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Numerical simulation of hydraulic fracture propagation in shale gas reservoir

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ABSTRACT

On the basis of damage mechanics, a 2D fracture propagation model for seepage-stress-damage coupling in multi-fracture shales was established. Numerical simulations of hydraulic fracture propagation in the presence of natural fractures were carried out, with the use of mechanical parameters of shale reservoirs. The results showed that when hydraulic fractures encountered natural fractures in a shale reservoir, the morphology of fracture propagation was jointly affected by the properties of natural fractures (permeability and mechanical properties of rocks), approaching angle, horizontal stress difference, and flow rate of fracturing fluids. At a small horizontal stress difference, or low approaching angle, or small friction coefficient, natural fractures had increased potential to be damaged due to shear and tension. In such cases, the hydraulic fractures tended to propagate along the natural fractures. As the flow rate of fracturing fluid increased and the width of hydraulic fractures expanded, branch fractures formed easily when the net pressure exceeded the sum of horizontal stress difference and tensile strength of the rocks in which natural fractures with approaching angle smaller than 60° existed. It is seen, a high flow rate will increase the complexity of fracture network. However, when a large number of natural fractures with approaching angles greater than 60° existed, a large flow rate generally led to propagation of hydraulic fractures beyond natural fractures, which was not favored. Hence, an appropriate flow rate should be selected based on the orientations of natural fractures and hydraulic fractures. At the early stage of hydraulic fracturing, a low flow rate was favorable for the initiation of natural fractures and the growth of complexity of regional fractures near the well. Later, a higher flow rate facilitated a further propagation of hydraulic fractures into the depth of reservoir, thus forming a network of fractures. The underlying control mechanism of flow rate and net pressure on the formation of fracture network still requires clarification. The bending degree of the fracture propagation path depended on the ratio of net pressure to stress difference at a distant point as well as on the spacing between fractures. When the horizontal stress difference (<9 MPa) or coefficient of horizontal stress difference (<0.25) was low, the ratio of net pressure to stress difference was high. In this case, the fracture-induced stress obtained an enhanced significance, while the interactions of hydraulic fractures intensified, leading to a non-planar propagation of fractures. In addition, a smaller spacing between fractures caused intensified interactions of hydraulic fractures, so the propagation path altered more easily. This work contributes to the prediction of morphology of fracture propagation in unconventional oil and gas reservoirs.

1. Introduction

Shale matrix has a very low porosity and permeability, and shale gas appears in different occurrence statuses (Ross and Bustin, 2007; Guo et al., 2013), which bring great difficulties for the exploitation of shale play. Hydraulic fracturing by stimulated reservoir volume (SRV) (Cipolla et al., 2010) is a new technology for the commercial development of shale gas. In treating traditional sandstone reservoirs, a transition of fractures with simple planar morphology to the formation of massive fracture zones generally occurs, which greatly increases the volume of stimulated fractures. SRV enables the formation of a fracture network to allow for gas flow in a shale gas play with low porosity and low permeability, thereby improving the initial production and ultimate recovery of a shale

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play.

An in-depth understanding of fracture propagation mechanism underlying hydraulic fracturing by SRV in a shale play is a basis for the design of fracturing operation. Thus, the control of morphology of fracture network by SRV can be realized to improve the production capacity of single well for shale gas. The key factors affecting the morphology of fracture network after hydraulic fracturing include horizontal stress difference, rock brittleness and physical properties of natural fractures (King, 2010; Sondergeld et al., 2010; Mathews et al., 2007; Britt and Schoeffler, 2009; Kassis et al., 2010; Rickman et al., 2008). In addition, the fracture morphology can also be affected by the fracturing operation factors (Soliman et al., 2010; Chen et al., 2010) and fracturing techniques (Mayerhofer et al., 2008).

Currently, numerical simulation of hydraulic fracturing for strata with natural fractures and random fracture propagation directions is the hotspot of research (Olson and Dahi-Taleghani, 2009; Cipolla et al., 2011; Weng et al., 2011; Wu et al., 2011; Zhao et al., 2014). The numerical simulation of complex fracture propagation mainly involves the following five methods: (1) Conventional finite element methods: fracture propagation is simulated by the principle of damage mechanics. One is cohesive element method (Zhang et al., 2010), which does not apply to random fracture propagation. In another method, all elements are assumed to have the same type. According to the judgment criteria, the dynamic fracture propagation can be simulated by changing the material properties of the elements (Li et al., 2009). Although this method is affected by the size of elements with lower precision, it is easy to simulate the random fracture propagation; (2) Extended finite element method (Belytschko and Black, 1999): this method has a high precision in simulating fracture propagation. But when there are a large number of natural fractures, the results may be difficult to converge; (3) Boundary element method (Olson, 2008): it has a certain advantages in simulating random fracture propagation, but may have problems in treating the load and flow on fracture surface; (4) Meshless method (Moes et al., 1999): this is a new simulation approach for fracture propagation, and easy to use for random fracture propagation. However, theoretical maturity and calculation efficiency should be further improved; (5) Analytic model (Weng et al., 2011): the simulation precision is lower due to the use of analytic model and formula for determining the direction of fracture propagation.

At present, the simulation of complex artificial fracture network in reservoirs with natural fractures is still a challenge. There is not yet a method for simulating the propagation of large-scale fractures at high efficiency and for multi-stage fracturing for horizontal wells. Some scholars have adopted numerical simulation to analyze the influence of natural fractures on hydraulic fractures and the controlling factors of the formation of fracture networks (Dahi-Taleghani and Olson, 2009; Nagel et al., 2011; Olson and Wu, 2012; Xu et al., 2010; Meyer and Bazan, 2011). However, in the existing studies on the numerical simulations of multi-stage and multi-cluster fracturing of shale reservoirs, the comprehensive influencing factors of fracture propagation are rarely concerned about. In the study, damage mechanics method was used (Yang et al., 2001) to establish the 2D fracture propagation model with seepage-stress-damage coupling for multi-fracture shales. Targeting at the mechanical parameters of rocks in a shale reservoir, the interference caused by a single natural fracture to the hydraulic fracture, as well as the influence of natural fracture, horizontal stress, coefficient of horizontal stress difference, flow rate and spacing of perforation clusters on the fracture propagation under single-stage and multi-cluster hydraulic fracturing for horizontal wells in multi-fracture shale reservoir were analyzed.

2. Mathematical model of fracture propagation

Based on the classical Biot's fluid–solid coupling equation (1955), the damage mechanics method was used to establish the 2D fracture propagation model with seepage-stress-damage coupling for multi-fracture formation. By self-compiled FORTRAN program, the finite element simulation of hydraulic fracturing was carried out, and the software “TECPLOT” was used for data analysis and visual processing.

Rock deformation is modeled with the theory of linear elasticity. Coupling of fluid flow and geomechanical deformations is based on the poroelastic theory developed by Biot. The fluid flow inside the fracture is usually simplified to the flow along a channel with a very narrow opening, which is represented by a nonlinear partial differential equation that relates the fluid flow velocity with the fracture width and pressure gradient along the fracture. The process of fracture propagation is usually considered in the framework of linear elastic fracture mechanics (LEFM) theory (Yang et al., 2001). To simplify this processes, we used different type of elements with their own properties in our model. Fluid element represents the induced hydraulic fracture. It has a very high permeability, but very low value of Young's modulus and Poisson's ratio. Natural fracture element represents the natural fracture inside the reservoir which is more permeable than normal formation element and has a lower Young's modules. Moreover, we also used the formation element with formation properties.

2.1. *Seepage equation (Chen et al., 1995; Rahman et al., 2009)*

$$\nabla^2 P = \frac{\mu C_t}{K}\frac{\partial P}{\partial t} \tag{1}$$

where P is the pore pressure (MPa); ∇^2 is the Laplace operator; μ is the fluid viscosity; C_t is the total compression factor ($C_f + C_l$), C_f is the rock compressibility, C_l is the fluid compressibility; t is the time; K is the permeability ($\times 10^{-3}\ \mu m^2$). This equation is the mathematical equation for unstable seepage of elastic, porous, single-phase micro-compressive fluid.

2.2. *Deformation field equation*

(1) Equilibrium equation (Chen et al., 1995)

Suppose shale has linear-elastic deformation. According to the effective stress principle, the equation characterizing the coupling between the stress field of solid and pressure field of fluid can be obtained:

$$\sigma^*_{ij,j} + (\alpha P \delta_{ij} + f_i = 0) \tag{2}$$

where $\sigma^*_{ij,j}$ is the tensor of effective stress; P is the pore pressure (MPa); f_i is the external load (MPa); δ_{ij} is the Kronecker constant; α is the effective stress coefficient ranging between 0 and 1.

(2) Geometric equation

$$\varepsilon_{ij} = \frac{1}{2}(u_{i,j} + u_{j,i}) \tag{3}$$

where ε_{ij} is strain tensor, and u is displacement.