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Pore-scale geometry effects on gas permeability in shale

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ABSTRACT

One main challenge for prediction of gas permeability in shale is the geometrical complexity at pore scale of shale. Shale structure is highly anisotropic and heterogeneous, which cannot be well described by packing of spheres or bundle of tubes. Besides, there are abundant nanoscale pores in shale so that the Knudsen number of gas flow is high, leading to failure of the conventional Darcy's law. Aiming at these challenges, we have studied the influences from pore-scale anisotropy and heterogeneity of shale microstructures on gas permeability including the high Knudsen number effect (or Klinkenberg effect for Darcy scale). First, a geometry-based method is proposed to quantify the pore-scale anisotropy and heterogeneity of shale. Then we reconstruct three-dimensional shale structures by the random generation-growth algorithm and use the lattice Boltzmann method to predict its permeability. To reveal the high Knudsen number effect, both intrinsic permeability and apparent permeability are evaluated. Our results suggest that the intrinsic permeability increases with the anisotropy of pore geometry in parallel direction to the bed, while decreases in perpendicular direction. The slip factor for Klinkenberg correction also exhibits anisotropy when high Knudsen effect is considered. On the other hand, the heterogeneity of pore distribution may have positive influences on intrinsic permeability for given porosities.

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1. Introduction

With the declination of conventional natural gas resources, shale gas becomes more and more important because of its huge storage and relatively matured exploitation technology. To optimize the exploitation and predict the gas production, the gas permeability of shale is an important parameter. However, there is no precise model for shale gas permeability yet, because shale has very complex geometry for gas transports. Generally, shale structure is highly anisotropic and heterogeneous, and most organic pores are at nanoscale. A quantitative description of these features and their influences on gas flow is essential for shale permeability modeling.

Experiments have shown that shale is strongly anisotropic and the permeability parallel to the bed is one, or more, order of magnitude higher than the perpendicular permeability (Kwon et al., 2004). The anisotropy of shale is reflected at both macro scale and pore scale. At macro scale, shale has layered structure, which has been studied and modeled by many researchers. Begg and Chang (1985) developed a statistical method to predict the perpendicular permeability of reservoir containing discontinuous plate-like shales. McCarthy (1991) considered the flow in layered sandstone-shale structure by both analytical modeling and numerical simulation. Burton and Wood (2013) provided quantitative characteristic data of the layered shale morphology and studied its influence on permeability. Besides, the anisotropy of shale is also observed at pore scale, for example, the structure of organic matter is anisotropic too. As shown by micro scanning, some organic pores in shale have large aspect ratio (Kwon et al., 2004) and the geometry parallel or perpendicular to the bed direction is quite different (Wan et al., 2015). This kind of anisotropy has been quantitatively characterized through neutron scattering by Gu et al. (2015), which, however, contains scattering intensity limiting the application as a result. A geometry-based definition of pore-scale anisotropy is desired and the relation to permeability is in demand.

The heterogeneity of shale exists at two scales as well. At macro scale, there are many material compositions in shale, such as kerogen, pyrites, clay and calcite (Loucks et al., 2009). Each composition has its own characteristic morphology and it is very

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difficult, if not impossible, to describe them in a unified model. The heterogeneity at pore scale refers to the non-uniform distribution of pores, which is clearly presented in many observations (Tang et al., 2015; Lin et al., 2015). Recently, some pore-scale models have considered the heterogeneous pore distribution, such as the pore-network modeling by Zhang et al. (2015) and lattice Boltzmann simulation by Chen et al. (2015). However, in these works the pore-scale heterogeneity was not quantified and therefore its influence has not been explained yet.

The third feature of shale geometry is that nanoscale pores are dominant (Chalmers et al., 2012). When pore size is comparable to the mean free path of gas molecules, the Knudsen number (*Kn*) becomes high and the gas permeability is no longer a constant (Karniadakis et al., 2005; Wang et al., 2008). Starting from Klinkenberg (1941), many models have been proposed regarding to the high *Kn* effect in porous flow (Civan, 2010). However most models are built for isotropic and homogeneous structures. When anisotropy is concerned, some works assume that the slip factor in Klinkenberg correction remains isotropic (Kaluarachchi, 1995; Shmonov et al., 2011), while recent experiments show that in graphite compression packings, the intrinsic permeability and slip factor are both highly anisotropic (Lasseux et al., 2011). It is very important and valuable to make clear whether the anisotropy of shale microstructure can enhance the high *Kn* effect or not.

In this work, we focus on the pore-scale anisotropy and heterogeneity, because macroscale anisotropy has been well-studied and the heterogeneity in macroscale is too complex to describe in a unified model. For simplicity, **we refer anisotropy and heterogeneity in particular to the pore-scale anisotropy and heterogeneity in below**. Both intrinsic and apparent permeability are studied to reflect the high *Kn* effect. We firstly develop a geometry-based method to quantify the anisotropy and heterogeneity and apply it to the micro scanning images of shale. Then, according to the quantified results, we reconstruct 3D shale structure based on Quartet Structure Generation Set (QSGS) method. Finally, the intrinsic permeability and apparent permeability are predicted by lattice Boltzmann method (LBM) and a quantitative relationship between geometry features and gas permeability is established.

2. Quantification of anisotropy and heterogeneity

2.1. Anisotropy

Because of the compaction in vertical direction, most shale has a transversely isotropic structure (Wang, 2002). This means that shale is isotropic in any direction parallel to the bed and the anisotropy only appears in the plane perpendicular to bed. As the formation process of shale is various, the anisotropy of pore structure is also different. Fig. 1 shows the varied pore geometry in the organic matters of shale.

To quantify the anisotropy, we firstly extract the pore geometry from shale image (take Fig. 1 (c) for example, as shown in Fig. 2). Then we consider a line crossing the structure along the bed and define the average pore number it can encounter per unit length as n_x. Similarly we can define n_y in the direction perpendicular to the bed. The anisotropy of the pore structure is defined as

$$A = \frac{n_y}{n_x}. \tag{1}$$

The quantified anisotropy of the 4 structures in Fig. 1 is shown in Table 1. It should be noted that although illustrated by 2D image, this definition is also suitable for 3D structure.

The defined anisotropy can reflect the aspect ratio of the pores, which is explained in details in Appendix A. As a simple illustration, we consider a specific case that all pores are elliptical with the same eccentricity and same orientation along x direction (the pore size can be varied). The anisotropy of the structure equals a/b, where a is the semi-major axis and b is the semi-minor axis, which is in agreement with common sense. There are mainly two advantages in this quantification method. First, it is purely geometry based and physical parameters, such as scattering intensity, are not included. Second, it is not affected by the non-uniform distribution of pores, which is necessary to study anisotropy and heterogeneity separately.

2.2. Heterogeneity

Before quantification, we need to clarify that the heterogeneity is depended on the observation scale. For example, if the observation scale is less than pore diameter, all porous structures are heterogeneous because the difference of pore and solid. On the other hand, if the observation scale is larger than the scale of representative elementary volume (REV), all porous structures are homogeneous. Thus, we firstly define the observation scale l_x, l_y, l_z along x, y, z direction respectively. After that, we divide the whole porous structure into blocks with side length of l_x, l_y, l_z. Then we use the relative standard deviation of each block's porosity to quantify the heterogeneity of pore distribution:

$$H = \frac{1}{\phi}\sqrt{\frac{\sum(\phi_i - \phi)^2}{n-1}} \tag{2}$$

where ϕ_i is the porosity of i-th block and ϕ is the total porosity. For 2D case, only two observation scales are required and the expression for heterogeneity is the same.

To demonstrate the heterogeneity of pore distribution in shale, we consider 4 images cutting parallel to bed, as shown in Fig. 3. After extracting the pore geometry, each image is divided into 4×4 blocks (Fig. 4) and the quantified heterogeneity is presented in Table 1. Just as before, the quantification of heterogeneity is geometry based and not affected by anisotropy, so the anisotropy and heterogeneity are studied separately in the following sections.

3. Structure reconstruction

For real shale samples, the properties such as porosity, anisotropy and heterogeneity are all varied. But to study the influence from a specific factor, all other parameters must be kept constant. Thus, direct simulation in real structure is not appropriate when we want to reveal the geometry effect on permeability. In contrast, structure reconstructed by statistical method has adjustable properties, while the morphology is consistent with real samples. Thus, we adopt the QSGS algorithm (Wang et al., 2007a; Wang and Pan, 2008) to reconstruct the porous structure, which is described as follows.

(1) Randomly generate cores in a grid system according to the core distribution probability c, i.e. each cell in the grid system has the probability c to become solid.
(2) Expand every solid element to its neighboring cell in normal directions based on the growth rate D_x, D_y, D_z in x, y, z directions respectively.
(3) Repeat step (2) until the porosity is reduced to the desired value ε.

The anisotropy of the structure can be realized by varying the growth rate in different directions. Since shale has transversely isotropic geometry, we choose $D_z < D_x = D_y$ and an example structure with $D_x/D_z = 7$ is presented in Fig. 5 (a).

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