# Stress-coupled simulation for fluid flow in fracture, matrix and across the interface in geothermal environment.

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*Abstract:* - This paper presents an innovative method to simulate fluid flow in fractured geothermal reservoirs. The geothermal reservoirs are considered at their full complexity, with variably oriented and intersected fractures with different sizes and irregular patterns. Fluid flows inside the matrix, fractures and fluid interactions between matrix and fractures are also taken into account. A boundary element method with periodic boundary conditions is used to calculate the permeability tensor in cells of jointed and fractured rock. A flux continuous model is used to implement the derived set of tensor in a finite volume simulation of the fluid flow, to estimate water production from the reservoirs. The finite element simulation is coupled and repeated for multiple time steps (unsteady state to quantify the effect of field stresses on the fluid flow and reservoir pressures. This integrated method is validated against results from analytical analyses. It is shown to balance the representation of physical complexity of the coupled processes with the need to avoid representing the complete set of discrete fractures in the problem domain, dramatically advancing the current state-of-the-art in the simulation of fluid flow through reservoirs with discrete fracture networks.

*Key-Words:* - Flow simulation, Discrete fracture network, Unsteady state, Field stress.

## 1 Introduction

Geothermal resources, exploited as heat from rocks at temperatures above 150°C and a few kilometres below the earth's surface, are one of the few safe, virtually pollution free and almost inexhaustible energy resources (Fig. 1) [1]. Geothermal reservoirs typically contain extensive (natural and/or artificial) fracture system. The common approach to extracting energy/heat from geothermal reservoirs generally requires drilling two or more wells into a high-temperature formation. Cold water is injected down one well, forced through the system of rock matrix and fractures, where it picks up heat. Hot water flows up the production wells to the surface power plant. Upon cooling, the water is pumped back down the injection wells in a closed re-circulation system, minimizing environmental impacts while increasing efficiency (Fig. 2). The development of a geothermal reservoir is generally divided into three areas [1]:

1. Reservoir characterisation: What are the properties of the rock and fracture system?
2. Reservoir simulation - fluid flow: How does the water flow through the fractured rock?
3. Reservoir simulation - heat transfer: How is heat transferred from the rock mass to the water?

Fluid flow simulation study is critical for developing geothermal reservoirs because it is the only means to determine many fundamental parameters: pressure drop near the boreholes, where fluid flux is high; pressure drop across the reservoir; circulating pump energy requirements; and potential fluid loss. It also allows us to identify the best locations and patterns of wells; assess responses of natural fractures under stimulation pressure, hence, develop the best hydraulic fracture treatments; carry out feasibility studies; design optimum production methods and improve reservoir potentials.

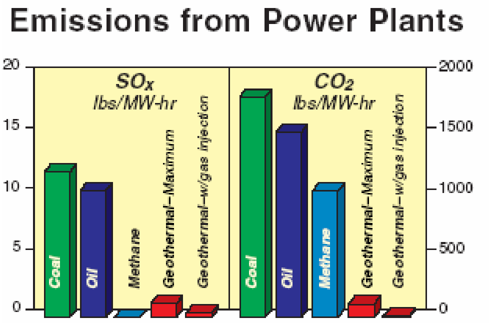

**Fig. 1:** Comparison of emissions from major energy sources: exceptionally low from geothermal sources [1].

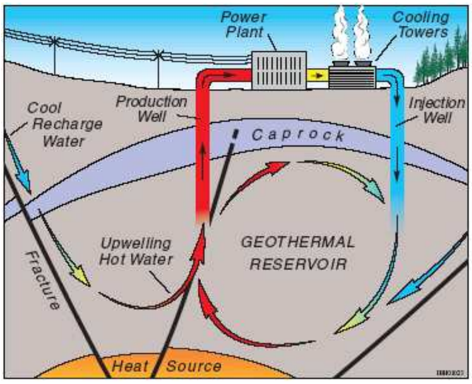

**Fig. 2:** A geothermal injection-production [1].

However, fluid flow simulation through fractured porous media is a complicated process. Because of the existence of natural and artificial fracture networks, geothermal reservoirs are typically highly complex. Fractures occur at a variety of scales (typically ranging from a few centimetres to a few kilometres) and of high degree of heterogeneity (various orientations, storage and flow capacities). In addition, fractures are not evenly distributed in the reservoir, such that the fracture network's spatial distribution and connectivity are extremely nonlinear. Therefore, modelling accurate fracture distribution and understanding fluid flow through the fracture system have always been a massive, challenging and ongoing task [2]. Moreover, rock matrix does contribute to fluid flow and storage, through its considerable permeability and porosity. The inter-flow between the rock matrix and fracture interfaces also need to be studied [3]. To add complexity to the matter, fracture properties are strongly related to field stresses [4], which continually change during the course of production. For example, an experimental work shows that there is 20% or more reduction in permeability due to stresses [5]. All of these complications make the problem difficult to solve numerically (too many unknowns result in massive equations).

Many geothermal projects have not been successful due to general lack of in-depth quantitative approaches to description and characterisation of the highly complicated rock and fracture systems as well as over-simplistic approaches in analysing fluid flows.

## 2 Literature review

Previous studies on fluid flow mechanism in fractured media may be divided into single continuum, dual continuum and discrete approaches.

First, in the single continuum approaches, fractured medium is represented by an equivalent porous medium. Bulk macroscopic values of the fractured medium are defined by averaging point-to-point variations in the petrophysical properties over a representative volume [6].

Second, in the dual continuum approaches, fractures and matrix are represented by two interacting continua, where the fractures provide permeability and the matrix provides storage capacity. Fractures are assumed to be infinitely long and distributed in a regular pattern [2]. Despite being effectively simple, both the single and dual continuum approaches are not suitable for the highly heterogeneous geothermal reservoirs. Properties of fractures such as geometry and orientation are not considered. Heterogeneity of the fractured reservoir is represented by their averaged properties and as a result, individual fractures are not treated explicitly.

Third, the more advanced discrete fracture approaches consider real fracture geometry and focus on fracture permeability. In general, each fracture and the matrix are discretized by a mesh system. Equations for fluid flow from one mesh to another are developed and subsequently solved by both analytically exact and approximated methods, e.g. boundary element method [7], finite element method [8] and finite volume method [9]. Despite their superiority over the continuum methods, the discrete approaches have an inherent disadvantage of requiring extremely high computational resource. This limits their uses either to a small area within a reservoir or to reservoirs of low fracture density, especially if the problem is expanded from one-phase to multi-phase flow. There are also hybrid approaches, where effective permeability tensor is introduced as an effective way to represent permeability in fractured formations [10, 11]. It is assumed that a grid-block with fractures can be replaced by a homogeneous grid-block having an equivalent permeability tensor taking into account geometry of the actual fracture systems. However, the previous effective permeability tensor approaches are based on simplistic assumptions on fracture distribution inside the matrix or simplistic assumptions on interactions of fluid flow between the matrix and fractures, such as parallel and uniform fracture distributions [6], no flow in matrix [12] and no flow interactions between matrix and fractures [10]. In some other numerical techniques [13], small and medium fractures are hierarchically modelled without considering the effects of larger fractures. Application of these models to large-scaled reservoirs is restricted by the extensive computational demands. In addition, the approaches have a common drawback that fluid flow can only take place through a network of connected fractures where flow through the matrix and isolated fractures is ignored. Although there have been considerable contributions to fluid flow in general fractured media, similar studies in geothermal reservoirs are very limited. In most geothermal developments, conventional reservoir simulators are used, where the previously outlined problems remain.

## 3 Methodology

This paper addresses the second area of Reservoir simulation – fluid flow, covering two important sub-aspects: (1) water flow through the system of rock matrix, interconnected fractures and inter-flow across matrix-fracture interfaces; and (2) fully-coupled for stress effects.

In this paper, variably oriented and intersected fractures with different sizes and irregular patterns (i.e. all fracture complexities) are considered. The fully-complex discrete fracture networks (DFN) are directly adopted from the authors' published methods [14-16]. Fluid flows inside the matrix, fractures and fluid interactions between matrix and fractures are also taken into account. A boundary element method with periodic boundary conditions is used to calculate the permeability tensor in cells of jointed and fractured rock. We propose to formulate a flux continuous model, implementing the derived set of tensor in a finite volume simulation of the fluid flow, to estimate water production from fractured geothermal reservoirs. The simulation is coupled and repeated for multiple time steps, quantifying the effect of field stresses and reservoir pressures on the fluid flow. This integrated approach balances the representation of physical complexity of the coupled processes with the need to avoid representing the complete discretization.

### 3.1 Fluid flow in the fracture, the matrix and across the interface

Effective permeability tensor is the basis of the proposed method to consider fluid flow inside the matrix, inside fractures and between matrix and fracture interfaces. Effective permeability is described as a full tensor that relates the average pressure gradient $\nabla P$ to the average fluid velocity V as $V = -K\nabla P$. Matrix $K$ represents the local permeability tensor, describing the cumulative directional effects of a set of fractures on fluid flow.

The governing equations for flow in fractures and matrix in a two-dimensional reservoir are expressed as in eqs. 1 and 2 [7, 10, 11], where $h$ is fracture aperture (eq. 3), $L$ is one-dimensional coordinate and subscripts $m$ and $f$ represent matrix and fracture, respectively. Term $Q$ represents the flow interaction between fractures and rock matrix. $qff$ represents fluid flow from all intersected fractures to a fracture $i$ at the lines of intersection.

Fracture: $$k_f \frac{\partial^2 p_i}{\partial L^2} + Q_i + q_{ff} = 0 \qquad (1)$$

Matrix: $$k_m \frac{\partial^2 p_m}{\partial x^2} + k_m \frac{\partial^2 p_m}{\partial y^2} + Q_i = 0 \qquad (2)$$

$$k_f = 7.842\times10^{12}.h^2 \qquad (3)$$

We employ the boundary element method with periodic boundary conditions to solve the fluid flow equations and calculate permeability tensor in each grid block. We present the coupling of fracture and the surrounding matrix (interface effects) using the Poisson's equation as in eq. 4. Fluid flow in the rest of the rock matrix is simulated by the Laplace's equation as in eq. 5.

$$c(\xi)p(\xi) + \sum_{j=1}^{NS} \int_{S_j} F(x,\xi)p(x)ds(x) = \sum_{j=1}^{NS} \int_{S_j} G(x,\xi)v(x)ds(x)) \qquad (4)$$

$$c(\xi)p(\xi) + \sum_{j=1}^{NS} \int_{S_j} F(x,\xi)p(x)ds(x) = \sum_{j=1}^{NS} \int_{S_j} G(x,\xi)v(x)ds(x) + \sum_{i=1}^{NC} \int_{A_i} Q(x)G(x,\xi)dA_i(x) \qquad (5)$$

In general, the proposed model represents the fracture-matrix system by an effective permeability tensor that permits the inclusion of realistic DFN features into a continuum model, significantly improving the computational efficiency. It also innovatively accounts for flow coupling between the fracture and matrix systems: flow inside the matrix and fractures as well as at the matrix-fracture interfaces. We also treat short and medium-long fractures separately, which brings about another key advantage of this approach as it is possible to discretize the region surrounding medium and long fractures, instead of the whole block. Different fluid flow governing equations can be used in different regions, significantly reducing computation time and numerical errors. Thus, shortfall of the previous models are overcome that fluid flow simulation in large-scaled reservoirs with high fracture density is now obtainable.

By implementing the effective permeability tensor, a flux continuous model is formulated using finite volume element methods. In the flux continuous model, the pressure equations [7, 11], expressed as two coupled partial differential equations for pressure and velocity (eqs. 6 and 7), are solved simultaneously. This minimizes the numerical errors in standard methods that are normally caused by differentiation of pressure and then by multiplication by rough coefficients.

$$\int_{\Omega} \mu K^{-1} v.w d\Omega - \int_{\Omega} \nabla p.w d\Omega = -< w.n, q > \partial\Omega \qquad (6)$$

$$\int_{\Omega} \nabla.vz dx = \int_{\Omega} qz dx \qquad (7)$$

Solutions of the simulation include flow rate through each grid block, field-wise pressure distribution, as well as the overall injection and production rates.

## 3.2 Stress coupling

Field stresses can be divided into natural and induced, according to their origin. Natural stresses exist in the rock prior to any artificial disturbance. This stress state is the result of various events in the geological history of the rock mass. It is due to gravitational (overburden), tectonic, residual and thermal forces. Tectonic stresses are important, yet difficult to predict in regard to direction and magnitude. Residual stresses can be identified by strain recovery measurements on samples of different sizes and x-ray analysis. Induced stresses are those perturbed by engineering, e.g. drilling and water injection/ production.

It is understood that field stresses have strong effects on many formation rock and fracture properties, e.g. matrix porosity and permeability, fracture aperture, porosity and permeability. There have been mathematical models [4, 17] and experimental works [5, 18] proving that effect of stress be very high, and could even rotate and change the magnitudes of principal permeability. While it is relatively simple to determine how matrix porosity changes under external/internal stresses (e.g. by using formation compressibility), the effect of stresses on permeability is more complex. It depends on the type of rock, pore geometry, channeling effect, hysteresis effect, geometric factor, shear dilation and normal closure [4, 19].

Through the course of simulation, fluid pressure and field stresses keep changing. Due to the complexity, it is essential to use coupled simulators to account for the effects of stresses on fluid flow, especially for highly deformable reservoirs [20]. In our simulation, since the effect of stresses on key reservoir properties are now known, the properties are updated at each simulation time step (Fig. 3).

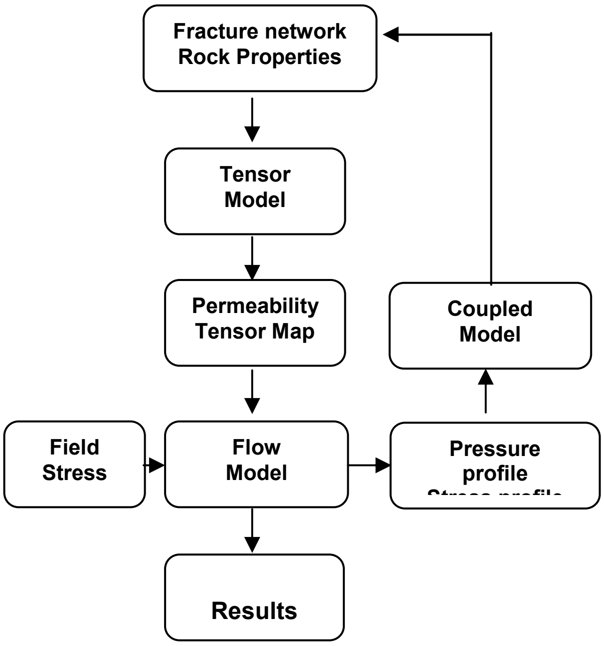

**Fig. 3:** Coupled simulation for stress-dependent DFN.

For matrix porosity [21]:

$$\Delta\phi_{i+1,m} = (1+\varepsilon_v)\phi_{i,m} \qquad (8)$$

Where $\varepsilon_v$ is the volumetric strain, $\phi_{i,m}$ is the porosity of previous time step $i$. The change in fracture porosity can be calculated via changes in bulk volume $V_b$, using exact method [21]:

$$V_b = (1+\varepsilon_v)V_{bi} \qquad (9)$$

Where $V_{bi}$ is the initial bulk volume.

Fracture permeability is calculated using cubic law, taking into account the friction factor $f$, which has major impact on flow through fracture [22] yet is mostly ignored in previous models [17, 23].

$$k_f = f\frac{h^2}{12} \qquad (10)$$

Where h is fracture aperture.

Fracture aperture also needs to be updated. A generalized equation is proposed to calculate the effect of stress in arbitrary oriented fractures, where the stress effect depends not only on the effective stress but also on the length of the fracture $l_{fi}$:

$$\Delta h = \frac{A_r \varepsilon_v}{\sum l_{fi}} \qquad (11)$$

Where $A_r$ (total area of the reservoir). The equation can be applied to any type of fracture networks with an assumption that all the fractures respond equally to the applied stress irrespective of the properties of surrounding rock.

Not only fracture and reservoir properties are updated for effects of field stresses, the equations to be used in flow simulation model are also updated. The balance of fluid momentum equation is:

$$\nabla\left(\frac{\vec{k}}{\mu}\nabla p\right) = \phi c_T \frac{D_s p}{Dt} + q \qquad (12)$$

The poroelastic equations for relationship between strain ($\varepsilon$), stress ($\sigma$) is:

$$E\varepsilon_x = \sigma_x - \alpha P \qquad (13)$$

$$E\varepsilon_y = \sigma_y - \alpha P \qquad (14)$$

Where $\alpha, P$ represents Biot's coefficient and pore pressure. Thus, field stress profile is updated at each time step.

As a result of the coupled simulation, the effective permeability tensor map and fluid flow model are more accurate, as they now take into consideration the important effect of pressure and stress changes through production. Results of the simulation include flow rate through each grid block, field-wise pressure distribution, as well as the overall injection and production rates.

## 4 Case Study

A case study is constructed to compare and validate the results. A reservoir of DFN is simulated, through three models: tensor, flow simulation and coupled (Fig. 3). There are one injection and one production wells, at two diagonally-opposite ends. For the purpose of validating with analytical solution, the reservoir is kept homogeneous (in terms of matrix porosity and matrix permeability), with constant water injection pressure. Full details of the reservoir properties are given in the Table 1 and of the rock in Table 2. The result of flow simulation is validated against analytical solution for steady state conditions, showing great match (Fig. 4). Other results are also available. The permeability tensor map is presented in Fig. 5 and the final pressure distribution profile is presented in Fig. 6.

| | |
|---|---|
| Reservoir Size | 50m,50m |
| Far field stresses | 15.8E+6,16.8E+6 |
| Flow rate | 100 RB/DAY |
| Fluid viscosity | 0.1cp |
| Initial Reservoir Pressure | 1611.11psi |
| Averaged fracture aperture | 0.001m |

**Table 1:** Reservoir properties.

| | |
|---|---|
| Matrix permeability | 1 md |
| Matrix porosity | 0.01 |
| Compressibility | 0.45Gpa |
| Poission's ratio | 0.333 |
| Modulus of elasticity | 7.00E+10 |

**Table 2:** Rock properties.

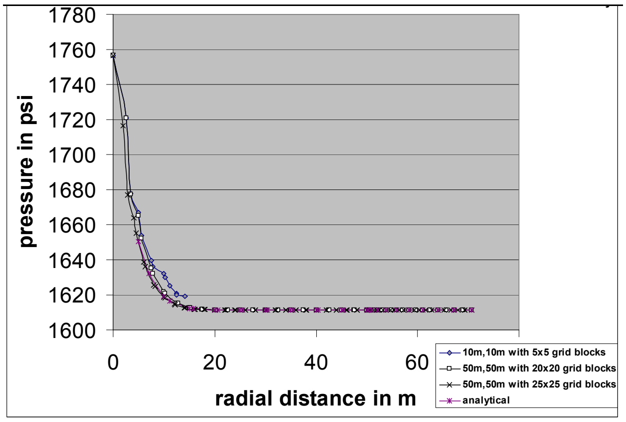

**Fig.4.** Flow model validation: great match.

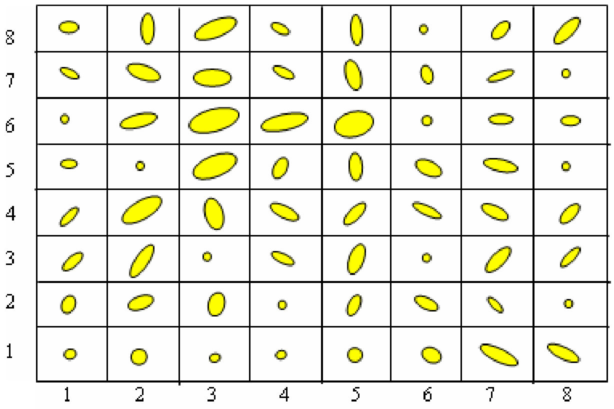

**Fig.5.** Permeability tensor map.

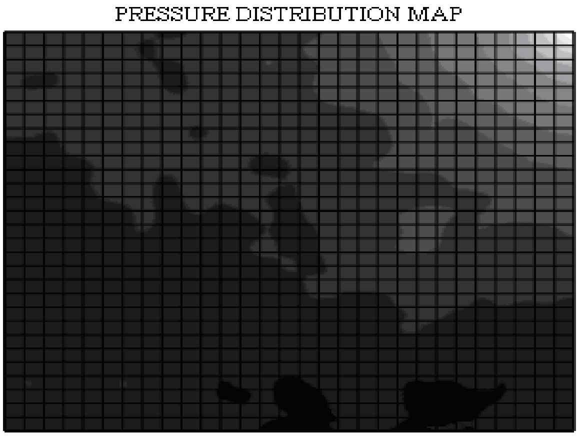

**Fig.6.** Result pressure distribution map. The injection well is at the NE end, the production well is at SW end. The pressure variation is due to the fracture distribution.

## 5 Conclusion

This paper presents an innovative method to simulate fluid flow in fractured geothermal reservoirs. The geothermal reservoirs are considered at their full complexity, with variably oriented and intersected fractures with different sizes and irregular patterns. Fluid flows inside the matrix, fractures and fluid interactions between matrix and fractures are also taken into account. Effects of stress are also accounted for, via a coupled simulation. The results are validated against analytical solution. They show it is possible to avoid representing the complete set of discrete fractures in the problem domain, dramatically advancing the current status in the simulation of fluid flow through reservoirs with discrete fracture networks.

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