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A calculation method of optimal water injection pressures in natural fractured reservoirs

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ABSTRACT

Injection pressures usually play a great role in the stimulation of low permeability fractured reservoirs. In this study, the stress state around an injection well was analyzed, and a three-collinear fracture model was established. Based on this model, the mode II fracture criterion was expressed in terms of a new form without stress intensity factor and fracture toughness involved. Based on this new form of fracture criterion, a calculation method of water injection pressures was proposed, and its effectiveness has been confirmed by the measurement results from Fuyu reservoir of Toutai oilfield. The factors that affecting optimal injection pressures have been investigated, and the results show that the water injection pressure is largely affected by the state of natural factures and the in-situ stress; According to Fuyu reservoir geological property and natural fracture distribution, the water injection pressure has been predicted and the result agrees well with that adopted in Fuyu reservoir. This study will have a beneficial application in the design and optimization of hydraulic fracturing in naturally fractured reservoirs.

1. Introduction

Hydraulic fracturing technique is extensively applied in the stimulation of low permeability fractured reservoirs. Although this technique has been used for decades for the stimulation of oil and gas reservoirs, a thorough understanding of some key issues is still lacking, such as the interaction mechanism between induced hydraulic fractures and natural fractures, and the relationship between injection water pressure and the reactivation of natural fractures. In oil exploitation engineering, the latter issue, i.e. how to determine the magnitude of water injection pressure based on the distribution of natural fractures and the injection and production wells is an imperative subject, which will be focused in this paper.

Under the tectonic stress and diagenesis, a mass of fractures were generated in reservoirs, and these fractures are called natural fractures, which often possess some same characteristics, such as most of them are parallel and collinear due to the same geological circumstance (Nelson, 1985; Ran and Gu, 1998). In an unconventional reservoir, without natural fractures, it is not possible to recover hydrocarbons from these reservoirs. Therefore, natural fracture systems are very important and should be considered for optimal stimulation. Generally natural fractures are partially or completely sealed, and they could be reactivated and propagated during hydraulic fracturing, and effective seepage channels will be developed (Gale et al., 2007). Because the permeability coefficient of fractures is dozens or even hundreds of times that of rock matrix, those fracture channels will reduce oil seepage resistance greatly, and therefore they will enhance the effective permeability and improve oil recovery efficiency. However, if water injection pressure is too large, abundant connecting fractures between the injection and production wells will be developed, which may lead to water breakthrough along fractures, producing water early, and even serious water channeling which will largely reduce oil recovery (Yuan et al., 2004; Chen and Dong, 2008). In the plan and design of a low permeability reservoir, the most concern for engineers is how to determine the magnitude of injection pressures. The optimal magnitude of injection pressure should be able to cause the reactivation and propagation of natural fracture, but without the phenomenon of water channeling occurring.

Under water injection pressures, hydraulic fracture initiation and propagation always first occur around the injection well, and then extend to the production well accompanying with the natural fracture reactivation and propagation. The problem of hydraulic and natural fracture interaction has been widely investigated both experimentally (Lamont and Jessen, 1963; Athavale and Miskimins, 2008; Zhou, Xue 2011) and numerically (Taleghani and Olson, 2009; Chuprakov et al., 2011; Keshavarzi and Mohammadi, 2012; Keshavarzi and Jahanbakhshi, 2013a,2013b), but in present paper, this problem will not be focused.

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For the problem of the reactivation and propagation of natural fractures, many significant research results have been published. Hubbert and Willis (1957) firstly put forward an argument about the influence of geological tectonic stress on bursting pressure of wellhole wall and the direction of fractures. Haimson and Fairhurst (1967,1969) firstly took into account the effect of fracturing fluid filtration on bursting pressure. Rahman et al. (2009) discussed that the pore pressure change affects hydraulic fracture and natural fracture initiation and propagation and the direction of fracturing. A number of core experiments show a plenty of intersecting, parallel and even collinear fractures with different azimuths are distributed in fractured reservoirs (Grimm et al., 1999; Grechka and Tsvankin, 2003). A propagation criterion for collinear fractures under compression in a 2D plane was proposed by (Zhu, 1999,2006,2009). Some scholars applied the numerical simulation approach to study the exploitation effect for water channeling in oil field, and mainly focused on investigating natural fracture density, azimuth, and length to affect oil recovery (Su et al., 2006). Some scholars applied a finite element numerical code F-RFPA2D to investigate the pattern of fracture propagation, injection wellhole size and shape, rock strength and stress conditions and other factors during hydraulic fracturing process (Guo, 2010). Dournary et al. (1986) introduced the fluid-structure interaction (FSI) theory, and discussed the hydraulic fracture initiation, propagation and closure, and pointed out that the FSI should be considered for hydraulic fracturing analysis. Based on FSI theory and fracture theory, a program to research rock fracture propagation was developed, and it is used to simulate the whole development process of water channeling successfully (Liu, 2001). Keshavarzi and Jahanbakhshi (2013) initially used extend finite element method (XFEM) to analyse the interaction between hydraulic fracture and natural fractures. Some experiments, such as a tri-axis Servo was adopted to recur the process of hydraulic fracturing, and investigated the impact on fracture propagation with different horizontal stress, different natural fracture azimuths and different shear strength, implied that in-situ stress and natural fracture were the key factors that controlling the geometry shape of fractures (Zhou et al., 2008).

The exploitation experiences of fractured reservoirs show that there are two main factors affecting oilfield recovery efficiency, one is reservoir fracture parameters, and the other is the well network deployment. How to determine injection well location and water injection pressure based on the distribution of natural fractures is an imperative subject in current oil exploitation engineering. Unfortunately, until now the corresponding study is still in the initial stage. In this paper, based on the fracture mechanics and fluid-structure interaction theory, a collinear fracture model under hydraulic injection pressure was established, and a fracture propagation criterion was presented. By using this criterion, the injection pressure can be evaluated. This research achievement will be of benefit to the design and exploitation of oil recovery.

2. Analysis of the stress state of fractured reserviors

Rock usually contains fractures or micro-fractures, and meanwhile rock is a porous material. Therefore, rock can be considered as a dual porosity medium, and it conforms to the general and continuous assumption of mixture theory (Aifantis, 1980; Zimmerman et al., 1986, 1993; Xue, 1999; Li and Xu, 2001). Considering the effects of formation pressure and the fracturing fluid filtration, this paper will try to establish a fracture propagation model around wellholes based on the elastic theory and the concept of effective stress (Rummel, 1987), and this model should be able to analyze the initiation and propagation of natural fractures in fractured reservoirs.

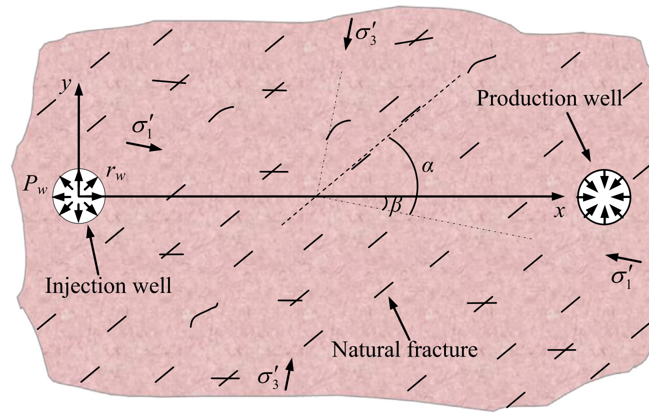

Fig. 1. Schematic of fractures distribution in fractured reservoir.

In a fractured reservoir, if we ignore the temperature stresses, there are four types of stresses should be considered, which are induced by (1) the original undisturbed geostress, (2) the hole-bottom water injection pressure, (3) the fracturing fluid filtration, and (4) the formation pressure of pores and fractures, and the total stress in fractured reservoirs can be obtained by superimposing these four types of stresses.

2.1. Stress induced by original geostress, water injection pressure and fluid filtration

The stresses induced by the original geostress and the hole-bottom injection pressure can be easily obtained by using elastic theory. During hydraulic fracturing, fluid filtration through pores and fractures will occur, and the study results (Cleary, 1959; Seth, 1966; Liu and Huang, 1995) showed that filtration will increase the effective stress for reservoir rock. Suppose the original major and minor principal geostresses in a reservoir before wellhole drilling are σ'_1 and σ'_3, respectively, and the angle between the line connecting the injection and production well and the original major principal geostress σ'_1 is β, as shown in Fig. 1. The angle between natural fractures and the original major principal geostress σ'_1 is α. By means of the principle of superposition, the total stresses (σ_r, σ_θ and $\tau_{r\theta}$) around the wellbore can be written as (Haimson and Fairhurst, 1967, 1969; Huang, 1981; Deng et al., 2002)

$$\sigma_r = \frac{1}{2}(\sigma'_1 + \sigma'_3)\left(1 - \frac{r_w^2}{r^2}\right) + \frac{1}{2}(\sigma'_1 - \sigma'_3)\left(1 - \frac{4r_w^2}{r^2} + \frac{3r_w^4}{r^4}\right)\cos 2\beta + \frac{r_w^2}{r^2}P_w + \left[\eta(1 - \frac{r_w^2}{r^2}) - \phi\right](P_w - P_p) \tag{1}$$

$$\sigma_\theta = \frac{1}{2}(\sigma'_1 + \sigma'_3)\left(1 + \frac{r_w^2}{r^2}\right) - \frac{1}{2}(\sigma'_1 - \sigma'_3)\left(1 + \frac{3r_w^4}{r^4}\right)\cos 2\beta - \frac{r_w^2}{r^2}P_w + \left[\eta(1 + \frac{r_w^2}{r^2}) - \phi\right](P_w - P_p) \tag{2}$$

$$\tau_{r\theta} = \frac{1}{2}(\sigma'_1 - \sigma'_3)\left(1 + \frac{2r_w^2}{r^2} - \frac{3r_w^4}{r^4}\right)\sin 2\beta \tag{3}$$

where r_w is wellhole radius, r is a polar coordinate, α_B is Biot parameter (i.e. porefluid pressure coefficient), η is poroelastic stress coefficient and $\eta = \alpha_B(1 - 2\upsilon)/2(1 - \upsilon)$, υ is Poisson's ratio, ϕ is porosity, P_w is bottom-hole injection pressure, and P_p is the formation pore pressure.

Considering a rectangle region $2w \times 2l$ as shown in Fig. 2, the