International Journal of Heat and Mass Transfer 95 (2016) 94–108

Contents lists available at ScienceDirect

International Journal of Heat and Mass Transfer

journal homepage: www.elsevier.com/locate/ijhmt

The lattice Boltzmann method for isothermal micro-gaseous flow and its application in shale gas flow: A review

Junjian Wang [a,b], Li Chen [c,b], Qinjun Kang [b], Sheik S. Rahman [a,*]

[a] School of Petroleum Engineering, University of New South Wales, Sydney, NSW 2033, Australia
[b] Earth and Environmental Sciences Division, Los Alamos National Laboratory, Los Alamos, NM 87545, USA
[c] Key Laboratory of Themo-Fluid Science and Engineering of MOE, School of Energy and Power Engineering, Xi'an Jiaotong University, Xi'an, Shanxi 710049, China

ARTICLE INFO

Article history:
Received 5 August 2015
Received in revised form 29 November 2015
Accepted 5 December 2015
Available online 18 December 2015

Keywords:
Shale
Lattice Boltzmann method
Micro-gaseous flow
Slip flow

ABSTRACT

The lattice Boltzmann method (LBM) has experienced tremendous advances and been well accepted as a popular method for simulating various fluid flow problems in porous media. With the introduction of an effective relaxation time and slip boundary conditions, the LBM has been successfully extended to solve micro-gaseous transport phenomena. As a result, the LBM has the potential to become an effective numerical method for gas flow in shale matrix in slip flow and transition flow regimes. Additionally, it is very difficult to experimentally determine the permeability of extremely low permeable media like shale. In this paper an extensive review on a number of slip boundary conditions and Knudsen layer treatments used in LB models for micro-gaseous flow is carried out. Furthermore, potential applications of the LBM in flow simulation in shale gas reservoirs on pore scale and representative elementary volume (REV) scale are evaluated and summarized. Our review indicates that the LBM is capable of capturing gas flow in continuum to slip flow regimes which cover significant proportion of the pores in shale gas reservoirs and identifies opportunities for future research.

Contents

---

* Corresponding author.
E-mail address: sheik.rahman@unsw.edu.au (S.S. Rahman).

http://dx.doi.org/10.1016/j.ijheatmasstransfer.2015.12.009
0017-9310/

1. Introduction

Shale gas reservoirs are thought to contain a significant proportion of hydrocarbon, and successful exploitation of such resource plays an increasingly important role in meeting world's demand for natural gas. Shale gas reservoirs are known to be fine grained sedimentary rocks which have complex porous structures with pores and fractures ranging from nano- to meso- scale [1,2], and in each level of pores and fractures different flow mechanisms are involved [3]. An in-depth understanding of flow processes involve in complex porous system in shale is essential for prediction of reservoir permeability and estimating production potential of shale gas reservoirs. This can be achieved by developing detailed descriptive transport simulators which are capable of predicting flow dynamics in shale.

Knudsen number (*Kn*), which is the ratio of the gas mean free path to the characteristic length of the media, is an important dimensionless parameter for gas transport in shale. Current studies conclude that gas transport through shale matrix can best be characterized by *Kn* in slip flow ($0.001 < Kn < 0.1$) and transition flow ($0.1 < Kn < 10$) regimes [4,5] (see Fig. 1). Under these conditions, continuum hypothesis is broken down and other rarefied gas transport mechanisms such as slip flow and Knudsen diffusion start to dominate the flow. Additionally, as a source rock, the presence of organic matter (kerogen) in shale matrix instigates other processes and adds complexities to gas flow simulation. Gas transport in nano-pores inside the kerogen involves adsorption/desorption as well as surface diffusion due to strong molecular interactions between gas and kerogen.

A variety of experimental and mathematical studies shows that rarefication effects influence the shale permeability measurements by increasing the apparent permeability values [6–13]. The effect of adsorption gas and the following surface diffusion on the permeability of shale, however, is not well understood and less widely explored. On one hand, studies confirmed that the multilayer adsorption can take place in organic pores because of the capillary condensation phenomenon [14,15], which will lead to a lower permeability in shale reservoirs [16]. On the other, it is confirmed that surface diffusion can account for 25% of total flux at low pressure [17]. Wu et al. [18]stated that when the pore size is less than 2 nm, the contribution of surface diffusion to total mass transfer can be as much as 92.95%.

Generally, on the basis of pore size distribution, two possible mathematical approaches are proposed to describe the gas transport mechanism and to calculate gas apparent permeability of organic shales. The first approach is to modify the non-slip boundaries in continuum model by accounting for slip boundary conditions. Beskok–Karniadaki [19] derived a unified Hagen–Poiseuille-type formula to take into account all flow regimes. Later, Civan and coworkers [20,21] and Florence et al.[22] proposed different forms of rarefaction coefficient for Beskok–Karniadaki model. By simply adding the mass transfer of adsorbed gas into Beskok–Karniadaki model, the impact of the adsorption and surface diffusion on gas apparent permeability is studied by Xiong et al. [23]. The second approach is the superposition of various transport mechanisms. Javadpour [3] combined slip flow and Knudsen diffusion into gas flux equation and derived an equation for apparent permeability. Freeman et al. [5] used dusty gas model to account for Knudsen diffusion in shale gas reservoir. Singh et al. [24] combined viscous flow with Knudsen diffusion in their non-empirical apparent permeability model (NAP), and then validated with previous experimental data. Results have shown that the NAP can be used for *Kn* less than unity. Wu et al. [25] further proposed two weighted factors for viscous flow and Knudsen diffusion, respectively. The surface diffusion was also coupled in their apparent permeability model.

Most of the above mentioned analytical/semi-analytical studies are originally proposed based on simple geometries such as channels and tubes, and are not suitable for more complex porous media, such as shales. Therefore, the numerical methods of solving transport equations to obtain an estimate for the permeability are attracting more attention. Especially after the current well-established characterization techniques such as BIB-SEM, FESEM, FIB-SEM and micro-CT enable us to identify a variety of pore structures in shale matrix [1,26–30], the detailed rock images further promote the use of image-based numerical simulation tools. Among them, the lattice Boltzmann method (LBM), which is vastly different from traditional computational fluid dynamics(CFD) methods, has proven to be an effective flow simulation choice in porous media, as the geometry definition in LB model is reduced

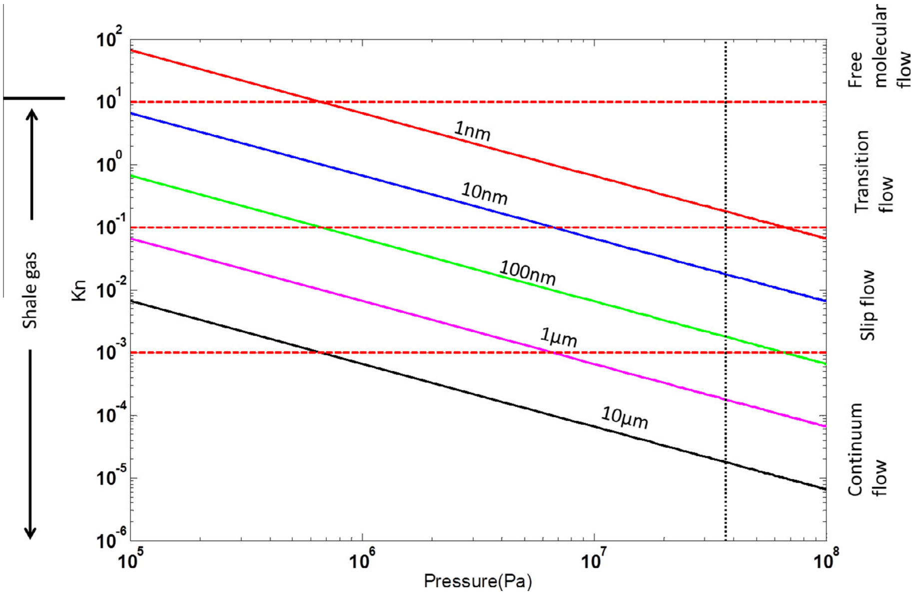

Fig. 1. Knudsen number relationship to pore diameter and mean reservoir pressure at 400 K. Vertical dash line represent a typical reservoir pressure condition of 37 MPa. (Figure adapted from Javadapour et al. [3] and Sondergeld et al. [2]).