PROCEEDINGS, Thirty-Eighth Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, February 11-13, 2013
SGP-TR-198

IMPROVING GEOTHERMAL PROJECT ECONOMICS WITH MULTI-ZONE STIMULATION: RESULTS FROM THE NEWBERRY VOLCANO EGS DEMONSTRATION

Susan PETTY, Yini NORDIN, William GLASSLEY, Trenton T. CLADOUHOS, Mike SWYER

AltaRock Energy, Inc.
7900 E. Green Lake Drive N, Suite 302
Seattle, WA, 98103
E-mail: spetty@altarockenergy.com

ABSTRACT

In both conventional geothermal projects and in EGS, the flow rate from each production well is the critical component of project economics and has a direct effect on the Levelized Cost of Electricity (LCOE). In conventional geothermal fields, the cost of the wellfield system makes up 25% - 50% of the total cost of the project. In EGS the wellfield makes up 60%-80% of the cost of the project. While intersecting adequate temperatures during drilling is a significant risk, low temperatures can be compensated by high flow rates. In EGS projects, the temperature is primarily a function of the drilling depth, so the ability to stimulate and achieve a high production rate without risking rapid temperature drop is critical not only to project economics, but also to expansion of the development of geothermal energy into areas where hydrothermal resources are not found. The oil and gas industry has developed stimulation techniques over the years that have allowed the enhancement of very low permeability rock for oil and gas production. Multi-stage stimulation and horizontal well completions can access larger volumes of tight rock to recover poorly connected pore volume. These technology changes in oil and gas stimulation have allowed the development of a resource that was previously thought to be uneconomic. In unconventional oil and gas resources, the permeability of shale is very low, just as heat transfer in rock is very small. The larger the surface area of the contact with the formation, the more production is possible. By focusing our efforts in geothermal energy technology on improving production and injection rates through stimulation, improving power plant efficiency to get more power output from the same flow and temperature and by managing the reservoir to reduce pressure and temperature decline, we can mitigate exploration risk and expand the base of geothermal power production.

The Newberry Volcano EGS Demonstration is not only a demonstration of an enhanced geothermal system, but a further demonstration of the benefit of multi-stage fracturing relying largely on hydroshearing. AltaRock has performed three stimulations using thermally degrading zonal isolation materials (TZIM) to block permeable zones and create multiple stimulated fracture systems in conventional geothermal reservoirs. These stimulations targeted deep, high temperature areas of the reservoir while isolating and preventing stimulation of shallow, low temperature zones. Previous results show not only up to 60% increase in flow rate, whether injection or production, but the production and or injection improvement is confined to higher temperature zones. Interim results from the Newberry EGS stimulation of multiple zones are discussed.

INTRODUCTION

Newberry Volcano is a shield volcano located in central Oregon, about 35 km south of the city of Bend and approximately 65 km east of the crest of the Cascade Range. The Newberry EGS Demonstration is being conducted on federal geothermal leases and National Forest system lands located in the Deschutes National Forest, adjacent to Newberry National Volcanic Monument (Figure 1). Since the 1970s, extensive exploration activities have been conducted in the Newberry area by public and private entities including various geoscience surveys, and then drilling of thermal gradient, slimhole, and deep, large-bore wells. AltaRock Energy, Inc. (AltaRock), in partnership with Davenport Newberry (Davenport), was awarded a DOE grant (Award Number DE-EE0002777) in 2010 to demonstrate EGS technology at Newberry. The demonstration project consists of three Phases.

During Phase I, the Newberry project team studied existing data and gathered new regional and well bore data to develop a comprehensive geoscience and reservoir engineering model of the resource underlying the Demonstration site. AltaRock formulated a detailed plan to conduct Phase II operations which included seismic monitoring, stimulation, drilling and testing. Throughout Phase I, the team assembled a large array of project information to conduct public outreach and inform regulatory agencies. The completed tasks include implementing a public relations campaign by distributing information and determining stakeholder concerns through the use of public meetings, an informational web site and social media, and providing detailed project plans and background information to aid the Environmental Assessment and Phase I stage-gate review.

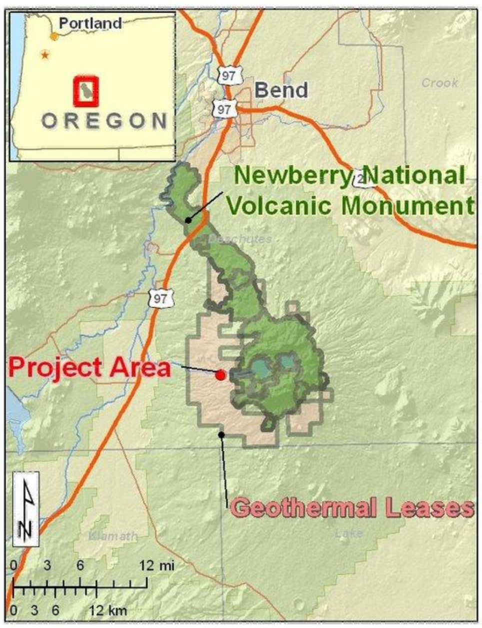

Figure 1: Newberry EGS demonstration 55-29 site location

PHASE II 55-29 STIMULATION PREPARATION

Phase II of the Demonstration began in April 2012. The stimulation preparation included various field and administration actives. A bidding process was used to obtain field stimulation equipment, including pumps, high-pressure piping, electrical pump control systems, instrumentation and seismic monitoring systems. Field activities included implementing the seismic monitoring network by drilling five new monitoring boreholes, prepping the well and well pad for high-pressure stimulation and road maintenance.

Permitting and public outreach efforts included development of comprehensive operation plans for 55-29 stimulation, and working with the BLM, the US Forest Service and the DOE to receive all permits necessary to conduct the stimulation. A series of public meetings were held to inform the public on the plans and ongoing activities for the stimulation and to receive comments and concerns to integrate into planning and regulatory compliance documents.

The stimulation of 55-29 began on October 17, 2012 and injection ended on December 7, 2012. During the process, three stages of stimulation were used to create multiple zones with the application of TZIM diverters. Downhole temperature was monitored with a Distributed Temperature Sensing (DTS) tool. Microseismic events were continuously monitored, then analyzed by Foulger Consulting, Lawrence Berkeley National Lab (LBNL), and the Pacific Northwest Seismic Network. Phase II micro-seismic installation and results are discussed further in Cladouhos et al. (2013).

55-29 STIMULATION SET UP

MSA drilling started in May 2012 after the spring snow melt. Four new MSA monitoring wells were drilled and one existing water well was deepened to complete the DOE approved MSA monitoring network. Seismic field install efforts began on August 2012 and were approved by DOE at the end of the month. High-pressure pipe and wellhead valves were installed to accommodate anticipated injection pressures up to 21 MPa on the surface (Figure 2). Two horizontal centrifugal pumps were leased from Baker Hughes CentraLift to be used as the main stimulation pumps. These stimulation pumps were designed with high-pressure piping and valve arrangement that allowed them to operate in series or parallel. The maximum injection pressure that could be achieved by the equipment is approximately 20 MPa with a flow rate up to 63 L/s.

A booster and sump pump system was rented to provide positive pressure to the stimulation pump inlet. The discharge from the stimulation pumps flowed through high pressure piping into a wellhead T. Due to the low initial injectivity of 55-29, 50mm bypass lines were also installed on the discharge side to extend the pumping rate range. An in-line differential pressure meter upstream of the stimulation pumps and a clamp-on ultrasonic flow meter downstream of the stimulation pumps were used to measure flow rate. Pressure transducers and temperature sensors also continuously recorded information to the onsite control room. The injection water was near ambient temperature, sourced from the water well next to 55-29. The stimulation was

Figure 2: Newberry stimulation site photo. Showing from right to left, booster pump system, stimulation pump, high-pressure piping, TZIM injection system, wellhead assembly, and flowtesting set-up

conducted rig-less and without drill pipe or packer in the hole.

The electrical horizontal pumps, powered by diesel generators, were ideal for the longer stimulation duration and required less maintenance compared to positive displacement pumps. TZIM were staged on site and fed into the intake of stimulation pumps using a blending unit and booster pumps. AltaVert 154 was chosen for Newberry due to its stable nature with temperatures between 150° and 200°C and complete degradation between 250° and 300°C (Figure 3). Reactive and nonreactive tracers were also injected in collaboration with Earth and Geoscience Institute at The University of Utah, Pacific Northwest Nation Laboratory and Los Alamos National Lab.

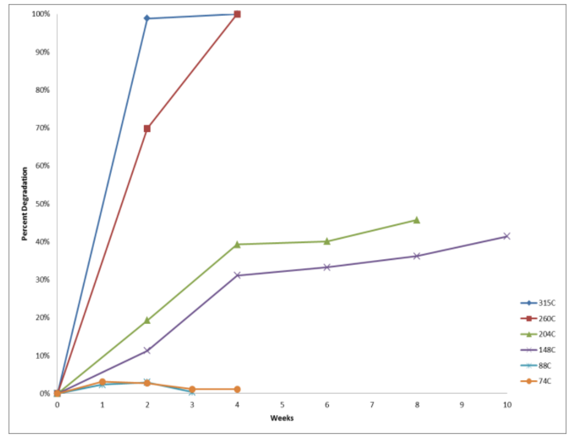

Figure 3: AltaVert 154 degradation results from lab testing

55-29 STIMULATION RESULTS

The stimulation started with a step-rate injection test in order to assess the pre-stimulation parameters and determine hydroshearing initiation pressure. The overall stimulation results are illustrated in Figure 4.

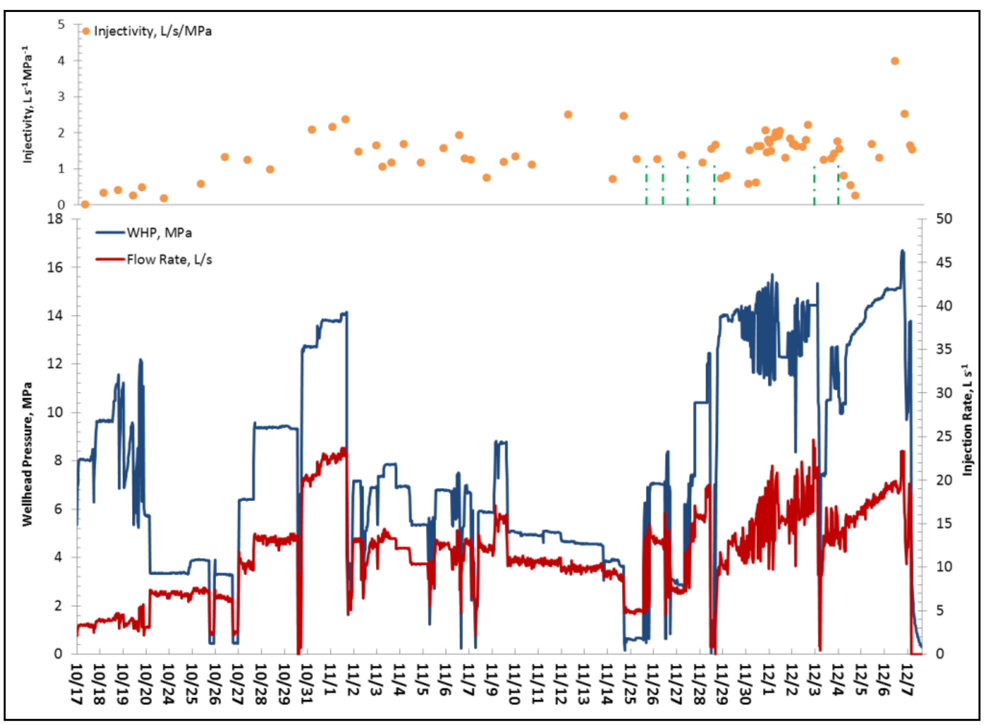

Figure 4: The stimulation of 55-29 parameters. Pressure (blue) and injection rate (red). Calculated injectivity (orange) and TZIM injection (Green). Gap in timeline is when stimulation pumps were offline

Injectivity calculated during the step-rate test averaged 0.37 L s^{-1} MPa^{-1}, equivalent to injectivity and flow testing results obtained after drilling in 2008. The highest wellhead pressure obtained during the injectivity test was 12.2 MPa with 5.5 L s^{-1} injected downhole. Shortly after this wellhead pressure was reached, the stimulation pumps experienced a series of start-up issues due to malfunctions with the electrical drive.

Stage I stimulation resumed on October 28. Injectivity improved when injection pressure exceeded 12.4 MPa and the corresponding flow rate reached 20.6 L s^{-1}. Moderate pressure injection stimulation continued with injectivity stable at the improved rate until November 14, when sustained drive, pump and DTS issues needed to be addressed and a two week break was taken. .

On November 25, both stimulation pumps and DTS were reinstalled and returned to normal operating conditions, though an obstruction at approximately 2,090 m down hole prevented the DTS from being lowered deeper. The improvement in injectivity during stage I stimulation is approximately 2 L s^{-1} MPa^{-1}.

Stage II stimulation started with overnight tracer injections on November 24, followed by 6 pills of TZIM from November 25 to 28. Approximately 1,340 kg of TZIM were injected over the period of 4 days as shown in Figure 5. After the first pill was injected, the rate decreased slightly while wellhead pressure maintained mostly constant.

The second, third, fourth and fifth pills were injected over the next two days while varying the concentration and particle distribution which produced similar results. Pill one through five consisted mostly of fine grained TZIM due to the injection filter mesh used to protect the stimulation pumps. In order to test the effectiveness of the course TZIM, the blending unit was disconnected and tied in directly at the wellhead on November 28. After 206 kg of course blend TZIM injection, the wellhead pressure increased beyond the pressure capability of the batch mixer blending unit (~1.38 MPa). After restarting the stimulation pumps, the injection rate decreased to approximately 9.5 L s^{-1} at 13.8 MPa. The decrease in injectivity as a result of TZIM injection indicated that the fracture zones enhanced in stage I had been at least 50% blocked and marked the beginning of stimulation of new zones in the wellbore. Wellhead pressure was maintained at 14 MPa with approximately 9 L s^{-1} injection rate overnight. Onset of hydroshearing was noted on November 29, when slight decrease in wellhead pressure occurred in conjunction with 4 L s^{-1} increase in injection rate.

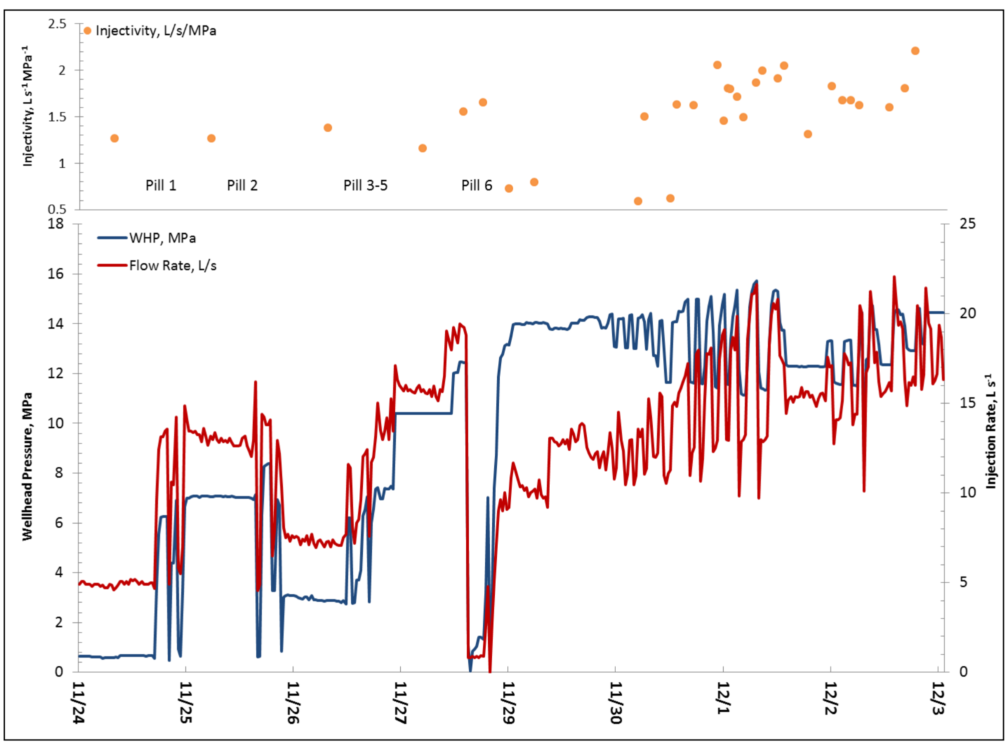

Figure 5: TZIM injection and stage II stimulation. Pressure (blue) and injection rate (red). Calculated injectivity (orange)

The well head pressure cycled between 12.4 and 15.2 MPa. The pressure cycling method seemed to improve injectivity over time. Over the course of the next five days the injectivity of stage II improved from 0.7 L s^{-1} MPa $^{-1}$ to 2.2 L s^{-1} MPa $^{-1}$. On December 3, the flow rate reached 19.4 L s^{-1} with 14.3 MPa corresponding wellhead pressure.

Stage III stimulation began after the second phase of TZIM treatment by pumping 8 more pills over the next two days. Total TZIM injected in this phase was 1,451.5 kg. Four consecutive pills were pumped each day. The flow decreased and wellhead pressure increased overnight after both TZIM injection efforts. After TZIM application the injectivity decreased to 0.26 L s^{-1} MPa $^{-1}$. The well responses for the second diversion are shown in Figure 6. The well head pressure for stage III was maintained between 13.3 and 16.7 MPa and the injectivity increased to 2.5 L s^{-1} MPa $^{-1}$ after two days of high pressure injection. The stimulation pumping continued until the night of December 7, when the well was shut in and allowed to heat-up post stimulation. The wellhead pressure fall-off data was recorded and analyzed. The improvement in injectivity is approximately 1.3 L s^{-1} MPa $^{-1}$during stage III stimulation. Post shut-in, the well did not build static wellhead pressure. Attempts were made to lift the well and initiate flow but winter weather and well conditions made it impossible to successfully flow test the well.

RESULTS DISCUSSION

Over 40,000m^3 of ground water was injected during the span of the stimulation. The maximum injection pressure was 16.7 MPa and preliminary locations were calculated for 179 microseismic events. The injectivity summary and improvement trends are shown in Figure 4 and Table 1. Wellhead pressures above 12.4 MPa were required to initiate microseismic events and improve injectivity during stage I stimulation. The decrease in injectivity after TZIM injection signifies that the existing permeable zone was sealed by TZIM. The improvement in injectivity as pumping progressed indicates that new zones were successfully stimulated. On average, injectivity per stage post stimulation ranged between 1.4 and 1.7 L s^{-1} MPa $^{-1}$. The estimated final injectivity for 55-29 based on injectivity improvements per stage is approximately 4.7 L s^{-1} MPa $^{-1}$. A final injectivity test was not performed after TZIM degradation due to weather conditions. Plans have been made to return in the spring after snow melts to perform injectivity testing and log the well. Based on previous lab testing, the time necessary for 100% TZIM degradation should be two to four weeks post shut-in.

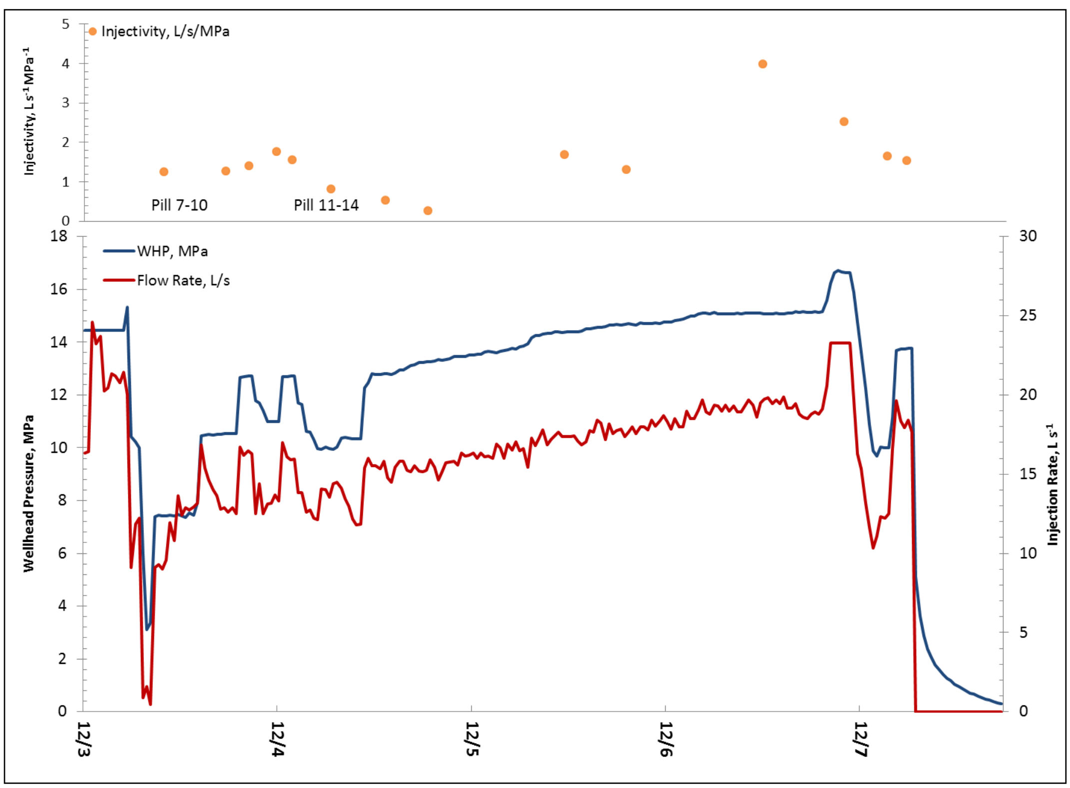

Figure 6: Second TZIM injection and stage III stimulation. Pressure (blue) and injection rate (red). Calculated injectivity (orange)

Table 1: Stimulation parameter summary for 55-29

	Duration (Hrs.)	Injected volume (m^3)	Maximum Wellhead Pressure (MPa)	Max Injection Rate ($L\ s^{-1}$)	Average Injectivity ($L\ s^{-1}\ MPa^{-1}$)	Total Seismic Event Count	% of Cumulative Moment	Cumulative Seismic Moment (10^{12} N m)
Stage I	960	26,225	14.15	22.9	1.4	54	10.1	1.5
Stage II	190	9,795	15.7	21.64	1.6	97	32.4	4.7
Stage III	80	5,305	16.7	23.28	1.7	129	72.2	10.4
Total	1,230	41,325	16.7	23.28	4.7	179	100	14.6 (12/31/12)

Post drilling injectivity and flow test attempts concluded that the pre-stimulated open hole permeability was extremely low. LBNL TOUGH-FLAC coupled THM model (Rinaldi et al., 2012) defined the baseline horizontal permeability to be 1E -17 m^2 (0.01 md).

55-29 wellhead pressure was monitored for 24 hours post shut-in. The pressure fall-off data (Figure 7) was used to conduct a Horner analysis in order to estimate the transmissivity of the last stimulated zone. Using first a semi-log analysis approach, the reservoir behavior is anticipated to start after a shut-in time of 0.94 hours. This corresponded to a Horner time of 254. Using Equation 1 from Horne (2008), the transmissivity is calculated to be 6.46E-13 m^3 (2,147 md-ft). Assuming a reservoir height of 200 m per stage as presented in Cladouhos et al. (2011), the equivalent permeability is 3.23E-15 m^2 (3.27 md). This result is comparable to the LBNL modeled shear enhanced horizontal permeability of 2E-15m^2. Both modeled and fall-off analysis results demonstrate two order magnitude of permeability increase after hydroshearing stimulation is applied.

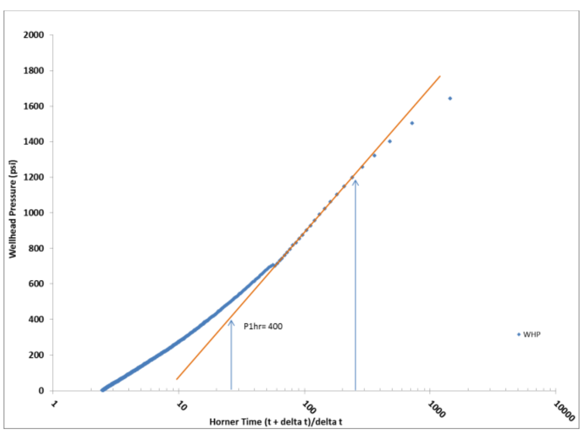

Figure 7: Horner analysis of 55-29 fall-off data pre TZIM degradation

$$k = 162.6\ \frac{qB\mu}{mh} \qquad \text{……………………..…………….}\textit{Eq. 1}$$

Microseismic monitoring also indicates that multiple distinctive zones have been created using TZIM. Table 1 lists the seismic event count and cumulative seismic moment during each stage. More results and microseismic data are discussed in Cladouhos et al. (2013).

DTS contour visualizing stage I stimulation (Figure 8) shows one main interval between 2,880-2,950 m taking the majority of the injected water. The figure compares temperature and temperature gradient over time in the open hole interval.

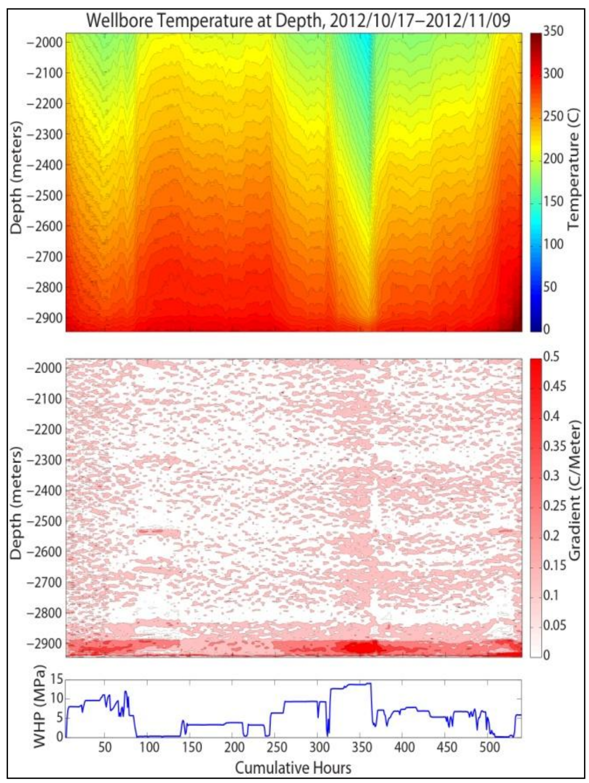

Figure 8: DTS conour visualizing stage I stimulation

Maximum cooling was achieved between hour 300 and 350, when injection pressure was approximaly14 MPa. The gradient below 2,890 m during high pressure pumping increased, indicating an increasing amount of fluid exiting below 2,890 m. Separations seen within the 2,880-2,950 m gradient plot suggest that multiple permeable fractures are taking fluid. Several other zones such as 2,550 m 2,670m and 2,850 m also showed periodic changes in temperature gradient, suggesting minor fluid loss during stimulation.

The main fluid exit intervals were not monitored during stage II and III stimulation due to the inability to lower the new DTS below 2,090 m. Contour plots of stage II (Figure 9) show that during the stimulation, a permeable interval beginning at approximately 2,080 m is taking fluid, marked by the high changes in temperature gradient. This zone is more than 100 m below the casing shoe. Other zones at 2,040 m and 2,060 m also showed small change in temperature gradient. These are not stimulated fractures, but are most likely minor permeable zones that reached temperature equilibrium as high pressure injection continued.

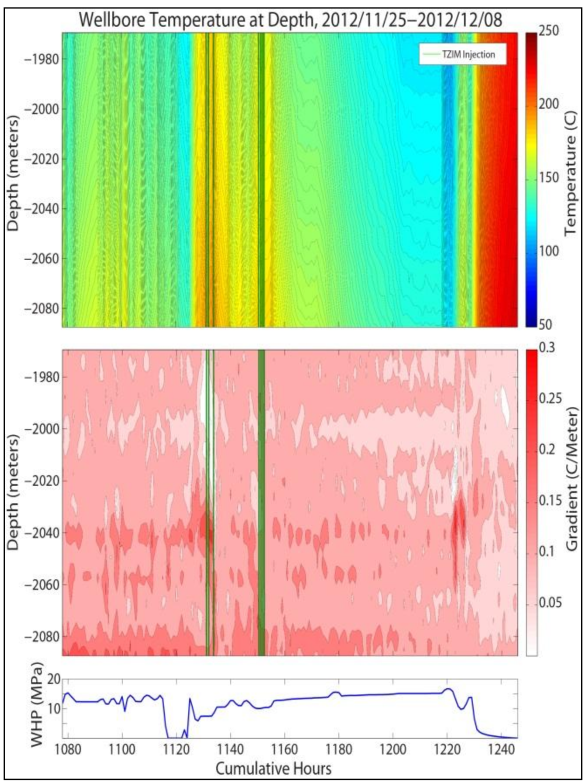

Figure 9: DTS contour visualizing stage II and stage III stimulation, including TZIM injection (vertical geen lines)

One goal of the second TZIM treatment on December 3 (marked by green lines) was to seal this 2,080 m zone. The decrease in gradient between 2,080-2,090 m post TZIM injection is an indication of successful TZIM plugging. The constant gradient sustained through the duration of stage III stimulation and heat-up further validated the effectiveness of TZIM.

CONCLUSION AND FUTURE WORK

Injectivity, DTS, and seismic analysis all indicate that previously impermeable fractures were enhanced during the 55-29 stimulation. The enhanced fracture network was then successfully sealed with the application of TZIM. This process was repeated to create three distinctive zones in a single wellbore without the use of mechanical isolation devices. Preliminary injectivity and fall-off analysis all point to improved well bore permeability.

Further work at Newberry includes:

- Conduct post TZIM degradation injectivity and fall-off analysis to quantify final injectivity and transmissivity
- Borehole televiewer and temperature logging to assess the stimulated zones
- Pass phase 2.1 DOE Go/No Go decision and move onto phase 2.2: drilling production wells that complete the EGS system

ACKNOWLEDGMENTS

This material is based on work supported by the Department of Energy under Award Number DE-EE0002777.

DISCLAIMER

This paper was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

INTELLECTUAL PROPERTY STATEMENT

AltaRock holds a portfolio of patents, patent applications, licenses and related proprietary intellectual property regarding its diverter and stimulation technology, materials and methods.

REFERENCES

Petty, S., Bour, D., and Nordin, Y., (2011), “Temporary Diverters for EGS Reservoir Optimization – Field Applications,” *GRC Annual Meeting, San Diego, California, October 23-26, 2011*

Cladouhos, T.T., Petty, S., and Nordin, Y., (2013), "Microseismic Monitoring of Newberry Volcano EGS Demonstration,” *PROCEEDINGS, Thirty-Eighth Workshop on Geothermal Reservoir Engineering Stanford University, Stanford, California, February 11-13, 2013 SGP-TR-198*

Cladouhos, T.T., Osborn, W.L., and Petty, S., (2012), "Newberry Volcano EGS Demonstration—Phase I Results,” *PROCEEDINGS, Thirty-Seven Workshop on Geothermal Reservoir Engineering Stanford University, Stanford, California, January 30-February 1, 2012 SGP-TR-194*

Horne, R.N., (2008), "Modern Well Test Analysis” *pg. 54-61.*

Cladouhos, T.T., Clyne, M., and Nichols, M., (2011), “Newberry Volcano EGS Demonstration Stimulation Modeling,” *GRC Annual Meeting, San Diego, California, October 23-26, 2011*

Rinaldi, A.P., Rutqvist J., Sonnenthal, E.L., (2012), “TOUGH-FLAC coupled THM modeling of proposed stimulation at the Newberry Volcano EGS Demonstration,” *Tough Symposium 2012, Berkeley, California, September 17-16, 2012*