



Numerical investigation of hydraulic fracture network propagation in naturally fractured shale formations



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ABSTRACT

Hydraulic fracture network (HFN) propagation in naturally fractured shale formations is investigated numerically using a 3D complex fracturing model based on the discrete element method. To account for the plastic deformation behavior of shales, the Drucker–Prager plasticity model is incorporated into the fracturing model. Parametric studies are then conducted for different Young's moduli, horizontal differential stresses, natural fracture (NF) properties, injection rates, and number and spacing of perforation clusters. Numerical results show that horizontal differential stress primarily determines the generation of a complex HFN. The plastic deformation of shale can reduce the stimulated reservoir volume; this is more obvious with Young's modulus of less than 20 GPa. In addition, a higher injection rate could largely increase the fracture complexity index (FCI). Moreover, increasing perforation cluster numbers per fracturing stage is beneficial for increasing the FCI, but it also increases the potential merging of neighboring fractures, which may lead to non-uniform development of HFN in far-wellbore regions. To achieve uniform development of HFN within a fracturing stage, the distribution of NFs should be fully considered. The results presented here may provide improved understanding of HFN generation and are favorable for optimizing fracturing treatment designs for shale formations.

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1. Introduction

Multi-stage fracturing with multi-perforation clusters per stage of horizontal wells is an essential technology used in the exploitation of ultra-low permeability shale formations, and the treatment aims to initiate several dominant hydraulic fractures (HFs) from the horizontal wellbore. It is intended that by opening the widely existing natural fractures (NFs) in the shale formation, the HFs will then branch out into the far-wellbore region with the aim of generating the largest possible hydraulic fracture network (HFN) for transporting hydrocarbon to the wellbore (Cipolla et al., 2010; Mayhofer et al., 2010). Thus, an accurate knowledge of the creation mechanism of complex HFNs is significant in the optimization of fracturing treatment design because it will ultimately improve well productivity.

To date, various complex fracturing models have been developed to simulate the complex HF propagation process in naturally

fractured formations. Such models consider the influence of NFs and the mechanical interactions among multiple fractures on the resulting HF geometry and aim to overcome the limitations of classical fracturing models in which the resulting HF is planar and has two symmetric wings. This study presents a brief review of associated literature, but for greater details on the fracturing models developed to simulate complex fractures in naturally fractured formations, the reader is referred to the latest literature reported by Weng (2015).

Xu et al. (2010) and Meyer and Bazan (2011) proposed a wire-mesh model and a discrete fracture network model, respectively, and in both of these pseudo-3D models, the HFN geometry is represented by an elliptical region consisting of two sets of parallel and uniformly spaced vertical fractures along directions of horizontal principal stress. Weng et al. (2011) and Kresse et al. (2013) developed an unconventional fracture model that incorporated conventional pseudo-3D models and considered both the interaction criterion of HF–NF and the interference among adjacent fractures by calculating the stress shadow. All of the three aforementioned models solve the fully coupled problem of fluid flow, proppant transport, and elastic deformation of the fracture

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network. Moreover, they require minimal computation time, which makes them suitable for practical engineering designs in real time.

Several other models based on various numerical methods have been used to study HFN generation including the boundary element method (BEM) (Olson, 2008; Olson and Dahi–Taleghani, 2009; Zhang and Jeffrey, 2014; Wu and Olson, 2015) and the extended finite element method (XFEM) (Dahi–Taleghani and Olson, 2009, 2014). Olson (2008) and Olson and Dahi–Taleghani (2009) described a pseudo-3D BEM-based model, where the growth of multiple fractures satisfied the subcritical power law, and where both tensile and shear failures were considered. Dahi–Taleghani and Olson (2009, 2014) used a 2D plane-strain XFEM model to simulate an HF intersecting with an NF and the fracture propagation in a formation containing a large number of pre-existing NFs. The advantages of BEM and XFEM methods are that they overcome the limits inherent in the mesh shape, and they efficiently treat fractures from arbitrary pathways.

The discrete element method (DEM) has also been used in modeling (Nagel et al., 2013; Hamidi and Mortazavi, 2014; Zhang et al., 2015). A number of significant studies have been conducted using commercially available codes PFC2D, UDEC, and 3DEC (Nagel et al., 2013; Hamidi and Mortazavi, 2014) based on the DEM (Itasca Consulting Group Inc., 2014), where the formation assembly of bonded particles or deformable blocks is interfaced by several sets of joints to form a flow network to generate HF, and no new fracture growths are allowed beyond the joint trajectories. Similarly, discrete fracture network (DFN) models have been used to simulate fluid flow in a formation containing a fracture network system generated according to joint spatial properties (joint orientation, size, density, transitivity, and other properties) using geological statistics. However, in most of these DFN models the fracture width was fixed rather than stress- and/or pressure-dependent during the HF propagation process, and to overcome this limitation, McClure and Horne (2013) proposed a method using a DFN that implicitly coupled fluid flow with stress induced by fracture deformation. The advantages of DEM- and/or DFN-based models are that dense pre-existing discontinuities or contacts between matrix blocks can be properly modeled as can their mechanical behavior during HF development in a fractured rock mass.

Although the models mentioned have been successfully applied in many naturally fractured formations, a number of remaining challenges need to be resolved. For example, all the models considered the shale to be a linear elastic and isotropic material, whereas some shales actually present plastic characteristics associated with a high clay content (Sone and Zoback, 2013) and/or anisotropic characteristics associated with the presence of inherent bedding planes (Waters et al., 2011). It is thus necessary to consider the direct influences of bedding planes on the HFN growth path in layered shale formations (Cooke and Underwood, 2001; Zhang et al., 2007; Guo et al., 2014; Zou et al., 2015a,b).

In this study, a 3D DEM-based fracturing model is presented to investigate the mechanism of HFN propagation within a single fracturing stage in a shale formation containing a preexisting NF system. The Drucker–Prager yield criterion was specifically incorporated into the model to consider the effects of plastic deformation for clay-rich shales. In addition, a series of numerical simulations were performed to illustrate the effects of Young's modulus, horizontal differential stress, NF properties (density, strike angle, and strength), injection rate, and number and spacing of perforation clusters.

2. Mathematical model

Numerical simulation of HFN propagation in a shale formation is performed using a 3D DEM-based complex fracturing model. The

shale rock mass in this model is divided into several block elements (the blocks represent the continuous matrix of a shale formation), which are bonded by virtual springs (Fig. 1a and b) that play a role in transmitting the interaction forces among blocks. The motion of each block is determined by the magnitude of resultant unbalanced forces acting on it. The joint elements inserted between all contacting blocks make a continuous flow network (known as a DFN) for generating HF (Itasca Consulting Group Inc., 2014), and the size, shape, and orientation of this DFN depends on the predefined trajectories of NFs (see Section 3.1). The fluid pressure distribution inside the DFN is calculated using the finite element method (FEM), and it is then exerted on the surrounding blocks, resulting in deformations and changes in the stress states at the block contacts. When the stress state at a contact satisfies the rock failure criterion, either in tension mode (maximum tensile stress criterion) or in shear mode (Mohr–Coulomb criterion), the bond between the two contacting blocks breaks and a (tensile or shear) fracture is generated as shown in Fig. 1c. In this model, the shale matrix block is considered to be homogeneous, isotropic, and impermeable, and although the shale deformation behavior is described using linear elastic law, the stress state is corrected to account for plastic deformation using the Drucker–Prager plasticity model. The governing equations used in this study are described in the following figure:

2.1. Fluid flow within the DFN

The fracturing fluid flow within the DFN is governed by the lubrication equation (Batchelor, 1967) as follows:

$$\frac{\partial w}{\partial t} = \frac{\partial}{\partial s} \left(\frac{w^3}{12\mu} \frac{\partial p}{\partial s} \right). \quad (1)$$

Given that the shale matrix block is considered impermeable because of its ultra-low permeability, fluid loss into the matrix is neglected. Therefore, the global volume balance within the DFN is expressed as follows:

$$\int_{\Omega_f} w ds = tQ_t, \quad (2)$$

where p and w are the fluid pressure and dynamic fracture width, respectively, at time, t , and point, s , inside the DFN; μ is the fluid viscosity; and Q_t is the total injection rate. For a single fracturing stage, the sum of flow rates into all perforation clusters (N_{perf}) should be equal to the total injection rate as follows:

$$Q_t = \sum_{i=1}^{N_{perf}} Q_i, \quad (3)$$

where Q_i is the flow rate into each perforation cluster ($i = 1, \dots, N_{perf}$), which is dependent on the fracture width and fluid pressure within the fracture. It is important to note that only a single transverse fracture is allowed to initiate from each perforation cluster in this study. In addition, a fracture is assumed to be completely filled with fluid and no flow occurs at the fracture tip. The initial pressure inside the DFN is p_{int} .

2.2. Rock deformation equation

In this study, it is considered that each block of rock mass has a deformation limit, is non-rotational, and that its motion follows Newton's second law. The dynamic stress equilibrium equation for the blocks is given as follows (Jaeger et al., 2007):

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