaction with realistic problems can the appropriate simulation needs be identified and the skills developed to apply them to other reservoirs. DOE should support active simulation of real EGS reservoirs which could be done as part of ongoing international projects or as part of future EGS development projects in the U.S.

Future research should be funded for improving both fracture-network simulators and discrete-fracture simulators for EGS use. Potential areas of improvement include the ability to:

1) Handle two-phase flow,
2) Simulate the formation of a hydraulically stimulated fracture network, and
3) Modify fracture aperture as a function of both effective and shear stress.

For hydrothermal simulators, the ability to handle rock deformation could be added. Furthermore, the use of hydrothermal codes to represent discrete, hydraulically active fractures could be investigated further.

RECOMMENDATIONS

1. Continue the effort to review, summarize and report on new and developing technology applicable to hydrothermal and EGS development. A paper summarizing this work should be developed for appropriate publication.

2. Conduct an indepth and exhaustive evaluation of several critical technologies. This report has provided, at best, an overview of recent advances. The most important at this time is the whole area of active seismics, both surface and downhole.

3. Analyze the impact of new technology on geothermal costs. This includes a fresh look at drilling and completion costs. What hasn□t been done is to examine the costs associated with reservoir definition and production.

4. Coordinate geothermal research in drilling and completion with the DOE Fossil Energy program. If this is not feasible, an alternative approach would be to remain aware of the FE program and not duplicate ongoing research.

5. Determine the capabilities and limits of commercially available equipment. Examples where this should be done are PDC bits where several companies have products and geosteering where AutoTrak is a commercial service.

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