Proceedings World Geothermal Congress 2005
Antalya, Turkey, 24-29 April 2005

Hydrofracture Characterization Using Downhole Electrical Monitoring

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Keywords: HDR, EGS, SP, self-potential, hydrofracturing.

ABSTRACT

Most proposed HDR development techniques seek to increase subsurface flow capacity by hydrofracturing hot but impermeable rock – pumping high-pressure fluid into one or more deep wells and enhancing permeability by opening pre-existing sealed fractures and/or creating new ones. During subsequent field operation, it is important that the hydraulic connections between production and injection wells be neither too poor (resulting in little fluid flow) nor too good (resulting in "short-circuiting" and rapid cooling). Unless the permeable fractures created by hydrofracturing can be accurately mapped, the cost of subsequent trial-and-error drilling to try to establish a suitable fluid circulation system is likely to dominate project economics and render HDR impractical. Theoretical calculations are presented to examine the feasibility of remotely monitoring hydrofracture propagation using downhole self-potential (SP) measurements in nearby shut-in observation wells. Combining microearthquake monitoring with downhole SP monitoring could provide more information than either technique alone. The computations suggest that SP signals far in excess of detection thresholds can propagate hundreds of meters from pressurized fractures within a few weeks. Practical issues pertaining to field deployment are also discussed.

1. INTRODUCTION

"Hot Dry Rock" (HDR) and *"Enhanced Geothermal System"* (EGS) development projects both involve the artificial stimulation of relatively impermeable high-temperature underground regions (typically at depths of 1 – 4 kilometers or more) to create sufficient permeability to permit underground fluid circulation, so that hot water can be withdrawn from wells and used to generate electric power. Several "HDR" research projects of this general type have been undertaken in the past in the U.S., Japan, Europe and Australia. Recent U.S. "EGS" activities along these lines focus mainly on stimulating marginal areas of existing operating hydrothermal fields rather than on fresh "greenfield" sites.

Usually, stimulation is accomplished by injecting water into a well at high pressure, enhancing permeability by the creation and propagation of fractures in the surrounding rock (a process known as "hydrofracturing"). Beyond just a *motivation*, low initial system permeability is also an essential *prerequisite* to hydrofracturing. If the formation permeability is too high, excessive fluid losses will preclude the buildup of sufficient pressure to fracture rock.

In practical situations, the actual result of high-pressure water injection is frequently to re-open pre-existing mineralized fractures rather than to create completely new fractures by rupturing intact rock crystals. Pre-existing fractures can often be opened using injection pressures in the range 5 – 20 MPa. Creation of completely new fractures will usually require pressures that are substantially higher. It is preferable to undertake development projects of this type in regions of tectonic extension, so that when pre-existing fractures are pressurized they will fail by shearing laterally. If this happens, the fracture will usually stay open afterwards even if injection subsequently ceases.

The principal barrier to HDR utilization for electricity generation is project economics. Prices for electricity obtained using conventional hydrothermal reservoirs are just marginally competitive. Unless and until the costs of routinely and reliably creating and exploiting artificial subterranean fracture networks that can deliver useful quantities of hot fluid to production wells for long periods of time (years) are reduced to levels comparable to those of other major cost components of a conventional geothermal development project (drilling, power station construction and connection to the grid), HDR will be of little interest to the electrical power industry.

A major obstacle is the difficulty of appraising the properties (exact location, geometry, fluid transmissivity, etc.) of the fractures that have been created/re-opened by hydrofracturing, so that subsequent production and injection wells can be suitably situated. Sustainability of power production is critically dependent upon reservoir thermal sweep efficiency, which depends in turn on the geometry of the fracture network and its interconnections with the various production and injection wells used to circulate fluid underground. If no permeable connections are created between the wells, fluid flow will be too slow for practical utility. If the connections are too good, however (such as a production/injection well pair connected by a single very permeable fracture), production wellhead temperatures will decline rapidly.

Except at those points where fractures actually intersect boreholes and can be detected directly by downhole fluid-loss and televiewer logs, characterization of the underground fracture network presently relies virtually exclusively on microearthquake surveys. During hydrofracturing, as fractures are opened and extended, small seismic events will occur along the dislocation surface which can be detected by arrays of sensitive seismometers (usually buried at shallow depths and/or in neighboring shut-in observation wells). Ray-tracing analyses and similar techniques are then employed to estimate the spatial location of each seismic source. Once a sufficient number of such events have been recorded, it is often possible to perceive patterns in the "cloud" of estimated epicenter locations that are suggestive of fracture network geometry. This approach has limited spatial precision, however (uncertainties are often worse than 100 meters), and can only discern fractures that actually produce detectable seismic events during pressurization. Moreover, microseismic surveys cannot discriminate among fractures of varying degrees of fluid transmissivity.

2. SELF-POTENTIAL MONITORING

In recent years, techniques have been devised to calculate the effects of subterranean reservoir evolution upon surface geophysical surveys, based on the results of conventional numerical reservoir simulation calculations for hydrothermal reservoirs (*Pritchett et. al*, 2000). If repeated surveys exhibit systematic temporal changes that can be correlated with events taking place in the reservoir, additional constraints are provided for history-matching studies, resulting in more robust and reliable reservoir models. Geophysical techniques considered to date include microgravity surveys, DC resistivity surveys (Schlumberger type), magnetotelluric (MT and CSAMT) surveys, and self-potential (SP) surveys. The computational postprocessors that carry out these calculations of changes in geophysical observables have been extensively tested and verified (*Pritchett*, 2003) and have been applied in various field studies, mainly in Japan (see, for example, *Nakanishi et. al*, 2001; *Pritchett and Garg*, 2002; *Pritchett and Garg*, 2003).

Of these methods, the SP ("self-potential") technique appears to be most appropriate for monitoring the growth of underground fractures in HDR stimulation operations. Conventional earth-surface SP surveys will not be very helpful owing to the great depth and limited strength of the signals from hydrofracturing, but continuous downhole SP monitoring (using electrodes in the uncased zones of nearby shut-in observation wells) could in principle sense the progress of the reservoir pressurization that results from stimulation operations. If so, data of this type could be used to supplement microseismic data to more completely characterize the fracture system.

Stable spatial distributions of electrical potential (voltage) are present naturally in the undisturbed earth, both at the ground surface and at depth. In geothermal areas, this "self-potential" (SP) can arise from as many as three different causes acting together: underground *temperature gradients* ("the earth as a thermocouple"), heterogeneities in subsurface formation *chemical composition* ("the earth as a battery"), and *electrokinetic effects* caused by fluid circulation through the rock ("the earth as a dynamo"). During field operations, however, temporal *changes* in the observed self-potential distribution will be dominated by electrokinetic effects, since the underground fluid flow pattern will change relatively rapidly with time as borehole flow rates change, compared to large-scale changes in system temperature or chemical composition (*Ishido and Pritchett*, 2000). Therefore, to interpret rapid changes in SP, it suffices to restrict attention to electrokinetic phenomena.

The essential question, of course, is whether SP changes of sufficient intensity for detection and interpretation (>10 millivolts or so) are likely to be generated by HDR hydrofracturing operations. Recent experiments in Japan using shallow wells have observed transient SP signals caused by relatively low-pressure injection into permeable formations (*Ishido and Pritchett*, 2003). HDR hydrofracturing in relatively impermeable rock will presumably produce electrical signals that are much more intense but also much deeper and that propagate more slowly through the earth.

3. THEORETICAL BASIS FOR SP MODELING

It may easily be shown (*Ishido and Pritchett*, 1999) that the three-dimensional distribution of electrokinetic self-potential at an instant of time may be determined by solving a boundary-value problem given by Poisson's equation (derivable from Ohm's Law):

$$\mathbf{div}\left(\frac{\mathbf{grad}\ V}{\Omega}\right) = \mathbf{div}\ \boldsymbol{I}_{\boldsymbol{DRAG}}$$

where V is electrical potential (volts), Ω (in general, a function of position and time) is electrical resistivity (ohm-meters), and $\boldsymbol{I}_{\boldsymbol{DRAG}}$ is the "drag current" density vector (amperes per square meter) induced by the flowing fluid. Therefore, if the distributions of electrical resistivity and drag current density are known at a particular instant of time, the above equation can be solved to obtain the simultaneous distribution of potential (V) everywhere underground.

"Drag current" is caused by the tendency of ions within the molecular-scale "electrical double layer" at the interface between solid rock and moving liquid to become detached and carried along with the fluid flow. To model the "drag current density" ($\boldsymbol{I}_{\boldsymbol{DRAG}}$), the formulation devised by *Ishido and Mizutani* (1981), which is based on extensive laboratory measurements on actual crustal rock samples of geothermal relevance, is adopted. Briefly, under single-phase liquid conditions this model expresses the drag current density as:

$$\boldsymbol{I}_{\boldsymbol{DRAG}} = \frac{\phi\varepsilon\zeta}{\rho_L k t^2}\dot{\boldsymbol{M}}_{\boldsymbol{L}}$$

where $\dot{\boldsymbol{M}}_{\boldsymbol{L}}$ is the local instantaneous liquid-phase mass flux vector (kilograms per second per square meter), ρ_L is the mass density of the liquid phase (kilograms per cubic meter), ϕ is the (dimensionless) system porosity, ε is the dielectric permittivity of the liquid phase (farads/meter), k is the absolute permeability of the rock (square meters), t is fluid-conduit tortuosity (dimensionless), and ζ is the adsorption potential, or "zeta-potential" (volts).

The zeta-potential ζ in the above equation is in general a function of local rock composition in an analogous fashion to density or heat capacity, and also depends on temperature, acidity (*p*H) and the concentrations of *1:1*- and *2:2*-valent electrolyte in the liquid brine; it is given by Equations 18, 20 and 21 of the above-cited paper by Ishido and Mizutani, assuming that the following empirical relationship holds for the distance (X_s) between the solid surface and the slipping plane in the electrical double layer:

$$X_s\,(\text{meters}) = 3.4\times10^{-4}\mu_L$$

where μ_L is the dynamic viscosity of the liquid phase in pascal-seconds. The above formulation (generalized to treat multiphase fluid flow) has been incorporated within the STAR simulator system (*Ishido and Pritchett*, 1999) and has been applied to several practical field situations to help interpret SP survey data (see *Pritchett and Garg*, 2003, for example).

4. CALCULATIONS OF SP CHANGE

To appraise the feasibility of monitoring HDR hydrofracture propagation using downhole SP measurements, we utilized the STAR reservoir simulation system (*Pritchett*, 1995; *Pritchett*, 2002) to calculate the behavior of an idealized "hydrofracturing" operation, including both conventional thermohydraulic effects (changes in fluid pressure, fluid flow pattern, etc.) and the resulting temporal evolution of the electrical potential field around the fracture. The subsurface flow and pressure history was first computed using the STAR reservoir simulator, and then the STAR "SP postprocessor" (*Ishido*

and Pritchett, 1999), which employs the above theoretical formulation of *Ishido and Mizutani* (1981), was used to calculate the time-dependent electrical potential distribution.

Consider the situation depicted in Figure 1. An injection well penetrates the center of a planar circular pre-existing fracture (diameter = 600 meters). Shut-in observation wells are nearby, and are instrumented to detect changes in underground electrical potential. The hot reservoir formation surrounding the fracture and the injection well consists of low-porosity (1%) low-permeability (10 microdarcy) liquid-saturated (dilute sodium chloride brine, 0.1% salinity) volcanic/metamorphic crystalline rock at 200°C temperature and is treated as homogeneous, with 100 ohm-meters electrical resistivity.

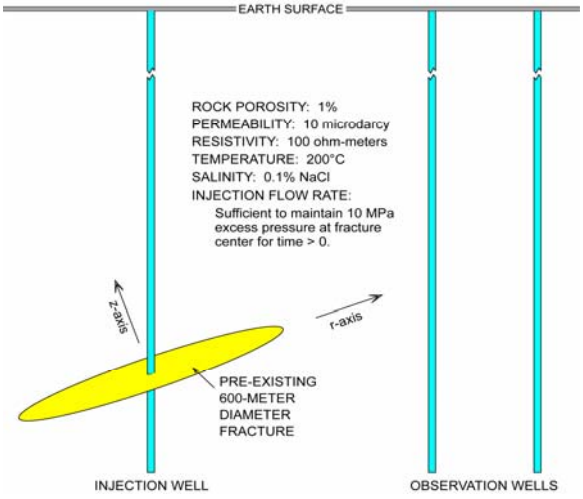


Figure 1: Sketch of problem geometry.

Starting at t = 0, the injection well begins to force water into the pre-existing fracture at whatever time-dependent flow rate is required to maintain the rockface excess pressure (excess above hydrostatic pressure) at 10 MPa (100 bars: ~1450 psi). Injection continues indefinitely thereafter, keeping the downhole injection pressure constant. For this first calculation it was assumed that the injected brine is the same as the *in-situ* reservoir fluid as regards temperature and composition. Initially, the injection rate required is about nine kilograms per second, but after about a week the flow rate has declined to 4.5 kg/s and after a month the rate is only 2.6 kg/s. Total fluid injected after one month is about ten thousand metric tons. A 200-horsepower injection pump would be more than adequate for this task. As time goes on, injected water fills the pre-existing fracture, pressurizing and inflating it and raising its transmissivity. Fluid then slowly seeps outward, perpendicular to the fracture, into the surrounding low-permeability rock matrix.

For computational purposes, the fracture itself is treated as a circular disk of infinitesimal initial aperture, 600 meters diameter (300 meters radius from the intersection with the injection well) and arbitrary spatial orientation. Initially (at zero excess pressure), the fluid transmissivity along the fracture is only 0.0005 darcy-meters (5×10^{-16} m^3), equivalent to that of a 50-meter-thick section of the unfractured matrix rock. As pressure increases at each point in the fracture, however, local fracture transmissivity increases exponentially so that once the fracture is fully inflated (excess pressure = 10 MPa) the local fracture transmissivity reaches 0.5 darcy-meters (5×10^{-13} m^3). Once the fracture is inflated, it completely dominates the fluid transmissivity of the system; 0.5 darcy-meters is equivalent to the transmissivity of a section of the unfractured matrix rock 50,000 meters thick. Inflating the fracture also causes its fluid storage capacity to increase – local fracture aperture is considered to increase linearly with local excess pressure inside the fracture, and 10 MPa of excess pressure causes an aperture increase of five millimeters. Thus, when fully inflated to 10 MPa, the fracture can store about 1200 metric tons of injected water.

These changes in underground fluid flow cause temporal evolution of the distribution of electrokinetic self-potential in the neighborhood of the fracture. Once water begins to flow in the z-direction from the fracture into the surrounding rock, a corresponding electric "drag current" appears parallel to the z-axis and directed away from the fracture surface (on both sides of the fracture). This diverging electric current creates a local electrical potential minimum at the surface of the fracture of about –3150 millivolts.

As time goes on, fluid continues to diffuse away from the fracture, the volume of rock in which "drag current" is flowing grows, and the initial potential singularity diffuses outward into the impermeable rock mass, both axially and radially. Figure 2 shows the resulting computed distribution of electrical potential around the fracture at t = 8 and 32 days. Note that the outermost contour line corresponds to 100 millivolts SP signal amplitude.

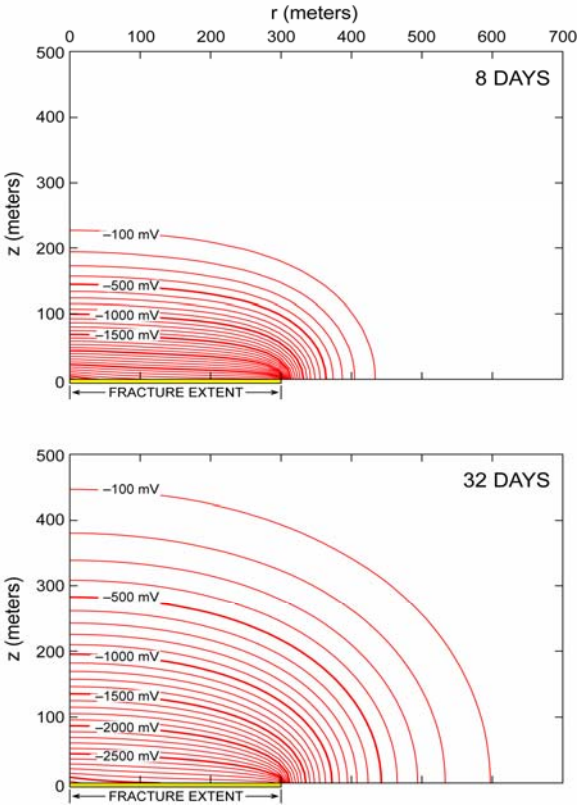


Figure 2: Computed propagation of underground SP signals caused by hydrofracturing.

It should be noted that if the "average" electrical resistivity differs from the 100 ohm-meter value assumed above, and many sites are more resistive, the amplitude of the SP signals will vary in direct proportion, so much stronger SP signals are possible. The effects of varying "average" formation permeability are twofold: *(1)* higher

permeabilities will require greater amounts of fluid injection to maintain the downhole injection pressure, and *(2)* higher permeabilities will result in more rapid diffusion of fluid mass and pressure (and "drag current") into the matrix surrounding the fracture, in effect compressing the time-scale. Lower permeabilities would have opposite effects. "Permeability" in this connection refers to both the classical intrinsic intergranular permeability of the rock as deduced from laboratory analysis of small samples and to any additional "fracture permeability" arising from the effects of relatively small randomly-distributed pre-existing fractures, if present.

The calculation suggests that downhole SP monitoring has a great deal of promise for complementing microseismic data to help characterize fracture stimulation and propagation. Conventional earth-surface SP surveys can routinely characterize temporal changes in SP as small as a few tens of millivolts. Although downhole instrumentation for SP measurements poses greater challenges than conventional earth-surface surveys, the "noise level" (caused by both cultural and meteorological phenomena) that limits surface survey precision is much less troublesome at great depths. The above calculation indicates that SP signals of hundreds of millivolts amplitude should be observable on time-scales of a few weeks or less even at considerable distances (hundreds of meters) from the fracture.

It should also be noted that, unlike the seismic technique, no SP signals occur unless the fracture is *actually pressurized*. In other words, SP responds only to *permeable* fractures. Consequently, the SP method may provide a tool for remotely discriminating among the various "fractures" and other features identified from seismic data.

5. OTHER QUESTIONS

The authors are presently engaged in further investigations (including both theoretical analyses and laboratory studies) aimed at generalizing the above results with the ultimate purpose of providing a new tool to help guide hydrofracturing operations and subsequent drilling to create efficient HDR geothermal reservoirs. The remainder of this paper (which really constitutes a progress report on this research) outlines the character of some of these ongoing activities.

5.1 Free-Field Signals

While the calculation presented above demonstrates the feasibility of the SP approach to HDR hydrofracture monitoring, it is important to recognize that it represents only a single case, with particular assumed values for the pertinent parameters likely to influence SP signals (formation electrical resistivity, formation permeability, fracture size and orientation, pressurization history, etc.). Naturally, the electrical signals that will be emitted from a particular hydrofracturing operation will depend on operational details, fracture characteristics, and the properties of the surrounding impermeable rock and of the fluid contained within its pores.

Some of these relationships are fairly clear already. For example, it is easy to show that the SP technique will *not* be effective in situations where the pores in the rock surrounding the fracture contain steam, or a mixture of steam and liquid water. There are two reasons. First, the "drag current" responsible for the changes in electrical potential is created only by liquid motion (steam flow generates no current), so if the liquid phase is absent (or sparse and immobile) no signal will be produced. Even more important, the effective fluid compressibility of a steam/water mixture exceeds that of liquid water alone by several orders of magnitude even if substantial liquid is present. As a result, fluid seepage from the fracture into surrounding rock containing a water/steam mixture will be enormously retarded compared to the all-liquid case, and so the propagation rate of any resulting SP signals (hundreds of meters in a few weeks in the preceding calculation) will be reduced so much that years of pressurization would be required to sense fractures at reasonable observation distances.

Fortunately, this situation appears to be unlikely under most conditions of practical interest. None of the international HDR project sites (Fenton Hill, Soultz, Hijiori, etc.) contain any *in-situ* steam at depth, and all of the various ongoing and proposed EGS projects in the U.S. (with the notable exception of any work contemplated at the Geysers field in California) involve liquid-phase reservoirs exclusively. HDR technology is intended to generate geothermal electricity using resources of moderate temperature at considerable depths, where *in-situ* steam is not likely to occur naturally.

We are presently repeating the above calculation many times, systematically varying key parameters from one calculation to the next to quantitatively appraise their effects on SP signal strength and propagation. These parameters include:

- fracture size, transmissivity, compressibility, and amount of pressurization,
- country rock porosity, permeability, compressibility and electrical properties, and
- temperature and composition of *in-situ* and injected fluids.

Moreover, although the original calculation assumes axisymmetric geometry (with a circular fracture in an unbounded uniform formation), fully three-dimensional versions of both the STAR reservoir simulator and the SP postprocessor are available. These will be used to go beyond the relatively simple geometry considered above, and examine various fracture shapes and non-uniform spatial distributions of key country rock properties such as permeability and electrical resistivity.

5.2 Near-Field Effects

In the immediate neighborhood of a borehole, local effects will modify the free-field electrical signals caused by hydrofracture growth. The main reason is that the presence of the well introduces local heterogeneities in electrical resistivity. These effects are of primary importance for the shut-in observation wells where SP response is to be measured. Clearly, it is absolutely essential that no metallic casings be installed in these wells at the depths at which SP signals are anticipated. Otherwise, when the free-field signal impinges upon the casing, electric currents will flow vertically and cause homogenization of the potential along the well length by short-circuiting. The presence of a metallic casing (no electrical resistance) in the observation well will have the same effect upon the electrical signal that the presence of the well itself (no hydraulic resistance) has on any incident pressure signals – namely, to diffuse the signal through the entire vertical length of the well, probably reducing the amplitude to undetectable levels and obscuring the depth of the incident free-field signal.

Even if no steel casing is present, of course, in general we expect the voltage histories measured by electrodes in a shut-in observation well to differ somewhat from the theoretical free-field signals. The effects of the presence of the well in modifying the free-field signals is being examined using the STAR SP postprocessor, employing high spatial resolution focused upon the region immediately adjacent to the well. The purpose is to provide quantitative understanding about two practical issues:

- How large must the uncased section be (in vertical extent, relative to the vertical extent of the hydrofracture-induced free-field downhole SP anomaly) to avoid "short-circuiting" and loss of signal? What "corrections" should be applied to measurements to account for this effect?
- How resistive must the fluid within the well be (relative to the electrical resistivity of the surrounding reservoir) for good results? The well resistivity can be adjusted by controlling temperature and composition of the downhole liquid column, or even packing off the test section and filling it with compressed air.

Although the local effects of vertical electric currents within the observation wells are the principal concern, we also expect that similar currents will flow in the injection well itself. These may modify the free-field signal at the observation locations to some degree. The STAR SP postprocessor will also be employed to examine this issue.

5.3 Laboratory Determinations of Formation Properties

We are presently engaged in a search for well-documented intact core samples of candidate deep rocks from HDR project sites to use in laboratory testing. The AIST laboratory facilities at the Geological Survey of Japan in Tsukuba will then be utilized for the direct determination of critical sample properties such as permeability, compressibility, zeta-potential and electrical resistivity (*Tosha et. al,* 2003). The objectives of this part of the research are both to establish a knowledge base concerning the probable ranges of these properties in typical HDR environments and to establish specific values for individual sites to facilitate practical calculations for particular fracturing operations (as contrasted to the generic calculation presented above).

5.4 Evaluation of Field Measurement Techniques

Before SP monitoring can become a useful tool for monitoring fracture creation and growth in HDR applications, practical field techniques must be established both for collecting the electrical potential measurements themselves and for estimating other critical parameter values that will be required for quantitative interpretation of the results.

For downhole measurements of self-potential in the various observation wells, two approaches are presently being considered. As discussed by *Telford et. al* (1990; see in particular Section 11.3), the usual method in oil-well logging and mineral exploration is to use a potentiometer to monitor the potential difference between a single moving downhole electrode and a fixed electrode at the surface or in the borehole near the surface. The moving electrode may then be repetitively raised and lowered in the uncased portion of the observation well to obtain the electrical potential as a function of both depth and time. An alternative approach is to install multiple fixed semi-permanent downhole electrodes at regular intervals in the uncased section and monitor potential for all of them continuously and simultaneously (relative to the shallow electrode near the surface). The advantages and disadvantages of various techniques for carrying out downhole SP monitoring will be examined further prior to making definite recommendations.

In addition to measuring SP itself, other supporting information will be needed for SP data interpretation. The most important unknowns are the permeability, compressibility and electrical resistivity of the country rock surrounding the fracture, between the injection well and the observation well(s). Although determinations of these quantities for small rock samples will presumably be available from the laboratory program, it is also important to obtain "field average" values. It is well known, for example, that the "average" permeability of real geothermal fields usually exceeds values obtained in the laboratory, owing to the presence of large-scale (relative to the size of a typical core sample) high-permeability heterogeneities in the reservoir (natural fractures). Thus, laboratory values of permeability should probably be regarded as lower bounds (and similarly laboratory resistivity values are upper bounds) on the field-wide values needed for SP data interpretation.

To obtain estimates of overall reservoir compressibility and permeability, measurements may be carried out in the injection well. Simultaneous monitoring of injection fluid flow rate into the growing fracture and the downhole pressure history at the same horizon may be used to evaluate these quantities using well-established pressure-transient analysis techniques. For electrical resistivity, conventional surface-survey results (using either Schlumberger-type DC arrays or electromagnetic methods such as MT or CSAMT) are unlikely to provide adequate spatial resolution at the depths of interest. By contrast, the electrical resistivity logs typically obtained during well drilling may be too highly resolved (and short-range) to be useful. Some kind of intermediate-scale downhole technique is preferable. If permanent fixed electrodes were installed in the observation wells (as suggested above), one possibility would be to impose a DC electric current across the uppermost and lowermost electrodes in the hole, and measure the resulting vertical distribution of voltage using the remaining electrodes. Analysis would then yield a one-dimensional vertical distribution of reservoir electrical resistivity along the well course. Downhole electromagnetic methods are also a possibility.

5.5 Joint Data Interpretation

Finally, it seems reasonably clear that the best way to establish the properties of the permeable region created by hydrofracturing an HDR reservoir is to bring multiple techniques to bear upon the problem simultaneously. Like microearthquake surveying, SP monitoring by itself is unlikely to provide sufficient uniqueness for practical design of subsurface fluid circulation networks and the optimum siting of production and injection wells. It is premature at this stage to be specific about exactly how this should be done, but we plan to examine the question of combining data sets of these types to obtain the best results.

6. CONCLUSIONS

The calculations reported herein demonstrate the feasibility of using downhole electrical monitoring techniques to characterize the permeable fractures created (or re-opened) by HDR hydraulic stimulation operations, at least under some credible circumstances. Work is underway to

generalize these results and to establish practical protocols for routinely conducting measurements of this general type during field development. We are also examining appropriate methodology for accomplishing joint inversion of these downhole electrical survey results with simultaneous microearthquake surveys and other reconnaissance techniques, to obtain optimum estimates of the properties of the synthetic geothermal reservoirs created by the stimulation operations. The long-term objective is to improve the success rate for drilling production and injection wells into HDR reservoirs and thereby to reduce project costs.

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