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Near-Field EGS: A Review and Comparison of the EGS Demonstration Projects at Desert Peak and Bradys

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ABSTRACT

Two US Department of Energy (DOE) Geothermal Technologies Office (GTO) Enhanced Geothermal Systems (EGS) demonstration project grants were awarded to Ormat Technologies, Inc. to evaluate the feasibility of EGS development in the Basin and Range geomorphic province. These projects focused on stimulating a non-commercial well on the periphery of the operating conventional geothermal system with the goal to evaluate characterization tools and methodologies, stimulation technologies, and ultimately improve the permeability enough to connect the well to the existing power plant. The first of these projects, Desert Peak, formed a stimulation road map that was followed at the second project, Bradys. These steps included detailing the lithologies and ambient stress field, developing a robust microseismic monitoring network, pre-stimulation permeability testing, implementing zonal isolation, and finally designing the optimal stimulation plan. Following the successful result of a 1.7 MW increase at the Desert Peak facility with new injection to the stimulated well 27-15, the stimulation at Bradys 15-12 resulted in lower than expected permeability increase. Each project, though with differing levels of success, have contributed tools, techniques, and analysis that will inform EGS projects going forward, including the FORGE project at Milford, Utah. Lessons can be learned from reviewing the types of data collected prior to the stimulation activities, the stimulation plan, and exploring why the results at Brady were different from those at Desert Peak.

1. INTRODUCTION

Ormat Technologies, Inc. was awarded the “Desert Peak East Enhanced Geothermal Systems (EGS) Project” by the US Department of Energy (DOE) in 2002 and the “Feasibility of Enhanced Geothermal Systems (EGS) Development at Bradys Hot Springs, Nevada” in 2008. These two EGS demonstration projects focused on developing new technologies to reduce stimulation costs while utilizing unproductive wells adjacent to the operating conventional geothermal system.

To evaluate the feasibility of EGS development in the Basin and Range geologic province, Desert Peak well 27-15 was selected as the stimulation candidate. Stimulating 27-15 focused 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 (Zemach, 2010).

Prior to stimulation of Desert Peak 27-15, the Bradys EGS project was awarded with well 15-12 being the stimulation candidate. Both projects proceeded with a detailed, integrated study of fluid flow, fracturing, stress and rock mechanics (Chabora, 2012). The studies were a collaborative effort led by Ormat Nevada, Inc. (Ormat) and included the following primary technical team:

- University of Nevada, Reno (UNR), for geological analyses, including structural assessment and 3D modeling, with support from the GeoForschungsZentrum (GFZ) in Potsdam, Germany;
- TerraTek, for analyses of mechanical and hydraulic properties of cores samples and petrological / mineralogical analyses of samples from cores and cuttings;
- The Energy and Geoscience Institute (EGI) at the University of Utah, for laboratory analyses of cores and cuttings and high-temperature reactor experiments to identify the best chemical stimulation agents;
- US Geological Survey (USGS) and Temple University, for new wellbore image logging with a high-temperature borehole televiewer (with Sandia National Laboratories, see below), and subsequent analyses of stress field and characterization of natural fractures;
- GeoMechanics International (GMI), for analysis of an existing wellbore image log and integration with more recent (USGS) wellbore image logging results for characterization of natural fractures, analyses of stress field, and creating a geomechanical model;
- Lawrence Berkeley National Laboratory (LBNL), for installation and operation of a seismic monitoring network; and
- GeothermEx, Inc. (GeothermEx), which supported the overall effort via various technical analyses, data integration, stimulation coordination and planning support, and field work during logging, injection testing and stimulations.

Additional cooperating research groups and individual consultants supported the projects:

- Bestec GmbH (Bestec) of Germany (Dr. Jörg Baumgärtner and Dimitra Teza), a team that has led the development of several EGS project in Europe (including Landau and Insheim in Germany);
- Dr. Roy Baria, who has participated in EGS R&D since the late 1970s, and was one of three team leaders of the Soultz-sous-Forêts EGS project in France;

- Hi-Q Geophysics (Hi-Q), which used seismic data to characterize geology and fractures;
- UNR reservoir modelers (Dr. George Danko and Stefano Benato), who developed an analytic-adaptive model of the Bradys field;
- Researchers from Los Alamos National Laboratories (LANL), who developed a numerical fracture network model to simulate changes in fluid flow in response to hydraulic stimulation at Bradys (Dr. Lianjie Huang and Dr. Sharad Kelkar);
- National Energy Technology Laboratory (NETL), which was undertaking work on modeling EGS fracture networks generally, and developed a fracture network model for Bradys, as well as characterizing core samples from BCH-3 using thin sections, X-Ray Diffraction (XRD) analyses, Computerized Axial Tomography (CT) analyses, porosity and permeability measurements, and measurements of seismic velocities (P- and S-wave velocities, or Vp and Vs) and their relationship to measured porosity;
- Temple University (Dr. Nick Davatzes), who initiated coupled analyses of InSAR and seismic data in support of EGS reservoir development (noting that well 15-12 ST1 is in a relatively un-depleted portion of the reservoir); and
- Sandia National Laboratories (SNL), which provided the tool, logging truck and personnel to run the high-temperature borehole televiewer.

An EGS stimulation plan, novel well completion, and monitoring network were designed for Desert Peak 27-15. Following years of study and analysis, a series of stimulation activities were carried out with the successful result of connecting the well to the operating reservoir. The EGS stimulation of Bradys 15-12 was conducted in consideration of the results and planning of the EGS stimulation of Desert Peak 27-15. The earlier successful stimulation of Desert Peak 27-15 informed and set the expectations for the Bradys 15-12 stimulation. However, the stimulation at 15-12 ultimately did not create a permanent connection to the operating reservoir at Bradys.

2. DESERT PEAK PROJECT SUMMARY

Desert Peak was chosen because of the existing operational infrastructure, an accessible resource database, reasonably well-known geological conditions, and available wells. Well DP 23-1 was initially selected to fracture and develop well connections in a low permeability eastern margin of the existing Desert Peak 15 MW geothermal development. The mechanical condition of DP23-1 prevented recompletion, so well DP 27-15 was selected as an alternate stimulation candidate. 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 Desert Peak field.

2.1 Description of the Desert Peak Geologic Setting

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. The Desert Peak area is one of several geothermal areas in the region. Others include Bradys Hot Springs, Stillwater, Soda Lake, and Dixie Valley; geothermal power plants are operating at all of these areas (Figure 1). The fields lie within the Humboldt structural zone, a region of high heat flow characterized by ENE- to NNE-striking fault zones (Zemach, 2010).

There are no surface thermal indications at the Desert Peak geothermal area, other than a few small occurrences of opal-cemented sand and travertine, probably from springs that are now inactive. The Desert Peak power plant taps a blind geothermal reservoir located about 3 miles southeast of Bradys Hot Springs. Geochemical and subsurface temperature data suggest that the Bradys and Desert Peak projects are associated with essentially independent thermal plumes (Benoit, 1982).

The youngest unit in the Desert Peak area is Quaternary alluvium, which consists of sands, playa deposits and Lake Lahontan sediments. The uppermost Tertiary rocks (Pliocene age) consist of an unnamed unit (andesitic tuff and basalt flow), the Truckee Formation (river and lake sediments and tuffs) and the Desert Peak Formation (similar lithologies to those in the Truckee Formation). These units are underlain by andesite and basalt lavas, agglomerates, air-fall tuffs and water-lain tuffs and shales of the Miocene-Pliocene Chloropagus Formation. The oldest Tertiary rocks encountered in the Desert Peak area consist of an unnamed late Oligocene rhyolitic volcanic sequence of inter-bedded welded tuffs, ashfall deposits, lava flows, and volcanic sediments (Benoit et al., 1982). Referred to herein as the Rhyolite Unit, this unit is about 2,500 feet (780 m) thick, and its upper part forms the cap rock for the Desert Peak hydrothermal system. Hydrothermal production is obtained from fractured zones in the lower portion of the rhyolite unit, and from a greenstone (metamorphosed basalt) in the underlying pre-Tertiary metamorphic rocks.

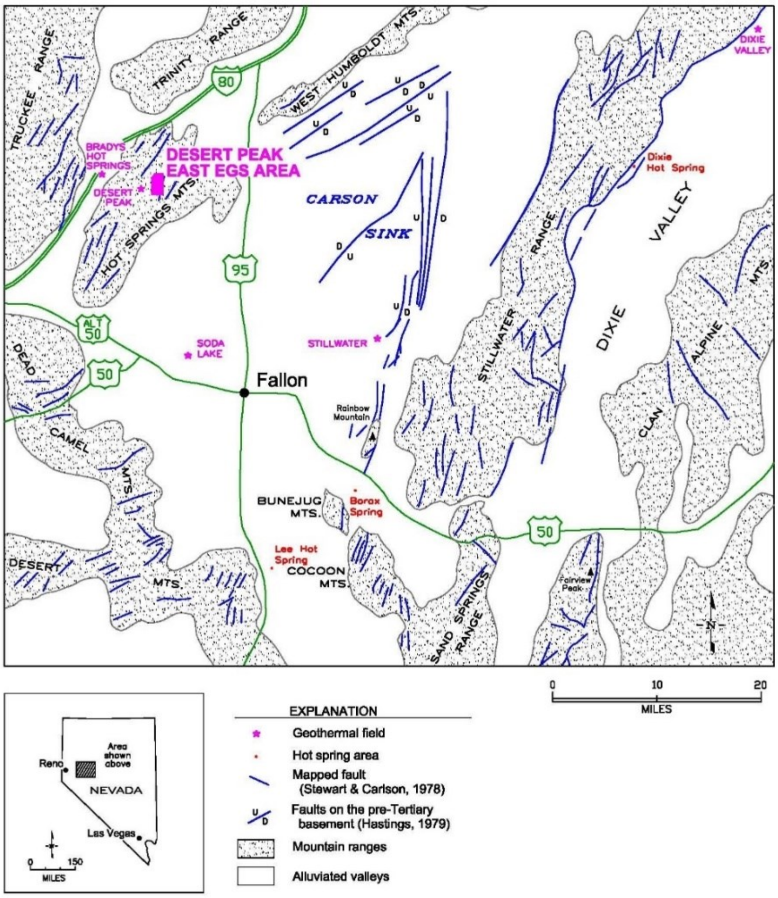

Figure 1: Location of the Desert Peak and Bradys EGS areas.

2.2 Data Collection and Analysis

A series of tasks were designed to achieve the goal of critically evaluating well 27-15 as a stimulation candidate. These included:

- seismic network improvement and calibration in preparation for seismic monitoring during stimulation(s);
- tracer testing using the existing injection wells to understand fluid flow paths within the hydrothermal reservoir;
- geochemical sampling to evaluate baseline reservoir liquid and gas compositions for comparison of pre- and post-stimulation conditions, evaluate the potential for mineral precipitation and dissolution, and assess fracture spacing and active surface area using isotope methods;
- evaluating historical generation, production and injection data from the field to establish baseline conditions against which post-stimulation conditions can be compared;
- evaluating existing geophysical data, most importantly a 2002 CSAMT/MT survey to help determine subsurface geologic structure;
- collection and evaluation of wellbore image logs and temperature-pressure-spinner logs to characterize the stress field and identify permeable fractures;
- conducting a pressure transient test to evaluate the hydraulic connection between well 27-15 and others in the field;
- conducting, processing and interpreting a 2-D seismic reflection survey to better understand the structural position of well 27-15 relative to the active part of the field to the south;
- developing a conceptual model of the geologic structure of the field to guide decisions about stimulating well 27-15, and to evaluate possible outcomes.

The comprehensive analysis identified pre-existing fractures within lithologies favorable for stimulation and oriented for slip upon increase in pore pressure (Zemach, 2010). A complex intersection of faults, when stimulated, would provide a hydraulic pathway south towards the existing reservoir.

A more extensive discussion of each of these can be found in Zemach et al. (2010), from which the two of the most important analyses are summarized below.

2.2.1 MEQ Monitoring

Seismic monitoring identifies the background deformation and ambient stress/strain in and adjacent to an EGS area. Once EGS stimulation is attempted, the monitoring array can detect and map the progress of fracturing and the interconnection between fractures that enhance permeability within a previously impermeable body of rock (Majer, 2007). Fourteen micro-seismic monitoring stations were installed by Lawrence Berkeley National Laboratory (LBNL) and the U.S. Geologic Survey (USGS) to provide real-time monitoring and processing of MEQ events prior to and during the stimulation activities (Chabora, 2012).

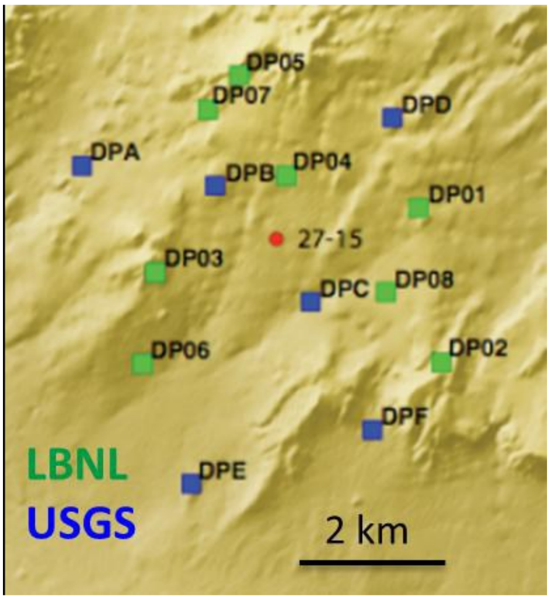

Figure 2: Desert Peak seismic array from Chabora 2012.

2.2.2 Stress Analysis

Preparing for stimulation and development of an EGS well requires a complete characterization of borehole geology, hydrology, and stress state (Davatzes et al., 2006). Elements of this evaluation include analysis of stress orientation and magnitude and the natural geologic characteristics including fractures/faults, primary structure including bedding/foliation and formation contacts, and rock properties in and around the wellbore. These data are used to determine formation characteristics including the distribution of permeability, lithologic variations and mechanical rock properties, and to characterize the existing natural fracture population and its tendency to slip during stimulation. A complete suite of geophysical logs was acquired for structural and stress analysis of well 27-15 in preparation for stimulation. These logs included image logs to characterize natural fractures and stress-induced borehole failure, 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 Technologies ABI85 Borehole Televiewer logs and Schlumberger Formation MicroScanner (FMS) image logs revealed extensive tensile fractures showing that the minimum compressive horizontal stress, S_{Hmin}, in the vicinity of well 27-15 is oriented 114 ± 17° with a magnitude of 1995 ± 60 psi (Davatzes, 2009).

2.4 Outline of Desert Peak EGS Activities

The stimulation activities for the Desert Peak EGS project included:

- Shear Stimulation: WHP<750 psi, Flow rate 115gpm
- Chemical Stimulation: WHP<750 psi, Flow rate 115gpm
- Controlled Hydro-Shear: WHP<1100psi, Flow rate ~850gpm
- Pulse stimulation: WHP<1,350psi, Flow Rate ~1,200gpm
- Two Stage stimulation: WHP<1,350psi, Flow Rate ~1,500gpm
- Long-term injection test

The shear stimulation through the pulse stimulation actions are thoroughly detailed in Chabora (2012), so additional descriptions are not included here.

The 2010-2011 stimulation activities in well 27-15 increased the open interval 3,035-3,500 feet injectivity by 57-fold (from 0.012gpm/psi to 0.8 gpm/psi). An in-depth analysis led the team to believe that further stimulation efforts in this zone would result in very modest gain in injectivity which doesn't fit with the project injectivity target. As a result, it was decided to isolate the lower portion of the well and conduct multi-zone stimulation from 3,035 feet to total depth (TD). Over November-December 2012, Ormat recompleted well 27-15 as part of preparation for a multi-zone stimulation. A 9-5/8" liner was run from 3,007 feet KB to TD with perforations in the desired zones. High-temperature, open hole swell packers were utilized to achieve annular isolation between the zones of interest. A stab-in float collar was installed above the deeper zone to allow isolation in stimulating the intermediate zone 3,035 to 5,586 feet, and the toe zone from 5,586 feet to TD (Figure 3). This method of stimulation has been patented under US Patent No. 9482082.

Following the well recompletion, well 27-15 was stimulated in January 2013 consisting of five steps:

1. Toe zone: injecting at 12bbl/min @ WHP 1500psi for 12hrs.
2. Intermediate zone: Injecting 24BBL/min @ WHP 670psi for 12hrs.
3. Both zones simultaneously: Injecting at 12BBL/min @ WHP_{toe} ~600psi and $WHP_{Intermediate}$ 1700psi for 12hrs.
4. Intermediate Zone: Injecting 28BBL/min @ WHP ~680psi for 12hrs.
5. Intermediate zone: Injecting 38BBL/min @ WHP ~780psi for 4hrs, flow was reduced to 28BBL/min @ WHP ~ 670psi for 8hrs

Over the course of this stimulation, 94 MEQ events, magnitude ranges Mw= -0.026–1.6, located in the vicinity of well 27-15, locations consistent with stress-field model.

In order to quantify the gain in injectivity, a long-term injection test was conducted lasting for 29 days. Three flow rates where used, 340gpm, 550gpm and 860gpm to determine the well injectivity. Tracer was also injected at the beginning of the test. A total of volume of 7.5 Mgal was injected throughout the test, and a total of 118 MEQ events were recorded through the week after the test. The event locations were consistent with the stress-field model, with magnitudes in the range Mw = -0.026 – 1.7. Tracer samples were collected on a daily basis from well 74-21, the nearest production well. Tracer returns were detected after 40 days.

The following table summarizes the Desert Peak 27-15 stimulation activities, showing the injection rates, wellhead pressures, and resulting injectivity. Over the course of all stimulation stages a max flow rate of 1,600gpm was achieved and the overall injectivity was increased by 175-fold, exceeding the project goal. It is assumed that all three zones, upper zone 3,035-3,500 feet, ~4,500 feet and toe zone were stimulated successfully. A total of 303 MEQ events were recorded throughout the stimulation stages. The event locations are consistent with the stress-field and in conjunction with the tracer analysis indicate a connection between the EGS well 27-15 and the main field (Figure 4).

Activity	**Duration**	**Injection rate (GPM)**	**WHP (PSI)**	**Injectivity (GPM/PSI)**	**Targeted Injectivity (GPM/PSI)**
Starting Point	8/1/10	<4	>450	0.012	- -
Shear stimulation	8/1/10- 2/10/11	~100	550	0.15	0.5
Chemical stimulation	2/10/11- 2/17/11	~75	550	0.05-0.15	0.5
Controlled hydro Shear **– Medium flow rate**	4/1/11- 4/10/11	550	1,000	0.52	0.7
Controlled hydro Shear **– High flow rate**	4/10/11- 4/23/11	735	835	0.73	0.7
Pulse Stimulation	10/26/11- 10/29/11	1,000	1,200	0.8	1.0
High Flow Rate Stimulation	1/16/13- 1/20/13	1,600	700	2.1	1.0
Post-high-flow rate hydro Shear conditions	**16/2/13-** **3/18/13**	**300-860**	**415**	**2.1**	**1.0**

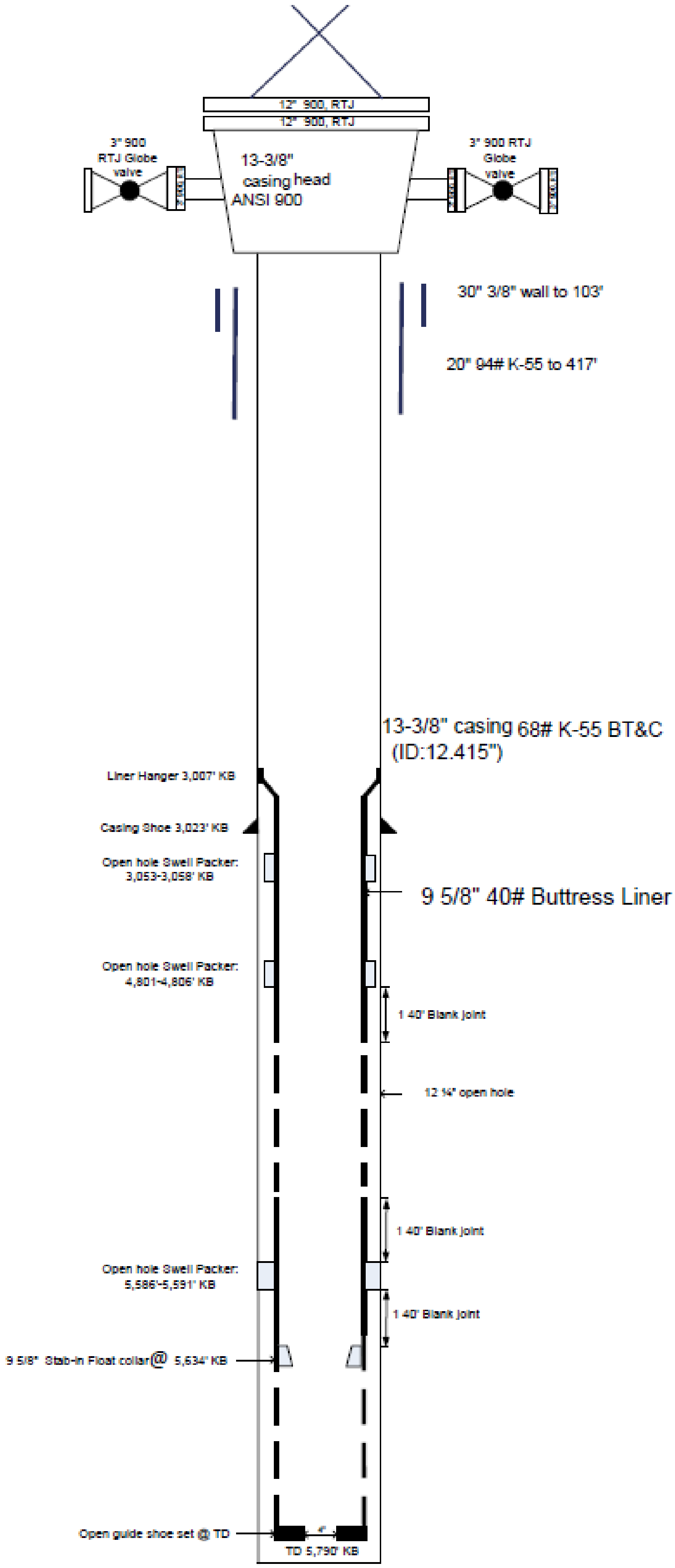

Figure 3: Desert Peak 27-15 well recompletion for zonal isolation.

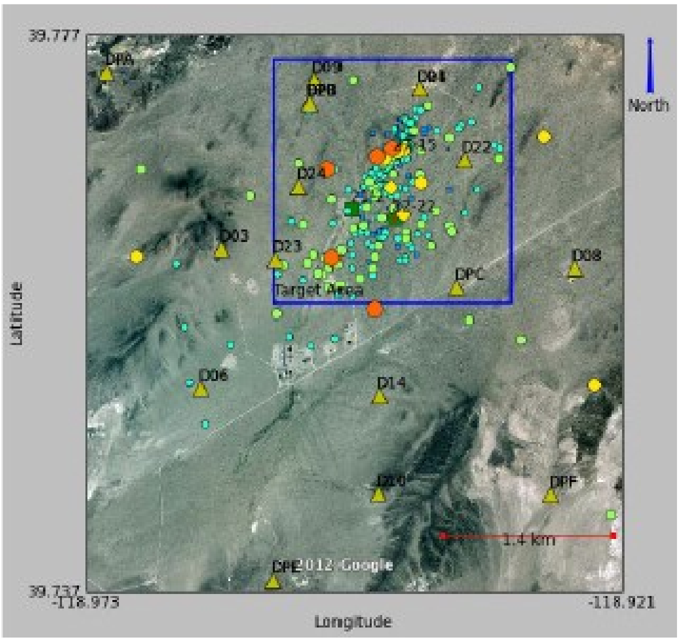

Figure 4: Desert Peak MEQ events throughout all stimulation activities.

3. BRADYS PROJECT SUMMARY

The Bradys EGS project focused on utilizing EGS technology to improve permeability in an existing non-productive well (15-12 ST1, located on BLM land) at Ormat's Bradys geothermal facility in Churchill County, Nevada. The Bradys geothermal field is located within the Hot Springs Mountains, approximately 50 miles northeast of Reno, NV, and also lies within the Carson Sink. The Bradys geothermal field has been producing power since 1992. In most of the Bradys wells, permeability is associated with the NNE-striking Bradys Fault Zone, which consists of a main fault and various splays and parallel faults. The primary injection wells to the north are hydraulically connected with the production zone, providing pressure support yet also causing temperature decline. Well 15-12 is located in the southern part of the field (Figure 5).

3.1 Description of the Bradys Geologic Setting

The stratigraphy of the Bradys geothermal field consists of a Mesozoic metamorphic and plutonic basement covered with Cenozoic volcanic and sedimentary sequences. The geothermal reservoir is located at a depth of 600m – 1500m below the surface and lies within the Oligocene ash-flow tuffs and Miocene lava flow formations (Jolie 2015). The Bradys fault zone runs approximately 10 km, striking NNE and dipping 60°-80° to the NW. This has been mapped extensively by Faulds and Garside (2003) and Jolie (2015) and from 2D seismic reflection surveys. The fault step-over accommodates multiple minor faults connecting the major overlapping fault segments (Faulds 2006). This yields active geothermal surface manifestations (fumaroles, steaming grounds, and alteration) over a nearly 300 m broad area (Jolie 2015).

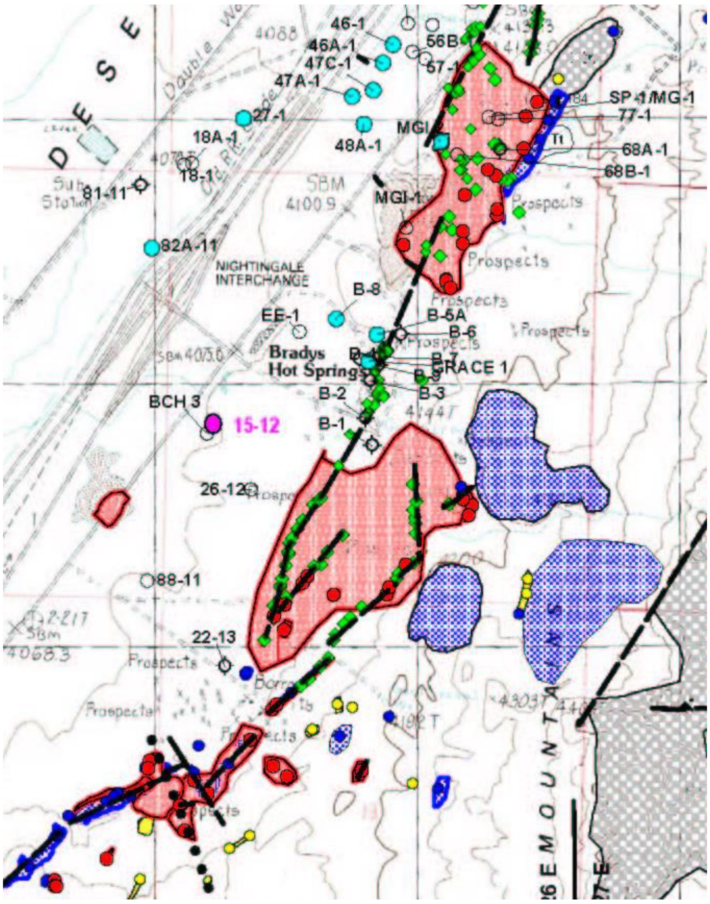

Figure 5: Bradys well locations, primary faults, and thermal features (red = silicic alteration, blue = calcareous alteration, yellow = argillic alteration, green = steam vents). Stimulation target well 15-12 is labeled in pink. Offset core hole BCH-3 is also shown.

3.2 Data Collection and Analysis

Built upon the studies completed ahead of the Desert Peak 27-15 stimulation activities, the following technical analyses were performed to assess the geomechanical properties and stimulation feasibility of Bradys 15-12:

- Temperature-pressure-spinner (TPS) surveys and a baseline step-rate injection test (conducted in November 2011) to:
    - measure static reservoir conditions (maximum temperature ~400°F at 5,000 feet; hydrostatic pressure gradient below a static water level at ~120 feet);
    - establish baseline injectivity (~0.05 gpm/psi at injection rates less than 84 gpm and 13.5 gpm/psi at higher injection rates, suggesting that the fracture propagation pressure began to be exceeded when the injection rate exceeded 84 gpm, resulting in 880 psi of over-pressure relative to static conditions; see Figure 1.2 below);
    - estimate permeability thickness by pressure transient analysis (630 md-ft); and
    - identify the main intervals accepting the injected fluid (4,450 to 4,600 feet).
- Geologic modeling to integrate relevant data, evaluate controls on permeability, characterize fluid flow, and assess the extent and character of the Bradys reservoir. This work concluded that permeability is associated with the complex NNE-striking Bradys Fault Zone. The main upflow of the hydrothermal system is associated with the horst-bounding faults.
- X-ray powder diffraction (XRD) analyses for petrologic and mineral evaluation of cuttings and cores and mechanical testing of cores to refine stratigraphy, identify zones of hydrothermal alteration and correlate changes in alteration with geologic features (contacts, faults), and characterize the target Mesozoic basement rocks in terms of their composition, fracturing, veining, thermal expansion coefficients, and mechanical properties (from scratch tests and triaxial testing).
- Laboratory analyses of cores and cuttings to support the development of a chemical stimulation plan. This work used 24 samples taken from BCH-3 cores, located on the same well pad as 15-12, in the planned stimulation depth interval for optical microscopy, QEMSCAN® analysis, and XRD analysis.

- Collection of a new wellbore image log (using the Sandia ABI 85 Borehole Televiewer) to identify and characterize fractures and support the development of a geomechanical model, with input to S_{hmin} and S_{Hmax} from the results of injection testing conducted in November 2011.

- Analysis of an existing wellbore image (FMI) log and development of a geomechanical model to characterize the fracture population, determine the pore pressures required for shear stimulation and identify the orientation(s) of fractures likely to experience shear failure in response to the pore pressure increase. This utilized a number of data (drilling records, TPS logs, geophysical logs, wellbore image logs, injection test data, rock densities and mechanical properties), and considered two different cases with reasonable lower and upper bounds on the minimum and maximum horizontal stresses (S_{hmin} and S_{Hmax}). The magnitude of S_{Hmax} is poorly constrained by the available data, the primary conclusions were that:
    - If their cohesive strength is low, there is a sufficient number of well-oriented fractures to allow shear stimulation using a pressure less than that required to propagate a hydraulic fracture.
    - If cohesive strength is higher (e.g., consistent with the upper range of residual strengths measured by TerraTek), then improving transmissivity by shear stimulation of pre-existing natural fractures at a pressure below Shmin is unlikely to occur across a widespread area.
    - Shear stimulation could be possible at a lower pressure if SHmax is larger (relative to the vertical stress Sv) than if it is smaller (e.g., close to or less than Sv).

- Developing and monitoring a seismic array to locate microearthquakes occurring before, during and after stimulation activities. The array consisted of 5 borehole stations and 3 surface stations centered on well 15-12.

- Evaluating the lessons learned from hydraulic stimulations at Desert Peak:
    - Early in the shear stimulation of well 27-15 at Desert Peak, injectivity increased by an order of magnitude; however, the stimulation went on far longer, without much gain. Therefore, for the Bradys stimulation, the plan called for shorter duration stimulation steps with most steps at higher pressure (but still less than S_{hmin}) to achieve similar results more quickly and at lower cost.
    - The detection threshold for the seismic monitoring array should be at least M = -1, and preferably -2, meaning that borehole stations are needed at Bradys (five 300-foot holes were drilled and instrumented with seismometers at Bradys).
    - For Desert Peak well 27-15, the stimulation plan included a chemical stimulation to help dissolve vein fillings in fractures followed by hydraulic stimulation. The chemical stimulation consisted of injecting an acidic chelating agent, followed by a mud acid treatment, which resulted in wellbore instability and sloughing (a clean-out was required). It was decided to reverse the treatment order at Bradys (hydraulic stimulation followed by chemical stimulation) to increase the effectiveness of the chemical stimulation (getting the chemicals further out into the fracture network) and reduce the likelihood of wellbore instability (although this was expected to be less of a problem at Bradys because the stimulation target zone is in basement rock rather than Tertiary volcanics, as was the case at Desert Peak).

3.3 Zonal Isolation for Bradys 15-12

A review of the hydrofracturing stimulation technologies used in oilfield applications was conducted by Ormat after the technical review was complete and the original stimulation plan was drafted. The multi-stage approach that is commonly used in tight-rock (shale) oil and gas wells was reviewed and determined to be applicable to well 15-12. This would allow hydrofracturing stimulation throughout the completion interval (4,245 – 5,096) by using zonal isolation technology, because of the reasonable concern only the zone from 4,640 feet to 4,800 feet (as indicated from the mini-frac) would be stimulated if the hydrofracturing was conducted in the full open-hole interval. Three intervals were chosen to stimulate: 4,255 to 4,414 feet, 4,414 to 4,750 feet, and 4,750 feet to TD. These intervals were chosen to isolate like lithologies and physical properties as much as possible while also containing identified natural fractures.

Various approaches for multi-stage stimulation were considered. One of the concerns was the reliability of packers (swell packers, inflatable or mechanical packer membranes) at high temperatures and in response to thermal cycling during the stimulation. After evaluating vendor responses to inquiries about high-temperature testing, the PackersPlus system was selected (Figure 6). The PackersPlus system allows for a ‘continuous pumping’ approach. The completion provides zonal isolation by using a series of 11-inch isolation packer assemblies (each combining two 1-foot mechanical set packers, and a 3-foot swell packer). Each stimulation stage is accessed through a ‘fracport,’ which is a sliding-sleeve completion section that can be either opened or closed, controlling access to each stage of the stimulation.

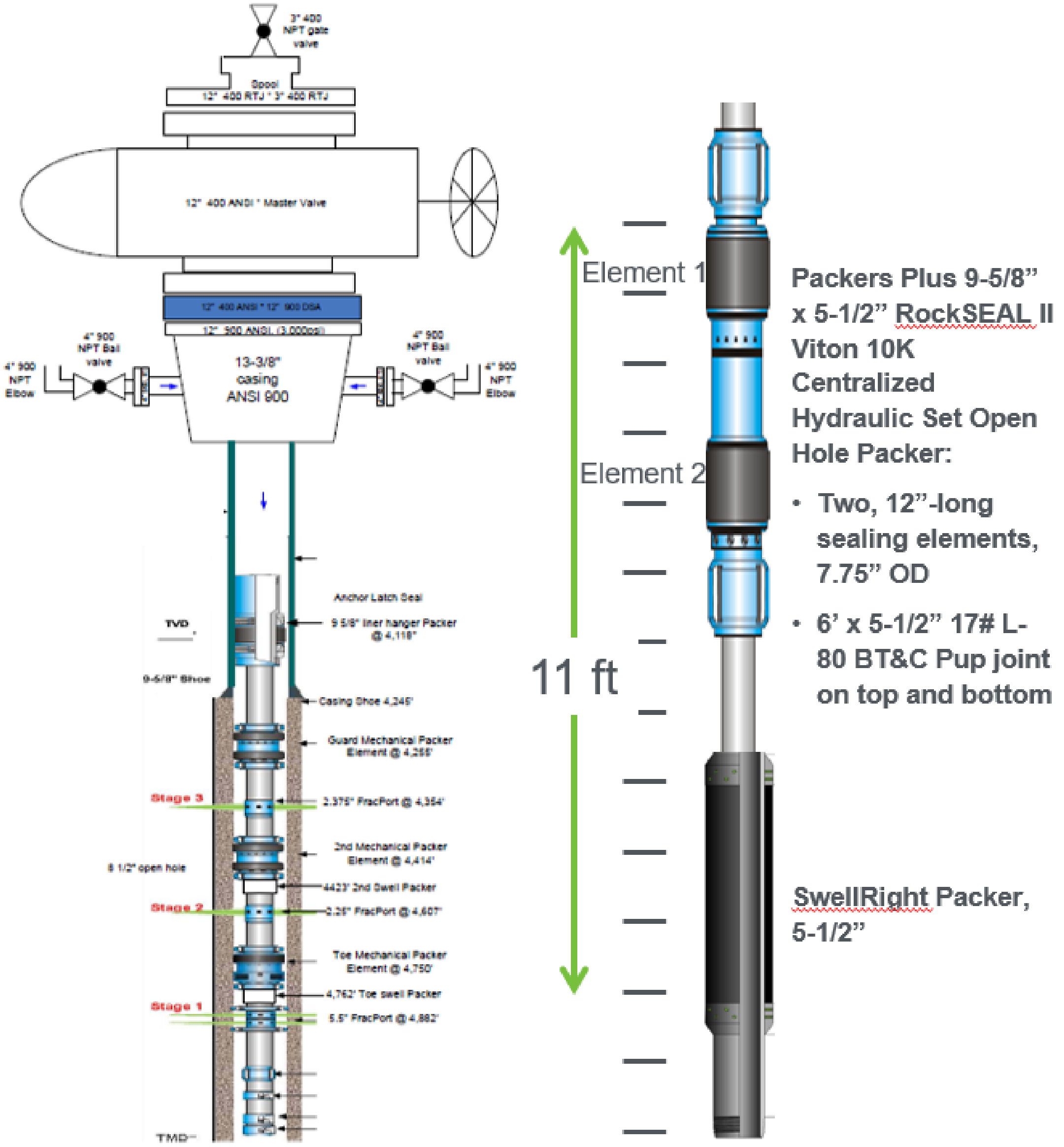

Figure 6: Bradys 15-12 zonal isolation well recompletion.

3.4 Outline of Bradys EGS Activities

There were four primary components to the well 15-12 stimulation plan:

- Pre-conditioning (shear stimulation) – Stage 1
- Multi-stage stimulation (hydro-fracture) – Stage 2
- Post-stimulation injectivity test
- Long-term injection

The plans for the 15-12 stimulation were influenced by and reflective of the results from Desert Peak 27-15. The decisions made about the stimulation plan for Bradys 15-12 were also based in part on the expectations set by the results from Desert Peak 27-15, though improved with the zonal isolation approach.

3.4.1 Pre-conditioning Stage (shear stimulation)

The pre-conditioning operation occurred from 15 April 2013 to 22 April 2013, prior to the well recompletion, with the goal of inducing shear slip on critically oriented natural fractures while maintaining injection wellhead pressure less than S_{hmin} (650 psi). The pre-conditioning stage was carried out in four stages: ramp up, stable injection, fall-off and injection test. The initial injection and ramp up of injection rate (until a stabilized injection rate was achieved, while maintaining BCH-3 wellhead pressure at less than 700 psi) was started on 15 April 2013 and lasted approximately 5 hours. This was followed by a period of stabilized injection from 16 to 18 April 2013 at approximately 100 gpm. The injection rate was initially slightly greater than 100 gpm and was gradually decreased to slightly less than 100 gpm during this 2-day time period. The pressure fall-off was recorded after the well was shut-in on 19 April 2013 and continued to 22 April 2013. Later the same day, an injection test was conducted to assess the injectivity after the pre-conditioning phase. The results from the pre-conditioning shear stimulation stage indicated an injectivity of approximately 0.18 gpm/psi during the stabilized injection period and an injectivity of approximately 0.3 gpm/psi during the post-stimulation injectivity test. No seismic events were recorded during this activity.

TPS surveys conducted in well BCH-3 during the injection to 15-12 identified fluid infiltration at depths between 4,640 and 4,800 feet. Because this pathway for fluid leak-off into the Tertiary section would impact the reservoir response to the stimulation, Ormat conducted a cement squeeze BCH-3 in early May 2013 to shut off the fluid loss interval. After filling the lower part of the hole with sand to protect the perforated interval, 8 bbl of cement were placed above the perforated interval to isolate it from the deeper fluid entry zone.

3.4.2 Multi-stage Stimulation

The multi-stage stimulation was conducted from 9 to 14 September 2013, with the goal of inducing both tensile (Mode I) and shear (Mode II) stimulation from injection at rates that would allow pore pressure to exceed S_{hmin}. Injection fluid was cooled to enable possible dilation of fractures at lower injection temperatures.

Stimulation of the deepest zone (Zone 1: 4,750.6 to 5,009 feet) was conducted 9-10 September 2013. Injection was started in well 15-12 with 500 gallons of the same heavy brine, then switched to the cooled separated brine from Bradys production wells. Injection began at 80 gpm (1-2 bbl/min) and was increased in a series of 10-15 minute intervals until reaching a maximum rate of 630 gpm (15 bbl/min) at the planned maximum wellhead pressure ~1,400 psia. The average injectivity for Zone 1 was 0.45 gpm/psi. Pressure transient analysis indicated permeability-thickness of 648 md-feet and Instantaneous Shut-In Pressure (ISIP) of 932 psia.

Another TPS survey in BCH-3 showed a zone of cooling between 4,300 and 4,600 feet that had not been present previously, indicating leakage from 15-12 to BCH-3. In 15-12, the depth range of 4,300-4,600 feet corresponds to the zone just below the uppermost packer and the base of the mini-frac zone, though the stimulation occurred in the deepest Zone 1. This could indicate a poor seal of the deepest packer that allowed injected fluid to leak upward into Zone 2 (the middle zone) then outward to BCH-3. This is a key consideration in understanding why the stimulation did not achieve the goal.

The second stimulation focused on the middle zone (Zone 2: 4,414 to 4,750 feet) and was conducted on 10 and 11 September 2013. Zone 2 stimulation was initiated by pumping pressure (1,550 psi) activating the fracport (sliding sleeve), therefore shutting off the lower zone and opening the middle zone. This was confirmed by the 2.375-inch ball drop, with the monitored pressure decrease indicating that the port had opened. Pumping to stimulate the middle zone started at a rate of 6 bbl/min for approximately 25 minutes. Thereafter, the rate was increased in brief (1-3 minute) steps of 2 bbl/min, up to a maximum rate of 26 bbl/min and a wellhead pressure approaching 1,400 psia. After 12 hours of stable injection, the well was shut-in to record the pressure fall-off. The average injectivity was 0.53 gpm/psi (1,434 psi WHP at 757 gpm) and pressure transient analysis indicated a permeability-thickness of 1,019 md-feet with an ISIP of 1,081 psia.

The third stimulation focused on the upper zone (Zone 3: 4,256 to 4,414 feet) and was undertaken on 11 and 12 September 2013. The upper interval was activated by pumping from surface with an activation pressure of ~1,980 psi, thereby shutting off the middle zone and opening the shallow zone. The injection rate to the shallow zone was ramped up to 7 bbl/min while maintaining the wellhead pressure below 1,400 psia. The injection rate was increased to 8 bbl/min and maintained for the next 7 hours, with wellhead pressure gradually decreasing from 1,400 psia. The rate was increased to 9 bbl/min for the remainder of the injection step. After approximately 12 hours of pumping, the pumps were shut down and the wells were shut-in for monitoring of the pressure fall-off. The average injectivity was 0.24 gpm/psi. Pressure transient analysis indicated permeability-height of 648 md-feet with an ISIP of 932 psia.

Despite a Richter magnitude threshold of -2.0, no detectable events were triggered in the real-time system, and all recorded data were re-processed later to confirm that no detectable events were recorded during the multi-stage hydrofracturing stimulation.

3.4.3 Post-Stimulation Injection Test

A post-stimulation injection test was conducted on 7 October 2013. The Packers Plus completion has remained in the 15-12 ST1 wellbore, so PT surveys were not conducted in well 15-12 due to concerns about wellbore restrictions. The post-stimulation injection test was conducted with the maximum injection rate at 100 gpm and at pressures below S_{hmin}. Average injectivity during this test was 1.17 gpm/psi. Pressure transient analysis from the recorded fall-off after injection indicated a permeability-thickness (kh) of the full open interval of 850 md-feet.

3.4.4 Long-Term Injection

Ormat conducted long term injection (approximately 100 gpm) at relatively low WHP (approximately 96 psi) in 15-12 from late 2013 until early 2015 with no improvement to the injectivity during that time.

4. DISCUSSION

While both projects were successful in analyzing old and newly-acquired technical data, creating a detailed geologic model, understanding the stress field, developing and executing detailed stimulation plans, monitoring and reacting to MEQ events in real-time, and isolating zones of interest within the target well, the end result yielded one commercial well. A permanent pipeline was built to Desert Peak 27-15 and has been in use since project completion after increasing the injectivity 175-fold to over 2 gpm/psi. The stimulation plan for Bradys 15-12 was reasonable based on the data available at the time. In general, it was demonstrated that a shorter time period of pumping at the maximum rate injection may be adequate for enhancing geothermal reservoirs, and the multi-stage approach was successfully implemented and used.

One of the main differences between Desert Peak and Bradys is that Desert Peak 27-15 was within the known reservoir volume, as observed by MEQ and confirmed by tracer returns prior to the stimulation. Thus, 'success' for the Desert Peak stimulation could be demonstrated only by achieving minor permeability improvement (although field performance improvement was also a goal at Desert Peak). Bradys 15-12 is hydraulically isolated from the main reservoir. 'Success' at Bradys required establishing connectivity to the reservoir and enhancing permeability. Injectivity increased 30-fold, indicating that the stimulation conducted did succeed in enhancing permeability, but the lack of tracer returns (and indications from InSAR and ME detailed in U.S. DOE award DE-EE0005510) indicate that 15-12 remains hydraulically isolated. Stimulating at significantly higher pressures could have been considered but may not have been successful because of the likelihood for upward growth of hydraulic fractures. For "in-field" EGS projects, an understanding of the relation of the target well to the main reservoir should be better understood prior to the planning of the stimulation. A single approach would not be expected for these two different cases; because heterogeneity is always present in geological environments, no two fields will be exactly the same. However, the differences between the EGS stimulations at Bradys and Desert Peak provide some insight into the relationship between the target well and reservoir geometry and the importance of considering that relationship in the process of candidate in-field well selection. In hindsight, if the Bradys stimulation had been considered on its own (i.e., not influenced by the Desert Peak stimulation), and if the hydraulic isolation of the well had been recognized somewhat earlier, the stimulation plan may have taken a different direction, with particular reference to treatment pressure. This might have led to a concern about creating a connection to BCH-3. Additional attention could have been paid to work undertaken after stimulation planning was well underway.

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