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Composite linear flow model for multi-fractured horizontal wells in heterogeneous shale reservoir

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ABSTRACT

Multi-stage fracturing is currently key technique to develop shale reservoirs. Different analytical models have been proposed to fast investigate post-fracturing pressure- and rate-transient behaviors, and hence, estimate key parameters that affect well performance. However, previous analytical models generally neglect reservoir heterogeneity or typical seepage characters of shale, such as adsorption/desorption, gas slippage, and diffusion effects. This paper presents an analytical model for pressure- and rate-transient analysis of multi-stage fractured shale reservoir, considering heterogeneity, typical seepage characters and, specifically, fluids flow from upper/lower reservoir when vertical fractures partially penetrate the formation.

This model is similar to five-region-flow model, but subdivides the reservoir into seven parts, namely, two upper/lower-reservoir regions, two outer-reservoir regions, two inner-reservoir regions, and hydraulic fracture region, which are all transient dual porosity media except the hydraulic fracture. As reservoir heterogeneity along the horizontal wellbore is included, the fracture distribution can be various. Fracture interference is simulated by locating a no-flow boundary between two adjacent fractures. The actual locations of these no-flow boundaries of a specific heterogeneous reservoir are determined based on the pressure value which varies with time and space. Thus, the two sides of this boundary has minimum pressure difference, satisfying the no-flow assumption. Adsorption/desorption, gas slippage and diffusion effects are included for rigorous modeling of flow in shale.

This model is validated by comparing with commercial well testing software, obtaining a good match in most flow regimes. Log-log dimensionless pressure, pressure derivative and production type curves are generated to conduct sensitivity analysis. Results suggest that larger desorption coefficient causes smaller pressure and its derivative value as a larger proportion of gas is desorbed in formation and contributes to productivity. Solutions from Azari's (1990, 1991) work, where the effect of fracture height is merely treated as a skin factor are investigated as well. Results show that our model is more accurate in partially penetrating cases, and errors of Azari's method become particularly noticeable in early-middle time response. The influence of other parameters, such as matrix permeability, matrix block size, secondary fracture permeability and hydraulic fracture conductivity, are also discussed. Optimal fracture pattern is selected based on cumulative production. Besides, field data are analyzed and compared graphically with modeling solutions, and reliable results are obtained.

As numerical and semianalytical methods require extensive computing processing, this model is a practical alternative to predict well-testing results and select optimal well pattern of shale reservoirs. Reservoir heterogeneities in vertical direction can be further added to our model by vertically subdividing the reservoir into more parts.

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1. Introduction

Shale reservoirs, which have recently gained extensive interests, bring many unique engineering challenges that may not commonly exist in conventional reservoirs. The natural gas within shale reservoir can be stored in the matrix nanopore space, natural fracture systems and adsorbed in the shale organic matter (Schein and Mack, 2007). Currently, multi-stage fractured horizontal wells (MFHWs), which significantly increase the contact area of fracture surface and payzone, are proved to be highly efficient in shale gas/oil extraction.

In published literatures, a number of analytically based solutions have been proposed to fast predict post-frac performance and evaluate critical factors that dominate well behavior since numerical models are time-consuming and need detailed description of fracture and reservoir properties which are usually not available or complete. Brown et al. (2011) proposed a new trilinear flow model with hydraulic fracture region, inner stimulated region (dual porosity) and outer reservoir region to facilitate investigating pressure behavior of MFHWs in shales. They also stated that transient dual-porosity model is more applicable for shale reservoir compared with pseudo dual-porosity idealization. Based on trilinear flow model, Ozkan et al. (2011) made comparison of MFHWs performance in tight sand and shale reservoirs. They concluded that increasing natural fracture density is an effective method to enhance productivity of shale. Later, Stalgorova and Matter (2013) extended Brown et al. (2011) model into a five-region model to simulate the fracture with a stimulated surrounding area. Deng et al. (2015) modified five-region model to deal with non-uniform distributed fractures cases, however, the location of impermeable boundary between two adjacent fractures is hard to determine in heterogeneous reservoir. To optimize fracturing treatment size and well spacing, Nobakht and Clarkson (2012) analyzed how the fractures in one well affect the adjacent well production in a zipper-shape fracture pattern. Clarkson et al. (2013) investigated the stress sensitivity of matrix permeability and fracture conductivity and found that they have significant impact on well production, especially for overpressured shale play. Recently, Ozcan et al. (2014), and Wang et al. (2015) combined linear flow with fractal theory and analytically studied the pressure behavior of multifractured unconventional wells, they provided alternative method to simulate well performance in fractured reservoir. In view of shale's multiple flow mechanisms, Zhao et al. (2013), Wang (2013), Liu et al. (2014), Zeng et al. (2015), Zhang et al. (2016), and Zhao et al. (2016) developed analytical and semi-analytical models accounting for desorption, diffusion, and viscous flow. In Wang's (2013) and Liu et al. (2014) models, the stress dependent natural fracture permeability and different angles between fracture and horizontal wellbore are also included. And by adding diffusion and desorption effects, Tian et al. (2014) improved Ezulike and Dehghanpour's (2013) quadrilinear flow model. Ren and Guo (2015) presented a more general semi-analytical model, incorporating various fracture length, diverse fracture intervals, different fracture-wellbore angles, fracture asymmetry and partially penetrating fracture.

In summary, these models are versatile enough to model predominant flow regimes for shale but neglect one or several of the following typical characteristics and possible situations in shale reservoir: (1) dual porosity feature caused by natural fractures and artificially created fracture networks, (2) gas slippage in the nanopores, (3) diffusion due to concentration gradient in the matrix pore, (4) desorption from the surface of organic matter, (5) various fracture spacing, (6) partially penetrating fracture, and specifically (7) reservoir heterogeneity.

1.1. Fracture networks in shale reservoir

Natural fractures, including discrete macro fractures and continuous micro fractures (Tian, 2014), are generally observed in shale gas plays which consist of thin layers of easily broken and fine grained rock. The existence of these fractures is a critical factor that enhances well production in such low-permeability formations with nanometer to micrometer pores. Normally, after fracturing operation, some of the pre-existing natural fractures can be reopened, conductive with proppant or intersected by hydraulic fractures, thus, forming complex fracture network which can be detected through micro-seismic mapping (Barree et al., 2002; Mayerhofer et al., 2010). From analytical point of view, dual-porosity models, triple-porosity idealizations and even fractional diffusion models are used to simulate the fluid transport in fractured unconventional reservoir. Although, discrete fracture network method is capable to account for detailed properties of individual fracture, it is computationally expensive owing to the requirement of thorough characterization data (Ozcan et al., 2014). Dual porosity models (Barenblatt et al., 1960; Warren and Root, 1963; Kazemi et al., 1969; de Swaan O, 1976) involve applying effective mean-characteristics to describe fractured formation are developed based on uniform fracture and matrix property assumption which is appropriate for continuous-fracture systems. Although, dual porosity models may not always be authentic in actual reservoir condition, they are practical for simulating fractured reservoirs on account of computer's run-time efficiency and minimum data requirement. As an alternative approach, triple-porosity model (Abdassah and Ershaghi, 1986) was proposed to consider two groups of different matrix blocks in addition to the fracture. Later, several investigators, such as Al-Ghamdi and Ershaghi (1996), Liu et al. (2003), Wu et al. (2004), Al-Ghamdi et al. (2010), and Dehghanpour and Shirdel (2011), extended the triple porosity model. By dividing the matrix volume into two subdomains, Ezulike and Dehghanpour (2013) developed quadrilinear flow model to conduct simultaneous matrix to microfracture and matrix to hydraulic fracture depletion. And fractal theory provides an optional way of sophisticated analytical study of fractured reservoirs (Cossio et al., 2012; Ozcan et al., 2014). In fact, dual porosity and triple porosity models are both special cases of multiporosity model (Bai et al., 1993), and the fundamental formulas of our model, similar with Ertekin et al. (1986) and Ozkan et al. (2010) works, are based on de Swaan O's (1976) transient dual porosity assumption combined with linear flow model.

1.2. Multi-mechanism flow of shale gas

Gas transfer mechanism in shale reservoirs seems to be significantly different compared with conventional gas formations because of the nanopore structure and adsorption/desorption effect. Therefore, it is crucial to understand how the fluids are stored and transported in the nanopore network before developing the gas-bearing formation. Although, a thorough understanding of gas transfer in shale reservoir has not been obtained, the following commonly accepted mechanisms are summarized, as shown in Fig. 1.

1.2.1. Slip flow, Knudsen diffusion and Darcy flow

Generally, the nanopore size of shale organic matrix (average size less than 4 nm-5nm (Kang et al., 2011)) is smaller than the gas molecular free path, thus, apart from gas molecules' collision, the collision between gas molecules and nanopore walls is essential as well and should not be ignored (Wu et al., 2016). In this situation, slip flow (random molecular flow) will occur in nanopores, where the assumption of continuum Darcy flow is no longer valid and