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Feasibility Evaluation of an "In-Field" EGS Project at Desert Peak, Nevada, USA

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ABSTRACT

Desert Peak well 27-15 was selected to evaluate the feasibility of EGS development in the Basin and Range geologic province. The 27-15 well is located immediately north of the operating conventional geothermal reservoir at Desert Peak and has favorable temperatures and rock units that are amenable to hydraulic stimulation, providing an excellent opportunity to enhance permeability and directly observe the results. During the second half of 2008 and first month of 2009, a series of technical analyses were undertaken to confirm the viability of well 27-15 for EGS stimulation. These analyses include analyzing cuttings from other wells in the field to better understand stratigraphic relationships, evaluating data from a wellbore image log and other logs, pressure transient testing, tracer testing, completing a reflection seismic survey, and developing a conceptual model of the geologic structure that is consistent with the results of the above and with surface mapping and subsurface geology determined from the existing wells drilled in the field. The results of these analyses have improved the understanding of the geologic and hydraulic relationships between well 27-15 and the productive area of the field to the south.

Three possible stimulation intervals have been considered: 1) between 3,000 and 3,300 feet (stimulating a silicified zone at the base of the Tertiary Rhyolite Unit); 2) between 4,500 and 5,300 feet (exploiting a zone of natural but limited permeability near the boundary between the upper and lower pre-Tertiary rock units); and 3) stimulating the deeper intrusive units within the lower pre-Tertiary unit near the bottom of the well. The results of the analyses described above indicate that while there are permeable fractures that are optimally oriented for shear with increased pore pressure in all intervals considered, connecting well 27-15 to the hydrothermal portion of the reservoir can probably be achieved most reliably by stimulating the base of the Rhyolite Unit. This will be attempted later in 2009, following a re-completion of the well and a "mini-frac" to enable the magnitude of the minimum horizontal stress to be estimated.

1. INTRODUCTION

The Desert Peak geothermal system is located within the Hot Springs Mountains, approximately 50 miles northeast of Reno, Nevada, in northwestern Churchill County. Lying at an elevation of about 4,000 feet (1,250 m) above mean sea level (msl) along the western boundary of a very large intermontane basin known as the Carson Sink, Desert Peak is one of several geothermal areas in the region.

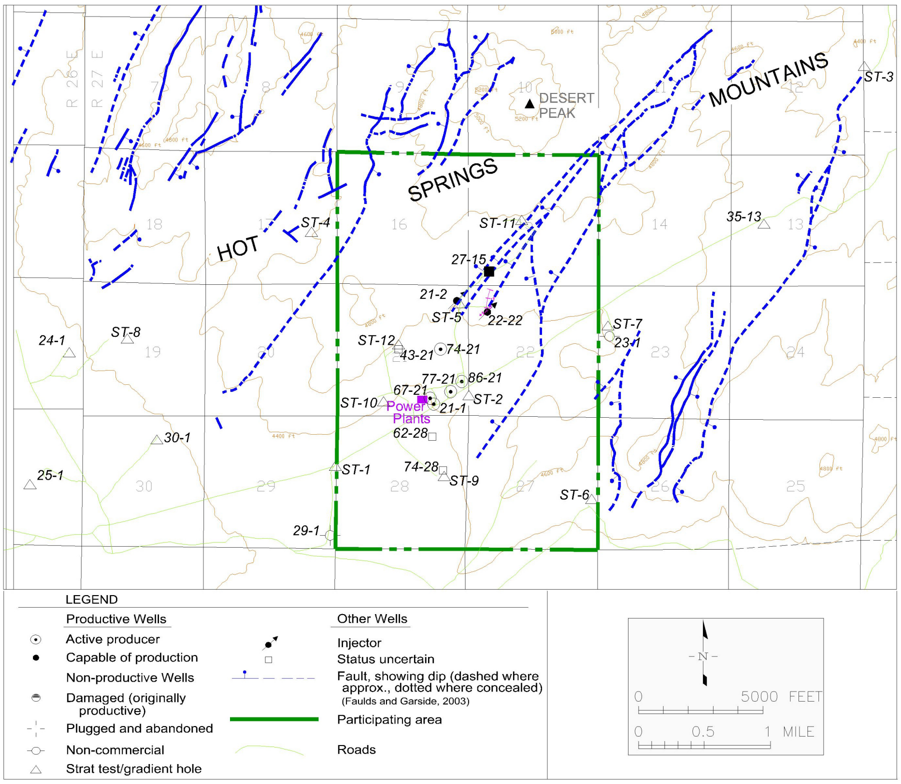

Figure 1: Location of wells, faults and the power plant at Desert Peak, Nevada

Nearby geothermal power plants are operating at Bradys Hot Springs, Stillwater, Soda Lake, and Dixie Valley. These fields lie within the Humboldt structural zone, a region of high heat flow characterized by ENE- to NNE-striking fault zones. The active and most successful wells at Desert Peak are associated with the NNE-trending Rhyolite Ridge Fault Zone.

Initial EGS field activities within the Desert Peak area focused on well 23-1 and developing an area of low permeability around it. Well 23-1 is located within the Desert Peak thermal anomaly, about 1.5 miles east of the producing field (Figure 1). A significant amount of work characterizing the structural setting and the subsurface formations within the Desert Peak field was undertaken (see, for example, Robertson-Tait *et al.*, 2004; and Robertson-Tait and Johnson, 2005). However, mechanical problems with well 23-1 precluded an EGS stimulation. Well 27-15, the focus of the current work, is located immediately adjacent to the producing field on the north side (Figure 1), and presents an attractive "in-field" target for applying EGS technology. An initial re-examination of geologic data revealed that 27-15 intercepts lithologies favorable for hydraulic stimulation, and core samples for most of these are available from well 35-13, a slim hole located in the northeastern part of the field (Figure 1).

2. CONSIDERATION OF WELL 27-15 FOR EGS STIMULATION

Stimulating 27-15 focuses on solving a common problem in the development of geothermal projects: improving the productivity or injectivity of wells that encounter sub-commercial permeability but have been successfully completed in lithologies and stress settings known to be favorable for the natural development of hydrothermal circulation systems. These wells are attractive for financial reasons and for providing a test setting for developing and/or enhancing hydraulic connections into and within existing hydrothermal systems. Located in or near developed geothermal fields, successfully stimulated EGS wells can mine additional heat and enable more generation from an existing power plant.

The selection of well 27-15 was based on favorable temperatures, the presence of rock formations amenable to hydraulic stimulation, and the well's location immediately adjacent to the operating area of the Desert Peak field. Basic downhole data for this well are presented in Figure 2. Despite its close proximity to active production and injection wells, well 27-15 would not flow on its own, and has limited injectivity.

The initial plan for this well was based on stimulating attractive lithologies (mechanically competent rock units) in the lower pre-Tertiary ("pT2;" see Lutz *et al*., 2003) unit near the bottom of the well. These are shown by the blue X and Δ patterns in the lithology column of Figure 2. However, logging during early 2008 firmly established that there is an obstruction ("fish") in the hole at a depth of about 5,630 feet. Considering that the total depth of the well is about 5,800 feet, and that the top of the most attractive units lie below an unstable phyllite unit (red diagonal stripe pattern in Figure 2) that extends to about 5,300 feet, the fish blocks off a significant portion of the zone initially considered for stimulation. The fish also reduces the ability to carry out critical elements of the evaluation and development program without significant re-drilling and/or workover operations to permit full access to these formations (e.g., for coring out of the bottom of the well and fully evaluating the section with well logs before and after stimulation).

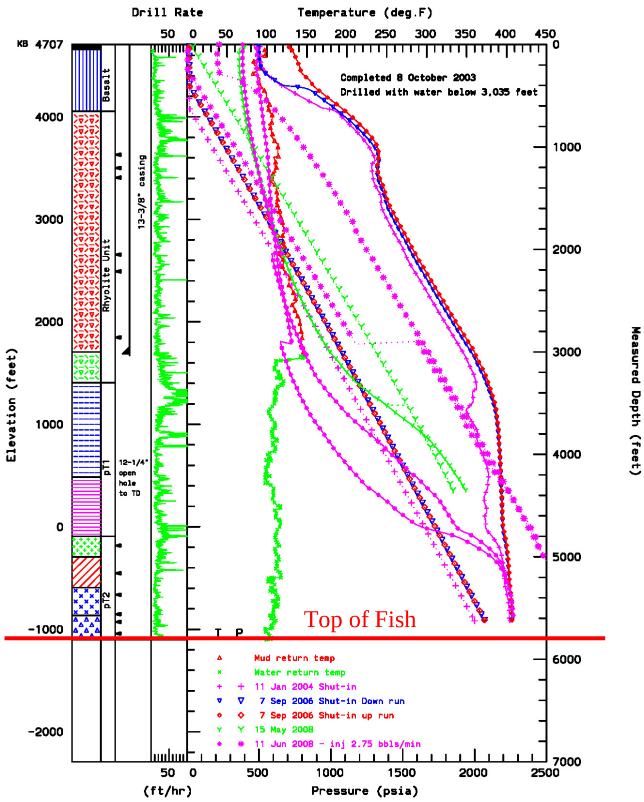

Figure 2: Basic downhole data from well 27-15

As can be seen in Figure 2, temperature data collected during an injection test in June 2008 show that the main zone of permeability in well 27-15 lies at a depth of about 4,700 feet, near the contact between the upper and lower pre-Tertiary units (pT1 and pT2; see Lutz *et al.*, 2003). The lithology within this permeable interval is dominantly shale, which has lower mechanical strength than other units in the well, as evidenced by significant "wash-outs" and hole enlargement, and therefore may not be particularly favorable for effective hydraulic stimulation. Further, as discussed below, the presence of the pT1 unit in 27-15 (which is not found in other wells within the producing area of the field south) indicates that 27-15 is located in a separate structural block from the producing field, suggesting the presence of a buried fault between the two areas (Lutz *et al.*, 2009). Such a fault might hinder the development of a hydraulic connection between the two blocks via EGS stimulation.

3. SUMMARY OF ANALYSES UNDERTAKEN TO CONFIRM 27-15 AS AN EGS STIMULATION CANDIDATE

As noted above, several avenues were investigated to better understand the relationship between 27-15 and the producing area of the field to the south, providing a means of critically evaluating this well as a stimulation candidate. The results of the most important of these analyses are summarized below.

3.1 Geological Analyses of Other Wells in the Field

The information in this section is discussed more extensively in Lutz *et al*. (2009), from which the following is summarized.

The analysis of drill cuttings from the Desert Peak wells show that the pre-Tertiary rocks in the Mesozoic basement at Desert Peak are composed of three major rock packages:

- an upper unit composed of weakly metamorphosed, fine-grained dolomudstones and metasedimentary rocks of probable Jurassic age (the Pre-Tertiary 1or “pT1” unit);
- a combination of complexly interstratified and faulted metamorphic rocks of Triassic to Jurassic age (the Pre-Tertiary 2 or ‘pT2” unit); and
- an extensive granitic intrusive that underlies the metamorphic rocks north and east of the geothermal field (penetrated by well 23-1 at a depth of about 7000 feet).

Cuttings from several additional wells drilled by Ormat in the 2002-2003 period (43-21, 74-21 and 77-21) were recently evaluated as part of this project to better understand stratigraphic and structural relationships in and around the field, with particular consideration to the similarities or differences between productive wells and the EGS target well 27-15. The most important difference is the presence of pT1 in 27-15, and the absence of the same unit in the three wells evaluated. The geologic sequence encountered by 27-15 shows similarities with that in well 23-1, the non-commercial well that was the focus of previous EGS characterization studies at Desert Peak (see, for example, Robertson-Tait *et al.*, 2004). The active wells in Section 21 from the producing part of the field do not encounter the pT1 unit, but instead pass directly from the Tertiary Rhyolite Unit into the pT2 section. In contrast, the unproductive 27-15 and 23-1 wells lie in a structurally deeper fault block, where potential reservoir rocks of the pT2 unit are overlain by the pT1 rocks.

3.2 Evaluation of Wellbore Image Log and Other Borehole Logging Data

The information presented in this section is discussed more extensively in Davatzes and Hickman (2009), from which the following is summarized.

Preparing for stimulation and development of 27-15 requires a complete characterization of borehole geology, hydrology, and stress state. Elements of this evaluation include analysis of stress orientation and magnitude and the natural geologic characteristics including fractures/faults, primary structure including bedding and formation contacts, and rock properties in and around the wellbore. These data are used to determine formation characteristics (including permeability, lithologic variations and physical rock properties) and to characterize the existing natural fracture population, design the optimal stimulation strategy, and determine the necessary stimulation pressures. Thus, this element of the study is critical to both stimulation planning and evaluation so that we can maximize the transfer value of lessons learned at Desert Peak to other EGS projects.

All of the existing logs have been acquired and interpreted; including image logs to characterize natural fractures and stress-induced borehole failure (tensile fractures and breakouts), density and velocity logs to constrain rock strength and the vertical stress, and temperature/pressure/spinner (TPS) logs to reveal fluid entry/exit points. Advanced Logic Technology ABI85 Borehole Televiewer logs and Schlumberger Formation MicroScanner (FMS) image logs revealed tensile fractures which were used to determine the azimuths of the horizontal principal stresses. Further analysis in conjunction with a mini-hydraulic fracturing experiment will be used to determine the magnitudes of both horizontal principal stresses before the well stimulation.

3.2.1 Stress Analysis

The minimum horizontal stress (S_{Hmin}) in the vicinity of well 27-15 is oriented 114±17°, as inferred from extensive borehole wall tensile fractures. Previous work in well 23-1 to the east has shown that S_{Hmin} from drilling induced tensile fractures and breakouts is approximately 119±15°, with a subset oriented 128±13° (Robertson-Tait *et al.*, 2004). Pending the results of the mini-frac, a normal faulting stress regime is tentatively assumed in the vicinity of these two wells based on the similarity between mapped normal faults at the surface (Faulds and Garside, 2003) and the S_{Hmin} azimuth. However, this *a priori* assumption cannot be verified without measurement of horizontal stress magnitudes; thus the potential role of strike-slip faulting during fracture stimulation cannot yet be assessed. Although the horizontal stress azimuth is fairly uniform, several minor rotations of the horizontal stresses are noted in the wellbore image log analysis that might reflect recent fault slip.

As shown by the caliper data plotted in Figure 3, the 27-15 wellbore is enlarged over much of the existing open-hole section, particularly (but not exclusively) within the pT1 unit. This is likely due in part to borehole breakouts. Although there are possible indications of breakouts in the image logs, the enlargement of the borehole from 12.25 inches to more than 20 inches has degraded image quality and limited our ability to identify breakouts with confidence and to use their width to constrain S_{Hmax} magnitudes. Given the identification of breakouts in well 23-1 from analysis by Geomechanics International (Robertson-Tait *et al.*, 2004) and the current washed-out state of 27-15, it is highly likely that breakouts will occur and could be imaged if a sidetrack is drilled and then logged with the ABI85 televiewer at a later date.

3.2.2 Fractures

The stress orientations noted above are consistent with normal slip on a set of ESE- and WNW-dipping, NNE-striking normal faults. Most of the formations imaged in well 27-15 include sub-populations of fractures sharing the orientation of modern normal faults mapped at the surface (compare Figures 1 and 3). Consequently, like the mapped and inferred normal faults, many of these fractures have orientations consistent with normal slip based on the orientation of S_{Hmin}. Note also that fracture density is strongly related to lithology and varies significantly across formation boundaries. The approach to identifying fractures in this analysis emphasizes the quality of the fracture picks and in general, results in a relatively conservative minimum fracture density.

3.2.3 Fluid Flow

Static and injecting (3 barrels/minute) TPS logs (Figures 2 and 3) reveal minor pre-stimulation fluid exit points within an extensive near-isothermal zone from approximately 3,000 feet measured depth below ground level (MD) to total depth (top of fish) at 5,627 feet MD. Anomalies are identified from local perturbations in temperature gradient or temperature, as shown in by the red and yellow diamonds near the left side of Figure 3.

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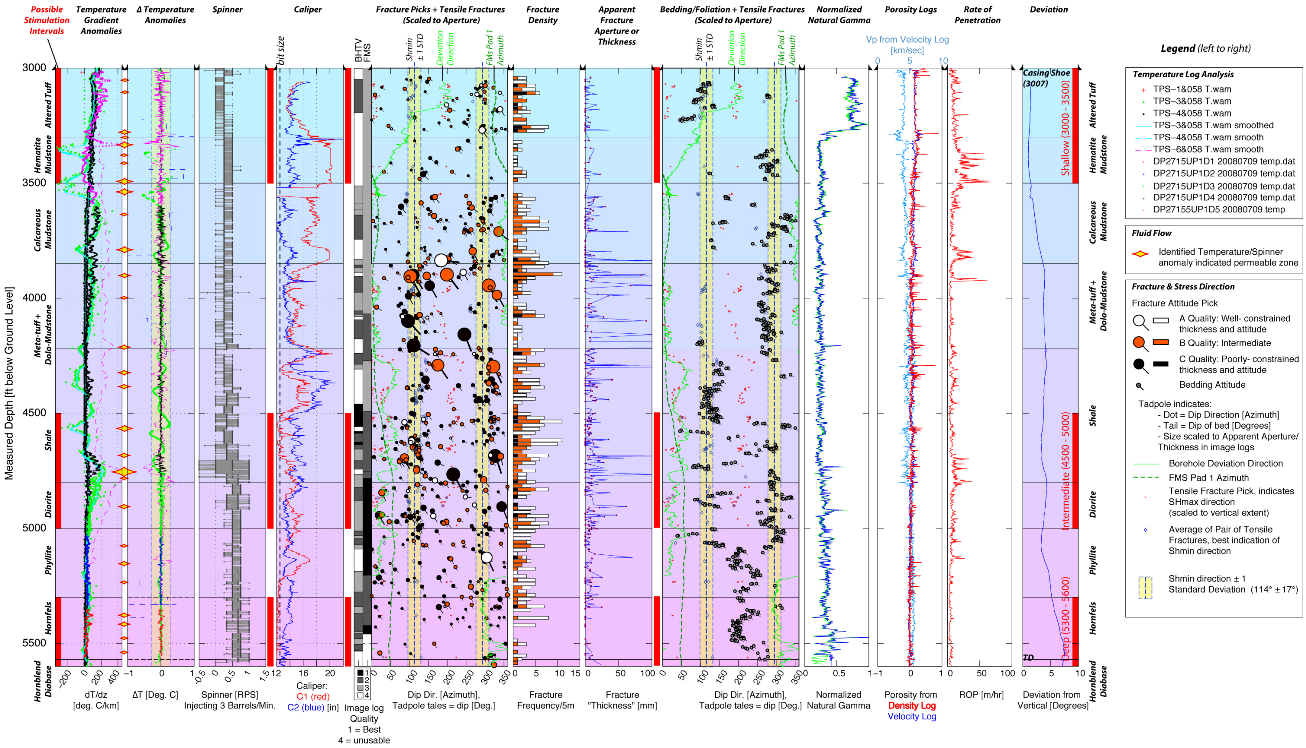

Figure 3: Geophysical log summary plot, Desert Peak well 27-15 (from Davatzes and Hickman, 2009)

Comparison of static equilibrated and non-equilibrium temperature logs help distinguish flow zones connected to the large-scale, persistent natural permeable network. A temperature anomaly associated with injection (non-equilibrium) and not with equilibrated temperature logs indicate fractures of significant permeability that may be isolated from the larger hydrothermal system. Analysis of these temperature logs is more sensitive than spinner logs and tends to identify a greater number of slightly permeable zones.

A step in the spinner log reveals a significant fluid exit point at 4,837 feet MD. This was revealed during injection at 3 barrels/minute at less than 100 psi wellhead pressure (Figure 3, third column). This zone is also associated with a persistent temperature gradient and ΔT anomaly in equilibrated temperature logs that occurs at a major lithologic change from shale to diorite (pT1 to pT2), and is also associated with strong illite-chlorite and quartz alteration at approximately 4,837 feet MD. Several additional permeable zones are evident in older static temperature logs. Some of the more significant short wavelength anomalies in the open-hole interval occur at: 3,054 feet; 3,360 feet; 3,497 feet; 3,535 feet; 3,777 feet; 4,225 feet; 4,394 feet; 4,580 feet; 4,737 feet; and 5,142 feet MD. Several of these locations (in particular 4,225 feet and 4,580 feet MD, and a minor anomaly at ~4,000 feet MD) appear to be associated with rotations of the horizontal principal stress that might indicate recent slip on nearby fractures.

3.2.4 Stimulation Intervals

All potential stimulation intervals include fractures that appear to be well-oriented for slip based on the orientation of S_{Hmin} alone. They also include temperature anomalies indicative of permeable zones, as indicated by:

- static equilibrium temperature logs indicating naturally flowing fractures;
- non-equilibrium (static or injecting) temperature logs indicating all permeable zones accessed by the well; and
- spinner logs showing the largest, most significant flow zones.

The detailed evaluation of all three candidate stimulation intervals (from Davatzes and Hickman, 2009) is described below.

Shallow Interval: 3,000 to 3,500 feet MD

This interval hosts two or three large temperature anomalies indicating permeable zones that are not expressed or are only slightly expressed in the spinner response. The borehole is somewhat enlarged and variable in this interval, particularly at the base of the Rhyolite Unit at about 3,300 feet MD and especially in the pT1 mudstone below. The fracture system is most poorly characterized in the deeper section due to the poor image log quality resulting from borehole enlargement. Nevertheless, there are a significant number of fractures in this interval that appear well oriented for normal faulting in the present stress field.

Intermediate Interval: 4,500 to 5,000 feet MD

This interval hosts the highest permeability zone encountered by the borehole (at 4,837 feet MD) and several additional permeable zones. The zone is characterized by high fracture density and fractures with significant apparent aperture that appear well-oriented for normal slip. This permeable zone also coincides with a major lithologic transition, which is associated with a change in rate of penetration (ROP), natural gamma logs, the density and velocity logs, and the dip of primary anisotropy due to bedding or foliation. This permeable zone might also be associated with a stress rotation of nearly 50°, but data are limited over this interval.

Deep Interval: 5,300 to 5,600 feet MD

This interval hosts several minor permeable zones and overall lower fracture density. The interval is characterized by relatively uniform drilling ROP, sonic velocity, and density porosity that together indicate good formation integrity. The presence of a change in dip direction at 5,290 feet MD might indicate either an erosional angular unconformity or a fault juxtaposing units of distinct dip. This location is associated with a minor temperature anomaly in some temperature logs. There are some fractures in this interval that are well-oriented for normal faulting in the present stress field, although not as many as seen in the shallower two intervals.

3.3 Pressure Transient Test of Well 27-15

In April 2009, a pressure transient test was conducted to evaluate the nature of any existing hydraulic connection between well 27-15 and the other wells in the field to the south. The test was designed and implemented under the following considerations: 1) Previous pressure monitoring in well 27-15, along with the previous injection test, indicates that the well does have some degree of connectivity to the Desert Peak reservoir; 2) Desert Peak is an operating geothermal field and any alterations in production rate would compromise the generation of electricity; and 3) well 27-15 is located immediately adjacent to the two active injection wells in the field (wells 21-2 and 22-22; see Figure 1). Therefore the basic premise of the test was to alter the relative rates of injection into the two injection wells while observing the downhole pressure response in well 27-15.

3.3.1 Evaluation of Pre-Test Pressure Monitoring Data

Prior to performing the pressure transient test, downhole pressure data collected from 9 December 2008 were evaluated to gain a preliminary understanding of the connectivity between well 27-15 and the reservoir to the south. The preliminary analysis of this pressure monitoring data indicated the reservoir around well 27-15 has an approximate permeability-thickness on the order of 5,600 md-ft. This would suggest an injectivity index of 100 pounds per hour per psi, which is similar to the value inferred from data collected by Ormat during a post-completion injection test in 2003.

The preliminary analysis of the reservoir surrounding well 27-15 provided insight into how long the injection test would be run, and what type of pressure response could be expected. Prior to the test, differential pressure flow metering equipment was installed on wells 22-22 and 21-2 so that their flow rates could be separately monitored, enabling one of the goals of the test to be met (determining which of the two injection wells has a greater connectivity with 27-15).

3.3.2 Test Description

The interference test at Desert Peak between injection wells 22-22 and 21-2 and monitoring well 27-15 began on 31 March 2009 and consisted of four step changes in the relative amounts of injection in the two injectors. Initial injection rates prior to the test were 1,240 gallons per minute (gpm) into 22-22 and 2,100 gpm into 21-2. The first step change lasted 21 hours, during which flow was diverted from 21-1 into 22 22, providing approximately equal injection rates of 1,700 gpm into each well. The second injection step change lasted 19 hours, during which the entire flow from 21-2 was diverted into 22-22, resulting in a total injection rate of 3,400 gpm in 22-22 only. Following a sustained period of 100% injection into 22 22, the next step was dictated by operational constraints, and some fluid was diverted back into 21-2, reducing the injection rate into 22-22 by 400 gpm. Injection continued under these conditions for 32 hours before returning the injection wells to normal operating conditions (with 1,240 gpm into 22-22 and 2,100 gpm into 21-2) on 3 April 2009. Monitoring of the pressure recovery in the reservoir at well 27-15 continued for the next week. Figure 4 below illustrates the step changes in injection and the corresponding changes in reservoir pressure observed at 27-15.

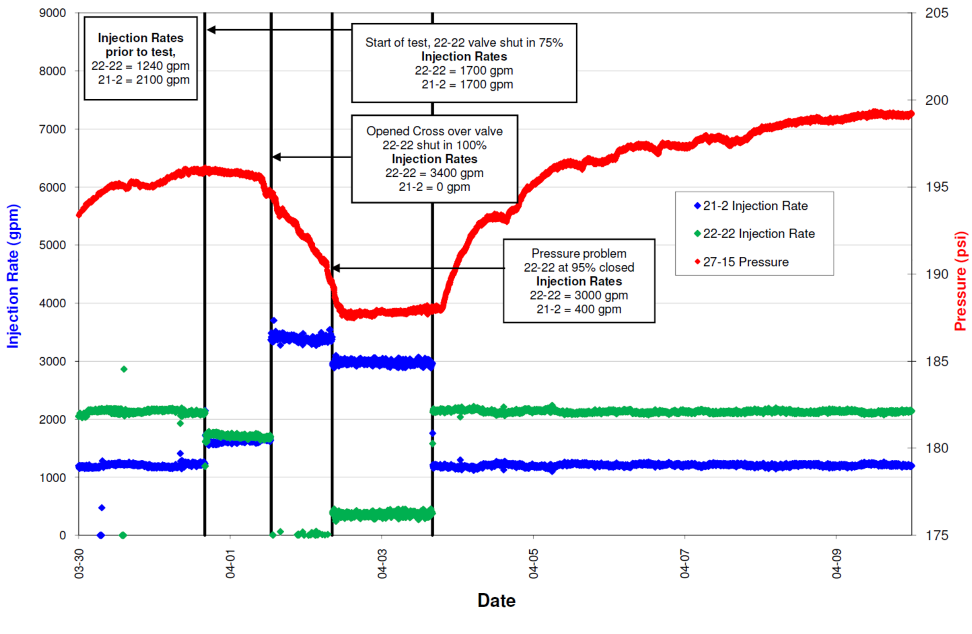

Figure 4: Results of April 2009 pressure transient testing at Desert Peak

3.3.3 Test Results

Figure 4 clearly shows that the changing injection scheme produced a pressure response that was recorded at 27-15. The nature of the pressure response indicates that of the two injectors, 22-22 has a much greater connectivity to 27-15; this is shown by the increase in pressure with increased injection and the decrease in pressure when the injection rate is 22-22 was reduced. Well 22-22 is open and has permeability both within the Rhyolite Unit (which is estimated to accept about 40% of the injected fluid) and the basement rock (which accepts the remainder). It is likely that most of the observed pressure responses in well 27 15 are affiliated with the deeper permeable zone in well 22-22.

A numerical model of the Desert Peak reservoir is being developed to fully quantify the connectivity of 27-15 to the reservoir, taking into account the two injection wells, the known high permeability zones each well intersects, and the low permeability zone impairing the high connectivity of 27-15 to the main reservoir to the south, and the data from this test will help calibrate the model.

3.4 Tracer Testing

As described in more detail in Rose *et al*. (2009), the objective of the tracer test conducted at Desert Peak is to determine the flow patterns of fluids injected at the two injectors (21-2 and 22-22) in anticipation of the stimulation of the EGS target well 27-15. With knowledge of the initial background flow patterns, the numerical model of the field can be better calibrated, and the results of the 27-15 stimulation can be better understood.

On 6 November 2008, 85 kg of 2,6-naphthalene disulfonate (2,6-nds) and 100 kg of 1,5-naphthalene disulfonate (1,5-nds) were injected into wells 22-22 and 21-2, respectively. Sampling of the five producing wells (21-1, 67-21, 74-21, 77-21, and 86-21) was initiated on 10 November 2008 and continued until 23 February 2009. The observed responses through the end of 2008 are shown in Figure 5.

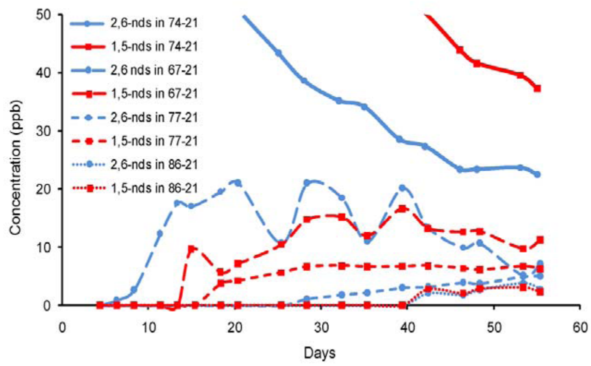

Figure 5: Tracer results through the end of 2008. The rapid, early tracer returns to well 74-21 are off-scale in this figure. For complete results, see Rose *et al*. (2009).

The return of the two tracers to well 74-21 (the closest producer to the south of the two injectors) was strong and immediate. For both tracers, both the first arrival and the peak concentration were missed by the time the first sample was taken four days after tracer injection. For the tracer 1,5-nds injected into well 21-2, a peak concentration exceeding 250 ppb was observed in 74-21 approximately 6 days after injection.

The well showing the next strongest returns was 67-21. The returns are delayed relative to those to 74-21, and the maximum measured concentration of each tracer was less than one tenth of the maximum concentrations measured by either tracer in well 74-21. Well 77-21 showed returns a bit later and at lower concentrations than 67-21. Well 86-21 had the slowest first arrivals and the lowest concentration of any of the monitored wells. Tracer returns are shown graphically in Figure 6, and suggest some re-circulation along strands of the Rhyolite Ridge Fault Zone.

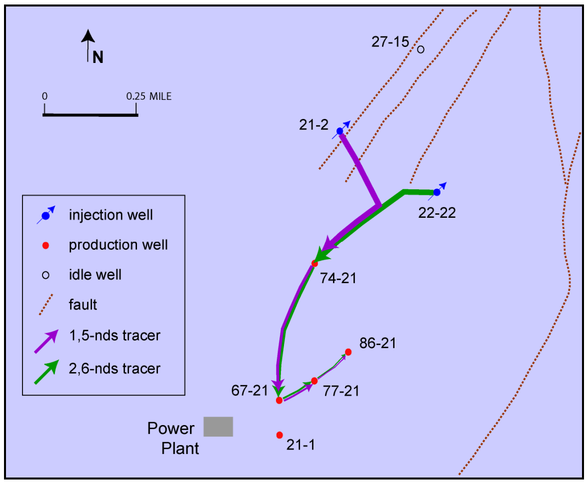

Figure 6: Schematic representation of tracer movement at Desert Peak (Rose *et al.*, 2009)

The most striking observation is that the returns of the two tracers to 74-21 were at least 10 times greater than those to any other well. Also, it is evident that the tracer concentrations decrease and the times for the first arrivals of peaks increase from 74-21 to 67-21 to 77-21 to 86-21. No tracer was observed in samples taken from 21-1.

3.5 Seismic Reflection Survey

Geologic data suggest that the separation between well 27-15 and the area of production and injection to the south is related to one or more faults that place 27-15 in a structurally lower block than the active production and injection wells. The position of these faults and the deep geology in the intermediate block (where well 21-2 is located) is uncertain. Therefore, a seismic reflection survey was undertaken to resolve fault locations, identify buried faults and provide better understanding of the geology, enabling (in turn) a better understanding of the ability to connect well 27-15 to the production and injection area of the field. Data were collected and analyzed along two lines, one trending N-S (from well 27-15 in the N to well 86 21 in the S) and one trending SW-NE (from well ST-1 on the SW to beyond well 23-1 on the NE).

The 2-D reflection seismic survey was completed in early October 2008 and used as a source an IVI Mini-Vibe II “thumper truck,” with a 16,000-pound force and a sweep frequency of 8-96 Hz. Although the Desert Peak reflection data are less definitive than similar reflection data typically collected in sedimentary environments, for a Basin and Range volcanic environment with steeply dipping mixed lithologies, the survey data were relatively coherent allowing reasonable imaging of the lithologies and structures beneath the Desert Peak field.

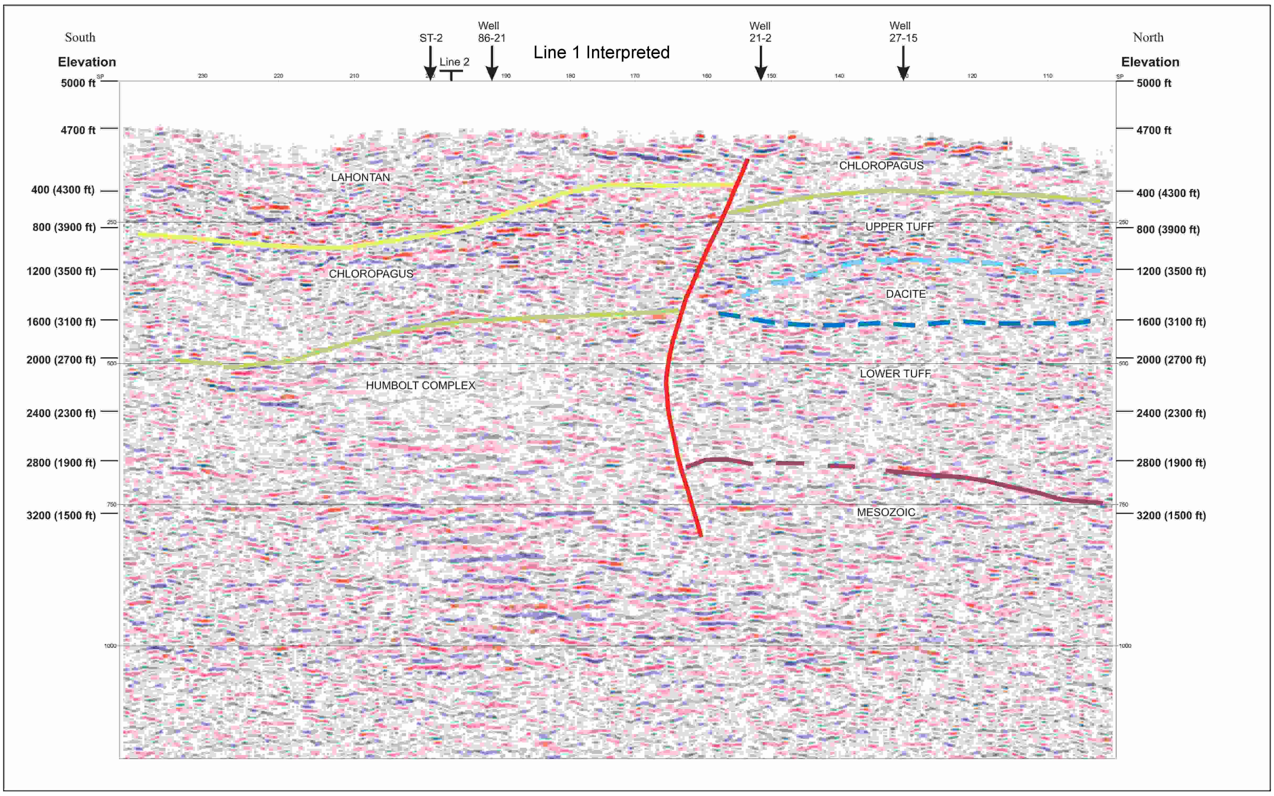

Figure 7: Interpreted 2-D seismic profle along N-S line (Line 1) at Desert Peak

Well courses and formation tops were added to the N-S seismic line (Figure 7 below) and reflectors corresponding to formation tops for principal lithologic units could be recognized within the section. The processed data confirms the Rhyolite Ridge Fault (or one strand) and much of the structural complexity in the pre-Tertiary rocks in the vicinity of the 21-2 and 27-15 wells discussed above, including the presence of a buried fault (the red line on Figure 7 below) offsetting the basement by more than 1,000 feet.

4. CONCEPTUAL STRUCTURAL MODEL

Figure 8 is a conceptual cross-section from Lutz *et al*. (2009) showing the stratigraphy and interpreted structure along a N-S cross-section from well 29-15 on the north to well 29-1 on the south. The key features of this section are the presence of pT1 in well 27-15 and the large vertical offset of phyllite and diorite in the upper pT2 sequence between wells 21-2 and 27-15, which are located within 1,000 feet of one another.

About 1,500 feet of displacement occurs along a buried fault between well 27-15 (in the down-dropped block) and the horst block containing the Section 21 wells (21-2, 74-21, 43-21, 77-21, and 21-1). Overlying Tertiary strata between wells 27-15 and 21-2 do not appear to be significantly offset, suggesting that development of the horst and subsequent erosion of the uplifted basement occurred before deposition of the first basal tuffs of the Rhyolite Unit in Oligocene time (Faulds *et al*., 2003).

The thick pT1 unit is found in wells 27-15 and 23-1, and in another well that is not shown on this cross section. This is well 22-22, the injection well that has the better hydraulic connection to well 27-15 (as compared to the other injection well 21-2). Lutz *et al*. (2009) conclude from these relationships that the buried fault lying between 27-15 and the productive part of the field to the south has a W to NW trend, and that well 22-22 is in the same structural block as 27-15. Thus, rock-based and seismic investigations provide new insight into the structural setting of the Desert Peak resource; the geoscientific results are consistent with those derived from pressure transient testing between the two injection wells and 27-15.

Tracer test results are difficult to interpret because each well involved typically has the potential for communication within the Rhyolite Unit, the basement (pT) units, and through one or more strands of the Rhyolite Ridge Fault Zone. Tracer testing shows that tracer injected into well 22-22 returned to well 74 21 almost immediately, followed by later returns to well 67-21. Tracer injected into well 21-1 also reached well 74-21, but later and in lower concentrations relative to the returns seen in 74-21. Lutz *et al*. (2009) believe that the tracer testing may support fluid flow along a NE-trending strand of the Rhyolite Ridge Fault Zone from 22-22 to 67-21, and that these two wells are isolated from an eastern fault block containing wells 21-1, 77-21, and 86-21. Although not discussed herein, geochemical analyses of produced fluids made by Lawrence Berkeley National Laboratory support this concept (Mack Kennedy, personal communication, 2009).

The buried NW-trending basement fault that separates well 27-15 from the productive wells to the south appears to be a barrier to fluid flow rather than a conduit. However, one or more of the strands of the Rhyolite Ridge Fault Zone appear to conduct fluids. Lutz *et al*. (2009) conclude that the productive portion of the Desert Peak geothermal system is found where permeable Jurassic basement rocks (of the pT2 unit) in the uplifted horst block are fractured along the younger, NE-trending structures of the Rhyolite Ridge Fault Zone. Near well 22-22, the Rhyolite Ridge Fault Zone appears to truncate against the NW-trending buried fault. To the S of this NW-trending fault, the Rhyolite Ridge Fault Zone "steps over" to the E.

5. DISCUSSION: STIMULATION OPTIONS

During the course of the work described above and indeed throughout the project, there have been extensive discussions among the team members about the geologic structure of the field and the best way to stimulate well 27-15. One of the participants in these discussions was Dick Benoit, a geologist who worked extensively at Desert Peak during its initial development in the 1970s and early 1980s, and lead author of a major geological analysis of the field undertaken at that time (Benoit *et al.*, 1982). This work was considered extensively in the development of the conceptual model of the field.

During a step-rate injection test of well 22-22 in December 1982, wellhead pressures as high as 725 psig caused hydro-fracturing of the Rhyolite Unit just below the casing shoe at a depth of about 3,000 feet (Dick Benoit, personal communication, 2008). This transformed well 22-22 (which was until that time a non-commercial well) into a sub-commercial producer and a reasonable injector. Temperature survey data collected during the test clearly show that the Rhyolite Unit began accepting injected fluid as a result of this "accidental" hydrofrac. This experience from the 1980s suggested the possibility of a shallow stimulation in well 27-15, as an alternative to the options of exploiting the zone of known permeability near the pT1-pT2 contact, or the originally envisaged plan of stimulating the deeper and more mechanically competent pT2 unit.

The analyses undertaken from late 2008 through early 2009 confirm the viability of undertaking an EGS stimulation in well 27-15. Although located in a separate structural block from all other active wells at Desert Peak except 22-22, well 27-15 has lithologies that are favorable for stimulation and pre-existing fractures within those lithologies that are optimally oriented for slip upon increase in pore pressure.

Well 27-15 is completed in the footwall of a buried (probably NW-trending) basement fault and between strands of the Rhyolite Ridge Fault Zone, a younger NE-trending fault that influences fluid flow patterns in the existing geothermal field. This complex intersection of faults (see Figure 7) provides potential fluid flow paths that can be enhanced by stimulation and exploited for additional heat recovery. In addition, there is a zone of existing permeability in well 27-15 that forms a weak hydraulic connection to the producing field; this connection could be exploited and enhanced via hydraulic stimulation. The earlier experience with increasing permeability in the basal section of the Rhyolite Unit (described above) suggests another possibility for enhancing well 27-15's connection to the producing field at shallower levels. Finally, the original concept of deep stimulation of favorable lithologies in the pT2 section still remains viable, but would require side-tracking and deepening of well 27-15 to get below the "fish." The advantages and disadvantages of these three options are discussed below.

5.1 Stimulate Volcanics 3,000 – 3,300 Feet

The Tertiary Rhyolite Unit bottoms at about 3,300 feet. As in other wells (including 22-22), the rhyolite in well 27-15 in this interval is heavily silicified. The interval is characterized by a relatively low drilling penetration rate and a reasonably "in-gauge" section of hole. The casing point was chosen based on the transition into this silicified zone, which has provided good permeability in other wells to the south.

The advantages of this option include:

- Because a connection through the silicified zone in the Rhyolite Unit has already been achieved in another well, this option carries low risk.
- It targets a zone that is known to be commercially productive in other parts of the field.

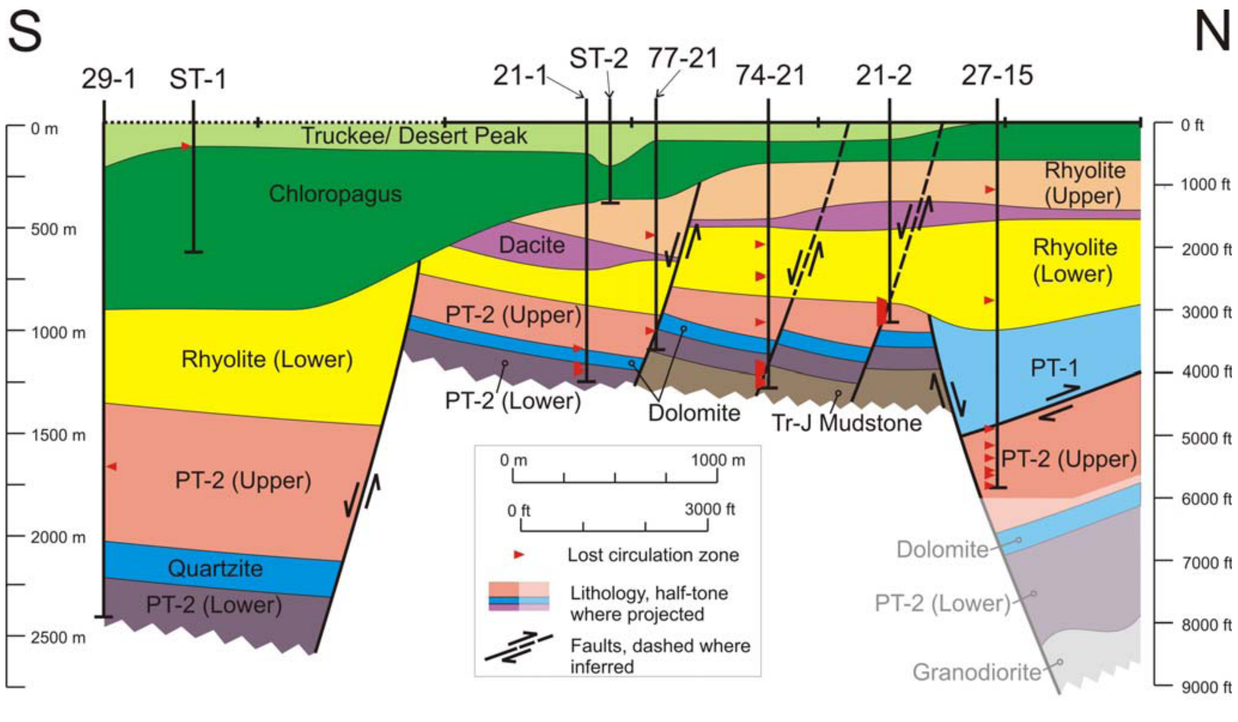

Figure 8: N-S geologic cross-section, Desert Peak field (from Lutz *et al.*, 2009)

- The formation targeted for stimulation (the Rhyolite Unit) is continuous between well 27-15 and the productive area of the field to the south; therefore, creating a connection via a fault (or faults) may not be required. Further, there appears to be no fault barrier to fluid flow within the Rhyolite Unit.
- Conducting this stimulation does not eliminate any of the other options from consideration; this stimulation could be undertaken, its results evaluated, and deeper zones could still be targeted for later stimulation(s).
- Core samples of the Rhyolite Unit are available from well 35-13; these can be used for mechanical testing to further constrain the stress/mechanical model.
- A "mini-frac" to determine the magnitude of SHmin can be undertaken.
- Results of this stimulation would be applicable to other shallow volcanic formations.
- The stimulated well could be used as a pumped production well, as the production zone temperature would permit this.

The disadvantages of this option include:

- The temperature in this interval is lower than that in deeper intervals, thus the potential for heat recovery is lower.
- In this stress environment, the stimulation may propagate upward as well as along the regional fault strike direction, potentially reducing heat recovery.
- There may be less induced seismicity than in harder rocks, providing less information to evaluate fluid migration and the stress field.

5.2 Stimulate Permeable Zone Below 4,500 Feet

The main permeable zone in well 27-15 is near the contact between the pT1 shale and the pT2 diorite at about 4,800 feet. In addition, permeability may develop in the deeper pT2 units. Therefore this option is designed to exploit those zones after casing off the upper part of the open-hole section.

The advantages of this option include:

- It exploits a zone of known permeability.
- The drilling operation is straightforward, making this the lowest-risk option of the three in terms of drilling.
- Casing is available on-site to re-complete the well by sealing off the upper portion of the open-hole section.
- It targets a zone that is thought to be a thrust fault contact between the pT1 and pT2 units, and similar contacts and lithologies are common in other areas of the western Basin and Range.
- Temperature in the target stimulation zone is higher than for the first option, potentially increasing heat recovery.

The disadvantages of this option include:

- The target zone is associated with increased rate of penetration and enlarged wellbore diameter, suggesting that less brittle fracturing (and less generation of microseismicity) will occur relative to other zones.
- No mini-frac would be conducted, thus the mechanical/stress model would not be significantly advanced.
- The well could not be used as a pumped producer as temperatures are too high; it would need to rely on self-flow (which may reduce its production capacity).
- Because of the fish, it would not be possible to evaluate the impact of the stimulation on the deeper parts of the well, nor determine if they were contributing to the productivity (or injectivity).

5.3 Side-Track, Re-Complete and Stimulate pT2 Units Below 5,600 Feet

In this plan, well 27-15 would be side-tracked below the 13-3/8-inch casing shoe and re-drilled. A 9-5/8-inch casing would be run to approximately 5,600 feet, below the (potentially unstable) phyllite unit. While drilling, cores could be collected and a mini-frac could be conducted out of the bottom of the new 9-5/8-inch casing before drilling ahead. The intrusive units in the pT2 section would be stimulated as originally envisaged, but in an uncompromised hole (i.e., no fish) and with more data to support the mechanical/stress model.

The advantages of this option include:

- It enables collection of the most data to support the mechanical/stress model, thus providing a better understanding of results.
- The temperature in this stimulation zone is the highest of the three options, potentially maximizing heat recovery and allowing for the most upward growth of the stimulated volume before encountering cooler zones.
- Casing is available on-site for the re-completion.
- It targets lithologies common in other areas of the western Basin and Range.
- It targets hard rock prone to brittle fracture and high differential stress, which should generate the most microseismicity of the three options.
- This interval targets lithologies most likely to experience permeability enhancement during hydraulic stimulation due to self-propping shear failure (Davatzes and Hickman, 2009).

The disadvantages of this option include:

- The well could not be used as a pumped producer as temperatures are too high; it would need to rely on self-flow (which may reduce its production capacity).
- It carries the highest costs of the three options.

6. STIMULATION DECISION

Having reached a Go / No-Go Decision Point, a Stage-Gate Review Meeting was convened by DOE in February 2009. During this meeting, the results of the analyses described above and others were presented and discussed, as were the three options for stimulating well 27-15. These presentations and subsequent analyses by the reviewers provided a basis for DOE's decision to proceed with stimulation; this decision was made in early May 2009.

Work undertaken to advance the understanding of the geology at Desert Peak has confirmed that the target EGS well (27-15) is located in a separate structural block from the main producing reservoir to the south. Well 27-15 in the down-dropped block on the north side of this fault, while the productive field is in the up-thrown (horst) block on the south side. The fault creating this structural offset is likely to trend NW, and probably serves as a barrier to fluid flow. While there is some hydraulic connectivity between 27-15 and the main reservoir area, the fault / flow barrier may inhibit the effectiveness of a deep hydraulic stimulation (and thus fluid flow between the two regions during routine operations).

Since the Rhyolite Unit was deposited after the period of movement on the NW-trending fault, the Rhyolite Unit is continuous between the two blocks. That is, the flow barrier (fault) does not extend up into the Tertiary Rhyolite Unit. Considering this and the previous experience with the shallow stimulation of well 22-22, Ormat and DOE have agreed that the shallow stimulation option should be pursued in well 27-15.

7. CURRENT STATUS AND NEXT STEPS

A detailed plan for re-completing the well has been developed; this includes plugging off the deeper sections of the well, undertaking a mini-frac below the 13-3/8-inch casing shoe (after setting a series of additional temporary plugs) and performing a pre-stimulation injection test. In addition, mechanical testing is underway using cores of the Rhyolite Unit from well 35-15. Cores were selected that are mechanically and lithologically similar to those encountered between 3,000 and 3,300 feet in well 27-15. Additional mineralogical characterization of the stimulation interval is also underway to better characterize it and to determine whether or not chemical stimulation techniques should be applied in addition to hydraulic stimulation techniques. Finally, a cement bond log will be run to confirm the integrity of the cement around the 13-3/8-inch casing shoe.

A numerical reservoir model of Desert Peak is under development. The conceptual modeling work described herein provides the geologic foundation on which the numerical model is based. The present focus is on initial state modeling to reproduce pre-exploitation conditions; this is the first phase of model calibration. The results of tracer and interference testing provide a basis for history matching, which is the second phase of model calibration. The purpose of the modeling is to evaluate the impact that the stimulation of 27-15 may have on the operation of the Desert Peak geothermal reservoir.

Stimulation planning is currently underway. Experts from StrataGen (formerly Pinnacle Technologies) will participate in the development of the stimulation plan together with the multi-disciplinary team of Ormat, GeothermEx, the US Geological Survey (USGS), Temple University, Lawrence Berkeley National Laboratory (LBNL), the Energy & Geoscience Institute of the University of Utah (EGI), and Schlumberger-TerraTek. Rig contracting activities are underway and the re-completion and mini-frac are planned for July 2009. An update will be provided during the presentation of this paper in October 2009.

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