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HYDRAULIC STIMULATION OF WELL 27-15, DESERT PEAK GEOTHERMAL FIELD, NEVADA, USA

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ABSTRACT

Following an integrated study of fluid flow, fracturing, stress and rock mechanics, silicified rhyolite tuffs and metamorphosed mudstones were hydraulically and chemically stimulated in Desert Peak well 27-15 as part of an Enhanced Geothermal System (EGS) project. The target well is located on the margins of an operating geothermal field, and the stimulated zones lie at a depth from 3,000 to 3,500 feet where temperatures range from 355 to 385°F.

A long initial period of shear stimulation was carried out at low fluid pressures (less than the least horizontal principal stress, S_{hmin}), which increased injectivity by more than one order of magnitude. After this, chelating agents and mud acid treatments were used to dissolve mineral precipitates and open up partially sealed fractures. This chemical stimulation phase temporarily increased injectivity, but led to increased wellbore instability. After a wellbore clean-out, a large-volume hydraulic fracturing operation was carried out at high pressures (exceeding S_{hmin}) and high injection rates over 23 days to promote fluid pressure transfer to greater distances from the borehole, resulting in an additional 4-fold increase in injectivity.

Locations of microearthquakes (MEQs) and tracer testing demonstrate growth of the stimulated volume between well 27-15 and active geothermal wells located approximately 0.25 to 1.25 miles to the SSW. The seismic array has been augmented and a final phase of hydraulic fracturing and shear stimulation is being considered to further improve permeability in the region around well 27-15.

INTRODUCTION

After showing poor initial potential as either a producer or injector, the proximity of well 27-15 to the existing infrastructure, favorable bottomhole temperatures (355 to 385°F), and recent demonstration of hydraulic connectivity to nearby injection wells (Rose et al., 2009) made 27-15 an attractive candidate for an Enhanced Geothermal System (EGS) project. This well is in the Desert Peak Geothermal Field (DPGF) of western Nevada and operated by Ormat Nevada Inc (Figure 1).

With financial support from the Geothermal Technologies Program of the U.S. Department of Energy (DOE), Ormat Nevada Inc. and a multi-disciplinary team of scientists and engineers commenced a rigorous investigation into the suitability of well 27-15 for a variety of stimulation techniques. Findings from these studies led Zemach et al. (2009) to determine that the lower Tertiary Rhyolite unit (between 3,000 to 3,300 feet in well 27-15) would be the primary target for the stimulation (Figure 2). Guiding the development of the EGS plan and management of the project were the following parallel goals of the operator (Ormat Nevada, Inc.) and the DOE:

- Develop and execute a site-specific EGS stimulation plan which demonstrates techniques that are practical, cost-effective, and transferrable to other project settings;
- Improve hydraulic communication between well 27-15 and the existing production field to commercially acceptable levels;
- Demonstrate the benefits to the overall power plant production gained through this project.

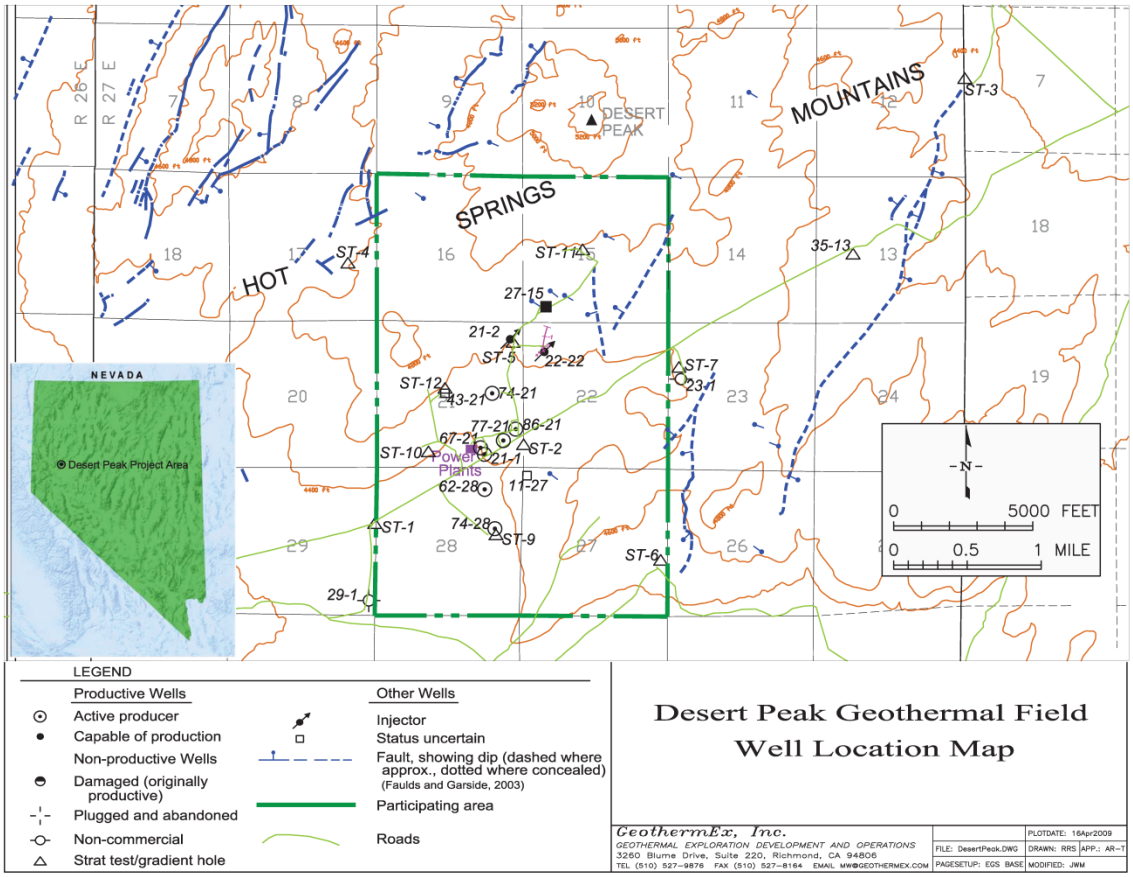

Figure 1. Map of Desert Peak Geothermal Field, Nevada, USA; faults from Faulds et al (2003).

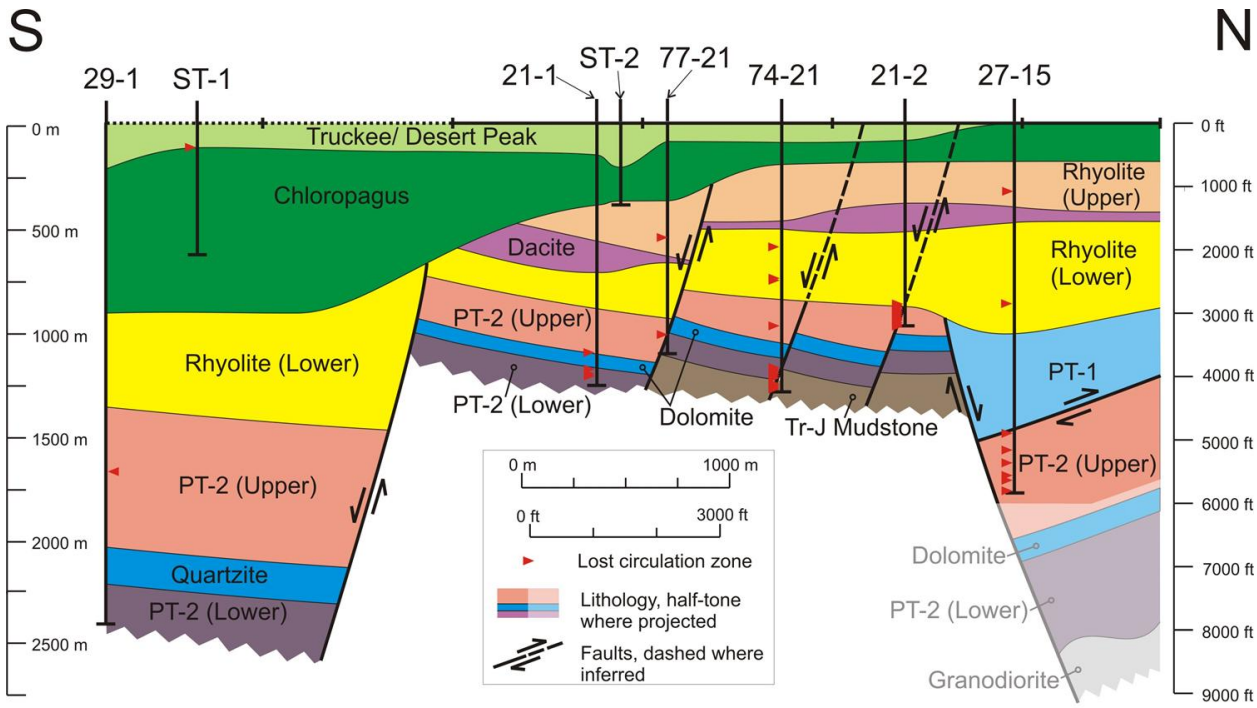

Figure 2. South-North geologic cross-section through Desert Peak Geothermal Field; from Lutz et al (2009).

With these targets in mind, a multi-phase EGS plan was developed by the project team, including several phases of low-pressure (i.e., below the minimum horizontal principal stress, S_{hmin}) shear stimulation, two stages of chemical stimulation, and an extended phase of high-pressure hydraulic fracturing. The plan also included a multi-faceted monitoring program, which included wellhead and downhole pressure monitoring and periodic pressure-temperature-spinner (PTS) surveys in the study well (27-15), tracer monitoring in nearby production wells (Figure 1), and the real-time observation of microearthquakes (MEQs) through an in-field multi-component seismic monitoring array with the goal of tracking the progress of the stimulation.

Linking each phase of the plan was a "living" decision tree that was updated according to the results of each operational task. This allowed the project team to quickly determine whether or not the outcome met pre-defined metrics and the appropriate subsequent steps to take in either case. Ultimately, the benchmark for "go/no-go" decisions throughout the operations was whether or not the injectivity of well 27-15 reached or exceeded commercially acceptable targets for an injection well in the Desert Peak field. For the purpose the project, the injectivity target was 1 gpm/psi or greater in order for 27-15 to be classified as a "very good" injection well.

Over the course of the stimulation operations conducted between September 2010 and April 2011, nearly a 60-fold increase in injectivity was realized in well 27-15. In addition, tracer testing and MEQ activity suggest marked progress of the stimulation towards the producing field. Finally, several valuable lessons learned are now informing follow-up work planned at Desert Peak and another DOE-supported EGS project at the nearby Bradys Hot Springs geothermal field.

BASIS FOR THE STIMULATION PLAN

Shear Stimulation Phase

Hydraulic shear stimulation is intended to promote the propagation of shear displacement along existing fracture planes, ideally resulting in self-propping dilatation that yields permanent gains in permeability after fluid pressures are reduced. With the goal of maximizing the stimulated volume at the reservoir depth around 27-15 for increased reservoir contact, shear stimulation was deemed appropriate in the context of EGS.

Petrographic, mineralogical, and mechanical analyses of drill cuttings from 27-15 and core specimens from an offset well identified several lithotypes within the Tertiary Rhyolite unit that would be amenable to shear failure stimulation, displaying both brittle failure and the tendency to form self-propping fractures, as documented during laboratory tests (Lutz et al., 2010). In addition, detailed fracture and stress analysis revealed that the density and orientation of fractures within the target interval relative to the in-situ stress field are favorable to hydraulic shear stimulation (Davatzes & Hickman, 2009; Hickman & Davatzes, 2010).

Interpretation of the three-dimensional state of stress (Davatzes & Hickman, 2009; Hickman & Davatzes, 2010) estimated the azimuth of the minimum horizontal principal stress (S_{hmin}) to be 114° ± 17° with a magnitude of 1995 ± 60 psi (equivalent to a wellhead injection pressure of 750 psi). This implies that the orientation of the maximum horizontal principal stress (S_{HMax}) – the dominant direction in which fractures undergoing shear failure as well as hydraulic fractures should strike – is approximately 25° ± 19°. Geomechanical analyses from well 23-1, located about 1 mile to the southeast of well 27-15, are in agreement with these results (Robertson-Tait et al., 2004). This NNE-SSW orientation is considered optimal since the goal of the stimulation is to improve the hydraulic connectivity between 27-15 and the existing injectors to the SSW, 21-2 and 22-22 (see Figure 1).

Together these analyses led to the formulation of the first phase of the plan: the low-pressure (i.e., below S_{hmin}) shear stimulation. Throughout this phase of the stimulation wellhead injection pressures, starting at 250 psi, would be stepped up in 100 psi increments until a maximum injection pressure of 650 psi was reached. This approach was intended to progressively extend the shear-stimulated volume outwards from the near-wellbore region into the far-field reservoir without creating new hydraulic fractures. Each step was planned to last approximately one week, after which injection would be stopped to allow for pressure fall-off observation, a static PTS survey, and a determination of the measured gain in injectivity. Success of this phase of the stimulation was based largely on the commercial acceptability criterion defined by the operator and on the relative improvements between injection steps (Figure 3). Failing to achieve acceptable gains in injectivity during this phase of the stimulation, the decision would be made to proceed with the chemical stimulation phase.

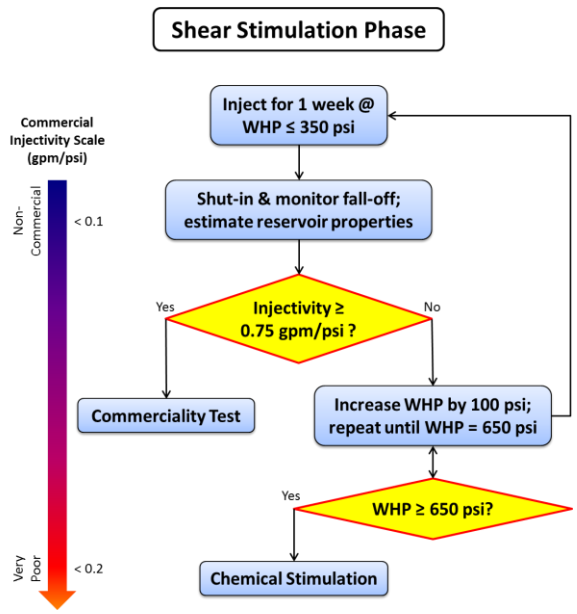

Figure 3. Shear stimulation decision tree.

Chemical Stimulation Phase

In an internal report to the project team, Rose et al. (2011) describes a two-stage chemical stimulation plan targeting carbonates and clays in the formation. During the first stage, 45,000 to 60,000 gallons of 2.0 to 4.0% (by weight) solution of a chelating acidic sodium sulfophthalate (SPA) would be injected into 27-15 and then displaced by water into the near-wellbore formation. The slower reaction kinetics of the chelating agent would require a period of 48 hours to interact with the formation. Afterwards, a step-rate injection test would be conducted to determine the effectiveness of the chelating solution in dissolving carbonate vein filling observed in the upper rhyolitic interval (Lutz et al., 2010).

Another key observation from the petrological work conducted by Lutz et al. (2010) was the presence of smectite-rich clays on the surface of induced failure planes of the argillaceous rhyolite core samples that were subjected to laboratory mechanical testing. Presence of clay smearing on the pre-existing fracture surfaces in the formation would likely result in ductile rather than brittle failure and would be less prone to self-propping dilatation.

During the second stage, if necessary, 12,000 gallons of a traditional mud acid treatment of 12% hydrochloric acid (HCl) and 3% hydrofluoric acid (HF) would be pumped into the formation to dissolve remaining silicas, silicates, and clays within the near-wellbore region. Afterwards, a second step-rate injection test and PTS survey would be conducted to verify the effectiveness of the treatment and estimate any gain in injectivity. A target injectivity of 0.3 gpm/psi was the criterion for success defined by the project team for this phase, under the assumption that little gain was achieved during the shear stimulation (Figure 4). In the case that the target injectivity was achieved, an additional phase of shear stimulation was planned; otherwise, the decision would be made to move into the controlled hydraulic fracturing phase.

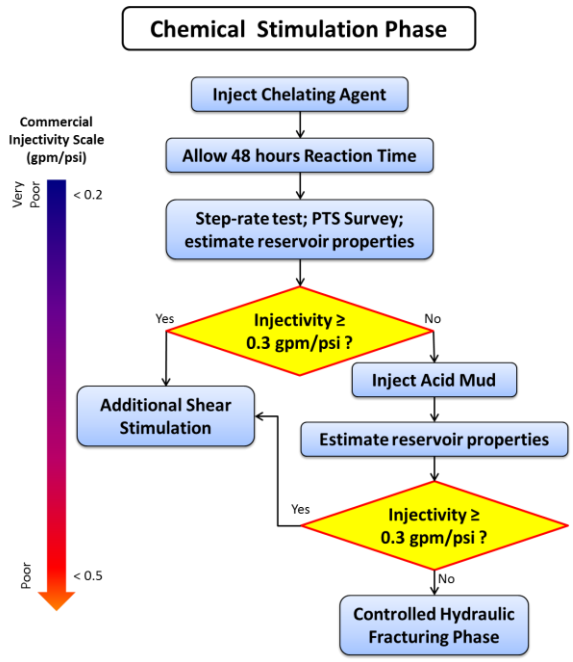

Figure 4. Chemical stimulation decision tree.

Controlled Hydraulic Fracturing Phase

Assuming limited gains after the chemical treatment, the stimulation plan then called for a phase of controlled hydraulic fracturing. From the perspective of the project team, this approach provided a technique proven in other industries to create substantial improvements in permeability and might promote additional shear failure in the reservoir by delivering fluid pressure to the formation away from the well. The plan for this phase of the stimulation was to inject at fluid pressures above S_{hmin} (the fracture initiation pressure) and at rates within the limitations of the surface pumps. Injectivity monitored in real-time and periodic PTS surveys would provide the basis for the project team to make the determination whether or not to increase injection rates and pressures (Figure 5).

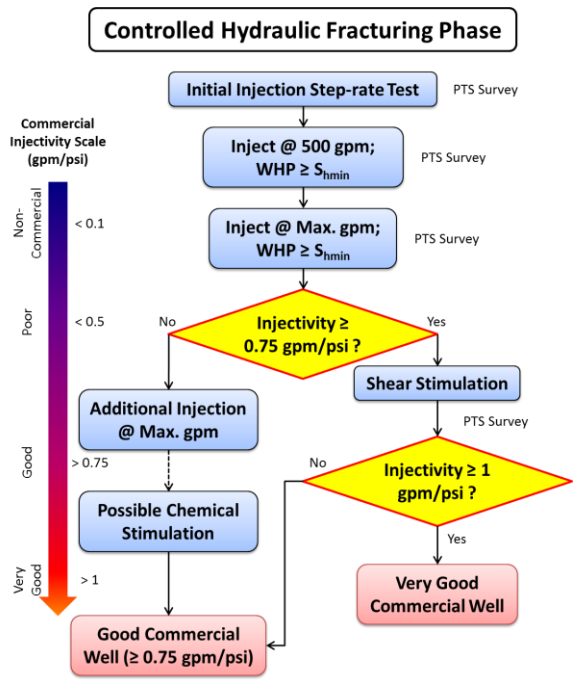

Figure 5. Hydraulic fracturing decision tree.

Tracer Testing

A series of tracer studies were planned throughout the stimulation in order to establish the initial state of connectivity between the study well 27-15 and the production wells – particularly well 74-21, which is the closest to well 27-15 (Figure 1) – and to monitor any changes in this relationship throughout the operations. Early in the shear stimulation phase, a fluorescein tracer was to be injected in 27-15 to establish the baseline connectivity to the production wells. Once the stimulation was determined to have altered the reservoir characteristics, a dual-tracer study comprised of a reactive tracer (Safranin T) and a conservative tracer (1,6-naphthalene disulfonate) would be conducted. The objective behind the reactive tracer was to constrain the stimulated reservoir fracture surface area, while the conservative tracer would provide a new estimate of connectivity between 27-15 and the production wells (particularly 74-21) that could be compared to the initial baseline.

MEQ Monitoring

Real-time observation of MEQ events is another key component of the monitoring program. A 14-station array (Figure 6), managed jointly by teams from Lawrence Berkeley National Laboratory (LBNL) and the U.S. Geological Survey (USGS), was configured with the objective of detecting MEQ events throughout the stimulation operations conducted in 27-15. In addition to resolving the spatial location and the depth of triggered events, the array is designed to allow the interpretation of the focal mechanisms, including both shear and dilatational components. Furthermore, real-time processing of triggered events allows the project team to visualize and estimate the progress of the stimulation and modify operational plans in response to seismic activity. For the purpose of the EGS stimulation, both a study area and a target area were defined around the project site as a means to quickly discriminate between events that may or may not be of significance to the operations (Figure 7).

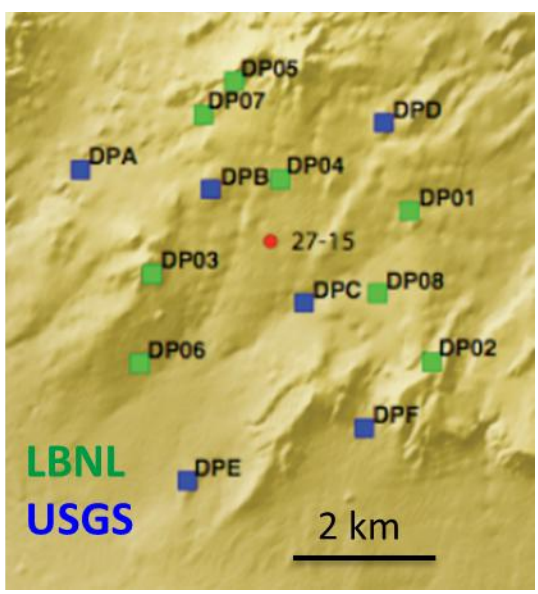

Figure 6. Original pre-stimulation configuration of Desert Peak Seismic Array: LBNL stations DP01-DP08; USGS stations DPA-DPF.

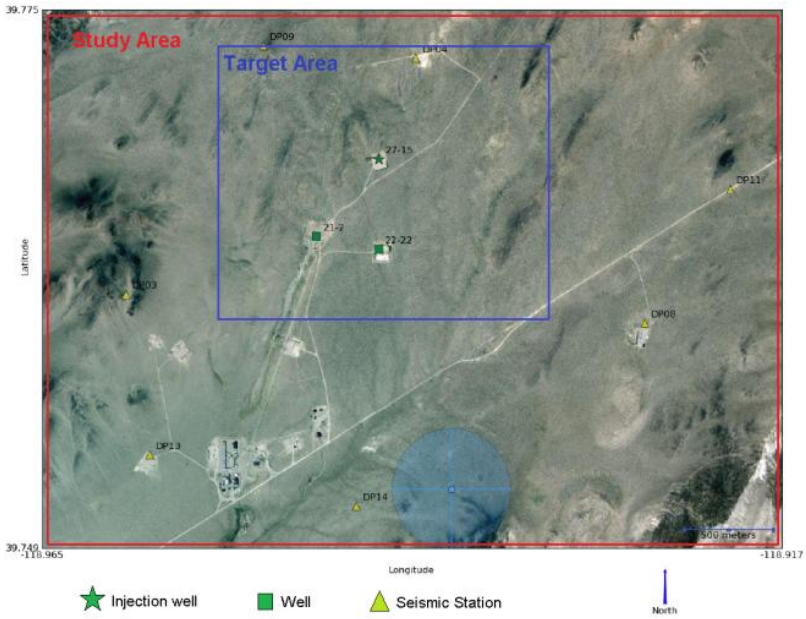

Figure 7. Desert Peak seismicity study and target areas, with EGS well 27-15 and two nearby injectors.

EXECUTION OF THE STIMULATION PLAN

Shear Stimulation Operations

Injection in 27-15 commenced at a wellhead pressure ≤ 250 psi and an initial injection rate of 3 to 5 gpm, followed by a second step with wellhead pressures ≤ 350 psi at 4 to 6 gpm. Both steps lasted about 8 to 9 days and exhibited stable injectivities ~ 0.01 gpm/psi, with no observed MEQs before shutting in the well for pressure fall-off observation. The wellhead injection pressure was then increased to 450 psi. Initial injectivity and flow rate was consistent with that of the previous steps for the first four days and then began to climb. As injection continued, the flow rate climbed from 6 gpm to nearly 70 gpm while the wellhead injection pressure remained below 450 psi, indicating a significant increase in injectivity. The measured wellhead pressure and injection rate over this period is presented in Figure 8.

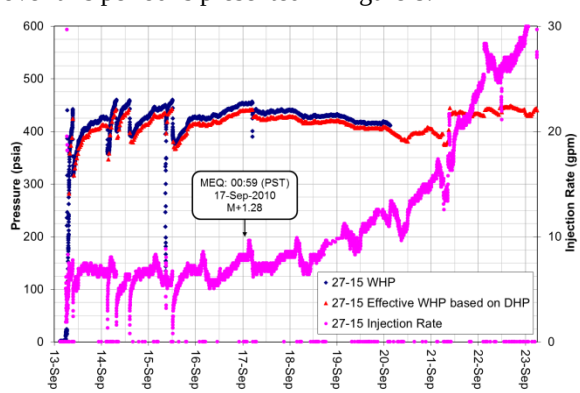

Figure 8. Well 27-15 wellhead pressure (WHP) and injection rate from Sept. 13-23, 2010.

Early in the shear stimulation, 50 kg of fluorescein tracer was injected into 27-15, with returns being monitored over the following 60-day period at the production wells using both a field fluorimeter and laboratory-based sample analysis. Results showed breakthrough of fluorescein at well 74-21 after 40 days, suggesting only a modest connection between 27-15 and 74-21 (Figure 9).

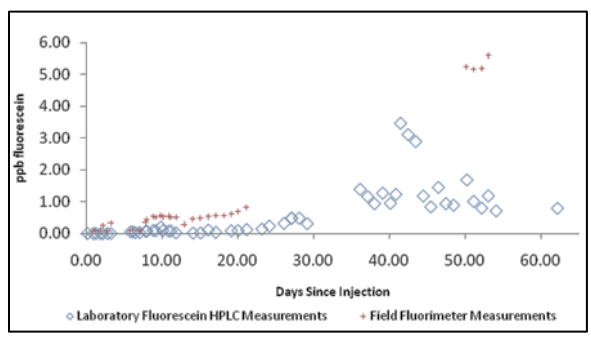

Figure 9. Fluorescein measured at well 74-21 during shear stimulation.

Through the course of injection at 450 psi, the rate had climbed to 70 gpm with a maximum injectivity of 0.13 gpm/psi. Pressure fall-off in the reservoir was monitored for the following 8 days before shutting down to reconfigure the surface setup.

During the final step of the shear stimulation phase, the wellhead injection pressure was maintained below 550 psi. The initial injection rate and injectivity were low (e.g., 40 gpm and 0.06 gpm/psi, respectively). Modest gains in injectivity were

realized throughout the injection period; however, no microseismicity was observed. By the end of this step, the injection rate reached a maximum of over 100 gpm and the injectivity was approximately 0.15 gpm/psi.

Comparison of pre- and post-shear stimulation PTS surveys showed increased fluid losses occurring between 3,370 to 3,420 feet measured depth. By the end of the shear stimulation phase an order-of-magnitude increase in injectivity was achieved; the absolute value 0.15 gpm/psi, however, was still too low for commercial applications. As a result, the decision was made to proceed with the chemical stimulation phase.

Chemical Stimulation Operations

Immediately prior to the first stage of the chemical stimulation, an injection test with a maximum wellhead pressure of 550 psi was performed in order to establish the starting injectivity conditions of well 27-15. Results of this test showed that injectivity gains observed during the shear stimulation phase were temporary, as the starting injectivity was 0.04 gpm/psi. In early February 2011 36,000 gallons of a 2% (by weight) solution of SPA was injected into 27-15 over a 2.5 hour period and then displaced into the formation by 22,000 gallons of fresh water. The chelating agent was allowed to react in the formation for a period of 48-hours, after which a step-rate injection test was conducted. Results of the step-rate test showed no significant improvement in injectivity; the observed injectivity was 0.05 gpm/psi.

The second stage of the chemical stimulation began with the injection of 12,850 gallons of 12%/3% HCl/HF acid at a wellhead pressure of approximately 550 psi. This was followed by the injection of 20,000 gallons of fresh water in order to push the acid into the formation and promote additional shear stimulation at a wellhead injection pressure of 550 psi. A slight but temporary increase in injectivity was observed immediately after the acid reached the open formation; however, this was short-lived and injectivity dropped to approximately 0.07 gpm/psi. Although seismic monitoring was continuous throughout this phase, no MEQ events were detected in either stage of the chemical stimulation.

Results of the chemical stimulation caused members of the project team to suspect that wellbore instability issues might explain the lack of progress in the chemical stimulation. A subsequent wireline survey with a sinker bar found the new measured well depth to be 3,292 feet – confirming that the bottom 208 feet of the well, and the entire lower outflow zone, had indeed been filled with debris.

In the interest of carrying out the remainder of the stimulation activities, a workover rig was brought to the wellsite in March 2011 to clean out well 27-15. During the course of the clean out operations, samples of the fill from were recovered at several different times for analysis. An attempt was made to interpret which intervals produced the fill; however, results of these tests were inconclusive due to the degree of mixing that occurred. Once the clean-out operations were complete, the project team was able to mobilize equipment for the controlled hydraulic fracturing phase of the stimulation plan.

Controlled Hydraulic Fracturing Operations

The interim period after the chemical stimulation allowed the project team to re-evaluate the surface equipment setup and devise a new configuration that would be better suited for the hydraulic fracturing phase of the stimulation. This new design included tandem duplex/triplex mud pumps each capable of 2,000 psi output; on-demand feed of separated brine from the power plant to the wellsite from nearby by injection well 21-2; and onsite storage of more than 160,000 gallons of injection brine between the lined sump and Baker tanks. A process flow diagram of the injection setup is depicted in Figure 10.

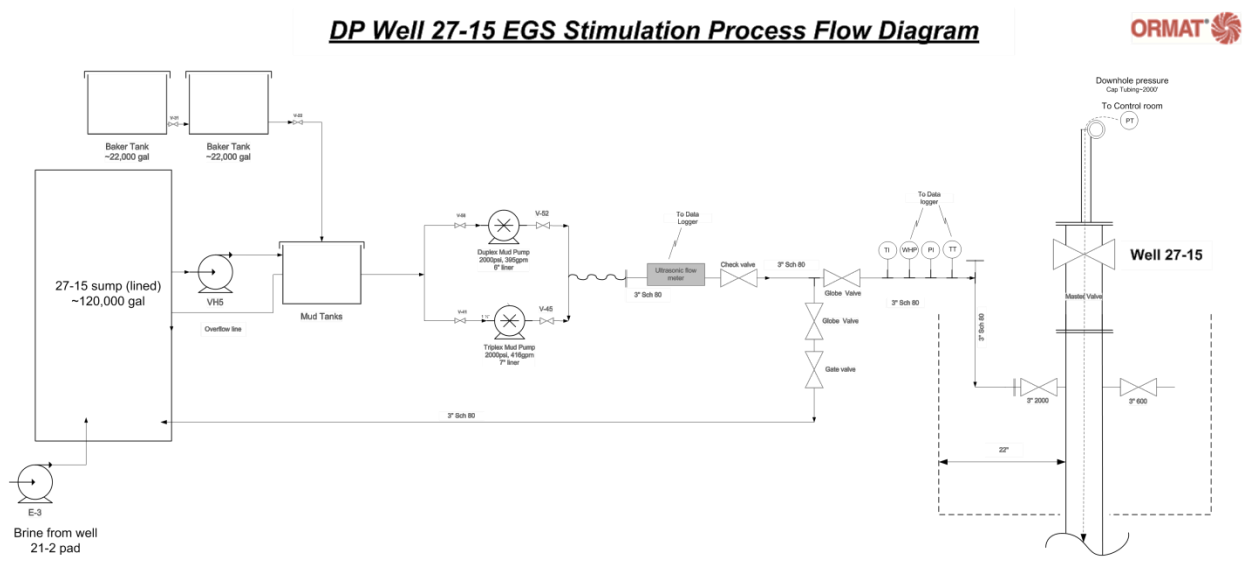

Figure 10. Process flow diagram for controlled hydraulic fracturing phase.

With the enhanced surface configuration in place, a two-step step-rate test at fluid pressures above S_{hmin} was conducted in order to determine whether or not the near-wellbore stress regime had been altered as a result of previous stimulation operations, and to observe the likely fluid egress points during hydraulic fracturing. Using cooling tower water from the power plant, the test commenced at an initial rate of 216 gpm and a wellhead injection pressure of approximately 900 psi. The rate was then increased to 316 gpm at a wellhead injection pressure of 950 psi with an injectivity of 0.32 gpm/psi. A PTS survey conducted during this test revealed the majority of the fluid exiting just below the casing shoe, in the measured depth interval from 3,030 to 3,107 feet. In this interval, fracture propagation pressures were measured between 900 to 950 psi and instantaneous shut-in pressures confirmed S_{hmin} to be approximately 750 psi at the wellhead, consistent with previous estimates by Hickman and Davatzes (2010).

Medium Flow-Rate Phase

Using the results from the preliminary step-rate test to guide the operational plan, the project team decided to begin the controlled hydraulic fracturing stimulation with a medium flow-rate phase. During this period, the flow rate was fixed at 500 gpm. At this point, the injection fluid had been switched to spent brine from the power plant in order to meet the high volumes of this phase of the stimulation.

Over the course of the medium flow-rate phase, the injectivity of well 27-15 increased from 0.32 gpm/psi to 0.52 gpm/psi and 33 MEQ events were detected within the project target area. Subsequent PTS surveys run during this period confirmed that approximately 70% of the fluid was exiting through the interval from 3,030 to 3,107 feet, with 30% exiting the wellbore below 3,250 feet, which was the same zone active throughout the shear stimulation. The increase in injectivity and dramatic increase in seismicity suggested that the newly-created fractures were allowing fluid pressures to reach previously un-stimulated parts of the formation, thereby inducing shear failure along pre-existing fractures. Data gathered throughout this operational period are presented in Figure 11 and Figure 12.

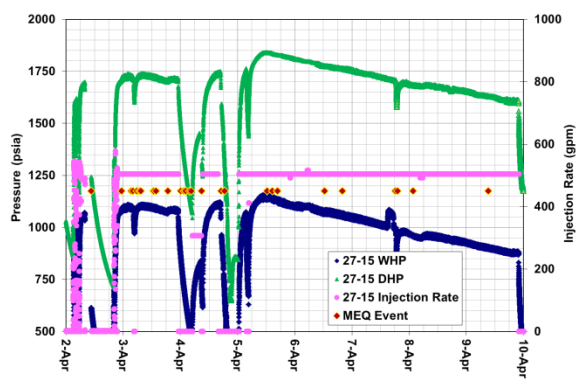

Figure 11. 27-15 wellhead and downhole pressures (WHP & DHP), injection rate, and located MEQ events during medium flow-rate hydraulic fracturing phase.

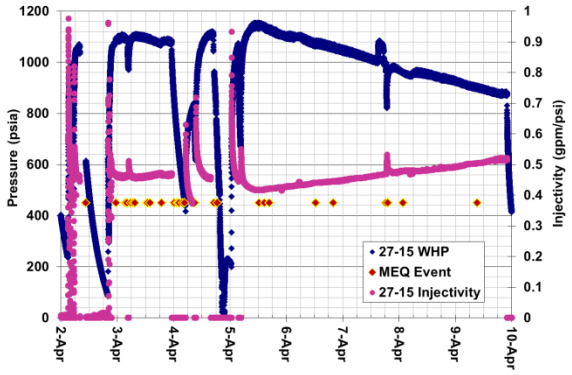

Figure 12. 27-15 wellhead pressure (WHP), calculated injectivity, and located MEQ events during medium flow-rate hydraulic fracturing phase.

High Flow-Rate Phase

Following the promising results of the medium flow-rate phase, the project team decided to transition into high flow-rate hydraulic fracturing phase, with the objective of injecting at the highest possible rate within the limitations of the pumps. During this 13-day phase high flow-rate phase, the injection rate increased from an initial value of 575 gpm to 725 gpm with the wellhead pressure dropping from 1,010 psi to 830 psi and a maximum calculated injectivity (during hydraulic fracture propagation) of 0.73 gpm/psi. Seven additional MEQ events were detected and located within the project target area. Data gathered throughout this operational period are presented in Figure 13 and Figure 14.

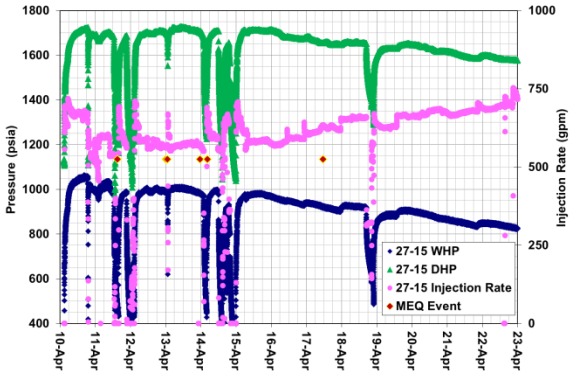

Figure 13. 27-15 wellhead and downhole pressures (WHP & DHP), injection rate, and located MEQ events during high flow-rate hydraulic fracturing phase.

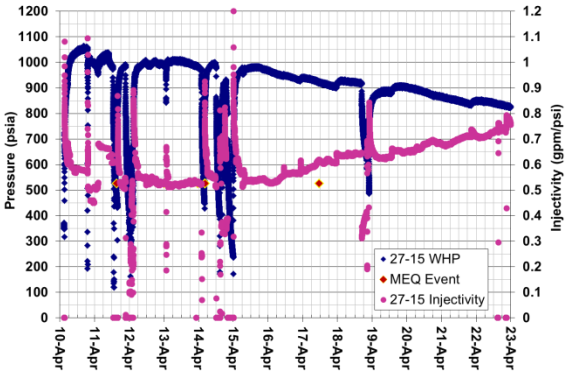

Figure 14. 27-15 wellhead pressure (WHP), calculated injectivity, and located MEQ events during high flow-rate hydraulic fracturing phase.

Several days after the high flow-rate phase was concluded, a step-rate test was conducted at wellhead injection pressures below S_{hmin} (approximately 750 psi) to verify whether or not the injectivity gains achieved throughout the hydraulic fracturing stimulation were permanent. The test was comprised of three steps at injection rates of 209 gpm, 265 gpm, and 321 gpm. Even at the highest rate during the test, the maximum wellhead pressure observed was approximately 450 psi, which is 300 psi below the fracture initiation pressure (or S_{hmin}). Additional PTS surveys conducted during the step-rate test re-confirmed that the majority of the fluid was exiting the wellbore at 3,070 feet with minor losses across the interval from 3,250 to 3,370 feet.

By the end of the test, the stabilized injectivity was estimated to be 0.63 gpm/psi – an additional 4-fold increase since the end of the shear stimulation phase. The fact that this result was achieved at pressures significantly below the fracture initiation pressure, suggests that self-propping shear failure in the formation was responsible for the persistent gains in permeability.

ASSESSMENT OF STIMULATION RESULTS

Microseismicity During Hydraulic Fracturing

A total of 42 MEQ events – with magnitudes ranging from 0.1 to 0.74 – were located within the project target area throughout the course of the controlled hydraulic fracturing phase. When plotted in the three-dimensional spatial context of the target area (Figure 15), the events appear to be clustered between 27-15 and the nearby injection wells (21-2 and 22-22) in the approximate depth range of the stimulated interval.

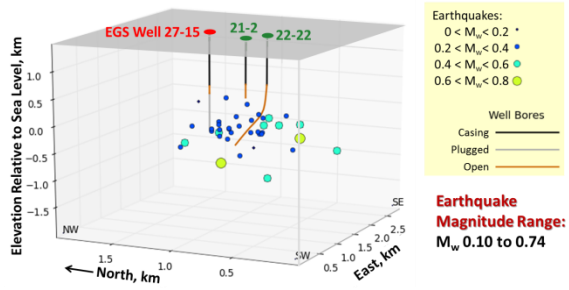

Figure 15. 3-D depiction of the 42 MEQ events detected during the controlled hydraulic fracturing phase.

A map-view representation of the relevant MEQ events in the target area – with the orientation of the maximum horizontal stress (S_{Hmax}) overlaid (Figure 16) – reveals the tendency of these MEQs to align with S_{Hmax} extending between 27-15 and the nearby injection and production wells in the Desert Peak field. While many events were locatable, poor focal sphere coverage made it difficult to derive the source mechanism and detect events smaller than magnitude $M_w < 0.2$ went undetected.

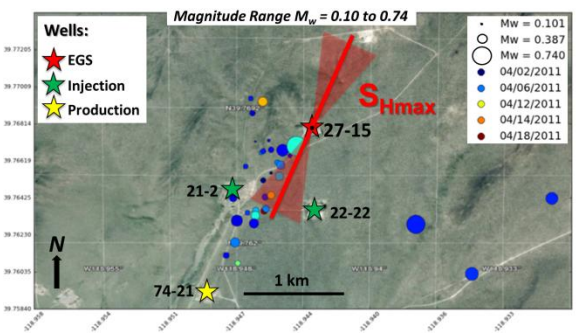

Figure 16. Map-view of MEQ events in Desert Peak target area with S_{Hmax} indicated.

Post-Stimulation Tracer Testing

Midway through the high flow-rate hydraulic fracturing phase, a second round of tracers was injected into well 27-15; this included 100 kg of the reactive tracer Safranin T (Saf-T) and 50 kg of the conservative tracer 1,6-naphthalene disulfonate (1,6-nds). Sample collection at the production wells was on-going several days prior to the tracer injection to establish a new baseline profile and continued at regular intervals throughout the hydraulic fracturing phase. Concentration profiles of the various tracer constituents are plotted in Figure 17 with respect to the elapsed time since their injection.

Results of the tracer study show relatively large concentrations of the fluorescein tracer – originally injected during the shear stimulation phase on September 30, 2010 – appearing at the production well 74-21. This suggests that much of the tracer was still residing in the formation and continuing to be flushed from 27-15 towards 74-21. The higher concentrations of fluorescein observed during the hydraulic fracturing stage (as compared to those observed during the shear stimulation phase; see Figure 9) indicate that the hydraulic connectivity between the two wells was significantly enhanced. Moreover, the rapid breakthrough of the conservative tracer 1,6-nds approximately 4 days after injection also supports this conclusion.

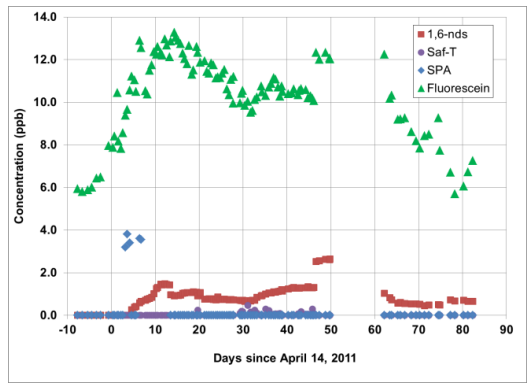

Figure 17. Tracer concentrations at well 74-21.

Another interesting observation in the tracer results is the early presence of the chelating agent SPA. Although there were no immediate or lasting improvements in injectivity observed during the chemical stimulation phase, it is possible that significant mineral dissolution may have occurred as permeable pathways to the production well 74-21 were created during the hydraulic fracture stage. Aside from trace amounts, the reactive tracer Saf-T was absent from the samples collected at well 74-21. Periodic sampling efforts have continued at well 74-21 throughout 2011, with an estimated recovery of 17% of the 1,6-nds and 14.5% of the fluorescein.

Post-Stimulation Commercial Testing

As part of the post-stimulation procedure, an injection test was conducted in order to determine whether or not well 27-15 was commercially acceptable. The three-day test commenced at an initial rate of 500 gpm and a wellhead injection pressure of approximately 750 psi. The injection rate was gradually increased to 550 gpm while the wellhead pressure remained the same (~750 psi). Injectivity eventually stabilized at 0.63 gpm/psi, re-confirming the permeability gains achieved during the controlled hydraulic fracturing phase. Ultimately, the incremental parasitic pump load required to maintain injection determines whether or not an injection well is an asset to the overall operation. In this case, the project team recognized that additional stimulation work on well 27-15 would be required in order to achieve commercial acceptability.

LESSONS LEARNED

As one of the key objectives of the Desert Peak EGS demonstration, the project team developed and executed a site-specific stimulation plan which consciously emphasized both practical and cost-effective techniques that would be applicable to other project settings. By the end of the hydraulic fracturing phase, the stimulation achieved nearly a 60-fold increase in injectivity in 27-15 – an encouraging result for both the operator and the project team. While the performance of the well fell just short of commercial acceptability, a number of valuable lessons were learned over the course of the EGS demonstration.

Consensus was reached among the project team that the shear stimulation was an effective first step in catalyzing the subsequent progress of the hydraulic fracturing phase. It was during the shear stimulation phase that the injectivity of well 27-15 increased by more than an order of magnitude (from ~0.01 gpm/psi to ~0.15 gpm/psi) and allowed the stimulation front to propagate beyond the immediate near-wellbore region. In retrospect, however, it was noted that much of the progress during the shear stimulation operations was realized early in the process rather than later. Therefore, a shear stimulation phase with shorter duration steps and with most of the stimulation carried out at the higher injection pressures (but still $< S_{hmin}$) may have been equally as effective and certainly less demanding with regards to operational time and resources.

Although the benefits of the chemical stimulation were difficult to quantify in terms of injectivity gains, the project team recognized that this approach may have been more beneficial as a means of permeability enhancement rather than a primary stimulation technique. In other words, implementing the chemical treatment after achieving significant gains in permeability may have allowed the agents to propagate into the formation more effectively rather than being concentrated in the near wellbore region. This, in turn, may have reduced the possibility of wellbore instability issues, which resulted in additional workover costs.

Real-time observation of MEQ events proved to be a valuable qualitative tool with which to validate the progress of the stimulation. The project team recognized, however, several areas for development in order to enhance the overall value of the system during future stimulation campaigns. First, the location of the geophones required further optimization with respect to the stimulation target and possible sources of noise. Second, excessive surface noise observed throughout the operations highlighted the need for more geophones to be deployed below the ground surface in dedicated boreholes. Finally, the detection algorithm would need to be further refined in order to filter false triggers more effectively and identify small events ($M_w < 0$) generated by the stimulation. Such improvements are needed to track the growth of the stimulated volume and adjust stimulation parameters in real time to obtain the optimal result.

One additional piece of anecdotal information from the Desert Peak operations underscores the tangible benefits of the EGS stimulation of well 27-15. During the hydraulic fracturing phase – when spent brine was being routed from the power plant to well 27-15 in order to maintain the high injection rates – the gross output of the Desert Peak power plant increased by approximately 1.5 MW. While this is only a transient observation during a portion of the stimulation operations, it demonstrates a measure of success in the other stated goal of the project: to improve the overall power production in the Desert Peak field.

In summary, the EGS operations carried out at Desert Peak have demonstrated a variety of practical and cost-effective stimulation techniques, which makes them readily transferrable to most project settings. Results of the operations have shown dramatically improved performance in well 27-15 and increased its connectivity to other wells in the reservoir. Finally, the temporary increase in power output noted during one phase of the operation reinforces the benefits that additional EGS stimulation operations in the Desert Peak Geothermal Field may yield.

ADDITIONAL STIMULATION PLANS

Following the encouraging results and lessons learned during this initial stimulation campaign, the project team has since devised and implemented several additional measures. A substantial effort was made to improve the sensitivity of the microseismic array, which included the drilling of several dedicated boreholes and modifications to the real-time detection algorithm. Finally, in late 2011, after additional modifications to the surface equipment configuration, a high flow-rate pulse stimulation was conducted. With injection rates reaching nearly 1,100 gpm, the goal of this most recent activity was to aggressively propagate fractures into previously un-stimulated portions of the reservoir over a short time frame.

Results of these subsequent activities are still being evaluated in conjunction with prior operations at 27-15. Findings from this investigation are already influencing the plans of another DOE-supported EGS

stimulation project at the nearby Bradys Hot Springs geothermal field, also operated by Ormat Nevada, Inc. In the meantime, Ormat Nevada Inc. and the Desert Peak EGS project team are continuing to work with the U.S. Department of Energy to develop a follow-up stimulation plan for Desert Peak in 2012.

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