

Numerical Assessment of Hydraulic Fracturing Stimulation Treatment of Geothermal Wells

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ABSTRACT

After years of exploiting steam, geothermal wells may need stimulation to remain economically profitable. Hydraulic fracturing can be a suitable technique to improve steam production or to create new geothermal pay zones. The goal is to stimulate the area around the well by connecting pre-existing fractures or by creating new pathways for the steam through the initiation and propagation of new tensile fractures. Even when a dense fracture systems results in large leak off volumes,, it has been shown that it is possible to induce tensile fractures of tens of meters around the injection well. Performing such a treatment in a geothermal reservoir presents several important challenges. The technical and geological issues that might affect the effectiveness and efficiency of the stimulation were investigated. If a hydraulic fracturing treatment is assessed to be technically feasible, it must be properly tailored to the particular geothermal field. A close connection between dynamic flow simulators and geomechanical models is essential to numerically simulate the effectiveness of a stimulation technique. To properly evaluate the stress changes induced by the pressure and temperature gradients in the geothermal field around the injection well, we linked in a 1-way coupled fashion numerical simulators and analytical solutions to connect the evolving fluid pressures and temperature with the changes in the stress field around the well. It has been found that hydraulic fracturing might not be the proper stimulation technique when isolation of a short section of the liner is not possible or is too expensive. On the other hand, the high injectivity that generates the high fracture leakoff can also be exploited to apply alternative stimulation approaches. The fast penetration of pressure and temperature fronts into the reservoir can make thermal and acid stimulation to be valuable alternatives to hydraulic fracture stimulation.

1. INTRODUCTION

Geothermal energy is rapidly raising as a valid green alternative to conventional energetic resources such as oil, gas and coal. Typically, geothermal power plants have virtually zero emission rate and they can provide stable energy supply. Geothermal wells, after years of production, might become underproductive and then requiring stimulation to return economically profitable. Several stimulations strategies can be applied if production is diminishing. The most popular techniques are certainly acid and thermal stimulations. In the first case, a chemical mixture is injected in the geothermal well with the scope of flushing off the minerals that have been deposited in the fractures around the well and that clog (or partially clog) such fractures and to lower the coefficient of friction of the fracture, facilitating the shear slip. The idea of thermal stimulation is to induced shear slip in the fractures that are located around the wellbore by generating a high thermal gradient in the rock matrix. The raise of thermal stresses around the injection well might also initiate and propagate short tensile fractures, further increasing the injectivity of the well.

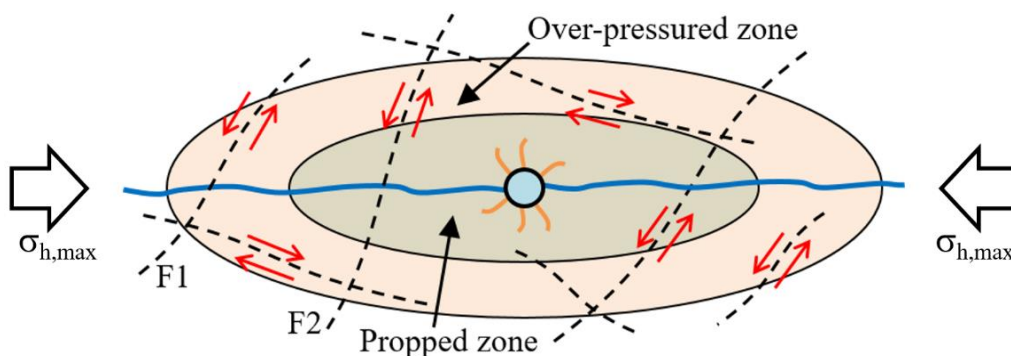


Figure 1: Top view of the area around the stimulated well that is interested by the hydraulic fracturing stimulation. The blue lines indicates the long tensile fractures that are induced by the treatment and that develops in the direction of the minimum in situ stress. Also secondary tensile fractures (orange lines) are propagated around the wellbore by the high pressure required to perform this technique. The existing fracture network (dashed lines) is affected in different ways: the new fractures will improve the connection between the existing ones (for example between fractures F1 and F2) and the induced overpressure will push the fractures towards a more instable condition that might lead to hydroshearing (red arrows). Modified after Dusseault, 2011.

Recently hydraulic fracturing is being, numerically and experimentally, investigated as an attractive alternative to the acid and thermal stimulation techniques, but it is not yet normally applied by geothermal operators. In its usual field of application, a hydraulic fracturing approach aim to stimulate a pay zone, while in a geothermal system, the target is creating new connection between the reservoir's fractures and by inducing new tensile fractures that become extra conduits for the hot fluids around the geothermal well.

Moreover, if proppant will be used during the hydraulic treatment, it will flow also in the existing fractures network, opening the fractures more than one of the traditional approaches will do. This will maintain the fractures open for longer time, postponing the healing process of the fractures and the successive stimulation treatment. Performing a hydraulic fracturing treatment can also stimulate the existing fractures via hydroshearing. The area in which an overpressure in the rock matrix is induced is much wider than the propped zone. In this extended area hydroshearing (shear slip induced by overpressure) can also occur, leading to so called naturally propped fractures and further increasing the production capacity of the stimulated well (Figure 1).

To design and perform a hydraulic fracturing treatment presents some technical challenges that must be properly addressed in order to achieve the desired outcome. First of all, productive geothermal fields usually exhibit high leakoff values because of the elevated permeability of the reservoir's rock and/or because of the a dense fractures network. Reservoirs with high leakoff are far from being an ideal candidate to perform an efficient hydraulic treatment because the fracture efficiency (the ratio between the injected volumes and the volume of the stimulated hydraulic fracture) will be inevitably very low. Despite this limiting feature typical of many geothermal systems, field studies have revealed that a hydraulic fracture treatment can be effectively performed. In his work, Legarth (2005) have shown that it is technically possible to stimulate propped hydraulic fractures despite the high leak off value of geothermal reservoirs. With a non-aggressive treatment, they could generate hydraulic fractures and a significant improvement in production has been achieved. Another issue to consider is related to the fact that often geothermal reservoirs are exploited in difficult geological environments that make extremely problematic to properly cement the drilled wellbore (Glauser, 2013). Moreover, frequently geothermal wells are completed with a very long open hole section or with a very long perforated liner. These circumstances further increase the complexity of performing an efficient fracking treatment because in many cases it will be not possible (or too expensive) to isolate a short section of the perforated liner.

Two different scenarios have been considered: in the first one (SC1) it is assumed that it was feasible to insert an isolating tool exclusively on top of the perforated liner, while in the second scenario it was assumed that it was possible to isolate a short interval of the casing (SC2), in order to increase the chance of success of the hydraulic treatment (Figure 2).

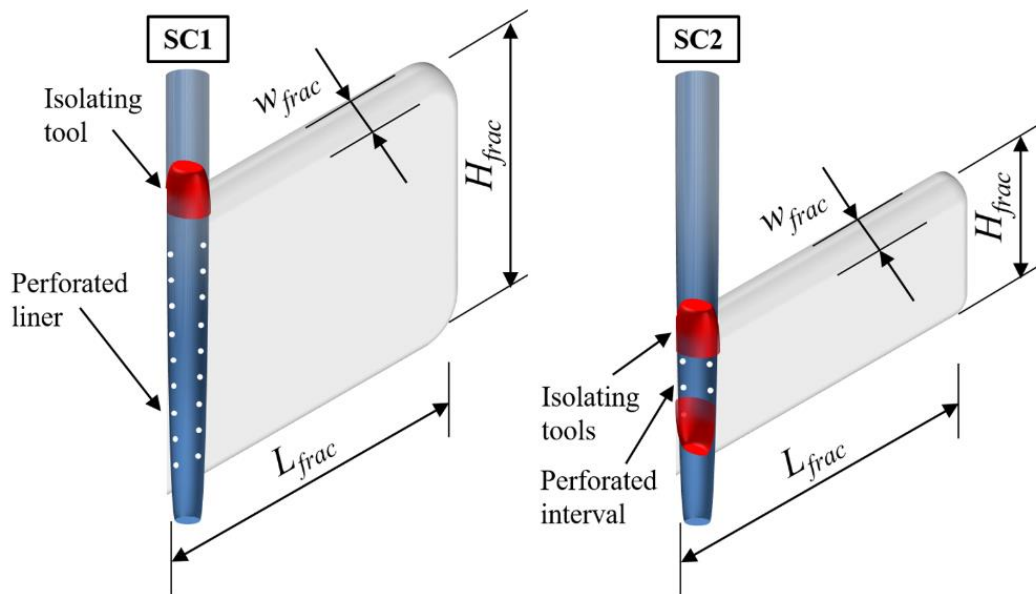


Figure 2: Side view of the studied scenario. Scenario 1 (SC1): an isolating tool is place on top of the perforated liner. In this case the well is completed with a long perforated not-cemented liner. The fracturing treatment is performed along the entire perforated interval. Scenario 2 (SC2): with the means of two isolating tools it was possible to create a short perforated interval in the casing.

To evaluate the hydro-thermal-mechanical changes that are provoked by a hydraulic fracturing treatment, we built a 1-way coupled model, that incorporates a mechanical and a dynamic flow simulator and a set of analytical solutions. We evaluated the effects on the geothermal system of the pressure increase in the rock matrix and of the thermal shock induced by the injection of fluids at much lower than the reservoir's one. Although it might play an important role in the evaluation of the effectiveness of the stimulation, the chemical modification of the fracture's surfaces (and the consequent lowering off the coefficient of friction of the fracture) generated by the injection of non-native fluids it was not included in the coupled model. This model was adopted for the analysis of the second scenario (SC2). To evaluate the first scenario (SC1) we considered sufficient the single-well reservoir model: in this case the focus was only on the geomechanical concerns.

This work was part of the Geocap project (Geothermal Capacity Building Program Indonesia – Netherlands, <https://www.geocap.nl/>), which focuses on the Indonesian geothermal market. For this reason, we referred to the Wayang Windu geothermal field (East Java, Indonesia). The findings of this work can be extended to any geothermal fields that present similar issues than the ones that are analyzed

here. All data that were required to performed the numerical and analytical calculations were found in literature (Masri, 2015. Bogie, 2008. Tingay, 2010).

2. METHOD

The data necessary to build the geological model were collected from literature. Masri (2015) collected a comprehensive set of the geological data of the Wayng Windu field. This data were the basis of our coupled model. The magnitude of the stress gradients was set as: $\sigma_{h,min} = 13$ kPa/m, $\sigma_{h,max} = 26.5$ kPa/m, $\sigma_v = 24.1$ kPa/m. The geological (layer cake) model was split into 4 zones. The overburden was separated into a medial (TVD at bottom 750 m) and a proximal (TVD at bottom 1350 m) zone. The reservoir was divided into a proximal (TVD at bottom 1525 m) and a distal (TVD at bottom 2300 m) zone. The base of the reservoir was positioned at 4000 m TVD. The permeability and porosity of the rock matrix were set in all zones at 0.001 mD and 15%. Respectively. The viscosity of the transition zone above the reservoir was set at 0.15 cp, in the reservoir (steam) at 0.013 cp and in the underburden (brine) at 0.6 cp.

2.1 Single-well reservoir model

This model was built to study Scenario 1 and it was created with the numerical simulators MSHALE and MFRAC. The goal of this model was to evaluate how an induced hydraulic fracture will develop if it would not be possible to isolate a short section of the section of the casing and the treatment will need to performed along the entire length of the perforated liner. A 3-dimensional fracture propagation type was selected to describe the profile of the induced fracture (Meyer, 2016). The selected options for fracture and proppant are displayed in Table 1.

Fracture Geometry	Three – Dimensional
Propagation Parameters	Default Growth
Fracture Initiation Interval	Minimum in situ stress
Proppant Transport Methodology	Conventional (Link Proppant)
Proppant Settling Transport	Convective Transport
Wellbore – Proppant Effects	Proppant Density Only
Fracture – Proppant Effects	Empirical

Table 1: Induced fracture and proppant option of the single-well model.

The Wayang Windu geothermal field is characterized by several semi-squared fractures clusters of size of approximately 70 by 70 meters. The dense fractures network (fractures density = $D_{frac} = 1.1$ m⁻¹) was modelled explicitly and a constant spacing (S) between the fractures was used ($S = 1/D_{frac}$). The low permeability of the rock matrix (0.001 mD) was considered separately. In scenario 1 we focused on the analysis of the effects of the stimulation of a single cluster. The underproducing well was placed for simplicity in the center of the cluster (Figure 3).

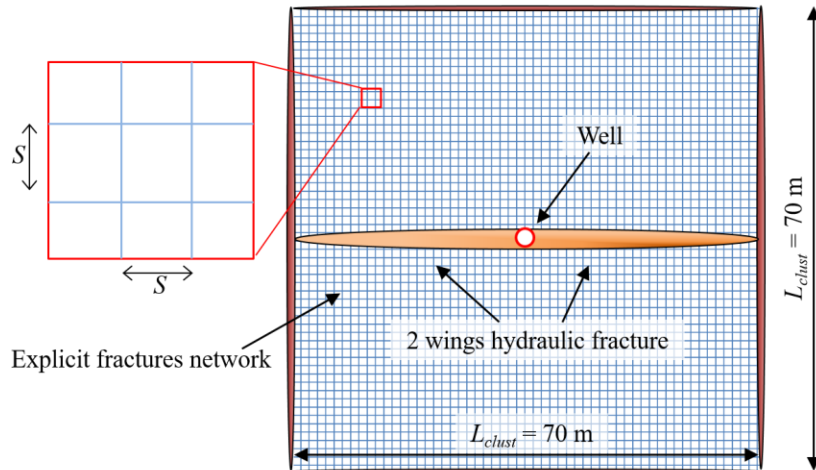


Figure 3: Top view of the fracture network of a 70 by 70 meters cluster. The injection well is located in the center of the cluster and a 2-wings hydraulic fracture that propagates in the direction of the maximum in situ stress is induced.

The aim of this model is to evaluate how and where a hydraulic fracture that is stimulated in a long perforated liner develops. Moreover, with the single-well model it is also possible to understand if the injected volume necessary to develop a hydraulic fracture that could reach the extremes of the fractures cluster were technically feasible.

To customize the design of the fracturing treatment for the special conditions of the Wayang Windu field is essential to increase the chances of success of the stimulation. Weijers (2002) and Dingwei (2011) suggested that using a smaller proppant grain size, in combination with a short perforated interval and a high pump rate, will help to maximize the effectiveness of the hydraulic treatment. To additionally enhance the aperture of the induced fracture, the fluid viscosity was augmented during the treatment.

2.2 1-Way coupled model

The coupled model was created to study Scenario 2. Such a model was needed because injecting not native fluid in the subsurface changes the thermo-hydro-mechanical properties of the rock matrix that is influenced by the injection and all these components mutually interacts (Gaucher, 2015).

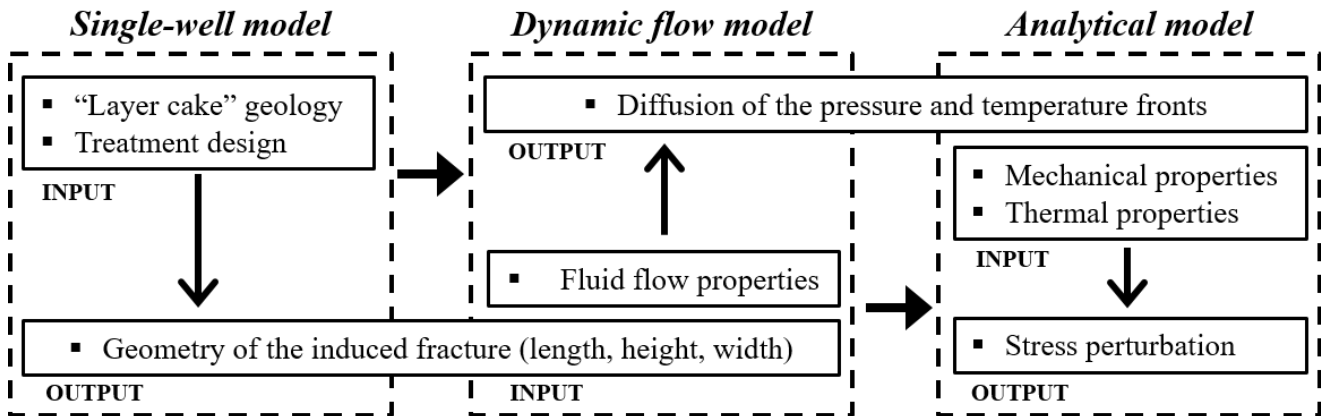


Figure 4: 1-Way coupled system. The output for a model is used as part of the input of the following model.

In the same way that it was shown in the previous section, the single-well reservoir model of the Wayang Windu field was made with the numerical simulator MSHALE. Again, a layer cake geological model was defined using the data collected from literature. Several adjacent fractures clusters were considered and the injection well was placed in the center of one of the them (Figure 5). In this case the dense fractures network was modelled implicitly by means of enhanced leakoff value of the rock matrix. Moreover, it was considered that the fractures clusters are 100 meters high and that it was possible to isolate a short interval in the casing in the center of the cluster height.

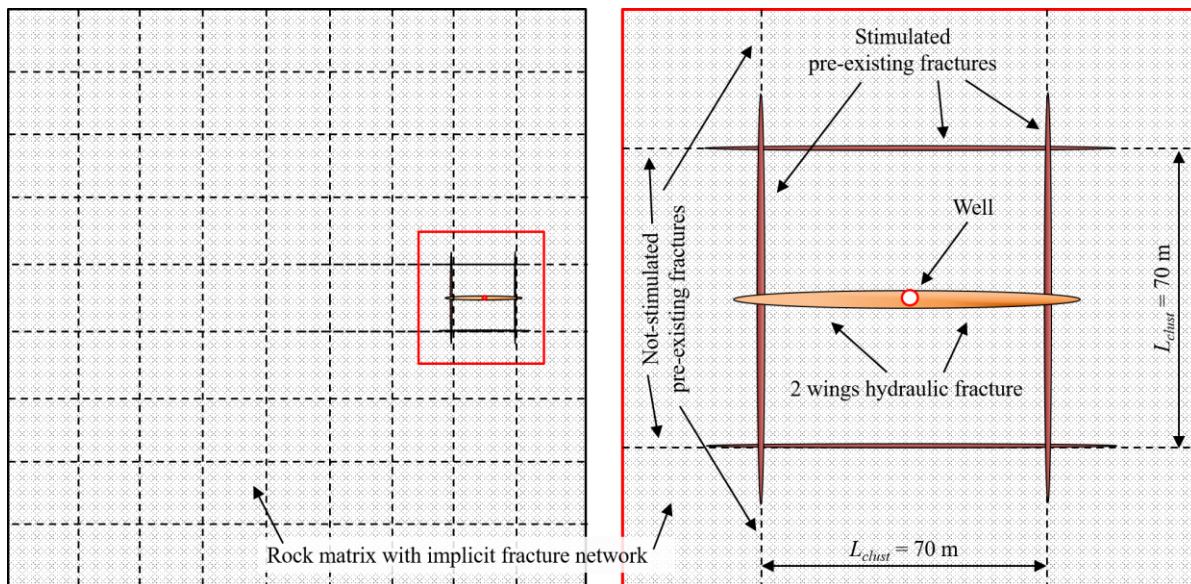


Figure 5: Top view of the fracture network made of several 70x70 meters clusters. The injection well is located in the center of one of the cluster. In this case the dense fractures network within the clusters was modelled implicitly in terms of enhanced leakoff of the rock matrix.

The dynamic reservoir model was created with the flow simulator Eclipse (Figure 6). The horizontal size of the dynamic flow model is 1420 by 1420 m. The layer cake geological system matched the one of the single-well reservoir model. The steam-brine contact was set at 2350 mTVD. The pre-stimulation condition for pressure and temperature were set at 233 bar and 300 °C (at 2580 mTVD). The borders of the fractures clusters were explicitly modelled using narrow grid cells of 0.1 meters width. The dimensions of the clusters were the same of the single-well reservoir model. To consider anisotropic permeability, different properties were considered for the fractures that runs parallel to the direction of the minimum in situ horizontal stress than the fractures that are parallel to the maximum in situ stress. Moreover, to consider the dense fracture network included in the clusters, an anisotropic permeability was assigned to each grid block. The grid size within the reservoir was set at 5 meters, while around the fractures it was set at 1 meter and coarsened next to the boundaries and away from the fractures (Figure 6, left).

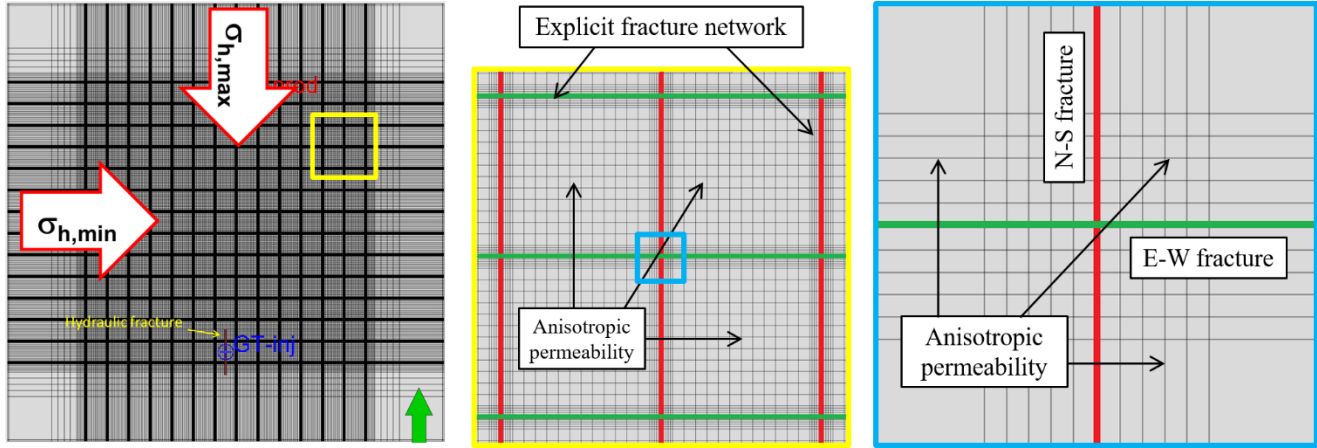


Figure 6: Eclipse dynamic flow model mesh. Left: top view of the fracture network (the thick black lines indicates the borders of the clusters). Center: zoomed view on a set of 4 clusters. The fractures that develop parallel to $\sigma_{h,max}$ (red lines, N-S fractures) have higher permeability of the fractures that run parallel to $\sigma_{h,min}$ (green lines, E-W fractures). Right: zoomed view on the mesh refinement around the cluster's borders. Within the cluster the rock matrix was modelled with anisotropic permeability. The main direction of flow stream lines is North-South. (Pizzocolo, 2017).

We considered a situation in which the hydraulic fracture was just stimulated ($t_0 = \text{end of the hydraulic stimulation}$). We simulated a continuous injection (with production rate of 2000 sm^3/day) for 5 years. The permeability of the induced fracture ($K_{hyd,frac}$) was 10 D and the temperature of the injected fluids was set 30 °C. The porosity of the rock matrix was set at 15%. Because the grid cells of the explicit fractures network were set very small (0.1 meter), to have a representative transmissibility a very high value of the permeability was chosen. In the Wayang Windu geothermal, the fractures network is the main pathways for the fluids. For this reason we selected a permeability of the existing fracture much higher than the permeability of the rock matrix. The vertical permeability of the fractures was selected equal to the corresponding horizontal permeability, while the vertical permeability of the rock matrix was set as half of the permeability of the rock in the corresponding horizontal direction.

The results of the temperature and pressure fronts profile after 1, 3 and 5 years of injection were used as input the last stage of the 1-way coupled model (Figure 4). The thermal (equations 1, 2 and 3) and poroelastic (equation 4) stresses generated around the well by the injected fluids were calculated following the analytical solutions for a circular horizontal cross section around the injection well in an infinitely high reservoir proposed by Perkins and Gonzalez (1984, 1985). In their work the total ($\sigma_{thermal}$), radial ($\sigma_{th,radial}$) and tangential ($\sigma_{th,tan}$) thermal stresses generated by the temperature gradient are given by:

$$\sigma_{thermal} = \alpha \cdot \frac{E}{1-\nu} \cdot (T_r - T_w) \quad (1)$$

$$\sigma_{th,radial} = \alpha \cdot \frac{E}{1-\nu} \cdot (T_r - T_w) \cdot \frac{1}{r^2} \cdot \int_{r_0}^{r_a} r \, dr \quad (2)$$

$$\sigma_{th,tan} = \alpha \cdot \frac{E}{1-\nu} \cdot (T_r - T_w) \cdot \frac{1}{r^2} \cdot \left[\int_{r_0}^{r_a} r \, dr - r^2 \right] \quad (3)$$

Where α is the coefficient of thermal expansion, E the Young's modulus, ν the Poisson's ratio, T_r the in situ temperature of the reservoir, T_w the temperature of the injected water, r_0 is the radius of the well and r_a indicates the radial distance from the injection well. Perkins and Gonzalez also gave a solution to calculate the poroelastic stress that results from the injection of water:

$$\sigma_{poro} = \beta \cdot \frac{1-2\nu}{1-\nu} \cdot (P_{fin} - P_{inj}) \cdot f_k \quad (4)$$

In equation 4 β represents the Biot's coefficient and f_k is Koning's factor (in this case, $f_k = 0.5$). This factor is necessary to consider the ellipsoidal distribution of the pore pressure around the fracture's surfaces (Koning, 1980). The poroelastic stress affects the hosting medium in the same way in all direction.

Thermal tensile will initiate and propagate when the combination of the tangential thermal stress and the poroelastic stress overcomes the initial minimum in situ stress. In other words, if $\sigma_{h,min,final}$ (equation 5), the perturbed by the injection of fluids minimum in situ stress, is positive (tensile state, $\sigma_{h,min,final} > 0$), tensile fractures are expected to develop in the direction of the $\sigma_{h,max}$.

$$\sigma_{h,min,final} = \sigma_{thermal} + \sigma_{poro} + \sigma_{h,min,initial} \quad (5)$$

The rock formation around the wellbore’s wall is damaged by the drilling procedure and by the stress concentration that can produce breakouts and generate short tensile fractures. For this reason it was assume that the rock matrix in the vicinity of the wellbore does not have tensile strength. Another aspect to consider it is related to the shear failure (and consequent slip movement) of the existing fractures. If the injection of fluid in the rock matrix lowers the minimum horizontal stress below a certain level, shear failure ($|\sigma_{h,min,final}| < |\text{shear failure limit}|$), or hydro-shearing, may occur on the fractures that develop in the direction of the $\sigma_{h,min}$. The shear failure limit was calculated with the Mohr-Coulomb frictional failure theory. During the hydraulic fracturing treatment the effect of the provoked overpressure is not limited to the region where the fractures are open and propped but will propagate further (Figure 1). Increasing the pore pressure will reduce the compressive stress, facilitating the slipping of the existing fractures. The shear failure limit has been calculated with the Mohr-Coulomb frictional theory. Because it was not possible to find precise mechanical data of the fractures, it was used a coefficient of friction of 0.6 and zero cohesion was assumed. An additional benefit of inducing shear slip is given by the additional aperture (shear dilation) created by the roughness of the fractures walls. Moreover, the fractures will not slip back to the initial position when the injection of fluid will stop, maintaining part of the enhanced aperture given by the shear slip (naturally propped fractures).

3. RESULTS

3.1 Scenario 1

In the single-well reservoir model used to analyze this scenario, all the pre-existing fractures were physically (explicitly) insert in the numerical model ($D_{frac} = 1.1 \text{ m}^{-1}$, $S = 0.91 \text{ m}$). The loading inputs were given by the desired length of one wing of the hydraulic fracture (35 meters, ideal situation in which the injection well is located in the center of the fractures cluster) and by the injection rate ($q_i = 7 \text{ m}^3/\text{min}$).

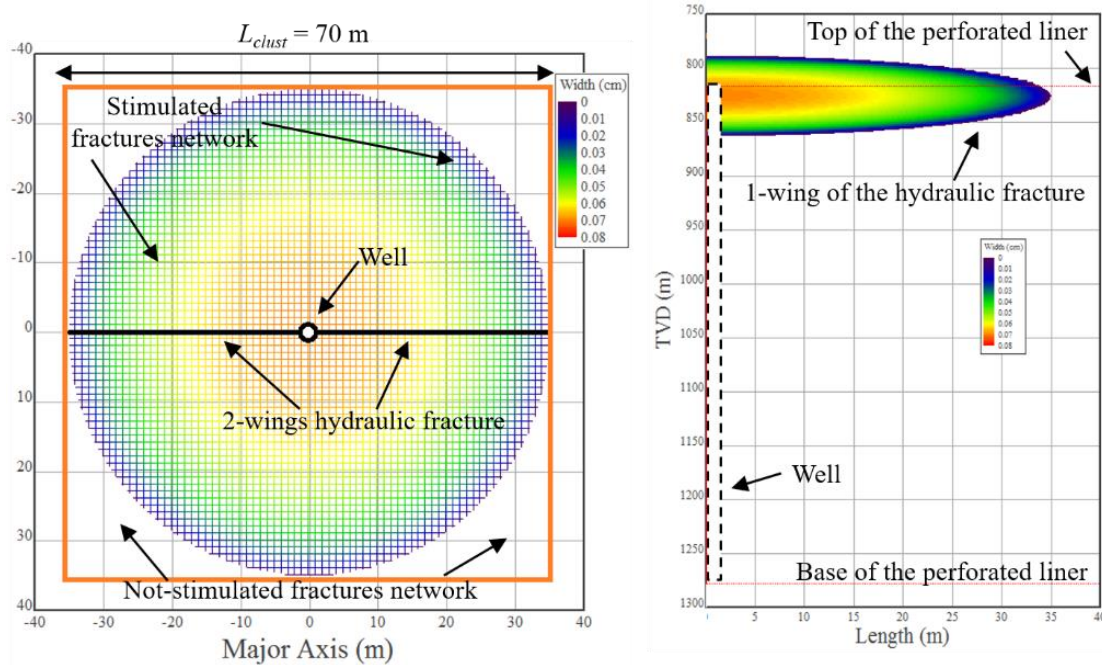


Figure 7: Left: top view of the 2-wings hydraulic fracture within a 70x70 meters fractures cluster. The color plot shows the width of the existing fractures when the stimulation ended. Right: side view of one of the wing of the hydraulic fracture. The dimension of the fracture are: $L_{frac} = 35 \text{ m}$ (given input), $H_{frac} = 75 \text{ m}$. The color plot shows the width of the stimulated hydraulic fracture at the end of the treatment.

We chose a proppant distribution allocation, the ratio between the proppant mass that actually remain in the hydraulic fracture after the treatment and the total injected proppant mass, of 50%. Because of the high leakoff of the geothermal field, the proppant will not remain in high percentages in the induced fracture but it will also spread in the fracture network around the wings of the induced hydraulic fracture. The calculated required injected volume to stimulate this fracture is 240 m^3 and the BHTP (bottom hole treating pressure) is 180 bars. The hydraulic fracture is not confined in the interval of the perforated liner but it propagates above the top of the reservoir. Despite being stimulated along a long perforated liner (~450 meters), the fracture propagates exclusively in the top part of the liner. The

fracture efficiency is low at the beginning of the stimulation (approximately 20%) and keeps decreasing during treatment because the injected fluids quickly spread into the existing fracture network (Figure 8).

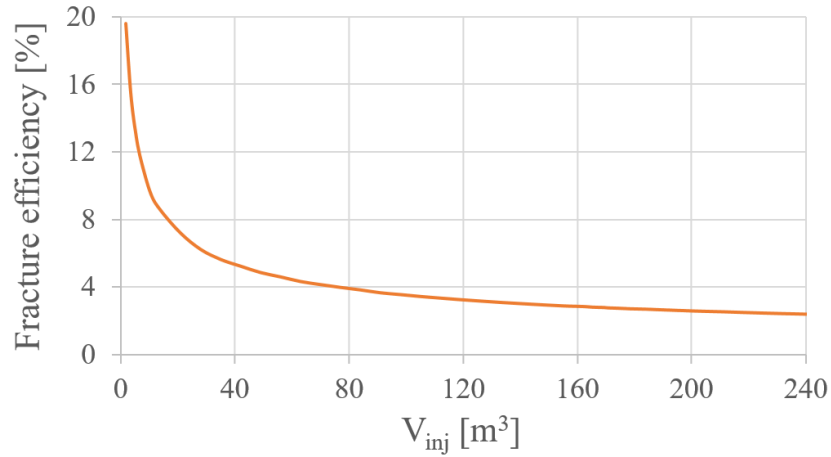


Figure 8: Evolution of the fracture efficiency of the induced hydraulic fracture during treatment.

3.2 Scenario 2

Using the design described in the previous section we modelled the propagation of a hydraulic fracture 60 m long and 100 m high. This resulted in a good fracture efficiency of the discrete fracture network (FN) surrounding the injection well. A low efficiency on the main hydraulic fracture was expected because of the high leak off coefficient of the geological setting that was modelled.

	HF	FN
Volume [m ³]	23.2	208.8
Efficiency [%]	7	60
Area [m ²]	6961	62646
Average fracture's width [mm]	3.3	-

Table 2: Geometry of the induced hydraulic fracture and of the part of fracture network that was stimulated. HF = hydraulic fracture, FN = fractures network.

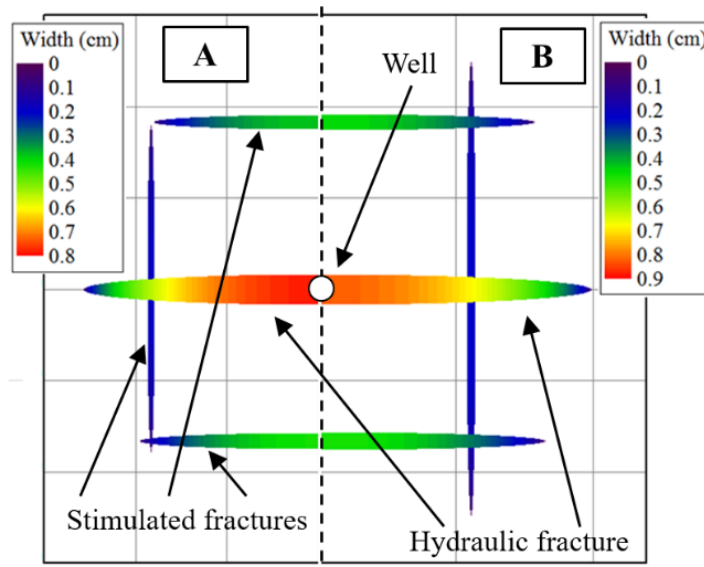


Figure 9: zoomed top view of the stimulated fracture network around the injection well after the stimulation treatment. A: assuming that the proppant mainly remains in the induced hydraulic fracture. B: assuming a uniform distribution of the proppant between the induced and existing fractures. Pizzocolo (2017).

The fractures that runs parallel to the direction (N-S) of the maximum in situ stress have a wider aperture than the fractures that develop in the direction of the minimum in situ stress. Assuming a uniform distribution of the proppant between the stimulated fracture and the existing ones, the length of the existing fractures that will be successfully stimulated will be higher (Figure 9, case A) than if it is assumed that the proppant mostly stays in the induced hydraulic fracture (Figure 9, case B).

The results collected with the single-well reservoir model (geometry of the hydraulic fracture) was used as input for the dynamic flow simulator (Figure 2). Because of the high contrast between the permeabilities of the fractures and of the rock matrix, the pressure and temperatures front extend much deeper into the fractures network (Figure 10, A3 and B3) than in the rock matrix (Figure 10, A2 and B2).

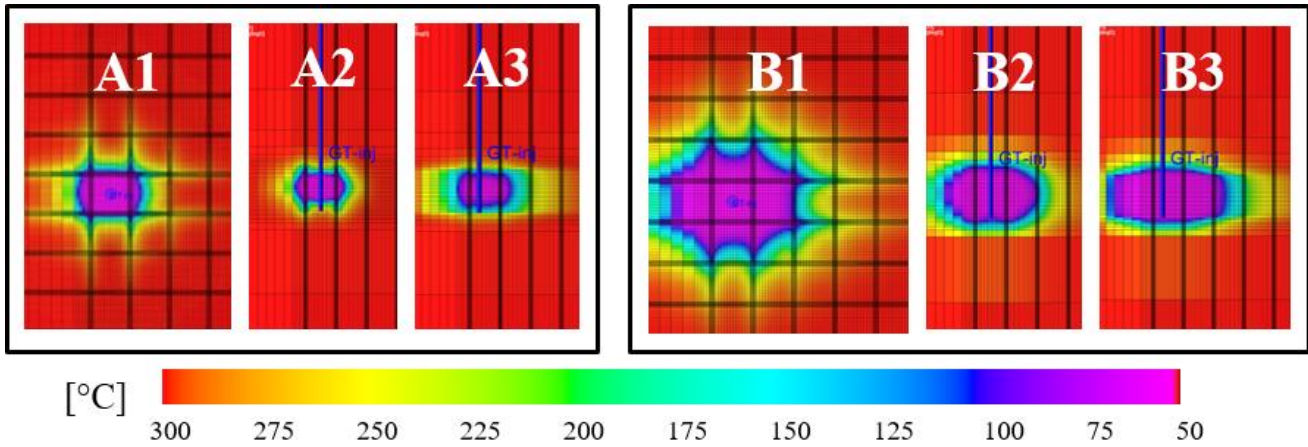


Figure 10: extension of the temperature front after 1 year (case A) and 5 years (case B) of injection after stimulation. A1, B1 = top view of the area around the injection well. A2, B2 = side view of the area around the injection well (cross section of the rock matrix). A3, B3 = side view of the area around the injection well (cross section of an existing fracture).

The last stage of the 1-Way coupled model is presented by the analytical solution of Perkins and Gonzalez. Here the analysis of the temperature and pressure fronts were used as input to calculate how the injection of the fluids modified the stress field ($\sigma_{h,min,final}$) and what are the implications of the stress changes on the rock matrix and on the existing fractures.

During the injection period that was considered (5 years) secondary tensile fractures as result of the induced thermal and poroelastic stress ($\sigma_{h,min,final} > 0$) did not initiate and propagate. On the other hand, the perturbed stress state ($\sigma_{h,min,final}$, green line, Figure 11) is above the shear limit for a distance of approximately 100 meters from the injection well. This means that the existing fractures that are located in this radius around the wellbore might undergo shear slip. Furthermore, the results shown in Figure 11 demonstrate that the most relevant stress changes are generated by the thermal gradient (red line).

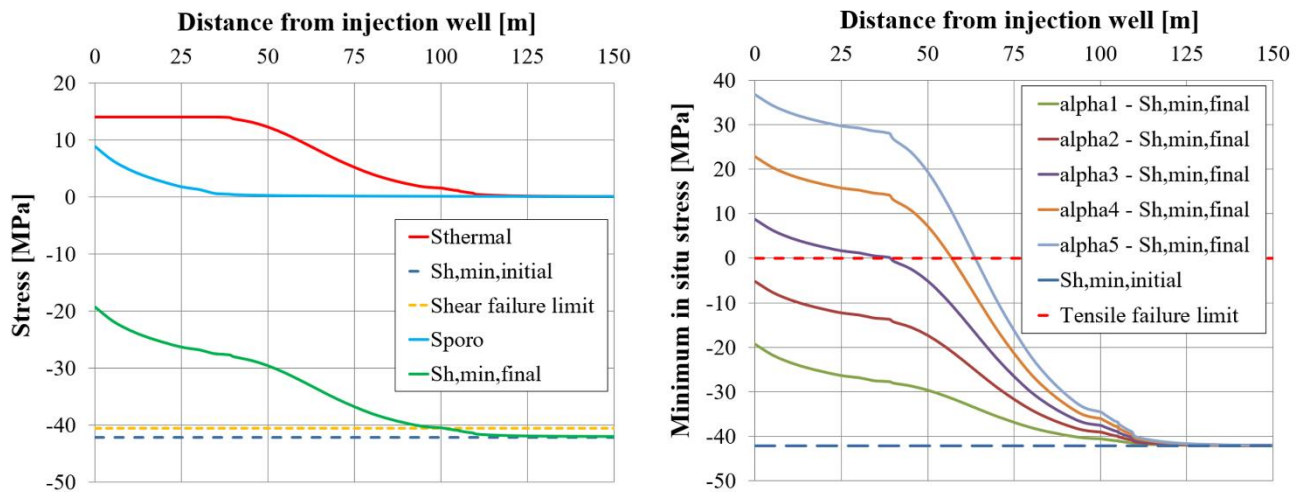


Figure 11: Left: stress changes in the rock matrix around the injection well 1 year after injection. The induced thermal and poroelastic stress (red and blue lines) tends to open tensile fracture but do not lower the initial in situ stress (dash blue

line) enough to generate new tensile fractures: the final minimum in situ stress (green line) is a compression state everywhere. Hydroshearing might occur on a radius of 100 meters around the injection well (crossing point between the green and the dashed yellow line). Right: sensitivity analysis over the coefficient of thermal expansion. $\alpha_1 = 0.1E^{-4} 1/^\circ\text{C}$, $\alpha_2 = 0.2E^{-4} 1/^\circ\text{C}$, $\alpha_3 = 0.3E^{-4} 1/^\circ\text{C}$, $\alpha_4 = 0.4E^{-4} 1/^\circ\text{C}$, $\alpha_5 = 0.5E^{-4} 1/^\circ\text{C}$.

The mechanical properties of the rock that mostly influence the calculation of the thermal stress (equation 1) are the Young's modulus (E) and the coefficient of thermal expansion (α). To take into account the uncertainties in the measurements of these two parameters, sensitivities analysis were ran for the range of values of the Young's modulus and of the coefficient of thermal expansion that can be found in volcanic rocks. The Indonesian volcanic rock have Young's modulus that typically last in the range of 7 – 10 GPa and for these values the calculated $\sigma_{h,thermal}$ does not varies significantly. On the other hand, for the range of the coefficient of thermal expansion that can be measured in such rocks ($\alpha = 0.1E^{-4} - 0.5E^{-4} 1/^\circ\text{C}$), tensile cracking will happen. For $\alpha \geq 0.3E^{-4} 1/^\circ\text{C}$, tensile fractures will propagate in the rock matrix around the injection well (Figure 11, right).

4. DISCUSSION

Two different scenarios were studied in this work (Figure 2). To analyze the development of a hydraulic fracture stimulated along a very long perforated liner, a single-well reservoir model was built. Analyzing the results of this model it seems that a tensile fracture reaching the extremes of the 70 by 70 meters cluster to be technically feasible (Figure 7). However the dense fracture network around the injection well would lead to a very low fracture efficiency (Figure 8). Depending on what is the target of the stimulation, a low fracture efficiency might not have a negative impact on the effectiveness of the treatment. The efficiency of the induced fracture will be low because the injected fluids and proppant will flow rapidly into the dense fractures network of the geothermal reservoir. If the goal was to develop a long hydraulic fracture in order to connect as many possible fractures that cross the path of the induced one, then a low efficiency strongly influence the effectiveness of the stimulation. On the other hand, if the goal of the treatment is to stimulate as many existing fractures possible, and the length of the induced one is not of primary importance, then injected several cubic meters of fluids (and proppant) at pressure higher than the in-situ one in the fractures network, might shear slip several existing fractures and consequentially improved production.

The bigger limitation of inducing a hydraulic fracture along a very long perforated liner is that it will mainly develop on top of the perforated liner at the border between the reservoir's top and the caprock (Figure 7). This was expected because the difference between the minimum horizontal stress of the top and the base of the perforated interval is very high ($\sigma_{hor,top} \ll \sigma_{hor,base}$), the hydraulic fracture will start develop as soon as the injection pressure will be enough to overcome $\sigma_{hor,top}$ and the fluid will immediately start flowing in the top part of the reservoir. Moreover, if a stress barrier is not present the fracture height will not be confined and the induced fracture develop vertically above the caprock instead than deeper into the geothermal reservoir.

Finally, if it would not be possible to isolate a short internal it must not be underestimate the risk of jeopardize the integrity of the well or to damage the perforated liner via local plastic buckling when the liner undergo high shear stress (Dusseault, 2001).

A hydraulic fracture treatment would be much more effective if it would be possible to isolate a shorter perforated interval (Scenario 2). In this case it would be possible to target the part of the geothermal reservoir that would benefit more from the stimulation treatment. In Figure 9 it is shown that it is possible to overcome the geological and technical challenges and induce hydraulic fractures that penetrate deep into a geothermal field. The single-well model can be used to quantitatively analyze the efficiency of the stimulation treatment.

Unfortunately in this model is not possible to introduce the degradation coefficient for the proppant. The challenges that the in situ condition of many geothermal environments present, need to be properly evaluated because the proppant will deteriorate quicker than in the typical settings where hydraulic fracturing is performed. This means that it will be necessary to perform extra stimulations of the geothermal system earlier than expected to maintain the production at economically profitable levels.

Introducing the geometry of the hydraulic fracture into the flow simulator we evaluated the extensions and the shapes of the cooling and pressure fronts. The rock matrix has poorly connected porosity. The fluid it is stored in the rock matrix as well, but because of the bad connection between the pore, it is difficult to activate. To improve the production rate it is essential to stimulate the interconnected fracture network. This can be achieved also by shearing existing fractures or by propagate new tensile ones via thermal-hydro-mechanical stimulation. The pressure and temperature profiles calculated with the dynamic flow simulator were used as input for the last stage of the 1-way coupled model: the analytical calculations. The thermal and poroelastic stresses (Figure 11) generated by the temperature and pressure gradients were not large enough to initiate and propagate new tensile fractures. The biggest contribution to the stimulation was given by the thermal gradient ($\sigma_{thermal} \gg \sigma_{poro}$) and the cooling effect penetrate in the geothermal field much deeper (110 meters) than the overpressure one (40 meters). After 1 year of continuous injection the fractures located up to a distance of 140 meters from the injection well could be reactivated because of shear failure.

Finally, sensitivity analyses were conducted on the parameters that influence the development of the thermal stresses in a geothermal system: Young's modulus (E), and coefficient of thermal expansion (α). At the range of magnitudes of E typical of Indonesian volcanic subsurface (7-10 GPa), the values of the calculated stress perturbation did not increase enough to change significantly the results. On the other hand, for values of coefficient of thermal expansion that can be found in such geological systems, long thermal tensile fractures can develop around the injection well.

5. CONCLUSIONS

After years of exploiting steam, geothermal wells may need stimulation to remain economically profitable. A forward-looking production strategy necessitate the investigation of stimulation options in case production is diminishing. Hydraulic fracturing can be a suitable technique to improve steam production or to create new geothermal pay zones. The goal is to stimulate the area around the well by connecting pre-existing fractures or by creating new pathways for the steam through the initiation and propagation of new tensile fractures. Performing such a treatment in a geothermal reservoir presents several important challenges. The technical and geological

challenges that might affect the effectiveness and efficiency of the stimulation were investigated. If a hydraulic fracturing treatment is assessed to be technically feasible, it must be carefully tailored to the geothermal field. A close connection between dynamic flow simulators and geomechanical models is essential to numerically simulate the effectiveness of this stimulation technique, a close connection between dynamic flow simulators and geomechanical models is essential. To properly evaluate the stress changes induced by the pressure and temperature gradients in the geothermal field around the injection well, we linked in a 1-way coupled fashion numerical simulators and analytical solutions to connect the evolving fluid pressures and temperature with the changes in the stress field around the well. Hydraulic fracturing will not be the proper stimulation technique when isolation of a short section of the liner is not possible or is too expensive. We have shown that in this case, the stimulation would not be effective because the induced fracture will only propagate on the top part of the perforated liner. If to isolate a shorter perforated interval, in order to target the section of the geothermal that mostly need stimulation, it is possible, then, with a tailored treatment design, it is doable to perform an effective fracturing treatment. Finally, the high injectivity that generates the high fracture leakoff can also be exploited to apply alternative stimulation approaches. The fast penetration of pressure and temperature fronts into the reservoir can make thermal and acid stimulation to be valuable alternatives to hydraulic fracture stimulation.

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