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ABSTRACT

A two-dimensional numerical model is used to study the response of enhanced geothermal reservoirs to stimulation and production. The numerical modeling approach is verified by comparing the model result with analytical solution for the problem of temperature draw-down in the rock due to injection of cold water into a single fracture. Subsequently, we investigated the behavior of geothermal reservoirs as a function of production well position. In the models, the discrete fracture network was explicitly represented. The solution is thermo-hydromechanically coupled. A series of metrics including injectivity, produced water temperature and produced power are evaluated for each case. Comparison of these metrics provides insight into the effect of well positioning (i.e., distance between injection and production wells), and also relative location of the production well with respect to the orientation of dominant fracture sets.

1. Introduction

This study focuses on understanding the response of Enhanced Geothermal Systems (EGS) during both the stimulation and heat production phases. For this purpose, a thermo-hydromechanically coupled numerical-modeling approach has been developed. Details of the developed numerical model are explained in Appendix 1. The approach is first verified by comparing its prediction with analytical solution for the temperature drawdown in the rock mass due to injection of cold water into a single fracture. Subsequently, a case study is presented that evaluates effect of production well positioning on heat production.

The numerical modeling approach is based on the discrete element method, in which the pre-existing discrete fracture network is generated stochastically and explicitly represented. In the adopted technique, the transient response of laminar flow through a pre-existing fracture network is modeled. The advective heat transfer by fluid flow, the convection at the boundary between moving fluid and rock, and the conduction of heat through surrounding rock are taken into account. The mechanical solution is fully coupled with thermal and hydraulic responses.

This study illustrates the role and importance of explicit representation of the pre-existing discrete fracture network in numerical modeling of unconventional resources, such as enhanced geothermal reservoirs. Also, it emphasizes the role that numerical modelling can play in better assessment and engineering of enhanced geothermal systems.

2. Verification of Thermal Response: Cold Water Injection Into a Single Fracture

The thermo-hydro model used in the subsequent analysis is verified first against the analytical solution presented in Gringarten et al. (1975) and Lowell (1976). The model geometry involves a single fracture with a length of 1 km in an infinite domain. The fluid is injected with a rate of $1.45 \times 10^{-4}$ m$^3$/s/m at one end of the fracture and is extracted from the other end. The inlet fluid temperature is 65° C, while the surrounding rock has a temperature of 300° C. For the purpose of this verification example, the hydromechanical and thermo-mechanical couplings are disregarded (i.e., there is no aperture change due to pressurization, and there is no deformation due to changes in temperature).

The solution method involves advective heat flow, convective heat transfer and conductive heat transfer within the surrounding rock (see Appendix 1). Table 1 shows the properties used in this analysis. It is noted that the exact solution assumes the interface of the rock-fluid is in thermal equilibrium with the fluid temperature (i.e., convective heat transfer is instantaneous).

The rock temperature contour after 80 years of production is shown in Figure 1. The produced water temperature is compared against the analytical solution in Figure 2, and indicates that there is a close match between the two solutions.
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3. Numerical Model of Full-Scale Reservoir: Evaluating the Effect of Production Well Positioning

3.1 Model Set-Up

The objective of this study was to evaluate the optimal position of a production well (with respect to the productivity and evolution of temperature of the produced water) given some information about the pre-existing discrete fracture network within a reservoir. A numerical model is used to study the thermo-hydromechanical response of a reservoir to cold fluid injection.

The pre-existing Discrete Fracture Network (DFN) is represented explicitly in this study. Definition, characteristics and the procedure for creation and simplification of DFN are explained in Riahi and Damjanac (2013a and 2013b). It is assumed that the DFN consists of two fracture sets. Both the primary and secondary fracture sets are oriented favorably (at angles of 160° and 45° with respect to the major principal stress) for slip. In other words, the pressure required for shearing on these fractures is below the hydraulic fracturing pressure (i.e., smaller than the minor principal stress). The primary set is defined as the fracture set that requires a lower pressure for slip. Also, it is assumed that the pre-existing fractures are already open and conductive, with the same initial apertures of all fractures within each fracture set. The initial aperture of each fracture set is calculated based on their orientation relative to the in-situ principal stresses. Because of its orientation with respect to principal stresses, fractures of primary set have a higher initial aperture compared to secondary fracture set. The primary and secondary fracture sets are assigned initial apertures of $3 \times 10^{-5}$ m and $1.1 \times 10^{-5}$ m, respectively. The failure criterion of the pre-existing fractures is defined by the Coulomb slip law with zero cohesion, a friction angle of 30° and dilation angle of 7.5°.

The numerical analyses are carried out using a discrete-element modeling approach using numerical code Universal Distinct Element Code UDEC (Itasca, 2011). The rock formation is represented by an assembly of rock blocks separated by a pre-existing fracture network. Fluid flow can occur only within the fractures. The blocks are considered to be impermeable and elastic. The pre-existing fractures are represented explicitly, as discontinuities that 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 model fracture propagation along the predefined planes only; it is noted that in this study, propagation of pre-existing fractures is not considered. In order to model propagation of a hydraulic fracture (HF), the trajectory of the fracture should be defined explicitly in the model before starting the analysis. The HF is assumed to be planar, aligned with the direction of the major principal stress. The two “incipient surfaces” of the HF plane are bonded initially 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 HF propagation as a single planar surface is a simplification. A more detailed description of the model can be found in Renshaw & Pollard (1995), Gu et al. (2011) and Weng et al. (2011).

In each of the cases presented, both the stimulation and production phases are modeled. The purpose of the stimulation phase is to increase permeability of the rock mass by injecting fluid into the reservoir at pressures sufficient to cause dilational slip on joints. The rate used during stimulation in the two-dimensional model (representative of unit thickness of the reservoir) is $2 \times 10^{-4}$ m$^3$/s/m, which is equal to 0.07 m$^3$/s or 70 kg/s for the assumed reservoir thickness of 350 m. Subsequent to the stimulation phase, the pressures are allowed to dissipate to the hydrostatic state before the production phase starts. The injection rate used during production is $1.5 \times 10^{-4}$ m$^3$/s/m. Only coupled hydromechanical processes are simulated during the stimulation phase; thermal effects are not included (i.e., considered not significant for the duration of the stimulation phase). The results of the stimulation phase, after excess pressures are dissipated, are used as initial conditions for the production phase.

### Table 1. Properties used in the Gringarten et al. (1975) solution.

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thermal conductivity (Kr)</td>
<td>6.20E-03 cal/cm</td>
</tr>
<tr>
<td>Rock density (Rr)</td>
<td>2.65 gr/cm$^3$</td>
</tr>
<tr>
<td>Fluid density (Rw)</td>
<td>1 gr/cm$^3$</td>
</tr>
<tr>
<td>Rock Specific heat (Cr)</td>
<td>0.25 Cal/gr.cm</td>
</tr>
<tr>
<td>Fluid Specific heat (Cw)</td>
<td>1 Cal/gr.Cm</td>
</tr>
</tbody>
</table>

The results of the stimulation phase, after excess pressures are dissipated, are used as initial conditions for the production phase.
During the production phase, which is much longer than the stimulation phase, the thermal effects are important and a different solution method is used. A flow model is coupled with models of heat transported by advection and conduction, and the mechanical model of rock deformation. Thermo-hydromechanical interactions are represented because (1) the fluid flow is a strong function of the fracture aperture, (2) the fracture aperture is a function of temperature and mechanical deformation, (3) stresses in rock are influenced by temperature change and (4) changes in fluid flow affect how heat is distributed in the rock.

Figure 3 shows the geometry and set-up of the UDEC model. The model represents a two-dimensional horizontal section through a reservoir with a thickness of 350 m. It is assumed that the injection is through a vertical well that is 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 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.

### 3.2 Well Positioning

During the stimulation phase, water is injected into a single well in the middle of the reservoir for a period of 120 hours. Subsequently, the injection is stopped in order for pressures to return to the hydrostatic pressure condition. For this study, a single production-well configuration is considered. Nine different scenarios for location of the production well are considered. Contours of permanent aperture increase and locations of production wells are shown in Figure 4. The wells are located 250 m, 500 m and 800 m from the injection well. Also, three different cases with respect to the orientation of fractures are considered: (a) Case I: the production well located (relative to the position of the injection well) in the direction of the primary fracture, (b) Case II: the production well located in the direction of the secondary fracture and (c) Case III: the production well located between the two directions.

Considering the change of apertures in the stimulated reservoir, the location of the wells in most cases is chosen such that they are positioned within the stimulated region. It is also studied how production is affected when the production well is located outside of the stimulated rock volume.

### 3.3 Results

For each of the nine cases, the thermo-hydromechanical response during the production phase is simulated. Production indices such as temperature of the produced water, injection pressure, produced power and injectivity (i.e., injection rate divided by the pressure) are assessed.

Out of the nine considered scenarios, Cases I and II for 800-m well spacing did not result in a substantial recovery of injected fluid. In Case I, the production well is located outside the stimulated region. In Case II, the well is located within the stimulated region; however, the flow takes a different, least resistant path as shown in Figure 5.

Figure 6 shows production indices for this study. Figure 6 (a) and (b) show that for all well distances considered, the produced water temperature in Case I has the quickest draw-down, while the injection pressure is the lowest. However, again considering
all well distances, it seems that Case II has resulted in the greatest produced energy. Figure 7 shows the rock temperature contours. From this figure, it can be interpreted that for well distances of 250 m and 500 m, Case I has resulted in the shortest flow path, which is the reason for lower required injection pressure. At the same time, the short flow path also has led to quickest temperature drawdown. From this figure, it also seems that Case II exhibits a more tortuous and longer flow path, which provides a greater heat exchange surface, and thus, results in slower temperature decay. However, this is achieved at a cost of higher pressure and lower injectivity.

Overall, Case III with a well spacing of 800 m shows the highest produced power, which is the direct result of the longest flow path. However, the trade-off in this case is greater uncertainty of recovery of the injected fluid, as for Cases I and II with a well spacing of 800 m.

4. Conclusions

This paper presents some initial results of a study on thermo-hydromechanical response of EGS reservoir with respect to different positions of the production well relative to the injection well. Three different distances between the production and the injection wells were considered, and for each of these distances three different relative orientations of the wells with respect to the orientation of in-situ fractures were considered. A series of quantitative metrics, such as injectivity, generated thermal power and produced temperature were evaluated and compared.

The following is a summary of the findings of this study.

1. Recovery of the injected fluid is controlled mainly by the location of the production well within and relative to the stimulated area, and permeability around the well region. Overall, flow takes the path of least resistance, which may not be connecting the injection and production wells, and in many cases, substantial fraction of the injected fluid cannot be recovered.

2. Temperature draw down is mainly controlled by the length of flow path. Longer path results in slower temperature decay.

3. For cases studied here, recovery was similar and power was controlled greatly by the distance that the fluid takes between injection and production well. Longer overall distance and more tortuous path (wells located off the primary fracture direction) are beneficial.

4. Injectivity changes significantly based on distance and well location. Longer distances and more tortuous paths can change injectivity by orders of magnitude.

5. Finally, it seems locating the production well directly along the primary fracture set relative to the injection well, results in the least favourable condition for power generation.

Overall, these numerical studies show the complex responses of reservoirs to stimulation and production, and illustrates a value of numerical modeling as a tool to better assess and engineer deep geothermal reservoirs.

Acknowledgments

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Appendix I: Production Phase Model

A new code has been developed by Itasca to model the fluid flow and heat transfer occurring during enhanced geothermal reservoir production. Flow in the fracture network resulting from injecting and producing water is modeled along with the transport of heat by this flow. The fluid temperature is coupled (via a convective heat transfer term) to a model of the rock temperature. Matrix flow is not represented.

To achieve thermo-hydromechanical coupling, the rock temperature predicted with this model is communicated back to UDEC at regular intervals. The UDEC model finds new fracture apertures using a meshing method and coupled solving continues. Typical models are run for 60 to 120 years with a one-month hydromechanical coupling interval.

The processes involved in production from enhanced geothermal reservoirs span several orders of magnitude in time-scale and length-scale. The fracture apertures are on the order of 0.1 mm to 1 mm, the size of fracture isolated blocks is on the order of 10 m and the size of the geothermal field may be on the order of 1 km to 10 km. The time-scale for thermal advection and convective heat transfer to the rock may be as small as 10 seconds, and the time-scale for heat conduction across a fracture delimited block is on the order of 100 years. This disparity in time-scale and length-scale presents practical difficulties to the modeler in terms of calculation time and spatial resolution. To get an accurate solution in a reasonable amount of time, a multi-stepping approach has been adopted where the thermal advection and convective heat transfer are solved on a shorter interval (approximately 10 s), and are coupled with the rock temperature over a longer interval (approximately one hour). To accomplish this, a meshing method and convective heat transfer coupling term have been developed. The fluid flow model is described first followed by a description of the rock temperature model and the convective heat transfer term. This section concludes with a comparison of our numerical results with an exact solution for a single fracture.

Steady-State Joint Flow

The coupling interval between hydromechanical updates is on the order of one month. During these intervals, the fracture apertures are assumed to be constant and the fluid flow is assumed to be steady state. At each hydromechanical update interval, new fracture apertures are found and a new steady-state flow rate is determined. The law governing the flow in fractures is the same as that used in UDEC: the flow rate, \( q \), in a given joint is

\[
q = -\frac{a^3}{12 \mu} \nabla P
\]

(1)

where \( a \) is the fracture aperture (contact aperture from UDEC), \( \mu \) is the dynamic viscosity of the fluid and \( P \) is the fluid pressure. As this is a two-dimensional model, \( q \) has units \( m^3/(sm) \). The incompressibility condition can be written as \( \sum q_i = 0 \). Where the summation is over the contacts of a fracture. The UDEC domains are used as the control volumes and the contact lengths and apertures are taken directly from the UDEC model. In other words, the flow into and out of each fracture must sum to zero. This is the discrete analog to the divergence of a velocity field being equal to zero. Summing over the contacts of each fracture on both sides of the first equation yields a single equation for pressure.

\[
\sum_i \frac{a_i^3}{12 \mu} \nabla P = 0
\]

(2)

This equation is a discrete analog to the Laplace equation. \( q \) is fixed at inflow wells according to the prescribed pumping rates. \( p \) is fixed to a reference pressure (taken as zero) at the extraction wells. \( p \) is also fixed to the reference pressure on the outer domain boundary to account for the continuous nature of the fracture network.

Solution Method

The UDEC model geometry is used to build a graph that describes the fracture connectivity. UDEC domains are the nodes of the graph and the UDEC contacts are the graph edges. Following the UDEC convention, the contacts are assigned a length and an aperture. From a fluid-flow perspective, this graph represents a series of connected fractures.

A weighted Laplacian matrix of the graph is defined as,

\[
A_{i,j} = \begin{cases} 
\sum_i \frac{a_i}{12 \mu l_i} & \text{if } i = j \\
\frac{-a_i}{12 \mu l_i} & \text{if } i \neq j \text{ and fractures } i \text{ and } j \text{ are connected} \\
0 & \text{otherwise} 
\end{cases}
\]

(3)

where \( a_i \) and \( l_i \) are the aperture and length of the contact connecting fractures \( i \) and \( j \). The summation in the diagonal term is over the contacts connected to fracture \( i \). This is an \( n \)-by-\( n \) sparse matrix where \( n \) is the number of fractures.

A length \( n \) forcing vector, \( b \), is defined. The elements of \( b \) are (i) zero for interior fractures, (ii) equal to the inflow pumping rate for fractures containing an injection well (Neumann boundary conditions) and (iii) equal to the reference pressure for fractures where the pressure is fixed (Dirichlet boundary conditions). To apply the constant pressure boundary conditions, the matrix \( A \) is altered. To fix the pressure of fracture \( i \), the off diagonal values of the \( i \)-th row of \( A \) are set to zero and \( A_{i,i} \) is set to 1. This results in a linear system of the form \( Ax = b \) where the vector \( x \) is the fracture pressure, which satisfies the original equations and boundary conditions. The contact flow rates \( q_i \) can be calculated from Eq. 1 with the pressures calculated from solving the matrix equation.

Transport Model

The next step is to solve the advection of fluid temperature along the fracture network. In UDEC terminology, the contact flow rates are defined and we need to solve for domain fluid temperature as a function of time. An explicit first-order upwind finite-volume method is used. The fracture temperature is updated as

\[
\frac{\Delta T_{f}^d}{\Delta t} = \frac{1}{V_i} \left( \sum_{\text{neighboring}} q_i T_d^d - \sum_{\text{neighboring}} q_i T_d^d \right)
\]

(4)

where \( T_d^d \) is the fracture fluid temperature and \( V_i \) is the fracture volume. The summation on the left-hand side is over the contacts in the upwind direction and the summation on the right side is
over the downwind contacts. $\Delta t$ is the integration time-step.

The maximum stable time-step is given by the CFL condition

$$\Delta t = \min \left\{ \frac{V_i}{2 \sum q_i} \right\}.$$  

The fracture with the smallest volume divided by total fracture flow rate controls the maximum stable time-step. The total fracture flow rate is the sum of the absolute values of the flow into and out of the fracture. A typical time-step for these calculations is 10 seconds.

**Rock Temperature Model**

The UDEC model geometry is used to create a computational mesh for solving the heat equation for block temperature. Heat transfer into the fracture delimited blocks has a large Biot number; this indicates the conduction into the block controls the time evolution of block temperature. As a result, it is important to represent the thermal boundary layer of each block. To get an accurate transient response, block elements that are thin in the directions perpendicular to the fractures are required. The thickness of these elements informs the time required between updates of the rock temperature model. Heat conducts a length $\sqrt{\alpha t}$ in time where $\alpha$ is the rock thermal diffusivity, a typical value for rock is $\alpha = 1 \times 10^{-6}$. For example, if the element length is 10 cm, the block temperature solution only needs to be updated approximately every hour.

The entire UDEC model is meshed as a contiguous group of elements; in other words joints do not have any effect on heat conduction within the rock. Each UDEC block is meshed with thin high aspect-ratio quadrilateral elements around the boundary, the element size increases towards the block center where a coarse triangular mesh is used. A standard cell-centered finite-volume method is used to solve the heat equation describing rock temperature.

**Convective Heat Transfer**

The convective heat transfer into the fracture fluid is used as a volumetric heat sink in the block elements adjacent to the fractures. The convective heat transfer coefficient, $h$, for fully developed laminar flow between infinite parallel plates is, $h = \frac{7.54 k}{2a}$ where $k$ is the thermal conductivity of water (taken as 0.6) and $a$ is the fracture aperture (Incropera et al., 2006). A typical value for $h$ in this system is 1,000 $W/(m^2\,^\circ C)$. Simply removing heat from the fluid according to the convective heat transfer and adding it to the appropriate thermal mesh element during each 10-second advection time-step leads to a numerical instability analogous to that observed in Euler integration. This instability can be overcome by considering that the thermal energy in the fracture fluid is several orders of magnitude smaller than the thermal energy in the thin thermal mesh elements adjacent to the fractures. The temperature evolution of the fracture-fluid temperature can be written as,

$$\frac{dT_f}{dt} = -\frac{h(T_f - T_b)}{\rho_f c_p V}$$  

where $T_f$ is fracture fluid temperature, $t$ is time, $h$ is the convective heat transfer coefficient, $T_b$ is temperature on the block boundary, $A$ is the area (fracture length), and $V$ is the fracture volume. Because of the length scale disparity (1-mm fracture vs. a 10-cm element length), it is safe to assume the rock temperature is nearly constant over a 10-second advection time-step. When the block temperature, $T_b$, is constant Eq. 2 has the solution,

$$T_f(t) = \left[1 - \exp\left(-\frac{hAt}{V\rho_f c_p}\right)\right](T_{f0} - T_{f0}) + T_{f0}$$  

where $T_{f0}$ and $T_{f0}$ are the fluid and block temperatures at the beginning of the advection step. For any time, $t$, this solution goes asymptotically to the block temperature. A thermal energy quantity equal to the increase in fracture fluid temperature is calculated and removed from the appropriate thermal mesh element.

**References**


