A MULTI-SCALE DYNAMIC PREDICTIVE MODEL FOR DRAINAGE AND IMBIBITION CAPILLARY PRESSURE IN HETEROGENEOUS ROCKS

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ABSTRACT

A multi-scale model for multiphase flow in heterogeneous rocks has been developed to predict drainage and imbibition porous plate capillary pressures. The need for such a simulation model arises from the inability to image and simulate at high-resolution large enough volumes that are representative of multi-scale rocks. The overall distribution of the different resolutions is defined by multi-scale x-ray imaging. A representative volume from the micro-CT image is segmented into pores, solids and Darcy regions with unresolved pores. The properties of Darcy region are further determined by separate high-resolution imaging and multiphase flow simulations for a smaller volume. Two-phase flow in the pore space is directly simulated using a lattice-Boltzmann model. Pore size in the Darcy region is smaller than the resolution of the lattice-Boltzmann simulation. The flow entering or exiting a Darcy region is determined by the fluid phase and its pressure around the Darcy region and the intrinsic properties of the Darcy region like the porosity and the Pc-Sw relationship. The boundary condition of the lattice-Boltzmann simulation on the surface of a Darcy region depends on the solid wettability and the fluids present in the Darcy region. The fluid distributions in pores and Darcy regions, and therefore the boundary conditions for different regions dynamically change with the applied capillary pressure. The multi-scale model has been used to compute the displacement parallel and perpendicular to a layered system packed with solid spheres of different size and compared to a fully resolved simulation to validate the model.

INTRODUCTION

The capillary pressure (Pc) and relative permeability in drainage and imbibition processes are important inputs for reservoir simulations. The capillary pressures have been experimentally measured in a core or a plug [1-3] for many decades. Recently digital core analysis has become an important alternative method. In the digital analysis, the rock geometry is digitized into a 3D matrix data to represent solids and pores by computerized tomography (CT). To calculate the transport of multiphase flow, either pore network model or direct simulation can be used. The pore network model replaces real pore bodies and throat shapes with simple geometric shapes [4, 5]. The fluid transport and distribution are determined by coupling semi-analytical solutions for the individual elements. The lattice-Boltzmann method (LBM) is a direct simulation method [6, 7]. The LBM solves a simplified kinetic equation and directly simulates the fundamental equations of multiphase flow in pores in a digitized rock sample.

This study develops a dynamic multi-scale model to calculate the capillary pressures in drainage and imbibition processes in heterogeneous rocks based on the LBM method. Different digital resolutions are assembled into a representative flow unit volume. The model is validated by digital porous plate experiments of a system packed with different sizes of solid spheres.

MATERIAL AND SIMULATION METHODS

In our multi-scale simulation, the distribution of different resolutions of the structure of a rock sample is determined by multi-scale x-ray imaging. A representative volume from the coarse micro-CT image is segmented into pores, solids and Darcy regions. Pore size in the Darcy region is smaller than the coarse micro-CT. Small volumes of Darcy regions are further imaged by a separate higher-resolution micro-CT or nano-CT acquisition and segmented into pores and solid. The Pc curves and the breakthrough pressures of Darcy regions are determined by the LBM simulation in the high-resolution volumes. These properties are assigned to the Darcy regions.

Now the two phase flow in the whole representative volume is simulated using the dynamic multi-scale LBM simulator. Two-phase flow in the resolved pore space is directly simulated using the LBM. The flow entering or exiting a Darcy region is determined by the fluid phases around the Darcy region, the Pc curves and the breakthrough pressures of the Darcy region. In the drainage process the Darcy region is first occupied by water. If a Darcy region contacts with oil phase, the oil enters the Darcy region gradually as the capillary pressure increases. The amount of oil entering the Darcy region at each time step of the LBM simulation is determined by the Pc curve of the Darcy region and the capillary pressure at that time step. When the capillary pressure becomes larger than the breakthrough pressure the oil is allowed to pass through the Darcy region. In the imbibition process, a Darcy region may be first completely or partially occupied by oil. If the Darcy region is connected to water through bulk water or a water film, the water enters the region gradually as the capillary pressure decreases. The amount of water entering the Darcy region is determined by the imbibition part of the Pc curve of the Darcy region.

We used the model in [8] to assign a contact angle at the interface between resolved pore space and Darcy region. The contact angle depends on the porosity, the intrinsic wettability and the fluid phases present in the Darcy region and is imposed through the interaction of LB nodes at the interface between Darcy region volume and resolved pore volume. The fluid distributions in pores and Darcy regions, and therefore the boundary conditions and the contact angle dynamically change with the applied capillary pressure.

In order to validate the multi-scale model, we simulated a digital porous-plate experiment [9] of a rock sample in a fine resolution that completely resolves all pores of the rock sample using a recently developed LBM solver [10]. Then we used the dynamic multi-scale model to simulate the porous-plate experiment of the same rock sample in a 10 times coarser resolution and compared the two results obtained from the two simulations. In the digital porous plate experiment [9], the one surface of the rock is attached to an oil reservoir and the opposite surface is attached to a water reservoir. The water pressure is kept constant throughout the simulation. In the drainage process the oil pressure increases step by step till the desired residual water saturation is reached. In the imbibition process the oil pressure decreases till it reaches the water pressure to simulate controlled spontaneous imbibition. In the recently developed LBM solver [10], we developed special boundary conditions at the solid wall to model thin water-film flows that allow transport of fluids through those thin films. These boundary conditions prevent e.g.: unrealistic high values of trapped water in the drainage and allow snap-off effects through the films in imbibition.

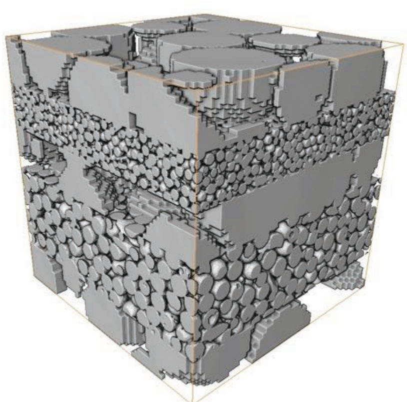

Fig. 1. The rock sample synthetized by packed solid spheres. The pixel size is 2 microns. The sample is a cube of 600^3 pixels. Three different pore sizes are present in the sample.

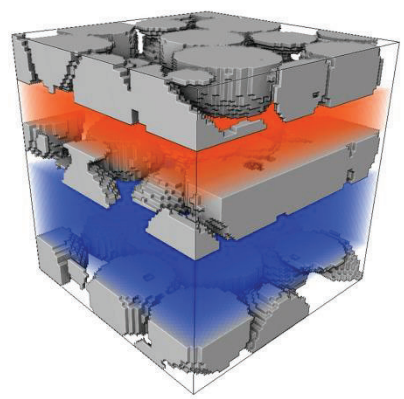

Fig. 2. The rock sample in figure 1 shown in a 10 times coarser resolution. The cube consists of 60^3 pixels. The pixel size is 20 microns. The pores in the Darcy regions colored by blue and red are unresolved.

As shown in Fig. 1, the rock sample was synthetized by packed solid spheres to simulate a multi-scale rock. The sample is a cube with side length of 600 pixels and is composed of 5 regions. The pixel size is 2 microns. In the resolution of 2 microns, all pores are resolved. Starting from the bottom, the thickness of the second region is 200 pixels and 100 pixels for each of the other four regions. The first, third and fifth regions have the largest pores. The second region has smaller pores and the fourth has the smallest. The average pore throat radii in the three different fabrics are 46, 9.2 and 4.6 microns respectively. The average pore radii in the three fabrics are 67, 13.4 and 6.7 microns respectively. The porosity of all regions is 0.4. Fig.2 shows the same rock sample in a 10 times coarser resolution. The sample is a cube with the side length of 60 pixels. The pixel size is 20 microns. The largest pores in the first, the third and the fifth region are still resolved with the 20 micron resolution. The pores in the second and the fourth regions are unresolved. The capillary pressures as functions of water saturations and the breakthrough pressures of the two unresolved regions have been obtained by separate LBM simulations for the tighter rock fabrics at a resolution of 2 microns and were assigned to the corresponding Darcy regions in the multi-scale predictive LB model to simulate the whole sample.

RESULTS AND DISCUSSIONS

Two digital porous plate experiments of the rock sample shown in Fig. 1 and 2 were carried out (Case A and Case B) to validate the multi-scale model. In Case A, the bottom surface of the rock sample is attached to an oil reservoir and the top surface is attached to a water reservoir. In Case B, the left-front surface is attached to an oil reservoir and the right-back surface is attached to a water reservoir. The other side are walls with the properties of the rock. The multi-scale predictor was using the system with 60^3 grids points depicted in Fig.4 and the single-scale LBM solver was applied to the rock cube with 600^3 grids depicted in Fig.3. The interfacial tension was set to 0.03 Nm^{-1}. Strongly water wet conditions were assumed and a contact angle of 30 degree was used in the simulations. The sample is initially filled with water, then a drainage with oil as invading fluid follows and finally an imbibition with water as invading fluid is performed.

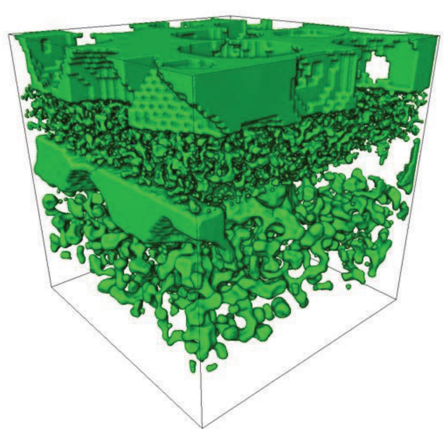

Fig. 3. Oil distribution after imbibition from the fully resolved LBM simulation for case A.

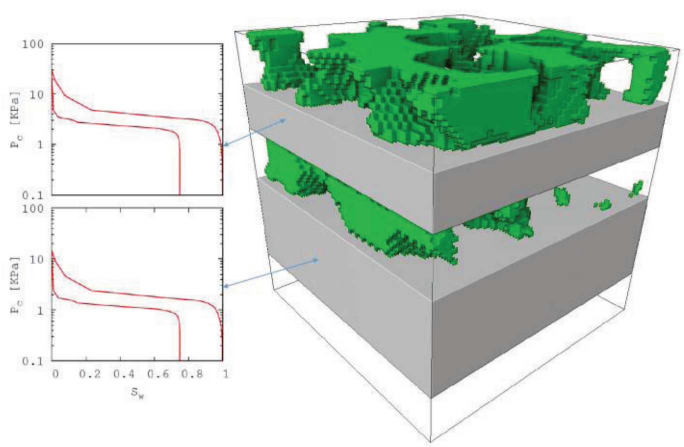

Fig.4 Oil distribution after imbibition from the multi-scale simulation for case A. Left Pc curves are from the separated high-resolution simulations in two Darcy regions.

Figs. 3 and 4 show the residual oil distributions after imbibition for Case A. The trapped oil distributions in regions 3 and 5 for the two simulations are very similar. The oil in pores of these two regions are almost completely trapped since the pore body to throat ratio is very large for this synthetic rock sample. As is shown in [10, 11] the residual oil saturation highly correlated with the pore body to throat ratio. The average pore body radius in the largest-scale pores is 67 microns and the pore throat radii in the two regions with small-scale pores are 4.6 and 9.2 microns respectively. The effective pore body to throat ratio is 14.6 for the imbibition process in regions 4 and 5, and 7.3 for the imbibition process in regions 2 and 3. The trapped oil in the two small-scale pore regions is shown in Fig.3 for the fully resolved LBM simulation. In the multi-scale simulation the amount of residual oil in the two unresolved regions, colored in Darcy in Fig.4, are given by the residual oil saturation in the Pc functions shown in Fig.4 which were computed by separate fine scale simulations. Fig.5 shows the capillary pressures as functions of water saturations of the two simulations in Case A. Each region has a similar porosity of about 0.4, so that each region 1,3,4,5 contributes 17% and region 2 contributions 33% to the pore volume. After an incremental fill-up of region 1 (Sw=0.83..1), the breakthrough of oil in the second region is clearly visible. The third region has large throats and no incremental pressure is needed to enter that region. The second and third region (Sw=0.33..0.83) are filled after the breakthrough in the second region. The region 4 and 5 (Sw=0..0.33) are filled as the pressure further increases. The amounts of residual oil and the whole Pc curves of the two simulations agree very well. Fig.6 shows the capillary pressures as functions of water saturations of the two simulations in Case B. The two simulations produce fairly consistent capillary pressures. The first plateau of the pressure curve in the drainage part (Sw=0.5..1) indicates the breakthrough of oil in the largest pores in the first, the third and the fifth regions. Then a breakthrough in the second region (Sw=0.17..0.5) occurs and finally in region 4 with the smallest pore throats. The amounts of residual oil obtained from the two simulations agree very well. The amount of residual oil in Case B is smaller than in Case A since the flow direction in Case B is parallel to the layers and in Case A perpendicular. The imbibition process first happens in small-scale pore regions and then the large-scale pore regions. The effective pore body to throat ratio inside these regions is about 1.5. For Case A the effective ratio is much larger as discussed earlier.

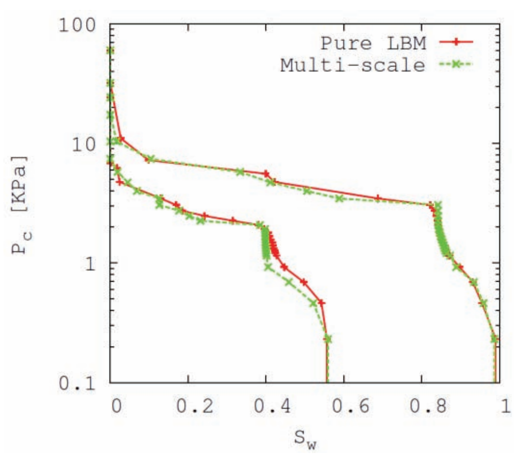

Fig. 5 Capillary pressures as functions of water saturations in Case A of the digital porous-plate experiments.

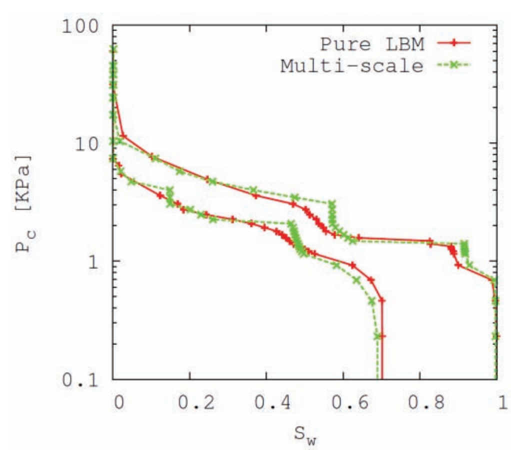

Fig. 6 Capillary pressures as functions of water saturations in Case B of the digital porous-plate experiments.

CONCLUSION

We have developed a dynamic multi-scale predictive model to determine two-phase flow distributions at certain capillary pressure for complex multi-scale rocks. The model was validated by two digital porous plate experiments of a synthetic multi-scale rock sample. The results of the multi-scale mode in a coarse grid agree well with these of a lattice-Boltzmann simulation in a 10 times finer grid that resolves all pores in the rock sample. The new multi-scale model differs from a common assembling approach that computes regions with different resolutions independently and then upscales in a post-processing operation to obtain the properties of the representative volume. The dynamic exchange of information about pressures and saturations between different regions in the multi-scale model improves the accuracy of the prediction.

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