Numerical Simulation of Fluid Circulation in Hydraulically Fractured Utah FORGE Wells

Sang H. Lee, Ahmad Ghassemi
Reservoir Geomechanics and Seismicity Research Group, The University of Oklahoma, Norman, OK 73069
ahmad.ghassemi@ou.edu

Keywords: Geothermal, Hydraulic Fracturing, FORGE, EGS, Reservoir Simulation

ABSTRACT
In this paper we investigate water circulation and thermal energy transport associated with multi-stage hydraulic fracturing at the Utah FORGE reservoir development. First a multistage fracturing of the injection well is simulated to assess the potential flow path between the injection and production wells. Then, reservoir performance is analyzed using a 3D reservoir model for heat transport. The numerical approaches are first calibrated using a lab-scale EGS experiment with fracturing, fluid circulation, and thermal transport to clarify the role of fracture flow, heat exchange and physical properties of the fluid and the rock. Then, simulations are performed to illustrate the pressure and temperature change by water injection and production in the presence of hydraulic fractures.

1. INTRODUCTION
The FORGE (Frontier Observatory for Research in Geothermal Energy) site is located 250 km south of Salt Lake City, Utah. Figure 1 is a simplified block diagram to illustrate well location and temperature distribution. The blue-colored inclined well is the Well16A(78)-32 which has been drilled in 2021, and the red-colored well is the production well.

Figure 1: (a) Block diagram illustrating the thermal regime and projected flow circulations between 65° inclined injector (blue-colored well) and future producing well (red-colored well) in the granite FORGE test site. (b) Satellite data, and aerial photographs for the location of Utah FORGE site. (Allice and Moore, 2019).

The intact rock permeability is very low (Zhou and Ghassemi, 2022) but many cracks and fractures in the reservoir enhance the fluid flow capacity and heat exchange rate for the extraction of geothermal energy. More than 2000 natural fractures are identified and the DFIT analysis indicated that the rock permeability is still not enough to allow the water to circulate between the wells (Moore et al., 2019, Xing et al., 2021, Xing et al., 2022). To improve the fluid connectivity, well stimulation by the hydraulic fracturing process is preferred. This has been demonstrated in a series of lab-scale experiment conducted to understand the heat transfer by water flow within the fractures using Acoustic Emission (AE) events, pressure and temperature monitoring, tracer test (Hu and Ghassemi, 2016, 2017, 2018, 2019, and 2020). In this work, we presented numerical modeling of water circulation in the planned Utah FORGE doublet consisting of a hydraulically fractured injection well and a production well. The fracturing is simulated using a rapid and highly efficient state-of-the-art GeoFrac-R3D model. The reservoir circulation is then simulated using a finite-difference method model accounting for the fluid flow and thermal energy transport. First, the simulation model is calibrated with a lab-scale EGS experiment (Hu and Ghassemi, 2020). Then,
numerical simulations are carried out for the Utah FORGE reservoir to analyze the fluid flow and temperature change when injecting into the hydraulic fractures. The simulation considers equivalent reservoir permeability due to the presence of natural fractures around the Well16A(78)-32. For the hydraulic fracture propagation, “GeoFrac” is used to estimate the hydraulic fracturing length, height and apertures. For the Utah FORGE water circulation modeling, we consider fluid circulations within the fractures for two cases: (i) homogeneous low permeability reservoir, (ii) reservoir with a discrete fracture network. The pressure changes in water circulation shows more pressure drop when the rock permeability is low compared to the discrete natural fracture permeability model. In the latter the simulations are repeated for various production well locations. The simulation results show that the circulation efficiency is improved when the production well is located parallel to the injection well. Also, the influence of natural fractures in water circulation between the wells was discussed. From the analysis of discrete fracture network permeability case, it is demonstrated that the production well located parallel to the injection well on the west side from the injector case resulted in good fluid circulation performance. This is because more permeable natural fracture flow paths on that side of the injector. However, because of the nature of uncertainty in natural fracture network estimations, further analysis is required to ascertain the best location for optimum flow potential between the injector and the producer.

2. NUMERICAL CALIBRATION FOR LAB-SCALE ENHANCED GEOTHERMAL SYSTEM EXPERIMENT

In this section, we present analysis of a lab-scale EGS (Enhanced Geothermal System) experiment to calibrate the model. Hu and Ghassemi (2020) presented a heat production test as a proxy of field scale EGS using granite and gabbro rocks. The test blocks had a five-spot system with one injection well at the center and four producers drilled about 9 cm away from it. The test began with stimulating the intact block by hydraulic fracturing from the injector to create a fracture within the injector and the producer. The acoustic emission (AE) activity was also recorded and reconstructed to estimate the fracture geometry by stimulation. Circulation test between the wells were performed after hydraulic fracturing, and the pressure and temperature change at the injection well and the production well were recorded. The experiment results clearly demonstrated that the pressure and temperature change from the injector and producers are highly related with the fracture geometry, connectivity, and tortuosity. The pressure changes at the injection well showed that the pressure increased as the injection rate increased at the early time of circulation. However, the pressure stabilized began to decrease while the injection rate increased. It can be explained as the production well needed fluid flow time from the injection well to reach the production well, also the aperture of the fracture is small at the beginning of injection and slowly increases to satisfy equilibrium between the injection pressure within the fracture and the in-situ stress of test rock. Significant temperature changes are observed when the injection well has a good connectivity with the production well.

![Figure 2: (a) Discretized grid model. The grid block size is 0.75 cm×0.75 cm×1.6 cm. The yellow-colored grid-blocks indicate the fracture grid-blocks. (b) Top view of 5 injection and production sources, injection well located at the center of 5-spot system, and other 4 producing wells are marked as Well No. 1, No. 2, No. 3, and No. 4.](image)

Flow and heat transport in EGS has been extensively studied in the past decades using the boundary and finite element methods (Cheng et al., 2001; Ghassemi et al., 2003, 2005, 2007, 2008; Zhou et al., 2009; Ghassemi and Zhou, 2011; Rawai and Ghassemi, 2014; Safari and Ghassemi, 2015 and 2016; Xia et al., 2017; Gao, Q., Ghassemi, A. 2020). In this work we utilize a finite difference model. The numerical model setup is described in Figure 2. The fracture grid-blocks are followed by the reconstructed fracture geometry (Hu and Ghassemi, 2020). The model’s grid block size is 0.75 cm for x- and y- direction each and the z-directional grid block size is 1.6 cm. Total number of grid-blocks are 45, 45 and 22 each. The yellow-colored grid-blocks shows hydraulically fractured areas and the red-colored grid blocks are injector and producers. The total number of injection grid-block is 5 and the production well grid-block is set to one per production well. The reason for the difference of source grid-blocks number is to follow the experimental setup where the injection and the production well diameters were 20.1 mm and 10.2 mm. We used trial and error to estimate the permeability change in the fracture grid-blocks as the injection rate changed. The input parameters are described in Table 1. It is assumed that the rock is homogeneous, and the physical properties are constant during the simulation, but the density and the viscosity are computed based on the thermodynamic table for liquid water and steam as a function of pressure and temperature. Estimated upscaled permeability was about 0.1 md at the beginning of the circulation, then gradually increased up to 120 md as the injection rate increased.
Table 2: Input parameters for lab-scale Enhanced Geothermal System simulation.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity, $\Phi$</td>
<td>0.01</td>
</tr>
<tr>
<td>Thermal conductivity, $K_T$</td>
<td>4.0 W/m-K</td>
</tr>
<tr>
<td>Matrix permeability, $K$</td>
<td>0.68 Micro Darcy</td>
</tr>
<tr>
<td>Heat Capacity, $c_T$</td>
<td>1200 J/Kg-K</td>
</tr>
<tr>
<td>Density of rock, $\rho_s$</td>
<td>2.7 g/cm$^3$</td>
</tr>
<tr>
<td>Residual saturation of water, $S_{wr}$</td>
<td>0.30</td>
</tr>
<tr>
<td>Residual saturation of steam, $S_{gr}$</td>
<td>0.05</td>
</tr>
</tbody>
</table>

Figure 3: (a) Comparison of the injection pressure from the numerical simulation with the lab-scale EGS experiment data. (b) Comparison of injection well temperature change from the numerical modeling to that from the lab experiment. (c) Comparison of producing well No. 4 temperature change from the numerical modeling to that from the lab experiment. (d) Comparison of producing well No. 1 and No. 3 temperature change from the numerical results to that from the experimental measurement.

Comparison of numerical modeling and the lab-scale experimental data is presented in Figure 3. The numerical simulation results for lab-scale modeling showed good agreement with the experimental data for pressure and temperature. Figure 3(a) shows that the pressure increases at the early stage as the injection rate is increased but it decreases after 800 seconds even as the injection rate increases. This can be explained by the small aperture and the low production rate. The cooling of temperature is also compared with experimental data for the injector at the center and the producers No. 4, No. 3, and No. 1. The boundary condition for injection water temperature was 20°C, and the equivalent temperature at the injector decreases as the rock is cooled by cold water injection (shown in Figure 3(b)). The lab-scale experimental test data show that the temperature drop is 16.0°C, 6.1°C, and 6.5°C for Wells 4, 1, and 3, respectively as shown in Figure
Lee and Ghassemi

3(c) and (d). Note that since most of the injected water flows to Well No. 4, it experiences the largest temperature drop among the 4 production wells. Physical properties variation due to cold water injection into the hot rock blocks contributes to matching of the experimental observations, but the permeability plays the key role in matching the pressure and temperature change in the hydraulic fracture connecting the wells.

Figure 4: Numerical results of pressure distributions for lab-scale EGS numerical modeling. Initial pressure is 2 MPa. Injector and producer pressure changes were calibrated based on the experimental test data results (a) $t = 600$ sec, (b) $t = 1500$ sec, (c) $t = 3400$ sec, and (d) $t = 7600$ sec.
Figure 5: Modeling results of temperature distributions for lab-scale EGS numerical modeling. Initial temperature is 63.6 °C and the injection water temperature is 20 °C (a) t = 600 sec, (b) t = 1500 sec, (c) t = 3400 sec, and (d) t = 7600 sec.

Figure 6: Distribution density, viscosity, enthalpy and Peclet number at t = 7600 sec. Density and viscosity changes in (a) and (b); enthalpy change in (c) and Peclet number in (d).
Lee and Ghassemi

Three-dimensional numerical results for pressure and temperature change with time are presented in Figure 4 and 5. The cross-sectional view of 3D pressure distribution illustrated that the significant pressure increases around injector at the early stage of circulation are observed as shown in Figure 4(b) and (c), then the pressure distributions are almost equally distributed within the fracture while water circulation between the wells. The onset of temperature drop at the producer is much slower compared with the pressure change because the heat exchange rate is much less than the fluid flow rate. Density and viscosity, as well as Péclet number distributions for \( t = 7200 \) sec are illustrated in Figure 6. Clearly the advective heat flux is dominant within the fracture flow for water circulation in geothermal reservoir. The highest Péclet number is observed around the injector and producer sources since the fluid velocity is highest around the wellbore due to the significant pressure increase and/or decrease.

3. NUMERICAL MODELING FOR UTAH FORGE WELLS

3.1 Multi-Stage Hydraulic Fracturing Simulation Using GeoFrac-R3D

“GeoFrac-R3D”, a hydraulic fracturing simulator that uses 3D displacement discontinuity method or 2D displacement discontinuity with height correction factor combined with equilibrium height growth for rapid analysis of fracture propagation problems. The DD method has been investigated by many authors (Wiles and Curran, 1982, Ghassemi and Roegiers, 1996), and the theory has been extended and applied to the multiple hydraulic fractures and three-dimensional cohesive zone model (Sesetty and Ghassemi, 2013, Kumar and Ghassemi, 2016 and 2018, Gao and Ghassemi, 2020). Details of numerical implementation of the model used in this work and their coupled solution procedure can be found in Ghassemi et al. (2013) and Kumar and Ghassemi (2016, 2018, and 2019). The GeoFrac-R3D program is used to model the fracture propagation for Well16A(78)-32. In the simulation we first considered the first stage at the toe (2600m, TVD), and then the hydraulic fracturing stage moved 50 m for stage 2 and 3 to obtain the estimated fracture geometry of the planned stimulation. We assumed a 5 cp fluid for improve stimulation outcome. It is assumed that the minimum horizontal stress is close to the closure pressure which is obtained from the Well16A(78)-32 DFIT analysis at 2609 m, TVD by Xing et al. (Xing et al., 2021). The input parameters for GeoFrac-R3D simulations are listed in Table 2.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>In-situ stress ( (S_{hmin}, S_{hmax}) )</td>
<td>42.6 MPa, 53.2 MPa</td>
</tr>
<tr>
<td>Young's modulus</td>
<td>50 GPa</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.01</td>
</tr>
<tr>
<td>Fracture toughness</td>
<td>2.4 MPa m(^{0.5})</td>
</tr>
<tr>
<td>Fluid viscosity</td>
<td>5 cP</td>
</tr>
<tr>
<td>Injection rate</td>
<td>( 5.2 \times 10^{-2} ) m(^3)/sec (20 bpm)</td>
</tr>
<tr>
<td>Pumping time</td>
<td>20 min, 40 min</td>
</tr>
</tbody>
</table>

![Figure 7](image.png)

Figure 7: GeoFrac-R3D simulation results for 3-stages hydraulic fracturing. Simulations are carried out at the toe (2600 m, TVD) for the Well16A(78)-32 for the first stage, moved to the second fracturing process, and the third stage carried out. The spacing between the stage is 50 m. (a) the fluid pumping time is 20 min, 20 bpm for each stage, (b) the fluid pumping time is 40 min, 20 bpm for each stage.

The GeoFrac-R3D simulation results are illustrated for 2 different pumping times where the fluid is injected for 20 min and 40 min per each stage. The injection rate was 20 bpm for both simulations. Figure 7(a) presented 3D plots of aperture in 20 minutes per each stage.
The resulting fracture width and height were 204 m, 89 m each and the apertures within the fractures range from 0.2 to 2.6 mm. Increasing the pumping time resulted in larger fracture creations as expected. The average fracture length and height were 315 m, 83 m and the apertures were in the 0.2 - 3.0 mm range. The following section will discuss the fluid circulation modeling with the implementation of stimulated wells for Utah FORGE wells.

3.2 Numerical Model Setup

The numerical setup for Utah FORGE reservoir fluid circulation is described here. The coordinate is (UTM (m) – \( x_0 \) (m), UTM – \( y_0 \) (m)) for \( x \)- and \( y \)-coordinates where \( x_0 = 333,358 \) m and \( y_0 = 4,261,781 \) m, and the depth TVD (m) from the surface of the well. The negative sign in depth values is for plotting purposes. It is assumed that the orientation of the maximum horizontal stress is N30°E (Moore et al., 2019) and the coordinate for \( x \)- and \( y \)-directions are transformed 30° to align with the maximum horizontal stress direction after subtracting \( x_0 \) and \( y_0 \) since it is assumed that the hydraulic fracture propagation direction is perpendicular to the minimum horizontal stress. Figure 8 illustrated reservoir simulation size, grid-blocks, fractures and well locations. The fracture geometry has been obtained from the GeoFrac-R3D simulation as described in the previous section. The model grid-block size for finite difference method simulation is 12 m, 15 m, and 4 m for \( x \)-, \( y \)-, and \( z \)-direction, and the number of grid-blocks are 50, 50, and 150, respectively. Initial pressure and temperature distributions are provided by Native State FALCON Model input data from Idaho National Laboratory. The input parameters used for simulations are listed in Table 2. In this circulation numerical modeling, it is assumed that the injection water temperature is 80°C. The hydraulically fractured geometries are inclined since the existing injection well, Well16A(78)-32, is inclined to about 65° as illustrated in Figure 8 - blue line. The production well is assumed to be located above or to the side of the injection well, and the distance between the wells is about 100 m as described in Figure 8 – red line.

![Figure 8: (a) reservoir simulation domain, grid-blocks, and fracture grid-blocks. The blue line is the existing Well16A(78)-32 and the red line is projected well location that is expected to be about 100 m distance, (b) magnified image of high permeability fracture grid-blocks which are based on GeoFrac-R3D simulation result (Figure 7-(a)).](image)

### Table 2: Input parameters for UTAH Forge fluid circulation simulation.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity ( \phi )</td>
<td>0.01</td>
</tr>
<tr>
<td>Thermal conductivity, ( K_T )</td>
<td>4.0 W/m-K</td>
</tr>
<tr>
<td>Matrix permeability, ( K )</td>
<td>2.6 md or Discrete Fracture Network upscaled permeability distribution</td>
</tr>
<tr>
<td>Heat Capacity, ( c_T )</td>
<td>1200 J/Kg-K</td>
</tr>
<tr>
<td>Density of rock, ( \rho_g )</td>
<td>2.7 g/cm³</td>
</tr>
<tr>
<td>Residual saturation of water, ( S_{sw} )</td>
<td>0.30</td>
</tr>
<tr>
<td>Residual saturation of steam, ( S_{gr} )</td>
<td>0.05</td>
</tr>
</tbody>
</table>

3.3 Fluid Circulation in Hydraulically Fractured Rock

In this section, we will discuss the simulation results for fluid circulation in Utah FORGE wells for the case of homogeneous low permeability reservoir. The matrix permeability is assumed to be 2.6 md, inferred from the Well 58-32 (the closest offset well from the Well16A(78)-32) Diagnostic Fracture Injection Test (DFIT) (Xing et al., 2022). The hydraulic stimulated grid-block permeability is assumed to be 1000 Darcy which is about 3.4 mm for the fracture aperture based on the cubic law. In the simulation, we first inject without production until the pressure reaches about 40 MPa, then commence production with the same rate of injection rate to study the circulation induced pressure and temperature evolution. We design the injection/extraction such that the pressure does not to exceed the...
Lee and Ghassemi

closure pressure, 42.7 MPa. This is to avoid fracture propagation and/or fault reactivation while circulating the water from the injector to the producer. As discussed, production follows a period of only injection because it is important to maintain the pressure in the fracture while circulation because the phase change can lead to therodynamic enthalpy energy loss at the production well if the well pressure drops below the critical pressure. According to the steam table property table, critical pressure for water is 22.064 MPa, so it is crucial to preserve the reservoir above the critical pressure limit. Initial pore pressure and temperature at 2600 m is about 26 MPa and 250°C, so the water is expected to be in critical state.

The red and blue lines in Figure 9(a) show pressure changes for injector and producer. The simulated injection and production rate is 5 Kg/sec. Pressure increases within the fracture grid-blocks rapidly because of the water pumped without production. The pressure reaches about 39 MPa after 0.3 day (7.2 hours), then the production starts at 5 Kg/sec as described in Figure 9 (b). The lower circulation case is plotted with the green and black dashed lines in Figure 9. It is observed that pressure declines gradually, and the higher circulation rate shows more pressure drop for both injector and producer. This can be explained by fluid leakoff as fluid travels from injector to the producer.

The 3D plot for pressure changes at different times are illustrated in Figure 10. As expected, most of the fluid flows within the high permeable fractured areas between the wells. The results show that the overall pressure decreases gradually, and the depleted zone after 300 days of circulation is around the wells stimulated by hydraulic fracturing. The distribution at temperature, enthalpy, density and the viscosity after 300 days of circulation are presented in Figure 11. The temperature and the enthalpy decrease around the injection well by cold water injection. The density and the viscosity also vary as the pressure and temperature changed during the water circulation. No phase change is observed since the pressure is maintained above the critical pressure.

Figure 9: (a) Pressure and temperature change with time at the injector and producer interval. The simulation set injection without production until the pressure reached about 40 MPa, then production begin with the same rate of injection. The red dash-dot line marked 42.7 MPa which is closure pressure from the DFIT analysis. The red and blue lines are pressure for Q = 5 Kg/sec case and the green and blue dashed lines are for Q = 1 Kg/sec case simulation results plot. (b) Bule and red lines showed injection without production for 0.3 day (=7.2 hours) with injection rate of Q = 5 Kg/sec, then production began with the rate of Q = 5 Kg/sec. The green and black dashed line showed injection only for 3 days with Q = 1 Kg/sec then production started with Q = 1 Kg/sec.
Figure 10: 3D plot for pressure changes with time for $k_{\text{matrix}} = 2.6$ mD and $k_{\text{fracture}} = 1000$ Darcy case. The circulation rate for injection and production was tested with $Q = 5$ Kg/sec. (a) $t = 36$ days, (b) $t = 73$ days, (c) $t = 182$ days, and (d) $t = 300$ days.

Figure 11: 3D plot for temperature, enthalpy, density, viscosity after 300 days circulation for $k_{\text{matrix}} = 2.6$ mD and $k_{\text{fracture}} = 1000$ Darcy case. The circulation rate for injection and production was tested with $Q = 5$ Kg/sec. (a) temperature, (b) enthalpy, (c) density, and (d) viscosity.
3.4 Fluid Circulation in Hydraulically Fractured Rock Mass with DFN Permeability

After testing the hydraulically fractured well circulation in homogeneous permeable rock, the numerical model is applied to an upscaled Discrete Fracture Network (DFN) permeability. The permeability data set is obtained from the stochastic DFN model (Xing et al., 2021) that was created in the toe region and combined the information from the Well16A(78)-32 FM1 (Formation Micro-Imager) log data. Note that there are slight differences in permeability distribution compared with the DFN permeability data since the data set is transferred to finite difference grid-blocks by an interpolation technique.

The permeability distribution of the rock mass with the discrete fracture network (DFN) model is described in Figure 12(a). It ranges from 40 md to 4000 md in the model domain. The hydraulic fracture permeability from the GeoFrac-R3D results are also included as seen in Figure 12b. It is assumed that the hydraulic fractures permeability is 1000 Darcy and the production well is located 100 m above the injection well. The size and the number of grid-blocks for the simulation are the same as the previous described circulation numerical model.

![Figure 12: (a) DFN upscaled permeability plot before hydraulic fracture creation. (b) Permeability plot included DFN upscaled permeability data and GeoFrac-R3D hydraulic fracture propagation model permeability.](image)

First, the fluid is injected without any production until the pressure reaches about 40 MPa and then production begins. Tested injection rate varied from 10 Kg/sec to 40 Kg/sec. The injection times without production to reach the target pressure are different for different injection rates. For example, the injection time for the $Q = 10$ Kg/sec case required 1.5 day (about 36 hours) whereas the $Q = 40$ Kg/sec case needed 2.4 hours to reach 40 MPa as presented in Figure 13(b). A pressure drop is observed immediately after production started for all cases. It is observed that the pressure drop is greater for the higher injection rate case, and the difference between the injector and producer is also larger than the smaller injection rate case. Temperature and enthalpy change at the production well are plotted in Figure 13(c), (d). It is quite clear that the higher circulation rate shows faster cooling at the production well. Figure 14 and Figure 15 illustrate 3D plots for $Q = 10$ Kg/sec injection rate case. Figure 14(a) shows that the pressure distribution change within the fractures is less compared to low permeable matrix case study. Also, overall depletion is less since the upscaled DFN permeability distribution ranges from 40 – 4000 md which is much greater than the matrix permeability (2.6 md) case study. Figure 14(c) shows that the cooling front reaches the production well and temperature drop is about 16°C after 365 fluid circulation. Based on the Péclet number plot in Figure 15(b), the heat transport mechanism in fractures is dominated by convective cooling rather than conductive cooling. The example of z-directional velocity plot shows the fluid path from the injector to the producer (Figure 15(c) and (d)). According to the numerical results, successful circulation can be established between the two wells if both hydraulic fractures and rock mass DFN permeability contribute to flow. The efficiency of the circulation and the productions rate can be influences by the production well location and this is further investigated next.
Figure 13: Pressure and temperature variation with injection and production rate change for DFN permeability. (a) Pressure changes with time for 365 days circulation (b) Compared pressure changes for $Q = 10$ Kg/sec and $Q = 40$ Kg/sec. (c) Temperature change at the production interval (d) Enthalpy change at the production interval.

Figure 14: 3D plots after 365 days circulation for $k_{\text{matrix}} = $ DFN upscaled permeability and $k_{\text{fracture}} = 1000$ Darcy case (a) Pressure, (b) Temperature, (c) Enthalpy, and (d) Density.
3.5 Fluid Circulation with Different Production Well Locations

In this section, numerical simulations for three different production well locations are presented. As described before, the Well16A(78)-32 has been drilled in 2021 for circulation test in Utah FORGE reservoir, and the production well is scheduled to be drill for the circulation test. Optimum design of the production well is important to establishing circulation. Possible production well locations are illustrated in Figure 16. The first case is a production well above the injector designed for fluid flow upward. The second case is parallelly aligned production well configuration to allow fluid flows from the right to the left. The last case study is also parallelly aligned production well but the fluid circulates from the left to the right direction. The simulations consider the equivalent permeability due to the DFN and the hydraulic fractures propagation. The pumping time increased from 20 min to 40 min for each stage in the hydraulic fracture propagation model since the larger fracture propagation model is needed to simulate fluid circulation within the fracture for the parallel configuration of injector and producer. The hydraulically fractured grid-block permeability is assumed to be 1000 Darcy.
Figure 16: Three possible well locations based on the existing injection Well 16A(78)-32. The blue line is the injection well and the red line is the production well. (a) the production well located above the injection well. The distance between the two wells is about 100 m. (b) the production well located on the left side of injection well from the wellbore “toe” to “heel” view. (c) the production well located on the right side of injection well from the wellbore “toe” to “heel” view. The arrows indicate the expected flow direction from injector. The short black lines presented hydraulic fracturing injection stages.

Pressure and temperature variations while circulation are plotted in Figure 17. It is observed that the overall fluid circulation efficiency is better when the production well is located next to the production well in the lateral direction. When the production well is located above the injection well (Case 1), the pressure drops and the pressure difference between the wells are greater. This can be explained by the influence of the DFN permeability distribution and gravity. Significant temperature drops are observed in Case 2 i.e., when the production well is on the left side of the injection well. After 1 year of circulation, the temperature in the production wells for Case 1-3 are 225.4 °C, 195.5 °C, and 218.2 °C, respectively with a corresponding temperature drop of 16.8 °C, 53.1 °C, and 29.6 °C. In short, the Case of production well on the left side from the injection well seems to result in the highest flow into the production well with a higher risk of short-circuiting.

Figure 17: Pressure and temperature change at injector and producer at different. Case 1: vertically aligned for two inclined wells, case 2 and 3: parallelly aligned for two inclined wells. Case 2: production well located on left side case 3: production well located on right side (a) pressure change for case 1, case 2, and case 3 (b) temperature change for case 1, case 2, and case 3

Figure 18 illustrates the permeability iso-volume plots that the permeability is larger than 1000 md - Figure 18(a), and larger than 800 md - Figure 18(b). The brighter boxes in Figure 18 indicated discrete fracture network clusters connected with hydraulic fractures near the producer in Case 2. It is inferred that the fracture clusters near the injection well increase the total fracture volume which allows fluid to circulate more efficiently. Pressure changes at different times for the Case 2 are presented in Figure 19. The pressure drop between the wells is initially relatively rapid but it quickly stabilizes after 36 days. The temperature and enthalpy distribution at 365 days are shown in Figure 20. It is observed that the production well is cooled from 250 °C to 210 °C, and the enthalpy is changed from 1080 KJ/Kg to
Lee and Ghassemi

900 KJ/Kg. The simulation results suggested that the influence of fracture networks around the injector and the producer play an important role in water circulation between the wells. Further study is needed to determine if Case 2 is the best performer in view of the potential for short-circuiting.

Figure 18: Permeability iso-volume plot around injector and producer. The plots are exaggerated due to the interpolation effect at the interface around large and small values (a) Image of discrete fracture network and hydraulic fracture created high permeability iso-volume plot for larger than 1000 md. The brighter box area showed cluster of high permeability DFN near the injector (b) Different view of fracture network near the hydraulically fractured high permeable grid-blocks for permeability is larger than 800 md.

Figure 19: 3D pressure plots at different time for the production well located on left side from the toe. Injection rate was 10 Kg/sec and the permeability distribution is upscaled discrete fracture network model. (a) t = 5 days, (b) t = 10 days, (c) 36 days, and (d) t = 365 days.
4. CONCLUSIONS
A coupled hydraulic fracture/reservoir model for EGS has been used to simulate water circulation between wells with capabilities to simulate two-phase flow pressure, temperature and enthalpy change has been demonstrated. The simulation simulations were first validated and calibrated using a lab-scale EGS experiment with hydraulic fracturing, fluid circulation, and the heat transport in a five-spot. Numerical results are in good agreement with experimental data for pressure and temperature change in injector and producers. Next the model was used to analyze hydraulic fracturing and circulation in the Utah FORGE doublet. Advanced hydraulic fracture model, GeoFrac-R3D was used to simulate multi-stage fracturing. Then, flow between the fractured well and potential producer well was simulated for different permeability distributions. It was observed that effective circulation would not be established by solely relying on the hydraulic fractures. Simulations considering hydraulic fracture and DFN permeability improved fluid circulation efficiency based on the pressure and temperature response of the wells. The impact of the location of production well on circulation was also studied to help optimize the production well design in Utah FORGE reservoir. The results were compared with 3 case scenarios – i) the production well located above the injection well, ii) the production well located on the left side from the injection well, and iii) the production well located on the right side from the injection well. Overall, better circulation is observed for production well drilled to the sides of the injector. This is mainly due to the gravity effect in fluid travel from the deeper injector to the shallow producer. The circulation efficiency is higher for cases where the production well is located laterally to the injector. This is highly impacted by the combined effect of the DFN permeability and hydraulic fracture geometry. Future work will consider rock and fracture deformation observations near the production well.

ACKNOWLEDGEMENT
This project was supported by the Utah FORGE project sponsored by the US Department of Energy, through the project “Fiber-Optic Geophysical Monitoring of Reservoir Evolution at the FORGE Milford Site.” The authors would like to thank Dr. Robert K. Podgorney and Aleta Finnila for their DFN and other reservoir data and valuable discussion.

REFERENCES
Lee and Ghassemi


Hu, L. and Ghassemi, A.: Experimental Investigation of Hydraulically Induced Fracture Properties in Enhanced Geothermal Reservoir Stimulation, 42nd Workshop on Geothermal Reservoir Engineering Stanford University, Stanford, CA (2017)


Xing, P., Winkler, D., Swearingen, L., Moore, J., McLennan, J., In-Situ Stresses and Permeability Measurements from Testing in Injection Well 16A(78)-32 at Utah FORGE Site, GRC Transactions, 45 (2021)

Xing, P., McLennan J., Moore, J., Minimum in-situ stress measurement using temperature signatures, Geothermics, 98 (2022), 102282

