Petroleum 2 (2016) 171–176

Contents lists available at ScienceDirect

Petroleum

journal homepage: www.keaipublishing.com/en/journals/petlm

Original article

Experimental study on gas slippage of Marine Shale in Southern China

Ying Ren [a, *], Xiao Guo [a], Chuan Xie [b], Hongqin Wu [c]

[a] State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Southwest Petroleum University, No. 8, Xindu Avenue, Xindu District, Chengdu 610500, China
[b] Shunan Division of Southwest Oil and Gasfield Company, PetroChina, Sichuan, Luzhou 646000, China
[c] Research Institute of Drilling Engineering, Sinopec Southwest Petroleum Engineering Company, Sichuan, Deyang 618000, China

ARTICLE INFO

Article history:
Received 11 January 2016
Received in revised form
4 March 2016
Accepted 22 March 2016

Keywords:
Shale gas
Permeability
Fracture
Slippage
Effective stress

ABSTRACT

The shale gas reservoirs are composed of porous media of different length scales such as nanopores, micropores, natural fractures and hydraulic fractures, which lead to high heterogeneity. Gas flow from pores to fractures is under different flow regimes and in the control of various flow mechanisms. The gas slippage would have significant effects on gas flow in shale. To obtain the effect of slippage on gas flow in matrix and fractures, contrast experiments were run by using cores with penetration fractures and no fractures from Marine Shale in Southern China under constant confining pressure. The results showed that slippage effect dominates and increases the gas permeability of cores without fractures. To cores with penetration fractures, slippage effect is associated with the closure degree of fractures. Slippage dominates when fractures close under low pore pressure. Slippage weakens due to the fractures opening under high pore pressure. Fracture opening reduces the seepage resistance and slippage effect. The Forchheimer effect occurs and leads to a permeability reduction.

1. Introduction

As shale gas reservoirs are increasingly becoming major fossil energy in today's world, understanding the gas flow mechanism in these unconventional gas resources is crucial. The dynamics of gas flow in shale gas reservoirs has become an important research topic during the current decade in the oil and gas industry [1].

There are four types of porous media of different length scales in shale gas reservoirs: nanopores, micropores, natural fractures and hydraulically induced fractures [2]. Fig. 1 shows the pores in conventional and shale gas reservoirs. As presented in the schematic figure, shale gas reservoirs contain more nanopores than conventional reservoirs. Radius of pore throats in gas shale sediments generally ranges from a few nanometers to a few micrometers [3]. These matrix pores make up the significant portion of reservoir space of natural gas. The complex fracture system composed of natural fractures and hydraulically induced fractures connects matrix pores, which forms a high-permeability network in gas shale.

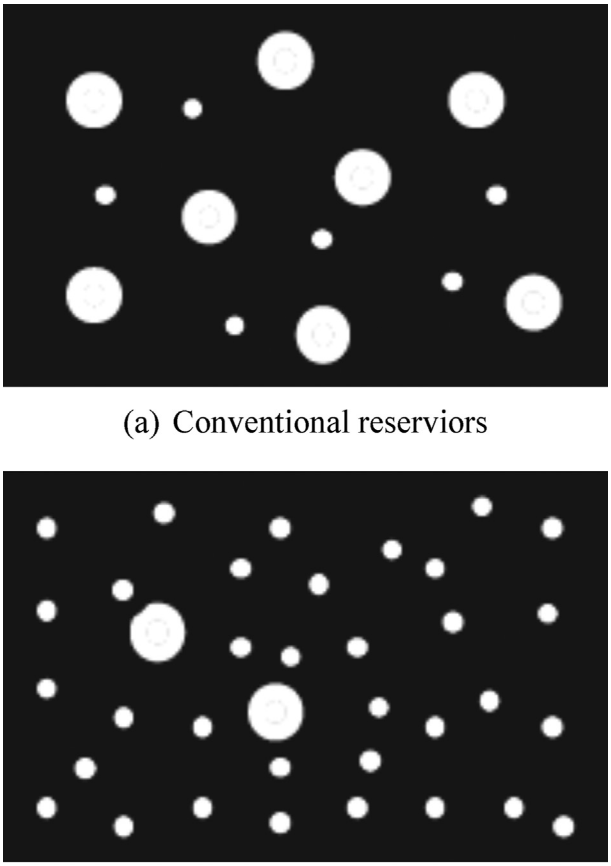
When gas flows from nanopores to fractures and from factures to wellbore, the flow mechanism varies due to the different length scales of flow channels. Gas flow in larger pores, throats and fractures generally follows Darcy equation, and in nanopores, slip flow and diffusion dominate [4]. The Knudsen number, a significant dimensionless parameter, is used to classify the flow regimes in porous media of different length scales. It is defined as the ratio of the gas mean free path λ (m) and the pore radius r (m) [3].

$$Kn = \frac{\lambda}{r} \tag{1}$$

* Corresponding author. Tel.: +86 18782943263.
E-mail address: swpuren@foxmail.com (Y. Ren).
Peer review under responsibility of Southwest Petroleum University.

Production and Hosting by Elsevier on behalf of KeAi

http://dx.doi.org/10.1016/j.petlm.2016.03.003



(a) Conventional reservoirs

(b) Shale gas

Fig. 1. Pores in conventional (a) and shale gas (b) reservoirs [3].

The gas mean free path λ is defined as

$$\lambda = \frac{K_B T}{\sqrt{2}\pi\delta^2 p} \tag{2}$$

in which K_B is the Boltzmann constant, 1.3805×10^{-23} J/K; T is temperature, K; p is pressure, Pa; δ is the collision diameter of the gas molecule. For methane, δ=0.4 $\times$ 10^{-9} m.

Different Knudsen numbers correspond to different flow regimes [5,6]: continuum flow ($Kn < 0.001$), slip flow ($0.001 < Kn < 0.1$), transitional flow ($0.1 < Kn < 10$), and free molecular flow ($Kn > 10$). Fig. 2 presents the Knudsen number as a function of pressure with various pore sizes ranging from 1 nm to 5 μm. The gas slippage typically occurs in the condition where the mean free path of the gas molecules is no more negligible compared to the average effective pore throat radius ($0.001 < Kn < 0.1$). The gas molecules would slip on the inner surfaces of the pores. This effect gives apparently higher permeability than the absolute permeability measured using a liquid [7,8].

Klinkenberg (1941) [9] first addressed the gas slippage in porous media and gave a linear correlation between the measured gas permeability and the reciprocal mean pore pressure.

$$k_a = k_\infty\left(1 + \frac{b_k}{\overline{p}}\right) \tag{3}$$

where k_∞ is the absolute permeability, mD; k_a is the measured gas permeability (apparent permeability), mD; b_k is the

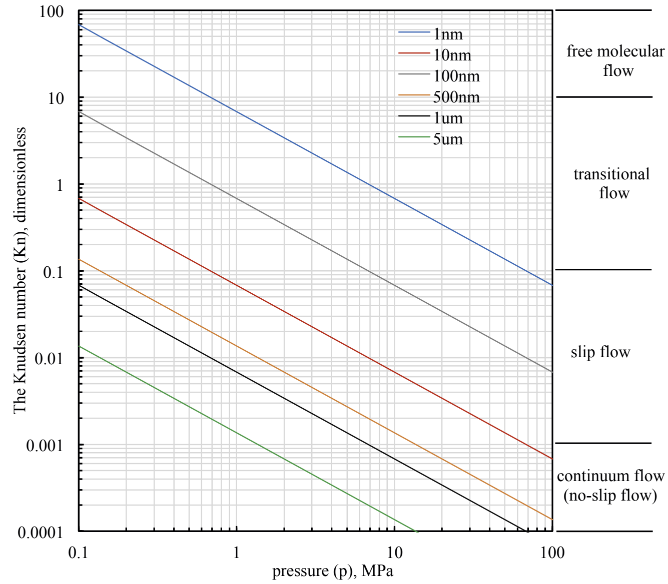


Fig. 2. Knudsen number as a function of pressure.

Klinkenberg slippage factor, MPa; $\overline{p}$ is the mean pore pressure, MPa. Table 1 presents various correlations for gas slippage factor b proposed in the subsequent work.

Beskok and Karniadakis(1999) [17] developed a rigorous equation for volumetric flow through a micro tube.

$$k_a = (1 + \alpha Kn)\left(1 + \frac{4Kn}{1 - bKn}\right)k_\infty \tag{4a}$$

$$\alpha = \frac{128}{15\pi^2}\tan^{-1}\left(4Kn^{0.4}\right) \tag{4b}$$

where α is the dimensionless sparse coefficient, b is gas slippage factor and generally $b \approx 1$. Civan (2010) [13] improved Beskok and Karniadakis model and demonstrated a simple inverse power-law expression of the sparse coefficient α as given below

$$\alpha = \frac{\alpha_0}{1 + \frac{A}{Kn^B}} \tag{5}$$

where $A = 0.170$, $B = 0.434$, $\alpha_0 = 1.358$.

Tang et al. (2005) [15] reported that the second-order term of the Knudsen number (Kn^2) cannot be neglected for gas flow with relatively high Knudsen numbers. They presented a widely known model given as follows

$$k_a = k_\infty\left(1 + \frac{A}{\overline{p}} + \frac{B}{\overline{p}^2}\right) \tag{6}$$

where A, B are constants that depend on gas properties and pore geometry.

Zhu et al. (2007) [16] also recommended using a higher-order equation which can be written as

$$k_a = k_\infty\left(1 + Ae^{\frac{\alpha}{\overline{p}}}\right) \tag{7}$$

Fathi et al. (2012) [18] proposed the following equation based on their numerical analysis.