MULTI-FRACTURING IN GEOTHERMAL RESERVOIR AND INDUCED SEISMICITY USING PARTICLE BASED, DISCRETE ELEMENT-FRACTURE NETWORK MODEL

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ABSTRACT

This paper presents discrete element fracture network model designed to simulate multi-stage hydraulic fracturing and induced seismicity in crystalline fractured rock mass at great depth. A series of fluid injection in consecutive way at three wells separated by 500 meter distance with constant rates are simulated. Results are compared which include: (i) spatiotemporal distribution of induced events, (ii) influence of injection rates and overall stimulated pattern, (iii) changes of stress states and maximum compressive stress directions around the injection points. Aim of this numerical study is to get ideas how the hydraulic fracturing operation should be designed for successful outcome of multi-stage hydraulic fracturing.

INTRODUCTION

Since the early 2000s, advances in drilling and completion technology have made drilling horizontal wellbores much more economical. Horizontal wellbores allow for much greater exposure to a formation than a conventional vertical wellbore. This is particularly useful in shale formations which do not have sufficient permeability to produce economically with a vertical well. The type of wellbore completion used will affect how many times the formation is fractured and at what locations along the horizontal section of the wellbore. Horizontal multi-stage hydraulic fracturing is the process by which multiple fractures are created along the horizontal section of the wellbore in a series of consecutive operations (Fig.1).

Dusseault and McLennan (unknown) addressed unresolved questions regarding use of multi-stage hydraulic fracturing in horizontal wellbores, which are:

(1) Is it better to maximize injection rate and pump continuously for several hours, or is it best to inject more slowly for many days or is some hybrid combination desirable?

(2) Should we try for short fat fractures near the wellbore or long, extended fractures of greater volume and larger surface area?

(3) Can we predict when secondary fractures are formed?

(4) In staged fracturing, do the stress changes arising from previous stages significantly affect the success of the current hydraulic fracturing activity?

(5) If so, then how far the distance between the stages should be and how long the time interval should be between the well shut-in time of the previous stage and injection start time of the current stage?
(6) What would be the appropriate rate and style of injection so as to avoid fracture coalescence, i.e. short-cut.

This paper presents Discrete Element Fracture network Model (referred to hereafter as DEFM) where hydro-mechanical coupling scheme is implemented enabling simulation of fluid flow in porous media and dynamic process of fluid pressure driven fracture initiation and propagation. Objectives of this numerical study is to examine if the presented numerical modeling is capable of answering some of the questions above, by looking into a series of multi-stage hydraulic fracturing simulations on a synthetic fractured crystalline reservoir. Results investigated are: spatiotemporal distribution of induced seismic events, changes of stress states due to previous stage of hydraulic-fracturing, sensitivity of injection parameters, such as (i) distance between injection points, (ii) rate and duration of fluid injection, (iii) injection style on the induced events and overall stimulated pattern.

**DISCRETE ELEMENT FRACTURE NETWORK MODEL (DEFM)**

Figure 1 shows the DEFM representing fractured geothermal reservoir constructed for this study. Detailed description of the model and how hydro-mechanical coupling scheme works in the model can be found in Yoon et al. (2013). Strength and deformation characteristics of rock matrix are designed so that the model resembles crystalline rock mass of Soulz-sous-Forêts France. Discrete fracture network is embedded in the model of which strength, stiffness and hydro-mechanical coupled parameters are taken from Forsmark Sweden (SKB 2010). Modeling parameters are listed in Yoon et al. (2013). Failure of rock matrix and discrete fractures is governed by Mohr-Coulomb criterion and resulting seismic magnitude and source mechanisms of the fluid injection induced events are computed using the numerical routine of Hazzard and Young (2002, 2004) and modified in Yoon et al. (2013) so to consider seismicity resulting from Mode I and II failures at pre-existing fractures. The constructed model is 3 km (horizontal) x 2 km (vertical) in size and subjected to compressive in-situ stresses with $S_{H} = 75$ MPa and $S_{h} = 60$ MPa, following depth-stress relation for Soulz site, assuming that the model section is at 4.5 km depth. Discrete fracture network is embedded, which are randomly generated but distributed in inhomogeneous pattern (more fractures near well #1, less near well #2 and #3).

There are three injection points with 500 meter distance between them (Fig.2, dots). Local stress monitoring technique (Yoon et al. 2012) is applied to capture local stress changes around the three injection points (Fig.2, circles). Stress monitoring circles are implemented with 500 meter diameter. This technique enables monitoring how much the stresses change around the next injection point, due to initiation and propagation of hydraulic fractures and fluid pressure migration in the previous stage injection.

![Figure 2: Fractured reservoir model in 3 km x 2 km size with embedded discrete fractures subjected to anisotropic in-situ stress of $S_{H} = 75$ MPa and $S_{h} = 60$ MPa. Three injection points are separated by 500 meter distance. Local stress monitoring circles are implemented at the injection points with 500 meter diameter.](image)

**PARAMETER SETTING FOR SENSITIVITY ANALYSIS**

Table 1 lists modeling parameters set up for sensitivity analysis of multi-stage hydraulic fracturing simulations.

<table>
<thead>
<tr>
<th>Parameters (unit)</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Injection rate (l/s)</td>
<td>10, 15, 20</td>
</tr>
<tr>
<td>Injection duration (hr.)</td>
<td>3 (constant) 6.4 (cyclic)</td>
</tr>
<tr>
<td>Injection distance (m)</td>
<td>500</td>
</tr>
<tr>
<td>No. of injection points</td>
<td>3</td>
</tr>
<tr>
<td>Injection interval (hr.)</td>
<td>10</td>
</tr>
<tr>
<td>Injection style</td>
<td>constant, cyclic</td>
</tr>
</tbody>
</table>

**RESULT – CASE 1 SIMULATION**

In case 1 simulation of multi-stage fracking, the injection rate is set to 10 liter per second and the distance between the three injection points is 500 meter. Figure 3 shows time variation of injection rates applied in three injection points with three downhole pressure histories. Bottom panel of the figure shows moment magnitude (Mw) of the induced events.
Figure 4 shows spatiotemporal distribution of the induced events. Color coding represents event occurrence time. Size of the symbols represents event source radius which is proportional to the moment magnitude. Black star denotes induced event with moment magnitude larger than 0.9. Stimulated cloud pattern at well #1 injection is short and fat, which implies that the applied injection rate is not large enough to produce optimized heat exchanger. Contrast to well #1, stimulation cloud patterns around well #2 and #3 are thinner and longer.

Again, similar to case 1 simulation, stimulated cloud pattern at well #1 injection is short and fat, whereas those around well #2 and #3 are thinner and longer.

**RESULT – CASE 2 SIMULATION**

In case 2 simulation of multi-stage hydraulic fracturing, the injection rate is set to 15 liter per second and the distance between the three injection points is 500 meter. Figure 5 shows time variation of injection rates applied in three injection points with three downhole pressure histories. Bottom panel of the figure shows moment magnitude (Mw) of the induced events.

Figure 6 shows spatiotemporal distribution of the induced events. Color coding represents the occurrence time of the events. Size of the symbols represents event source radius which is proportional to the moment magnitude. Black star denotes induced event with moment magnitude larger than 0.9.

**Figure 3:** Case 1 simulation. (Top) Injection rates (10 liter per second) applied to three injection points (gray bar) and histories of downhole pressure monitored at the injection points. (Bottom) Moment magnitude (Mw) of the induced events.

**Figure 4:** Case 1 simulation. Spatiotemporal distribution of induced events from three multi-stage hydraulic fracturing simulation. Color coding corresponds with event occurrence time. Size of the symbols represents event source radius, proportional to the moment magnitude. Black star is event with Mw>0.9.

**Figure 5:** Case 2 simulation. (Top) Injection rates (15 liter per second) applied to three injection points (gray bar) and histories of downhole pressure monitored at three injection points. (Bottom) Moment magnitude (Mw) of the induced events.

**Figure 6:** Case 2 simulation. Spatiotemporal distribution of induced events from three multi-stage hydraulic fracturing simulation. Color coding corresponds with event occurrence time. Size of the symbols represents event source radius, proportional to the moment magnitude. Black star is event with Mw>0.9.
RESULT – CASE 3 SIMULATION

In case 3 simulation of multi-stage hydraulic fracturing, the injection rate is set to 20 liter per second and the distance between the three injection points is 500 meter. Total injected volume is 216 m$^3$ (= 20 l/s x 3 hr. x 3600 s/hr.). Similar to case 1 and 2 simulations, stimulated cloud pattern at well #1 injection is short and fat and oriented in NW-SE, with many induced events at the surrounding pre-existing fractures (Fig.8). The stimulated pattern around well #2, however, is thinner and longer. Stimulated cloud around well #3 is fat and long, oriented NS. Large volume of the cloud is due to the induced events interacting with the surrounding pre-existing fractures, which consequently triggering many number of post-shut-in induced events and large magnitude events occurring long after the well shut-in (at 30 hr.).

There is another thin fracture with blunt tip propagating in NW, approaching the well #2 simulation cloud, showing potential for thermal breakthrough. Question remains is why branching fracture occurs and whether it is possible to mitigate such secondary fracture by controlling the injection parameters, e.g. rate and duration and style, assuming that injection point is fixed.

![Figure 7: Case 3 simulation. (Top) Injection rates (20 liter per second) applied to three injection points (gray bar) and histories of downhole pressure (MPa) monitored at three injection points. (Bottom) Moment magnitude (Mw) of the induced events.](image)

TEMPORAL CHANGE OF MAXIMUM PRINCIPAL STRESS AT INJECTION WELL AREA

Using local stress monitoring technique (Yoon et al. 2012), four stress components ($\sigma_{xx}$, $\sigma_{yy}$, $\sigma_{xz}$, $\sigma_{yz}$) are monitored at the three injection point areas (see Fig.2) and converted to $\sigma_1$ and $\sigma_3$, and maximum principal stress ($\sigma_1$) direction is calculated. Figure 9-11 show temporal change of maximum compressive stress direction locally evolving within three areas surrounding three injection points. In case 1 simulation (injection rate is 10 l/s) and during injection at well #1 (0-3 hr.), $\sigma_1$ direction at well #1 area slightly changes. It hardly changes at well #2 and #3 area, and maintained at 90°±15° range. This means that the fluid injection at well #1 and induced seismicity have very little effect on the (local) stress condition at well #2 and #3 areas. Slight deviation from 90° is in accordance with orientation of longer axis of the elliptic stimulated cloud. During injection at well #2, $\sigma_1$ direction at well #2 area changes from 90° to 120°. This is in agreement with event cloud advancing NNW (at 13 hr. green dots at upper part of the event cloud at well #2 area, see Fig.6).

When the injection rate is increased to 15 liter per second (case 2 simulation), stress conditions at well #2 and #3 areas are more affected by the fluid injection and induced seismicity at well #1 compared to case 1 simulation. However, the degree of stress condition change is more significant at well #2 area than well #1 and #3 areas, due to relatively less fracture density. Induced seismicity at less fractured region, i.e. failure of intact rock matrix, results in higher stress drop which in turn brings in larger degree of stress disturbance. This can be seen when
comparing red curve (10-15 hr.) and blue curve (20-25 hr.) (Fig.10).
When the injection rate is further increased to 20 liter per second (case 3 simulation), there appear more number of induced events, which result in large degree of stress condition change and also affecting stress condition at well #2 area. In 5-10 hours time range in Figure 11, the angle of $\sigma_1$ direction at well #1 area is maintained at 100-110° which is NNW. This direction matches with the longer axis direction of the elliptic shape of the event cloud. Again, occurrence of induced events at well #2 area during well #2 injection, i.e. less fractured region, results in drastic change in $\sigma_1$ direction almost to 80° within relatively short time period (11-14 hr., second half of the injection period) which could be responsible for branching of fracture in Y shape. Fluctuation of blue line in Figure 11 takes place in longer period, i.e. it starts at 20 hr. (initiation time of well #3 injection) and ends at 28 hr. (long after the well shut-in). Such drastic change in $\sigma_1$ direction results in, similar to well #2, branching of fracture in Y shape. However, in well #3 area, there is large number of pre-existing fractures compared to well #2 area, resulting in fat stimulated event cloud (Fig.8 blue event cloud). There is one fracture emanating from the main cloud and propagates in NW, which can potentially coalesce to stimulated event cloud in well #2 area, resulting hydraulic interference of fracture development, that should be avoided in design of multi-stage hydraulic fracturing.

![Figure 9: Case 1 simulation. Temporal change of angle of $\sigma_1$ direction (positive in counter clockwise) evolving within three areas surrounding the injection points.](image9)

![Figure 10: Case 2 simulation. Temporal change of angle of $\sigma_1$ direction (positive in counter clockwise) evolving within three areas surrounding the injection points.](image10)

![Figure 11: Case 3 simulation. Temporal change of angle of $\sigma_1$ direction (positive in counter clockwise) evolving within three areas surrounding the injection points.](image11)

**CONCLUSIONS**

From this numerical study, conclusions can be drawn as following.

- Discrete element fracture network mode is presented which enables simulation of fluid flow in porous media and fluid pressure driven dynamic failure and seismicity.
- Multi-stage hydraulic fracturing is simulated with 3 points of fluid injections tested with 3 levels of injection rates (10, 15, 20 liter per second).
- Constant rate injection in highly fractured area resulted in short and fat stimulated event cloud, whereas long and thin stimulated event cloud is simulated in less fractured area, but branching fractures.
- Local stress monitoring technique is used to see how the regional stress fields at well #2
and #3 areas change while hydraulic fracturing is performed at well #1.

- Changes of $\sigma_1$ directions at injection wells are calculated and the results show that 20 liter per second constant rate injection resulted in large changes in $\sigma_1$ direction (up to 80°). This explains why branching in fracture pattern occurs deviating largely from the far-field $\sigma_1$ direction.

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