Journal of Natural Gas Science and Engineering 34 (2016) 486–498

Contents lists available at ScienceDirect

Journal of Natural Gas Science and Engineering

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

Theoretical and experimental study on fracture network initiation and propagation in shale that considers the capillary effect

Di Wang [a, b], Mian Chen [a, b, *], Yan Jin [a, b], Zhixi Chen [c]

[a] State Key Laboratory of Petroleum Resources and Prospecting, Beijing, 102249, China
[b] College of Petroleum Engineering, China University of Petroleum, Beijing, 102249, China
[c] The University of New South Wales, Sydney, Australia

A R T I C L E I N F O

Article history:
Received 23 December 2015
Received in revised form
11 May 2016
Accepted 6 July 2016
Available online 9 July 2016

Keywords:
Shale fracture network
Capillary effect
Width heterogeneity
Fracturing fluid wettability

A B S T R A C T

Shale reservoirs contain multi-scale natural fractures, which result in the growth of a complex fracture network during hydraulic fracturing. However, existing studies regard natural fractures as discontinuities without considering width heterogeneity and fracturing fluid wettability. In reality, width and wettability significantly influence fracture morphology because of the capillary effect. In this study, a new model was established to simulate fracture network propagation by considering the capillary effect. The approaching angle between hydraulic and natural fractures was 90°. In addition, the fracture initiation condition was considered based on the fracture mechanics. Results showed that natural fracture width and fracturing fluid wettability significantly influenced fracture network propagation. A small natural fracture width and strong fracturing fluid wettability led to the easy initiation of natural fracture and a complex fracture network propagation. Finally, the simulation results were compared with the results of hydraulic fracturing experiments in shale specimens carried out in laboratory and by other researchers. The results of the experiments are in good agreement with the results of the numerical simulations. Both the numerical and experimental results indicate that treatment parameters and geological characteristics, particularly fracture dimensions and horizontal in-situ stress difference, significantly influence fracturing results.

1. Introduction

Natural fractures abound in shale reservoirs and significantly influence hydraulic fracturing. In the presence of natural fractures, hydraulic fracturing will develop into a complex fracture network that is substantially distinct from that in reservoirs without natural fractures (Warpinski and Teufel, 1987), as evidenced by microseismic monitoring (Maxwell et al., 2002; Fisher et al., 2002; Daniels et al., 2007).

Issues on hydraulic fracture propagation in a formation with pre-existing natural fractures have been widely investigated both experimentally and numerically. Renshaw and Pollard (1995) derived a criterion to predict whether a fracture would propagate across a frictional interface that was oriented perpendicular to the approaching fracture. Experiments were conducted to validate this criterion. Zhou et al. (2008) studied hydraulic fracture geometry in naturally fractured reservoirs through a series of fracturing experiments and determined that in-situ stress and natural fractures mainly controlled hydraulic fracture propagation. Gu et al. (2012) developed a criterion to determine the behavior of a hydraulic fracture that encountered a pre-existing fracture at non-orthogonal angles. This criterion quantitatively accounts for the effect of intersection angle on crossing. Olson et al. (2012) embedded planar glass discontinuities into a cast hydrostone block as proxies for cemented natural fractures. The results showed that oblique embedded fractures were more likely to divert a fluid-driven hydraulic fracture than those occurring orthogonal to the induced fracture path. These findings are consistent with the theoretical predictions. Fan and Zhang (2014) observed the evolution of hydraulic fracture networks in naturally fractured formations with specimens that contained two groups of orthogonal cemented fractures in a laboratory. The result suggests that hydraulic fracturing can generate a complex fracture network in naturally fractured formations; moreover, natural fracture density and injection rate affect the propagation behavior of hydraulic fractures. Xu et al. (2010) presented a numerical model to predict the growth of

* Corresponding author. 18, Fuxue Rd., Changping, Beijing, 102249, China.
E-mail address: chenmiancup@163.com (M. Chen).

http://dx.doi.org/10.1016/j.jngse.2016.07.016
1875-5100/

hydraulic fracture networks during hydraulic fracturing treatment by considering two perpendicular sets of vertical planar fractures with mechanical interaction. Meyer and Bazan (2011) constructed an induced hydraulic discrete fracture network (DFN) mathematical model and laid the foundation for predicting the behavior of discrete hydraulic fractures in shale. Weng et al. (2011) developed a new hydraulic fracture model to simulate complex fracture network propagation in a naturally fractured formation. This model considers the interaction between hydraulic and natural fractures. Moreover, the stress shadow effect among adjacent fractures is also taken into account.

All of the aforementioned studies regard natural fractures as discontinuities without considering fracture dimensions, particularly natural fracture width. In reality, however, natural fractures are unequal. They exhibit multi-scale characteristics ranging from micro-scale to macro-scale, even to engineering-scale due to sedimentary and postdepositional process (Wang, 2008; Wang and Reed, 2009). Small natural fractures are important properties of shale; they are critical to shale gas production when they are opened and connected with hydraulic fracture treatment (Wang and Reed, 2009; King, 2010). In the Barnett Shale, the population of narrow fractures follows a power-law size distribution where the largest fractures are open (Gale et al., 2007). These smaller fractures act as planes of weakness and reactivate during hydraulic fracture treatments (Gale et al., 2007; Gale and Holder, 2008; Jacobi et al., 2008). Moreover, nano-scale natural fractures (Fig. 1) were observed with a high resolution, versatile environmental scanning electron microscope (SEM) platform in our laboratory. These natural fractures manifest a variety of configurations. Each configuration exhibits its own connectivity and potential interaction with hydraulic fractures. The complex and pervasive multi-scale heterogeneity of natural fractures limits understanding of fracture network propagation.

In addition, the wettability between fracturing fluid and shale was disregarded in previous studies on hydraulic fracturing. The capillary effect is a general concern during production given that it will reduce gas productivity because of water block (Holditch, 1979; Warpinski, 1991). Moreover, capillary force plays an important role in the study of wellbore stability, which is a main reason of shale instability (Yunhu et al., 2012; Liang et al., 2014). Nevertheless, the surface and capillarity forces of fluids at nano-scale in shale may produce the complicated behavior of fracture network propagation during the fracturing process. (Wang and Reed, 2009).

The width of natural fractures ranges from nano-scale to macro-scale, and even to engineering-scale. It significantly influences fracture network morphology during hydraulic fracturing. In this study, a new model was constructed to simulate fracture network propagation in shale by considering the width of natural fractures and fracturing fluid wettability. The fracture initiation condition was considered based on the fracture mechanics. Finally, hydraulic fracturing experiments were conducted in our laboratory using shale cubic specimens from Sichuan Province. The results of experiments conducted in our laboratory and by other researchers were compared with the results of the developed numerical model. The simulation results exhibit good agreement with the experiments results.

2. Model formulation and results

Natural fractures are widely developed in shale reservoirs and their width ranges from nano-scale to marco-scale, and even to engineering-scale. When the width of a natural fracture is very small, the capillary force will be significantly enhanced. Therefore, when the wetting fracturing fluid encounters a natural fracture, fluid will be absorbed into the natural fracture because of the considerable capillary force. Subsequently, the natural fracture phase consists of two components, namely, the influent fluid, such as fracturing fluid, and the original fluid, such as natural gas. Therefore, pressure in a natural fracture is divided into two parts: the pressure of fracturing fluid and that of natural gas. The pressure of the fracturing fluid in a natural fracture is approximately equal to that at the intersection because of the connection between the fracturing fluid in natural and hydraulic fractures. In addition, the pressure of natural gas differs from that of fracturing fluid in a natural fracture with a difference in capillary force. As the fracturing fluid is of wetting capacity, the pressure of natural gas increases. As the hydraulic fracture continues propagating, the pressure at the intersection changes, which contributes to the variation in natural gas pressure. Consequently, pressure will be redistributed in a natural fracture. When the stress intensity factor at natural fracture tip exceeds fracture toughness, the natural fracture will initiate and propagate. In the hydraulic fracture propagation process, hydraulic fracture will come across a mass of natural fractures. When the fracturing fluid flows into natural fractures and causes natural fracture propagation, a fracture network will be generated. In this study, a numerical model that presented fracture network propagation by considering the influence of the capillary effect was established. Moreover, natural fractures with a small width were mainly studied. The model considered fracture initiation condition based on the fracture mechanics. The simulation results showed that a small natural fracture width and strong fracturing fluid wettability would lead to easy initiation of natural fractures and a complex fracture network. Fig. 2 shows the magnified schematic of the model, and the relevant assumptions are provided as follows.

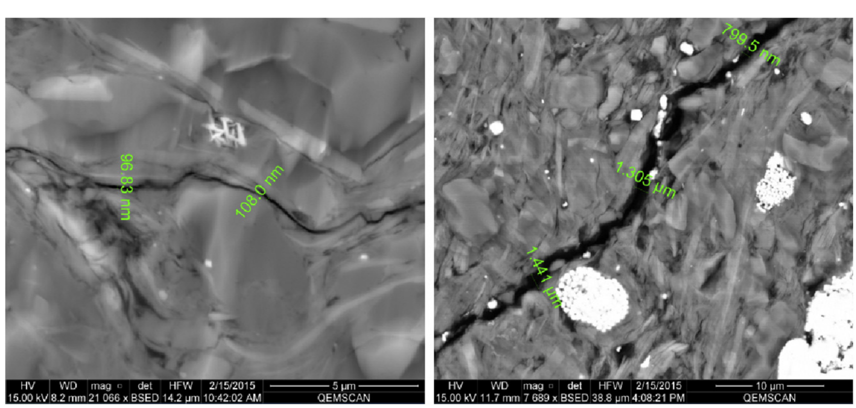

Fig. 1. Nano-scale and multi-scale characteristics of natural fractures in shale specimens.