Design, Modeling, and Evaluation of a Doublet Heat Extraction Model in Enhanced Geothermal Systems

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ABSTRACT

A conceptual Enhanced Geothermal System (EGS) model, where water is circulated through a pair of parallel injection and production wells connected by a set of single large wing fractures, is designed, modeled, and evaluated in this work. The water circulation and heat extraction in the fractured reservoirs is modeled as a fully coupled process of fluid flow and heat transport. Using a newly developed, open-source, finite element based geothermal simulation code, FALCON, simulation results were obtained for a 30-year operation at a depth of 3km and geothermal gradient of 65°C per km of depth. With a sensitivity study of the heat production to the design parameters, preferable fracture horizontal spacing, downward deviation angle of the parallel wells, and injection flow rate are recommended. Upscaling calculations of the developed EGS model have shown that, an industrial production-level system may be achievable if it consists of 40 equidistant fractures that connect two 1.2 km long parallel well sections with a well separation of 500 m; and if a system of these dimensions operates for 30 years at a flow rate of 0.1 m³/s, with an electric power output at least 5 MW and pumping power of less than 1 MW. In particular, the performance metrics demonstrated in this work match well with those suggested by others, thus indicating the general applicability of our conceptual models.

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1 **Keywords:** Renewable energy, EGS, fractured reservoir, heat production, finite element method

2 LIST OF SYMBOLS

<i>Symbols</i>	<i>Unit</i>	<i>Notation</i>
c_w	$J \cdot kg^{-1} \cdot K^{-1}$	Specific heat capacity of fluid
c_r	$J \cdot kg^{-1} \cdot K^{-1}$	Specific heat capacity of rock
g	$m \cdot s^{-2}$	Magnitude of gravitational force
K_m	$W \cdot m^{-1} \cdot K^{-1}$	Average thermal conductivity of the porous medium
k	m^2	Reservoir intrinsic permeability
Pe_h	--	Element Peclet number
p	Pa	Fluid pressure
$\dot{Q}$	$J \cdot s^{-1}$	Thermal energy source/sink
$\mathbf{q}$	$m \cdot s^{-1}$	Flux (Darcy velocity) vector
s	$kg \cdot m^{-3} \cdot s^{-1}$	Specific mass source/sink (or specific injection/production rate)
T	K	Fluid temperature
t	s	Time
μ	Pa·s	Fluid viscosity
ρ	$kg \cdot m^{-3}$	Fluid density
ρ_r	$kg \cdot m^{-3}$	Rock density
ϕ	--	Reservoir porosity
∇	m^{-1}	Vector differential operator

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1 INTRODUCTION

1.1 Heat Extraction Process in EGS

The concept of creating an engineered, or enhanced geothermal system (EGS) (Batchelor 1982, Cornet 1989), first described as a hot dry rock (HDR) system (Smith et al. 1975, Tester et al. 1989, Duchane 1990, and Duchane et al. 2002), originated at the Los Alamos National Laboratory (LANL) in the 1970s, and is of continuing interest due to the need for low CO₂-emission energy sources. Among the many aspects of EGS design, number and spacing of fractures, optimal placement of injection and production wells, flow rates and pressures, are all critical factors affecting heat production performance. However, largely due to the difficulty and expense of creating an EGS, many uncertainties exist regarding the optimal system design (U.S. Department of Energy 2008). Numerical modeling and simulation methods provide one way of testing EGS design concepts, and incorporating much of the geometric complexity and complicated physics of those designs.

Based on the various conceptual designs of EGS well layout, the heat extraction process has been investigated extensively in recent years. The well layout schemes that are often modeled include three basic forms: 1) doublet (an injection and production well pair), 2) triplet (an injector flanked by a production well on each side), and 3) five-spot (an injector at the center and a production well at each corner of a square). Due to the great volume of literature published in this area, only some of the most recent works are reviewed here. Sanyal et al. 2005 simulated a 30-year power generation period of a 3D hypothetical EGS model with a five-spot well layout, and analyzed the optimal performance of the model by performing a sensitivity study on fracture spacing, reservoir permeability, and well geometry. Zeng et al. 2013(a) investigated the performance of a 2D conceptual EGS model with a horizontal doublet well layout, and concluded that the energy efficiency mainly depends on the reservoir permeability and the water production rate. Jiang et al. 2014 designed and simulated a 40-year heat extraction period of a 3D

conceptual EGS with a triplet well layout, and demonstrated that it is able to retain the preferential flow in the reservoir and significantly elongate the heat production by 10 years over its doublet counterpart. Chen et al. 2015 conducted a comparative study on the long-term performance between a doublet scheme, two triplet schemes, and a five-spot scheme for well layouts. Their results have showed that the performance of EGS could not be necessarily improved by simply deploying more production wells. Later on, Chen et al. 2016 performed a detailed sensitivity study of design parameters for the EGS heat extraction process with a doublet well, and revealed that the heat extraction rate and lifetime of the system are tightly related to the flow pattern in the reservoir, while the thermal compensation from rocks surrounding the reservoir contributes little heat to the working fluid if the operation period is short. Though most of those works were based on hypothetical models that assumed isotropic and homogeneous subsurface environment, they have substantially advanced our understanding of how to optimize the long-term performance of the EGS heat extraction process.

1.2 Numerical Modeling and Simulation Methods

Modeling the operation of an EGS plant requires reliable numerical methods to simulate the coupled thermal-hydraulic-mechanical (THM) processes. Nevertheless, the mechanical interaction between rock and fluid as well as the rock thermoelastic effect has been often neglected for simulating long-term EGS heat extraction process in many recent studies (with the reasons to be discussed later). For example, Zeng et al. 2013(a), Zeng et al. 2013(b) and Bujakowski et al. 2015 used the finite difference method (FDM) based TOUGH2 code (Pruess et al. 1999) for simulating the heat extraction process from EGS systems. However, FDM has a known disadvantage in that it requires high-quality structured meshes to obtain accurate solution, which could largely limit the complexity of the fracture features to be modeled. Though the FDM can also handle irregular meshes, the use of irregular meshes, in turn, could result in overly diffused solutions of convection-dominated heat transport in fractured reservoirs, which might lead to significantly inaccurate estimates of EGS design parameters. The inconvenience associated with

FDM triggered the use of unstructured mesh based methods, such as the finite volume methods (FVMs) and finite element methods (FEMs). For example, based on the computational fluid dynamics (CFD) solver, Fluent®, Jiang et al. 2014 developed a 3D hydrothermal flow model that uses the cell-centered FVM for solving the transient incompressible flow and heat transfer with the Navier-Stokes equations in both the reservoirs and wells. It was then applied in an extensive study of EGS well layouts (Chen et al. 2015, and Chen et al. 2016). However, it is not clear if their first-order FVM spatial discretization scheme was able to retain sufficient solution accuracy for long-term simulation of convective heat transport in fractured reservoirs. Alternatively, the Galerkin FEMs and so-called “Control-Volume” FEM (CV-FEM, nothing but the node-centered FVM) may offer more flexibility for reservoir modeling, as they support the implementation of 1D, 2D, and 3D elements in the same model (e.g., in a 3D EGS model, the fractures can be represented with 2D planar surfaces embedded in 3D rock matrix, and the wells can be represented with 1D curves). Examples include the “FEHM” code developed at LANL (Zyvoloski 2007), the “FRACTure” code by Kohl et al. 1995 and applied in Held et al. 2014, and the “PANDAS” code by Xing et al. 2015. However, so far most of the FEM codes are not as powerful as the mature FDM code such as TOUGH2 to model some very complex problems, such as the coupled THMC processes (where “C” stands for chemical reactions). Further development of the FEM based numerical methods to overcome their existing weaknesses is in urgent demand.

1.3 Objectives and Novelties

The objectives of the present work are to evaluate performance of several variants of a common conceptual EGS model. In this model, water is circulated through two parallel wells connected by a set of single large wing fractures in a fully saturated geothermal reservoir (see Figure 1). The sensitivity of EGS heat production to some key design parameters, including the fracture horizontal spacing, flow rate, and well deviation angle, will be assessed, respectively. A newly developed, open-source FEM based geothermal simulation code, FALCON (Xia et al. 2015), has been used for the simulations. The novelty of this

work is two-fold. First, a mixed-dimensional rock–fracture model is employed, where the fractures are represented using 2D planar domains that are embedded in a 3D domain that represents the surrounding rock matrix, with the same governing equations applied in both domains. Unlike the 2D single fracture model used in Zeng et al. 2013, our 3D model takes into account the inter-fracture thermal interference, for which the long-term impact on the production wellbore temperature cannot be neglected where the fractures are spaced at reasonable distances. Second, this work considers a doublet parallel well layout with a downward deviation angle, and compares its performance to a similar system of horizontal wells. Third, open-source FALCON code used, and the simulation files for this study, are available to the public for continued development and/or testing of other scenarios.

The rest of this paper is organized as follows: Section 2 presents the governing equations for the coupled fluid flow and heat transport in geothermal reservoir environment, and constitutive models for calculating the density and viscosity of liquid-phase water. Section 3 describes the proposed 3D conceptual EGS model. Section 4 reports the numerical results of the simulation test cases and sensitivity analysis. Finally, Section 5 gives concluding remarks and outlook for future work.

Figure 1 Schematic of a parallel doublet well layout in a 3D conceptual EGS model.

2 Mathematical Model

Initially introduced in Podgorney et al. 2010, our geothermal simulation code, FALCON, featured a parallel, fully implicit capability for modeling the fully coupled THM processes in a singly integrated code. FALCON has been developed using both pressure-temperature (P-T) and pressure-enthalpy (P-H) formulations (Podgorney et al. 2011). The P-T formulation is limited to the modeling of single-phase water-saturated systems, while the P-H formulation can be used for both single- and two-phase systems. The P-T based liquid flow and heat transport module of the FALCON code is used for the reservoir simulations in this work. This module has been rigorously validated through a number of benchmark problems in Xia et al. 2016b, and made available as an open-source toolkit (Xia et al. 2015).

2.1 Governing Equations

The mathematical models describing geothermal systems can be found in Brownell et al. (1977), Faust & Mercer (1979a), and Faust & Mercer (1979b). In the P-T based formulation for a single-phase water-saturated system, mass conservation for the fluid phase in the porous medium may be written as:

$$\frac{\partial(\phi\rho)}{\partial t} + \nabla \cdot (\rho\mathbf{q}) - s = 0 \quad (1)$$

When considering momentum conservation of the system, we assume that Darcy's law is valid, and that momentum balance for the fluid phase may be represented as:

$$\mathbf{q} = -\frac{k}{\mu}(\nabla p + \rho g \nabla z) \quad (2)$$

where ∇z is a vector of components (0, 0, -1), when the gravity force is taken to align in the negative vertical direction. Combining Eq. (1) and Eq. (2) yields the following equation for liquid-phase water flow in a deformable, compressible geologic medium:

$$\frac{\partial(\phi\rho)}{\partial t} - \nabla \cdot \left(\frac{k}{\mu} \rho (\nabla p + \rho g \nabla z) \right) - s = 0 \quad (3)$$

If we assume that the thermal equilibrium exists between the fluid and solid phases, the energy conservation can be described as below:

$$\frac{\partial[\phi\rho c_w + (1 - \phi)\rho_r c_r]T}{\partial t} - \nabla \cdot (K_m \nabla T) + \nabla \cdot (T\rho c_w \mathbf{q}) - \dot{Q} = 0 \quad (4)$$

Eq. (3) and Eq. (4) serve as the governing equations for the coupled flow and heat transport in a porous medium. Furthermore, if we assume ϕ , k , and K_m are constants, Eq. (3) and Eq. (4) can be reduced to the following:

$$\phi \frac{\partial \rho}{\partial p} \frac{dp}{dt} + \nabla \cdot \mathbf{q}_M - s = 0 \quad (5)$$

$$C_m \frac{dT}{dt} - K_m \nabla \cdot \nabla T + \nabla \cdot (T \mathbf{q}_E) - \dot{Q} = 0 \quad (6)$$

Eq. (5) and Eq. (6) are the P-T based governing equations being used in this work, where the terms $\rho \mathbf{q}$, $\phi \rho c_w + (1 - \phi)\rho_r c_r$, and $\rho c_w \mathbf{q}$ are replaced by $\mathbf{q}_M$, C_m , and $\mathbf{q}_E$, respectively, for simplicity. In the FALCON code, the Galerkin finite element method is used for the spatial discretization of the governing equations above, and the second-order backward Euler method (BDF2) is used for the time integration of the resulting nonlinear system of equations. Detailed description of the numerical methods implemented in the FALCON code can be found in Xia et al. 2016a.

2.2 Constitutive Relationships

The FALCON code has adopted the IAPWS industrial formulation 1997 (denoted IAPWS-97) to calculate the phase thermodynamic properties (i.e., density, internal energy, and viscosity) of water and/or steam (Wagner et al. 2000). This formulation uses pressure ($\leq 100\text{MPa}$) and temperature ($\leq 800^\circ\text{C}$) as input parameters, and returns density and internal energy, which can be applied in the liquid water, steam and supercritical regions. The formula of viscosity in IAPWS-97 uses density and temperature as input variables, and returns fluid viscosity of either water or steam, depending on the input density value. An update to the IAPWS-97 formulation was released in 2008 (Cooper et al. 2008) and has also been imple-

mented. Our earlier study shows that satisfactory results were obtained with the IAPWS-97 model in a series of benchmark test problems in single-phase water-saturated systems (Xia et al. 2016b).

3 THE CONCEPTUAL MODEL

3.1 Fractured Reservoir

Our reservoir model is comprised of two distinct, but connected domains. These are (1) un-fractured rock matrix blocks and (2) fractures that separate those blocks. The matrix blocks and fractured reservoirs are both treated as slightly compressible homogeneous porous media, where the coupled flow and heat transport may be represented by Eq. (5) and Eq. (6). These assumptions have been adopted in many recent studies, including, for example, Sanyal et al. 2005, Jiang et al. 2014, Bujakowski et al. 2015, and Chen et al. 2016.

The characteristics of a multi-dimensional fractured reservoir network, such as the permeability, aperture and fracture geometric shapes, may be subject to change during the heat production process of an EGS. Modeling the coupled THM processes in the fractured reservoir normally requires an explicit description of fracture distribution that resolves many aspects of the rock physics, for example, variations of fracture aperture with respect to local effective stress, rock deformations due to shear failure, and constitutive relationships between the fracture aperture and fracture thermal conductivity as well as thermo-elasticity. Modeling the coupled THM processes instead of TH may result in a more accurate but also significantly more complex EGS model for the heat production process. In one study of the impacts of different coupled processes on EGS performance (e.g., hydro-mechanical and thermo-hydro-mechanical), McDermott et al. 2006 showed that the productivity of the reservoir is lower when fluid properties in fractured reservoir are functions of only fluid pressure and temperature, and rock mechanical properties are assumed constant. This is mainly because the permeability of the fracture system will increase as the reservoir is cooled if hydroelastic and/or thermoelastic interactions between the rock

and fluid are considered (McDermott et al. 2006). Hence, a lower productivity may be estimated in the case that the physical properties of rock are constant in the system. Thus, in our conceptual EGS reservoir model, we consider it a conservative assumption that, after the man-made fractures have been created by stimulation, the mechanical properties of the fractured reservoir remain unchanged during the heat production process.

3.2 Well Layout

As illustrated in Figure 1, two horizontally parallel doublet wells are connected by a set of vertically extended, equidistant single wing fracture planes, where N_{frac} is the total number of fracture planes. The vertical distance between the lower injection well and the higher production well is denoted by d_v . The horizontal spacing between each two neighboring fracture planes is denoted by d_h . In Figure 1, the thickness of the planar fractures is exaggerated for visualization purpose only, and is very thin compared to the other dimensions of the plane. The fractures can therefore be treated as zero-thickness planar geometry by neglecting mass and heat transport in the across-plane direction. The geomechanics of creation of this type of fracture were discussed in Jung 2013, and Li & Lior 2015. According to Jung 2013, 30~40 such fractures may be required to achieve the desired thermal productivity. To lower the computational burden of simulating a system containing that many fractures, we created a reduced-scale model that contains only five fractures (see Figure 2). While symmetry of the problem for the horizontal well problem would allow a single-fracture representation, the 5-fracture domain allows comparison of the performance of the inclined and horizontal borehole scenarios. The fractures are numbered from #1 to #5 along the x-direction and the midpoint of the #3 fracture is chosen as the reference depth, z_{ref} , below the ground surface. We assume a geothermal gradient of 65°C per km of depth in our imaginary subsurface domain, and specify a reference temperature of 200°C and reference pressure of 30 MPa at our reference depth of -3 km. We believe this reduced-scale model is sufficient to reveal the sensitivity of long-term heat production performance to the design parameters of interest, and through symmetry

can be used to estimate the performance of the full-scale model. In addition to the horizontal well layout, an alternative well layout with a downward inclination angle of $\alpha = 45^\circ$ is also considered (see Figure 2b). Because an inclined system of fractures reduces the total drilling distance, the goal here is to compare performance of these two systems when other factors are held constant. Well drilling is a very expensive process in terms of the capital investment (Barbier 2002, and Polsky et al. 2008), so system design that minimizes drilling is usually preferred. To make a fair comparison of heat production performance between these two well layouts, the d_v and d_h are kept identical between the two scenarios.

(a)

(b)

Figure 2 Two reduced-scale well layout schemes: (a) horizontally parallel doublet wells, (b) parallel doublet wells with a downward deviating angle of α .

To complete the water circulation and heat production processes, an injection pump that connects the injection well and a suction pump that connects the production well are installed on the ground. We assume that the water mass rate from each injection wellbore into the fracture plane is constant. The suction pump draws the heated water out of the reservoir through the production well, and pumps the water into a binary cycle power plant. The outflow from the power plant is cooled down, and re-injected into the fractured reservoir via the injection well.

3.3 Geometric Configuration and Domain Discretization

Figure 3 illustrates the two steps to create the geometric configuration and the finite element mesh for our hypothetical geological system: 1), the creation of a 2D domain and mesh; and 2), the creation of a mixed-dimensional 2d-fracture/3d-matrix system. The CUBIT toolkit (Blacker et al. 1994) is used for creating the geometry and meshes. Due to the symmetry of our model in the x - z plane, only half of the domain is modeled. In step 1, a 2D planar fracture-matrix system is created in the y - z plane with the x -coordinate equal to zero, where the fracture (colored in red) is represented by a semielliptical disk with a primary radius of $r_p = 750$ m in the z -direction and secondary radius of $r_s = 500$ m in the y -direction (see Figure 3a). The fracture is encompassed by the rock matrix (colored in grey) whose outer boundary is represented by a semicircular curve with a radius of 1 km. Due to the absence of actual data of such a single large fracture, its shape and size are determined hypothetically, but reasonably enough to indicate the directions of the minimum and maximum in situ stresses in the initial stimulation process. Notice that since we are not interested in the near-wellbore flow behaviors, the fluid injection and pumping is modeled using two semicircular boundary curves with a relatively large radius of 2 m, and aligned vertically with $d_v = 500$ m. The 2D domain is then discretized using the quadrilateral elements, most of which are clustered near the injection and production boundaries. This simplification of wellbore geometries can help substantially reduce the total elements of the mesh, and improve the efficiency of solv-

ing. Also notice that the simulated physical quantities at the injection and production boundaries of our computational domain only represent their values near the wellbore, but not right at the wellbores.

Figure 3 The mixed-dimensional geometric configurations and meshes of the EGS model: (a) the initial 2D geometry; (b) the extrusion from 2D to 3D along the direction of wells; (c) the five planar fractures.

In step 2, the 2D planar geometry is extruded in the x -direction for a total horizontal length equal to $4d_h + 2d_{ex}$, with an optional downward deviating angle, $\alpha = 0^\circ$ or 45° (see Figure 3b). The resulting 3D block is then split by a plane normal to the x -direction at locations $x = d_{ex}$ (tagged #1), $d_{ex} + d_h$ (#2), $d_{ex} + 2d_h$ (#3), $d_{ex} + 3d_h$ (#4), and $d_{ex} + 4d_h$ (#5), respectively, as shown in Figure 3c. The d_{ex} is the extra horizontal space beyond the first and last fracture planes, and it has to be wide enough (i.e., $d_{ex} = 60\text{m}$) so as not to let the cooling front reach the far-field boundary at the end of simulations. Thanks to its mixed-dimensional modeling capability, the FALCON code allows zero-thickness planes to represent the fractures surrounded by the 3D matrix blocks. It was shown in Reichenberger et al. 2006 that the use of lower-dimensional fractures in higher-dimensional reservoirs could reduce the computational costs,

and also improve the efficiency of implicit time integration. Finally, 10 and 15 equidistant layers of hexahedral elements are filled for the sub-blocks between each two neighboring fractures, and for the sub-blocks of the extra space beyond the first and last fractures, respectively. Thus a 3D mesh with any combination of d_h and α will result in the same total number of elements (111,160) and points (118,570).

3.4 Boundary Conditions

A number of common boundary conditions (BCs) have been implemented in the FALCON code. Three basic BCs for the mass conservation in Eq. (5) include: a) the Dirichlet pressure BC; b) the Neumann mass flux BC, with which a mass flux normal to the boundary face, $-\mathbf{q}_M \cdot \mathbf{n}$, can be prescribed at the wellbore boundaries; and c) the Neumann free outflow BC, with which the $\mathbf{q}_M$ values at the quadrature points of a boundary face are interpolated from the host boundary element. Likewise, three basic BCs for energy conservation in Eq. (6) include: a) the Dirichlet temperature BC; b) the Neumann heat inflow BC, with which a heat flux normal to a boundary face, $(-K_m \nabla T + T \mathbf{q}_E) \cdot \mathbf{n}$, can be fixed at the injection wellbore boundary; and c) the Neumann heat outflow BC, with which the heat flux $\mathbf{q}_E$ value at the quadrature points of a boundary surface are interpolated from the host boundary element.

For our EGS model depicted in Figure 3, a constant mass flux with fixed re-injection water temperature of 80°C is imposed at each of the five injection boundaries (see Figure 3c). The heat outflow conditions are prescribed at each of the five production boundaries, with a fixed reference fluid pressure of 30 MPa at the #3 production boundary. No-flow boundaries for both fluid and heat (i.e., zero pressure gradient and zero temperature gradient) are imposed at the x-z symmetry plane and at the far-field boundary.

3.5 Reservoir Material Properties

The material properties of a dual-porosity/dual-permeability subsurface environment for our conceptual EGS model are summarized in **Error! Reference source not found.**, where both the fracture planes and

rock matrix blocks are considered as fully-saturated, isotropic, homogeneous porous medium. Notice that in our numerical model, the unity thickness, i.e., 1 m, is used for fracture planes. This indicates that, if one assumes the fracture planes to be 1cm-thick, the actual fracture permeability can be considered as 100 times larger than the input value. In this work, an input value of $0.5 \times 10^{-12} \text{ m}^2$ was chosen for the permeability of the fracture planes. This value was determined based on a detailed sensitivity study of design constraints (Plummer et al. 2016). Noticed that a larger permeability should result in a higher power production rate but also a shorter overall production stage. On the other hand, a smaller permeability might not provide sufficient power production rate as needed. Other properties, such as permeability of the matrix zone, porosity and thermal conductivity, were determined according to the documented data of the Eastern Snake River Plain, Idaho (Blackwell et al. 1992). Recently, Zeng et al. 2013a and Zeng et al. 2013b had systematically investigated optimization of these properties in an EGS. Thus we chose to not further extend this discussion in this work.

Table 1: Material properties used in the test cases

<i>Parameters</i>	<i>Values</i>
Density of the rock	2700 kg/m ³
Density of the fluid	Computed from IAPWS-97
Viscosity of the fluid	Computed from IAPWS-97
Permeability of the matrix zone	$1.0 \times 10^{-20} \text{ m}^2$
Permeability of the fractured zone	$0.5 \times 10^{-12} \text{ m}^2$
Porosity of the matrix zone	0.01
Porosity of the fractured zone	0.1
Specific heat capacity of the matrix zone	790 J/(kg K)
Specific heat capacity of the fluid	4818 J/(kg K)
Medium average thermal conductivity of the matrix zone	3.0 W/(m K)
Medium average thermal conductivity of the fractured zone	1.5 W/(m K)

3.6 Initial Conditions

A steady-state simulation of fluid flow is conducted first, to obtain a pressure distribution with a constant density and viscosity of water evaluated at average reservoir conditions. A time-dependent simulation of the coupled fluid flow and heat transport is then started, where the initial condition (IC) for pressure is taken from the result of the first simulation. A linear distribution of the initial temperature along the z -direction is specified in the field based on $z_{\text{ref}} = 3$ km. The geothermal gradient is specified as 65°C per km of depth, representing the higher end of the range of values measured in the Eastern Snake River Plain (Blackwell et al. 1992). As a result, the initial temperature at $z = z_{\text{ref}}$ is 200°C , and the difference of temperature between the injection and production boundaries in each fractured plane is 32.5°C .

4 NUMERICAL RESULTS

As listed in Table 2, four test cases have been designed with the combinations of three parameters: 1) the fracture horizontal spacing, d_h , 2) the downward deviating angle of the parallel wells, α , and 3) the injection mass flow rate per fracture, $\dot{q}$. Most of the material properties for water and rock have been kept constant, while the density and viscosity of water are treated as functions of pressure and temperature of water, and are calculated using the IAPWS-97 formulation. According to the three geometric scenarios in Table 2, three meshes were generated and used for the simulations, respectively. The injection of cool water is started at time = 0, and terminated after 30 years of operation.

Table 2: Configuration parameters used in the four simulations.

Test Case	d_h (m)	α	$\dot{q}$ (kg/s)
1 (base)	30	0°	3.14
2	50	0°	3.14
3	30	45°	3.14
4	30	45°	6.28

4.1 The Base Case

We chose Test Case 1 ($d_h = 30\text{m}$, $\alpha = 0^\circ$, $\dot{q} = 3.14\text{kg/s}$) as the base case for the initial validation of our conceptual model in terms of some important EGS performance metrics. Notice that in order to determine if grid resolution of the mesh used in this work (111,160 elements and 118,570 points) is sufficient, we carried out a grid dependence study by running the simulation on a uniformly refined mesh (i.e. each hexahedral element was split into eight), and found that in this base case, the key performance metrics (as will be described later) obtained on the refined mesh differed no more than 1.2% from those calculated on the original mesh. Assuming such level of errors from the grid resolution is negligible, we used the original mesh in the rest of the test cases, since it is much cheaper in terms of computational costs.

4.1.1 Production Temperature and Thermal Energy Production Rate

The thermal energy production rate from each fracture plane, Q_{pro} (J/s), can be calculated using the following area integral equation at the production boundary of each fracture plane:

$$Q_{\text{pro}} = \int_{A_b} (T_{\text{pro}} - T_{\text{inj}}) \mathbf{q}_E \cdot \mathbf{n} d\Gamma \quad (7)$$

where $T_{\text{inj}} = 80^\circ\text{C}$ is the temperature of the re-injection fluid, T_{pro} the temperature of the produced fluid that changes with time. We assume that no further electricity power can be produced when T_{pro} drops down below 160°C .

In our numerical model, a complete heat extraction process may be considered to comprise two stages: first a stable (production) stage, and then a declining stage. The stable stage is when T_{pro} stays above or at its initial value measured at the production wellbores. In the stable stage, the thermal energy production can be sustained above its initial rate, and the output electricity power can be steadily transmitted. The declining stage starts when T_{pro} drops below its initial value, and lasts until no electric power can be generated. If we assume only a fraction of the extracted thermal energy can be converted into the useful electric power through a binary plant, and further on a fraction of the generated electric

power can be transmitted to the end consumers, the final effective electric power rate, Q_{eff} , can be approximated as follows,

$$Q_{\text{eff}} = c_{\text{eff}} Q_{\text{pro}} \quad (8)$$

where c_{eff} is an approximate ratio of conversion efficiency. A modest estimation of $c_{\text{eff}} = 10\%$ is used in this present study.

Figure 4 shows the simulated time histories of T_{pro} at the five production boundaries, as well as Q_{eff} over a 30-year operation. At the beginning, T_{pro} rises steadily from the initial value of 183.75°C for about 7 years, until it reaches 192°C. This is because the production wellbore, being shallower than most of the region from which it will draw heat, is initially at relatively low temperature. After pumping begins, the fracture flow paths are heating because of heat exchange with the deepest, and therefore hottest, part of the fracture. Thus, the production well temperature initially increases, until about the end of the 7th year, when the cooling front migrating outward from the injection has effectively reduced the hottest temperature to that of the production well elevation. After that, temperature of the pumped fluid starts to decrease, and drops down below the initial value at the end of 16.5-th year. Accordingly, Q_{eff} stays above the initial 0.136 MW per fracture in the stable stage, with a rise at first and then a decline back to its initial rate. In the declining stage that follows the stable one, T_{pro} continues to drop, finally reaching 160 ~ 170°C at the end of the 30th year. Accordingly, Q_{eff} has decreased to 0.105~0.115 MW per fracture by that time, equal to a ratio of loss by 15.4%~22.8%. Notice that the increasing difference of Q_{eff} between the production boundaries in the declining stage is due to the fracture horizontal spacing of $d_h = 30\text{m}$, which is not wide enough to avoid inter-fracture interference. In addition, it is worth of mentioning that the computational results obtained in this case were validated independently by Plummer et al. 2016 in a comparative study, where a similar problem was setup and simulated using the COMSOL® Multiphysics modeling software.

4.1.2 Spatial Temperature Distribution

Figure 5 shows the evolution of the cooled regions in the reservoir over the 30-years operation, where the cooled regions are highlighted using the solid volume with the lower and upper thresholds as 80°C and 160°C, respectively, indicating the regions that no more effective thermal energy can be further extracted. After the operation begins, the cooled region in each fracture plane grows gradually from the injection boundaries in an annular shape (Figure 5 b-c). During the initial 16.5 years of operation, the annular cooled regions grow steadily, except when the cooling fronts reach the lower end of the fracture-matrix interface. Meanwhile, the thermal energy near the injection wells are extracted first, and the temperature around the production boundaries remains above 183.75°C. From the 17th year on, the outer boundaries of the cooled regions start to bulge out toward the production boundaries quickly (Figure 5 e-f), and the temperature near the production boundaries falls below its initial level, which marks the beginning of the declining stage. It also indicates that the thermal energy near the production boundaries starts being extracted.

4.1.3 Up-scaling and Performance Evaluation

An industrial production-scale EGS requires a significantly larger electric power capacity than that of our five-fracture model. As previously discussed, a well doublet system in a reservoir consisting of large single-wing fractures should contain ~30 to 40 equidistant fractures connecting two 1-km long parallel well sections with a well separation of about 500m; and a system of these dimensions should operate for at least 25 years at a flow rate of 0.1 m³/s, and an electric power output between 5 and 10 MW and pumping power of less than 1 MW (Jung 2013). Aiming to identify similar performance, we up-scaled the five-fracture system based on the least performing fracture #3, and obtained an average Q_{eff} of about 5.6 MW with 40 fractures for a 30-year operation period. The resulting metrics indicate an acceptable level of performance for our conceptual EGS model. Note that the thermal energy production rate may be improved if rock deformation due to thermo-elasticity is considered (McDermott et al. 2006), although

that effect could also lead to the increased short-circuiting, as flow through the cooled regions of the flow system increases preferentially. In general, however, the presented conceptual EGS model can be regarded as reasonable in terms of thermal energy production rate for long-term operations.

4.2 Sensitivity Analysis of Design Constraints on Heat Production

Following the base case, the simulated time histories of T_{pro} and Q_{eff} , as well as the evolution of cooled regions for the other three test cases (as listed in Table 2) are shown in Figure 6 - Figure 11, respectively. Now with the results from these four test cases, it is possible to assess the sensitivity of heat production to the following design parameters in our conceptual EGS model: 1) d_h ; 2) α ; and 3) $\dot{q}$. Since the #3 fracture plane has been observed as the least performing one in each of the four test cases, we have chosen the results obtained from those #3 fracture planes for a comparative study.

4.2.1 Sensitivity to d_h

The sensitivity of heat production to d_h can be assessed by increasing d_h from 30m in Test Case 1 to 50m in Test Case 2, while $\alpha = 0^\circ$ and $\dot{q} = 3.14$ kg/s in both cases. Figure 12 a-d show the dependence of T_{pro} , P_{inj} , Q_{eff} , and cumulative electric power production, $\sum(Q_{eff}\Delta t)$, on d_h , respectively, where Q_{eff} and $\sum(Q_{eff}\Delta t)$ are multiplied by an upscale factor of 40 to measure the performance of a full-scale model containing 40 of such fractures. As seen in Figure 12a, the stable stage in Test Case 2 lasts 22.5 years – 6 years longer than that in Test Case 1. Noticeably, T_{pro} reaches the peak value of 192°C in both cases at the 7th year, but declines faster in Test Case 1 since the 8th year, because of the earlier occurrence of the inter-fracture interference (see Figure 5d). The T_{pro} in the #3 fracture has dropped 13°C in Test Case 1 (Figure 4a). In comparison, the inter-fracture interference in Test Case 2 is very weak, as the T_{pro} in the #3 fracture is only 4°C lower than that of the best performing fracture at the end of the 30th year (Figure 6a). This leads to a difference in the up-scaled $\sum(Q_{eff}\Delta t)$ by 125×10^6 kWh after 30-years (Figure

12d). Besides, the total increase of P_{inj} in Test Case 2 is 25% lower than that in Test Case 1 (Figure 12b), indicating the slightly lower impedance for water reinjection and thus higher system efficiency.

The above analysis indicates that d_h is an important design constraint in our conceptual EGS model. Though the inter-fracture interference could be completely avoided during the EGS lifetime given a sufficiently large d_h , it might require substantially more capital investment for the horizontal well drilling process. For example, the distance for horizontal drilling will be more than 2km if d_h is 50m and N_{frac} is 40, which may not be economically feasible at all. Besides, the choice of d_h is tied to other constraints, for example, the vertical distance between the injection and production wells, d_v . Li & Lior 2015 have demonstrated a conceptual EGS reservoir similar to ours in terms of the layout of wells and fractures: five large fracture planes with $d_v = 1\text{km}$ and $d_h = 120\text{ m}$. The scales of the fractures involved in such models emphasizes certain difficulties of construction, including that of creating such large fractures, with $d_v/d_h \sim 10:1$, without fracturing the rock matrix between the fractures; in addition to the difficulty of consistently creating such large fractures in the desired locations.

4.2.2 Sensitivity to α

The sensitivity of heat production to α can be assessed by changing α from 0° in Test Case 1 to 45° in Test Case 3, while $d_h = 30\text{m}$ and $\dot{q} = 3.14\text{kg/s}$ in both cases. Figure 13a-d show the dependence of T_{pro} , P_{inj} , Q_{eff} , and $\sum(Q_{eff}\Delta t)$, on α , respectively. Again, Q_{eff} and $\sum(Q_{eff}\Delta t)$ are both upscaled by a factor of 40 to indicate the performance of a full-scale model that contains 40 of such fractures. The change of α has led to no major variation in the time histories of performance metrics, except for some slight difference in the evolutions of T_{pro} and Q_{eff} . This has confirmed that the average impact of inter-fracture interference to the #3 fracture plane in Test Case 3 is close to that in Test Case 1, no matter what α is. As is well known, a major geotechnical challenge for deep borehole drilling is how to efficiently overcome the increasing in situ stress along the vertical direction. In reality, it may not be always possible to drill straight vertical to reach the designed underground depth and desirable reservoir temperature, considering the

uncertainties of actual distribution of reservoir physical properties. Therefore, on one side, a well layout such as in Test Case 3 might relief some geotechnical difficulties for well drilling. But on the other side, longer drilling distance is required for creating the same horizontal fracture spacing, which indicates higher costs. To conclude, though potential advantages of the well layout design in Test Case 3 may not be reflected through hydrothermal simulations, yet α is an important practical design. Further questions such as whether or not to choose a typical downward deviating angle α , or even a variable α at different ranges of depth, vary case by case. To guide a well layout design in a realistic EGS system, sufficient in situ stress data are required to model the creation of wells for determining a proper choice of α .

4.2.3 Sensitivity to $\dot{q}$

The sensitivity of heat production to $\dot{q}$ can be assessed by raising $\dot{q}$ from 3.14kg/s in Test Case 3 to 6.28kg/s in Test Case 4, while $d_h = 30\text{m}$ and $\alpha = 45^\circ$ in both cases. Figure 14a-d show the dependence of T_{pro} , P_{inj} , Q_{eff} , and $\Sigma(Q_{\text{eff}}\Delta t)$ on $\dot{q}$, respectively. With the injection mass flow rate doubled in Test Case 4, the stable production stage is able to last for only 5.5 years, due to the early thermal breakthrough as observed: T_{pro} drops quickly since the 6th year of operation, and the production life is over at the end of the 17th year (see Figure 14a-b). By comparing Test Case 3 with Test Case 4, it has been clearly shown that a higher $\dot{q}$ may lead to a higher Q_{eff} during the early period of production, but may also result in a significantly shortened stable production stage and total lifespan of the EGS site if $\dot{q}$ is too high. Moreover, the average increment of P_{inj} over the production life in Test Case 4 is over four times higher than that in Test Case 3 (see Figure 14d), indicating a substantial increase of the required power for the water reinjection process. Indeed, a long lasting stable level of Q_{eff} as well as the other metrics is more preferable for operation and management of the power plant. Therefore, despite the doubled Q_{eff} for the initial few years of production, the simulated history of EGS performance in Test Case 4 is rather unfavorable, because of the overly shortened stable production stage and total lifespan. As analyzed above, the choice of $\dot{q}$ has profound impact on the output electric power rate and lifespan of the EGS. An optimal $\dot{q}$

1 depends on various factors, such as the desired Q_{eff} , production lifetime, and the cost of electric power
2 for reinjection and pumping. From the perspective of numerical modeling, sufficient time will be possi-
3 ble for hot fractured reservoir to heat the circulating water and T_{pro} could stay in the stable production
4 stage over an entire lifetime of an EGS site, when $\dot{q}$ is under a reasonable condition. To achieve such an
5 ideal conceptual EGS model, probably some EGS parameters have to be assumed as extremely favora-
6 ble, e.g., $d_v = 1\text{km}$ (Li & Lior 2015). However, as discussed in Section 4.2.1, it has yet to be investigated
7 whether those parameters are ever realistic.

8

Figure 4 Time histories of (a) the produced fluid temperature from the five production boundaries and (b) the corresponding effective electric power rates for Case 1 ($d_h = 30\text{m}$, $\alpha = 0^\circ$, $\dot{q} = 3.14\text{kg/s}$).

Figure 5 Evolution of the cooled regions in the reservoir for Case 1 ($d_h = 30\text{m}$, $\alpha = 0^\circ$, $\dot{q} = 3.14\text{kg/s}$).

Figure 6 Time histories of (a) the produced fluid temperature from the five production boundaries and (b) the corresponding effective electric power rates for Case 2 ($d_h = 50\text{m}$, $\alpha = 0^\circ$, $\dot{q} = 3.14\text{kg/s}$).

Figure 7 Evolution of the low-temperature regions in the reservoir for Case 2 ($d_h = 50\text{m}$, $\alpha = 0^\circ$, $\dot{q} = 3.14\text{kg/s}$).

Figure 8 Time histories of (a) the produced fluid temperature from the five production boundaries and (b) the corresponding effective electric power rates for Case 3 ($d_h = 30\text{m}$, $\alpha = 45^\circ$, $\dot{q} = 3.14\text{kg/s}$).

Figure 9 Evolution of the cooler regions in the reservoir for Case 3 ($d_h = 30\text{m}$, $\alpha = 45^\circ$, $\dot{q} = 3.14\text{kg/s}$).

Figure 10 Time histories of (a) the produced fluid temperature from the five production boundaries and (b) the corresponding effective electric power rates for Case 4 ($d_h = 30\text{m}$, $\alpha = 45^\circ$, $\dot{q} = 6.28\text{kg/s}$).

Figure 11 Evolution of the cooled regions in the reservoir for Case 4 ($d_h = 30\text{m}$, $\alpha = 45^\circ$, $\dot{q} = 6.28\text{kg/s}$).

Figure 12. Comparison of the performance metrics of a 30-year EGS heat extraction process with respect to d_h , with $\alpha = 0^\circ$ and $\dot{q} = 3.14\text{kg/s}$ per fracture in both Test Case 1 and 2.

Figure 13. Comparison of the performance metrics of a 30-year EGS heat extraction process with respect to α , with $d_h = 30\text{m}$ and $\dot{q} = 3.14\text{kg/s}$ per fracture in both Test Case 1 and 3.

Figure 14. Comparison of the performance metrics of a 30-year EGS heat extraction process with respect to $\dot{q}$ (per fracture), with $d_h = 30\text{m}$ and $\alpha = 45^\circ$ in both Test Case 3 and 4.

5 CONCLUSIONS

This work has presented the design, modeling, and evaluation of heat extraction based on a set of doublet well layout schemes in a conceptual enhanced geothermal system. A hydrothermal model that fully couples the fluid flow and heat transport has been used to model the water circulation and heat extraction process in fractured reservoirs. Apart from the horizontal and parallel well layout often seen in literature, an alternative layout with a downward deviating angle has been considered in this work. These conceptual models were simulated using a newly developed, open-source, finite-element based geothermal reservoir simulation code, FALCON. Simulation results of a 30-year operation at a depth of 3km and geothermal gradient of 65°C per km of depth have been presented. The main contribution of the work is that the developed well layout schemes as well as the EGS heat extraction models have been quantitatively verified and validated for a potential objective of industrial production-level heat production, though further revision and calibration of the models will always be required upon more field data being collected. In particular, the preferable well layout design parameters as well as the material properties suggested in this work match well with those suggested by others (i.e., Jung 2013), indicating the general applicability of our conceptual models.

In addition, from the sensitivity study of the heat production to the equidistant horizontal spacing between the large single wing fractures, d_h , the downward deviating angle for parallel doublet wells, α , and the injection mass flow rate per fracture, $\dot{q}$, we have found that:

- 1) The inter-fracture interference is sensitive to the choice of d_h , and the long-term performance of heat production may be significantly undermined if d_h is too small. Though the inter-fracture interference could be minimized conceptually by setting d_h large enough, yet it may usually cost substantially more for horizontal well drilling than it could probably pay back by eliminating such the inter-fracture interference (e.g., when d_h has to be at least about 120 m as found in Li & Lior

2015). Thus regarding the capital investment, the inter-fracture interference does not have to be necessarily avoided when designing the d_h in practice.

2) Long-term EGS performance is practically insensitive to choice of α , if the initial average temperature of the fractured reservoir is the same. Nevertheless, a well layout with a downward deviating angle may be considered in practice, as it is not economical or possible for the initial vertical drilling to reach a desirable depth and production temperature directly, due to the uncertain in situ stress. Therefore upon the field data from preliminary drilling test, a deviating angle of the wells may be determined to avoid drilling along the direction of maximum in situ stress. The α in our conceptual model as well as the material properties could be adjusted to accommodate the specific subsurface environment for simulation and evaluation.

3) All of the key EGS performance metrics are sensitive to $\dot{q}$. In practice, an optimal $\dot{q}$ for the best long-term EGS operation depends on many important reservoir conditions, such as the fracture permeability, and the spatial extend of fractures. A proper $\dot{q}$ not only helps avoid early thermal drawdown, but also leads to an economically favorable average increment of P_{inj} during the operation so as to reduce the electric power for water re-injection.

Finally, we would like to note that the study of EGS is yet at a young stage despite the R&D efforts over the past 30 years. As no EGS project has been economically successful at the industrial production level, there is still a long way before EGS energy could be demonstrated as a stable source of renewable energy. So far as the EGS conceptual design is concerned, we would caution that without considering the plausible geo-techniques that may be employed to create the desirable fractures, it will still be very difficult to prove the feasibility of even a numerically verified & validated EGS heat production model. Aiming to further enhance our understanding of the EGS systems, our future study will be focused on the coupled thermo-hydro-mechanical processes that include the fracture creation and propagation.

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