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Impact of Coupled Behavior of Natural Fractures on Geothermal Systems

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ABSTRACT

ParaGeo is a finite-element software specifically designed for solving coupled thermo-hydro-mechanical (THM) problems in the subsurface (Three Cliffs Geomechanical Analysis Ltd., 2023). ParaGeo is the result of almost ten years of collaboration and co-development by Chevron and Three Cliffs Geomechanical Analysis Ltd (TCGA, Swansea UK), and is currently being used for a wide-range of geomechanical applications within Chevron, like mechanical earth models (MEMs), basin-scale geological restoration and forward modeling, fault stability analyses, water, or CO_2 injection, etc. Given the increasing interest of Chevron in geothermal opportunities around the world, a development effort is currently underway to make ParaGeo suitable for modeling problems such as enhanced geothermal systems (EGS) or advanced closed-loop systems. With relatively minor developments, ParaGeo is now able to make predictions of temperature distributions, stress and pore pressure changes, temperature breakthrough, ground deformation, fault movement and re-opening of natural fractures due to changes of temperature and effective stress in the subsurface. ParaGeo is able to model fractures as discrete contacts and/or with an effective medium approach. Discrete contacts can be used for modeling large geological faults or man-made hydraulic fractures, whereas effective media can be used to model natural fractures with relatively small spacing. In either case, ParaGeo can resolve the fracture aperture and hydraulic conductivity as non-linear functions of stress, fluid pressure and/or temperature, using either predefined functions (such as the Barton-Bandis model) or user-defined functions, which gives great flexibility to the model. Modeling results demonstrate the importance of leveraging fully-coupled THM tools such as ParaGeo to more accurately inform geothermal business decisions. Specifically, we show that for fully-coupled cases in which the fracture aperture is allowed to change with stress and temperature, parameters like the initial fracture aperture and stiffness have a significant effect on the model outputs including the predicted energy output, thermal breakthrough time and expected project lifetime. This brings to the forefront the need for proper characterization of the natural fractures, as well as constitutive models to describe fracture behavior that are calibrated with lab measurements.

1. INTRODUCTION

Heat extraction from geothermal resources involves coupled thermal, hydraulic, and mechanical processes (Evans et al., 1999; Kohl et al., 1995). In convection dominated geothermal reservoirs (EGS), a uniform distribution of the injection fluid over a large reservoir volume is required to prevent early thermal breakthrough and achieve a high thermal recovery factor (Armstead & Tester, 1986; MIT, 2006). Yet, injection of a cool working fluid changes the subsurface temperature, pore pressure, and stresses (Segall, 1989; Segall & Fitzgerald, 1998). The local stress changes may preferentially increase fracture permeability along dominant fluid flow paths and accelerate thermal breakthrough if the natural/hydraulic fracture aperture is sensitive to stress changes, e.g., compressible fractures near low normal effective stresses (Gee et al., 2021; McLean & Espinoza, 2023). Initially closed fractures under compressive in-situ stress can re-open during operation if fracture pressure exceeds total normal stress (likely to occur for large injection rates and small initial fracture aperture) or thermally induced reservoir contraction holds fractures open, but may require several years to do so. Hence, the distribution of injection fluid within the geothermal reservoir is a coupled THM problem and impacts the long-term thermal performance.

Numerical modeling of coupled THM problems is useful in guiding geothermal reservoir development and management (Ghassemi, 2012). However, coupled modeling is a non-trivial task because multiple processes may operate simultaneously and progress another process, e.g., thermo-poroelastic coupled feedback between stress and permeability changes. Presence of natural and hydraulic fractures further increases modeling complexity as each THM process is sensitive to reservoir discontinuities. Moreover, a high degree of coupling may arise during simulation of a geothermal reservoir including undrained response, natural fracture shear reactivation, stress dependent elastic moduli and fracture permeability, among others. Yet, accurate numerical solutions require capturing complex THM phenomena.

ParaGeo is a geomechanical finite-element software designed for solving coupled THM problems in complex geological settings. The software has been extensively used to predict the state of stress in the subsurface with mechanical earth models and geological restorations. Recent developments have made ParaGeo suitable for modeling geothermal systems including EGS and deep closed-loop systems. In particular, faults and fractures can be modeled with advanced constitutive behavior (either discretely with contact mechanics or implicitly with effective medium theory) including effective stress-dependent aperture and compressibility as well as elastoplastic models.

The objectives of this work are to (1) demonstrate the numerical modeling capabilities of ParaGeo for geothermal systems and (2) explore the role of natural fracture compressibility on the long-term thermal performance of naturally fractured geothermal systems. The numerical model adopted in this work is based on the FORGE site and utilizes effective medium theory to implicitly account for anisotropy, effective deformation moduli, and effective permeability of a fractured geothermal reservoir without explicitly defining the fractures as discrete contact surfaces. This work also highlights the importance of leveraging fully-coupled THM tools such as ParaGeo to more accurately inform geothermal business decisions.

2. METHODS

2.1 Governing Equations and Solution Scheme

The quasi-static equations of a thermo-poroelastic solid saturated with a single-phase fluid are (McTigue, 1986; Palciauskas & Domenico, 1982):

$$(\rho c)_s \frac{\partial T}{\partial t} - \kappa_T \frac{\partial^2 T}{\partial x_i^2} + (\rho c)_f q_i \frac{\partial T}{\partial x_i} = Q_T \tag{1}$$

$$\frac{\alpha^2}{K_u - K} \frac{\partial p}{\partial t} - \frac{\partial q_i}{\partial x_i} = -\alpha \frac{\varepsilon_{ii}}{\partial t} + Q_p \tag{2}$$

$$\frac{\partial}{\partial x_i}\left(C_{ijkl}\left[\frac{\partial u_k}{\partial x_l} - \alpha_L \delta_{kl} \Delta T\right]\right) - \alpha \frac{\partial p}{\partial x_i} = b_i \tag{3}$$

where ρ is the density, c is the specific heat capacity, T is the temperature, κ_T is the thermal conductivity, q_i is the Darcy flux, Q_T is an energy source/sink, α is the Biot coefficient, K_u is the undrained bulk modulus, K is the drained bulk modulus, p is the pore fluid pressure, ε_{ii} is the volumetric strain, Q_p is the mass source/sink, C_{ijkl} is the elastoplastic tangent stiffness matrix, δ_{kl} is Kronecker's delta, u_k is the displacement, α_L is the linear thermal expansion coefficient of the solid matrix, and b_i is the gravitational body force (indices follow Einstein's summation notation). The Darcy flux is equal to $q_i = -\frac{k}{\mu}\left(\frac{\partial p}{\partial x_i} - \rho_f g_i\right)$ where k is the rock permeability, μ is the fluid viscosity, and g_i is the gravitational vector. In the above equations, the subscripts s and f refer to the solid matrix and pore fluid, respectively.

ParaGeo employs a convergence based sequential solution scheme for fully-coupled THM analysis. Mass and energy balance problems (Eq. 1, 2) are solved with an implicit algorithm. The mechanical problem (Eq. 3) is solved with an explicit dynamic algorithm (although an implicit solver is also available for quasi-linear problems). This work utilizes mass and material viscosity damping along with several hundred mechanical steps per coupling step to recover a quasi-static solution.

2.2 Effective Medium Model for Naturally Fractured Reservoirs

Modeling natural fractures as discrete contact surfaces requires explicit representation of the fracture in the mesh with two surfaces that may separate in normal and shear directions (Goodman et al., 1968). However, this method is not practical for naturally fractured reservoirs with close fracture spacing. Instead, an effective medium approach accounting for intact rock and fracture properties is preferred to avoid complex meshing. Further motivation of this approach includes: (1) accounts for anisotropy in mechanical deformation and strength as well as in permeability, (2) accounts for non-linear and stress dependent elastic moduli through fracture stiffness, (3) accounts for natural fracture shear strength, and (4) accounts for stress dependent effective permeability. The natural fracture stiffness K_n is a non-linear function of normal effective stress σ_n' (Bandis et al., 1983):

$$K_n = K_{ni}\left(1 - \frac{\sigma_n'}{K_{ni}V_m + \sigma_n'}\right)^{-2} \tag{4}$$

Where K_{ni} is the initial fracture stiffness (the value for zero normal loading $\sigma_n' = 0$) and V_m is the maximum fracture closure, e.g., the height of the tallest asperity along the fracture face. We treat the shear stiffness as a fraction of the normal stiffness and is a dynamic parameter that changes as stresses change. Furthermore, fracture permeability follows the cubic law and scales with normal effective stress (Zimmerman & Yeo, 2000). Fracture orientation, spacing, and aperture significantly alter the fluid flow field.

As an example of non-linear stress changes due to the presence of compliant fractures, let us explore a drained isochoric response to thermal depletion. Analytical solutions for the elastic compliance matrix of a rock with three intersecting fracture sets (one set vertical and two conjugate sets with a dip of 60°) can be found elsewhere (Huang et al., 1995). Thermally induced stress changes tend to be much less when fractures are present because some of the thermal strain is absorbed by fracture compressibility rather than by the intact rock (Figure 1a). Notice that the mechanical response is anisotropic ($\Delta\sigma_{xx} \neq \Delta\sigma_{yy} \neq \Delta\sigma_{zz}$) because fracture orientation causes the effective moduli to be directionally dependent. Furthermore, critically oriented fractures may reactivate in shear and limit the amount of stress change (Figure 1b). Hence, effective medium models can capture complex constitutive behavior that linear elastic models cannot capture.

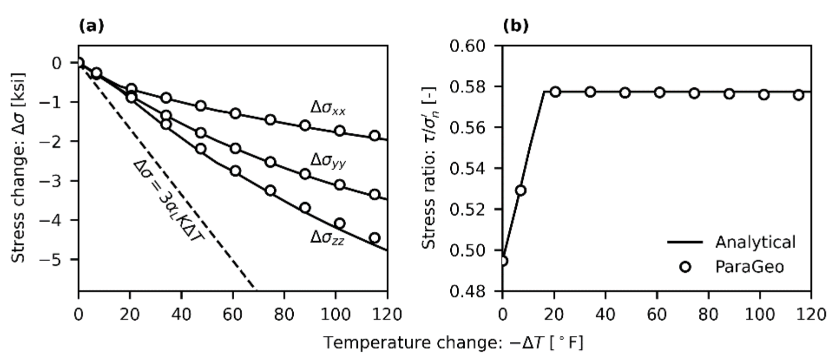

Figure 1. Drained isochoric response to thermal depletion for a fractured rock with non-linear compliance. (a) Stress changes compared to linear elastic response (dashed line). (b) Stress path with shear reactivation for $\tau/\sigma_n' = 0.577$.

3. NUMERICAL SIMULATION OF FORGE

3.1 Model Description

The numerical model is based on the FORGE site with in-situ temperature, pore pressure, and stress calibrated to field measurements for the injection well (16A) and monitoring well (58-32) (Podgorney et al., 2021). The modeling domain is $13.1 \times 13.1 \times 13.8 \cdot 10^3$ ft (length, width, depth), discretized into ~1,000,000 tetrahedral elements. Mesh refinement is applied near the injection and production wells with 30 ft element size to capture large temperature and stress gradients due to fluid injection and production. The wells are deviated in the direction of minimum principal stress with a vertical separation of 1,150 ft. The modeling domain is rotated 25° counter-clockwise such that the in-situ horizontal principal stresses align with the global coordinate system (Figure 2a). Two lithologies compose the model: (1) fractured granitic reservoir and (2) overlying sedimentary basin fill. The reservoir is modeled as a thermo-poroelastic material with four natural fracture sets each with distinct orientation and density (Figure 2b). To reduce computational cost, the overlying basin fill is modeled as a thermo-elastic material, i.e., effects of pore pressure changes on stress changes are not considered.

Following the interpretation based on wellbore breakouts by Xing et al. (2022), the initial stress regime was set on the limit between normal and strike-slip, with $S_{Hmax} \approx S_V$. The initial value of S_{hmin} gradient was set at approximately 0.75 psi/ft as inferred from available leak-off tests (LOTs). The initial pore pressure and temperature were defined as spatial distributions based on data available from the Utah FORGE website (Energy and Geoscience Institute at the University of Utah., 2019) and Podgorney et al. (2021).

The numerical model is divided into two stages: (1) an initialization stage consisting of gravity loading and tectonic loading (e.g., applied horizontal displacements) to reach the desired in-situ stress field and (2) a geothermal operation stage consisting of constant rate injection and production at 55,000 bbl/day with 120°F injection temperature. Working fluid injection is divided evenly along the ~3,300 ft deviated portion of the injection well. The initial normal/shear stiffness, aperture, and permeability of each natural fracture set is determined numerically during the initialization stage. The simulated thermo-poromechanical properties of the geothermal reservoir are listed in Table 1.

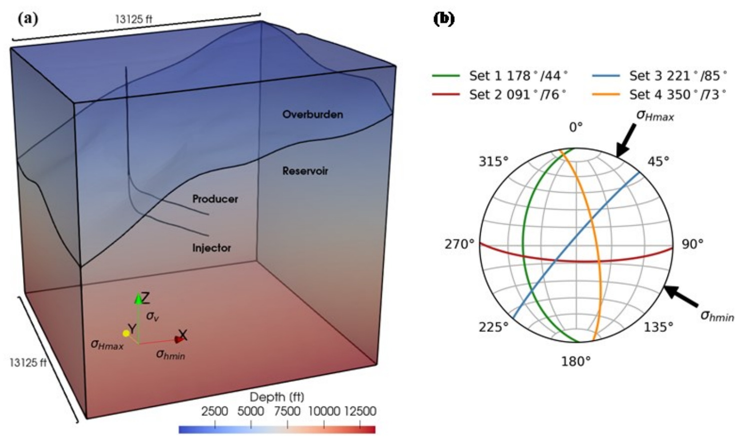

Figure 2. (a) Numerical modeling domain of the FORGE site. (b) Stereonet of the four natural fracture sets for the geothermal reservoir. Average natural fracture spacing is between 2.4 and 5.0 m.

Table 1. Geothermal reservoir properties for the numerical simulation. The four fracture sets all have the same mechanical properties.

Intact rock		
Property	**Value**	**Unit**
Drained bulk modulus	8000	ksi
Shear modulus	3600	ksi
Grain bulk modulus	15000	ksi
Porosity	0.02	-
Biot coefficient	0.47	-
Permeability	0.1	nd
Thermal conductivity	1.76	Btu/hr-ft-°F
Specific heat capacity	0.19	Btu/lb-°F
Linear thermal exp. coefficient	5.5×10^{-6}	1/°F
Embedded natural fractures		
Initial normal stiffness	220	ksi/ft
Maximum closure	4.1×10^{-3}	ft
Shear stiffness factor	0.5	-

3.2 Reservoir Mechanical Response

Continuous geothermal operation for two decades disrupts the natural temperature distribution and causes thermal depletion everywhere between the injector and producer because the natural thermal recharge rate is small compared to the heat extraction rate (Figure 3a). The largest temperature changes, however, occur along the most dominant fluid flow paths which mostly follows the orientation of natural fractures with largest aperture and permeability. While thermal depletion is constrained to a relatively small reservoir volume, stress changes can occur within the thermal front and at great distances ahead of the thermal front because working fluid injection results in stress redistribution around the thermally depleted zone, i.e., stress relaxation near injector/producer and stress concentration away from injector/producer.

The predominant stress path within the thermally depleted zone is quasi-isotropic unloading with stress changes largely following $\Delta\sigma_1' = \Delta\sigma_3'$ (Figure 3b). The stress path is not fully-isotropic, however, because horizontal effective stresses decrease slightly more than vertical effective stresses do. This is a result of laterally constrained reservoir shrinkage (near zero horizontal strain: $\varepsilon_h \sim 0$) that maximizes horizontal stress changes. Notice that the stress changes predicted by the numerical model are significantly smaller than that for simple linear elastic analytical solutions. For example, consider the drained thermo-elastic uniaxial strain response for horizontal stresses: $\Delta\sigma'_h = \alpha_L E \Delta T/(1-\nu)$. The simple linear model results in a stress change of 11 ksi for a temperature change of 150°F. Yet, the numerical solution predicts stress changes less than 5 ksi. Hence, much of the thermally induced strain is absorbed by natural fracture compressibility that decreases as stresses decrease, i.e., thermal stresses decay with time as natural fractures open and become more compressible. This necessitates accounting for the non-linearity of reservoir discontinuities in the mechanical response, as otherwise simple linear elastic models may overpredict changes of effective stress.

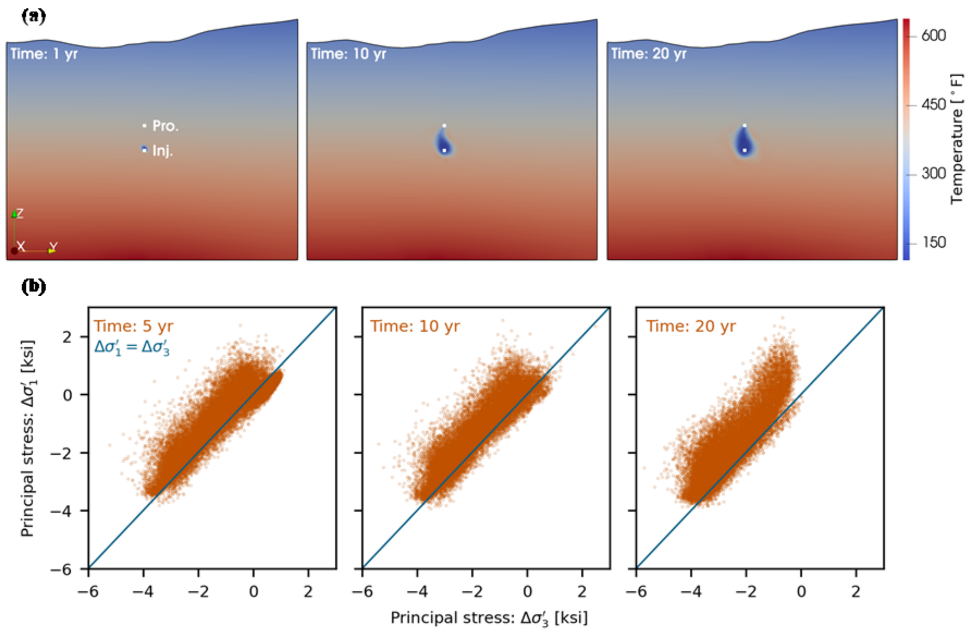

Figure 3. (a) Gun barrel view of reservoir temperature changes due to geothermal operation. (b) Reservoir stress changes in principal stress space compared to an isotropic stress path (blue line). Each point represents stress changes for a single mesh element within the reservoir volume contributing to heat extraction, i.e., threshold of $\Delta T < -10$°F.

3.3 Fracture Aperture Response

The aperture and permeability of natural fractures within the geothermal reservoir respond to changes of effective stress (Figure 4). Prior to working fluid injection and production, natural fracture aperture decreases with depth where effective stresses are larger. With high enough stress, we consider the fractures closed such that the permeability is small (Figure 4a – dark blue color). Cold working fluid injection quickly re-opens the fractures near the producer with aperture on the order of 10^{-1} in. The time required to do so is less than one year because (1) aperture is initially small leading to quick increase in pore pressure and (2) there is a large contrast between reservoir temperature and injection fluid temperature leading to stress relaxation. As time progresses and the thermal front reaches the production well, fractures re-open with large aperture and permeability everywhere within the thermally depleted zone. This constrains the injection fluid to a small reservoir volume with preferential fluid flow paths directly to the producer, i.e., more injection fluid is unable to contact new reservoir areas (Figure 4b – 50 md permeability).

Geothermal operation in a reservoir with compressible fractures results in a coupled thermo-poroelastic feedback cycle where local effective stress relaxation increases local fracture permeability, evoking localized fluid flow to regions of large permeability, and in turn further reduce effective stresses. The amount of fluid flow localization is, however, highly dependent on fracture compliance. For example, the aperture of stiff fractures under large in-situ stresses may not change much (resulting in a large heat drainage volume without preferential fluid flow paths) unless stress relaxation overcomes in-situ compressive stresses, something expected in reverse faulting environments. Hence, geothermal reservoirs in a normal faulting environment with small horizontal stresses are most likely to be affected by fracture compressibility.

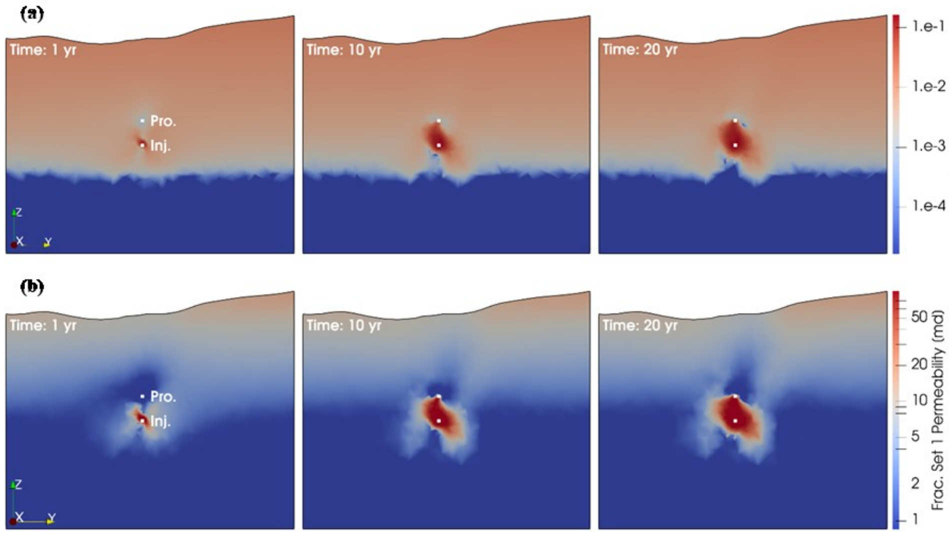

Figure 4. Gun barrel view of natural fracture set 1 (a) aperture and (b) permeability evolution through time (overburden not shown). Injection of a cold working fluid causes normal effective stress relaxation and an increase in fracture aperture/permeability, accelerating thermal breakthrough.

4. DISCUSSION

4.1 Impact of Fracture Compressibility

This section compares the long-term thermal performance between a geothermal reservoir with: (1) constant fracture aperture (neglecting mechanical response) that does not change from the initial distribution and (2) effective stress dependent fracture aperture as detailed in section 3. Both cases start with an equivalent aperture distribution. The first case is taken as an ideal scenario in which the maximum power is achieved, i.e., thermo-hydraulic response.

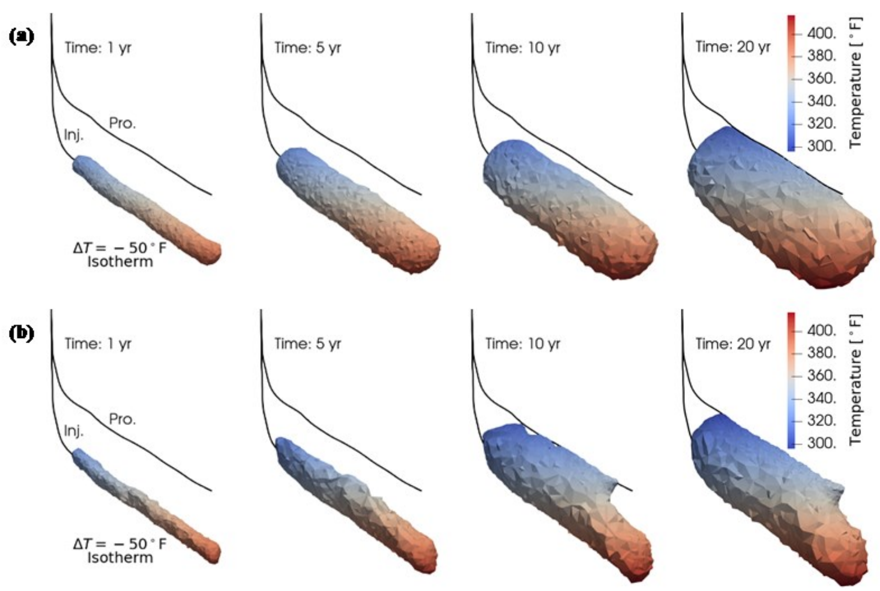

Figure 5. Comparison of heat drainage volume between cases with (a) constant fracture aperture and (b) effective stress dependent aperture. Aperture increase causes a smaller heat drainage volume and quicker thermal breakthrough.

First, the injection fluid contacts a larger reservoir volume with constant fracture aperture compared to stress dependent aperture because preferential fluid flow paths do not develop and the injection fluid can disperse evenly within the geothermal reservoir – not considering effects of heterogeneity on the initial permeability field (Figure 5a). However, the opposite is true for a geothermal reservoir with compressible natural fractures that constrains the injection fluid within the thermally depleted zone where apertures are large. Secondly, the thermal breakthrough time is delayed by several years for the simple constant aperture model (Figure 5a, b at 10 yrs.). Heterogeneity in the initial aperture field could, however, further decrease the heat drainage volume and accelerate thermal breakthrough for both cases as preferential fluid flow paths may exist from the beginning, but is not considered in this section.

Now let us compare the long-term thermal performance between the two cases. The electric power is estimated by: $P = \eta\dot{m}(h_p - h_i)$ where η is the power plant efficiency, $\dot{m}$ is the mass flow rate at the production well head, h_p is the produced fluid enthalpy, and h_i is the injection fluid enthalpy. A general geothermal power plant efficiency (including single flash, double flash, and binary power plants) is employed: $\eta = 7.88\ln(h_p) - 45.65$ with h_p in units of kJ/kg and η in percent. Figure 6a shows that the effects of natural fracture compressibility greatly compromise the thermal performance of a geothermal system. For example, the long-term electric power for case 2 (considering stress dependent aperture) is ~35% of that for the ideal thermo-hydraulic case. Recoverable heat energy is also less for case 2 because thermal breakthrough occurs faster and production temperature decreases quickly thereafter. Furthermore, the project lifetime (time to which production temperature falls below 300°F, likely required for conversion to electricity) is in the range of 10-12 years for case 2 but may greatly exceed 20 years for the ideal case. Lastly, the poor thermal performance of case 2 is compounded by powerplant efficiency because production temperature rapidly decreases after thermal breakthrough falling to 3.5% (Figure 6b). This analysis indicates that (1) accurate forecasting of geothermal resources requires fully-coupled THM models with realistic constitutive behavior and (2) numerical models are important to predict the geothermal project lifetime.

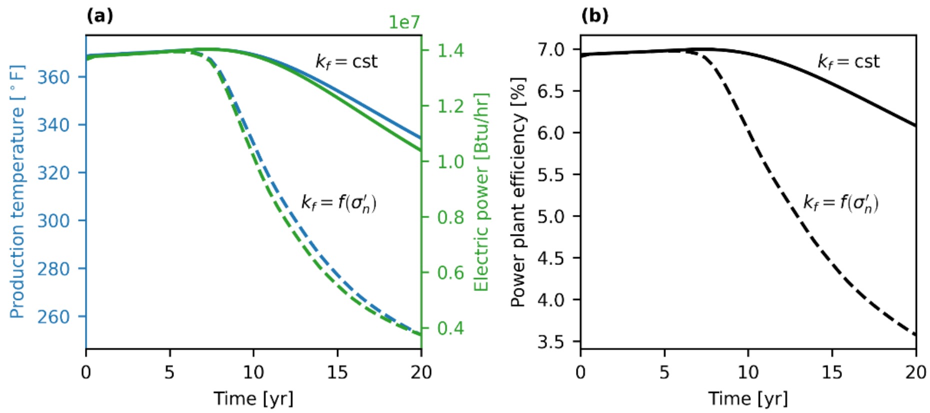

Figure 6. (a) Thermal performance comparison between two cases: constant fracture permeability (k_f = cst.) and stress dependent fracture permeability ($k_f = f(\sigma_n')$). (b) General geothermal power plant efficiency for the two cases.

4.2 Impact of Heterogeneity

This section compares the thermal performance between a geothermal reservoir with a (1) homogenous initial aperture distribution (V_m – Eq. 4) and (2) heterogenous initial aperture distribution. For the heterogenous case, we assume that V_m follows a normal distribution with mean of 0.05 in. and standard deviation of 0.0075 in. The homogenous case is the same model detailed in section 3 with $V_m = 0.05$ in. Fracture closure is selected as a spatially varying parameter because actual rock fracture surfaces are rough such that the maximum closure varies along the fracture plane, i.e., some asperities may be initially in contact (small closure allowed) while others are not in contact (large closure allowed) under compressive in-situ stress. This also affects the initial permeability distribution, assuming a relationship between fracture aperture and permeability (Figure 7b). The spatial variation is applied on an element basis. Note that the heterogenous fracture closure distribution greatly influences the mechanical response because fracture stiffness is inversely proportional to aperture and effective elastic moduli are proportional to fracture stiffness.

Modeling results indicate that the effects of fracture compressibility are more significant to the long-term thermal performance than the effects of heterogeneity in the initial aperture distribution for the parameters chosen here (Figure 7a). A larger contrast in initial aperture (such as a broad distribution) could, however, cause heterogeneity to have a larger impact on the thermal performance. Thermal breakthrough is delayed 1-2 years for the heterogenous case because (1) some regions within the heat drainage volume are restricted by small permeability and (2) the mechanical response for those regions with large initial aperture are less severe because fracture stiffness is smaller. The reservoir areas with small fracture closure may quickly open because stress changes are larger but maximum permeability is limited by small aperture. The opposite is true for areas with large fracture closure: aperture changes are smaller because of small normal stiffness but maximum permeability is large. Both modeling cases predict an increase in fracture permeability along dominant fluid flow paths that constrains the injection fluid to a smaller reservoir volume than that expected for constant aperture models. Hence, the modeling results indicate that the two opposing processes mostly balance each other out and the production temperature is close to that of a homogenous fracture closure distribution with effective stress dependent aperture.

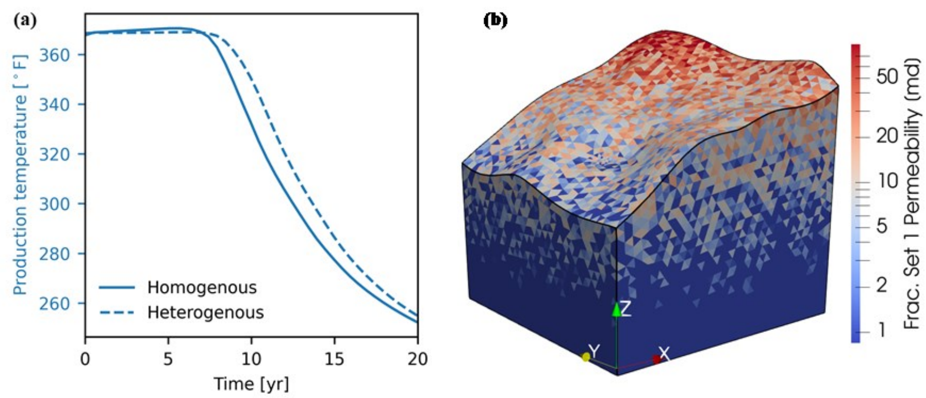

Figure 7. (a) Thermal performance comparison between homogenous and heterogenous maximum fracture closure. (b) Initial natural fracture permeability distribution within the geothermal reservoir (overburden not shown).

4. CONCLUSION

Heat extraction from geothermal resources involves coupled thermal, hydraulic, and mechanical processes. This work demonstrated the numerical modeling capabilities of ParaGeo for geothermal systems and explored the role of natural fracture compressibility on geothermal systems. The numerical model is based on the FORGE site and utilizes effective medium theory to implicitly account for fracture orientation, density, compressibility, and permeability within the geothermal reservoir. Numerical modeling results indicate that the long-term thermal performance of naturally fractured geothermal systems may be compromised by localized fracture re-opening that accelerates thermal breakthrough. Compressible fractures with apertures sensitive to effective stress changes are most likely to re-open and cause a sharp decline in produced fluid temperature because permeability can change several orders of magnitude during operation. Heterogeneity in fracture properties also affects the thermal performance but is highly dependent on the spatial distribution. Furthermore, modeling results indicate that accurate forecasting of geothermal systems requires fully-coupled THM models that account for dynamic properties such as fracture stiffness and permeability. Numerical solutions are important to predict project lifetime and expected power output.

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