1 **Laboratory simulation of binary and triple well EGS in large granite blocks**
2 **using AE events for drilling guidance**

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9 **Abstract**

10 Multiple-well Enhanced Geothermal Systems (EGS) can enable economic
11 recovery of energy from underutilized hot dry rock (HDR) reservoirs. Hydraulic
12 fracturing is a promising stimulation method for improving fluid flow and heat extraction
13 in EGS. Laboratory simulations of EGS with hydraulic fracture stimulation have recently
14 been completed in two large 300×300×300 mm³ granite block specimens to better
15 understand this complex process of geothermal energy recovery. The first experiment
16 implemented a binary well layout with an injector and producer. The second experiment
17 used a triplet well layout with one injector and two producers. Selection of production
18 well trajectory so as to intersect the hydraulic fractures was guided by acoustic emission
19 (AE) events collected during stimulation. Both model reservoirs were subjected to
20 heating and true-triaxial stress confinement throughout a series of drilling, stimulation,
21 and flow and heat circulation tests. Stimulated thermal reservoir flow was characterized
22 by a series of constant pressure, constant flow rate, stepped constant pressure and stepped
23 constant flow rate injection tests. Tested blocks were cross-sectioned to characterize final
24 locations and 3D geometries of the induced fractures. Insights and lessons learned from
25 these experiments are presented with focus on application to field-scale EGS.

26 **Keywords:** Enhanced Geothermal Systems (EGS), Hydraulic Fracture, Acoustic
27 Emission (AE), Discontinuities, Fracture Flow

1. Introduction

Enhanced Geothermal Systems (EGS) have the potential to enable economic recovery of energy from underutilized hot dry rock (HDR) reservoirs or increase production from conventional geothermal reservoirs (Tester et al., 2006). The basis of EGS involves drilling an array of injection and production wells into a target hot-rock reservoir and stimulating the reservoir to improve in-situ permeability. This allows for sustained injection and circulation of fluid through the reservoir for commercial extraction of heat energy, a process also referred to as geothermal heat-mining. Hydraulic fracturing offers a means for stimulation where fluids are injected with sufficient rate and pressure to create new fractures. EGS is intended for implementation in deep high-temperature rocks which have complex geologic structures and contain significant thermal energy. However, experience with hydraulic fracturing in abundant crystalline HDRs, such as granites and diorites, is limited in comparison with sedimentary applications common to the oil and gas industry.

Research to advance EGS and hydraulic fracturing technology has included modeling efforts, laboratory experiments and field scale tests (GTO, 2014; Tester et al., 2006; Valkó and Economides, 1995). One topic that remains uncertain through the existing research is a strong understanding of how hydraulic fractures propagate through complex crystalline rocks, how actual prominent fracture locations relate to acoustic emission (AE) source locations, and how fluid flows through hydraulically stimulated fractures between wells (Warpinski et al., 1987). Laboratory experiments can offer insight on these questions as a benefit of physical data collected in controlled conditions using measurement and monitoring capabilities beyond what is possible at the field scale.

Relevant laboratory experiments have included hydraulic fracturing studies (Abass et al., 1996; Behrmann and Elbel, 1991; de Pater et al., 1994; Haimson and Zhao, 1991; Hallam and Last, 1991; Ishida et al., 2004; Warpinski et al., 1982) and fracture conductivity tests (API RP61, 1989). These studies, to the best knowledge of the authors, mostly neglect thermal effects, use ideal or sedimentary rock specimens, do not incorporate multi-borehole systems and coarsely inspect the final fracture geometry. A comprehensive study which includes these experiment parameters and meticulously investigates created fracture geometry, through cross-sections paired with AE, is expected to offer beneficial insights building on previous studies. The results from such a study are expected to improve understanding of the difficulties with applying EGS to crystalline HDR and the respective causes of these difficulties. This understanding can be applied to the field-scale where similar measurements are not possible but similar fracturing and fluid flow behavior can be assumed or inferred.

Comprehensive laboratory experiments were recently conducted in an effort to improve understanding of multiple-well EGS reservoirs in crystalline HDR. Two large 300×300×300 mm³ granite blocks were subjected to HDR conditions and hydraulically fractured to create EGS models. A binary well configuration with one injector and one producer was implemented for the first experiment. The second experiment used a triplet configuration with an injector and two production wells. In both experiments, production well trajectories were selected so as to intersect the main hydraulic fracture wings using acoustic emission (AE) event source locations collected during stimulation. Both rock specimens were subjected to heating and true-triaxial stress confinement throughout drilling, stimulation and production operations. Simulation methods included

conventional hydraulic fracturing, hydraulic re-fracturing and mechanical impulse stimulation. Treatment schedules for each test were tailored according to the observed response of the reservoir to successive injection and circulation treatments. Well injectivity and productivity was characterized by a series of repeated fluid injection tests. Creation of EGS reservoirs was successful in both experiments but the need for improvement to the stimulation process and well design was also apparent. Suggestions are presented for future EGS design following lessons learned from these experiments.

2. EGS Simulation Methodology

Details on the test materials, equipment and procedures used for this study are provided in this section. Fluid flow data collected during experiments were synthesized to representative values following the methods described in this section to enable direct comparison of results.

2.1. *Rock Specimen Characteristics*

Granite specimens were obtained from the Liesveld Quarry in Lyons, Colorado. The specimens were extracted from an outcrop using water jet cutting and trimmed to 300×300×300 mm³ cubes by diamond wire sawing. This specimen preparation process minimized mechanical damage. Supplemental element tests were performed to characterize the rock properties following relevant ASTM standards with the exact procedures detailed in Frash (2012). The respective results are shown in Table 1. The granite specimens typically exhibited low-porosity and low-permeability so matrix leak-off during fluid injection was expected to be negligible. Pre-stimulation well injectivity tests were performed for improved evaluation of stimulation effects.

The dominant minerals in the granite were quartz and feldspar with minor biotite and muscovite. The grains of the granite were heterogeneous in size and distribution as is common for natural rocks. Typical grain sizes ranged from less than 0.0005 mm up to 15 mm in length, measured by photomicrographs and calipers. Large grains contained striations and composite structures making precise definition of grain size difficult. This difficulty is common in heterogeneous rocks and remains a topic of active research in regards to characterizing materials for modeling. Fig. 1 shows a typical photomicrograph of the granite's heterogeneous grains. This heterogeneity was preferred for these EGS experiments because real rock has a potential for producing more complex results than idealized materials. Complex results can in-turn offer insight for field-scale EGS where heterogeneity and discontinuities are a fact of nature.

2.2. *True-Triaxial Equipment*

A true-triaxial apparatus was used to apply heating and confining stresses to the cubical rock specimens. Stresses were applied by an assembly of flat jacks and platens as shown in Fig. 2. Heating was applied by external electrical elements with constant temperature control. Passive platens enabled drilling of multiple wells at orientations ranging from vertical through horizontal. The maximum confinement stress provided by the apparatus was 13 MPa and the maximum proof temperature was 100 °C. Data monitoring systems included pressure transducers, thermocouples, strain gages, and six Acoustic Emission (AE) sensors. Capability for pore pressure application and control at the boundary of the specimen was not incorporated into this equipment because HDR conditions were intended. Additional details on the equipment and instrumentation can be found in Frash (2012), and Frash et al. (2013b).

2.3. *Injection Fluids and Equipment*

Fluids injected for stimulation and flow testing included Valvoline® DuraBlend® SAE 80W90 gear oil and tap water. Estimated properties for these liquids at selected temperatures are shown in Table 2 (ASTM D341, 2009; Valvoline, 2012; White, 2009). Gear oil was used for hydraulic fracturing and water was used for most injection flow testing. Oil was chosen for its high viscosity relative to water. Previous studies suggest higher viscosity fluids are beneficial for laboratory hydraulic fracturing with respect to scaling laws (de Pater et al., 1994) and creation of less tortuous fracture pathways (Ishida et al., 2004). It was assumed that more ideal planar bi-wing hydraulic fracture geometries would result with increased fluid conductivity between the injection and production wells during EGS fluid flow testing. Water was used for injectivity testing to allow increased flow rates without an associated increased risk of additional stimulation as can occur with high-viscosity fluid injection. Water also gave the advantage of well-known thermo-mechanical properties (White, 2009). Tap water was selected because it was anticipated that dissolved minerals would buffer chemical reaction with minerals in the granite. No significant chemical dissolution or precipitation was observed in post-test cross-sections indicating that fluid residence times and chemical buffering were sufficient to neglect geochemical effects.

Hydraulic injection equipment included two Teledyne Isco 65DM syringe pumps, a vacuum pump, a computer control system with automated valves, and a combination of injection and production wells. A basic diagram of this hydraulic system is presented in Fig. 3. Drilling of the injection well was executed in two stages while the rock specimen was maintained at heated and confined conditions. The upper interval of the well was

drilled at 10 mm diameter and cased with 9.8 mm O.D. 316 stainless steel tubing having 6.4 mm I.D. The casing was sealed for high pressure injection by filling the annulus between rock and casing with epoxy grout. Threads were cut on the outside of the casing wall to improve seal strength. A lower open injection interval (uncased) was drilled at 5.6 mm diameter after the epoxy grout fully cured. Production wells were drilled open at 10 mm diameter and sealed for vacuum pumping. Vacuum sealing was provided by a 9.8 mm O.D. vinyl sleeve overlying a 6.4 mm O.D. nylon tube. A copper ferrule fixed to the nylon tube was pulled into the sleeve to expand the vinyl into the well annulus forming a sealed ring. Produced fluids were pumped through a condenser and respective flow rates into an outflow fluid reservoir were measured with a digital mass balance.

2.4. Hydraulic Stimulation Procedures

Multiple hydraulic stimulation procedures were applied to create permeable fluid flow pathways through the granite specimens and to link injector and producer wells to these pathways. Stimulation injections included conventional hydraulic fracturing, hydraulic fracture re-stimulation and mechanical impulse hydraulic fracturing (MIF).

Conventional hydraulic fracturing and re-fracturing was performed by injecting fluid at constant flow (CF) rate. Idealized pressure and flow rate curves are shown in Fig. 4. In this figure, P is the injection well pressure, Q is the fluid injection rate, P_0 is the reservoir pore pressure, P_b is the initial fracture breakdown pressure, P_s is the fracture shut-in pressure or fracture closure pressure, and P_r is the fracture reopening pressure. These critical pressures are directly related to the rock effective stress state. A basic method to relate these parameters is detailed in ASTM D4645 (2008).

Hydraulic fracturing treatments were performed with two objectives. The primary objective was to create a new hydraulically conductive fracture in the rock specimen. This event typically coincided with real-time AE which could be located and monitored to estimate fracture length. A secondary objective was to contain the final hydraulic fracture extents within the confines of the rock specimens to minimize boundary effects. Interception of the fracture with the boundary of the specimen causes significantly increased leak-off due to a lack of applied pore pressure at the boundary, a situation comparable to intercepting a large permeable fault at the field-scale. Fracture growth was halted by ceasing fluid injection when AE associated with fracture propagation approached the boundary of the specimen. Injection fluid flow reversal was an additional method used limit fracture length if significant fracture growth continued after ceasing injection. Heterogeneity and pre-existing discontinuities in granite specimens complicate this procedure and add uncertainty to estimations of the created fracture extents.

MIF stimulation was performed using a method where the pumps supplied a high pressure impulse to the injection well. The procedure involved pressurizing the pumps while the valve at the wellhead was closed to isolate the pump fluids from the well fluids. The well was filled with liquid and maintained at hydrostatic pressures during pump pressurization. An impulse was generated by opening the wellhead valve and permitting the high pressure pump fluid to contact the well fluid. The treatment was performed with the accumulator temporarily removed from the hydraulic system to reduce compliance and consequentially reduce injected fluid volumes as estimated by Eq. 1. Additional details on this treatment method and its motivations are discussed in Frash et al. (2013b).

2.5. *Well Injectivity and Productivity Testing*

Constant pressure (CP), constant flow rate (CF), stepped constant pressure (SCP) and stepped constant flow rate (SCF) injection tests were used to quantify well injectivity and productivity for EGS reservoir characterization. Flow rate and pressure control were provided by the dual syringe pump hydraulic system. A series of repeated CP and SCP tests were executed before and after hydraulic stimulations to characterize well flow and changes caused by stimulations. An example plot of SCP data is provided in Fig. 5 with a single injection step highlighted. Typical step durations programmatically controlled with 15 min or 30 min durations. Longer durations applied when thermal stability was desired. Pseudo-steady flow rates and pressures were estimated from the final 30% of data for each step. The pseudo-steady data was compiled into summarizing plots, such as shown in Fig. 6, to aid comparison of multiple SCP tests. Inspection of the pseudo-steady data also provides information about hysteresis and repeatability for each SCP test. Comparison of analyzed data between SCP tests provides insight regarding changes in reservoir flow behavior such as enhancement of well injectivity and the permanence of any enhancement.

2.6. *Hydraulic Compliance Correction*

Correction for hydraulic compliance was implemented using calibrated linear-correlations between well pressure and pumped fluid-volume:

$$(1)$$

where V_{stored} is the volume of fluid stored in the hydraulic system due to elastic expansion of tubing and other wetted components as caused by pressurization (compliance), m is a calibrated compliance coefficient and P_{well} is the well pressure. The compliance

coefficient was estimated from the maximum slope of the pressurization interval preceding hydraulic fracture initiation. Corrections for leakage were also applied to improve estimation of m with reference to pre-stimulation injection rates measured during constant pressure injection at 2 MPa, a value significantly below the expected hydraulic fracturing pressure of at least 7.5 ± 1.8 MPa for the granite (Haimson and Fairhurst, 1967).

3. EGS Simulation Results

The two granite specimens used for EGS simulation were given reference names of G01-90 and G01-93. A binary well layout was used for G01-90 and a triplet well layout was used for G01-93. The two specimens were subjected to differing reservoir conditions with G01-93 maintained at a higher temperature. G01-90 was hydraulically fractured with oil injection in multiple stages while G01-93 was fractured with oil and proppant slurry injection. Geothermal fluid production was successful and fully characterized in both experiments. Individual injection tests are labeled according to test type and sequence for consistent referencing within the discussion of each experiment.

3.1. G01-90: Binary Well Test

Images of the G01-90 granite specimen prior to testing are shown in Fig. 7. A discontinuous band characterized by a relatively dense concentration of quartz with roughly 20° dip was visible in the specimen. No persistent discrete fractures were identified prior to testing. Positions of thermocouples, strain gages, and AE sensors placed on the specimen's surfaces are shown in Fig. 7. The granite specimen was heated to 50 °C and subjected to confinement of 12.5, 8.3, and 4.1 MPa for the vertical (σ_v , z -axis), intermediate (σ_H , y -axis), and minimum principal stresses (σ_h , x -axis), respectively.

These conditions represent an idealized 460 m deep crystalline low-temperature HDR reservoir in an anisotropic stress state.

Table 3 provides an overview of the schedule for this test which included four stimulation stages and a series of CP, CF, SCP and SCF injection tests, lasting 106 days in total. Well drilling, hydraulic stimulations and injection tests were performed with HDR reservoir conditions applied. A temporary interruption to the applied HDR conditions occurred after CF #5 due power loss caused by a windstorm. Analysis of water injection data collected before and after this event indicated that the temporary loss of HDR conditions had a minimal effect on the results. HDR conditions were applied slowly to reduce risk of thermally induced fracturing.

Fluid injection was performed through a centered vertical well with 107 mm cased depth and 74 mm open length, giving a total injection well depth of 181 mm into the specimen. Fluid was captured through an oriented production well drilled after hydraulic fracturing. The initial injection fluid was clean SAE 80W90 gear oil for conventional hydraulic fracture stimulation and hydraulic fracture re-stimulations. Tap water replaced oil as the injection fluid after hydraulic connectivity between the injection and production wells was confirmed through SCP injection testing.

Fig. 8 shows well pressure and injected fluid volume data for each of the four stimulation stages. A constant pumped flow rate of 0.05 mL/min was used for the hydraulic fracture and re-fracture stimulation treatments. The upstream pressure for MIF stimulation was set at 65 MPa. Injected fluid volume data was corrected for hydraulic compliance following Eq. (1) with compliance coefficients of 5.7×10^{-5} mL/kPa for the hydraulic fracture and re-fracture stimulations, and 4.0×10^{-5} mL/kPa for the MIF

stimulation. Compliance values differed in value due to change of the hydraulic configuration.

The initial hydraulic fracture breakdown was brittle with a peak pressure of 18.0 MPa. The peak pressure exceeds the prediction from ASTM D4645 but this was expected due to the small well diameter used relative to the field scale (Haimson and Zhao, 1991). Peak pressures in the re-fracture treatments were more ductile and of lower magnitudes at 15.4 and 17.4 MPa, sequentially. The reduction in peak pressure after the initial hydraulic fracture was anticipated because initial fracture growth is expected to decrease rock tensile strength near the wellbore. The similar magnitude between each of the three peak pressures indicates that fracture toughness was less influential than other effects. Exponential extrapolation was needed to estimate the peak pressure for the MIF treatment at 18.7 MPa because pressure was recorded at only 1 Hz, the maximum rate from the data acquisition system used. Strain data was recorded at 5000 Hz and aided the interpolation process giving increased accuracy for the impulse arrival time and improved estimation of the pressure profile.

AE event source locations acquired during the stimulations are shown in Fig. 9. Data from the initial hydraulic fracture stimulation was used to estimate the hydraulic fracture location as propagating away from the injection well on a plane perpendicular to the x -axis, the least principal confining stress axis. Clustering of AE events indicated that the fracture was likely bi-wing with a dominant wing propagating in the $-y$ direction. The re-fracturing treatments were observed to continue propagation of the bi-wing fracture. MIF produced a distinctive large magnitude AE event coincident with the arrival of the pressure impulse. The hypocenter of this event (largest circle) was located at the base of

the injection well casing. Fig. 9 also includes the mapped 3D geometry of the fractures observed from cross-sections cut from the specimen after the conclusion of the test. Correlation between recorded AE events and the fracture location is clearly evident.

A production well alignment intersecting the AE indicated dominant fracture wing was selected and drilled after the initial fracture stage. The surface position of the production well relative to the injection well was 58 mm in the $-y$ direction and 68 mm in the $-x$ direction with a declination angle of 60° from the x -axis. This alignment intercepted the hydraulic fracture at approximately 118 mm depth into the granite specimen and provided a distance of at least 58 mm (5 borehole diameters) between the axes of the injection and production wells.

Fig. 10 compiles and compares all CP, CF, SCP and SCF results from G01-90. SCP injection tests were found to produce more repeatable results than SCF. Injection flow rates were observed to diminish with time during each step and with total injection time but did not exhibit simple asymptotic behavior. Similar fracture flow degradation behavior has been observed in previous work regarding proppant pack conductivity testing (API RP61, 1989). Typical hysteresis in SCP tests indicated higher injection rates associated with decreasing pressure steps than with increasing steps. Overlap of results between consecutive SCP tests shows non-permanence of the hysteresis effects and time-dependent decreases to injectivity (Frash et al., 2013a). Low levels of AE activity indicated negligible new fracture growth during SCP and SCF injections. Significant and permanent increases to injectivity were observed after each hydraulic stimulation, with the highest level of stimulation achieved by MIF. Oil injection data is highlighted to distinguish the effects of viscosity from those of stimulations.

Production from the simulated EGS reservoir was negligible until MIF was performed. Fig. 11 shows the production rate from the reservoir as a function of injection rate using data from SCF tests. A maximum ratio of fluid production rate to injection rate of 18% was measured at a water injection rate of 0.5 mL/min. Higher injection rates resulted in a larger percentage of injected fluid leak-off into the simulated EGS reservoir. Fluid leak-off was expected to be dominated by flow through the fracture breakthrough at the surface of the granite specimen but also included minor flow through the granite matrix as evident from staining observed proximal to the hydraulic fracture. Similar behavior can be expected at the field-scale when hydraulic fractures intersect natural permeable fracture networks. Likely consequences of high fluid loss include faster cooling of the reservoir and increased required pumping power (parasitic energy loss). It is possible that fluid loss can also contribute to induced seismicity but additional research is necessary to fully understand this phenomenon. When leak-off is significant it is expected that an optimal injection rate to production rate ratio ought to exist. An optimized injection scheme could potentially be achieved by balancing injection rates with production rates.

Temperatures, pressures, and flow rates measured during SCF tests were used to estimate fluid enthalpy and energy transfer rates through elements of the simulated EGS reservoir (Fig. 12). Energy transfer rates were estimated as enthalpy change multiplied by flow rate through each reported interval. Leak-off fluid temperature was assumed to equilibrate with the average boundary temperature of the granite specimen at the local atmospheric pressure of 83 ± 1 kPa at the 1760 m (5780 ft) elevation of the test site (NOAA, 2014). Note the boiling temperature of water at 83 kPa is approximately 94 °C

(Borgnakke and Sonntag, 2009). Leak-off flow rate was estimated as the difference between the measured rates of injection and production. The results in Fig. 12 show that most fluid heating occurred through conduction of heat through the injection well casing. Sufficient flow velocities were not achieved to counteract this dominant heat flow pathway due to the low hydraulic conductivity of the stimulated fractures and the high thermal conductivity of both the steel and the granite.

Flow from the production well was observed to be non-steady with fluctuating temperatures. The pressure in the production well was 31.5 ± 2.0 kPa and the nearby rock temperature was stable at 50 ± 3 °C. Steam tables (e.g. Borgnakke and Sonntag, 2009) show that this state is near the boiling point for water so mixed-phase flow was induced when vacuum was applied to pump fluid from the production well. The steam quality (mass fraction of gas to liquid) of the produced fluid was not measured for this experiment so the bottom-well enthalpy of the produced fluid could not be accurately determined. An estimate of the produced fluid enthalpy was calculated using the measured absolute pressure of 31.5 kPa and temperature measurements from the center of the specimen's top face ($x = 150$ mm, $y = 150$ mm, $z = 300$ mm).

Fig. 13 shows a cross-section cut from the granite specimen at 123 mm depth after injection testing was completed. Two bi-wing fractures were observed in the cross-sections, four fracture wings in total. One wing of the dominant bi-wing fracture propagated to the boundary of the specimen in the +y direction. A different wing from the secondary bi-wing fracture appeared to propagate directly between the production and injection wells with a twisting curvature becoming roughly parallel with and intersecting both wellbore axes. All four fracture wings propagated perpendicular to the minimum

principal stress axis (x -axis). The production well successfully intercepted wings from both the dominant and secondary fractures. The twisting geometry of the secondary bi-wing fracture suggests that it propagated after the production well was drilled. It is expected that the secondary fractures were created or substantially extended by the MIF treatment as indicated by the significant increase to both injectivity and production shown in Figs. 9 and 10.

3.2. G01-93: Triplet Well Test

Images of the G01-93 granite specimen prior to testing are shown in Fig. 14. A single band of discontinuous material, characterized by a higher than average quartz concentration, was observed dipping at a 70° angle, striking at 20° from the x -axis, and passing near the center of the specimen. No other large or persistent discontinuities were observed from the surfaces of the specimen. Thin concrete filler with a thickness of 3 mm or less was applied to the specimen's faces to improve surface flatness for load application with the flat jack and steel platen assemblies. The filler improved uniformity of the applied true-triaxial stresses and provided protection for sensors embedded in the surfaces of the granite specimen. Positions of installed thermocouples and AE sensors are shown in Fig. 14. No strain gages were installed for this experiment. The specimen was heated to 80°C and subjected to confinement stresses of 13.0, 8.0, and 4.0 MPa for the vertical (σ_v , z -axis), intermediate (σ_H , y -axis), and minimum principal stresses (σ_h , x -axis), respectively.

Table 4 provides an overview of the fluid injection schedule for this test which included one hydraulic fracture stimulation stage and a series of CP, CF, SCP and SCF injection tests, lasting 28 days in total. Reservoir conditions were maintained throughout

with 24 hour monitoring. Hydraulic fracturing was performed using SAE 80W90 oil with 170 to 325 mesh (0.045 to 0.090 mm nominal diameter) Ballotini[®] glass beads added at a loosely packed (gravity settled) concentration to serve as proppant. Two production wells were drilled after fracturing using AE event locations for guidance to create a triplet EGS well layout. The initial oil and proppant slurry was purged from the hydraulics and well after SCP #2 and the system was then refilled with tap water for improved injectivity with the lower-viscosity fluid. A heat exchanger was installed on the injection wellhead after SCP #37 to cool injection fluid prior to entry into the true-triaxial cell, increasing the temperature differential between the injected fluid and the model EGS reservoir.

The injection well was drilled with a 75° declination angle from the $-x$ axis along an alignment that passed through the center of the specimen. The respective top surface coordinates were 190 mm and 150 mm in the $+x$ and $+y$ directions, respectively. An oriented alignment was chosen with the intent of producing twisting hydraulic fractures. Hydraulic fractures can initiate parallel with the injection well in the near-well region and then transition to an orientation perpendicular to the minimum principal stress (σ_h , x -axis) with propagation (Abass et al., 1996; Hallam and Last, 1991; Valkó and Economides, 1995; Weijers et al., 1994).

Fig. 15 shows well pressure and injected fluid-volume data for the initial hydraulic fracturing treatment (CF #1) and additional water injection tests where fracture propagation possibly occurred (CF #2, CF #6 and SCF #5). Hydraulic fracturing was performed with a constant oil injection rate of 0.05 mL/min and exhibited multiple breakdown events with a peak pressure at 30.1 MPa. A pressure pulse with a magnitude of 30.9 MPa occurred at the end of the hydraulic fracture treatment resulting from closure

of two valves in the hydraulic system. Subsequent SCP tests indicated low injectivity but did confirm fluid flow between the injection and production wells. CF re-stimulations with water injection were performed in an attempt to increase hydraulic conductivity between the wells. These re-stimulations used injection rates of 0.05, 0.10, 0.20, 0.40, and 0.80 mL/min, sequentially. Well pressure instability was observed during the first re-stimulation (CF #2), but associated AE activity was low and no permanent increase to injectivity was measured by subsequent SCP tests. Injection pressures in subsequent re-stimulations were stable, as with CF #6, and also exhibited low AE activity and negligible increases to injectivity.

Fig. 16 shows the complied SCP test data where the injectivity as a function of pressure was observed to be consistent despite the water re-stimulations attempts. There is a slight change in the profile of the SCP results after SCF #5 but no net increase to injectivity. These observations led to the implementation of high pressure SCP tests with a maximum pressure of 18.0 MPa instead of 8.0 MPa. Also, high flow rate SCF tests were implemented with peak flow rates up to 6.40 mL/min. AE activity remained low through the modified SCP and SCF injection tests but higher production rates and larger temperature differentials were achieved for heat transfer study.

An unexpected pressure response was observed during high-rate SCF testing where increased injection rates were associated with lower injection pressures but minimal new fracture stimulation. This result suggests a transitional flow condition exhibiting an apparent inverse relationship between injection pressure and flow rate. One possible explanation for this result is a transition from laminar to turbulent flow along at least a portion of the flow path once the flow rate exceeds a critical value. It is also

possible that this phenomenon is a consequence of thermal flow effects. Two-phase flow effects were developed when vacuum pumping the production well induced boiling. Note that the apparent inverse pressure-flow phenomenon was observed both with and without vacuum pumped production. Future modeling efforts could offer additional insight on this phenomenon but this work has not yet been attempted.

AE event locations from the initial hydraulic fracture stimulation, shown in Fig. 17 (CF #1), were used to select fracture-intercepting production well alignments. A significant amount of AE activity was observed throughout the stimulation and an activity spike was coincident with the pressure breakdown event. Breakdown associated events (red) were plotted separately from other events (green). Breakdown events were clustered indicating a created fracture with an orientation perpendicular to the minimum principal stress (x -axis). Other events seemed to be clustered near the quartz-rich discontinuity band identified in the specimen prior to testing. The alignments of these two groups of events likely suggested a shear stimulated zone and a tensile hydraulic fractured zone, highlighted in Fig. 17. Event locations throughout all injections tended to follow the same trend as the initial hydraulic fracture stimulation. Inspection of the post-test cross-sections identified a fracture plane co-located with the breakdown associated AE events but no prominent fractures were found in the shear zone.

The first production well was drilled into the tensile zone and the second was drilled into the shear zone, as shown in Fig. 17, enabling a comparison of production rates between the two. Production Well #1 was drilled at $x = 206$ mm and $y = 193$ mm top surface coordinates to a depth of 120 mm with a dip of 60° from the $-x$ -axis. This alignment intercepted the mid-plane of the breakdown event AE cluster at an

approximate depth of 100 mm. Production Well #2 was drilled at top $x = 45$ mm and $y = 174$ mm top surface coordinates to a depth of 162 mm along an azimuth of 315° from the x -axis with a dip of 60° . This alignment intercepted the mid-plane of the other AE event cluster at an approximate depth of 150 mm. Production was ultimately successful only from Production Well #1 which was confirmed to intersect a prominent fracture by post-test cross-sections.

Fig. 18 shows production rate as a function of injection rate using data from SCF #3 and SCF #5. Production rates were measurable with vacuum pumping at most injection rates. Passive artesian production was successful only at high rates of injection. No fluid was ultimately produced from Production Well #2 so vacuum pumping was only installed in Production Well #1. A maximum fluid production rate to injection rate ratio of 34% was measured at a water injection rate of 2.20 mL/min. This fluid recovery ratio decreased at lower injection rates and when the production well was maintained at artesian pressures rather than vacuum. It is expected that the lower net fracture pressures associated with vacuum pumping reduced the leak-off pressure gradient and enabled higher fluid recovery ratios. Higher in-situ pore pressures and in-well artificial lift technologies at the field-scale can be expected to mitigate some issues with fluid leak-off and vacuum induced boiling but balancing is still important to optimize production and injection rates.

Bottom-well temperatures in Production Well #1 were observed to be unstable when vacuum pumping with values ranging from 48 to 80 °C. The absolute pressure in Production Well #1 during vacuum pumping was measured at 31.5 ± 2.0 kPa. This low pressure and the nearby injection well temperature of 76 ± 3 °C indicate that boiling

(mixed-phase flow) was likely the cause of the observed production well's temperature variance (Borgnakke and Sonntag, 2009). The enthalpy of the produced fluid could not be directly determined in this condition because the steam quality was unknown. Therefore an approximation for the enthalpy of the produced fluid was obtained using an absolute pressure of 31.5 ± 2.0 kPa and the temperature recorded in Production Well #2 when vacuum pumping was applied.

Fig. 19 shows the estimated energy transfer rates to and from the injected fluid through selected flow intervals. Fluid production rates for SCF #5, in which vacuum pumping was not applied, were estimated by linear interpolation between zero and measured rates associated with injection at 6.4 mL/min. Most fluid heating occurred through the injection well and only minimal heating was measured across the fracture flow interval. These results demonstrate the crucial importance of achieving high hydraulic conductivity through the stimulated reservoir such that parasitic energy losses can be reduced and heat transfer from the rock to the circulated fluid can be improved. The results also demonstrate the significant role of steel casing in the well as a heat transfer element. Generally the thermodynamic system was expected to be conduction dominated.

A cross-section from G01-93 at 103 mm depth is shown in Fig. 20. One bi-wing fracture propagated away from the injection well and this fracture was intercepted by Production Well #1. The fracture extended sub-vertically and parallel with the alignment of the injection well. The fracture length away from the injection well was not extensive enough to produce a twisted fracture surface. Injected blue dye aided in fracture identification but highlighting was still needed for better contrast in the photograph. The

discontinuity collocated with the AE indicated shear zone is highlighted in Fig. 17. No prominent fractures or evidence of fluid penetration were identified in the discontinuity band. The 3D fracture surfaces compiled from all cross-sections are shown in Fig. 16.

4. Discussion

The two experiments described provide examples of successful model EGS reservoir simulation where hydraulic fractures were created within initially intact HDR specimens, production wells were drilled using AE for guidance, thermal flow data was acquired, and created fracture geometries were measured. The applied reservoir conditions represent shallow dry low-temperature EGS in natural crystalline rock having negligible initial permeability and porosity. Successful reservoir creation depended upon stimulation of hydraulically conductive fractures between a set of injection and production wells. Hydraulic fracturing contained within the bounds of the specimen was attempted but unsuccessful for effective EGS simulation due to poor hydraulic conductivity through the resulting small fractures. General challenges during these experiments included accurately estimating fracture geometry, understanding the effects of natural heterogeneity and discontinuities, and achieving high-enthalpy fluid production at high-rates while minimizing fluid loss and induced seismicity. HDR conditions increased the challenge of EGS thermal fluid production where pore pressures were not applied to resist fluid leak-off. These same challenges exist at the field-scale so the lessons learned from these experiments can offer insight for the design and optimization EGS.

4.1. *Selecting Well Alignments using AE*

Successfully selecting the location of production wells in these experiments depended on accurately estimating the location of stimulated fractures in the rock specimen and intersecting the fractures with the new wells. Data filtering significantly benefitted estimation of fracture locations where poorly-localized and low-magnitude AE events were neglected to improve visualization. This basic filtering was successful for identifying the location of the hydraulic fracture in G01-90 but additional filtering was required for G01-93. Temporal filtering in G01-93 enabled isolation of AE activity along a pre-existing discontinuity from the main tensile hydraulic fracture location. Fluid production from G01-93 was ultimately successful from a well in the tensile hydraulic fractured zone but not from a second well in the pre-existing discontinuity. This result stresses the importance of coupled fluid flow and AE analysis at the field-scale to improve interpretation of stimulation data. Specifically, a parsed analysis of the AE data coincident with pressure breakdown was effective in this laboratory test and a similar benefit can be expected for field-scale experiments. It is important to note that AE analysis for G01-90 and G01-93 was performed without referencing the known applied stress directions to reduce bias.

4.2. *Thermal-Fluid-Production Relationships*

Thermal fluid flow through G01-90 and G01-93 was observed to be a complex function of geometry, injection pressure, temperatures and flow history. Geometry was the dominant factor controlling fluid flow where fluid more easily passed through fractures than the rock-matrix. SCP and SCF injection tests demonstrated that injectivity decreased but was more constant as a function of injection pressure rather than flow rate.

Pressure controlled injection tended to produce pseudo-steady flow conditions while flow rate control produced unsteady fluctuating pressures and a greater likelihood of additional stimulation. Fluid and rock temperatures had a complex interdependent effect on flow where faster injection of cold fluid was observed to increase hydraulic conductivity through the fractures. Flow history effects were evident through SCP hysteresis where injection at high-rates of flow typically resulted with increased injectivity in subsequent lower-rate injections, even associated AE indicated fracture propagation was negligible.

Similar complex multi-physical interactions are also likely at the field-scale. Generally the results from G01-90 and G01-93 suggest that constant flow rate control for injection can be beneficial for improving hydraulic conductivity. These results also show that balancing injection pressures with production well pressures is important for optimizing fluid leak-off and improving production efficiency. This balance is expected to be improved by in-situ pore pressures and saturating fluids in the field which can aid in reduction of leak-off given adequate well pressure and flow rate balancing. Additional experimentation is necessary to fully understand the interactions between these multiple effects to aid in optimization and EGS design.

4.3. Effect of Re-stimulations

Injectivity and productivity was increased by re-stimulations in both experiments with the most significant improvement observed after MIF #1 in G01-90. The MIF treatment was performed as a dynamic treatment rather than as a conventional hydraulic fracturing treatment (Frash et al., 2013b). The most significant injectivity increases were observed after treatments which produced high AE activity, indicating new fracture growth.

A similar benefit from re-stimulations can generally be expected at the field-scale. The lack of negative effects from additional stimulations as observed from these laboratory experiments, aside from increased leak-off, suggests that more stimulation is typically better than less. .

4.4. *Effect of Proppant*

The effect of adding proppant to the injection fluid was inconclusive from these experiments. The intent of adding proppant was to improve hydraulic conductivity through the fractures at low injection pressures but the results when comparing G01-90 and G01-93 appear to imply the inverse. The short stimulated fracture extents and narrow aperture in G01-93 relative to G01-93 are expected to be a strong factor causing this misleading result. Cross-sections indicated minimal, if any, penetration of proppant into the fractures. The impact of adding proppant at the field-scale is not expected to have the detrimental effect implied by these experiments.

4.5. *Fracture Geometry and Rock Structure*

Fracture geometries observed from cross-sections after testing showed a tendency for hydraulic fractures to match the alignments of wellbores that they intersected and fracture growth was also strongly affected by discontinuities and heterogeneities. In G01-90, a secondary bi-wing fracture twisted and matched the alignments of both the injection and production wells which it intersected. In G01-93, the created fracture followed the injection well alignment matching the 75° dip but otherwise propagated sub-perpendicular to the minimum principal stress axis. These geometries agree with previous studies on the effects of borehole orientation (Behrmann and Elbel, 1991; Weijers et al., 1994; Abass et al., 1996; Warpinski and Teufel, 1987).

Pre-existing discontinuities and heterogeneity affected the fracture geometries and observed AE activity during these tests. In G01-90 the sub-horizontal quartz-rich discontinuity was observed to inhibit upward fracture growth, as shown with Figs. 7, 9 and 13. In G01-93 the sub-vertical discontinuity was observed to generate significant AE activity without any associated prominent fracture growth, as shown with Figs. 14, 17 and 20. These discontinuities appeared to inhibit fracture growth through increased strength (G01-90) or decreased stiffness (G01-93) relative to the surrounding rock. Grain-scale heterogeneity was observed to have a direct effect on fracture roughness and local complexity as evident from the cross-sections. The effects of heterogeneity and discontinuities on fracture geometry are more apparent when compared with fractures in other materials such as concrete and acrylic (Frash, 2014).

Rock heterogeneity and discontinuities are abundant in the field with relevant structural features ranging in size from the grain-scale and smaller to the dimensions of massive faults and varying lithologies. Real granite was used in these experiments with known contained discontinuities in an attempt to better mimic the complex structures expected in the field. The result was non-ideal fracture geometry including a mixture of shear and tensile fracture propagation modes as injected fluids followed the path of least-resistance when forced into the rock through a borehole. Fracture propagation behavior through laboratory-scale granite specimens can be expected to obey the same physics as larger scales so similar geometric fracture complexity between the two scales can be expected to occur. Additional study is needed to characterize heterogeneity and distributed discontinuities to bridge the gap between absolute dimension scales in the laboratory, field and models.

4.6. *Lessons for Future EGS Concepts*

The G01-90 and G01-93 experiments demonstrate the importance of achieving effective stimulations to create successful EGS reservoirs and they also showcase important details and implementation methods which can be beneficial for improving the chance of success in the field. First, these experiments demonstrate that multiple diverse stimulation attempts are generally beneficial. Second, these experiments demonstrate how temporal filtering of AE events coincident with hydraulic pressure breakdown events can aid in isolating hydraulically fractured zones from pre-existing discontinuities. Third, the flow data demonstrates the complex interdependence of fracture geometry, injection pressure, temperatures and flow history on the injectivity and productivity of wells. Fourth, the thermal flow data emphasizes that poor hydraulic conductivity and low flow rates can result with conduction dominated heat transfer in EGS systems. Fifth, the complex fracture geometries demonstrate the difficulty of predicting single-stimulation fracture geometry due to the influence of heterogeneity and discontinuities. Lastly, these two experiments provide examples of successful EGS reservoir creation where AE activity was used to guide production well drilling.

5. Conclusions

Two laboratory experiments were performed to provide examples of EGS production from binary and triplet well layouts in hot dry crystalline rock. Specimens were initially intact granite with injectivity induced entirely through hydraulic fracturing, re-stimulations, and MIF. Successful production was dependent upon intercepting created hydraulic fractures with a production well using AE event locations for guidance. Improved estimation of fracture locations was gained by correlating AE data with the

injection well pressures, specifically pressure breakdown events. Higher fracture fluid pressures relative to the boundary pore pressures resulted in higher leak-off rates. Flow rates were observed to be a direct function of injection pressure but pressure was not observed to be uniquely dependent upon flow rate. Flow was observed to be strongly interdependent with hydraulic geometry, temperature, and flow history. Stepwise decrements to injection pressures were associated with higher injectivity than increments. Heat exchange was observed to be conduction dominated with low flow rate and poor hydraulic conductivity. Fracture geometries were strongly influenced by well alignments, discontinuities and stresses where fractures tended to propagate parallel with the well axis, have propagation inhibited by discontinuities and propagate perpendicular to the minimum principal stress.

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704

705 **Tables**

706 **Table 1**

707 Granite material properties.

Property	Value
Uniaxial Compression Strength (MPa)	152 ± 19
Poisson's Ratio	0.32
Elastic Modulus (GPa)	56.9
Density (g/cm ³)	2.63 ± 0.03
Indirect Tensile Strength (MPa)	7.5 ± 1.8
Thermal Conductivity (W/m ²)	3.14 ± 0.05
Volumetric Specific Heat Capacity (kJ/m ³ ·K)	2063 ± 92
Porosity	0.008 ± 0.001
Permeability (μD)	≤ 1.16
Shear Wave Velocity (km/s)	2.62
Compression Wave Velocity (km/s)	4.45

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710 **Table 2**

711 Properties of injected fluids.

Fluid	Temperature (°C)	Viscosity (cP)	Density (g/mL)
Tap Water	23 °C	$9.42 \cdot 10^{-1}$	0.998
	50 °C	$5.46 \cdot 10^{-1}$	0.988
	80 °C	$3.54 \cdot 10^{-1}$	0.971
80W90 Oil	23 °C	$3.23 \cdot 10^2$	0.887
	50 °C	$7.15 \cdot 10^1$	-
	80 °C	$2.26 \cdot 10^1$	-

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714 **Table 3**

715 G01-90 testing schedule.

General Stage	Fluid	Stage ID	Stage Details
Hydraulic fracturing	SAE 80W90 oil, 68 cP @ 51 °C	CP #1	2.0 MPa
		CF #1	0.05 mL/min
		-	Drilled production well
Re-fracture #1	SAE 80W90 oil, 68 cP @ 51 °C	SCP #1	2.0 to 4.0 MPa
		CF #2	0.05 mL/min
		CP #2	4.0 MPa
Re-fracture #2	SAE 80W90 oil, 68 cP @ 51 °C	SCP #2 to #7	2.0 to 6.0 MPa
		CF #3	0.05 mL/min
		SCP #8	2.0 to 6.0 MPa
Water injection	Water, 0.55 cP @ 50 °C	SCF #1	0.00001 to 0.003 mL/min
		SCF #2	0.003 to 0.03 mL/min
		-	Purged oil from injection well
		CF #4	0.05 mL/min
		CF #5	0.10 mL/min
		-	Temporary loss of heating and confinement conditions
MIF	Water, 0.55 cP @ 50 °C	SCF#3	0.05 to 3.0 mL/min
		CP #3	2.0 MPa
		SCP #9	2.0 to 6.0 MPa
		CP #4	2.0 MPa
		SCP #10 to #11	2.0 to 6.0 MPa
		CF #6	0.05 mL/min
		CF #7	0.10 mL/min
		CP #5	2.0 MPa
		SCP #12 to #15	2.0 to 6.0 MPa
		MIF #1	65 MPa impulse stimulation
		SCP #16 to #17	0.5 to 7.0 MPa
		CF #8	0.50 mL/min
		CF #9	1.00 mL/min
		CF #10	3.00 mL/min
		CF #11	5.00 mL/min
		SCP #18	0.5 to 6.0 MPa

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718 **Table 4**

719 G01-93 testing schedule.

General Stage	Fluid	Stage ID	Stage Details
Hydraulic fracturing	80W90 oil and proppant, 22 cP @ 80 °C	CP #1	2.0 MPa
		CF #1	0.05 mL/min
		-	Drilled production well #1
		SCP #1	2.0 to 8.0 MPa
		-	Drilled production well #2
		SCP #2	2.0 to 8.0 MPa
Water injection	Water, 0.35 cP @ 80 °C	-	Purged oil from injection well
		SCP #3 to #4	2.0 to 8.0 MPa
		CF #2	0.05 mL/min
		SCP #5 to #9	2.0 to 8.0 MPa
		CF #3	0.10 mL/min
		SCP #10 to #13	2.0 to 8.0 MPa
		CF #4	0.20 mL/min
		SCP #14 to #20	2.0 to 8.0 MPa
		CF #5	0.40 mL/min
		SCP #21 to #24	2.0 to 8.0 MPa
		CF #6	0.80 mL/min
		SCP #25 to #26	2.0 to 8.0 MPa
		SCP #27 to #32	2.0 to 18.0 MPa
		SCF #1	0.05 to 2.20 mL/min
		SCP #33 to #37	2.0 to 18.0 MPa
		-	Wellhead heat exchanger installed
		SCP #38 to #40	2.0 to 18.0 MPa
		SCF #2 to #3	0.05 to 2.20 mL/min
		SCP #41 to #44	2.0 to 18.0 MPa
		SCF #4	0.05 to 2.20 mL/min
		SCP #45 to #47	2.0 to 18.0 MPa
		SCF #5	0.05 to 6.40 mL/min
		SCP #48 to #49	2.0 to 18.0 MPa

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722 **Figures**

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724 **Fig. 1.** Photomicrograph showing typical grain heterogeneity in the granite.

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Fig. 2. True-triaxial apparatus showing platen and jack assemblies.

Fig. 3. Hydraulics system showing the layout of the pump fluid reservoir (a), valves (b), syringe pumps (c), injection fluid accumulator (d), rock specimen (e), vacuum condenser (f), injection well (g), and production well (h).

Fig. 4. Idealized hydraulic fracture stimulation with three injection stages into one well (adapted from ASTM D4645, 2008).

Fig. 5. Example raw data from a stepped constant pressure injection test with a single step highlighted (data from G01-90 SCP #14; Table 3).

Fig. 6. Analyzed pseudo-steady fluid flow data from Fig. 5 using averages of the last 30% of data from each constant pressure step.

Fig. 7. G01-90 granite specimen prior to testing with surface sensor locations and natural discontinuity shown.

Fig. 8. G01-90 stimulation pressures and fluid volumes.

Fig. 9. AE events recorded during G01-90 stimulations and observed final fracture geometry with interpolated intersections between the wells and fractures.

Fig. 10. Compiled analyzed data from CP, CF, SCP and SCF injections in G01-90.

Fig. 11. G01-90 measured fluid production rates as a function of injection rate.

Fig. 12. Rate of energy transfer through selected zones in G01-90 after MIF.

Fig. 13. G01-90 cross-section from 123 mm depth showing four fracture wings.

Fig. 14. G01-93 granite specimen prior to testing with sensor locations and natural discontinuities shown.

Fig. 15. G01-93 injection pressures and fluid volumes.

Fig. 16. Compiled analyzed data from SCP and SCF injections in G01-93.

Fig. 17. AE events recorded during G01-93 stimulations and observed final fracture geometry with interpolated intersections between the wells and fractures.

Fig. 18. Fluid production rates from G01-93.

Fig. 19. Rate of energy transfer through selected zones in G01-93.

Fig. 20. G01-93 cross-section at 103 mm depth highlighting location of discontinuity.