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A pore structure based real gas transport model to determine gas permeability in nanoporous shale

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ABSTRACT

Gas flows in the forms of multiple transport mechanisms in shale nanoporous media with complex pore structure and different pore types. Laboratory pressure pulse decay technique is often applied to measure gas permeability but the current gas permeability interpretation model is mostly based on the homogeneous macro scale model while the influence of pore structure on real gas transport is neglected. In this study, a novel pore structure based real gas transport model is proposed to determine gas permeability in nanoporous shale combining laboratory pressure pulse decay technique with pore network simulation. The laboratory pressure pulse decay process is simulated in a virtual system based on the similarity principle which contains upstream vessel, downstream vessel, and core sample. The core sample is constructed by a series of connected pore networks and the sizes of pores and throats in each location of the pore network are randomly assigned according to laboratory measured pore size distribution. Gas transport mechanisms inside the core sample consider viscous flow, Knudsen diffusion, surface diffusion and real gas effect. At each time step, the upstream vessel pressure decreases and the downstream vessel pressure increases until the upstream vessel pressure and downstream vessel pressure become equal. The simulated pressure drop versus time curve is obtained and is applied to fit the laboratory measured pressure drop data by repeating core sample construction and pressure pulse decay process. The proposed model is applied to measure gas permeability of Sichuan basin, Longmaxi formation shale core sample. The results indicate that the predicted value based on the proposed model matches well with the experimental measured pressure drop data. The proposed model is used to study the influences of test gas type and pore size on gas permeability. When the average organic pore radius is less than 20 nm, helium tested permeability overestimates at least 40% of the methane permeability.

1. Introduction

Shale is the typical porous media with large amounts of nanopores [1]. The heterogeneities of shale nanoporous media are expressed in terms of complex pore structure and different pore types. Because shale pore size approaches to the molecular mean free path, the gas flow deviates from viscous flow [2] and the flow regime is conventionally subdivided according to the Knudsen number, the ratio of molecular mean free path to the pore radius. Loucks et al. [3] categorised pore types in shale into three types: interparticle mineral pores, intraparticle mineral pores and intraparticle organic-matter pores. Intraparticle organic-matter pores are referred to as organic pores and the other two types of pores are referred to as inorganic pores in our study. Organic pores represent the pores inside the organic matter (kerogen) and are also named as kerogen pores. An organic-rich pore has a large specific surface area and the organic matter can adsorb a significant amount of gas molecules [4]. Surface diffusion takes place within the adsorbed gas to enhance the transport of gas molecules along molecular concentration gradients [5]. In order to assess gas flow ability in nanopores, Civan [6] developed apparent gas permeability models based on the Knudsen number. Song et al. [7] considered the influence of different pore types on apparent gas permeability. Javadpour et al. [2,8,9] and Singh [10,11] developed apparent gas permeability models based on superposition of Knudsen diffusion and slip flow. While gas transport mechanisms are considered in apparent gas permeability model, conventional

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apparent gas permeability model is based on homogeneity assumption and neglects the influences of organic matter spatial distribution, pore size distribution on gas flow ability. The heterogeneity of shale pore structure is neglected and therefore predicted permeability of shale sample is not reliable. Kou et al. [12] proposed a convective–diffusive transport model including the capillary wall effects and studied steady-state transport in the network of nanocapillaries using a multi-scale theoretical approach. Alafnan and Akkutlu [13] extended the pore network modeling approach to describe the interaction between organic materials and single crack from which a coupling flow exchange term that can be used in continuum modeling of shale matrix dynamics is developed. Recent advances in high-resolution imaging technology and so-called digital core analysis approach have made it possible to characterise pores and solids in porous material [14]. Using such pore-structure models, numerical simulations can be carried out to predict transport and mechanical properties [15].

Currently two approaches are applied to measure permeability of porous media namely indirect and direct method. The indirect method involves steady state permeability and unsteady state permeability measurements. Permeability obtained from the direct approach is based on the homogeneous correlation method like the Carman–Kozeny or Hagen–Poiseuille equations. For shale with strong heterogeneities and nanoscale pore size, permeability is dependent on gas transport mechanisms, pore size spatial distribution and reservoir properties (pore pressure, temperature) and therefore the direct method is not applicable. The traditional steady state flow permeability measurement is extremely time consuming for shale core samples and is not practical because of the instrumentation requirements for measuring extremely small pressure drops or flow rates. The unsteady state method namely pressure pulse decay method measures the decay of upstream pressure and the increase in downstream pressure and has been used extensively to estimate permeability of shale samples [16]. The slope of pressure gradient change versus time is used to estimate the permeability [17] and the measured permeabilities order can reach as low as 10^{-12} D [18–20]. CUI et al. [18] improved the pressure pulse decay technique to consider the influence of adsorption on effective permeability by correcting effective porosity in homogeneous macro scale model. Akkutlu et al. [21] developed dual porosity model to incorporate the influences of organic and inorganic pores and randomized maximum likelihood method was applied to analyze pressure drop data. However, the above mentioned pulse decay data interpretation models are homogeneous model based on the porosity and the influences of pore size spatial distribution and different pore types on gas flow are neglected [22]. Furthermore, the gas permeability is not pressure dependent during derivation of the analytical solutions of the gas permeability. Attempts have been made to put more and more shale pore structure characteristic information into the pressure pulse decay data interpretation. Naraghi et al. [23] constructed ensemble-based stochastic model conditioned to total organic content (TOC) and the characteristics of pore-size distributions in organic and inorganic matrix.

The purpose of this study is to develop a pore structure based real gas transport model to determine shale gas permeability combining laboratory pressure pulse decay technique with pore network simulation. In Section 2, the laboratory pressure pulse decay process is simulated in a virtual system based on the similarity principle which contains upstream vessel, downstream vessel, and core sample. In Section 3, gas flow models for different gas types and solution method are introduced. In Section 4, the proposed approach is applied to measure gas permeability of Sichuan basin, Longmaxi formation shale core sample and is compared with available model from the literature. This is followed by a section of conclusion.

2. Physical model description

The shale core sample in Fig. 1(a) is gathered from Sichuan basin, Longmaxi shale formation. The porosity of the studied shale is 6.5% and the studied shale sample mainly contains pores and solids. Parameters used in pulse-decay experiment are shown in Table 1. The laboratory pressure pulse decay process is simulated in a virtual system in Fig. 2 based on the similarity principle which contains upstream vessel, downstream vessel, and core sample. A 3D pore-solid shale model in Fig. 3(a) is generated stochastically using Multiple-Point Statistics (MPS) method [24] from a 2D binary SEM image in Fig. 1(b) acquired on a polished thin-section of the shale core sample. The resolution of the SEM image is 400 × 400 pixels and the pixel size of the SEM image taken is 20 nm × 20 nm. From the generated 3D model, pore structure mid axis in Fig. 3(b) is extracted from the pore space based on mid axis method, where each intersection of skeletons is designated as a centre for a spherical pore node and connected pore centres is replaced by a circular cylinder of infinitesimal radius. The sizes of pores and throats in each location of the pore topology are randomly assigned according to laboratory measured pore size distribution in Fig. 4. The core sample is constructed by connecting a series of same pore networks obtained from above mentioned procedure and the physical length of the simulated core sample is the same as that of the laboratory core sample. It should be mentioned that the throat size is smaller than the size of two connect pores during randomly assigning process. The upstream volume V_{up} and downstream volume V_{down} are given in Eqs. (1) and (2) based on the similarity principle according to the ratio of simulated core sample volume V_{core_sim} to the laboratory core sample volume V_{core_lab}.

$$V_{up} = V_{up\_lab}\frac{V_{core\_sim}}{V_{core\_lab}} \tag{1}$$

$$V_{down} = V_{down\_lab}\frac{V_{core\_sim}}{V_{core\_lab}} \tag{2}$$

$$V_{core\_sim} = l_x l_y L_{core} \tag{3}$$

where l_x, l_y are the length of simulated core sample and reconstructed shale digital core in x direction and y direction, respectively (m), L_{core} is the length of laboratory core sample (m).

3. Numerical method

3.1. Gas flow models for different gas types

For nonadsorbing gas like helium, gas flows in the forms of viscous flow and Knudsen diffusion [25]. Gas flow regimes are identified by the Knudsen number, the ratio of the mean free path of gas molecules and the radius of a capillary. The mean free path for real gas can be expressed by Eq. (4) [26]. Real gas property for helium is obtained from the experimental data given in Seibt et al. work [27].

$$\lambda = \sqrt{\frac{\pi ZRT}{2M}}\frac{\mu}{p_o} \tag{4}$$

where Z is gas compressibility factor, dimensionless, R is the ideal gas constant, 8.314 J/(K·mol), T is temperature (K), M is gas molecular weight (g/mol), μ is the gas viscosity (Pa·s), p_o is the pore pressure (Pa).

The Knudsen number can be written as [28]:

$$K_n = \frac{\lambda}{r} \tag{5}$$