Coupled Fluid Flow Through Discrete Fracture Network: A Novel approach

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Abstract— In this paper, key difficulties of a modeling and simulation of naturally fractured reservoirs are discussed. They are discrete fractures of variably oriented and intersected fractures with different sizes and irregular patterns; flow interaction between matrix and fracture; effect of field stresses on the fluid flow. A coupled simulation approach is presented, which is consisted of high level boundary element method with periodic boundary conditions and flux continuous finite volume element method. The simulation approach is validated analytical results and further illustrated through a series of sensitivity analyses.

Keywords—Coupled simulation, fractured reservoir, boundary element method, finite element method

I. INTRODUCTION

NATURALLY fractured reservoirs are highly heterogeneous and commonly occur in nature. A comprehensive reservoir characterization and reliable fluid flow simulation model is necessary for development of these reservoirs. This study allows us to estimate production forecasting, the pressure drop around the wells, potential fluid loss, well location and well spacing. It also allows us to assess response of natural fractures under stimulation pressure for hydraulic fracture optimization.

Simulation of Fluid flow provides quantitative estimation of flow and transport behavior of the fracture system. However, fluid flow through fractured porous media is a complicated process as fractures occur at a variety of scales (typically ranging from a few centimeters to a few kilometers) 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, fracture characterization and fluid flow through fracture system has always been a difficult task. [1]. Moreover, flow through matrix to matrix, fracture to fracture and fracture to matrix has to be studied [2]. To add complexity to the matter, stress sensitive rock properties continually change during the course of production [3]. For example, an experimental work shows that there is 20% or more reduction in permeability due to stresses [4]. All of these complications make the problem difficult to solve numerically.

Previous fluid flow simulation models can be divided into continuum and discrete approaches. Continuum approach is further divided into single continuum and dual continuum 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 [5].

Second, in the dual continuum approaches, reservoir rock is represented as uniform matrix blocks separated by fractures, where the fractures provide permeability for fluid flow. Fractures are assumed to be infinitely long and distributed in a regular pattern [1]. Despite being effectively simple, both the single and dual continuum approaches are not suitable for the highly heterogeneous 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 discrete fracture approach considers real fracture geometry and focus on flow through fractures. In general, fractures system is discretized by a mesh system. Equations for fluid flow from one developed and subsequently solved by both analytically exact and approximated methods, e.g. boundary element method [6], finite element method [7] and finite volume method [8]. 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. The problem gets more complicated for multiphase flow.

There are also some hybrid approaches, where effective permeability tensor is introduced as an effective way to represent permeability in fractured formations [9, 10]. It is assumed that a grid-block with fractures can be replaced by a homogeneous grid-block having similar fluid flow properties of the actual fracture systems. However, the previous effective permeability tensor approaches are based on simplistic assumptions on interactions of fluid flow between the matrix and fractures, such as ignoring flow through intersecting fractures [5], no flow in matrix [11] and no flow interactions between matrix and fractures [9]. In some other numerical techniques [12], small and medium fractures are hierarchically modelled without considering the effects of larger fractures. These 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. Application of these models to large-scaled reservoirs is restricted by its limitations.

II. PROBLEM FORMULATION

The objective of this paper is to investigate two important aspects of fluid flow simulation: (1) fluid flow through the rock matrix, interconnected fractures and inter-flow across matrix and fracture interfaces; and (2) production induced stress effect on fluid flow.

Full fracture complexity (variably oriented and intersected fractures with different sizes and irregular patterns) is considered. The discrete fracture networks (DFN) are directly adopted from the authors' published methods [13-15]. 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 proposed to implement the derived set of permeability tensor in a finite volume simulation of the fluid flow, to production forecasting from naturally fractured reservoirs. The simulation is coupled and repeated for multiple time steps, quantifying the effect of production induced stress on the fluid flow. Please submit your manuscript electronically for review as e-mail attachments.

A. Flow through fracture network

Effective grid block permeability tensor concept is the basis of the proposed method. In this work, grid block permeability tensor is modified to consider fluid flow inside the matrix, inside fractures and between matrix and fracture interfaces. Fluid flow through intersected fractures is one of the novelties of this approach.

Generally effective permeability is described as a full tensor that relates the average pressure gradient ∇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. [6, 9, 10], 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: (1)
$$k_f \frac{\partial^2 p_i}{\partial L^2} + Q_i + q_{ff} = 0$$

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

$$k_f = 7.842 \times 10^{12} . h^2 \qquad (3)$$

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 [6, 10], 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.

B.Stress coupling

Natural fractured reservoir reservoirs are greatly influenced by geomechanical behavior of rocks. This stress sensitivity of the rock have great impact on matrix permeability, fracture permeability, matrix porosity, fracture porosity and fracture aperture. Ignoring such production induced stress will lead to inaccurate production estimation.

There have been mathematical models [3, 16] and experimental works [4, 17] 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 [3, 18].

Through the course of simulation, fluid pressure and the effective stress keep changing. The change in effective stress is calculated based on the following poroelastic equations for strain (ε), stress (σ):

$$E\varepsilon_x = \sigma_x - \alpha P \qquad (8)$$

$$E\varepsilon_y = \sigma_y - \alpha P \qquad (9)$$

where α, P represents Biot's coefficient and pore pressure. Thus, field stress profile is updated at each time step.

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 [19]. 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. 1).

For matrix porosity [20]:

$$\Delta\phi_{i+1,m} = (1+\varepsilon_v)\phi_{i,m} \qquad (10)$$

Where ε_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 [20]:

$$V_b = (1+\varepsilon_v)V_{bi} \qquad (11)$$

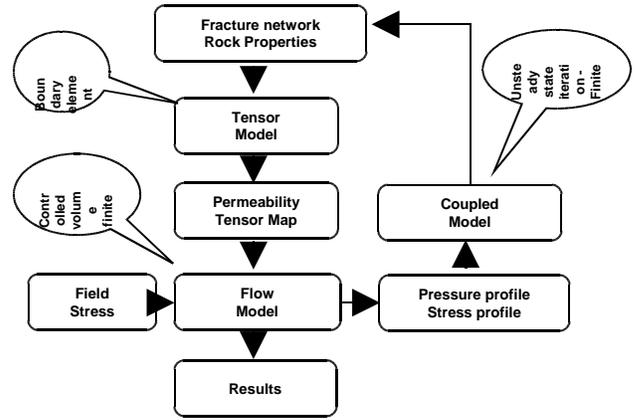Where V_{bi} is the initial bulk volume.

Fig. 1: Coupled simulation for stress-dependent DFN.

Fracture permeability is calculated using cubic law, taking into account the friction factor f, which has major impact on flow through fracture [21] yet is mostly ignored in previous models [16, 22].

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

where h is fracture aperture. Fracture permeability is treated dynamically based on its fracture aperture, which is calculated based on Eqn 11.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 production induced stress. Results of the simulation include flow rate through each grid block, field-wise pressure distribution, as well as the overall injection and production rates.

III.RESULTS AND DISCUSSION

Two case studies are constructed one to validate and other one to simulate fluid flow at field scale. In the first, a fluid flow simulation is performed on a homogeneous reservoir with a constant bottom hole pressure. Full details of the reservoir properties are given in the Table 1 and of the rock in Table 2. Pressure profile after 2 years is compared with analytical solution, showing a great match (Fig. 2).
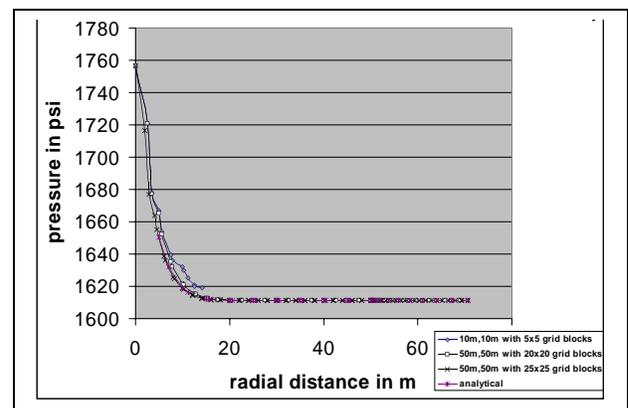

Fig.2. Flow model validation: great match.

In the second case study, a reservoir of DFN is simulated,

through three models: tensor, flow simulation and coupled (Fig. 1). The injection well is placed at the NE end, the production well is at SW end as shown in Fig. 3. The permeability tensor map is generated by tensor model is presented in Fig. 4 and the final pressure distribution profile is presented in Fig. 5.
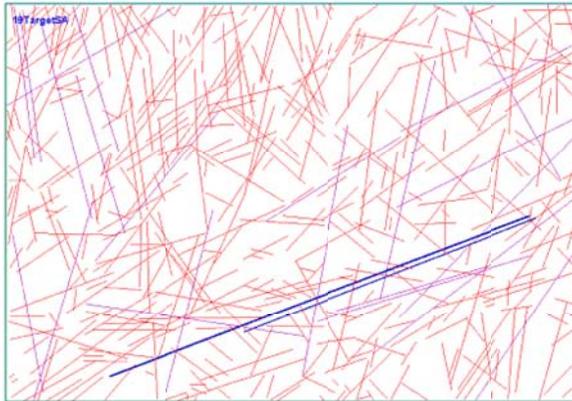

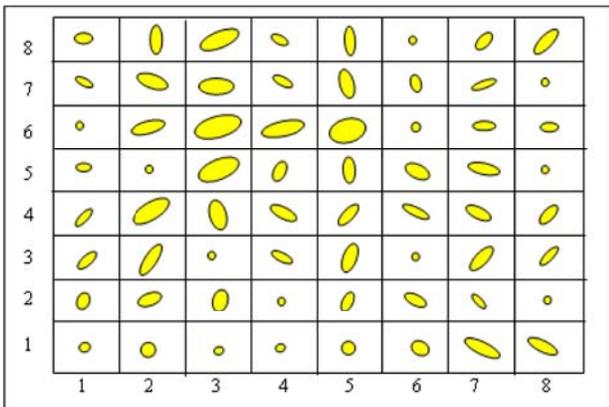Fig.3. 2D planar view of the reservoir and its fractures.
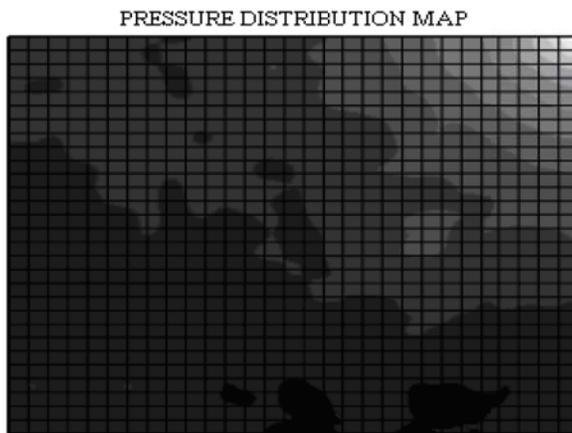

Fig.4. Permeability tensor map.

PRESSURE DISTRIBUTION MAP

Fig.5. 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.
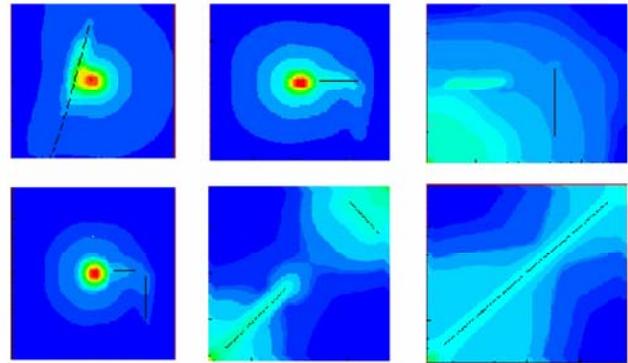

Fig.6. Fluid velocity in different scenarios.

The procedure is further utilized in a sensitivity analysis. Here fluid velocity is observed in different scenarios. The fractures are varied in terms of their length, orientation and placement. The profiles in Fig. 6 clearly show that fractures do indeed play a very important role in fluid flow, and that this procedure can be applied for reliable simulation for many different cases.

TABLE I
RESERVOIR PROPERTIES

Reservoir dimension	50m x 50mx
Far field stresses	15.8 E+6, 16.8 E+6
Flow rate	100RB/Day
Fluid viscosity	0.01cp
Initial reservoir pressure	1611.11psi
Average fracture aperture	0.01m

TABLE 2
ROCK PROPERTIES

Matrix permeability	1md
Matrix porosity	0.001
Poission's ratio	0.333
Modulus of elasticity	7E10

IV. CONCLUSION

This paper presents an innovative method to simulate fluid flow in fractured geothermal reservoirs. The naturally fractured 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. The rock properties are treated dynamically via a coupled simulation. The results are validated against analytical solution. They show it is possible 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.

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