Hydro-Shearing and Hydraulic Fracturing for Enhanced Geothermal Systems in Archetypical Normal, Strike-Slip, and Thrust Faulting Terrains

Aleta Finnila¹, William Dershowitz¹, Thomas Doe¹, and Robert McLaren²

¹Golder Associates Inc., Redmond WA, USA
²Golder Associates Ltd., Cambridge, Ontario, Canada
afinnila@golder.com

Keywords
Enhanced geothermal systems (EGS), discrete fracture network (DFN), hydraulic fracturing, critical stress, hydro-shearing, thrust faulting, strike-slip faulting, normal faulting, stimulation model

ABSTRACT

This paper advances understanding of the feasible space of Enhanced Geothermal Systems (EGS) by evaluating the effects of in situ stress, natural fracture patterns, and hydraulic stimulation on processes of geothermal conduction and convection. EGS require stimulation techniques to improve fracture network transmissivity in sparsely fractured rock masses in a way that balances conductive and convective heat transport. Three archetypical terrains with in situ stress typical of normal, strike-slip and thrust faulting regions of North America are hydraulically fractured and hydro-sheared in Discrete Fracture Network (DFN) models so that the total available fracture area and fracture spacing at depth become sufficient for geothermal energy production.

The adequacy of fracture spacing and area was determined using analytic equations for parallel fractures of uniform aperture which are considered a best case scenario. Connected fracture networks are developed using simulation of both hydro-shearing of existing natural fractures and induced tensile fracturing. The average initial temperature of the reservoir was required to be 200°C and this constraint along with the regional thermal gradient was used to define the depth of the geothermal reservoir. Pumping pressures and durations required to develop and later utilize these systems are discussed.

Low geothermal gradients and high minimum stress values limit the practicality of creating EGS resources in major thrust faulting regions of the United States. Development of EGS in normal and strike-slip faulting regions seems to be more tractable, but potentially requires horizontal drilling for both the stimulation well and any injection or production wells. Differences in rock lithology affect constraints on fracture spacing. Designing an appropriate stimulation program that balances enhancing the reservoir permeability while maintaining adequate fracture spacing is challenging.

Introduction

Current US conventional geothermal power supplies provide 3.4 GWₑ (Matek, 2014). Estimates of potential EGS resource in the United States vary widely. One of the first comprehensive studies based on total heat in place between depths of 3 to 10 km reported an EGS potential of 100 GWₑ over the next 50 years (Idaho National Laboratory, 2006). Later estimates suggested even higher EGS potential, exceeding 500 GWₑ for the US; this increased projection occurring even though EGS prospects were restricted to locations in 13 Western States and drilling depths less than 6 km (Williams et al., 2008a, b). A 2013 study on EGS potential limited recoverable energy to depths above 5 km due to exponential drilling costs with depth and included a much smaller heat recovery factor of 2% compared to previous studies. The 2013 study suggested that EGS development in the near-term (5-10 year) should only focus on expanding existing conventional geothermal systems which could extend total geothermal power supplies by an additional 5-10 GWₑ (JASON, 2013). The DOE on their public web site currently uses the 2006 estimate for EGS potential of 100 GWₑ (EGS Fact Sheet, 2012).
With such a large range in projections for the potential of EGS, the question arises whether the potential for EGS is available just about anywhere in the US or if there are severe restrictions on locations where EGS is viable. To answer this, we need to understand the feasible parameter space for EGS. There are many properties that potentially affect EGS performance including:

- **rock properties**: density, thermal diffusivity, heat capacity, thermal conductivity, compressibility, thermal expansion coefficient, chemistry, porosity, elastic moduli, mineralogy and crystal size
- **reservoir properties**: depth, permeability, heat flow and thermal gradient, natural fracture size, spacing and orientation, formation geometry, pore pressure, stress state including local and relative magnitudes and orientation, block size and shape
- **fluid properties**: density, thermal diffusivity, heat capacity, thermal conductivity, chemistry

We take the approach that the key factors for initial EGS success are rock temperature, permeability, fracture surface area and fracture spacing using the logic presented by Doe et al. (2014). This paper focuses on how the regional stress state may restrict where EGS development is possible once thermal and impedance requirements are taken into account. Fluid-rock chemical interactions are not considered although it is recognized that these could play a significant role in the long-term viability of EGS.

Any discussion of the feasibility of EGS must define what a successful production site entails. This includes defining the range of water temperatures and fluxes that are needed to produce electricity as well as the useful lifetime of the resource. Minimum temperatures for this purpose in the literature range from 80°C for binary systems to 180°C for flash power systems (JASON, 2013). We consider an output temperature range of 200-180°C for a period of 20 years sufficient for electric energy production linked with flux rates of 0.07 m$^3$/s (70 l/s). In order to keep the impedance of the system below 1MPa/(l/s) production surface pumping pressures are restricted to less than 70 MPa (~10,000 psi). Note that this impedance level is still quite high as values lower than 0.15 GPa/(m$^3$/s) are generally accepted as desirable for geothermal systems (Idaho National Laboratory, 2006).

How restrictive are these constraints? To find out, we created a Discrete Fracture Network (DFN) model for EGS reservoirs representative of three tectonically distinct regions of the United States using Golder Associates’ FracMan software. We used the lithology of each model to calculate the minimum fracture area and spacing needed to maintain water outflow temperature and flux based on the parallel plate model. The model was then stimulated using two different methods to enhance the reservoir permeability. The first was a multi-stage hydraulic fracturing simulation using a well oriented parallel to the minimum stress direction with pumping rates and times necessary to create the required total fracture area, fracture spacing, and fracture transmissivity. The second method was to significantly increase the transmissivity of fractures experiencing shear failure due to elevated pore pressure to simulate the effects of hydro-shearing. Both hydraulic fracturing and hydro-shearing techniques were utilized separately and the resulting system impedance calculated.

**Tectonic Settings**

The goal of this work is to compile favorable and unfavorable factors for EGS development. To do this, we compiled geologic, geomechanical and hydrothermal information for three regions of the United States corresponding to extensional, thrust and strike-slip settings. We created archetypical models with properties consistent with being in various geomorphic provinces including Basin and Range in Nevada, New England in New Hampshire, and Colorado Desert in California. The aim is not to reproduce an exact replica of a location, but to provide a generic representation for that region while exploring a range of lithologies and stress conditions between the three locations.

**Extensional Stress Field**

The extensional tectonic region is often the most favorable for EGS due to the generally lower minimum stress state and higher thermal gradients. We chose a model having parameters consistent with metavolcanic...
Table 1. Model parameters for Normal Faulting Model (Nevada).

<table>
<thead>
<tr>
<th>Reservoir properties</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Thermal gradient [°C/km]</td>
<td>60</td>
<td>Depth to Reservoir [km]</td>
<td>3.3</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Discrete fracture network (DFN)</th>
<th>Generation Model/Concentration</th>
<th>Top/Center/Bottom Intensity (P32) [1/m]</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Normal Set Trend/Plunge [deg]</td>
<td>25/60</td>
<td>Fisher/10</td>
<td>0.03/0.045/0.03</td>
</tr>
<tr>
<td>Vertical Set</td>
<td>115/0</td>
<td>Fisher/10</td>
<td>0.02/0.03/0.02</td>
</tr>
<tr>
<td>Bedding Set</td>
<td>295/30</td>
<td>Fisher/25</td>
<td>0.01/0.015/0.01</td>
</tr>
<tr>
<td>Random Set</td>
<td>0/0</td>
<td>Fisher/25</td>
<td>0.005/0.005/0.005</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Rock Properties (Metavolcanics)</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Density [kg/m³]</td>
<td>2,650</td>
<td>Heat capacity [kJ/kg°C]</td>
<td>700</td>
</tr>
<tr>
<td>Thermal conductivity [W/m°C]</td>
<td>1.9</td>
<td>Young’s modulus [GPa]</td>
<td>34.2</td>
</tr>
<tr>
<td>Poisson ratio [-]</td>
<td>0.18</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fluid properties (Water)</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Density [kg/m³]</td>
<td>1000</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>In Situ Stress State</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Stress [MPa/km]</td>
<td>Orientation, Trend [deg]</td>
<td></td>
<td></td>
</tr>
<tr>
<td>σ₁ = 25</td>
<td>Vertical</td>
<td></td>
<td></td>
</tr>
<tr>
<td>σ₂ = 17</td>
<td>Horizontal, 25</td>
<td></td>
<td></td>
</tr>
<tr>
<td>σ₃ = 15</td>
<td>Horizontal, 115</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pore pressure = 9.9</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(8.9 \times 10^{-8} \text{ m}^2/\text{s}) and was correlated to fracture size. Aperture and storativity values were calculated as functions of the transmissivity (Hjerne et al., 2010). We used horizontal wells to best intersect the vertical induced tensile fractures during hydraulic fracturing and the naturally occurring fractures best oriented to fail during hydro-shearing. Work by Li et al. (2014) support EGS designs having parallel horizontal wells and multiple stage fracturing for normal and strike-slip faulting regimes in order to maximize economic performance.

### Strike-Slip Stress Field

Development of EGS in strike-slip tectonic environments is similar to that in the normal faulting regions. These areas are common at some tectonic boundaries where heat flow can be quite high and minimum stresses can be much lower which allows for lower pumping pressures for stimulation and production. To demonstrate these features, we chose to create a DFN model in a basaltic lithology similar to what might be found in the Salton Sea area of California in the Colorado Desert geomorphic province.

Parameters used in the DFN are shown in Table 2. With a thermal gradient of 90°C/km, the depth at the center of the reservoir is only 2.2 km, making it the shallowest system modeled in this paper. We placed the wells on a volcanic range next to a sedimentary basin such that the simulated area was contained in the basalt. Three sets of natural fracture sets were included in the basaltic reservoir, one horizontal and two conjugate vertical sets,
one aligned with the $\sigma_{\text{HMax}}$ direction of N45°E (Kilb, 2010; Holland, 2002). The modeled area is 2000m x 2000m x 1000m centered at a depth of 2,300 m with the DFN model, igneous fracture orientation and well geometry shown in Figure 2.

With the orientations of induced fractures being vertical for strike-slip regions, horizontal wells are appropriate for both the injection and producing wells. Like the normal faulting case, distance between the two outer wells is 1 km and the horizontal sections of the wells are 500 m.

**Compressional Stress Field**

Is EGS feasible in geologic regions experiencing a compressional stress state? Thrust faulting regions are the most challenging terrains for EGS development. Looking at maps of heat flow and stress state in the United States shown in Figure 3, in general the regions experiencing thrust faulting have much lower heat flow which often corresponds to a lower geothermal gradient.

For our compressional tectonic setting, we chose an area characteristic of the White Mountains of New Hampshire due to its relatively high heat flow (Johnson and Dunstan, 1998; Barton, 1996). While the heat flow is high (at least for the East Coast of the United States), the granitic lithology also has a high thermal conductivity leading to lower thermal gradients than is desirable. Lower geothermal gradients mean that EGS reservoirs need to be deeper in order to attain sufficiently high temperatures for electricity production. With a thermal gradient of only 24°C/km, a well would need to be drilled to a depth of more than 8 km in order to reach temperatures of 200°C. It is important to note that this thermal gradient is approximately equal to the average geothermal gradient of the Earth’s surface away from tectonic boundaries, so it is not extraordinarily low. Compounding this issue is the fact that native rock permeabilities are significantly lower at depth in compressional environments. Williams and DeAngelo, 2015, summarize some of the studies of how permeability changes with depth using different relationships between effective normal stress and permeability (Figure 4).

Initial permeability differences ranging from half an order of magnitude to several orders of magnitude higher in compressional environments will make enhancing the permeability up to EGS productive levels that much more challeng-
If the permeability of a system is very low, the impedance of water flowing through that system can be too high for flow rates to be attained using current pumping technology. Another factor related to the lower permeability that makes the thrust-faulting regions more difficult to stimulate lies with the higher minimum stress values present at the same depth in comparison with strike-slip or normal faulting regions. If increased permeability is to be achieved through hydraulic stimulation, pumping pressures needed to reach the critical normal or shear stresses can be unattainably high.

The lithology of our thrust faulting model is based on the White Mountain granitic rocks with DFN parameters listed in Table 3 (Bothner and Boudette, 1997). The direction of the maximum horizontal stress was estimated from data provided in the World Stress Map (Reinecker et al., 2005) and the Mirror Lake Report (Johnson and Dunstan, 1993). The vertical stress was calculated from the weight of the overburden assuming a density of 2500 kg/m$^3$. The maximum horizontal stress gradient was estimated based on the qualitative observation that this is solidly a thrust-faulting region, there is no evidence of strike-slip faulting so $\sigma_1$ is probably significantly higher than $\sigma_3$ (vertical). The minimum horizontal stress was estimated to lie between the vertical stress and the maximum horizontal stress. While these are rough estimates, our conclusions are not sensitive to these values given the great depth of the reservoir.

The enclosing region for the Thrust faulting model is based on the White Mountain granitic rocks with DFN parameters listed in Table 3 (Bothner and Boudette, 1997). The direction of the maximum horizontal stress was estimated from data provided in the World Stress Map (Reinecker et al., 2005) and the Mirror Lake Report (Johnson and Dunstan, 1993). The vertical stress was calculated from the weight of the overburden assuming a density of 2500 kg/m$^3$. The maximum horizontal stress gradient was estimated based on the qualitative observation that this is solidly a thrust-faulting region, there is no evidence of strike-slip faulting so $\sigma_1$ is probably significantly higher than $\sigma_3$ (vertical). The minimum horizontal stress was estimated to lie between the vertical stress and the maximum horizontal stress. While these are rough estimates, our conclusions are not sensitive to these values given the great depth of the reservoir.
We have a stimulation well in the center of the model and place an injection well on one side and a production well on the other side, the stimulation well is not used during production. The DFN model, fracture orientation and well geometry are shown in Figure 5.

**Required Fracture Area and Spacing**

In Doe et al. (2014), the authors start with an analysis of the Gringarten et al. (1975) solution to heat transport in homogenous, uniformly spaced parallel fracture networks. They provide a simple recipe for determining minimum fracture spacing and area as a function of rock and water properties, flow rate and target time for EGS operation. The paper continues its analysis using numerical simulation with more realistic fracture networks including variable spacing between fractures, variable apertures of the fractures and allowing fractures to intersect with one another. Greater complexity in the fracture geometry resulted in shorter durations of EGS viability due to the effect of concentrating the thermal drawdown into fewer fractures. Therefore, we use the equations governing the parallel fracture network to provide minimums for combined fracture area and spacing for parallel induced tensile fractures due to hydraulic fracturing.

The governing equations are presented in dimensionless variables of time, \( t_D \), outlet temperature, \( T_{WD} \), and half-fracture spacing \( X_{eq} \). This allows solutions using specific values of properties, spatial dimensions and rates to reduce to one set of thermal decline curves differentiated by the fracture spacing (Figure 6). Using \( c \) for heat capacity, \( K \) for thermal conductivity, \( \rho \) for density, and \( w \) and \( R \) as subscripts for water and rock respectively we have the dimensionless variables,

\[
\begin{align*}
    t_D &= \left( \frac{\rho_w c_w}{K_R} \right) \left( \frac{2x_e q}{xyz} \right)^2 \quad (1) \\
    T_{WD} &= \left[ \frac{T_{R0} - T_w(z, t)}{T_{R0} - T_{w0}} \right] \quad (2) \\
    X_{eq} &= \left( \frac{\rho_w c_w}{K_R} \right) \left( \frac{2x_e q}{xyz} \right) x_e \quad (3)
\end{align*}
\]

The flow rate through the entire system is \( q \), the width of the reservoir is \( x \) and the fracture area is \( y \times z \). With \( x_e \) being the half-spacing between fractures, the number of fractures in the system is \( x/(2x_e) \). \( T_{R0} \) and \( T_{w0} \) are the initial rock and water temperatures while \( T_w \) is the outlet water temperature which varies with location in the fracture and time.

Actual EGS systems having more realistic fracture networks will require greater fracture surface areas to be successful in the long term. So if the Gringarten case is the easier engineering challenge, what does this look like for the stimulation required in various tectonic settings? Table 4 shows the results for the three models.

<table>
<thead>
<tr>
<th>Tectonic Setting</th>
<th>Fracture Spacing [m]</th>
<th>Number of Fractures</th>
<th>Single Fracture Area [m²]</th>
<th>Total Fracture Area [m²]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Normal Faulting (Nevada)</td>
<td>100</td>
<td>5</td>
<td>7.8 x 10⁵</td>
<td>3.9 x 10⁶</td>
</tr>
<tr>
<td>Strike-Slip Faulting (California)</td>
<td>130</td>
<td>4</td>
<td>1.1 x 10⁶</td>
<td>4.4 x 10⁶</td>
</tr>
<tr>
<td>Thrust Faulting (New Hampshire)</td>
<td>152</td>
<td>3</td>
<td>1.2 x 10⁶</td>
<td>3.6 x 10⁶</td>
</tr>
</tbody>
</table>

From the table above, given the reservoir physical properties appropriate to the New Hampshire region, our model would need 3 parallel fractures each having an area of \( 1.2 \times 10^6 \) m². Given the reservoir physical properties appropriate to basalts in the Salton Sea region, the Strike-Slip (California) model would need 4 parallel fractures each having an area of \( 1.1 \times 10^6 \) m². Notice that this result is very similar to the Thrust faulting granitic model suggesting that either the minimum fracture area and spacing are not very sensitive to the rock physical properties, or that the range in these properties found between these two lithologies is not very great.

If fracture spacing in the EGS reservoir is smaller than this minimum fracture spacing, the reservoir will need to have greater total fracture area. There is a breakthrough-delays effect of decreasing the rate per fracture that is stronger than the breakthrough-accelerating effect of smaller fracture spacing (Doe et al., 2014). Table 5 shows this relationship...
calculated for the Normal stress model (Nevada) to illustrate a range of total fracture area and spacing pairs possible for this scenario.

Results of Hydraulic Fracturing

The thermal calculations were based on a parallel plate fracture model. It is possible to generate parallel induced tensile fractures using multiple stages of hydraulic fracturing using pumping pressures that exceed the minimum stress at depth.

The hydraulic fracturing simulations use Golder Associates’ FracMan DFN code which is based on the theory of critical stress analysis and involves solving a constitutive relation conserving the material mass within the fracture network (Dershowitz et al., 2011; Cottrell et al., 2013). An induced tensile fracture develops from the well having a normal parallel to the minimum stress direction. Intersecting natural fractures having a normal stress less than the fracture pore pressure also accept water. FracMan simulates the hydraulic fracturing by maintaining a volume balance between the pumped water and the expanded volume of the natural fractures and the developed hydraulic fracture.

Normal Faulting/Extensional Region – Nevada Model

Since the thermal calculations for the extensional tectonic region (Nevada) required five fractures each having a surface area of $7.8 \times 10^5$ m$^2$ (Table 4), we added five perforated zones to our stimulation well evenly spaced 100 m apart. Pumping at 600 gpm over five days at pressures 138 kPa (20 psi) above the minimum stress for each stage created appropriately sized, semicircular, vertical fractures centered around the horizontal well. Once an induced fracture intersected a large, similarly oriented natural fracture, the pumping fluid also inflated it, reducing the expansion rate of the induced fracture. Figure 7 shows side and top views of the hydraulic fracturing results.

Strike-Slip Region — California Model

The strike-slip stress model has the shallowest reservoir of the three presented here. Some natural fractures were inflated along with the four induced tensile fractures (see Figure 8). Each of the

Table 5. Minimum total fracture areas required for the Normal Faulting (Nevada) model for different production rates and economically useful reservoir lifetimes calculated by applying Equations 1-3 using the physical parameters listed in Tables 1-3. Production water temperatures allowed to decrease from 200°C to 180°C.

<table>
<thead>
<tr>
<th>Fracture Spacing</th>
<th>Production Rate (m$^3$/s)</th>
<th>Minimum Area (x 10$^6$ m$^2$)</th>
<th>Minimum Area (x 10$^8$ m$^3$)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>$X_eD=2$ or higher, 100 m</td>
<td>$X_eD=0.5$, 32 m</td>
</tr>
<tr>
<td>20 years</td>
<td>0.05</td>
<td>2.8</td>
<td>3.6</td>
</tr>
<tr>
<td></td>
<td>0.07</td>
<td>3.9</td>
<td>5.1</td>
</tr>
<tr>
<td></td>
<td>0.10</td>
<td>5.5</td>
<td>7.2</td>
</tr>
<tr>
<td></td>
<td>0.14</td>
<td>7.8</td>
<td>10</td>
</tr>
<tr>
<td>30 years</td>
<td>0.05</td>
<td>3.4</td>
<td>4.4</td>
</tr>
<tr>
<td></td>
<td>0.07</td>
<td>4.7</td>
<td>6.2</td>
</tr>
<tr>
<td></td>
<td>0.10</td>
<td>6.8</td>
<td>8.8</td>
</tr>
<tr>
<td></td>
<td>0.14</td>
<td>9.5</td>
<td>12</td>
</tr>
</tbody>
</table>

Figure 7. (Top) Side and top views of five induced fractures (red) having surface areas between $7.4 \times 10^5$ – $8.6 \times 10^5$ m$^2$. Existing natural fractures that were inflated during the stimulation are shown in green. The region boundaries are 2000 m x 2000 m x 1000 m.

Figure 8. (Bottom) Side and top views of four induced fractures (red) and inflated natural fractures (green) for the Strike-Slip model. The region boundaries are 2000 m x 2000 m x 1000 m.
four stages in the system was pumped at 600 gpm for 20 days requiring a total water volume over \(2.6 \times 10^5\) m\(^3\) (69 million gallons or 212 acre feet).

**Compressive Region — New Hampshire Model**

The depth of this EGS reservoir is a serious concern. Not only do drilling costs currently increase exponentially with depth (JASON, 2013), but you need to be able to pump water at pressures above 100 MPa (14,500 psi) so the bottom hole pressure exceeds the minimum stress of 186 MPa in order to create induced fractures. During our simulation, the natural fractures were not able to significantly inflate, regardless of their orientation with respect to the maximum horizontal stress, so the only increase in permeability comes from the induced fractures. These new fractures will need to be kept open with a proppant in order to maintain the enhanced permeability once stimulation ends. Each of the three hydraulic fracturing stages was pumped at 100 gpm for 7 days to achieve the desired single fracture area of \(1.2 \times 10^6\) m\(^2\). One favorable feature of the thrust faulting region is that induced fractures are oriented horizontally, so connecting to them with vertical injecting and producing wells is straightforward (Figure 9).

**Results of Hydro-Shearing**

While hydraulic fracturing creates parallel induced tensile fractures that can be engineered to have the desired fracture spacing and area, this method of enhancing geothermal reservoir permeability has several potential drawbacks.

![Figure 9](image.png)

**Figure 9.** Side and top views of three horizontal induced fractures (red) and inflated natural fractures (green) for the Thrust Faulting system. The induced fractures each have a surface area of \(1.2 \times 10^6\) m\(^2\).

![Figure 10](image.png)

**Figure 10.** (Top row) Equal area stereoplots for the three regional models showing the poles of critically stressed natural fractures (red) under excess pore pressure provided during hydro-shearing stimulation. The poles of non-critically stressed fractures are shown in green. The direction of least principal stress is shown labeled as “Sigma 3”. (Bottom row) Associated Mohr diagrams showing critically stressed fractures (red) as a function of normalized shear and normal stresses. Fractures do not line up precisely with the Mohr circles due to the range of depths and corresponding stresses represented in each model.
Some authors have suggested that transmissivity of induced fractures can actually be too high with the greater permeability focused in too narrow of a volume. We overcame this limitation in our models by creating several parallel fractures, however, for vertical wells in normal or strike-slip settings where vertical induced fractures are not ideal, the permeability enhancement is often attempted using lower pumping rates and keeping pumping pressures below the minimum stress to only cause critically stressed fractures to fail in shear.

To estimate the effects of hydro-shearing on our models, we modified the natural fractures that would experience Mohr-Coulomb frictional failure at pore pressures ranging from hydrostatic up to the minimum stress. There is still a lot of uncertainty as to how fracture transmissivity changes during shear failure. Recent work by Miller (2015) suggests that it may be possible to use a very simple model such as having the transmissivity increase by a factor of 1000. We use this simplifying assumption and examine how the overall permeability of the reservoir would change at different pore pressure values caused by low volume, long duration hydraulic stimulation. We assume that the duration of the hydraulic stimulation is long enough to reach the boundaries of the model, without calculating how long that would take.

Critically stressed fractures due to hydro-shearing are oriented in a conjugate pair of sets symmetric about the minimum stress direction (Figure 10). These sets are best intersected with a well aligned with this minimum stress direction which would be a horizontal well for normal faulting and strike-slip faulting regions and a vertical well in thrust faulting regions.

### Impedance Considerations

Impedance values for geothermal systems are generally desired to be below 0.15 MPa/(l/s). Table 6 shows the measured impedance at current and historical EGS sites. Of these, the Soultz site is closest to reaching desired combined flow rates and pumping pressures.

To estimate the impedance of these regional models, we used the code, MAFIC (Matrix/Fracture Interaction Code), from the FracMan software. MAFIC simulates flow in fractures using three-dimensional networks of triangular finite elements. We set up no-flow boundary conditions about the edges of the model and added a positive flow rate of 0.07 m$^3$/s in the injecting well and a negative flow rate of -0.07 m$^3$/s in the producing well. The impedance was calculated from the resulting pressure differential between the two wells during steady state.

The number of fractures in our model was too great to capture all of them during the finite element simulation, so we created a workflow to capture just the most conductive pathway between the wells selecting from just the top 10% most transmissive of the fractures. We used this much smaller subset of fractures to run the MAFIC simulation (see Figure 11 for an example). While this technique greatly reduces the required computation time, it is potentially overestimating the impedance by limiting flow to the best fracture pathway, mimicking extreme channelization. Conversely, transmissivities of the induced and inflated fractures from the hydraulic fracture simulation were adjusted by scaling them to the storage apertures calculated during stimulation. This assumes that fracture aperture was not reduced once the stimulation was complete which certainly overestimates their transmissivity and leads to lower calculated system impedance than is perhaps realistic. Also, the results are quite sensitive to each particular stochastic realization of the fracture sets so re-running the analysis on multiple realizations would improve the accuracy of the results.

Given the simplifications made in adjusting fracture transmissivity by the two stimulation methods, the impedance results shown in Table 7 are rough estimates, nonetheless, they show expected patterns of critically high impedance

---

**Table 6.** Measured impedance from EGS sites around the world. 1DuTeau and Brown, 1993. 2Brown, 2009. 3Batchelor, 1986. 4Tenma et al., 2008. 5Genter et al., 2012. 6Sanjuan et al., 2006. 7Cladouhos et al., 2015, with impedance measurement taken from injectivity of single stimulated well.

<table>
<thead>
<tr>
<th>Well</th>
<th>Impedance [MPa/(l/s)]</th>
<th>Well Spacing at Depth [m]</th>
<th>Highest Borehole Temperature [°C]</th>
<th>Production Temperature [°C]</th>
<th>Depth [m]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fenton Hill1,2</td>
<td>2.1 – 3.3</td>
<td>100-300</td>
<td>235</td>
<td>165-190</td>
<td>2800-3500</td>
</tr>
<tr>
<td>Rosemanowes3</td>
<td>1.0</td>
<td>300</td>
<td>-</td>
<td>55-84</td>
<td>2600</td>
</tr>
<tr>
<td>Hijiori4</td>
<td>0.3</td>
<td>45-130</td>
<td>270</td>
<td>110-180</td>
<td>1800-2200</td>
</tr>
<tr>
<td>Soultz5,6</td>
<td>0.2</td>
<td>450-650</td>
<td>200</td>
<td>152-165</td>
<td>5000</td>
</tr>
<tr>
<td>Newberry7</td>
<td>2.7 (injectivity) one well</td>
<td>300</td>
<td>-</td>
<td></td>
<td>3000</td>
</tr>
</tbody>
</table>

**Table 7.** Calculated impedance values using finite element analysis.

<table>
<thead>
<tr>
<th>Model Impedance [MPa/(l/s)]</th>
<th>Normal (NV)</th>
<th>Strike-Slip (CA)</th>
<th>Thrust (NH)</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Stimulation</td>
<td>32</td>
<td>8.0</td>
<td>25</td>
</tr>
<tr>
<td>Hydro-Shearing Only (HS)</td>
<td>0.22</td>
<td>0.39</td>
<td>0.17</td>
</tr>
<tr>
<td>Hydraulic Fracture Only (HF)</td>
<td>0.26</td>
<td>0.44</td>
<td>8.1</td>
</tr>
<tr>
<td>Both HS and HF</td>
<td>0.06</td>
<td>0.04</td>
<td>0.17</td>
</tr>
</tbody>
</table>
before stimulation and dramatic decreases to the impedance after the various stimulation techniques.

After hydraulic fracturing, the Thrust Faulting model still required pressures exceeding the minimum stress value of 185 MPa to pump water at the desired flow rate through the connected fracture network. The failure of thrust faulting to significantly increase permeability is perhaps not particularly surprising. While there is anecdotal evidence that normal and strike-slip earthquake events cause short-term increases to groundwater discharge, no such increase has been observed for similar magnitude thrust faulting events (King and Woods, 1994).

For conventional geothermal resources which already have acceptable permeability, having a compressional stress environment can be quite beneficial. As discussed by Anderson and Brahn (2012) for the Utah hot springs, an existing thrust fault at great depth which has significant permeability can be accessed via higher dipping faults. The issue for EGS development is the difficulty in creating sufficient permeability in these settings at great depth.

Temperature Drawdown

The temperature of the outlet water temperature for each regional case and stimulation method was calculated over time using the simulation code, HydroGeoSphere (Therrien and Sudnicky, 1996; Brunner and Simmons, 2012). The most transmissive fractures of each FracMan DFN model were mapped onto a similar, orthogonal HydroGeosphere model and simulated over time using the same boundary conditions and pumping parameters as were used for the impedance simulations. The results are shown in Figure 12.

Three of the models were successful at maintaining a production temperature above 180°C over a period of 20 years and three were not. The Normal Faulting hydraulic fracturing model failed due to the large vertical extent of the induced tensile fractures. The apertures of the induced fractures were larger at the top due to the lower stresses and the water flow paths preferentially traversed the shallower, lower temperature regions of the reservoir (Figure 13). Placing the wells at a lower depth may have corrected this issue so that the average temperature in the induced vertical fractures was higher.

The pattern of success and failure of the models correlates with the stimulated average transmissivity of the fractures. Successful models had average transmissivities in the range $3.4 \times 10^{-4}$ m$^2$/s (normal faulting hydro-shearing) to $2.4 \times 10^{-3}$ m$^2$/s (strike-slip faulting hydraulic fracture) while the failed models had average transmissivities in the $1.2 \times 10^{-6}$ m$^2$/s (thrust faulting hydraulic fracture) to $6.9 \times 10^{-5}$ m$^2$/s (normal faulting hydraulic fracture). These results reflect our assumptions on how the two stimulation techniques affected these fractures. Hydraulic fracturing affected a small number of the fracture population and assumed that the final aperture equaled the storage aperture created during high-pressure pumping. As a result, the affected fractures probably have
be applied. Estimates of pumping rates, water volumes and durations for well stimulation can be calculated. For any demonstration of EGS viability, both the long-term thermal requirements must be met along with reasonable stimulated system impedance levels.

The initial stimulation simulations of these three regional models discussed in this paper highlight many of the different challenges to successful EGS development by combining restrictions placed by thermal considerations along with those due to the regional stress state.

The Normal Faulting model and the Strike-Slip model behaved in a similar fashion with their high thermal gradients allowing reservoir depths to be shallow enough to use reasonable pumping pressures for hydraulic stimulation. Horizontal well orientation aligned with the minimum stress orientation, Sigma 3, would maximize intersections with both induced tensile fractures from hydraulic fracturing and critically stressed fractures experiencing shear failure due to hydro-shearing stimulation.

Our Thrust Faulting model, represented by a granitic location in New Hampshire, revealed some of the issues with locations having normal or low geothermal gradients. The depth to the reservoir was over 8 km and pumping pressures required to stimulate this zone were prohibitively high. One benefit of this stress orientation is that vertical wells are best suited to access the horizontal induced tensile fractures and hydro-sheared fractures.

Acknowledgements

The authors gratefully acknowledge the funding support of Sandia Laboratories and the US Department of Energy. We’d also like to thank our Golder colleagues Hooman Hosseinpour, Glori Lee and Neal Josephson for their technical support of the hydraulic fracturing simulation.

References


Finnila, et al.


Swyer M. W., and N. C. Davatzes, 2013. “Evaluating the role of the rhyolite ridge fault system in the Desert Peak geothermal field with robust sensitivity testing through boundary element modeling and likelihood analysis.” 38th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, 16p.


