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An analytical method for modeling and analysis gas-water relative permeability in nanoscale pores with interfacial effects

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ABSTRACT

This paper provides an analytical method for modeling and analyzing gas-water relative permeability in nanoscale pores with interfacial effects in terms of Hagen Poiseuille formula and capillary pressure curve. The flow models considering the interfacial effects in nanoporous shows good agreements with experimental data comparing with other models. The changing characteristics of gas-water relative permeability were analyzed under different conditions such as nanotube radius, film thickness, surface diffusion and contact angle. The results show that the larger the nanotube radius, the greater the relative permeability values because of decreasing both interfacial microstructure effect and the resistance of fluid flow. With the increasing of film thickness, surface diffusion which is positive for flow decreases in nanoscale pores. When the contact angle >90° solid interface repel water and the hydrophobic of surfaces reduce the resistance to fluid flow, and the gas-water relative permeability increases with increasing contact angle. On the contrary when contact angle <90°, the solid interface shows hydrophilic properties which play a negative effect to the fluid flow. This study has provided a new insight and theoretical basis for development of shale gas reservoirs with nanoscale pores.

1. Introduction

With the increase of world energy demand, unconventional oil and gas resources play an important role in the global energy structure such as shale gas and tight gas. The characteristics of shale gas reservoir are low porosity, low/ultra-low permeability, and containing nanoscale pores. For example, the Mississippian Barnett Shale basin, the reservoir pore size range is 5–750 nm, and the average pore size is 100 nm (Yang, F. et al., 2013). The fracture network of shale gas reservoir is formed by hydraulic fracturing to improve the flow capacity of shale gas in industrial production. Up to now, about 85% of US production of shale gas wells used horizontal wells and multi-stage fracturing technology (Haifeng, Z. et al., 2012). The fracture network is the main gas flow passage in the shale gas production process which artificial fracture width is generally in the 500 nm–50 μm and entire fracture network scales across 50 nm–50 μm (Yang, F. et al., 2013).

According to Knudsen number, gas flow can be divided into four kinds of flow regime: continuous flow ($Kn < 10^{-3}$), slip flow ($10^{-3} < Kn < 0.1$), transition flow ($0.1 < Kn < 10$) and Knudsen flow ($Kn > 10$) (Beskok, A. et al., 1996). The reason of different flow regimes is interfacial effects essentially. When the tube diameter is large, the flow regime of gas mainly belongs to continuous flow, just only show up slip flow regime near the tube wall (Ozkan, E. et al., 2010). However Knudsen flow and transitional flow are the most important flow regimes that cause the strong interfacial effects in nanotubes. Therefore, single phase fluid flow in nanoscale pores should consider the interfacial effects.

Because of the existence of initial water and fracturing fluid in shale gas reservoir, there is obvious gas and water two-phase flow in the shale production (Haifeng, Z. et al., 2012), but otherwise, there is a big difference between the flow pattern of two-phase flow and single gas flow. And it cannot determine the two phase flow regime that only relies on Knudsen number. The research on relative permeability of gas and water phase in fracture network of shale gas reservoir with nanoscale pores is very important for shale gas production.

There is little research on relative permeability of gas and water phase in fracture network with nanoscale pores with interfacial effects currently. However there are some theoretical and experimental research results on two-phase relative permeability without interfacial effects. On the one hand, in terms of theoretical research, the primary study on the relative permeability in natural fractures is Romm's model or X model (Romm 1966), which assumed no phase interference existence between two phases. So the X-model is too idealistic to describe relative permeability as functions of saturation. Then, Brooks (1966) proposed a semi-empirical model based on Corey model (Corey, 1954) and tortuosity-saturation function, which could be called

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the Brooks–Corey model. And it has been widely used for modeling two-phase relative permeability. Fourar and Lenormand (1998) derived viscous-coupling model, which is a new analytical model considering the influence of viscosity from Stokes' equation. Chima and Geiger (2012) also proposed an analytical model of relative permeability, based on shell momentum balance, Newton's law of viscosity and cubic law for flow in fractures (Fig. 1). When ignoring the capillary force, Chima's model could be transformed into viscous-coupling model. The details of relative permeability models are given in Appendix A. On the other hand, in terms of experimental research, Persoff and Pruess (1995) studied the rules of gas-water relative permeability through natural fracture cores, the results show that the rules of relative permeability in fractures is similar to the rules in porous media. Diomampo et al. (2001) obtained similar experimental results through the experiments of relative permeability in fractures by nitrogen and water. So it is reasonable to use the porous media flow model to study the relative permeability in fractures (Babadagli et al., 2015).

Numerous studies have demonstrated that the flow regime will be changed by interfacial effects when fluid flows in nanotubes. Myers (2010) figured out that the interfacial effects were existed in the wall surface when the single-phase liquid flowed in nanotubes, which lead to form a thin liquid film and change flow characteristics. So there are two areas of flow pattern in nanotubes. Joseph and Aluru (2008) confirm that Myers' model is correct by molecular dynamics simulation method. Exerowa et al. (1987) and Derjaguin and Churaev (1974) studied the solid–liquid interface microscopic phenomenon further. The result shows that there are three microscopic forces between liquid and solid surfaces. Table 1 shows that they are long-range van der Waals force, double layer repulsive force and short-range structure repulsive force which are the reason of stable thin film formation on solid surface of nanotube.

For shale gas reservoirs, the main gas flow channels are natural micro-fracture spacing in 50–1500 nm normally. However these natural micro-fractures often have poor communication. After artificial hydraulic fracturing, the more penetrating fracture network is formed to benefit shale gas flow. While on the fracturing process, the formation of initial water and fracturing fluid will be in fracture network containing nanoscale pores. The fluid flow in nanoscale pores near interfaces will be affected by interfacial microstructure effects. Therefore, the interfacial effects cannot be ignored to gas-water relative permeability research in shale gas reservoirs with nanoscale pores.

In this paper we made a research in four aspects. At first, two analytical models of permeability for single phase flow considering that interfacial effect was established based on Hagen Poiseuille formula. In addition, the model of gas-water relative permeability in nanoscale pores was obtained further using capillary pressure curve. Then, we verified the tube flow model and parallel-plate flow model with classical models and experimental data, the results show that the tube flow model have good agreements with the laboratory result. Finally, the analysis of diameter, thickness of film, surface diffusion and contact angle were carried to figure out the relationship with relative permeability in nanoscale pores. The results could provide new insight and theoretical basis for shale gas reservoir production.

2. Analytical model of relative permeability

In this paper, we have used the tube flow model and the parallel-plate flow model to study the flow behavior in fracture network of shale gas reservoir with nanoscale pores. And then, the gas-water two phase permeability model was derived on the basis of the two models. Comparing with the experimental data, we could draw a conclusion about which model can describe the relative permeability more accurately in the nanoscale fracture.

2.1. Tube flow model with interfacial effects

The physical model is shown in Fig. 2. There are two flow regions in nanotube. Region 2 is the thin film with interfacial effects and region1 is bulk flow (Myers, 2010). No matter Knudsen flow or transitional flow in nanoscale pores, the interface microstructure effects are considered in Region 2 already, so fluid flow in the whole nanotube still satisfy the Hagen Poiseuille law (Prabha and Sathian, 2012).

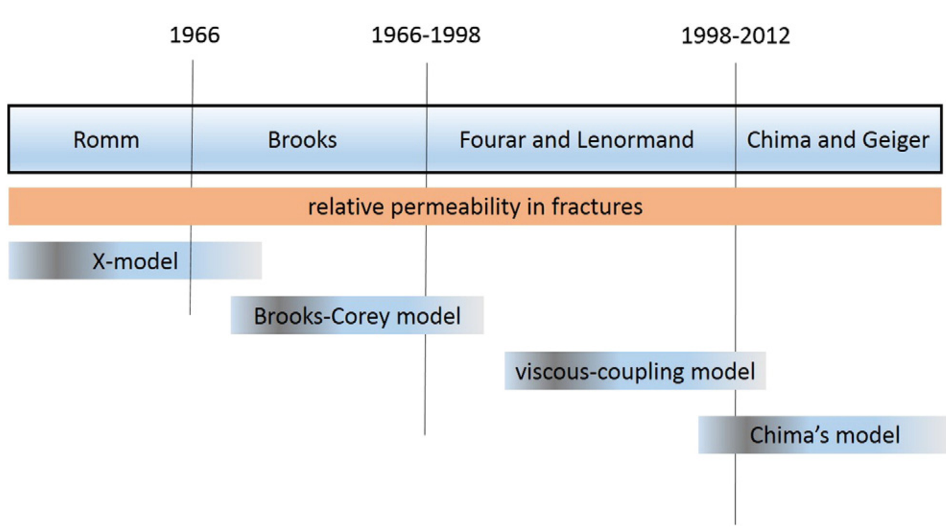

Fig. 1. Research progress of relative permeability model in fractures.