Unsteady State Relative Permeability and Capillary Pressure Estimation of Porous Media

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ABSTRACT

To take capillary effect into account, a series of primary drainage experiments of water by a sample oil fluid have been studied. The experiments performed under different low flow rates on a horizontal glass type micromodel as a model of porous media. Based on conventional macroscopic flow equations, the relative permeabilities and capillary pressure are determined by parameter estimation technique from history matching of saturation and pressure data of unsteady state immiscible displacements. The Coery type of relative permeability and capillary pressure functions are used. The results show that the end point relative permeability of oil phase and the dynamic term and the exponent of capillary pressure function increase with flow rate, but the saturation exponent of relative permeability functions are decreasing with flow rate. Also the results show that the capillary pressure and relative permeability curves are rate dependent and the relative permeability curves are increasing with flow rate.

1. INTRODUCTION

Relative permeability and capillary pressure are the primary flow parameters required to model multiphase flow through porous media. They are depending on pore space morphology, capillary number, Bond number, saturation, saturation history and wettability [*Marle, 1981*]. However, relative permeability estimation are developed by pore network modeling [*Blunt and King, 1991*] but, experimentally measurements of these functions have been interested by many researchers [*Heaviside et al., 1983; Mohanty and Miller, 1991; Sahni et al., 1998*].

Micromodels are small-scale laboratory experiments; equipped with the ability to observe behaviors at the pore level through microscopy. They were used as early as 1960 for fluid displacement studies [*Mattax and Kyte, 1961*], not only have been used to understand the flow mechanism taking place in porous media at pore scale [*Lenormand, 1988*] but also used for investigation of alternative displacement of phases [*Van Dijke et al., 2002*]. Although micromodel is an effective research tools for investigation of fluid flow through porous media but there is little information about the estimation of macroscopic flow properties using that. So in this work a glass type micromodel is employed as porous media sample.

Briefly, the experimental methods for estimating of relative permeability and capillary pressure functions from measured data may be classified as steady and unsteady methods [*Richmond and Watson, 1990a*]. In the steady-state method two fluids are injected at a certain volumetric ratio simultaneously until both the pressure drop and the composition of the effluent stabilize. The saturations of the two fluids in the porous media are then determined. Steady-state test data processing is relatively simple, but experiments are tedious and lengthy. In the unsteady-state method which is less expensive and faster than the steady state method, and for that reason it is widely used, a single fluid is injected at a constant flow rate into a sample initially saturated with the other fluid phase. The transient phase saturation and pressure drop are measured. Using the frontal advance theory and estimates of the derivatives of the measured data, relative permeability values corresponding to saturation values are calculated implicitly [*Watson et al., 1988; Richmond and Watson, 1990b*] or explicitly by conventional methods at exit face [*Johnson et al., 1959; Jones and Roszelle, 1978],* or explicitly *by* a novel method along the medium [*Schembre and Kovscek, 2003*]. JBN and some related method values only corresponding to saturations above the shock saturation are obtained [*Buckley and Leverett, 1942*]. This saturation range may be very narrow, and in a strongly wetting system, only end-point values may result. Also the calculation of the derivatives of data can introduce large errors in the estimates of relative permeability values [*Tao and Watson, 1984*]. Such Disadvantages can be avoided with an implicit interpretive method. In this method data evaluation is a much difficult task, the measured experimental data is matched with a mathematical model of the experiment and the relative permeability curves have to be inferred indirectly from measurements taken during the test using nonlinear parameter estimation techniques.

Determining capillary pressure and relative permeability separately gives a static capillary pressure curve, while it is the dynamic capillary pressure that influences the flow. The dynamic capillary pressure is affected by many factors including pore structure, flow rate and wettability may be different from that in a static case. So it is preferable to estimate the relative permeability and capillary pressure of a porous medium simultaneously.

In this study unsteady state primary drainage of sample oil fluid performed on a horizontal glass type micromodel as a porous media sample saturated with water for four different low flow rates. Although the conventional methods for estimating relative permeabilities are based on measurements outside the porous media, we now have the opportunity to do precise characterization of the time evolution of oil fluid saturation fronts advancing into a transparent porous media and pressure drop data to obtain more accurate estimates of flow functions. The relative permeability and capillary pressure are estimated simultaneously using history matching of displacement data. The power law model is used for relative permeability and capillary pressure functions. The rate dependency of relative permeability and capillary pressure curves are investigated.

2. EXPERIMENTAL SYSTEM CHARACTRISTICS

2.1 Setup and micromodel property

The setup is composed of a micromodel holder which is placed into a steel vessel containing visible widows, a camera which is equipped with a video recording system; a precise pressure

transducer and a very accurate low rate pump which is used to control the fluid flow through micromodel. The pump is able to inject oil or water depending on the request from minimum 1.5e-5 ml/min to a maximum 10 ml/min. The camera can be moved horizontally automatically. The pressure transducer is used to measure the pressure drop across the model during experiments.
Micromodel permeability was determined by measuring the pressure drop/flow rate response [*Dullien, 1992*] during distilled water injection. Because the etched depth of the pores in the micromodel is relatively uniform, the areal porosity of micromodel is equal to the ratio of colored water area to the total area of fully saturated micromodel. A more realistic porosity measurement which consider the variation of porosity versus x is used in all subsequent calculations as a primary input parameter for mathematical models.. The average etched depth and pore volume is measured by ordinary method. The physical and hydraulic properties of micromodel are shown in table1.

TABLE 1. Physical and hydraulic properties of micromodel

Length(cm)	7.5	Width(cm)	1.2
Absolute Permeability(D)	13.3	Average areal Porosity	0.485
Average depth(micron)	32	Pore volume(cm^3)	0.014

2.2 Fluids and test procedure

The red colored sample oil fluid and blue colored distilled water are used in the all experiments. Both colored fluids were filtered using fine filter paper. All experiments were conducted at a room temperature and atmospheric pressure and in horizontal geometry. The micromodel was saturated with clear distilled water and subsequently displaced with blue colored water. Then the colored oil phase is injected into micromodel through its inlet port at a pre-selected flow rate using high accuracy flow controlled injection pump. All fluids passed through inline 5 micron filter. The outlet was at atmospheric pressure and the inlet pressure is such that the constant flow rate achieved.

During experiments the saturation of oil and water phases are determined by measuring the relative area occupied by the different fluids using image analysis method. An Image analysis computer code generated and the Adobe photoshop software is used to process the images.

For four different capillary numbers unsteady state primary drainage experiments of sample oil fluid to water performed. The time evolution of the oil phase saturation and pressure drop of model, which is depend strongly on the imposed oil injection flow rate precisely characterized. Pictures of phase displacements are captured with a video camera and are recorded on the hard disk of PC. The pressure drop data are recorded during oil injections. The oil phase saturation in the model $S_o(t)$ is determined as a function of time by analyzing of images and measuring the relative area occupied with red colored oil phase.

3. Measurement of flow properties

3.1 Formulation

The formulation is based on one dimensional displacement of two incompressible and immiscible phases in a homogenous and isotropic porous medium. Based on the continuity and momentum equations, the final formulation was derived. The details of derivation are given elsewhere [*Ghazanfari, 2006*]. In the mathematical model, before the oil phase breakthrough the total pressure drop is equal to the sum of oil and water phase pressure drop and macroscopic capillary pressure at the front. After the breakthrough of oil phase, the pressure drop across the model coincide the pressure drop of oil phase.

3.2 Analytical representation of relative permeability and capillary pressure

Relative permeability and capillary pressure curves are dependent to saturation and some unknown parameters. They are represented by the conventional Coery type functions as follow:

$$k_{ro} = k_{ro}^{0}\left(\frac{S_o}{1-S_{wc}}\right)^{m} \tag{1}$$

$$k_{rw} = k_{rw}^{0}\left(\frac{1-S_{wc}-S_o}{1-S_{wc}}\right)^{n} \tag{2}$$

$$P_c = P_c^{o}\left(\frac{1-S_{wc}-S_o}{1-S_{wc}}\right)^{-l} \tag{3}$$

where m, n, l and P_c^0 are four unknown parameters which should be adjusted by parameter estimation method, S_{wc} is connate water saturation and k_{ri} , P_c are relative permeability of water or oil phase and capillary pressure, respectively . For primary drainage process the water phase end point relative permeability $k_{rw}^0 = 1$, while the oil phase end point relative permeability k_{ro}^0 can be determined using experimental data and Darcy law by introducing ΔP_o^* into the relation $k_{ro}^0 = u\mu_o L / K\Delta P_o^*$ which u is the Darcy velocity, K is absolute permeability and L is length of model and ΔP_o^* is the experimental measured pressure drop along the oil phase at steady state.

3.3 Parameter estimation model

Parameter estimation approach is a numerically automatic adjustment of unknown parameters of relative permeability and capillary pressure functions. The set of unknown parameters are finding by minimizing an objective function. This requires the derivative, or gradient, of the calculated variables with respect to the history matching parameters. The objective function formed by the sum of the square of the differences between experimentally and numerically simulated data. An optimization tool minimizes that objective function. The main part of the algorithm is the objective function, which is affected by the quality and quantity of the measured data, the errors inherent to the two-phase flow simulation model, the functional representations of relative permeabilities and capillary pressure, and the optimization technique.

The objective function, J , has the following form:

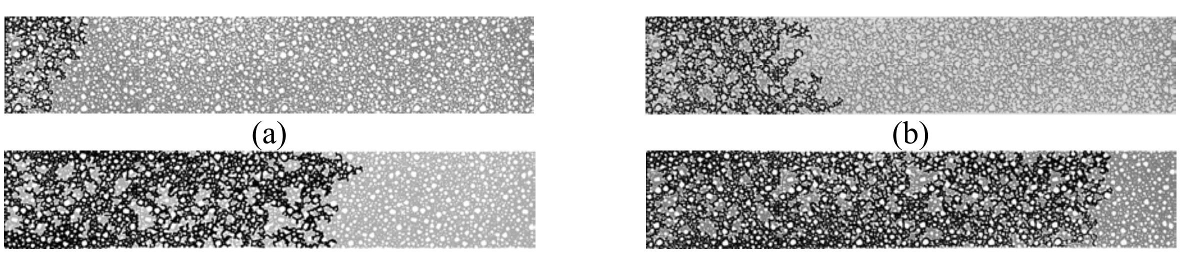
$$J = [Y - F(\beta)]^T W [Y - F(\beta)] \tag{4}$$

where β is the vector of unknown parameters, Y is the vector of experimentally measured data values, W is the weighting matrix, and $F(\beta)$ represents the corresponding quantities as calculated from the mathematical model of the experiments, using the current estimates of the unknown parameters values. For this study the minimization is performed by applying Quasi-Newton Approximation (QNA) algorithm [*Bard, 1974*].

4. RESULTS AND DISCUSSION

The role of capillary force which it acts against the flow during drainage process is of special importance in a porous medium, where the interface between the two fluids consists of many menisci. Capillary force acts at the scale of this menisci, that is at the pore scale and therefore are significant with respect to other forces that governs the displacement. The type of displacement observed during drainage in horizontal porous medium depends on the relative magnitude of viscous force to heterogeneous capillary force. The typical ratio of viscous pressure drop at pore scale to the capillary pressure is equal to $\Delta p_{vis} / \Delta p_{cap} = \mu u a^2 / K\sigma$. Where μ =0.6 cp is oil phase viscosity, a is typical pore size and $\sigma \approx 40$ dyne/cm is interfacial tension .The capillary number is defined as: $Ca = \mu u / \sigma$ and for the micromodel we have $\Delta p_{vis} / \Delta p_{cap} = a^2 Ca / K \approx 10Ca$. So if $Ca < 10^{-4}$ the system is capillary dominant.

All primary drainage experiments have been conducted at injection rates ranging from 1.2e-4 to 6e-3 ml/min, corresponding to capillary numbers 1.6e-7 to 8e-6 and performed in a horizontal geometry. Fig.1 shows the images of successive injected oil into the model for *Ca*=1.6e-6. The color of oil phase has been changed to black to have more clearance. Also, the grains and water phase color are changed to white and gray respectively. For other capillary numbers (*Ca*=1.6e-7, *Ca*=8e-7 and *Ca*=8e-6) the changes in drainage patterns with the imposed flow rate are reflected in the saturation profiles, which have very different time evolutions. At low flow rate capillary diffusion act so more straight drainage profile are observed, while at high flow rate, the drainage profile are broaden.



(a) (b) (c) (d)

FIGURE 1. Oil saturation evolution during primary drainage process for *Ca*=1.6e-6
Evolution times in fraction of breakthrough time are: (a) 1/5 (b)2/5 (c) 3/5 (d) 4/5

The distribution of the oil phase saturation along the model is determined by a generated computer code. The code numerically solves the nonlinear mathematical model based on iterative method. The QNA optimization algorithm is used for estimating of four unknown parameters of capillary pressure and relative permeability functions by fitting transient experimental oil phase saturation and pressure data. The estimated parameters, calculated end point relative permeability of oil phase and experimentally measured residual water saturation for four different capillary numbers are shown in table2.

TABLE 2. Measured and estimated parameters of flow functions

Ca	P_c^0 (pa)	m	n	l	k_{ro}^0	S_{wc}
8e-6	1012.4	1.05	2.51	0.35	0.725	0.11
1.6e-6	923.4	1.11	2.82	0.24	0.470	0.13
8e-7	728.2	1.18	3.63	0.17	0.210	0.16
1.6e-7	593.1	1.23	4.11	0.13	0.080	0.22

Fig. 2 shows the dependency of the capillary pressure with the injected oil flow rate. It tends to an asymptotically amount near the residual water saturation. Fig. 3 shows the dependency of increasing of the relative permeability curves with the capillary number. It is clearly obvious that the relative permeability curves are increasing with the imposed oil flow rate. It is because of tending the displacement to piston like when capillary number increases. Both of these experimental results are consistent with the theoretical results of dynamic pore network modeling [*Singh and Mohanty, 2003*].

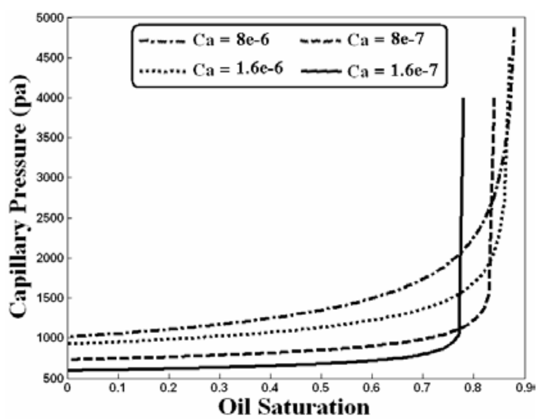


FIGURE 2. Dependency of estimated capillary pressure curves with the flow rate

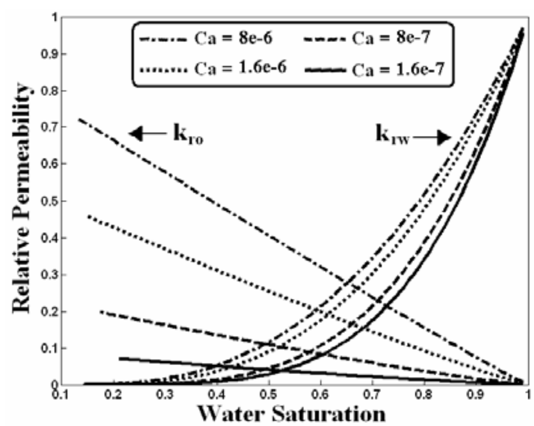
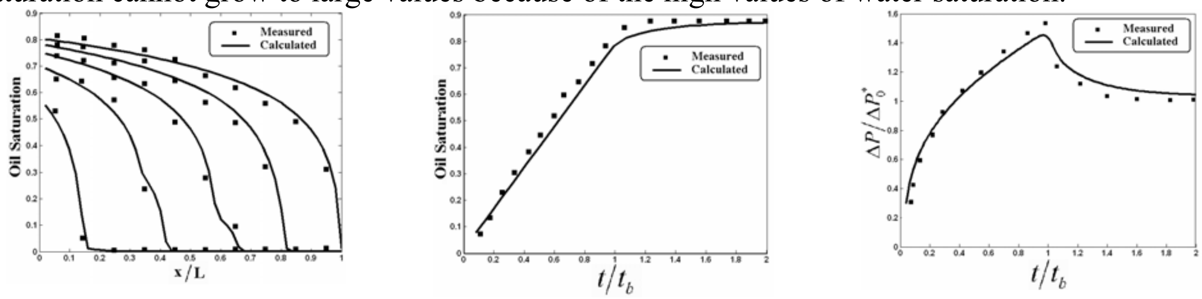


FIGURE 3. Dependency of estimated relative permeability curves with the flow rate

Fig. 4(a) depicts the time evolution of oil saturation profiles versus dimensionless length for numerically solved and experimentally measurement which conducted at constant injection rate of 1.2e-3 ml/min, corresponding to capillary number equal to 1.6e-6. For small x there is an effect of the strong initial accumulation of water on inlet face of the porous medium so the oil saturation cannot grow to large values because of the high values of water saturation.



(a) (b) (c)

FIGURE 4. Experimentally measured and numerically prediction comparison for *Ca* = 1.6e-6 (a) oil phase saturation versus dimensionless length which evolution times in fraction of breakthrough time are: 1/5, 2/5, 3/5, 4/5 and 1 (b) average oil phase saturation versus dimensionless time (c) dimensionless pressure drop versus dimensionless time

The same numerically calculation and experimentally measurements are done for other capillary numbers (*Ca*=1.6e-7, *Ca*=8e-7 and *Ca*=8e-6). The results show that the oil saturation fronts evolve with time in very different manners, depending on the capillary number. At low capillary numbers, these profiles are very much spread out.

Comparisons of experimentally measured and numerically predicted of average oil phase saturation versus dimensionless time for *Ca*=1.6e-6 is shown in Fig. 4(b). The same numerically calculation and experimentally measurements are done for other capillary numbers (*Ca*=1.6e-7, *Ca*=8e-7 and *Ca*=8e-6). The results show that average oil saturation tends to a constant steady state value of residual water saturation. The residual water saturation increases when the capillary number increases. Also the slopes of curves are increasing with increasing of capillary numbers.

The total dimensionless pressure drop of experimental measurements and the transition response of mathematical model are compared in Fig. 4(c). Before breakthrough of oil phase the total pressure drop of model is originated from the pressure drop of oil phase and water phase and capillary pressure at the displacement front. After the breakthrough the oil phase the capillary pressure and water phase pressure drop terms disappear and the total pressure drop falls suddenly and tending to a constant steady state value. The results for other capillary numbers clearly show that at breakthrough the total pressure drop takes on a local maximum which increase as capillary number decrease. Before the breakthrough of oil phase the slope of the curves are decreases when the evolution times increase.

5. CONCLUSION

The results show that the capillary pressure and relative permeability curves are rate dependent and the relative permeability curves are increasing with capillary number. The dynamic term and exponent of capillary pressure function and the end point relative permeability of oil phase increase with flow rate, but the saturation exponent of relative permeability functions are decreasing with flow rate.

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