

Thermal Performance Implications of Flow Orientation Relative to Fracture Shear Offset in Enhanced Geothermal Systems

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ABSTRACT

Fractures and faults are the main conduits for flow in enhanced geothermal systems (EGS). These fractures and faults may have spatial variations for which the aperture is not constant across the fracture plane. The presence of these spatial variations can result in flow channeling and reduced contact area and consequently could impact the thermal performance of the EGS.

This study investigated the thermal performance of enhanced geothermal systems considering flow relative to the direction of fracture shear offset and considering spatial variations in the fracture aperture. The system studied consisted of a single fracture with a horizontal injector providing cold fluid, which contacts the hot rock of the EGS, and heat is extracted through a horizontal producer. Several aperture distributions were analyzed with the objective of determining if a direction of flow relative to the fracture shear offset provided better thermal performance.

The results showed that where there is continuity across the fracture plane, the flow perpendicular to the fracture shear offset provided better thermal performance than flow parallel to the fracture shear offset. The thermal drawdown was inversely related to the average permeability across the fracture plane and the area contacted by the flowing fluid.

1. INTRODUCTION

In Enhanced Geothermal Systems, heat exchange has some relationship with fluid flow. Heat from the rock surrounding the fracture is transferred to the production well(s) through the flowing fluid and hence only the portion of the fracture that carries flow provides effective heat exchange surface area. The more heat exchange surface area encountered by the flowing fluid, the more efficient is the heat extraction. Fractures and faults are the main conduits for flow in enhanced geothermal systems. Studies (Abelin, et al., 1991; Tsang and Neretnieks, 1998; Tester, et al., 2006; Watanabe, et al., 2008; Mattson, et al., 2018) have shown that these fractures and faults have rough surfaces for which the aperture is not constant across the fracture plane and this has led to flow channeling. The implications of a heterogeneous local aperture distribution in faults and fractures are that individual well productivity and interwell connectivity can be impacted significantly by the well locations (Abelin, et al., 1991); and the contact area available for heat conduction will be reduced thereby leading to inadequate heating (Neuville, et al., 2010) and ultimately premature thermal breakthrough, which could affect the total energy produced in geothermal reservoirs dramatically (Co, 2017).

Because flow channeling has the ability to impact the recovery of EGS, it is imperative to model it accurately for better thermal performance estimation and forecasting. It is also important to investigate how flow channeling could be harnessed to improve thermal performance and ultimately recovery.

This study aimed at evaluating the variation in thermal performance of an EGS if the direction of fluid flow from an injector to a producer relative to the direction of fracture shear offset. In this study, a parallel flow direction and a perpendicular flow direction were considered. In the parallel flow configuration, fluid flow and pressure drop were parallel to the lateral direction of shear offset while in the perpendicular flow configuration flow and pressure drop were perpendicular to the lateral direction of shear offset. Figure 1 shows what the lateral direction of shear offset implies in creating a sheared fracture from a mated fracture. The flow configurations are illustrated in Figure 2.

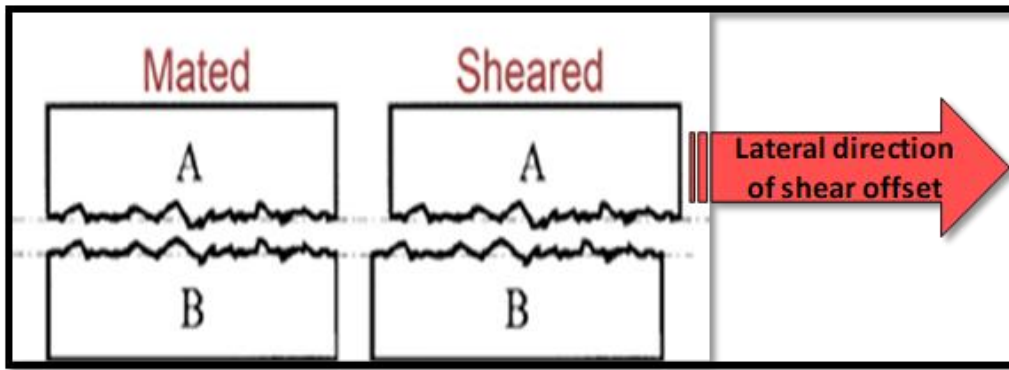


Figure 1: Illustration of lateral direction of shear offset.

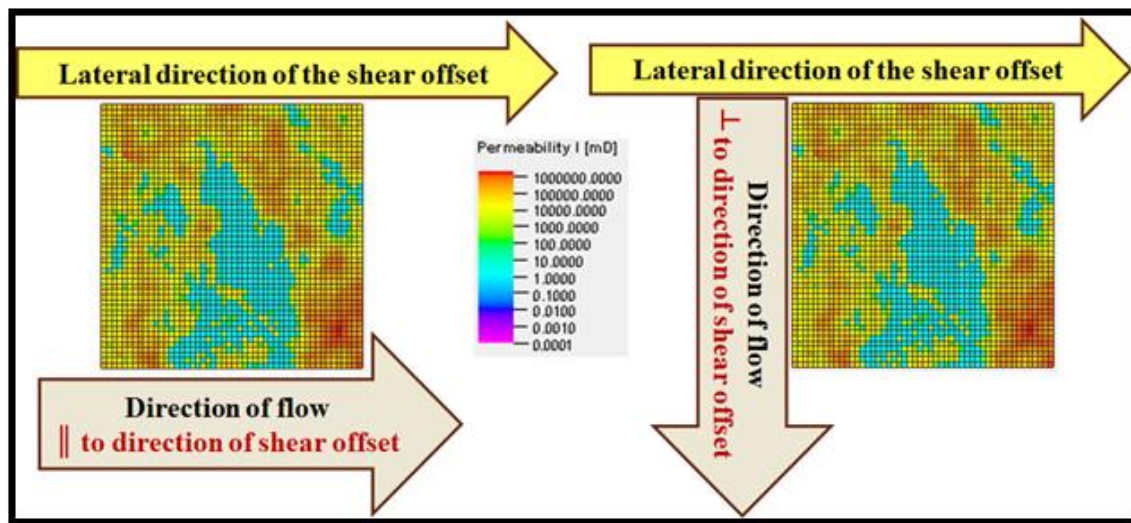


Figure 2: Flow configurations with respect to the lateral direction of shear offset. Permeability is the displayed property on the fracture's x-y plane. On the left is parallel flow configuration while on the right is perpendicular flow configuration.

2. METHODOLOGY

The system investigated is an EGS doublet where cold fluid is injected at one point and flows through the high permeability fracture. The fluid is heated up on contact with the hot rock, and the heated fluid is transported to a production well at another location. The fracture is horizontal.

The transport mechanism in this system consists of heat conduction by contact between the rock and fluid, then convection (which is the heat driven part of the transport) and also mass transport in the fluid (from pumping in and producing out – as the cold or hot fluid is in motion).

The following assumptions were considered: -

1. The injected fluid is single-phase water and stays in liquid state throughout the life of the field. Hence only single-phase flow will be considered.
2. There is no gas trapped in the rock fracture.
3. Fluid flow is in the laminar regime and the Reynold's number is low to allow the application of Darcy's law.
4. There is no fluid-rock interaction such as chemical dissolution/deposition, etc.

2.1 Modeling the thermohydraulic process of EGS Doublet heat extraction

The thermohydraulic process of EGS heat extraction was modeled using ECLIPSE thermal compositional numerical simulator. This program is a finite difference simulator. For the purpose of this modeling, the simulator was run in fully implicit mode. The thermodynamic properties of water and steam were based on the International Association for the Properties of Water and Steam (IAPWS-IF97) (Wagner, et al., 2000) using the keyword: THSTT97. Cartesian block-centered geometry in three dimensions was used. ECLIPSE is an oil and gas industry-reference reservoir simulator but Stacey and Williams (2017) demonstrated its suitability for modeling geothermal reservoirs.

In order to validate the software for modeling the heat extraction in the EGS doublet, a series of steps were taken. These base case validations are described in the work by Okoroafor and Horne (2018).

2.2 Determination of Fracture Permeability from Fracture Aperture

Once theoretical studies and actual flow behavior had demonstrated that flow channeling was a common phenomenon in fractured rocks (Tsang and Neretnieks, 1998), the need to characterize the spatial variation of the fracture aperture developed.

Local aperture can be defined as the pointwise variation in aperture along a fracture (Oron and Berkowitz, 1998). The local cubic law model is a variant of the cubic law model applied to local apertures, and has been used widely to characterize the fracture's hydraulic aperture and in some cases the permeability (e.g. Brown (1987); Tsang & Tsang (1989); Huo & Benson (2014)). The fracture is modeled as a two-dimensional, variable-aperture medium having local parallel-plate segments, with negligible fracture surface undulation in the third dimension. The fracture plane is subdivided into equal-sized grid blocks. The cubic law is assumed to apply locally and each grid block is assigned a permeability based on the local fracture aperture value. In flow simulations, the internode transmissivities are calculated from the harmonic mean of the apertures.

The work by Ishibashi, et al. (2012) described the methodology for generating lab-scale single fractures using a granite sample. A hydraulic aperture was computed using the expression:

$$e_h = \left(-\frac{12\mu LQ}{W\Delta P} \right)^{1/3} \quad (1)$$

where Q is the flow rate, ΔP is the differential pressure, μ is the viscosity of water, and L and W are the apparent lengths of the fracture in the directions parallel and perpendicular to the macroscopic flow direction.

The hydraulic aperture was then used to compute the fracture permeability based on the cubic law assumption.

$$k = \frac{e_h^2}{12} \quad (2)$$

Ishibashi, et al. (2012) referenced these equations from the work by Watanabe et al. (2008). To apply the local cubic law, the permeability for each grid block is computed from the hydraulic aperture corresponding to that grid block

2.3 Base Case Aperture Map

The base case fracture aperture map was taken from the work by Ishibashi, et al. (2012). The fracture aperture map of the 5 cm \times 7.5 cm sheared fracture (Figure 3) was upscaled assuming the aperture distribution to be self-similar, and a square section of it was used to describe the fracture of the model in this study. The apertures were made to have a maximum value of 5 mm to ensure the simulations were not too different from the case of a fracture with constant aperture of 5 mm. The fracture permeability was computed as described in section 2.2 and the permeability became input for the three-dimensional model characterizing the layer represented by the fracture.

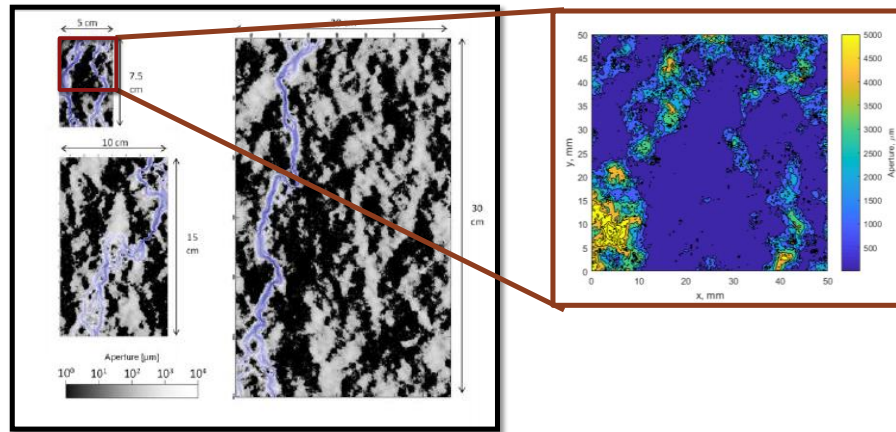


Figure 3: Section of the granite sample from Ishibashi et al. (2012) used to describe the roughness of the fracture for the ECLIPSE numerical model.

2.4 Fracture Aperture Map Generation

As described by Co (2017), Sequential Gaussian simulation (SGSIM) is one method for generating fracture aperture map using the variogram and histogram data of an existing aperture distribution. For the SGSIM method, the conditional cumulative density function (CCDF) is assumed to be multivariate normal. Co (2017) added that the simple kriging method can be used to calculate the mean and variance that are used to generate the conditional distribution function at each estimation point. At each estimation point, the distribution function is also Gaussian. Co (2017) used this methodology to generate several aperture distributions to study the effect of spatial variation on mass transport. In this study, the aperture distributions from Co (2017) were used to investigate the effect of spatial variation on heat transport. Figure 4 shows some of these analog aperture distributions from the base aperture map.

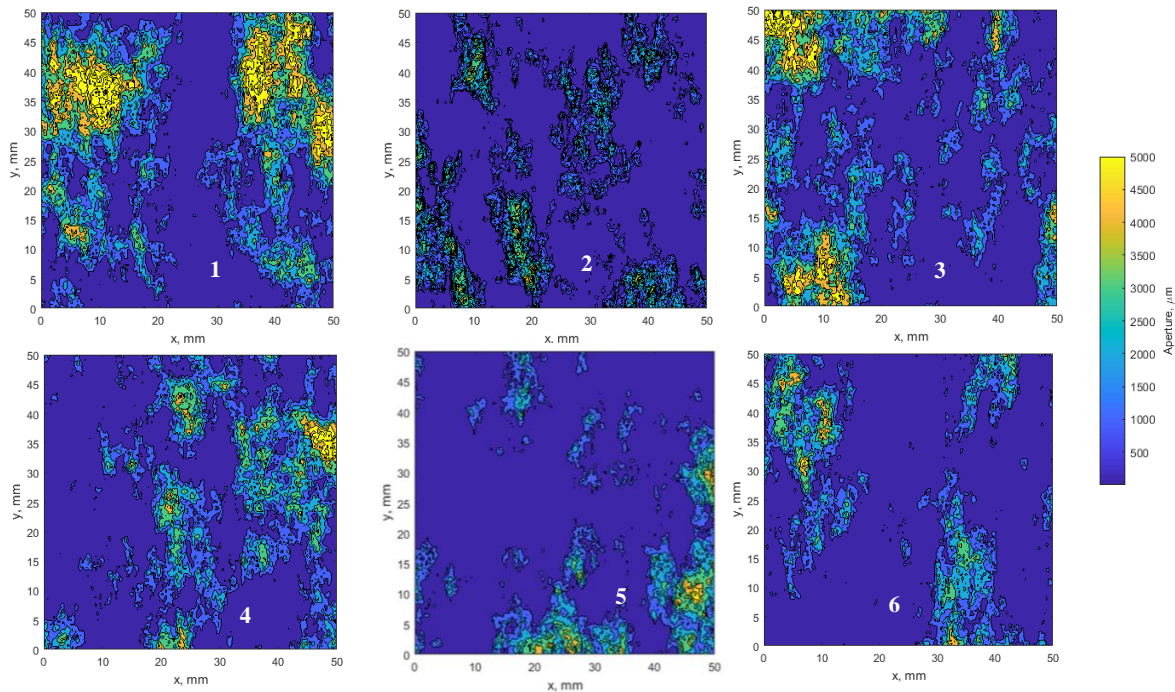


Figure 4: Analogue fracture aperture distributions generated from the base aperture map using SGSIM from Co (2017).

2.5 Numerical Model Input Parameters

The dimensions of the numerical model on the x-y plane is a square of length L 1000 m. The water injection temperature and pressure were 45 °C and 230 bar respectively. The initial temperature of the system was kept at 250 °C and no effect of a geothermal gradient was considered during the simulation. The initial pressure of the reservoir was at 180 bar. The thermophysical properties include rock thermal conductivity, $k_r = 2.4$ W/(m °C), rock density of 2300 kg/m³, specific heat capacities of the rock and water, $c_r = 1000$ J/(kg °C)

and $c_w = 4184 \text{ J/(kg } ^\circ\text{C)}$). To simulate a hot rock with flow dominant in the fracture, the reservoir was set to a very small value of permeability except at the fracture where the permeability is very high. Density and viscosity of the water were not constant but varied with temperature and pressure.

3. RESULTS

3.1 Constant Injection Pressure, Bottomhole Pressure Control at the Producer

The first set of simulations were done at a pressure of 230 bar and a mass flow rate of 40 kg/s. The objective was to determine how much thermal energy could be recovered at the producer after 10 years. For the cases where there was significant connectivity between the injector and the producer, almost 40 kg/s was recovered at the producer. However for cases where there seemed to be permeability restrictions between the injector and producer, the flowrate at the producer was reduced significantly.

Table 1 shows the rate of flow at the producer after 10 years.

Table 1: Mass flow rate at the producer after 10 years of injection

| Realization # | M_{para} (kg/s) | M_{perp} (kg/s) |
|---------------|--------------------------|--------------------------|
| Base Case | 39.20 | 39.18 |
| 1 | 1.75 | 39.20 |
| 2 | 0.60 | 14.70 |
| 3 | 38.80 | 39.20 |
| 4 | 4.40 | 39.30 |
| 5 | 0.65 | 0.29 |
| 6 | 2.86 | 18.40 |

Table 1 shows that in most of the cases, the perpendicular direction supported more flow. This would imply higher average permeability in the perpendicular direction compared to the parallel direction. Two exceptions were in the base case and realization 5 where the mass flow rate at the producer was slightly higher for the parallel flow direction compared to the perpendicular direction, although both were very small. For the base case, however, the thermal performance of the perpendicular flow direction was much better than the thermal performance of the parallel direction, suggesting that not only permeability of the fracture/channel contributes to thermal performance but perhaps how much area is contacted by the flowing fluid contributes to the thermal performance. Figure 5 shows the temperature profile at the producer for the base case while Figure 6 shows the fracture plane after 10 years.

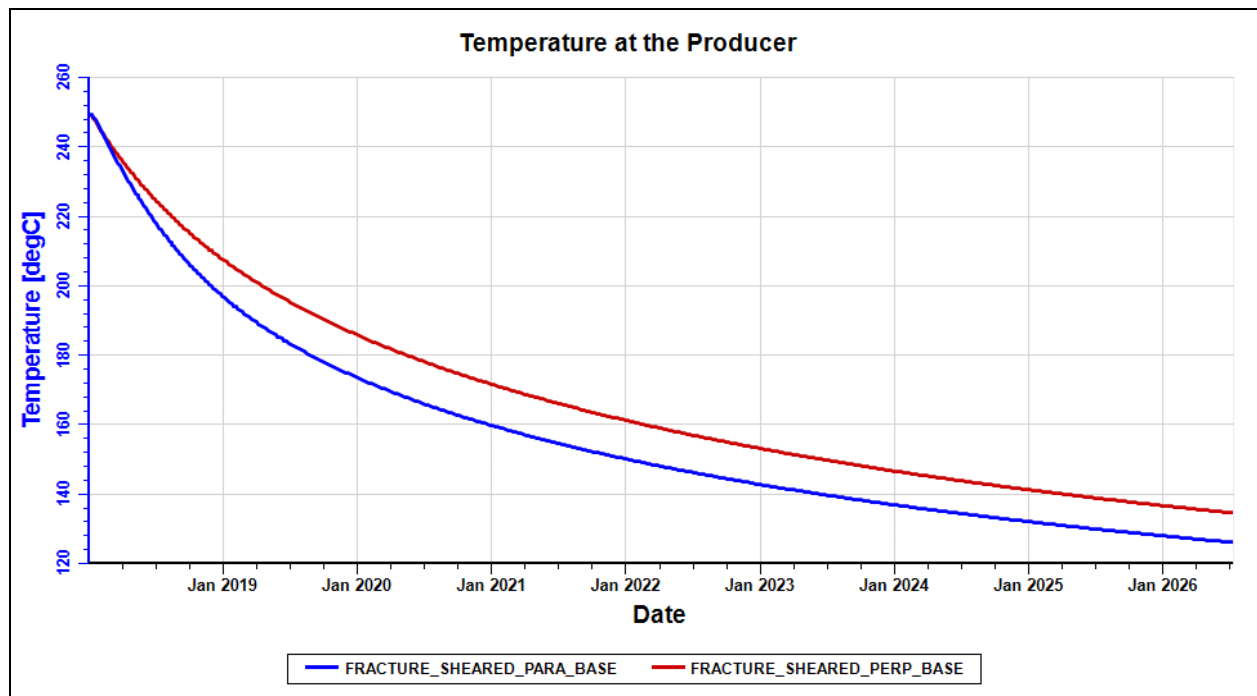


Figure 5: Temperature profile at the producer for the parallel (blue) and perpendicular (red) flow orientations.

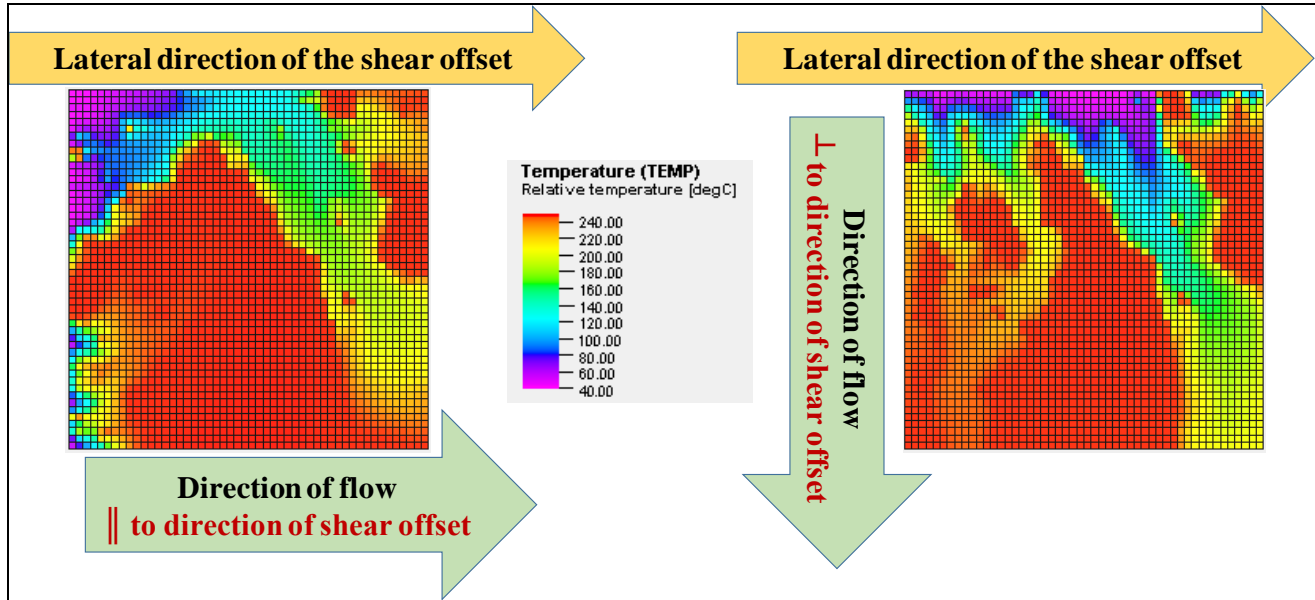


Figure 6: Temperature distribution after 10 years at the fracture X-Y plane. On the left is the temperature distribution for the parallel flow orientation while on the right is the temperature distribution for the perpendicular flow orientation. By visual inspection, more area appears to be contacted in the perpendicular flow direction.

The varying mass flow rates at the producer were not sufficient to make inferences concerning the thermal performance of the different cases. For instance, for realization 1 where the mass flow rate recovered at the producer after 10 years was 1.75 kg/s for the parallel flow configuration and 39.20 kg/s for the perpendicular flow configuration, the parallel flow configuration resulted in lower thermal drawdown compared to the perpendicular flow configuration at the same value of time. This lower thermal drawdown was not due to a better thermal performance of the system, but simply because there was less fluid in contact with the rock, the rock is not cooled as rapidly as when more fluid is in contact with the rock (the perpendicular case) and the fluid that goes to the producer remains at a higher temperature. The temperature profile for realization is shown in Figure 7. Due to this shortcoming in the simulation controls, it was decided to compare the thermal performance of all the cases for a fixed flowrate at the producer at constant injection temperature and pressure. This is discussed in Section 3.2.

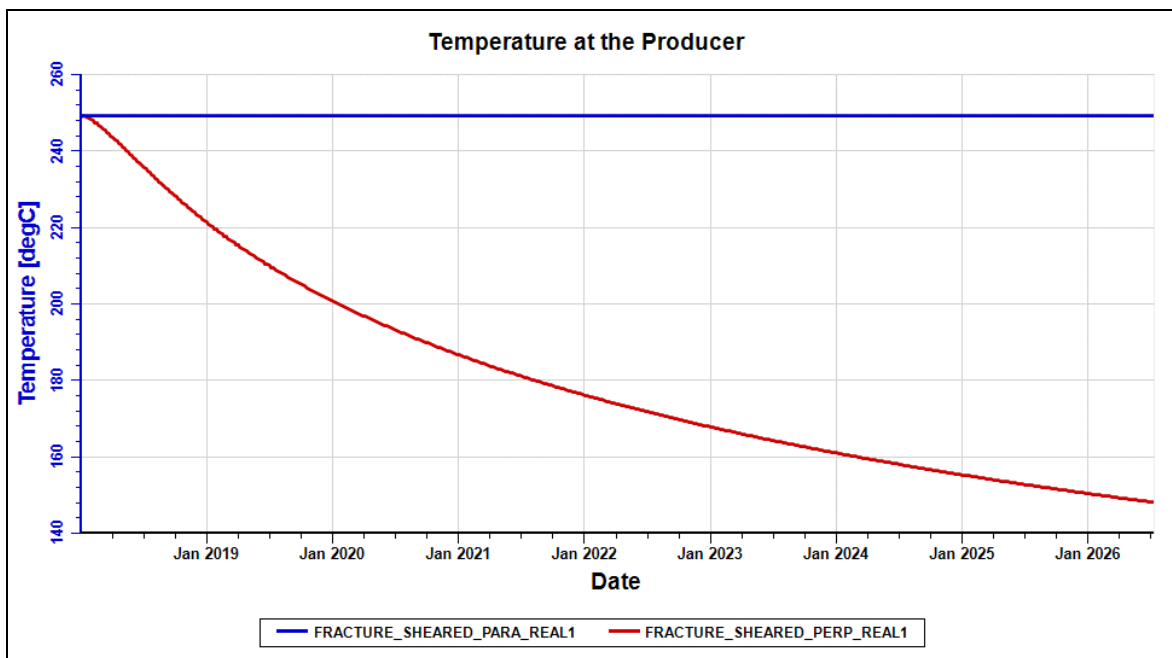


Figure 7: Temperature profile at the producer for the parallel and perpendicular flow orientations of aperture realization 1.

3.2 Constant Injection Pressure, Flowrate Control at the Producer

A fixed mass flow rate of 0.5 kg/s (corresponding to 43.2 m³/day for water) was imposed as the flowrate control at the producer for all the cases. The injector pressure and injector temperature remained at 230 bar and 45 °C respectively. Though this rate was small, it was to provide a uniform basis for comparing the thermal drawdown for all the different cases and determine what factors were contributing to the reservoir’s thermal performance. Figure 8 shows the temperature profile for the cases during the first year. Though the thermal drawdown was small due to the small volume of fluid being injected and produced, there were differences seen in the temperature profile.

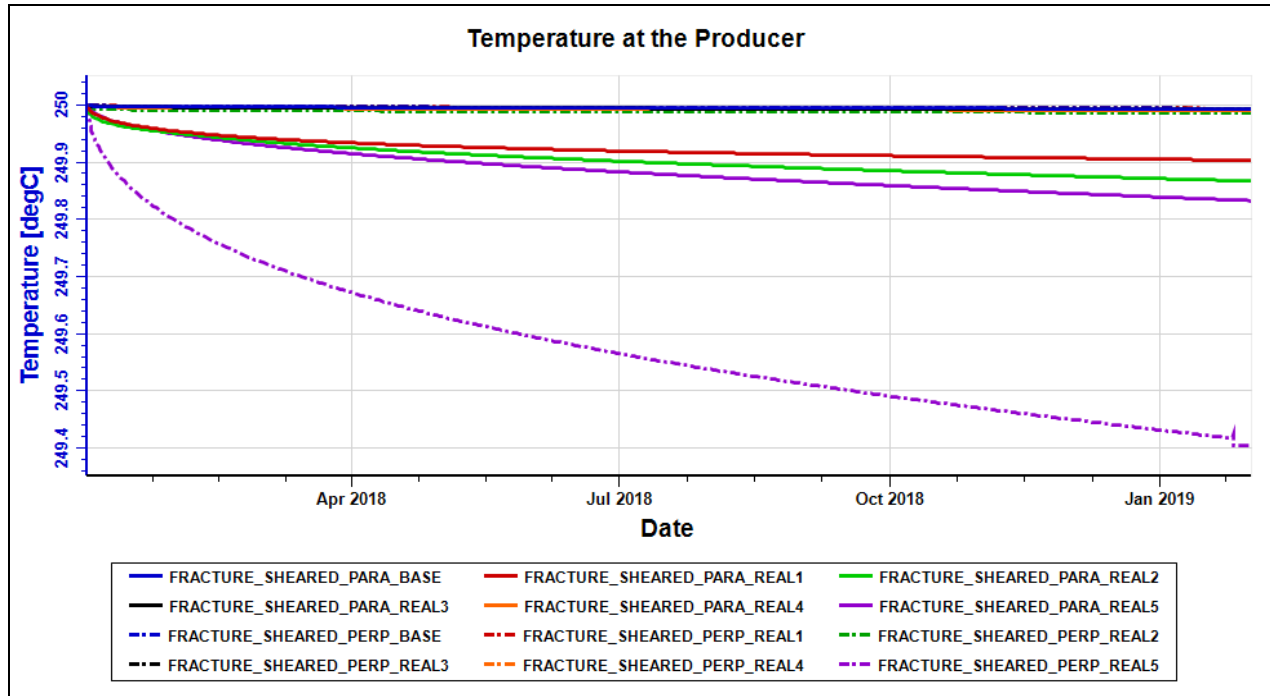


Figure 8: Temperature profile for the different cases after 1 year.

To understand what other factors, in addition to the fracture permeability, that may have been impacting the thermal performance of the EGS with spatial variations in the fractures, the flow contact area was examined for each flow configuration. Flow within the fracture was modeled as three dimensional but presented in Figure 9 is the water flow path in the x direction and y direction for the base case and realization 1. The water flow path for the z direction was not included due to the small amount of flow in that direction.

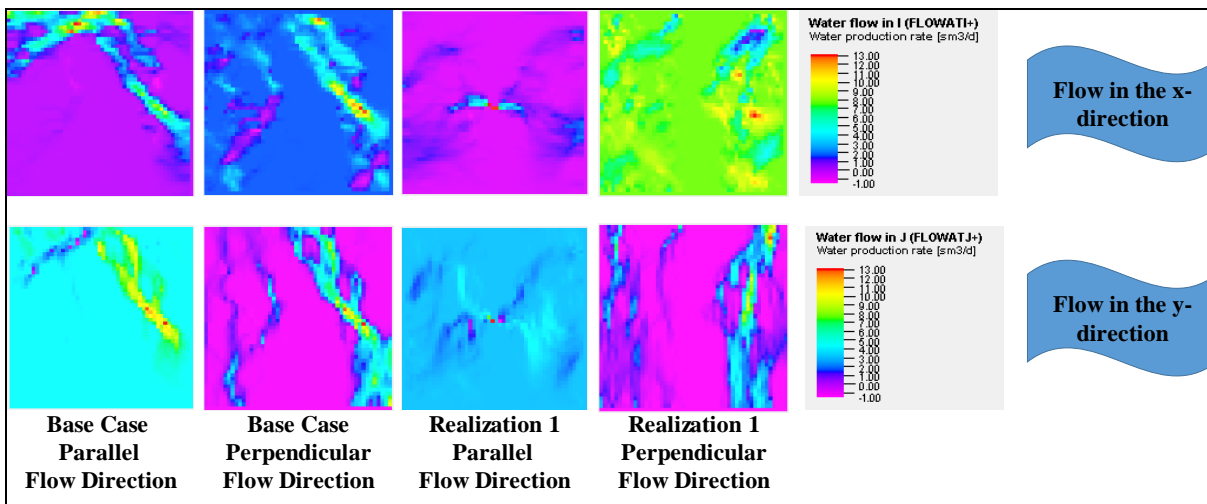


Figure 9: Flow contact area for the base case and realization 1 two months into the simulation. Flow in the x and y direction are presented.

A zoom into the temperature profile at the producer (Figure 10) helps to explain what is seen in Figure 9. In the cases presented in Figure 9, the perpendicular flow configuration had more flow contact area. In realization 1, the flow contact area in the parallel direction was significantly less than the flow contact area in the perpendicular direction. Comparing the four areas, the flow contact area for the perpendicular direction of realization was much higher, resulting in less thermal drawdown as seen in Figure 10.

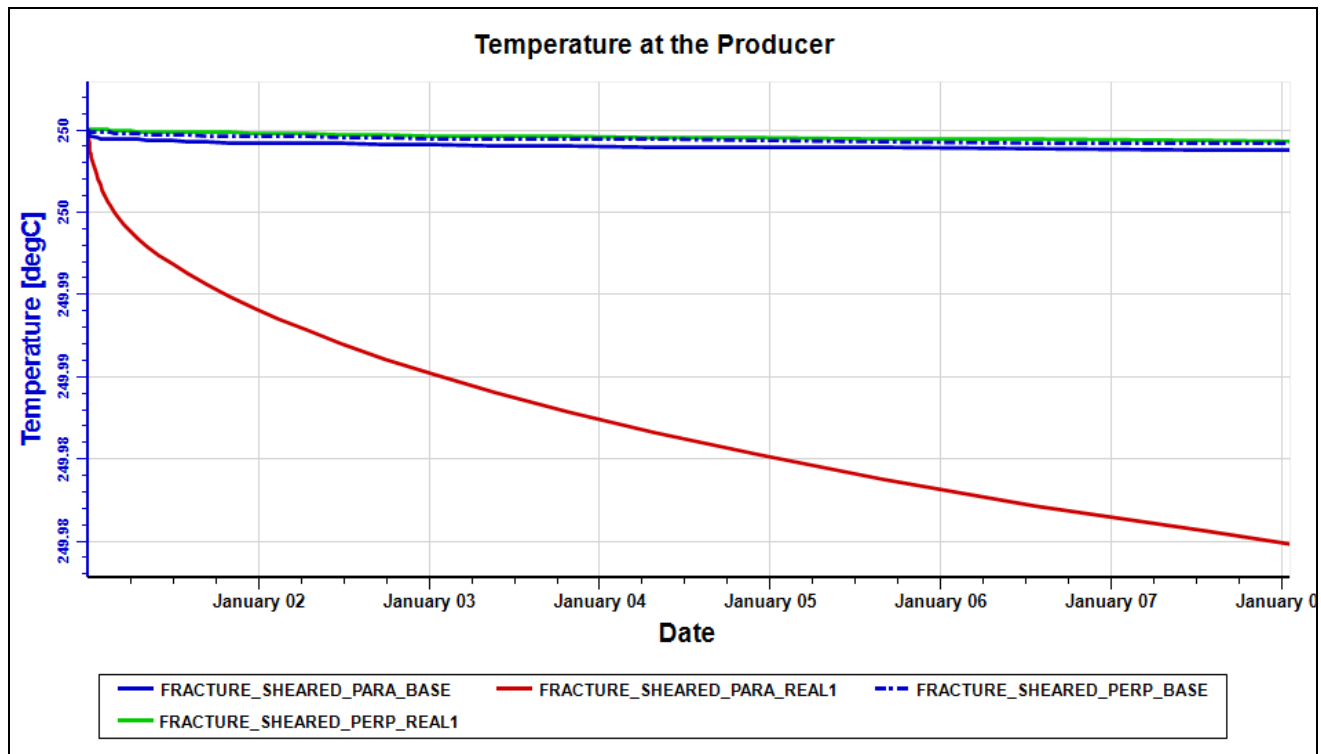


Figure 10: A zoom into the early times of the temperature profile at the producer of selected cases.

4. CONCLUSIONS

In this study, we investigated the thermal performance implications of flow orientation relative to fracture shear offset applicable to Enhanced Geothermal Systems. A numerical approach was used and several realizations of fracture aperture distribution were considered.

A major finding was that in most of the cases, the perpendicular flow orientation gave rise to better thermal performance than the parallel flow orientation. This was seen either as more fluid extracted at the producer or less thermal drawdown over time.

Two important factors that contributed to the thermal performance of the system being investigated were the average permeability of the fracture (inferred from the flowrates at the producer at constant injection pressure and no flow rate constraint) and the area contacted by the fluid. These two factors were directly related to the thermal performance of the system for other factors being constant.

Spatial aperture variations lead to flow channeling. The more channelized the flow was, the less area was available for fluid flow, heat transfer and contact with the hot rock, thus reducing thermal performance of the system.

Further studies will evaluate how thermal stresses impact the aperture distribution, and how these will consequently impact the thermal performance of Enhanced Geothermal Systems while considering flow orientation relative to the fracture shear offset.

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