AAPG Research Launcher Program

Modeling of fluid transport and storage in organic-rich shale

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Technical Research Proposal

1 Statement of problem

Accurate determination of the transport and storage properties of the shale reservoirs is of great importance due to the significance of these resources in future of energy market. These resources secured US energy supply and reduced the greenhouse emissions. Depleted shale gas reservoirs are important when looking for alternative storage formations for large-scale geologic storage of CO_2. The potential to recover gas from shale and/or store CO_2 has been increasing due to new technologies to fracture and better modeling of flow and production mechanisms. Meaningful economics of shale gas projects request more improvements in the characterization and modeling, and also inventing predictive tools and techniques.

Conventionally, transport of single-phase fluid flow through porous media is introduced to the reservoir simulators as intrinsic permeability, which is a property of porous media and independent of the fluid type. The current problem with the permeability is that the laboratory measurements taken with the matrix core plugs indicate a heterogeneous and anisotropic quantity, which is sensitive to effective stress, pore pressure, temperature, and the measurement fluid type. In addition, these are source rocks that are often identified as naturally occurring nanoporous materials. The nanoscale pores and capillaries that make up a significant portion of the total pore volume are changing the nature of the discussion of fluid storage and transport and bringing *new molecular level non-Darcian transport effects* into the simulation, such as pore-diffusion and surface-diffusion effects of fluid molecules in the capillaries. Although we have advanced significantly in our understanding of transport in nanoscale capillaries and in trying these results to laboratory experiments by use of core plugs, *an overall permeability reflecting the impact of local phenomena is yet to be achieved*. Therefore, new models are needed to describe fluid transport and sorption in nanopores.

2 Literature Review

Shale gas is the key to U.S. energy independence. It is estimated that the United States has from 500 to 780 trillion cubic feet of natural gas in place. Much of this is in the form of shale gas. Depleted shale gas reservoirs are also important as alternative storage formations for large-scale geologic storage of CO_2. However, recovering this valuable resource poses significant challenges. It has been shown that shale resources consist of interparticle, intraparticle, and organic matter intraparticle pores with sizes from the order of micrometer (interparticle pores) down to the range of 3-100 nanometers [7]. Flow in these extremely tight formations violates the continuum assumptions based on which Darcy's law is derived. Darcy's law highly underestimates the fluid flow rates when applied to the shale reservoirs [8]. Four types of porous media are present in productive gas-shale systems: inorganic matrix, organic matter, microfractures, and macrofractures. Gas storage and flow in shale gas sediments are a combination of different controlling processes. Gas is stored as compressed gas in pores, as adsorbed gas to the pore walls, and as soluble gas in solid organic materials, i.e., kerogen and clays [6] .

The flow in nanopores in the shale gas resources is characterized by Knudsen number (ratio of mean-free-path of gas molecules to the characteristic length of the pores) and can be in the range of continuum, slip, transition, and free molecular flow. Classical continuum-based gas flow equations can be used to describe the gas flows with small Knudsen numbers ($Kn < 0.01$) [9]. For flow in gas shale reservoirs, however, the Knudsen number is not sufficiently small ($0.1 < Kn < 10$) and the flow cannot be described by classical hydrodynamic equations [4] . For systems with nanopores, different modeling approaches such as Molecular Dynamics, Direct Simulation Monte Carlo (DSMC), Burnett equation, and reduced-order Boltzmann equation can be used [6]. Molecular alternatives are often very expensive for practical purposes. The Boltzmann equation has proved applicable for all ranges of the Knudsen number [2]. The Boltzmann equation, however, must be solved numerically even for simple problems and therefore, posing high computational costs. Several reduced methods are proposed to use Boltzmann equation to simulate the gas flow with less computational times. Lattice Boltzmann Method (LBM) forms a well-defined numerical method for solving Boltzmann equation based on the discrete velocity sets. There are a few studies in the literature focusing on the applications of LBM for simulating flow of fluids in high-Knudsen number regimes [3]. Fathi and Akkutlu [4] introduced a new LBM to numerically investigate the pore-wall adsorption and nanoscale fluid transport in simple pore geometries. Their approach takes into account molecular-level interactions by use of adsorptive/cohesive forces among the fluid particles and defining a Langmuir-slip boundary condition at the organic pore walls. Ansumali et al. [1] used a different set of discrete velocities and found an exact solution to the hierarchy of nonlinear lattice Boltzmann kinetic equations at nonvanishing Knudsen numbers. Several reduced methods, such as Grads thirteen-moment method are also proposed to the Boltzmann equation to simulate the gas flow with less computational times [5].

3 Tools and Methodology

The shale gas reservoirs are characterized by small pore sizes in the range 3 to 100 nm. **Figure 1** depicts different scales of fluid transport in the hydrocarbon-bearing shales. In order to simulate the gas flow in shale reservoirs an effective transport model is required to allow fast and accurate solutions of the gas microflow. The dynamics of dilute gases are perfectly described by the Boltzmann equation. The numerical or analytical solution of the Boltzmann equation is rather involved, and thus, in practice, computational difficulties still remain as the major problem in direct application of the Boltzmann equation. Some of these methods are developed to determine macroscopic equation systems that go beyond the capabilities of the continuum-based equations. Several reduced-order methods, such as Grad's thirteen-moment method are proposed to use Boltzmann equation to simulate the gas flow with less computational times [5]. The Grad's thirteen-moment method incorporates the Boltzmann transport equation (microscopic) and derives a set of thirteen differential equations based on the first five meaningful moments. This method has shown promising results for simulation of rarefied gas flows. The unknown variables in this system of differential equations are the

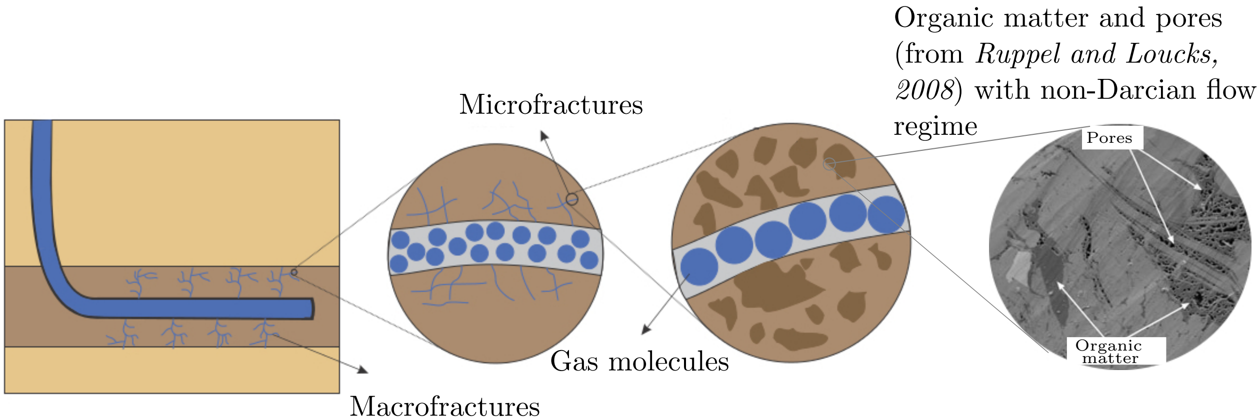


Figure 1: Schematic depiction of the multiscale modeling of a shale gas reservoir. At the largest scale, fluid transport exists in macrofractures. These macrofractures are either hydraulic fractures or activated natural fractures. Fluid transport in these media is Darcian. At a lower scale (middle figure), fluid transport in the microfractures are depicted. Microfractures are created through volume changes in kerogen during thermal maturation and also induced by the hydraulic fracture. Fluid transport in these media is usually considered to be Darcian (Knudsen number is less than 0.01). At the lowest scale (figure in the right), fluid flows through nanopores of the inorganic matrix and organic matter. Fluid in these media is considered to be non-Darcian. Gas molecule sizes are exaggerated in the figures.

macroscopic properties of the system including density, velocity, temperature, stress, and heat flux.

The *longterm goal* of the proposed project is to present a meaningful model for the fluid transport and sorption in nanopores of shale gas resources and develop a framework for upscaling of the transport from nanopores into the micro- and macrofracture networks. The proposed work can lead to development of effective methods for CO_2 storage in subsurface geological structures.

4 Preliminary results

The derived system of differential equation is closed and can be solved using the modern algebraic computer programs, e.g. Mathematica®. Preliminary results are presented in the figures below. In these results, gas adsorption on the walls of the nanocapillaries is ignored.

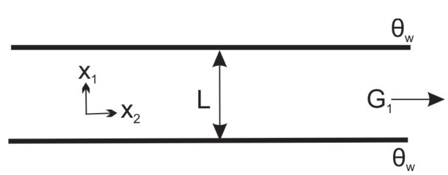
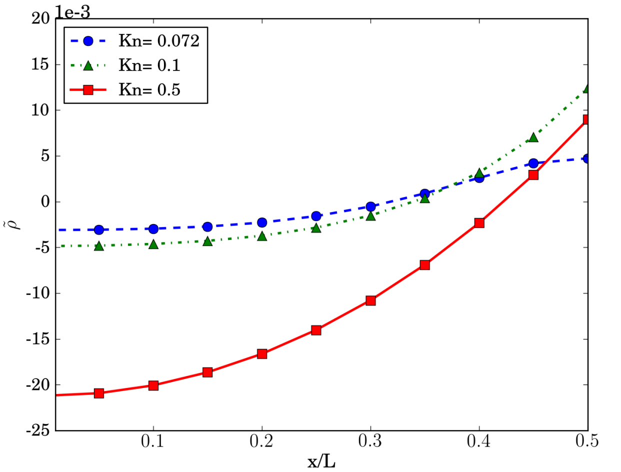
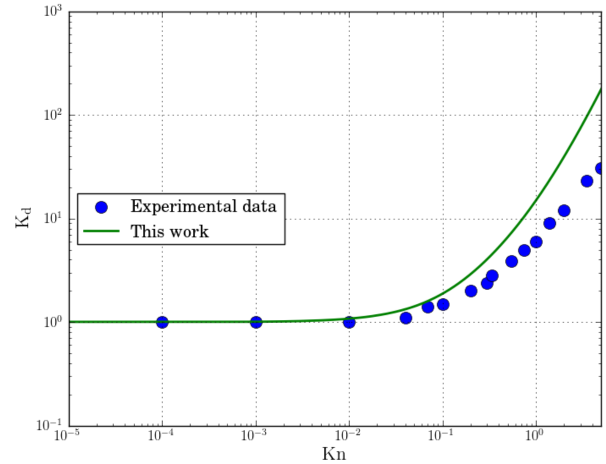


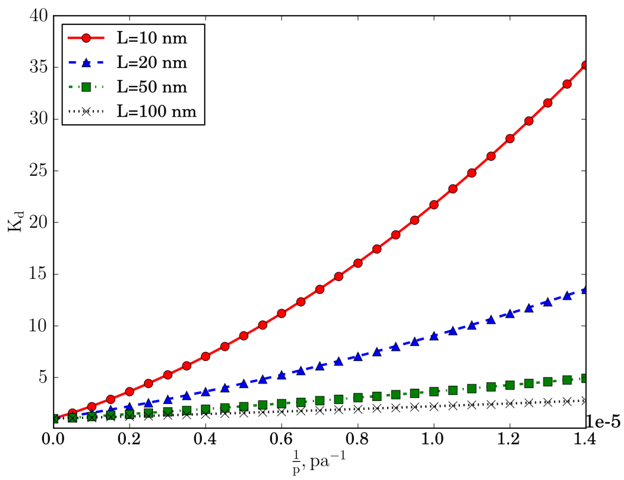
Figure 2: Problem set-up



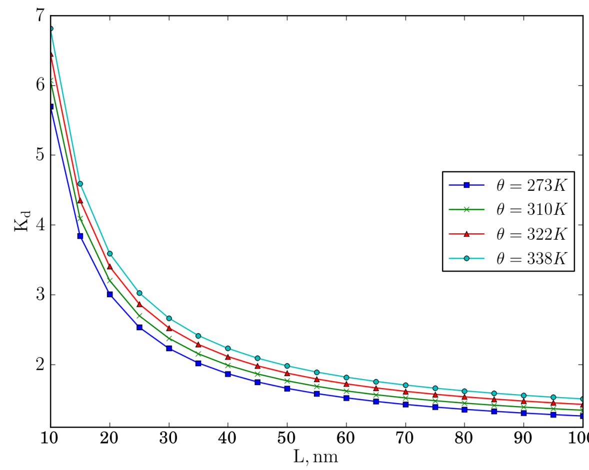
(a) Density deviation from the mean vs. channel half-length



(b) Dimensionless permeability vs. Knudsen number



(c) Dimensionless permeability vs. pressure



(d) Dimensionless permeability vs. temperature

Figure 3: Preliminary results of gas flow in nanocapillaries. Dimensionless permeability in (a), (b), and (c) is the ratio of the permeability of gas at the specified Knudsen number to that at infinite pressure, K_∞.

References

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