Numerical Simulation of Non-Newtonian Fluid Flow through a Rock Scanned with High Resolution X-ray Micro-CT

Moussa Tembely, Ali M. AlSumaiti, Khurshed Rahimov, and Mohamed S. Jouini

***Abstract*—Most of the pore-scale models are concerned with Newtonian fluid due to its simplicity and the challenge posed by non-Newtonian fluid. In this paper, we report a non-Newtonian numerical simulation of the flow properties at pore-scale by direct modeling of the 3D micro-CT images using a Finite Volume Method (FVM). The numerical model is based on the resolution of the mass and momentum conservation equations in conjunction with an adaptive meshing technique used to generate the mesh along with the appropriate boundary conditions to compute the porous media permeability. To describe the fluid rheology, a concentration-dependent power-law viscosity model in line with the experimental measurement of the fluid rheology is proposed. The model is first applied at isothermal condition to 2 benchmark rocks samples, a sandstone and a carbonate. The implemented FVM technique shows a good agreement with the Lattice Boltzmann Method (LBM). Subsequently, at non-isothermal conditions, the numerical simulation is carried out where the effective mobility is introduced to make a sensitivity study at different operating conditions and fluid rheology. The normalized mobility on the polymer concentration leads to a master curve while the flow rate displays a contrast between the carbonate and the sandstone.**

***Index Terms*—Pore-scale model, non-Newtonian fluid, finite volume method, digital rock physics.**

I. Introduction

MANY applications ranging from hydrology, environment, water management, to oil and gas industry would benefit from an accurate model of fluid flowing inside porous media. In order to optimize reservoir management, the fluid flow processes in porous media should be investigated through a multiscale approach ranging from the field to the core level, down to the pore-scale. Most of the digital rock physics (DRP) simulations focus on Newtonian fluids and overlook the rheology of the fluid [1], [2]. However, in petroleum engineering many fluids such as heavy oil and polymer solutions used for enhanced oil recovery (EOR) are non-Newtonian [3], [4]. One of the most important petrophysical properties for reservoir rock is the permeability, which prediction through an accurate and efficient numerical tool is highly desirable [5], [2], [6]. Despite a large body of work, modeling of New-Newtonian is still challenging and remain an active field of research [3], [7]. In the present paper, we use a finite volume method (FVM) coupled with an adaptive meshing technique to perform the pore-scale simulation from the micro-CT images of a sandstone and a carbonate from the literature with a Newtonian and non-Newtonian fluid.

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II. Governing Equations

A. Mass and Momentum Conservations

The continuity and momentum equations to be numerically solved in the finite volume method (FVM) formulation expresses as follows:

$$\nabla \cdot \mathbf{V} = 0 \tag{1}$$

$$\rho \mathbf{V} \nabla \mathbf{V} = -\nabla p + \rho \mathbf{g} + \nabla \cdot \tau \tag{2}$$

where $\mathbf{V}$ is the fluid velocity vector, and g denotes the gravity, while the fluid is assumed incompressible of density ρ, viscosity μ. The stress tensor τ, assuming the viscosity to depend on both the polymer concentration(C) and shear rate ($\dot{\gamma}$), can be written as:

$$\tau = \mu(C, \dot{\gamma})[\nabla \mathbf{V} + \nabla \mathbf{V}^{\mathrm{T}}] \tag{3}$$

B. Concentration Power-Law Viscosity Model

We propose for the viscosity a modified power-law accounting for the effect of the polymer concentration as follows:

$$\mu = \chi \exp[\alpha C] \dot{\gamma}^{n-1} \tag{4}$$

where C is the polymer concentration, α a constant, χ is the consistency factor and n the flow behavior index. The proposed equation (see Fig. 1) is line with experimental measurement of polymers fluid used for EOR [4].

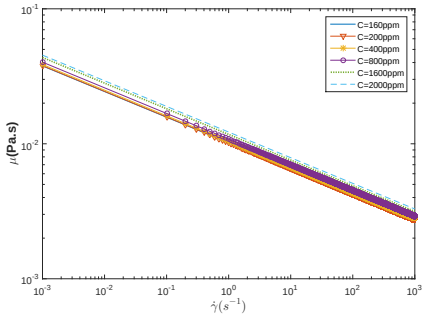

Fig. 1. A Concentration Dependent Power-Law Viscosity Fluid Function of the Shear Rate at Different Concentrations.

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Due to the non-Newtonian nature of the fluid and viscosity dependency on the concentration, and for convenience, we will adopt the fluid mobility to characterize the non-Newtonian fluid flowing inside the porous media as:

$$M_{eff} = -\frac{1}{\Delta P}\frac{LQ}{A} \tag{5}$$

where Q is the flow rate, ΔP the pressure gradient imposed on the sample, L and A are the sample length and surface area, respectively.

C. Numerical Approach

The workflow from the micro-CT image to the petrophysical properties is summarized in Fig. 2. The rock is first scanned at high resolution then segmented to discriminate between pore and solid phases; before the generation of the 3D digital rock model as input for the simulation.

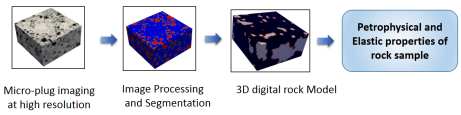

Fig. 2. Workflow of the Numerical Simulation at Pore-Scale of the Micro-CT Image of the Rocks.

In order to run the simulation, the segmented micro-CT image is meshed using SnappyHexMesh/C++ code to perform an Adaptive meshing technique, through refinement and adjustment to fit onto the provided geometries of the rock; the addition of the boundary layers cells near the solid surface is also performed for better accuracy (Fig. 3).

The SIMPLE algorithm is used to calculate the pressure and velocity fields using a Generalized Geometric-Algebraic Multi-Grid (GAMG) solver in conjunction with a Gauss Seidel smoother. The convergence criteria set for the pressure and velocity fields is of the order of 10^{-6}. The simulations are run in parallel using a domain decomposition method.

D. Validation: Newtonian Fluid

For validation purpose of our model, we apply the FVM model to 2 rocks samples from the literature, the Fontainebleau sandstone and Grosmont carbonate [2]. Similarly, we performed the simulations under the same conditions using the widely used LBM (Palabos library) from the literature. We provide in Table I the simulation results (Fig. 4) of the absolute permeability in (milliDarcy) along with the relative errors. The sample size and resolution are 288x288x300 voxels at 7.5 μm and 400x400x400 voxels at 2.02 μm of the sandstone and carbonate, respectively.

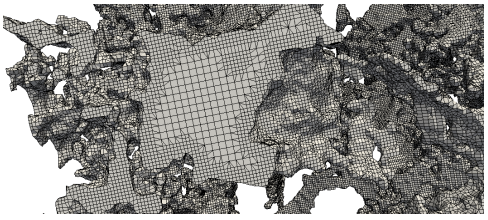

Fig. 3. Adaptive Mesh at the Pore-Scale from the Digital Image of the Rock.

TABLE I
NUMERICAL SIMULATIONS RESULTS OF THE ABSOLUTE PERMEABILITY IN Z-AXIS

Sample	FVM	LBM	Relative Errors (%)
Sandstone	1614	1610	0.2
Carbonate	217	214	1.4

The difference is less than 2% suggesting that the implemented finite volume method is capable to simulate accurately the simulation at pore-scale. Unlike in the LBM the extension of the Navier-Stokes Equations to Non-Newtonian fluid is straightforward with no numerical tuning parameters.

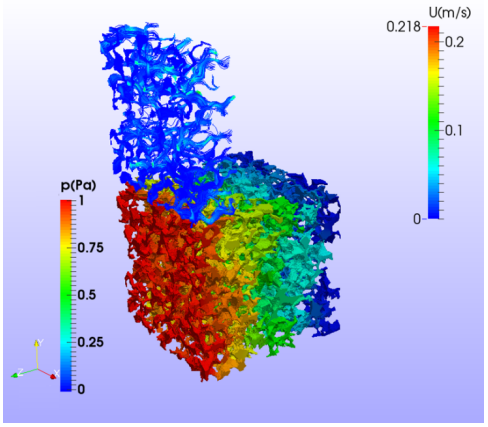

Fig. 4. Results of the Numerical Simulation by the Finite Volume Method (FVM) of the Sandstone. Streamlines Shown at the Top of the Pore Structure for Clarity.

E. Non-Newtonian Fluid Flow Simulation

1) Effect of the polymer concentration on the mobility: We simulated the fluid flow at pore-scale using the concentration power law fluid given in Eq. (4) . In order to investigate the concentration effect, we performed the simulation of the non-Newtonian fluid (Fig. 5) at different concentrations of the polymer solutions. The results of the simulation on the mobility variation are given in Fig. 6. As expected, the mobility seems to evolve inversely proportional to the concentration. Interestingly, while the viscosity exponentially depends on the concentration, the mobility seems to evolves linearly with the concentration. Furthermore, the normalized mobility leads to a master curve.

2) Effect of the gradient of pressure on the mobility : We investigated the model sensitivity to different gradient pressure. In Fig. 7, we provide the results of simulations

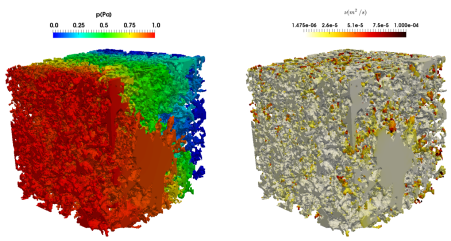

Fig. 5. Results of the Numerical Simulation of the Non-Newtonian Fluid at Pore-Scale (left) Pressure Field and (right) the Kinematic Viscosity Field for the Carbonate.

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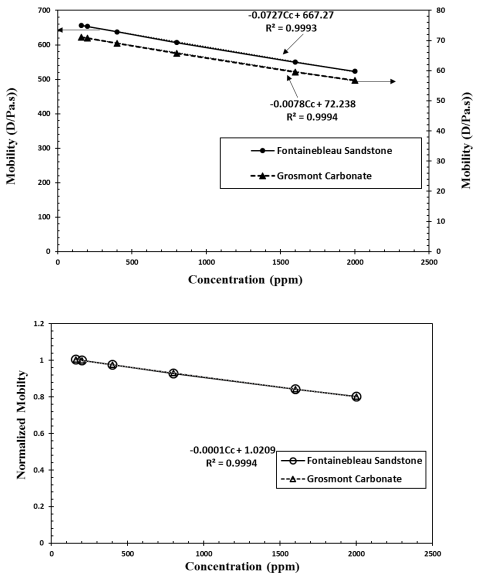

Fig. 6. The Simulated Results of the Variation of the Mobility Based on the Polymer Concentration: (top) Absolute Mobility and (bottom) Normalized Mobility.

where evolution of the normalized flow rate and pressure gradient is found to follow a power-law, $Q/Q_0 \approx \Delta P^{1/n}$, where n is the behavior index. The non-linearity nature of the fluid flow within the porous media seems to be more marked for the carbonate, of complex structure, than for the sandstone sample.

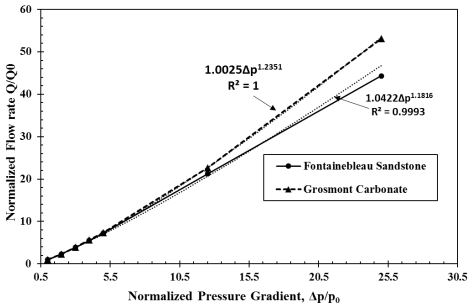

Fig. 7. Normalized Flow Rate and Pressure Gradient from Pore-Scale Numerical Simulations.

III. Conclusion

In this work, we present a comprehensive numerical method based on the Finite Volume Method (FVM) and an adaptive meshing technique to describe the flow properties at pore-scale of a non-Newtonian fluid. The fluid rheology is modeled by incorporating its dependency to the concentration into a power-law viscosity fluid. Based on Newtonian fluid through rock samples from the literature, the FVM algorithm is validated against a Lattice Boltzmann Method (LBM). After implementing the non-Newtonian fluids, the model sensitivity to the rheology is tested by evaluating the effect of polymer concentration on the mobility as well as the relationship between flow rate and the pressure gradient. The normalized mobility function of the polymer concentration leads to a master curve while the flow rate displays a disparity between the carbonate and sandstone.

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