

Progress on the Desert Peak East EGS Project

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ABSTRACT

An industry-DOE cost-shared project is underway to evaluate the technical feasibility of developing an EGS power generation project on the eastern side of the Desert Peak geothermal field. An existing well (DP 23-1) is the focus of much of the Phase I investigation, including re-interpretation of lithology, acquisition and analysis of a wellbore imaging log, conducting and analyzing a step-rate injection test, performing a “mini-frac” to determine the magnitude of the least principal stress, and re-completing the well in preparation for hydraulic stimulation in Phase II. In addition, numerical modeling has been undertaken to estimate heat recovery and make generation forecasts for various stimulated volumes and well configurations.

The target formations for hydraulic stimulation in well DP 23-1 lie below an unstable phyllite which bottoms at about 1,740 m (5,700 feet). The formations beneath this unit include a section of Jurassic/Triassic metamorphic rocks (of which the phyllite is a part) and an underlying, younger (Cretaceous?), massive granodiorite that intrudes the older rocks above. This granodiorite unit extends from 2,140 m (7,020 feet) to TD (2,939 m or 9,641 feet) in DP 23-1 and is likely to have considerable lateral extent.

A wellbore image log obtained over a significant portion of the open hole has been analyzed in terms of the distribution and orientation of natural fractures and borehole failure phenomena (tensile fractures and breakouts). The features analyzed from the image log have been used to evaluate the orientation of the stress field and constrain the magnitudes of the principal stresses. These analyses permit an evaluation of the effects of pore pressure increase on pre-existing fractures, and, in conjunction with lithology, mineralogy, drilling rate

and geophysical log data, have been used to identify the most prospective interval for stimulation.

Work remaining to be completed in Phase I includes the “mini-frac” and re-completion of well DP 23-1 in preparation for hydraulic stimulation; this is planned for August 2005. Future plans for the project in Phase II focus on planning, conducting, monitoring and evaluating a massive hydraulic stimulation of well DP 23-1. Should the stimulation result in the creation of a large enough reservoir, a second and perhaps a third well would be drilled and stimulated, and the system would be tested for several months to determine its capacity. In Phase III, a 2-5 MW stand-alone binary power plant would be designed and constructed at Desert Peak East, and in Phase IV, the power would be either sold to a utility customer or used to supply the parasitic power needs of the existing Desert Peak hydrothermal power plant.

A recent additional focus of the project involves evaluating the feasibility of stimulating a non-commercial well drilled in the hydrothermal portion of the field (DP 27-15).

Introduction

ORMAT Nevada Inc. (ORMAT) has received funding from the US Department of Energy (DOE) on a cost-shared basis to investigate the technical and economic feasibility of creating an artificial underground heat exchanger in the eastern part of the Desert Peak geothermal field, located about 130 km (80 miles) ENE of Reno, Nevada. This project has as its ultimate goal the development of 2 - 5 MW of EGS-derived power from a stand-alone binary power plant supplied by a well doublet or triplet. Focusing initially on well DP 23-1, a hot but tight hole about 2.5 km (1.5 miles) east of the producing hydrothermal wells at Desert Peak (Figure 1), a systematic evaluation of the EGS potential of this area is nearing completion as of May 2005. This Phase I evaluation includes:

- analysis of existing geological data, including new petrologic analyses of samples from well DP 23-1 and a nearby core hole (35-13 TCH);

- review of previously collected geophysical data;
- mechanical testing of cores from 35-13 TCH (none are available from well DP 23-1);
- obtaining and evaluating a new wellbore image log in well DP 23-1 to determine stress field orientation and evaluate the intrinsic fracture population;
- conducting an injection test of well DP 23-1 to determine baseline (pre-stimulation) well and reservoir characteristics;
- developing a conceptual model of the EGS portion of the field;
- numerical modeling of heat recovery to develop generation forecasts for various well configurations over a range of stimulated volumes;
- designing and conducting a “mini-frac” in well DP 23-1 to determine the magnitude of the least principal stress;
- re-completing well DP 23-1 in preparation for hydraulic stimulation; and
- preparation of a detailed plan to guide the next activities at the field (Phase II).

Basic Data From Well DP 23-1

Well DP 23-1 was completed in May 1979 with a 13-3/8 inch production casing from the surface to 908 m (2,980 feet). Below this is a 12-1/4 inch open hole to 1,613 m (5,292 feet), an 8-1/2-inch open hole to 2,445 m (8,022 feet) and a 7-7/8 inch open hole to TD (2,931 m or 9,641 feet). Circulation losses occurred while drilling between 2,533 and 2,586 m (8,310 and 8,485 feet) and losses continued to 2,809 m (9,215 feet). Below this depth, the drilling fluid was changed from mud to aerated water, and it is not possible to discern if or where any fluid losses occurred in this lower interval.

During drilling and after completion, various attempts were made to flow test the well, sometimes with air or nitrogen assist. During testing in November 1979, the well bridged off below the 13-3/8-inch casing shoe. In December 1984, a 9-5/8-inch liner was hung and cemented from 810 to 1,309 m (2,658 to 4,293 feet) to cover the bridging zone. The depth for the bottom of this liner was chosen on the basis of temperature (the well reaches 400°F at 4,300 feet; see Figure 2). There were no returns of drilling fluids while cleaning out bridges down to 4,608 feet. After setting and cementing the 9-5/8 inch liner, the bottom of the hole was cleaned out with full returns to 2,755 m (9,040 feet), and with about 95% returns below that depth.

A step-out from the known productive area at Desert Peak, well DP 23-1 was unable to sustain flow at commercial rates and pressures. Several flow tests were made before installing the 9-5/8 inch liner; during the November 1979 test, the well flowed unassisted. After the workover was completed, a brief injection test was conducted. While injecting at approximately 250 gallons per minute (gpm), the wellhead pressure varied between 100 and 150 psig. The following day, the injection rate was increased to about 850 gpm, and the corresponding wellhead pressure increased to about 600 psig. A temperature survey was collected during the first injection period and is included in Figure 2 (“10 Dec 1984 - Injecting 250 gpm”).

Well DP 23-1 is drilled through a thick section of Tertiary sediments and volcanics to a depth of about 1,000 m (3,300 feet). As shown in Figure 2, a high, conductive temperature gradient persists throughout this section; temperature at the base of the Tertiary (the bottom of formation 3) is about 190°C (370°F). The temperature gradient decreases in the pre-Tertiary section, where a maximum temperature of 216°C (421°F) is observed at about 1,615 m (5,300 feet). A modest temperature reversal occurs below this maximum, and there is a long, nearly-isothermal section at about 207°C (405°F) extending from 2,430 to 3,130 m (7,000 to 9,000 feet), below which the temperature increases again, reaching about 211°C (412°F) at TD. A comparison of static temperature surveys from September 1979 and December 2002 (Figure 2) shows that temperatures have remained stable with time, although the 2002 survey suggests that there is a small amount of circulation around the 9-5/8 inch x 13-3/8 inch liner lap (which had not been installed when the September

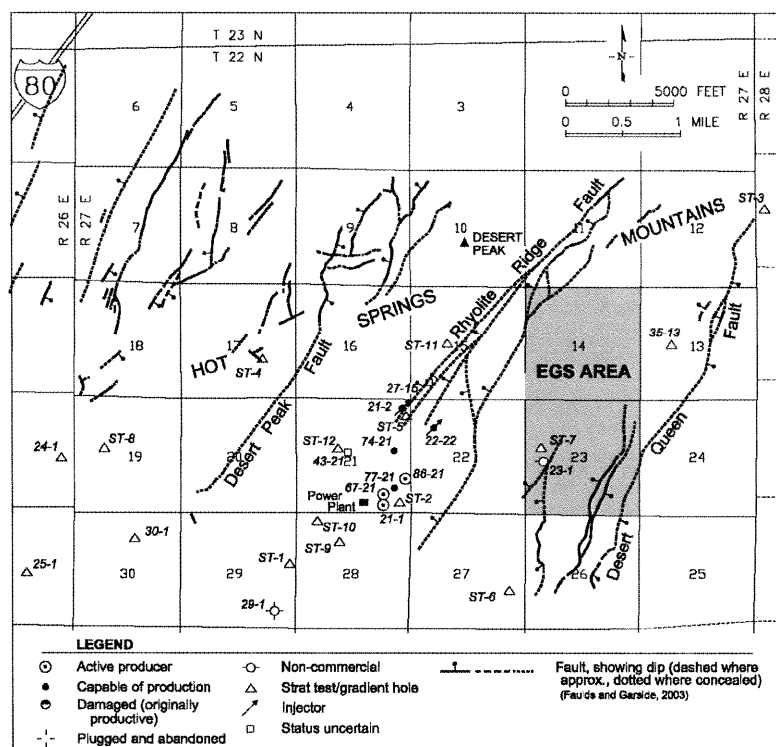


Figure 1. Desert Peak well location and fault map (faults from Faulds and Garside, 2003). The EGS area is shaded gray.

At the time of writing this paper (May 2004), most of these tasks are nearing completion. As the present focus is on the mini-frac and re-completion of well DP 23-1, we present herein: 1) the criteria used to select an interval for hydraulic stimulation; 2) the workover operations that need to be undertaken to prepare the well for stimulation; and 3) the approach we are taking to conduct a mini-frac in this well.

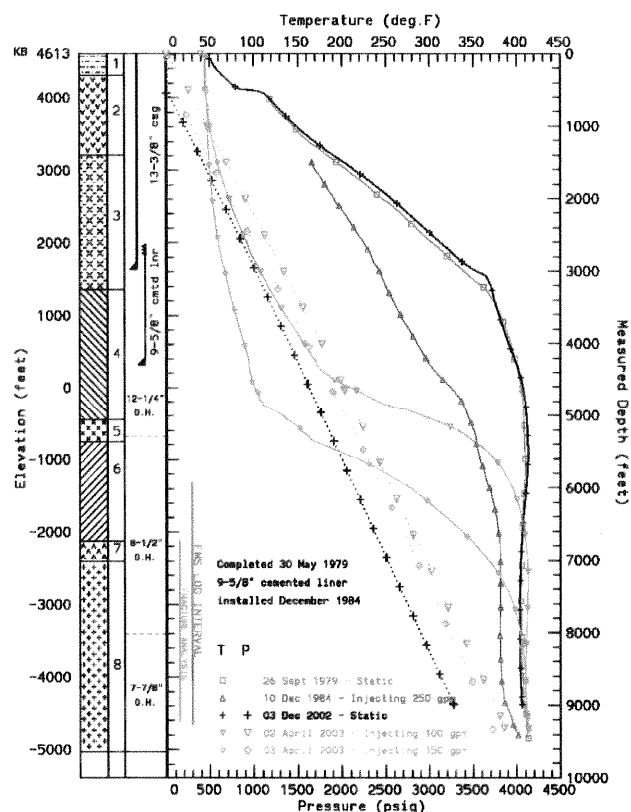


Figure 2. Lithology, completion and downhole survey data, well DP 23-1. April 2003 FMS log interval shown (lower left) by red line; data subset for fracture analysis shown by green line. Formations: 1 - Truckee+Desert Peak; 2 - Chloropagus Formation; 3 - Rhyolite Unit; 4 - pT1 Metasediments; 5 - Quartz Monzodiorite (pT2); 6 - pT2 Metasediments; 7 - Hornblende Diorite (pT2); 8 - Two-Mica Granodiorite (see Lutz *et al.*, 2003 for full descriptions of these units).

1979 survey was run). Also shown in Figure 2 are temperature surveys collected during injection in December 1984 (after installing the 9-5/8 inch liner) and in April 2003 (during the recent injection test). The static water level sits at about 180 m (600 feet).

Geological Analysis

A simplified lithologic column for DP 23-1 is included in Figure 2. Formation picks were developed based on mud log data, recent petrological analysis (summarized below), and geophysical logs collected at the time of drilling in 1979, some of which are included in Figure 3. The following summary of the pre-Tertiary section, which includes the target formations for hydraulic stimulation, is taken largely from Lutz *et al.* (2003).

The pre-Tertiary metamorphic section in DP 23-1 is formed of two distinct subgroups with a sharp contact between them. The upper subgroup (pT1), which covers a depth range of 994 to 1,542 m (3,260 to 5,060 feet), is dominated by marine metasediments that have undergone regional greenschist facies metamorphism. The lower subgroup (pT2) extends to 2,140 m (7,020 feet) and is composed of a series of Jurassic/Triassic

phyllite, schist and mafic-to-intermediate plutonic rocks, all more strongly metamorphosed than the pT1 section. This is underlain and intruded by a two-mica granodiorite that is similar to Cretaceous intrusive rocks typical of the Sierra Nevada batholith found to the west in Nevada and California.

Several formations of interest from an EGS perspective were identified in the pT2 subgroup and below. The first is a quartz monzodiorite extending from 5,060 feet to 5,380 feet in well DP 23-1 (formation 5), which was also found in 35-13 TCH from 3,123 to 3,484 feet. The second is a hornblende diorite unit extending from 6,800 feet to 7,020 feet in well DP 23-1 (formation 7); this is not observed in 35-13 TCH owing to the relatively shallow depth of the core hole. Beneath these units is a third formation of interest: the two-mica granodiorite (referred to herein simply as granodiorite), which is less altered, less veined and more massive than the two intrusive units above. Thin dikes near the bottom of 35-13 TCH imply the presence of this granodiorite beneath the bottom the core hole (Lutz *et al.*, 2003). Therefore, this unit is likely to have considerable lateral extent.

A moderate temperature (430-460°F; 220-240°C) propylitic-phyllitic alteration assemblage consisting of chlorite, pyrite, calcite, epidote and sericite is present in the granodiorite and overlying rocks in DP 23-1. The propylitic alteration appears to be younger than the magmatic-hydrothermal alteration and may represent cooling of the granodiorite after its initial emplacement. The upper 300 m (1,000 feet) of the granodiorite body is moderately sericitized. Most of the primary biotite and some of the hydrothermal biotite has undergone retrograde alteration to chlorite and calcite. There is a general decrease in chlorite with depth in the granodiorite and also a slight increase in epidote below about 2,740 m (9,000 feet). The granodiorite is microbrecciated in sheared or fractured zones at 2,207 m (7,240 feet) and 2,332 m (7,650 feet), and the comminuted rock is cemented with chloritic gouge. The youngest veins in the granodiorite are rare calcite, calcite-hematite and calcite-quartz veins that cut across fractures containing higher-temperature minerals such as biotite and epidote. These carbonate veins may represent alteration related to the current geothermal system.

The resistivity, gamma ray and density logs collected at the time of original drilling were used in combination with the petrographic analysis of Lutz *et al.* (2003) to refine the formation picks in the deeper part of the well. Figure 3 shows these data below 1,525 m (5,000 feet), and subdivides formation 6 into two parts: a section of black phyllite and schist (formation 6A) and a section of metamorphosed intrusive units (formation 6B). Also shown in this figure are the drilling penetration rate (in feet/hour) and the caliper data collected using the arms of the wellbore imaging tool (see below).

Wellbore Image Log Analysis

Schlumberger's "hot hole" Formation Microscanner (FMS) tool was run in well DP 23-1 in April 2003 after injecting for ~2.5 days to determine well and reservoir hydraulic parameters (see Sanyal *et al.*, 2003) and to cool the well to ensure image quality. While running a TPS survey during the injection

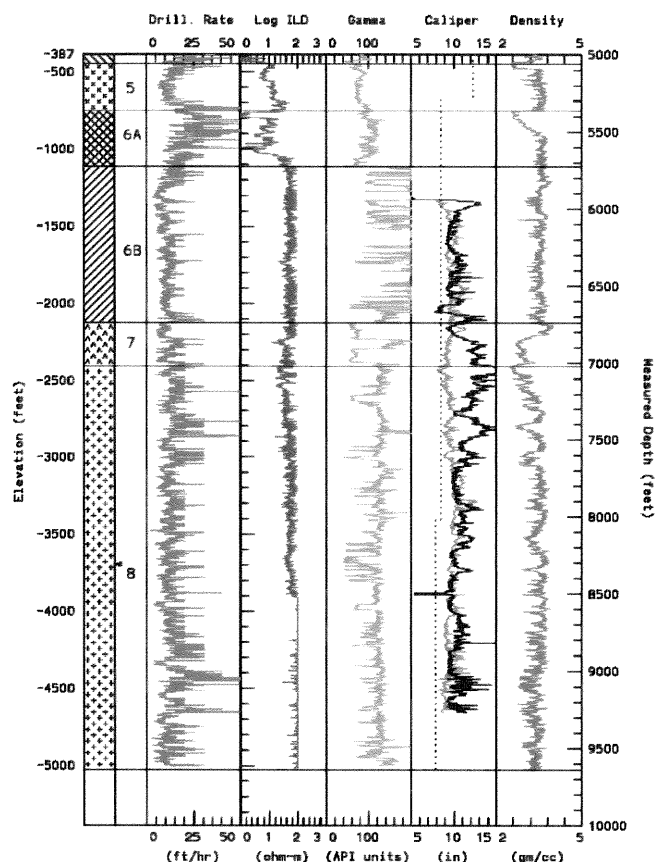


Figure 3. Lithology, penetration rate, geophysical logs and caliper data below 5,000 feet, well DP 23-1.

period, an obstruction was encountered at 1,783 m (5,850 feet) in formation 6A. This zone was sloughing into the hole during injection, and an increasing amount of fill was noted at bottomhole on subsequent tool runs. The FMS tool was run into the hole and began logging up from 2,824 m (9,265 feet); logging stopped at 1,806 m (5,924 feet) to avoid encountering the obstruction with the tool arms open. Therefore, the upper quartz monzodiorite unit (formation 5) was not logged. However, wellbore images were obtained through most of the granodiorite and a portion of the overlying pT2 units. The logged interval corresponds to the interval for which caliper data are shown in Figure 3, and is also shown by the red line in Figure 2.

The digital data for the FMS log were obtained from Schlumberger and provided to GeoMechanics International (GMI) for analysis, along with supporting data from the well, including previously collected geophysical logs, temperature logs, drilling data and well test data. Wellbore failure features were identified and analyzed to determine the stress field orientation and (in conjunction with other data) to constrain the local stress tensor, and the fracture population was analyzed in a portion of the logged interval (2,051 to 2,812 m or 6,730 to 9,228 feet).

Figure 4 presents a summary of the observed wellbore failure data. Borehole breakouts were determined from both image data and caliper data (using the FMS tool arms); ten-

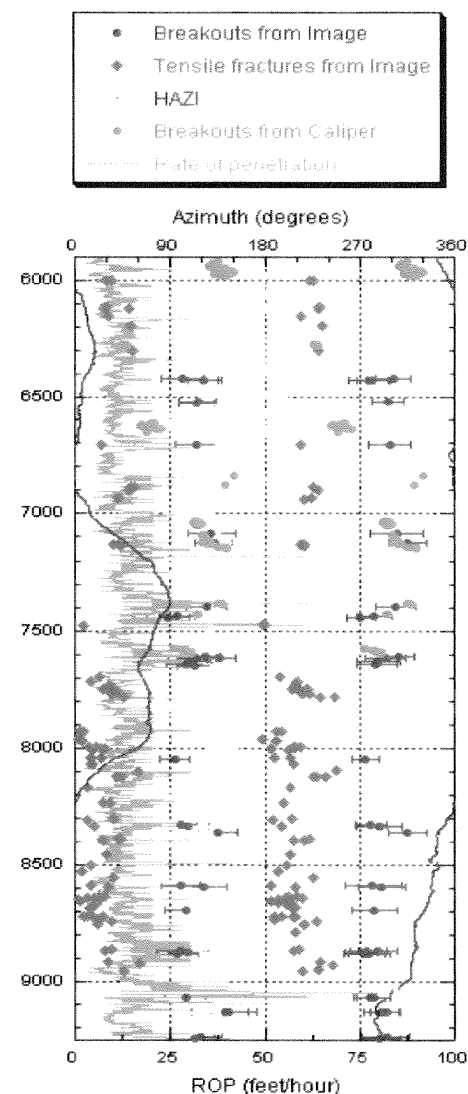


Figure 4. Observed wellbore failure features and drilling penetration rate (ROP), well DP 23-1.

sile cracks were identified from image data. Using the caliper data, a total of 52 breakouts were identified between 1,805 and 2,315 m (5,922 and 7,594 feet), and show a dominant direction of N128°E (39 breakouts) and a subordinate direction of N68°E (13 breakouts). As breakouts form at right angles to the direction of the maximum horizontal stress (SHmax), the dominant trend suggests an SHmax direction of N38°E. Using the image data, a total of 65 breakouts were identified between 1,956 and 2,817 m (6,418 and 9,241 feet); these suggest an SHmax direction of N27°E. A total of 170 tensile cracks were identified between 1,829 and 2,728 m (6,000 and 8,949 feet); these also suggest an SHmax direction of N27°E.

Owing to budget considerations, the fracture analysis used only a portion of the logged interval; as shown in Figure 2, this covered most of the granodiorite and extended about half way through the pT2 hornblende diorite unit above it. GMI identified nearly 11,000 fractures in this interval; Figure 5 shows their orientation. The dominant fracture direction is

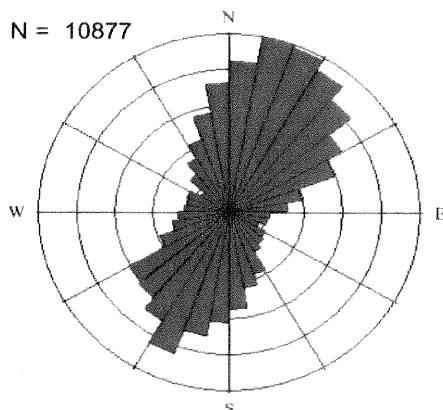


Figure 5. Orientation of natural fractures between 6,730 and 9,230 feet, well DP 23-1.

NNE, dips range from 30 – 75°, and the dominant dip directions are NW and SE.

The analysis of the FMS log data leads to several observations:

- The wellbore failure data and the dominant strike of natural fractures show a stress field orientation that is not only consistent between data sets but also reflects the current stress field as indicated by both regional and local geologic data (Faulds et al., 2003).
- Breakouts tend to occur where the drilling penetration rate is high (i.e., in zones of weaker rock), while tensile cracks tend to occur where the drilling penetration rate is low (i.e., in stronger rock).
- Significantly more tensile cracks are observed below 2,310 m (7,600 feet) than above it. Possible reasons for this include a greater amount of cooling in the portion of the well during drilling and injection, more quartz in the reservoir rock, and/or stronger rock overall below 2,310 m (7,600 feet).

Hydraulic Stimulation Target Zone

As described in Robertson-Tait *et al.* (2004), the various data sets were compared to evaluate the possibility that changes in primary lithology and/or secondary mineralization may correlate with some or all of the observations made from the analysis of the image log. There is an overall decrease in secondary mineralization passing from the pT2 units into the granodiorite. XRD analyses show that the granodiorite has a relatively consistent overall composition with depth, including quartz content. Illite is minor but constant through both the hornfelsic pT2 units and the upper part of the granodiorite. Within the granodiorite, there is a consistent decrease in chlorite and illite with depth and an overall decrease in alteration and fracturing below the lower shear zone at 2,332 m (7,650 feet). Caliper data show the hole to be “out of gauge” to a greater degree, and to have a greater variation in hole diameter on the two tool arms above this shear zone, while below it, the caliper data show a more regular borehole (Figure 3). In addition, the

upper, more sericitized granodiorite drills somewhat faster than the lower granodiorite. Taken together, the competence of the rock appears to be greater below the shear zone than above it.

The temperature survey conducted during injection after re-completing the well in 1984 (the blue survey in Figure 2) shows a permeable interval at approximately 2,740 m (9,000 feet), with an isothermal interval above it to a depth of 2,057 m (6,750 feet), which is near the top of the hornblende diorite. This survey was run after cleaning and circulating the hole, running and cementing the 9-5/8 inch liner, cleaning and circulating again (about 2 weeks were spent with the rig on the hole altogether), and injecting at about 5 bpm for several hours. The presence of a permeable zone at this depth is also suggested by the fluid losses noted while cleaning the hole after setting and cementing the liner (see above).

Owing to the relatively low injection rate and short duration, the permeable zone at 2,740 m (9,000 feet) cannot be identified in the two injecting temperature surveys from the pre-logging cooling period in April 2003 (Figure 2). However, the well went on vacuum after a day of injection, and was progressively cooling deeper and deeper. Spinner surveys run concurrently with the two injecting temperature surveys show different results: the later survey appears to indicate a fluid loss zone at or below 2,740 m (9,000 feet) while the earlier does not. The reduction in spinner rate on the later survey occurs within about 100 m of the recently filled bottom of the well, leaving some ambiguity regarding its significance. Nevertheless, we believe this permeable zone exists, and that fluids will exit the well at deep levels during stimulation. There is no sign that any preferential cooling took place around the shear zone at ~2,332 m (7,650 feet) on any survey.

Intrusive units are of primary interest from a hydraulic stimulation perspective. Although the upper quartz monzodiorite (formation 5) is laterally extensive and coincides with the temperature maximum in the well, it is relatively thin and is underlain by a formation that becomes unstable during injection. The lowermost pT2 (a hornblende diorite, formation 7) and the deeper, younger granodiorite (formation 8) are more massive and look mechanically attractive. The granodiorite is less altered, particularly below a shear zone at 2,332 m (7,650 feet), where a significant increase in the number of tensile cracks is observed from the image log. The rate of penetration is slightly greater and the hole is more irregular above the shear zone than below. Taken together, this information suggests that the competence of the rock below the shear zone is greater than that above it. For massive hydraulic stimulation, the lower portion of the granodiorite will be targeted. The presence of a zone of deep permeability at about 2,740 m (9,000 feet) should facilitate the stimulation of a long interval.

Mini-Frac and Re-Completion of DP 23-1

Having selected the lower granodiorite as the target zone for hydraulic stimulation, the next step before designing the stimulation program itself is to better constrain the stress tensor and mechanically prepare the well for stimulation. Constraining the stress tensor can be achieved through the determination of: 1) the compressive strength of cores taken

from the target formation; and 2) the magnitude of the least principal stress within or near the interval of interest. Mechanical well preparation will be achieved by casing off the unstable phyllite and other intervals of the well. This work is planned for August 2005.

A mini-frac is a series of small volume, high pressure injection tests that are undertaken while measuring downhole pressure. The parameters of interest from the mini-frac are the formation breakdown pressure and the instantaneous shut-in pressure (for details, see Hickman *et al.*, 1988). These parameters are identified by analyzing pressure versus time data collected throughout the series of injection and shut-in periods. Ideally, a mini-frac is undertaken in a relatively short, un-fractured, low-permeability interval of the well. Because of temperature effects, inflatable straddle packers (typically used to isolate the interval of interest in a mini-frac) are unlikely to seal effectively against the walls of the existing open hole in DP 23-1. Therefore, we have developed an alternative method that involves:

- acquiring core from TD for mechanical and sonic velocity testing;
- running a sonic velocity log through the interval to be stimulated later (from 2,350 m [7,700 feet] to TD);
- preparing for re-completion by setting a retrievable bridge plug near the top of the interval to be stimulated, topping it with two alternating layers of sand and cement;
- re-completing the well by running and cementing a 7-5/8 inch casing from 670 m (2,200 feet) to the top of the cement plug at ~2,350 m (~7,700 feet), covering the old 13-3/8 x 9-5/8 liner lap, the unstable phyllite and other formations down to the top of the target zone in the granodiorite;
- drilling out the upper cement plug at the 7-5/8 inch casing shoe and reversing out the sand, leaving a short open interval for the mini-frac;
- performing the mini-frac test with downhole pressure monitoring inside the new 7-5/8-inch casing; and
- drilling out the lower cement plug, washing out the sand, retrieving the bridge plug and cleaning out the hole to TD for later stimulation.

This approach is essentially the same as that developed for conducting mini-frac stress tests at Dixie Valley (Hickman *et al.*, 1998). This technique was subsequently used for the Coso EGS project in well 38C-9, after setting and cementing the 13-3/8-inch production casing and drilling a short pilot hole out the bottom of this casing (Sheridan and Hickman, 2004). At Coso, the mini-frac testing was conducted at the top of the interval of interest before drilling ahead. However, since DP 23-1 is an existing well, an alternative approach is required. The method we have developed will not only constrain the stress field, but also will allow the extrapolation of stress data through the interval of interest.

Future Work

The Phase I feasibility study is nearing completion, and planning is underway for the next phase of development of the

field. The first major element will be conducting, monitoring and analyzing data from a massive hydraulic stimulation. This would be followed by the drilling of a second and perhaps a third well to complete an EGS doublet or triplet, and one or more periods of circulation testing. If the characteristics of underground heat exchanger are favorable, a small (2-5 MW), stand-alone binary power plant would be constructed in the third phase of the project. Power from the facility would be used either to supply the parasitic load of the power plant(s) in the hydrothermal portion of the field, or would be sold to the local utility.

While the focus to date has been on the eastern side of the field, a recently drilled well (DP 27-15; see Figure 1) presents an additional opportunity for the implementation of EGS concepts at Desert Peak. Although this well intercepts the same formations and the same fault zone that is the locus of permeability in the hydrothermal portion of the field, it is not a commercial producer. Preliminary evaluation of the feasibility of using hydraulic stimulation to enhance its permeability is just getting underway.

Conclusions

In this cost-shared feasibility study for EGS development at Desert Peak, we have focused on an existing hot, non-commercial dry well. Geological analysis has yielded an improved understanding of the regional and local geology, particularly the pre-Tertiary units encountered at depth in well DP 23-1. Analysis of a wellbore image log has allowed the orientation of the stress field to be determined, and together with geologic and hydraulic data, has led to the identification of a target interval for hydraulic stimulation. Plans have been formulated to obtain essential stress-related data and re-complete well DP 23-1 in preparation for massive hydraulic stimulation in Phase II of the project. Additional evaluations focus on enhancing the permeability of a non-productive well in the hydrothermal portion of the field.

For the Desert Peak EGS project, we have leveraged to the fullest extent possible the previous and ongoing work of individuals and groups already working in this field in an attempt to adapt them for commercial EGS implementation. We view this commercial perspective as one of the most important contributions we can make to wide-scale EGS development, which can provide a significant amount of renewable power in many countries. Collaboration with specialists at the University of Nevada (Reno) and the University of Utah, and technical contact with other EGS and HDR project teams around the world, have contributed significantly to the progress made at Desert Peak. This cooperation will expand as the project enters its second phase, during which the underground heat exchanger will be developed, analyzed and tested.

Field demonstrations such as those underway at Desert Peak and elsewhere in the world are essential steps toward EGS commercialization. The heat reserves in the United States are significant, particularly in the Basin and Range, where the Desert Peak project may well serve as a blueprint for other EGS projects.

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