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Reactivation mechanism of natural fractures by hydraulic fracturing in naturally fractured shale reservoirs

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ABSTRACT

Hydraulic fracturing technique has been commonly used in the development of shale reservoir aiming to produce from complex network of fractures. One of the key parameters that affects the hydraulic fracture complexity is the natural fracture in the shale reservoir. Hydraulic fractures being trapped by natural fractures propagate non-planar fracture in three dimensions. Therefore, conventional hydraulic fracture model cannot include the non-planar characteristics of these fractures. In case a hydraulic fracture crosses a natural fracture, the dependence of the natural fracture reactivation on injection rate remains poorly understood. A non-planar propagation model for hydraulic fracturing in naturally fractured shale reservoirs was developed based on PKN model. A dynamic model was derived to calculate the stress intensity factor for a natural fracture being crossed by a hydraulic fracture based on the theory of rock fracture mechanics. Based on the experimental data from Longmaxi shale reservoir, the fluid pressure threshold to activate the natural fractures was obtained for different approaching angles. The effects of fluid pressure on the propagation angle of natural fracture were discussed. According to different initial injection rates and approaching angles, the time and minimum injection rate were determined to adjust the pump, which can improve the complexity of hydraulic fracture. True tri-axial hydraulic fracturing test with rapidly variable injection rate was conducted on the shale outcrop from Longmaxi formation. Experimental results proved that increasing the injection rate at the right time can reactivate the natural fractures, which can induce a network of fractures in shale reservoirs.

1. Introduction

Due to the ultra-low permeability in shale gas reservoir, large-scale hydraulic fracturing is a must in the development of these reservoirs to get the industrial gas production. Extensive experimental and theoretical investigations (Blanton, 1982; Cheng et al., 2014a; Daneshy, 1974; Gu and Weng, 2010; Norman and Jessen, 1963; Renshaw and Pollard, 1995; Taleghani and Olson, 2009, Taleghani, 2011; Warpinski and Teufel, 1987; Zhou et al., 2008, Zhou and Xue, 2011) indicated that discontinuities, such as faults, lamination and natural fractures etc., have a significant influence on the propagation path of a hydraulic fracture. Encountering the natural fractures, a growing hydraulic fracture can propagate with either of these two probable behaviors: penetrating the natural fracture or not (Cheng et al., 2014a, 2014b). As a result, a lot of mechanical criteria (Cheng et al., 2014a; Gu and Weng, 2010; Renshaw and Pollard, 1995) were proposed to determine these propagation modes. If a hydraulic fracture propagates along a natural fracture (non-planar propagation), the natural fracture can be easily activated and the complexity of hydraulic fracture can also be significantly improved, aiming at a hydraulic fracture network (Chen, 2013; Gu and Weng, 2010; Taleghani, 2011; Zhao et al., 2012). Generally, if a natural fracture is penetrated through by a hydraulic fracture straightly, the natural fracture would be hardly activated. In general, geological parameters, such as in-situ stresses, natural fracture orientation and rock elastic constants etc., are hardly controlled by petroleum engineers. By contrast, hydraulic fracturing parameters, such as injection rate and fluid volume could be controlled by oil field operators. Therefore, when to change the pump rate and how much pump rate we should choose for reactivating the natural fractures remain poorly understood. This is an urgent scientific problem to solve in the developing fractured shale

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reservoir.

A non-planar propagation model of hydraulic fracture was developed for fractured shale reservoir, and a dynamic model was established to calculate the stress intensity factor at a natural fracture-tip which is penetrated through by a hydraulic fracture. Taking a real case from Longmaxi shale formation for example, the moment to change the pump rate associated with minimum pump rate were obtained and validated by using a tri-axial hydraulic fracturing test on shale outcrop. Theories and experiments both proved that natural fractures could be reactivated using rapidly-variable pump rate fracturing technique, which has the possibility to achieve network fracturing in shale reservoirs.

2. Non-planar propagation model of hydraulic fracture

In a naturally fractured shale reservoir, a hydraulic fracture has the potential to propagate as a non-planar fracture if a hydraulic fracture encounters a natural fracture. To illustrate this characteristic, a model was built under the following assumptions: (1) The natural fracture is closed, and its cementation strength can be characterized by shear and tensile strength; (2) The pores in a natural fracture are filled with fluid and the pressure equals to formation pressure; (3) Both the hydraulic and natural fractures are

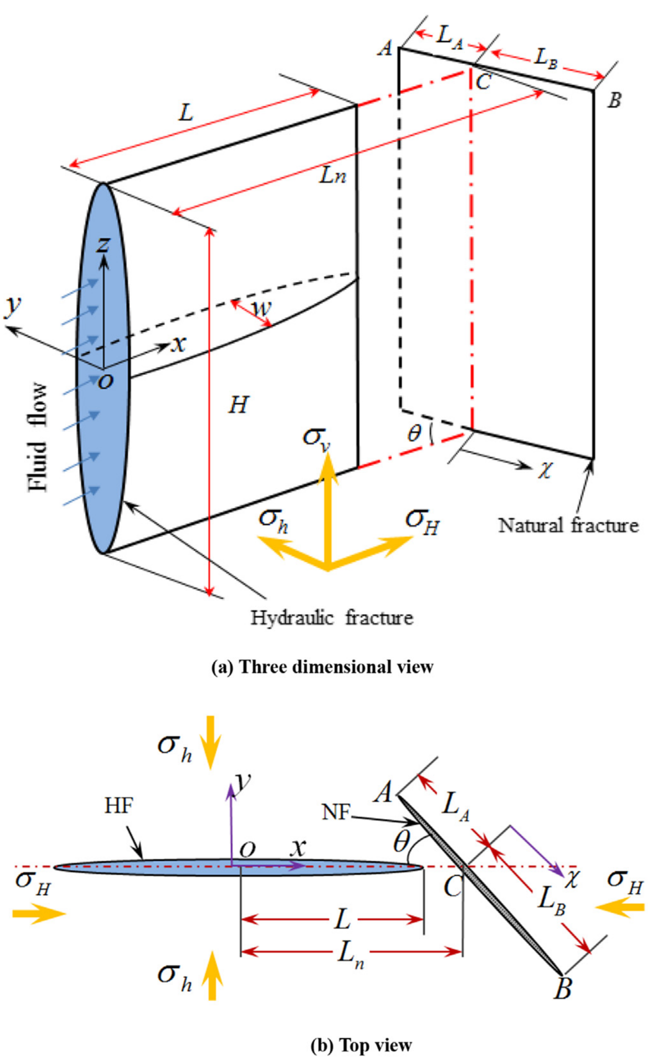

Fig. 1. Schematic of a hydraulic fracture approaching a natural fracture.

vertical fractures under normal fault stress, and their heights equal to the thickness of reservoir; (4) The fluid lag (Dmitry, 2006) region is ignored at the hydraulic fracture tip, and the gravity gradient of fracturing fluid is also ignored during the process of the hydraulic fracture propagation; (5) The vertical profile of a hydraulic fracture is an ellipse before a hydraulic fracture contacts a natural fracture; (6) The hydraulic fracture propagation direction close to the natural fracture and before intersection is not influenced by the existence of the natural fracture. As shown in Fig. 1, Cartesian coordinate x–y–z is established with the origin at the center of a hydraulic fracture. The natural fracture is separated into two parts (*CA* and *CB*) by point C.

The fracture-width theories are based on the assumption that fracture surface deforms in a linear elastic manner. If the direction of fracture propagation is taken as *x*-direction, fracture-width equation (England and Green, 1963) relating fluid pressure can be obtained under plane-strain conditions, and reads

$$w(x,z,t) = \frac{1-\upsilon}{G}\left(H^2 - 4z^2\right)^{1/2}[P(x,t) - \sigma_n(x)] \tag{1}$$

When z = 0, the maximum fracture-width of the hydraulic fracture for different *x* and *t* is given by

$$W_m = w(x,0,t) = \frac{1-\upsilon}{G}H[P(x,t) - \sigma_n(x)] \tag{2}$$

The dynamic fluid pressure inside a hydraulic fracture depends on the volumetric flow rate and the fluid viscosity. The geometry of a hydraulic fracture is an ellipse with a very small eccentricity rather than parallel plates. Lamb (1932) shown that the flow equation of a Newtonian fluid in elongated elliptical cross-section is expressed as

$$q(x,t) = -\frac{\pi W_\mathrm{m}^3 H}{64\mu_e}\frac{\mathrm{d}[P(x,t) - \sigma_n(x)]}{\mathrm{d}x} \tag{3}$$

Considering the loss of fracture fluid in the direction normal to the hydraulic fracture face, fluid conservation equation (Chen, 2013) in each unit length of hydraulic fracture is

$$\frac{\partial q(x,t)}{\partial x} + q_L(x,t) + \frac{\partial A(x,t)}{\partial t} = 0 \tag{4}$$

The fluid leak-off rate is given by Carter's (1957) model and the fracture cross-sectional area can be given by

$$\begin{cases} q_L(x,t) = 2HC_L[t - t_0(x)]^{-1/2} \\ A(x,t) = \displaystyle\int_{-H/2}^{H/2} w(x,z,t)\mathrm{d}z = \frac{\pi}{4}W_\mathrm{m}H \end{cases} \tag{5}$$

Substituting Eqs. (2), (3) and (5) into Eq. (4) gives the following equation of a non-planar propagation model.

$$\begin{aligned} &-\frac{\pi(1-\upsilon)^3H^3}{128\mu_e G^3}\frac{\partial}{\partial x}\left(\psi^3\frac{\partial\psi}{\partial x}\right) + \frac{C_L}{\sqrt{t-\tau(x)}} + \frac{\pi(1-\upsilon)H}{8G}\frac{\partial\psi}{\partial t} = 0; \\ &\psi = P(x,t) - \sigma_n(x) \end{aligned} \tag{6}$$

Basically, the hydraulic fracture width is zero before fracture initiates. If the injection rate can keep constant Q_0, the boundary conditions of this governing equation is given by