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Investigation of multi-scale gas transport behavior in organic-rich shale

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ABSTRACT

Gas flow in shale is controlled by different space scales and time scales due to its ultra-fine pore structure, high content of clay minerals, high content of organic matter and serious anisotropy. In this work, multi-scale gas transport in organic-rich shale is investigated by theoretical modeling and pore structure analysis. Characteristics of multi-scale gas transport in shale are sufficiently confirmed through study of multi-scale flow tube, multi-scale pore structure and multi-scale flow regime. The effect of Knudsen diffusion on non-linear gas flow in shale is analyzed. Contribution of Knudsen diffusion to apparent gas permeability is calculated to be greater at the lower pressure or permeability. Knudsen diffusion coefficient and its corresponding hydraulic radius are calculated to be lower at the lower permeability or higher pressure. Finally, an equivalent permeability formula is put forward to model the apparent permeability of shale at specific pressure, temperature and petrophysics. The increase multiples of permeability for gas slippage during the development of the studied shale gas reservoir is determined, indicating that the effect of non-linear flow on shale permeability measurement and well production forecast should be paid abundant attention. Results from this study are beneficial to comprehensively understand multi-scale gas transport in shale.

1. Introduction

Shale gas reservoir is a representative type of tight gas reservoir. It is playing an increasingly important role in Chinese natural gas industry due to the huge amount of resources and increasing production (Zhang et al., 2008; Zou et al., 2010; Wang, 2013). In 2015, China's Ministry of Land and Resources has published that Chinese geological reserves of shale gas are 134.42 $\times$ 10^{12} m^3 and the recoverable reserves are 25.08 $\times$ 10^{12} m^3. SINOPEC has announced its Fuling Gas Field will be the first domestic annual production of 100 $\times$ 10^8 m^3 for shale gas in 2017. All of these demonstrate the enormous potential of shale gas exploitation in China.

Gas-shale is characterized by ultra-fine pore structure, high content of clay minerals, high content of organic matter and serious anisotropy, which result in different sizes and types of flow channels in shale (Pan et al., 2015; Liu et al., 2011; Passey et al., 2010; Loucks et al., 2009; Curtis, 2002). In general, gas flow in shale is controlled by different space scales and time scales (Javadpour et al., 2007; Akkutlu and Fathi, 2012; Alharthy et al., 2012). Its flow mechanisms are quite different from conventional gas reservoirs. The linear flow theory is never suitable for shale (Li et al., 2004; Javadpour, 2009; Swami et al., 2012). Therefore, gas flow in shale belongs to the typically multi-scale gas transport. It has been demonstrated that gas slippage or Knudsen diffusion is critical for investigating gas flow in matrix shale, no matter for correcting laboratory permeability or analyzing field data (Javadpour et al., 2007; Freeman, 2010; Schepers et al., 2009; Wang et al., 2009). However, the study of non-linear flow theory is still in the start stage, which is mostly based on theoretical researches (Dreuzy et al., 2012; Wang et al., 2013; Ebrahimi et al., 2014). The most important theory in the early age is the Klinkenberg model (Klinkenberg, 1941). Since the porosity of unconventional gas reservoirs is much tighter than that described by Klinkenberg, by now, many models about non-Darcy flow in porous media has been presented, such as correction of the slippage factor in Klinkenberg model (Jones and Owens, 1980; Sampath and Keighin, 1982; Ertekin et al., 1986; Thornstenson and Pollock, 1989; Florence et al., 2007; Fathi et al., 2012) and equivalent permeability based on the work of Beskok and Karniadakis (Beskok and Karniadakis, 1999; Michel

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et al., 2011; Civan, 2010; Ziarani and Aguilera, 2012). Yet, the main shortness of these researches is that the particular pore structure of organic-rich shale has not received enough attention and the corresponding experiments of gas (methane) flow in shale are rarely implemented.

The combination of theoretical modeling and laboratory experiment should be the effective way to study multi-scale gas transport in shale. In this work, data from the Longmaxi Shale in the eastern Sichuan Basin of China are used to characterize multi-scale gas flow tubes in shale. The multi-scale characteristic of flow regimes is studied for the development of the studied shale gas reservoir. What's more, multi-scale pore structure of shale samples is sufficiently studied by various kinds of methods, such as low-pressure gas (N_2) adsorption, high pressure mercury injection capillary pressure, nuclear magnetic resonance, X-ray microscopic CT scanning, field emission scanning electron microscopy and naked eye observation. Meanwhile, essence of non-linear flow in shale is deeply analyzed and the contribution of Knudsen diffusion to apparent gas permeability is quantitatively calculated for shale samples with multi-scale pore structure. Then an equivalent permeability is put forward to model the apparent gas permeability of shale at specific pressure, temperature and petrophysics. The results from this study are beneficial to deeply understand multi-scale gas transport in organic-rich shale and its influence on shale gas development.

2. Characteristics of multi-scale transport in gas-shale

Shale samples from the Longmaxi Formation in China, which is a Lower Silurian marine shale gas play in the east of Sichuan Basin, are used in this section to investigate the characteristics of multi-scale gas transport in shale. These samples are organic-rich siliceous and carbonaceous shale. The mineralogical composition and geochemical parameters are shown in Table 1.

2.1. Multi-scale flow tube

Gas-shale is a kind of porous media characterized by serious anisotropy, which results in different sizes and types of flow channels in shale (Alharthy et al., 2012). According to the formula calculating hydraulic radius of flow tube in tight porous media (Civan et al., 2011), the effective mean radius of pore which dominates gas flow in shale is expressed as:

$$r_H = 2\sqrt{2\tau}\sqrt{\frac{k_\infty}{\phi}} \tag{1}$$

in which τ is the tortuosity, Φ is the porosity and k_∞ is the equivalent liquid permeability.

In order to investigate the scale of flow tube in shale, steady state methane flow experiment was conducted (Kang et al., 2015). The samples used in the core methane flow experiments were cored parallel to the bedding planes, which are 2.5 cm in diameter and 4 ~ 5 cm in length. Steady state permeability measurement was designed with three backpressure values (0.1 MPa, 2 MPa, 5 MPa) at the outlet of core samples. The schematic diagram of the methane flow measurement is shown in Fig. 1.

Based on the core flow experimental data shown in Kang et al. (2015), we selected four cores with different permeability to calculate their mean effective pore radius (Table 2).

As is shown in Table 2, for the samples with different permeability, slippage factor increases with the decrease of core permeability. Also, the calculated pore size decreases. Since a core sample represents a corresponding small scale in shale gas reservoir, the results shown in Table 2 indicate that gas flow in shale is characterized by multi-scale space or pore size.

For different backpressure condition, the calculated radius is variable, which decreases with the increase of backpressure. Because pore pressure increases obviously with the increase of backpressure, gas slippage effect weakens in high backpressure condition. Meanwhile, with the increase of pore pressure, adsorption of methane on organic matter increases, which causes the adsorption layer thicker and makes the gas flow channel smaller.

Gas slippage in porous media results from the little viscosity resistance of pore interface to gas molecules. In general, gas flow regime at different pore sizes and gas pressure conditions is classified through Knudsen number (Kn).

$$Kn = \frac{\lambda}{r_H} \tag{2}$$

in which, λ is the mean free path of gas molecules and r_H is the hydraulic radius of flow tube in porous media characterizing the mean pore radius approximately.

The expression of the classical Klinkenberg model is shown as follows:

$$k_g = k_\infty\left(1 + \frac{b}{p_m}\right) \tag{3}$$

$$b = \frac{4C\lambda p_m}{r_H} \tag{4}$$

where b is the slippage factor, k_g is the apparent gas permeability, p_m is the mean pore pressure and C is a constant closing to 1.

Inserting Eq. (4) into Eq. (3), another expression for the Klinkenberg correction is given as:

$$k_g = k_\infty\left(1 + \frac{4\lambda}{r_H}\right) \tag{5}$$

Comparing the expression shown in Eqs. (2) and (5):

$$\frac{k_g}{k_\infty} = 1 + 4Kn \tag{6}$$

The increase multiples of permeability (k_g/k_∞) at different Kn can be plotted (Fig. 2) based on Eq. (6). As presented in Fig. 2, k_g/k_∞ increases with the increase of Kn. It could be caused by the reduction of pore scale. Meanwhile, gas slippage effect is more remarkable and the apparent gas permeability is higher. Knudsen diffusion plays a more and more important role in gas flow.

Table 1
Mineralogy, total organic carbon (TOC) and vitrinite reflectance (Ro) of samples.

Mineralogy, wt.%							TOC, wt.%	Ro, %
Clay	Quartz	K-Feldspar	Plagioclase	Calcite	Dolomite	Pyrite		
33.71	45.55	1.96	6.02	3.33	5.94	3.49	3.09	2.94