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An analytical model for relative permeability in water-wet nanoporous media

Tao Zhang [a,*], Xiangfang Li [a], Zheng Sun [a], Dong Feng [a], Yanan Miao [a,b], Peihuan Li [a], Zenghua Zhang [a]

[a] *Key Laboratory of Petroleum Engineering of the Ministry of Education, China University of Petroleum (Beijing), Beijing 102249, China*
[b] *College of Engineering, Texas A&M University, TX 77843, USA*

HIGHLIGHTS

- We model the gas-water two phase flow in water-wet nanoporous media.
- Gas-water two phase flow behavior in water-wet nanoporous media is revealed.
- Nanoscale effects (gas slippage, multilayer sticking and water film) are considered.
- Nanoscale effects affect relative permeability in nanoporous media significantly.
- Sensitivity of nanopore size distribution on relative permeability is examined.

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ABSTRACT

A relative permeability model for gas-water two phase flow in water-wet nanoporous media is proposed based on the continuity equation with modified non-slip boundary in a single nanotube and the pore size distribution (PSD) of the media. The present model takes into account the nanoscale effects including gas slippage in the entire Knudsen range, multilayer sticking (near-wall structural water film) and the quantified thickness of water film. The flow model in single nanotube and relative permeability model in nanoporous media have been validated by comparing with the various molecular simulations, experimental data, and analytical models. The results show the nanoscale effects play an extremely significant role in determining both the gas and water phase relative permeability in nanoporous media: the gas phase relative permeability increases dramatically due to the gas slippage effect, especially at low water saturation; the multilayer sticking of the water film will reduce the water phase relative permeability as well as slightly decrease gas phase relative permeability; the flow of water film has a negative impact on both the gas and water phase relative permeability. Additionally, logarithmic normal distribution function is adopted to characterize PSD, and the sensitivity analysis of PSD on the relative permeability are examined as well.

1. Introduction

During the past decade, with the huge amount of conventional petroleum-based fuels' consumption and their serious greenhouse effect, natural gas from unconventional shale and tight gas reservoirs has attracted considerable interests due to its abundant reserves, wide distribution, low CO_2 emission and economic efficiency (Wu et al., 2016). Horizontal well combined with multi-stage slip water hydraulic fracturing makes it possible for the unconventional resources, containing nanoscale dominating pores (Li et al., 2016a), to be developed economically and efficiently (Vidic et al., 2013). In this situation, the injected fracturing fluid and the existence of initial water in the reservoir obviously reveal the gas-water two phase flow in underground nanopores (Zhao et al., 2012; Li et al., 2016b). Therefore, modeling and predicting the gas-water two phase transport behavior in nanoporous media are extremely important for the simulation and evaluation of tight reservoir performance and are also possible for the application in other nanoporous media (Gruener et al., 2009; Gambaryan-Roisman, 2014).

Relative permeability has been proven to be a feasible and successful tool to characterize the complicated multiphase flow behavior of porous media at macroscopic in the variety of fields, such as natural gas recovery, carbon dioxide (CO_2) storage, coal gasification, and geothermal energy exploitation (Iii et al., 1981;

* Corresponding author at: 18# Fuxue Rd Changping District, Beijing, China.
E-mail address: tobiascheuing@163.com (T. Zhang).

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Berkowitz et al., 2002). Generally, the determination methods of relative permeability can be classified into three types: (1) laboratory experiments (Honarpour and Mahmood, 1988; Li and Horne, 2006; Pini and Benson, 2013), (2) simulation methods (Knackstedt et al., 2001; Cantisano et al., 2013), (3) analytical modeling (Finsterle, 2000; Helmig et al., 2006; Xu et al. (2013); Li et al., 2016b). Two kinds of laboratory measurement techniques, steady and unsteady state methods, are widely employed to determine the relative permeability in the porous media with micro-macro pores (Honarpour and Mahmood, 1988). However, to obtain relative permeability for nanoporous media, utilizing the laboratory experiments is very challenging and even impossible due to the ultra-low permeability (Yassin et al., 2016). Simulation methods, mainly including pore-scale network modeling (eg. Lattice Boltzmann method), are another way to determine relative permeability. Unfortunately, it consumes huge computational resources and time, which is not suitable for gas-water transport investigation (Wu et al., 2015). In contrast, the analytical modeling, based on discrete model using an idealized pore structure and displacement mechanisms (Finsterle, 2000) or a continuum approach relying on a porous medium with continuum scale representation (Helmig et al., 2006), not only provides instantaneous calculation results and identifies the effect of each key physical parameter but also yields general predictions and observations, which makes it a promising and meaningful method to calculate the relative permeability in nanoporous media.

Nanoscale pores, ranging from a few nanometers to several hundred nanometers, are abundant in shale and tight sandstone formations (Curtis et al., 2012), and the transport mechanism in these formations is considerably different from that in conventional gas formations (Wu et al., 2017a). For the single gas phase transport through the nano-channel, the momentum transport for molecules near the solid surface, about a mean free path in thickness adjacent to the solid, is in a severe nonequilibrium state, known as slip effect (Millikan, 1923). Through Knudsen number K_n, defined as the ratio of gas mean free path to the characteristic dimension, gas transport mechanisms can be classified into continuum regime ($K_n < 10^{-3}$), slip regime ($10^{-3} < K_n < 10^{-1}$), transition regime ($10^{-1} < K_n < 10$) and free molecular regime ($K_n > 10$) (Lei et al., 2016). Relying on Knudsen number K_n for the flow regimes classification, there has been a significant amount of gas transport models proposed, providing a new framework for permeability prediction in tight formation (Cantisano et al., 2013). These models can be classified into two types: the continuity equations by modification of a non-slip boundary condition (slip flow and Knudsen diffusion) (Javadpour et al., 2007; Civan, 2010; Darabi et al., 2012); the unified gas transport equations by weight coefficient to combine several transport mechanisms (Brown et al., 1946; Scott and Dullien, 1962; Wu et al., 2015). However, these aforementioned expressions are only valid for single gas phase transport. It is well known that there is a huge difference between the gas-water two phase flow and single gas phase flow from the macroscale to microscale tube, not to mention in the nanoscale (Akbar et al., 2002). Hence, distinguished from the single gas phase flow, establishing a gas-water two phase relative permeability model in nanoporous media is of more practical significance to the development of shale and tight sandstone gas reservoirs.

To understand and simulate the gas-water two phase flow in nanoporous media, the single water phase transport in the nano-channel needs to be reviewed firstly. Owing to the surface-dominated characteristics of fluid flows at nano-channel (Cao et al., 2009), where the structure of the water is strongly modified by the confinement and this changes the boundary conditions at the walls, there is a great amount of works indicating that the conventional no-slip assumption in Poiseuille flow is not well obeyed for water flows in nano-channel in both hydrophobic and hydrophilic cases (Lei et al., 2016). In this study, we mainly focus on gas-water transport and relative permeability in the water-wet porous media with nanoscale pores, thus, hydrophobic cases are not within the scope. In the hydrophilic nano-channel, as measured by atomic force microscopy (AFM) and other surface force measurements, a unique structural ordering of water confined in hydrophilic channel has been observed, showing a sharp increase in the viscosity ("negative slip length") and significantly different from those of bulk water (Antognozzi et al., 2001; Li et al., 2007). Therefore, when modeling the gas water two-phase flow in the water-wet nanoporous media, the high viscosity of near-wall structural water film, named "multilayer sticking", should be considered.

Until now, there is only a handful of research on relative permeability of gas and water phase in nanoporous media because of the complicated gas-water transport behaviors and challenges to measure it with laboratory experiments. Cantisano et al. (2013) determined the oil-water relative permeability of shale formation by taking the advantages of the digital rock physics along with lattice Boltzmann method, while they neither considered the nanoscale effects for gas nor water. Daigle et al. (2015) utilized the combination of critical path analysis, effective medium theory and percolation theory, and determined relative permeability for bulk shales and isolated kerogens. They concluded that relative permeability to the nonwetting phase is linear with water saturation, which is impractical for the strongly nonlinear transport of gas phase (Javadpour et al., 2007). Yassin et al. (2016) extended Purcell's model to describe the gas-water two phase flow through the dual-porosity/dual-wettability system, and the applicability of the model was verified with the black-oil simulator by simulating the measured data from water imbibition into the shale rocks, but the model was not based on the basic flow characteristic of the fluid. Li et al. (2016b) provided an analytical method for modeling and analyzing gas-water two phase relative permeability in nanoporous media, and the interfacial effects in terms of Hagen-Poiseuille formula and capillary pressure curve were incorporated in their model. Nevertheless, no quantitative expression for water film was given and the gas slippage effect as well as the multilayer sticking were ignored in his work.

Inspired by above and aware of possible limitations, a physical conceptual model of relative permeability is developed for gas-water two phase flow in water-wet nanoporous media. Four parts are included in this article: first, gas-water two phase transport model in circular nanotube is established, and the model of gas-water relative permeability in water-wet nanoporous media is obtained with combination of PSD. The present model considers the nanoscale effects including gas slippage in the entire Knudsen regime, multilayer sticking and the quantified thickness of water film; second, the present flow model in single nanotube and relative permeability model in nanoporous media are validated by comparing with the various molecular simulations, experimental data, and analytical models; third, the nanoscale effects on the relative permeability are discussed, and the effect of PSD including standard deviation of pore radius and mean pore radius on the relative permeability are analyzed; finally conclusions.

2. Mathematical modeling

Firstly, the film thickness around the circular nanotube is quantified according to the theory of surface force and disjoining pressure; then the model of gas-water two phase flow in a nanotube coupled with gas slippage and multilayer sticking is established by combining continuity equation and modification of a non-slip boundary condition; finally, based on this and the pore size