Modeling of Heat Extraction from Variably Fractured Porous Media in Enhanced Geothermal Systems

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Abstract

Modeling of heat extraction in Enhanced Geothermal Systems is presented. The study builds on recent studies on the use of directional wells to improve heat transfer between doublet injection and production wells. The current study focuses on the influence of fracture orientation on production temperature in deep low permeability geothermal systems, and the effects of directional drilling and separation distance between boreholes on heat extraction. The modeling results indicate that fracture orientation with respect to the well-pair plane has significant influence on reservoir thermal drawdown. The vertical well doublet is impacted significantly more than the horizontal well doublet.

Keywords: reservoir modeling, enhanced geothermal systems, heat extraction, fractured orientation, well orientation, stochastic methods

1. Introduction

Enhanced Geothermal Systems (EGS) have the potential to extract heat in low permeability fractured rock in locations largely unsuitable for conventional hydrothermal systems. EGS allows extraction of heat through natural reservoirs with suitable permeability or stimulated reservoirs where permeability and heat transfer area are mechanically or chemically enhanced. The economic viability of EGS is dependent on variables such as drilling costs, initial reservoir temperature, decrease in temperature during the operational time (thermal drawdown), and fracture permeability. Understanding the relationships and dependencies between these variables will enable developers to optimize system design to increase viability and reduce economic risk.

Estimation of extraction of heat from fractured geothermal reservoirs has been a subject of study for decades. Gringarten et al. (1975) used mathematical models to produce analytical solutions to predict heat extraction from fractures in hot dry rock using injection and withdrawal wells. The authors investigated the use of directional drilling to optimize heat extraction based on orientation of fractures. Similar studies using the analytical method were conducted by other researchers (Gringarten and Sauty, 1975; Cheng et al., 2001; Ghassemi et al. 2003; Yang and Yeh, 2009). To overcome the limitations of the analytical solutions (dimensionality and constant parameter values) various numerical models have been developed to study the effect of fracture characteristics on reservoir behavior (Juliussen and Horne, 2010; Hao et al., 2013; Doe et al., 2014). The various numerical models use different mathematical models designed for specific applications. The majority of the EGS studies consider the vertical wells. Only a few studies evaluated horizontal wells (Shiozawa and McClure, 2014). Our study provides in depth analysis of both, vertical and horizontal wells.

45 Previous studies have looked at thermal performance and economic evaluation of the use of
46 directional wells for EGS (Lowry et al., 2014, Kalinina et al., 2014a and 2014b) and showed that
47 well orientation played an important role in thermal drawdown with the most advantageous
48 configuration consisting of a horizontal well-pair with the injection well below the production
49 well. The economic viability was highly influenced by the drilling and pumping costs, the latter
50 being a function of the effective permeability between the wells.

51 For this study the Fracture Continuum Method (FCM) was used to develop stochastic
52 representations of reservoir permeability. The FCM was developed by McKenna and Reeves
53 (2006) to generate multiple permeability fields using field observations of fracture set data. The
54 method was later enhanced by adding anisotropy using the approach of Chen et al. (1999).
55 Applications of the FCM method to modeling EGS are reported in recent publications (Kalinina
56 et al. 2012a, 2012b, 2014a, 2014b). The FCM does not need upscaling because the REV-size
57 grid blocks used are sufficiently small. McKenna and Reeves (2005) recommended that the size
58 of the numerical model grid blocks to be kept small enough that fracture properties can be
59 assumed constant over the size of the grid block. The constant grid block size and the fracture
60 properties used in this study are in line with the recommendation of McKenna and Reeves
61 (2006). Hao et al. (2013) showed that the output of a continuum model is comparable to that
62 from a discrete fracture model.

63 The method of Chen et al. (1999) allows representation of multiple fracture sets for different
64 fracture orientations. FCM maps the permeability of discrete fractures onto a regular grid using a
65 continuum approach. This approach defines fracture sets using distributions of strike, dip,

aperture, and spacing of parallel fractures in the system. The permeability tensor of Chen et al. (1999) defines permeability for each grid cell in the model domain. For one fracture set, the permeability tensor is given as:

$$k_{ij} = \frac{b^3}{12d} \begin{bmatrix} (n_2)^2 + (n_3)^2 & -n_1n_2 & -n_3n_1 \\ -n_1n_2 & (n_3)^2 + (n_1)^2 & -n_2n_3 \\ -n_3n_1 & -n_2n_3 & (n_1)^2 + (n_2)^2 \end{bmatrix}, \quad (1)$$

where k_{ij} is the permeability tensor in the $i = x, y, z$ and $j = x, y, z$ directions, b is fracture aperture, d is fracture spacing, and $n_{1,2,3}$ is the unit normal to the fracture plane in the x , y , and z direction, respectively.

The unit normal components to the fracture plane are defined as:

$$n_1 = \cos\left(\alpha \frac{\pi}{180}\right) \sin\left(\omega \frac{\pi}{180}\right) \quad (2a)$$

$$n_2 = \cos\left(\alpha \frac{\pi}{180}\right) \cos\left(\omega \frac{\pi}{180}\right) \quad (2b)$$

$$n_3 = -\sin\left(\alpha \frac{\pi}{180}\right) \quad (2c)$$

where $\alpha = 90^\circ$ - dip and $\omega = \text{strike} - 90^\circ$. The permeability tensor represents permeability anisotropy. Note that only the principal components (k_{xx} , k_{yy} , and k_{zz}) of the permeability tensor are used in the heat transport model. This assumes that the x , y , and z coordinate directions coincide with the principal directions of anisotropy, as used in anisotropic groundwater flow models (Bear, 1972; Freeze and Cherry, 1979).

In the case of multiple fracture sets, the permeability tensor can be computed by adding the permeability tensors for individual fracture sets as follows.

$$k_{ij} = \sum_{m=1}^N k_{ij}^m \quad (3)$$

where N is the number of fracture sets and k_{ij}^m is defined by Eq. (1). The summation assumes that the total porosity within a grid-cell changes very little, which is valid for most EGS conditions.

The k_{xx}^m , k_{yy}^m and k_{zz}^m values are calculated for each grid block based on the parameters of fracture aperture, spacing, strike, and dip probability distributions that are defined for each fracture set m .

The FCM is also applicable to cases where fracturing varies with depth. For such cases the FCM is applied to separate zones at different depths.

2. Method

Thermal-hydrologic simulations were carried out to study the effect of fracture parameters, well orientation, and well separation distance on heat extraction in an EGS system. The focus is on understanding the effect of fracture orientation (i.e. strike and dip), well separation distance and well orientation on EGS heat extraction to support decision making on drilling and fracture enhancement methods. Note that geomechanical effects were assumed to be negligible during the injection/production phase of an EGS that is either naturally fractured or stimulation has been completed. For a large reservoir and injection/production period of decades, such as used in this study, geomechanical effects were assumed to be minimal thus were not included (see also Bachler and Kohl, 2005).

For the analysis a representative EGS system was developed to simulate thermal conditions in a geothermal system. The numerical simulator FEHM was used for thermal-hydrologic

simulations (Zyvoloski et al. 1997). FEHM is a control volume finite element code for simulating subsurface non-isothermal multi-phase, multi-fluid heat and mass transfer. The numerical code has been extensively used for modeling geothermal systems, groundwater flow, and flow and transport for nuclear waste disposal applications. FEHM assumes Darcy's law is applicable for fluid flow, and that thermal equilibrium exists between fluid and rock (locally). Other assumptions include an immovable rock phase and negligible viscous heating. Below is a description of the mass and energy balance equations used by FEHM.

Conservation of mass for water is described as:

$$\frac{\partial A_m}{\partial t} + \bar{\nabla} \cdot \bar{f}_m + q_m = 0 \quad (4)$$

where the mass per unit volume, A_m , is given by:

$$A_m = \phi(S_v \rho_v(1 - \eta_v) + S_l \rho_l(1 - \eta_l)) \quad (5)$$

and the mass flux, $\bar{f}_m$ is given by:

$$\bar{f}_m = (1 - \eta_v) \rho_v \bar{V}_v + (1 - \eta_l) \bar{v}_l \rho_l$$

where, ϕ is the porosity of the matrix, S is saturation, ρ is density, η is the concentration of the noncondensable gas and is expressed as a fraction of the total mass, $\bar{v}$ is velocity, and the subscripts v and l indicate quantities for the vapor phase and the liquid phase, respectively. Source and sink terms are represented by the term q_m .

Conservation of fluid-rock energy is described as:

$$\frac{\partial A_e}{\partial t} + \bar{\nabla} \cdot \bar{f}_e + q_e = 0 \quad (6)$$

where the energy per unit volume, A_e , is given by:

$$A_e = (1 - \varphi)\rho_r u_r + \varphi (S_{v\rho} \rho_v u_v + S_{l\rho} \rho_l u_l), u_r = c_{pr} T \quad (7)$$

and the energy flux, $\bar{f}_e$ is given by:

$$\bar{f}_e = \rho_v h_v \bar{V}_v + \bar{v}_l \rho_l h_l - K \bar{\nabla} T \quad (8)$$

The subscript r refers to the rock matrix, u_r , u_v , and u_l are specific internal energies, c_{pr} is the specific heat, h_v , and h_l are specific enthalpies, K is an effective thermal conductivity, T is the temperature, and q_e is the energy contributed from sources and sinks.

It is assumed that Darcy's Law applies to the movement of each phase and the velocity can be expressed as:

$$\bar{v}_v = \frac{k R_v}{\mu_v} (\bar{\nabla} P_v - \rho_v \bar{g}) \quad (9a)$$

$$\bar{v}_l = \frac{k R_l}{\mu_l} (\bar{\nabla} P_l - \rho_l \bar{g}) \quad (9b)$$

$$P_v = P_l + P_{cap} \quad (9c)$$

where k is the permeability, R_v , and R_l , are the relative permeabilities, p_v and p_l are viscosities, P_v and P_l are the phase pressures, P_{cap} is the capillary pressure and $\bar{g}$ represents the acceleration due to gravity.

Geometry:

144 For the study the reservoir is assumed to be at a depth of 4 km. The model geometry is 1605 m x
145 435 m in the horizontal direction and 1605 m in the vertical direction. The three-dimensional
146 mesh consists of a structured grid with 332,021 elements (349,920 nodes) and a constant grid
147 block size of 15 m x 15 m x 15 m (Figure 1).

148
149 Figure 1: Geometry and meshing of the model domain
150

The geothermal system is assumed to be at an initial condition of hydrostatic pressure at the corresponding depth and a constant temperature of 200 °C. The boundary conditions use constant temperature (200 °C) and pressure (hydrostatic) on all sides except the bottom, which assumes zero flux for both mass and heat. Water injection is implemented using a fixed injection mass-flow rate of 50 kg/s and injection temperature of 80 °C. Production is from a production well that uses a fixed bottom-hole pressure that maintains the 50 kg/s mass-flow rate and provides a production draw-down pressure. The injection/production well-pair were modeled in both vertical and horizontal configurations with identical screened intervals. Rock properties include rock grain density of 2850 kg/m³, porosity of 0.01, thermal conductivity of 3 W/m K, and specific heat of 950 J/kg K.

Fracture properties are statistically represented in the FCM using distributions of parameters. The probability distributions for the fracture parameters were developed based on the fracture properties common for granitic rocks, which have been studied worldwide for many different applications. The different applications include mining (quarry development), contaminant transport, oil and gas exploration and geologic disposal of radioactive waste. A literature review was conducted to compile the fracture data from these various studies. When possible, information on fracture orientation, dip, spacing, aperture and length was collected. The results of this review are documented in Kalinina et al. (2012a).

For this study fracture spacing was represented using an exponential probability distribution with a rate parameter (λ) value of 1, and the distribution was taken over the span of 0.1 m and 15 m. Fracture aperture is modeled using a normal probability distribution with mean of 0.1 mm and a standard deviation of 0.01 mm. In the study the mean values of fracture spacing and aperture

were kept constant. But the mean values of fracture strike and dip were varied. The strike and dip angles of the mean fracture planes were varied using a normal distribution and means of 5, 33, 61, 89, 117, 145, and 173 degrees for the strike and 5, 18, 31, 44, 57, 70, and 83 for the dip. The standard deviation was set at 3 degrees across all angles of strike and dip. It should be noted that a dip of zero degrees corresponds to a horizontal fracture plane and a strike of zero degrees means the fracture plane is parallel to the plane of the well-pair. A graphical representation of parameter distributions are given in Figure 2. Well separation distances of 495 and 600 m were used for both the horizontal and vertical well configurations. The ‘base case’ assumes a separation distance of 495 m. A production/injection interval of 250 m was used. For the horizontal well configuration, the production well is above the injection well. The thermal and hydrologic conditions are simulated over a 30 year time-span to correspond with the typical lifetime of a geothermal power plant. Table 1 is a list of inputs that were varied, the statistical model used to represent them (if applicable), and the parameter and/or input values. Figure 3 is a representative three-dimensional plot of a permeability calculated with the FCM approach using a mean strike and dip of 5 and 44 degrees, respectively.

Table1: Parameter models and variations used in the FEHM simulations.

Variable	Distribution	Parameters	Units	Comments
Fracture Spacing	Exponential	$\lambda = 1$	m	Truncated to a minimum of 0.1 m and a maximum of 15 m.
Fracture Aperture	Normal	$\mu = 0.1$ $\sigma = 0.01$	mm	
Strike	Normal	$\mu = 5, 33, 61, 89, 117, 145, 173$ $\sigma = 3$	Degrees	$0^\circ = \text{horizontal}$

Dip	Normal	$\mu = 5, 18, 31, 44, 57, 70, 83$ $\sigma = 3$	Degrees	$0^\circ =$ perpendicular to the well-pair plane.
Well Spacing	NA	495, 600	m	
Production/Injection Interval	NA	250	m	Production and injection use same interval
Mass Flow Rate	NA	50	kg/s

NOTE: The fracture spacing and aperture probability distributions are the same for all the cases while fracture strike and dip probability distributions are case dependent.

Figure 2. Simulated Values of Fracture Strike, Dip, Spacing, and Aperture for the 5° Strike and 44° Dip Case.

Figure 3: FCM generated permeability field with the following fracture properties. Strike: normal distribution with mean 5° , and Dip: normal distribution with mean 44° .

3. Results and Discussion

Figure 4 shows the effective permeability in the x-direction (i.e., along the well-pair plane) as a function of the strike and dip for the base case (Equations 2a, b). At low dip angles, the permeability values are insensitive to the strike angle. However, as the dip angle increases the permeability decreases as the strike angle nears $0 / 180$ degrees. Figure 5 shows the effective

206 permeability in the z-direction (i.e., vertical) as a function of the strike and dip for the base case
 207 (Equation 2c). Not surprisingly, the vertical permeability is insensitive to the strike angle and
 208 increases as the dip angle decreases.

209

210 Figure 4: Horizontal permeability as a function of strike and dip.

211

Figure 5: Vertical permeability as a function of strike and dip.

Figure 6 shows the time varying production temperature for the horizontal well configuration across all combinations of strike and dip, and show that production temperature is mostly insensitive for most strike and dip combinations with the exception of the cases where the dip is high and the strike is closely aligned with or perpendicular to the well-pair plane. These scenarios create preferential pathways that effectively reduce the volume from which heat is able to be extracted, creating quicker thermal break through and drawdown. Figures 7 and 8 compare the final (total time) temperature distribution of one of the best (strike = 5° , dip = 18°) and one of the worst (strike = 89° , dip = 83°) performing scenarios with respect to the thermal drawdown. The earlier thermal breakthrough is clearly illustrated for the worst case scenario.

224

225 Figure 6: Average production temperature as a function of time for various fracture mean strike
 226 and dip values. Horizontal wells with injection interval of 250 m, well separation distance of 495
 227 m, and injection rate of 50 kg/s. Worst performers indicated.

Figure 7: Temperature distribution at 30 years simulation time, for strike: normal distribution with mean 5° , and dip: normal distribution with mean 18° . Horizontal wells with injection interval of 250 m, well separation distance of 495 m, and injection rate of 50 kg/s. The lines represent injection well (bottom) and production well (top)

Figure 8: Temperature distribution at 30 years simulation time, for strike: normal distribution with mean 89° , and dip: normal distribution with mean 83° . Horizontal wells with injection interval of 250 m, well separation distance of 495 m, and injection rate of 50 kg/s. The lines represent injection well (bottom) and production well (top).

Figures 9 to 11 show the same information as Figures 6 to 8 but for the vertical well configuration. The variability in performance is much higher than for the horizontal cases with, the worst performers associated with shallow dips. Figures 10 and 11 compare one of the best and worst case scenarios with respect to thermal drawdown. Like the horizontal case, the earlier

244 thermal breakthrough for the worst case is easy to see. The impact of density driven flows are
245 also evident in these figures.

246
247 Figure 9: Average production temperature as a function of time for various fracture mean strike
248 and dip values. Vertical wells with injection interval of 250 m, well separation distance of 495
249 m, and injection rate of 50 kg/s. Worst performers indicated.

250

251 Figure 10: Temperature distribution at 30 years simulation time, for strike: normal distribution
 252 with mean 5° , and dip: normal distribution with mean 18° . Vertical wells with injection interval
 253 of 250 m, well separation distance of 495 m, and injection rate of 50 kg/s. The lines represent
 254 injection well (right) and production well (left).

255

Figure 11: Temperature distribution at 30 years simulation time, for strike: normal distribution with mean 89° , and dip: normal distribution with mean 83° . Vertical wells with injection interval of 250 m, well separation distance of 495 m, and injection rate of 50 kg/s. The lines represent injection well (right) and production well (left).

Figure 12 shows a three-dimensional plot of the final production temperatures as a function of strike and dip for the horizontal well configuration. The drop in thermal performance at strike angles that are multiples of 90° , and then only at high dip angles is clearly evident. Outside of these strike and dip angles, the horizontal wells show little thermal drawdown over time. Figure

13 shows a three-dimensional plot of the pressure difference between the injection and production wells at 30 years as a function of strike and dip. Note that the difference in pressure develops during the first year of injection and remains relatively constant during the flowing period of time. The figure shows a strong correlation between pressure difference and dip (i.e. vertical permeability) with an exponential-like increase at low dip (low vertical permeability) values. Very little correlation is indicated between pressure difference and fracture strike. High pressure differences can influence the pumping requirements for the system, which in turn increases operating costs, energy requirements, and the LCOE.

Figure 12: Production Temperature as a function of fracture mean dip and strike, at total simulation time of 30 years. Horizontal wells with injection interval of 250 m, well separation distance of 495 m, and injection rate of 50 kg/s.

279

280 Figure 13: Pressure difference between injection and production wells as a function of fracture
 281 mean dip and strike, at total simulation time of 30 years. Horizontal wells with injection interval
 282 of 250 m, well separation distance of 495 m, and injection rate of 50 kg/s.

283

284 Figure 14 shows a three-dimensional plot of the final production temperature as a function of
 285 strike and dip for the vertical well configuration. The figure shows a strong correlation at lower
 286 dip angles for all strike values, and for all dip angles when the strike is close to 90°. Figure 15
 287 shows a three-dimensional plot of the pressure difference between the injection and production
 288 wells at 30 years as a function of strike and dip. The figure shows a strong correlation between
 289 pressure difference and dip at high dip values for strike values of 5°, 89° and 173° but is
 290 otherwise mostly insensitive to the fracture orientation. Note that for the vertical well
 291 configuration, the highest pressure differences are still less than the lowest pressure differences
 292 associated with the horizontal well configuration.

293

294 Fig 14. Production Temperature as a function of mean dip and strike, at total simulation time of
 295 30 years. Vertical wells with injection interval of 250 m, well separation distance of 495 m, and
 296 injection rate of 50 kg/s.

297

298

299 Fig 15. Pressure difference between injection and production wells as a function of fracture mean
 300 dip and strike, at total simulation time of 30 years. Vertical wells with injection interval of 250
 301 m, well separation distance of 495 m, and injection rate of 50 kg/s.

302

303 To examine the effect of well separation distance, the worst performing scenarios for each of the
 304 well configurations were simulated using a separation of 600 m, versus the 495 m for the base
 305 case. The rest of the input data are the same as above. Simulation results are shown in Figures 16
 306 and 17. In both cases, increasing the separation distance improved the thermal performance over
 307 time. More improvement was observed for the vertical wells case.

308

309 Figure 16: Average production temperature as a function of time for fracture mean strike of 5°
310 and dip of 83° . Horizontal wells with injection interval of 250 m, and injection rate of 50 kg/s.
311 Effect of well separation distance.

k 17: Average production temperature as a function of time for fracture mean strike of 89° and dip of 5° . Vertical wells with injection interval of 250 m, and injection rate of 50 kg/s. Effect of well separation distance.

4. Conclusions

The modeling study presented in this article uses the FCM approach of fracture representation to identify parameters of importance to heat extraction in EGS applications. The simulation uses doublet horizontal and vertical wells with selected injection interval, well separation distance and injection rate values. The central part of the current study examines the influence of fracture orientation on production temperature of EGS wells.

The results show that there is a larger set of fracture orientations that negatively impact thermal drawdown for the vertical well configuration than for the horizontal configuration. With regards to thermal performance, the horizontal well configurations were nearly insensitive to strike or dip with the exception of cases with high dip angles. For the vertical well configuration, the best performing fracture orientations are limited to high dip angles in combination with low and high strike angles. With regards to the pressure difference between the injection and production wells, which in this case is used as an indicator of the pumping requirements, the vertical well configuration performed best, with the highest pressure difference being lower than the lowest pressure difference for the horizontal configuration.

From a risk perspective, the implications of these results are significant. Since risk is also a function of uncertainty (Lowry et al., 2014), reducing the uncertainty with regards to thermal and economic performance of an EGS site is paramount if investments are to be made in this promising technology. These results show that the horizontal well configuration is the most consistent performer for both thermal drawdown and pumping requirements when the dip angle is bounded between 30 and 70 degrees. The fact the horizontal configuration is insensitive to the strike angle reduces the need to characterize that parameter in the field and provides greater flexibility for well placement and other surface facilities.

Glossary

EGS Enhanced Geothermal Systems
FCM Fracture Continuum Method

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