Journal of Natural Gas Science and Engineering 45 (2017) 38–52

Contents lists available at ScienceDirect

Journal of Natural Gas Science and Engineering

journal homepage: www.elsevier.com/locate/jngse

Effect of water and nitrogen fracturing fluids on initiation and extension of fracture in hydraulic fracturing of porous rock

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ARTICLE INFO

Article history:
Received 11 January 2017
Received in revised form
16 March 2017
Accepted 4 May 2017
Available online 25 May 2017

Keywords:
Hydraulic fracturing
Water
Nitrogen
Porous rock
Fracture initiation pressure
Crack extension

ABSTRACT

An improved fracture initiation pressure criterion based on the initiation criterion of the mode I crack is proposed to interpret the different phenomena induced by water and nitrogen fracturing fluids. Hydraulic fracturing experiments on sandstone, coal and shale cores are performed using water and nitrogen to investigate the effects of the rock type and fracturing fluid type on the fracture initiation pressure and to verify the improved initiation pressure criterion. The crack propagation process and extended fracture complexity are also investigated based on hydraulic fracturing experiments. The sensitivity of the key parameter to the crack initiation pressure is explored using the improved initiation pressure criterion. The results show that the improved initiation pressure criterion is reliable. Nitrogen fracturing fluid can effectively reduce the fracture initiation pressure of rock compared with water, especially for low permeability shale. Micro-crack initiation occurs more easily before failure and the crack extension process is more violent in nitrogen fracturing. In water fracturing, a single fracture is induced, but complex fractures including tortuous and multiple fractures are produced in nitrogen fracturing. The extended fracture complexity in nitrogen fracturing is more likely to be affected by the lithologic character of rock compared with water fracturing. From the parameter sensitivity study, there are upper and lower limits on the permeability of shale causing pressurization rate to have a significant impact on the fracture initiation pressure. The upper and lower limits of permeability for nitrogen are four orders of magnitude greater than those for water. In the affected range of permeabilities, whether the fracturing fluid is water or nitrogen, changes in the fracture initiation pressure with the increase of the pressurization rate show an approximately logarithmic increase, linear increase and exponential increase in order of increasing permeability.

1. Introduction

Hydraulic fracturing is usually employed to generate fractures in oil and gas formations to promote the migration of oil and gas and prolong the production period of oil or gas wells (Abdollahipour et al., 2016; Huang et al., 2016; Baghbanan et al., 2014; Saldungaray and Palisch, 2012). Water-based fluids are the most common fracturing fluids used to stimulate reservoirs, but water injection has caused a series of problems that includes the shortage of water resources, swelling of clay, the water locking effect and environmental pollution (Hou et al., 2016b; Brantley et al., 2014; Small et al., 2014; Holditch, 2013). Thus, injection of gaseous stimulants, particularly nitrogen and carbon dioxide, have been proposed and regarded as one of the most promising approaches because they can overcome the shortcomings of conventional water-based fluids (Lashkarbolooki et al., 2016; Hou et al., 2016a; Li et al., 2015; Elsworth et al., 2014). As we know, there are clear distinctions between the physical properties of water-based fluids and gaseous stimulants, which may induce different penetration behavior and then impact the fracturing behaviors of formations. Differences in the fracturing behaviors between water-based fluids and gaseous stimulants have been reported in some of the published literature. For example, Alpern et al. (2012) and Li et al. (2015) implemented hydraulic fracturing experiments with HO_2, CO_2 and N_2 to compare the fracture pressures and fracture patterns with different fracturing fluids. Gomaa et al. (2014) experimentally

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http://dx.doi.org/10.1016/j.jngse.2017.05.012
1875-5100/

observed that, in nitrogen fracturing, the breakdown pressure can be reduced and the morphology of the fracture is more complex compared with water fracturing. However, these studies focused only on several fracture characteristics after sample failure, and the mechanisms of fracture initiation and propagation have not been well investigated in hydraulic fracturing using different fracturing fluids.

In the conventional theory models, fracture initiation occurs on the borehole surface when the tensile circumferential stress induced by the borehole pressure and tectonic stresses around the borehole reaches the tensile strength of the formation rock, and the borehole pressure at fracture initiation is regarded as the fracture initiation pressure (Hubbert and Willis, 1957). Since these models suppose that the fracture initiation occurs at the periphery of the borehole, they cannot explain the influences of the fracturing fluid type, the pressurization rate of fracturing fluids and the permeability of the formation rock on the fracture initiation pressure. However, previous studies suggest that these factors have clear impacts on the fracture initiation pressure and other fracturing behaviors (Zhang et al., 2017b; Li et al., 2015; Gomaa et al., 2014; Alpern et al., 2012; Ito, 2008; Zeng and Roegiers, 2002; Ito and Hayashi, 1991; Zoback et al., 1977). To interpret such impacts, Ito and Hayashi (1991) proposed a new model based on the point stress criterion (Nuismer and Whitney, 1975). They assumed that fracture initiation occurs when the maximum tensile effective stress reaches the tensile strength of the rock at a point that is not on the borehole surface but is inside the rock, which is a very good idea. In addition, they also thought that the distance between the point and the borehole wall is a material constant and called it the characteristic length determined by the mode I crack initiation criterion. However, in the same model, two crack initiation criteria are employed, which can easily encounter problems. In the subsequent study of Ito (2008), the characteristic length is derived by hydraulic fracturing experiments with different pressurizing rates, but a deviation can be observed between the effective stress at the characteristic length and the tensile strength of the rock. Recently, Zhang et al. (2017b) established a crack initiation criterion with the stress intensity factor of the mode I crack to study the effects of HO_2 and N_2 fracturing fluids on the fracture initiation pressure of shale; while the value of the initial crack length that is a very important key parameter is arbitrary to a certain extent because the initial crack length inside the rock is difficult to obtain.

Considerable investigation on fracture extension mechanisms in oil and gas reservoirs has been performed using water-based fracturing fluid (Li et al., 2015; Gomaa et al., 2014; Guo et al., 2014; Chitrala et al., 2013). The results indicate that fracture propagation is mainly influenced by the horizontal ground stress difference. In addition, fracture propagation is related to the lithologic character of the rock and the rheological properties of the fracturing fluid (Hou et al., 2016b; Bennour et al., 2015; Chen et al., 2015b; Gomaa et al., 2014). For example, the permeability of formations and the viscosity of fracturing fluids influence the transmission of borehole pressure and the complexity of extended fractures so that the morphology and quantity of fractures can be controlled by these factors. A complex fracture can enlarge the fracture surface area, which makes the fluid in the matrix of the formation migrate along the shortest path and decreases the required driving pressure difference for oil and gas flow (Warpinski et al., 2009). Therefore, comparing the complexity of extended fractures in formations with different permeabilities using water and nitrogen fracturing fluids is essential for the development of nitrogen fracturing technology.

Accordingly, an improved model for crack initiation is proposed in this paper. Next, hydraulic fracturing experiments are performed on sandstone, coal and shale using water and nitrogen gas. The influences of the rock type and fracturing fluid type on the fracture initiation pressure are analyzed and the improved model is verified by the experimental results. The crack extension within the rock sample is investigated through deformation, acoustic emission (AE) and failure mode. Finally, the effects of the key parameters on crack initiation are explored based on the improved model. The results can provide a guide for the design of fracturing programs.

2. Determination of fracture initiation

2.1. Distribution of pore pressure in porous rock

Fig. 1 shows the force-bearing condition around borehole. When fracturing fluid is injected into the borehole, the fracturing fluid penetrates through interconnected pores into the rock from the borehole wall resulting in pore pressure. Based on prior researches, pore pressure not only causes an additional circumferential stress in compression around the borehole but also produces a loss of strength of porous rock in failure (Detournay and Cheng, 1993; Ito, 2008). Hence, it is essential to first understand the distribution of pore pressure in porous rock.

To quantitatively represent the pore pressure distribution in rock, the following basic assumptions are made (Middleton and Wilcock, 1994): (1) The rock is an isotropic medium, and its permeability is constant; (2) the fluid flow is laminar and obeys the Darcy's law under the isothermal condition. Based on these assumptions, the pore pressure can be established as follows

$$\begin{cases} \dfrac{\partial^2 p}{\partial r^2} + \dfrac{1}{r}\dfrac{\partial p}{\partial r} = \dfrac{1}{\chi}\dfrac{\partial p}{\partial t}, & a < r < r_0, \quad t > 0 \\ p(r,t) = f(t), & r = a, \quad t > 0 \\ p(r,t) = p_0, & r = r_0, \quad t > 0 \\ p(r,t) = p_0, & a \le r \le r_0, \quad t = 0 \end{cases} \tag{1}$$

where p_0 is the initial borehole pressure and the pore pressure, a is the borehole radius, r_0 is the radius of the sample, $f(t)$ is the injection pressure, and t is time; χ is the diffusion coefficient, and its expression is given as follows

$$\chi = \frac{k}{\phi \mu c} \tag{2}$$

where k is the rock permeability, ϕ is the rock porosity, μ is the viscosity of the fluid, and c is the compressibility of the fluid.

By variable substitution, the homogeneous theorem and the separation of variables, the solution of Eq. (1) is obtained

$$\begin{aligned} p(r,t) &= f(t) + \frac{p_0 - f(t)}{r_0 - a}(r - a) \\ &+ \sum_{m=1}^{\infty}\left\{\frac{R(\beta_m, r)}{N(\beta_m)}\int_0^t e^{-\chi\beta_m^2(t-\tau)}\int_a^{r_0} rR(\beta_m, r)\left[\frac{\chi(p_0 - f(\tau))}{r_0 - a} - \frac{(r_0 - r)}{r_0 - a}f'(\tau)\right]dr d\tau\right\} \end{aligned} \tag{3}$$