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Permeability prediction of numerical reconstructed multiscale tight porous media using the representative elementary volume scale lattice Boltzmann method

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ABSTRACT

Tight oil sandstones have obscured flow characteristics because of their complex pore structure and ultralow permeability. In this study, representative elementary volume (REV) scale lattice Boltzmann method (LBM) was applied to simulate fluid flow in the multiscale tight porous media generated by coupling digital cores from two scales, and the effects of clay permeability, clay volume fraction and interparticle pores (interP) volume fraction on the permeability of the multiscale tight porous media were analyzed. The tight multiscale porous media were generated by assigning the nanometer scale digital core of clay to each pixel of clay constituent in the micron scale digital cores containing three constituents of matrix, interP and clay. The porosity of the generated multiscale tight porous media ranges from 11.12% to 14.98%, among which the porosity contributed by the interP is 4.06–5.00%, and the porosity contributed by the clay is 6.40–9.98%. The pore size distribution curves are bimodal with the pore size ranging from 0.05 to 100 μm, and show good agreement with our previous experimental results. The porosity and permeability inputted to the REV scale LBM were from pore scale simulation results of fluid flow in the nanometer scale digital cores. The simulated permeability of the multiscale tight porous media is 0.05×10^{-3}–0.23×10^{-3} μm^2, which is close to our experimental results. The permeability of the multiscale tight porous media shows positive linear correlation with the clay permeability and clay volume fraction, but is unrelated to the interP volume fraction in the reasonable porosity range. It is hoped that this study can provide some new insights into the core analysis of tight oil sandstones.

1. Introduction

Triggered by the shale gas revolution in the U.S., tight oil, as a type of unconventional resources with great potential, has become a hotspot around the whole world [1–5]. The most significant differences between tight oil sandstones and the conventional oil reservoirs include: (1) tight oil sandstones have multiple pore types and multiscale pore size ranging from several nanometers to hundreds of microns, with the majority in the nanometer scale; (2) the porosity and permeability of tight oil sandstones are ultralow (overburden porosity <10%, and overburden permeability <0.1 $\times 10^{-3}$ μm^2); (3) the flow mechanism in tight oil sandstones deviates from the Darcy equation. To date, scholars have done much research on characterizing the pore structure of tight oil sandstones. Various types of pores in tight oil sandstones including residual interparticle pores (interP), grain dissolution pores, clay dominated pores, and micro fractures have been identified [6,7], the occurrence of these pore types have been unveiled[8], and their contributions to the hydrocarbon storage have been discussed [8–10]. The overall pore size distribution of tight oil sandstones have been measured by a combination of different quantitative characterization techniques, like pressure-controlled porosimetry (PCP) [6,11], rate-controlled porosimetry (RCP) [6,12], small angle neutron scatter (SANS) [13], gas adsorption (N2A) [11], and neutron magnetic resonance (NMR) [12]. The 3D connectivity of the pores has been characterized with the help of computer tomography (μCT, nanoCT) [14], focus ion beam scanning electron microscopy (FIBSEM) [15,16]. Despite the fruitful achievements in the pore structure characteristics of tight oil sandstones, the flow characteristics in the matrix of tight oil sandstones remain a puzzle.

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Core plugs based flow experiment is the general method for studying the flow mechanism of conventional reservoirs. Yet applying this method to tight oil sandstones is difficult because of their complex pore structure and ultralow permeability. The difficulties, to our best knowledge, lie in the following three aspects. Firstly, the core plugs are hard to be saturated or drainaged due to the ultra-small pore throat radius [17]. Secondly, measuring the flow rate is challenging because of the ultralow permeability. Last but not least, the experiment is quite time consuming that requires weeks before arriving steady state [18]. Thanks to the development in numerical simulation techniques, the digital core based pore scale simulation may act as an effective method to study flow in tight oil sandstones [19]. The routine of the pore scale simulation technique is first extracting structures, called digital cores, that representing the key characteristics of the targeted porous media, and then applying computer fluid dynamics (CFD), pore network method (PNM), or lattice Boltzmann method (LBM) to simulate flow in the extracted digital cores. The most direct and accurate way, if possible, to extract 3D digital cores is by CT experiment. However, the multiscale characteristics of tight oil sandstones make it impossible to obtain representative pore structures from CT images [14]. Historically, many numerical reconstruction algorithms have been proposed, including Gaussian simulation [20], simulation annealing [21], quartet structure generation set (QSGS) [22], Markov chain Monte Carlo (MCMC) [23,24], process based (PB) algorithms [25–28], etc. In this study, we applied three algorithms, i.e., QSGS, MCMC and PB, which will be introduced briefly in Section 2.1, for other algorithms one may refer to [20,21].

LBM, which is based on the Boltzmann equation, is a mesoscale numerical simulation method. LBM can be regarded as a solver of the Naiver-Stokes equation [29–31]. And the most significant advantage of LBM is the flexibility in dealing with the complex fluid-solid boundaries. Not long after its appearance, LBM was applied to simulate the flow in porous media and verify fundamental flow mechanisms. Succi et al. adopted LBM to simulate flow in 3D porous media with different porosity, found that the flow rate was linear related to the pressure difference, thus verified the Darcy equation [32]. Koponen et al. proposed the concept of effective porosity based on the LBM simulation result in 2D porous media, and corrected the Kozeny-Carman equation using the effective porosity [33]. Pan et al. compared the results of single-relaxation-time and multiple-relaxation-time (MRT) collision operators, and analyzed the effects of different boundary conditions [34]. They concluded that the boundary effect caused by viscosity can be significantly decreased by using the MRT collision operator. Besides, the LBM has also been adopted to multiphase flow simulation [35,36], shale gas flow simulation [37–40], and diffusion and thermal advection simulations [41–44]. Other than the pore scale LBM, Guo and Zhao proposed a LBM, which can be used to solve the generalized Naiver-Stokes equation, thus is called the generalized lattice Boltzmann equation (GLBM) or representative elementary volume (REV) scale LBM [45]. By adding porosity into both the equilibrium equation and force term and modifying the flow rate equation, the resistance caused by the porous media is incorporated into the standard LBM. Gao et al. modified the porosity parameter in Guo's model as a variable value related to mineral composition, and proposed a REV scale LBM that can simulate flow in porous media having several mineral compositions [46]. Considering the low flow rate in real subsurface formation, Chen et al. eliminated the non-linear term in Guo's model [47]. By incorporating the slippage effect, they proposed a REV scale LBM that can simulate gas flow in multiscale porous media. Afterwards, Chen et al. applied this LBM to simulate shale gas flow in 3D digital cores, and analyzed the effects of grain size, interP, slippage and adsorption on the apparent permeability of shale [48].

In this study, the permeability of numerical generated multiscale tight porous media was predicted by adopting the REV scale LBM, and the effects of the structural parameters on the permeability were discussed. The multiscale tight porous media were generated by coupling digital cores with different scales under the constraint of experimental data. The applied reconstruction algorithms include QSGS, PB, and MCMC. The adopted REV scale LBM was proposed by Guo and Zhao [45], and three constituents, i.e., quartz, interparticle pore (interP) and clay, were considered in this study. The discussed structural parameters are clay permeability, clay volume fraction, and interP volume fraction. It is hoped that the conclusions of this study can provide new insights into the core analysis of tight oil sandstones.

2. Multi-scale digital core reconstruction

2.1. Digital core reconstruction algorithms

In this study, we applied the QSGS, MCMC, and PB algorithms to generate the porous media for fluid flow simulations. The reasons of applying these algorithms will be clarified in Section 2.2. For completeness, we first give a brief introduction about the three algorithms. In the QSGS algorithm, according to Wang et al. [22], a porous medium is generated by simulating matrix growing in void spaces. The structure of the porous medium is controlled by four parameters, which are core distribution probability c_d, directional growth probability D_i, phase interaction growth probability $I_i^{n,m}$ and volume fraction P^n. The advantages of the QSGS algorithm lie in its simplicity and flexibility, and its capacity of generating porous media containing multiple constituents.

The MCMC algorithm, which is proposed by Wu et al. [23], contains the ideas of both Markov chain and Monte Carlo simulation. After considering several types of neighborhood, Wu et al. found that neighborhoods of 2-pxiel and 5–6 pixels are the smallest units that can reproduce the properties of 2D porous media. The conditional probability of each neighborhood is obtained by analyzing 2D binary images of the porous media. And the state of every unknown pixel is determined according to the conditional probability of the neighborhood to which the unknown pixel belonging. Later, Wu et al. proposed 15-pixel neighborhood [24], which can be divided into three orthogonal neighborhoods of 5–6 pixels, thus the MCMC algorithm was extended to generating 3D porous media. The most important advantage of the MCMC algorithm is that its statistical properties are close to the real binary images of the porous media.

The PB algorithm is originally proposed by Bryant et al. [25], who simulated the packing process of equal sized quartz spheres, the compaction process of the quartz spheres, and the overgrowth cementation of the quartz spheres. Soon afterwards, Bakke and Øren extended the algorithm proposed by Bryant et al., and presented a new algorithm that represented the sandstone-forming geological process [26–28]. The improvements of the new algorithm include: (1) quartz spheres with different radius is used for simulating the packing process, and the radius is determined from grain size analysis of real rocks; (2) the overgrowth of quartz considers anisotropy; and (3) the diagenesis process of clays are simulated. The advantage of the PB algorithm is that the generated porous media have good connectivity, thus is suitable for pore scale flow simulation.

2.2. Multiscale tight porous media generation

The multiscale tight porous media are generated by coupling digital cores from two different scales, and the gap between the two scales is bridged by the clay constituent, which has aggregate