NUMERICAL STUDY OF HYDRO-SHEARING IN GEOTHERMAL RESERVOIRS WITH A PRE-EXISTING DISCRETE FRACTURE NETWORK

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ABSTRACT

This paper is focused on evaluating the potential of shear stimulation in enhancing productivity of low permeability rocks using a computational modeling approach. The study is performed as a part of an in-depth examination of rock mass response to EGS style stimulations. Two-dimensional computational model studies have been used in an initial attempt towards understanding how reservoir response to fluid injection is affected by some of the DFN characteristics and operational variables such as injection rate.

INTRODUCTION

Increasing permeability of the reservoir and circulating fluid in a larger portion of hot dry rock volume is critical for sustainable heat production in Engineered Geothermal Systems (EGS). The low permeability of the igneous formations suitable for geothermal projects often necessitates application of different stimulation techniques to enhance circulation of water. Shear stimulation or hydro-shearing is the method of injecting a fluid into the reservoir with the aim of increasing the fluid pressure in the naturally fractured rock and inducing shear failure or slip events. This mechanism can enhance the system’s permeability through permanent dilatational opening of the sheared fractures.

The success of shear stimulation in enhancing overall permeability of the reservoir depends on many in-situ and operational parameters. There is a great level of uncertainty associated with field characteristics such as the three-dimensional fracture network, regional in-situ stress state, fracture properties (e.g., cohesion and friction coefficient), hydrological properties of intact rock and fractures (e.g., intact rock and fracture permeability), thermal properties (e.g., conductivity, coefficient of expansion/contraction) and chemical phenomena associated with solution and precipitation. The limited data on field characteristics as well as the uncertainties over how the reservoirs respond to stimulation and production operations makes it difficult to achieve the desired level of stimulation effectiveness.

Using a computational modeling approach in a two dimensional framework, this paper focuses primarily on sensitivity analysis with respect to some in-situ and operational parameters under conditions that are relatively favorable for shear stimulation. A previous study [1], has focused on the effect of injection into less permeable reservoirs, and has investigated the potential of initiation and propagation of hydraulic fracture (HF).

The results presented in this paper are part of a comprehensive study that is aimed at understanding the complexities and uncertainties in design of EGS system using a computational modeling approach. In particular, these relatively simple two-dimensional comparative studies help confirm understanding of the essential hydro-mechanical processes before proceeding to more complex models that will elucidate complicated scenarios and mechanisms important for sustainability of heat production in three-dimensional framework.

It is hoped that application of numerical approaches with capabilities such as representation of coupled hydro-thermo-mechanical processes in rock masses with pre-existing discrete fracture network will lead to a better understanding of the response of the
reservoir to stimulation, and thus to more effective approaches to the design of EGS.

**REPRESENTATION OF THE DISCRETE FRACTURE NETWORK**

It is believed that the characteristics of the Discrete Fracture Network (DFN) are key to the way that injection interacts with the EGS formation during both stimulation and production phase. To evaluate the importance of DFN characteristics, the reservoir fracture network is represented explicitly in this study.

Numerous realizations of different DFNs have been generated statistically. The statistical parameters associated with a DFN typically characterize the fracture size distribution, orientation distribution and density of each fracture set.

The DFN used in this study consists of two fracture sets each with a given fixed orientation. The fracture length distribution follows a power law distribution, which relates the probability of occurrence of a fracture with a length of \( l \) to the negative exponent of the length, i.e., \( n(l) \propto l^{-\alpha} \). The value of \( \alpha \) is site specific, but often ranges between 2 and 4. In this two-dimensional study, \( P_{21} \) is used as the measure of the fracture density. \( P_{21} \) is defined as the sum of the lengths of all of the fracture or traces divided by the area of the sampling or mapping domain — i.e., \( P_{21} = \sum \frac{l}{L^2} \), where \( L \) is the linear dimension of the DFN domain.

The flow characteristics of the DFN are determined by identifying the fracture clusters and evaluating the overall DFN connectivity. A cluster is a group of fractures that are connected to each other; no fracture inside a cluster intersects a fracture belonging to a different cluster. A fully connected DFN is defined as a DFN in which one cluster extends to a part of the boundary of the domain. The fully connected DFN was created through a trial-and-error process, at the critical density that would lead to formation of one cluster. The partially and sparsely connected DFNs were created by decreasing the fracture density and visually inspecting the size of formed clusters relative to the size of the model.

Considering the computational requirements of the numerical tool used in this study, it was impractical to represent DFNs with the same level of complexity as that observed in the field. Therefore, the DFN realizations were simplified by:

(a) Disregarding fractures with a length smaller than a prescribed threshold (the minimum fracture length cut-off is determined based on the length scale of the problem analyzed); and

(b) Disregarding the smaller of the two closely spaced, sub-parallel fractures (sometimes generated by the Poisson process used for generation of the fracture locations in the synthetic DFN).

**NUMERICAL APPROACH**

The numerical analyses of this study simulated the hydromechanical response of the discrete fracture network to fluid injection. In each analysis, both the stimulation and production phase are modeled. During the stimulation phase, fluid was injected into the reservoir at a rate higher than that of the production phase. After twenty hours of stimulation, injection was stopped, and the pore pressures allowed to dissipate fully. The production phase then was simulated. The injection rate used during production was 75% of the rate used during stimulation. In order to be able to compare different models, similar production scenarios were considered in all analyses. In each case, two production wells located approximately 250 m from the injection well are installed. Considering the change of apertures in the stimulated reservoir, the location of the wells is chosen such that they are favorably positioned for production.

Quantitative evaluation of the response of the reservoir to injection is conducted by looking at time history of the following indices.

- **Injection pressure**, defined as the pressure at the injection point.
- **DFN affected surface area**, defined as the surface area of the DFN that has experienced a fluid pressure increase due to injection.
- **DFN shear-stimulated surface area**, defined as the area of fractures that have experienced more than 1 mm of slip.
- **Average DFN aperture**, defined as the volume of fluid injected into the DFN divided by the DFN-affected surface area.
- **Recovery**, defined as the percentage of the injected fluid that is recovered from the production well.
- ** Injectivity**, defined as the injection rate at the injection well divided by the pressure at the injection well.
- **Productivity**, defined as the production rate at the production well divided by the pressure at the injection well.

DFN affected surface area, DFN shear-stimulated surface area and DFN average aperture attempt to quantify the surface area of fractures that are affected by injection, and the change in conductivity of those
fractures. These indices provide insight on how overall permeability in enhanced, and are correlated with the surface area that can be engaged during heat production.

Recovery, injectivity, and productivity indices are evaluated during the production phase only. These indices attempt to quantify how various stimulation scenarios affect production.

The numerical analyses of this study are carried out using a discrete-element modeling approach. Simulations were completed using distinct element code UDEC [2]. In this approach, the rock formation is represented by an assembly of intact rock blocks separated by a pre-existing fracture network. The numerical simulations are performed using a fully coupled hydromechanical model. Fluid flow can only occur within the fractures. The blocks between the fractures are considered to be impermeable. Initially, the formation is dry. The fluid is injected into the center of the model at a constant rate.

The rock blocks are modeled as elastic and impermeable. The pre-existing fractures are represented explicitly. They are discontinuities which deform elastically, but also can open and slip (as governed by the Coulomb slip law) as a function of pressure and total stress.

UDEC can simulate fracture propagation along the predefined planes only. It is noted that in this study, propagation of pre-existing fractures is disregarded. In order to simulate propagation of a hydraulic fracture (HF), the trajectory of the fracture should be defined explicitly in the model prior to simulations. In this model, the HF is assumed to be planar, aligned with the direction of the major principal stress. The two “incipient surfaces” of the plane of the HF initially are bonded with a strength that is equivalent to a specified fracture toughness. Propagation of the HF corresponds to breaking of these bonds. Clearly, the assumption of propagation of the HF in a single planar surface is a simplification. In practice, the massive hydraulic fracturing, used in shale stimulation for example, results in a large number of fractures propagating simultaneously or sequentially. Under certain conditions, the mechanical interaction between these fractures can lead to non-planar and complex trajectories as demonstrated by the results of numerical modeling [3, 4] and by experimental observations [5]. Also, non-planar fracture geometry may develop as a result of the interaction with pre-existing fractures and frictional interfaces [6, 7, 8].

Figure 1 shows the geometry and set-up of the UDEC model. The model represents a 2D horizontal section through a reservoir with a thickness of 350 m. It is assumed that the injection is through a vertical well located at the center of the model. The core part of the model containing the DFN is embedded into a larger domain with a regular network of pipes with a permeability equivalent to that of the core region. The linear dimensions of the full model are twice as large as those of the core part. The model core measures 1000 m × 1000 m. The state of stress in the plane of the model is assumed to be anisotropic, with the maximum principal horizontal stress equal to the vertical stress and the minimum principal horizontal stress equal to half of the vertical stress.

The applied injection rate is 0.07 m³/s or 70 kg/s. This rate is approximately equal to 26.4 bpm. Considering the assumed thickness of the formation, an injection rate of 2×10⁻⁵ m³/s/m was applied in the 2D model. Some sensitivity analyses with respect to injection rate were performed. It is assumed that the pre-existing fractures are already open and conductive, with a uniform aperture for each fracture set. The initial apertures of each fracture set are calculated based on their orientation relative to the in-situ principal stresses. The primary and secondary fracture sets are assigned an initial aperture of 3×10⁻⁵ m, and 1.1×10⁻⁵ m, respectively. The failure criterion of the pre-existing fractures is defined by the Coulomb slip law, with zero cohesion, friction angle of 30° and dilation angle of 7.5°.

RESULTS

Effect of Fracture Size Distribution

The objective of this study is to evaluate the effect of fracture size distribution on response of the DFN to fluid injection. The DFNs used in this study have identical connectivity characteristics; that is the three realizations (shown in Figure 2) are fully connected. However, the realizations belong to three different DFNs with different length exponent, α, and maximum fracture length, l_max. Both the primary and secondary fracture sets are oriented favorably (at 160° and 45° with respect to maximum principal stress) for shear failure. In these analyses, injection pressure remains below the HF pressure.
Figures 2, 3, and 4 show contours of fracture apertures and slip after 14 hours of stimulation. These figures suggest that when compared to Realization II, Realization I, which is characterized by a more uniform fracture size distribution with a maximum fracture length smaller than the DFN region, experiences a much larger DFN shear-stimulated surface area. The shear-stimulated surface area for Realization III seems to be smaller than that for Realization I, but greater than for Realization II. This observation is supported by the graphs of the DFN shear-stimulated surface area shown in Figure 5(a).

These results indicate that the DFN shear-stimulated surface area can be correlated to the uniformity of the fracture size and also to the probability of having large fractures relative to the domain size. The uniformity of the fracture size is a function of the negative exponent of length, $l^{-\alpha}$. A more negative exponent $\alpha$ results in a less uniform fracture sizes. However, it should be noted that Realization I has the smallest $\alpha$, but the maximum fracture length is also capped, resulting in fairly uniform fracture size. Thus, the DFN has a relatively uniform fracture size distribution with a mean length that is much smaller...
than the reservoir size. This condition seems to be optimal for shear stimulation.

Figure 5(b) suggests that the DFN affected surface area follows an opposite trend to the DFN shear-stimulated surface area. This is due to the fact that the fracture dilation associated with slip creates additional volume to accommodate injected fluid, resulting in slower propagation of the pressure front.

Figure 6 shows the history of production phase indices. Contours of permanent aperture increase at the end of the stimulation phase and the location of the production wells are shown in Figure 7.

Figure 6(a) shows the history of injection pressure at the injection well. For different DFN realizations, injection pressure, and thus injectivity and productivity indices, can be greatly affected by localized features at the injection point. Pressure contours (shown in Figure 8) provide better insight into the values and variation of pressures in the models. Figure 6(b) shows that Realization II very quickly reaches 100% recovery. However, Figure 8 shows that the extent of the rock mass involved in fluid flow is lowest in Realization II. Therefore, despite showing the fastest recovery, Realization II is the least favorable for sustainable heat production.

Realization I, which experienced the greatest shear stimulated area, shows the greatest injectivity but the slowest recovery. The recovery index remains close to 80%.

Figure 6: Effect of fracture length distribution: history of production phase indices.

Figure 7: Contours of permanent aperture increase and location of the wells.

Figure 8: Effect of fracture length distribution: pressures at the maximum value of recovery.
EFFECT OF ORIENTATION OF IN-SITU STRESSES

In this section, the effect of relative orientation of fractures with respect to the principal stresses is evaluated. In general, change in fracture orientation is relevant only in an anisotropic state of stress. Stress affects the reservoir response because of the two following mechanisms.

1) It changes the initial normal stress acting on a fracture plane and thus the fracture opening pressure.
2) It changes the initial shear stress acting on the fracture plane, which combined with the effective normal stress, affects the potential for slip and subsequent dilatational opening.

Two different realizations belonging to two different DFNs are considered for this study (see Figure 9(a)).

In both cases, the stress state is anisotropic with the maximum and minimum principal horizontal stress (in this 2D model acting in the horizontal direction) equal to the vertical stress and half of the vertical stress, respectively. Both DFNs are generated using a length exponent of 2 and a maximum fracture length of 250 m. In Realization I, fracture sets have dip angles of 160° and 60°, while in Realization II fracture sets have dip angles of 160° and 45°. Again, in this study, the applied injection rate of $2 \times 10^{4} \text{m}^3/\text{s}/\text{m}$ is such that for the given DFNs, the maximum pressure remains lower than the hydraulic fracturing pressure. As a result, the effects of fracture orientation on DFN stimulation can be studied independently of the secondary effects arising from hydraulic fracturing.

Figure 9(b) and (c) show slip taking place in both fracture sets of Realization I, while in Realization II only fractures belonging to the primary set slip. As a result of shearing of both fracture sets, the enhanced permeability in Realization I will be more isotropic than that of Realization II.

The histories of the DFN shear-stimulated surface area are shown in Figure 10(a). They indicate greater area for Realization I, in the early stages of solution. The results at later stages (after seven hours) cannot be compared because the flow in Realization I has reached the outer boundary of the model. In Realization II, additional fracture shear continues due to the direction of flow. The DFN-affected surface areas in both realizations are shown in Figure 10(b). Again, it seems that the DFN-affected surface area is correlated inversely to the DFN shear-stimulated surface area. Greater shear-stimulated surface area results in a lower area in which there is an appreciable increase in pressure.
Histories of production phase indices for the cases discussed above are shown in Figure 11. The permanent aperture increase and locations of the wells are shown in Figure 12.

This example illustrates very well the importance of stimulation, and shows that injection into Realization I results in a lower injection pressure, better injectivity and a faster and higher productivity. This is due to the fact that in Realization II, the secondary fracture set is not stimulated, and the response of the reservoir is controlled by the opening of these fractures by the pressure increase.

Finally, Figure 13 shows the pressure contours for the maximum value of recovery.

\[
\Delta a_{\text{dil}} = \Delta d_{\alpha} \times \tan(\alpha_{\text{dil}})
\]

**EFFECT OF DILATION ANGLE**

Understanding the effect of fracture dilation angle is important because dilation determines how much irreversible opening and permeability increase can occur during stimulation. The DFN used in this study is shown in Figure 2(a). Again, the applied injection rate results in injection pressures below the HF pressure.

Figures 14 and 15 show contours of slip and aperture after 20 hours of injection into the fully connected DFN. Fracture slip contours indicate that as dilation angle increases, the magnitude and the extent of fracture slip decrease. The history of the DFN shear-stimulated surface area shown in Figure 16(a) also indicates a clear increase in shear slip with decreasing dilation angle. This observation is consistent with the fact that as the dilation angle increases, the confining pressure also increases.

Figure 16(b) shows the average increase in aperture \(\Delta a_{\text{dil}}\) with increasing dilation angle. This observation is explained by noting that the dilational opening is \(\Delta a_{\text{dil}} = \Delta d_{\alpha} \times \tan(\alpha_{\text{dil}})\). In this formula, for the range of dilation angles considered, the rate of increase in \(\tan(\alpha_{\text{dil}})\) is much greater than the rate of decrease in shear displacement.
Figure 14: Effect of dilation angle on slip (20 hours of stimulation).

Figure 15: Effect of dilation angle on apertures (20 hours of stimulation).

Figure 16: Effects of dilation angle: history of shear stimulated area and DFN affected area, and average DFN aperture.

Neither aperture contours nor Figure 16(c) show a significant difference in the total affected area as a function of dilation angle. The negligible change in the DFN affected surface area can be explained as follows. First, the change in DFN shear-stimulated surface area is relatively small considering the scale of DFN affected surface area. Also, while shear-stimulated surface area decreases with increasing dilation angle, the average aperture increases with increasing dilation angle. Therefore, the total fluid volume accommodated by sheared fractures remains relatively unchanged, resulting in similar pressure increases.

Figure 17: Effect of dilation angle: history of production phase indices.
The histories of injection pressure, recovery, productivity and injectivity for this study are shown in Figure 17. Location of production wells is shown in Figure 18. Considering that the initial aperture of the fractures was $1.1 \times 10^{-5}$ m and $3 \times 10^{-5}$ m, the permanent increase in aperture due to even small values of dilation, e.g., angle of $3^\circ$, is more than one order of magnitude. But, apertures in the model with a dilation angle of $15^\circ$ are approximately twice those in the model with a dilation angle of $3^\circ$.

Differences in pressures, injectivity and recovery in the models with various dilation angles exhibit a relatively similar behavior.

![Figure 18: Contours of permanent aperture increase and location of the wells.](image)

**EFFECT OF INJECTION RATE**

The injection rate and injection pressure along with viscosity of the injected fluid are the operational parameters that can be used to design DFN stimulations effectively. In this section, we examine how the injection rate affects reservoir stimulation and propagation of the HF.

The DFN used in this study is fully connected, with a length exponent of 2, and maximum fracture length of 250 m. The primary fracture set is oriented at $160^\circ$ with respect to the $x$ axis, and the secondary fracture set is oriented at $60^\circ$. The orientation of fracture sets with respect to the direction of principal stresses is such that only the primary fracture set can experience slip.

The initially considered range of injection rates is such that it covers injection pressures smaller than the hydraulic fracturing pressure, as shown in Figure 19.

![Figure 19: Effect of injection rate: history of injection pressure for low injection rates.](image)

Figure 20 shows contours of aperture and pressure for the four injection rates of $2 \times 10^{-5}$, $4 \times 10^{-5}$, $8 \times 10^{-5}$ and $2 \times 10^{-4}$ m$^3$/s/m. The results in these figures are compared at the times when the same volume of fluid has been injected into the formation.

![Figure 20 Effect of injection rate: aperture and pressure contours for different injection rates (injected volume of 4.32 m$^3$/s/m).](image)

Figure 21 shows the histories of the DFN-affected area and suggests that for similar injected time, higher injection rates result in a greater DFN-affected surface area. This observation is expected, since the volume injected into the DFN is higher at higher injection rates. The plot of the DFN-affected area versus injected volume shows the opposite trend. That is, for similar injected volume, greater injection rates result in smaller DFN-affected surface areas. This is due to the fact that for a lower injection rate, the time required to inject a similar volume is much longer. Thus, during this longer time, the pressure front can propagate to a larger distance from the injection point.
Figure 22 shows the histories of the DFN shear-stimulated surface area. Again, for similar injection times, greater injection rates result in a greater DFN shear-stimulated surface area, due to injection of a larger volume of fluid. Comparing the DFN shear-stimulated surface areas for similar injected volumes indicates that higher rates result in greater DFN shear-stimulated surface area, which is different from the trend observed for the DFN affected surface area. This observation is attributed to the fact that higher rates lead to higher pressures and more slip (as observed in Figure 20(b)).

The contours of permanent aperture increase and location of production wells are shown in Figure 23. Figure 24 shows the histories of production phase indices. It is noted that in this example, production starts after injection of 7.2 m$^3$/m into the reservoir. The injection rate during the production phase is $1.5 \times 10^{-4}$ m$^3$/s/m. The increase in injection rate during stimulation results in a reduction in injection pressures and an increase in injectivity during production (Figure 24). However, increase in permeability in a larger volume of the rock mass for greater injection rates results in a slower increase in recovery, and consequently, slower increase in productivity index. The main reason for the small effect on injection pressure, injectivity and productivity, despite the clear difference in stimulation around the injection point, is attributed to the fact that the stimulated fractures are disconnected (i.e., stimulated in only one set), and flow through the network is still controlled by the secondary fracture set connecting the stimulated fractures.

In this study, effect of higher injection rates, which result in pressures required for HF initiation, is also studied. The histories of injection pressures for these injection rates are shown in Figure 25.

Figure 26 shows contours of aperture and pressure for injection rates greater than $2 \times 10^{-4}$ m$^3$/s/m. The results are shown for the same injected volumes. Figure 27 shows the history of DFN affected surface area for the higher injection rate. This indicates a trend similar to that observed at lower rates. For identical injection volume, DFN-affected surface area increases with decreasing injection rate.
Figure 24: Effect of injection rate: history of production phase indices.

Figure 25: Effect of injection rate: history of injection pressure for high injection rates.

Figure 26: Effect of injection rate: aperture and pressure contours for different injection rates (injected volume of 14.0 m$^3$/s/m).

Figure 27: Effect of injection rate: history of total affected area.

However, Figure 28 suggests that the history shear-stimulated surface area versus volume shows a decreasing trend with increasing injection rate. This change in trend is attributed to propagation of the HF at the higher injection rates. Once the HF propagates, pressures remain roughly equal to the fracturing pressure. Presence of the HF, with an average aperture greater than the aperture of the DFN fractures, results in preferential fluid flow along the HF. As a result of redistribution of flow, potential of shear stimulation decreases.
These results suggest that the injection rate will have different effects depending on the induced injection pressures. The effect of the injection rate is evaluated for situations in which the injected volume remains constant.

For injection pressures lower than the hydraulic fracturing pressure:
- Smaller injection rates result in a greater DFN-affected surface area; and
- Higher injection rates result in a greater DFN-shear stimulated surface area.

For injection pressures equal to the hydraulic fracturing pressure:
- Smaller injection rates result in a greater DFN-affected surface area; and
- Higher injection rates result in a smaller DFN-shear stimulated surface area.

Results also indicate that once the HF is formed, increase in injection rate will not result in additional shear stimulation.

CONCLUSIONS

This paper presents some initial results of what is intended to be a more comprehensive study focused on gaining a better understanding of the complex processes involved in shear stimulation or “hydro-shearing” of naturally fractured geothermal reservoirs. In an initial attempt to elucidate the hydro-mechanical response of reservoirs to injection, a two-dimensional approach was adopted in which the discrete fracture network was explicitly simulated. The hydro-mechanical response of pre-existing fracture networks to fluid injection has been studied numerically. The sensitivity of the models with respect to various in-situ and operational parameters has been evaluated.

It is well understood that success of shear stimulation process depends on many in-situ conditions, such as magnitude and orientation of in-situ stresses, characteristics of the discrete fracture network, and properties of the fractures.

The scenarios considered in this study are generally favorable for the development of hydro-shearing. Thus, the stress state is assumed to be anisotropic; fractures are orientated favorably for slip, and the discrete fracture network is dense, forming a fully connected DFN. Results of the study show, however, that differences in geometric properties of the DFN can lead to different stimulation and production scenarios.

It is observed that the potential for shear stimulation, measured by the surface area of fractures that experience slip, increases as the fracture size becomes more uniform. Also, favorable conditions require that fracture orientations be within the favorable range relative to the orientation of the principal stresses. The reservoir stimulation is better, i.e., stimulation results in a more isotropic increase in permeability, when different fracture sets (of different orientations) experience stimulation. At the same time, however, it was observed that greater shear-stimulated area and more isotropic enhancement of permeability can increase the potential of production loss.

The effect of injection rate, one of the operational parameters, on the stimulation is also evaluated. Two regimes of behavior were observed in the sensitivity studies with respect to the injection rate:
(a) Low injection rates, which result in injection pressures below the pressure required for hydraulic fracturing; and
(b) High injection rates, which result in injection pressures sufficient to create the HF.

The effect of injection rate on DFN-affected surface area (i.e., the surface area of the DFN where an increase in fluid pressure is observed), is independent of injection pressure. In other words, for a given injected volume, a lower injection rate always increases the proportion of the DFN that is affected. However, most of this increase in aperture is reversible.
The injection pressure is critical for the DFN-shear stimulated surface area. For a given injected volume, higher injection rates lead to a greater DFN-shear stimulated surface area, provided that the pressures remain below the hydraulic fracturing pressure. If the HF is propagated, the trend is reversed; higher injection rates result in a smaller DFN-shear stimulated surface area.

These preliminary results on the effect of injection rate can be applied in better design of injection rate/injection pressure history. In general, it is concluded that during early stages of stimulation, low injection rates are preferred, since they provide a relatively uniform aperture increase independent of fracture orientation. This uniform aperture growth increases the chances of fluid flow in different directions, and thus, provides access to more of the reservoir. Eventually, however, higher injection rates, in the range of pressures below the hydraulic fracture pressure, are favorable since they result in a greater shear-stimulated area, i.e., the area with permanent increase in permeability.

It is emphasized that desirable stimulation conditions should lead to simultaneous increase in the surface area exposed to fluid flow and enhanced recovery. The numerical results of these analyses indicate that the correlation between the stimulated volume of rock and enhancement of recovery is complex. Results of this study are promising in that they show that better site characterization with optimized injection rate/injection pressure history can lead to more reliable EGS systems. These results also show that the complexities involved in the hydro-mechanical process require more comprehensive approaches in understating the interaction between injection and the discrete fracture network.

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