Analytical Gas-Oil Relative Permeability Interpretation Method for Immiscible Flooding Experiments under Constant Differential Pressure Conditions

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ABSTRACT

Oil-gas relative permeability is a key parameter in evaluating gas-related EOR/IOR processes. It is normally determined from steady-state, unsteady-state gas flooding or centrifuge experiments. This paper presents an examination and further development of an analytical interpretation method for determining relative permeability from unsteady state core flooding experiments under constant differential pressure conditions. It was applied to an oil-water unsteady state core flooding experiment and this work is to further examine the method for the interpretation of relative permeability from unsteady state gas-liquid displacement. Several gas-liquid displacement experiments under constant differential pressure boundary conditions are conducted. The experimental data are interpreted using the JBN method, the newly presented method and the numerical method of history matching using software CYDAR. The performance of the new method on gas-oil displacement scenario is evaluated and compared with other methods. Since the capillary pressure is ignored in the analytical method, this technique is only valid for interpretation of viscous dominated flow; the effects of the capillary pressure still have to be corrected.

INTRODUCTION

Porosity and permeability are the main properties of small and large scale porous media. Porosity of large-scale porous media has been known to have long range correlation (Dashtian et al. 2011). This makes the study of porosity straightforward comparing with the complexity of investigation of permeability in heterogeneous formations with multi-phase fluid flow. Two and three phase relative permeabilities are important parameters capturing the relative simultaneous flow of gas, oil, and water in porous media. Relative permeability data are used in commercial simulation packages, where the phase permeability is a function of liquid (water or oil) saturation. While inaccurate relative permeability data leads to a significant error in the simulation of different EOR scenarios, a good estimation of phase permeabilities helps to obtain reliable reservoir simulation models. The fluid saturation can be estimated based on both experimental data and well log data (Dashtian et al. 2015).

Generally, relative permeability data are calculated from steady state and unsteady state core flooding experiments. Although steady state experiments are the most reliable methods, they are expensive and time consuming. Unsteady state experiments are cheaper and less time consuming. However, they are not as accurate as steady state methods and data processing is more complicated. Interpretation of unsteady state laboratory data and converting them to useable relative permeability curves is challenging. Normally, the fractional flow of different phases is calculated and then relative permeability curves are determined using an interpretation method. Although unsteady state experiments are time efficient, the accuracy depends on the interpretation method. Welge (1952) presented a method to calculate the ratio of relative permeabilities from experimental results when capillary pressure is negligible. The most popular interpretation method was developed by Johnson et al. (1959) known as the JBN method. The JBN method requires the inlet and the outlet pressure and the fluids' production data, and capillary end effects are neglected. Jones and Roszelle (1978) later presented a graphical construction method, based on the JBN method, facilitating the calculation of relative permeabilities from experimental results. Tao and Watson (1984a, 1984b) provided an error analysis for the JBN method and modified their technique to improve the accuracy of the results. Archer and Wong (1973) introduced the history matching and numerical simulation approach to calculate relative permeabilities. They matched the oil recovery and relative injectivity curves to determine the relative permeability data from core flood experiments, ignoring capillary pressure. Batycky et al. (1981) later included the effect of capillary pressure in numerical simulations and calculated the relative permeabilities. Cable et al. (1999) later applied experimental techniques to measure the relative permeabilities for gas condensate reservoirs in near wellbore regions.

In this paper, the new relative permeability interpretation method presented by Cao et al. (2014), based on the generalization of the Buckley-Leverett theory for constant pressure boundaries (Johansen and James, 2014) is presented for immiscible gas/liquid unsteady state relative permeabilities. This interpretation method applies analytical solution to fractional flow theory under constant pressure boundary, therefore reducing the need for numerical differentiation and associated errors. As an alternative to JBN method, this interpretation method was applied for water/oil displacements by Cao et al. (2015) and now is extended to immiscible gas flooding systems. In the following sections, the methodology is first explained. Then, it is demonstrated how this method is applied for gas/oil and gas/water core flooding displacements with constant pressure boundaries, when gravity forces are included. In this interpretation approach analytical techniques are employed to determine the saturation profile along the core. Afterwards, the laboratory data are also interpreted using JBN and history matching methods using software CYDAR. A comparison of three methods shows the accuracy of the presented technique.

METHODOLOGY

Suppose we have immiscible two phases of gas and liquid flowing in the homogeneous and incompressible porous medium in one dimension. Assume that the liquid phase is incompressible and the gas phase has a constant compressibility inside the porous medium. Also, assume that the capillary pressure can be ignored. The fractional flow model in terms of the displacing phase (gas) can be formulated as

$$\phi \frac{\partial S_g}{\partial t} + u_T(t)\frac{\partial f}{\partial x} = 0, \tag{1}$$

where S_g is the gas saturation and f is the fractional flow function in terms of gas, defined as

$$f(S_g) = \frac{\lambda_g}{\lambda_T} - \frac{\lambda_l \lambda_g \Delta\rho}{u_T \lambda_T}; \; \lambda = \frac{Kk_r}{\mu}; \; \lambda_T = \lambda_g + \lambda_l. \tag{2}$$

Under constant differential pressure boundaries, the inlet and outlet pressures are kept constant while the total volumetric flux u_T is a function of time. During the displacement experiment, the breakthrough time is recorded. The breakthrough time (t_S) of a series of saturation points (S) are then measured based on mass balance and experimental data. The corresponding fractional function $f(S)$ is determined based on produced volume of gas and liquid. Detailed calculation procedures are described in previous research by Cao et al. (2014). Analytical solutions to pressure and saturation distributions and derivative of fractional function can be found in Johansen and James (2014).

In this paper, two gas/liquid displacement experiments are performed and the results are interpreted using the newly proposed method, the JBN method, and the history matching method. The results from different methods are compared and the performance of the new method is discussed.

EXPERIMENTAL DETAILS

Two phase gas/water and gas/oil core flooding experiments under constant differential pressure were conducted to examine the interpretation method proposed by Cao et al. (2014) for immiscible gas-oil and gas-water relative permeabilities. Carbon tan and Berea sandstone cores were used (see properties in Table 1).

Nitrogen (Praxair, purity > 99%) was used as the gas phase to ensure immiscibility. A synthetic brine with the salinity of 10,000 ppm, viscosity of 1.02 cP and density of 1005 kg/m^3, and a dead crude oil with viscosity of 5.9 cP and density of 855 kg/m^3 were used. The experiments were conducted at low injection pressures. An accurate gas regulator was used to keep the pressure constant at the inlet where the pressure was supported by a high pressure gas tank. The outlet pressure was set to atmospheric pressure. The effluent was collected in a separator at the outlet. The bottom of the separator was connected to a graduated cylinder and a gas meter was connected to the top of the separator to measure the produced liquid and gas flow rates, respectively. Once the experiment began, the gas and the oil flow rates, the inlet and the outlet pressures with time were recorded, as well as the breakthrough time. In order to have accurate results, the data were recorded more often at early times. General information about the experiment and the core samples are provided in Table 1. The experimental schematic is shown in Figure 1.

RESULTS

The interpreted results from the gas-oil and gas-water unsteady state relative permeability core flooding experiments are shown in Figures 2 and 3. The end points from each method are the same since they are achieved in a steady state flow where no more displaced phased is produced.

The history matching method applies numerical simulation of displacement process to optimize the defined objective functions, which are the evenly weighted functions of liquid production, gas production and the differential pressure between inlet and outlet. However, the relative permeabilities obtained from history matching are in good agreement with the JBN results. The main reason is that the history matching method applies a Corey Model or a modified Corey Model fitted from JBN results and then matches the production data by modifying the coefficients in the Corey Model. This also indicates that a more flexible relative permeability model, like one using B-Splines, could improve the flexibility and accuracy in numerical matching.

The results are shown in Figures 2 and 3 for gas-oil and gas-water, respectively. Both cases show that the results from the three interpretation methods are consistent in trend; however, the liquid phase relative permeability from the new method are lower than that from the JBN method. The gas relative permeabilities from the three methods in both cases are very similar to each other. Furthermore, in both cases, the new method results lie on a smoother curve than the JBN method, with less oscillation in relative permeabilities. This is mainly because that the new method reduced the use of numerical differentiation by applying analytical solution of saturation and pressure profiles.

Figures 2 and 3 show that the oil and water phase relative permeabilities obtained from the new method are lower than those obtained from traditional the JBN and history matching approach. Therefore, these results will lead to a lower recovery factors in reservoir simulations. Thus, further research is required to examine the accuracy of the analytical methods. However, not a big difference is observed in the results obtained for the gas phase. The new method is examined as an alternative to JBN method for relative permeability interpretation from gas-liquid immiscible flooding experiments. The advantages over classical analytical methods are application of the fractional flow fundamentals under constant differential pressure boundary and the reduced use of numerical differentiation. Further experiments and research are needed to verify accuracy of the new method. Optimal differential pressure for gas-liquid flooding experiments is to be investigated.

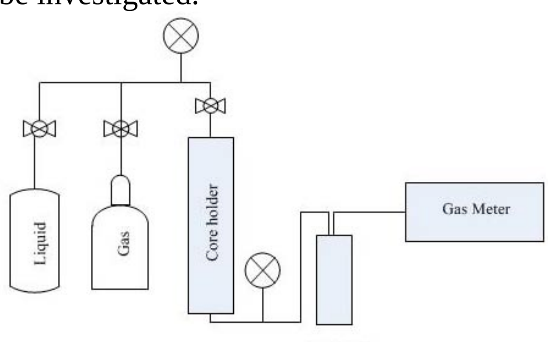

Figure 1. Experimental Setup Schematic

Table 1. Core & Experimental Data

Core sample	Carbon Tan	Berea sandstone
Displacement type	Gas/water	Gas/oil
Porosity (%)	18	15
Permeability [mD]	9	133
Differential Pressure [psi/bar]	17.98/1.16	2.18/0.15
Core Length [cm]	29.97	30.48
Core Diameter [cm]	3.81	3.81

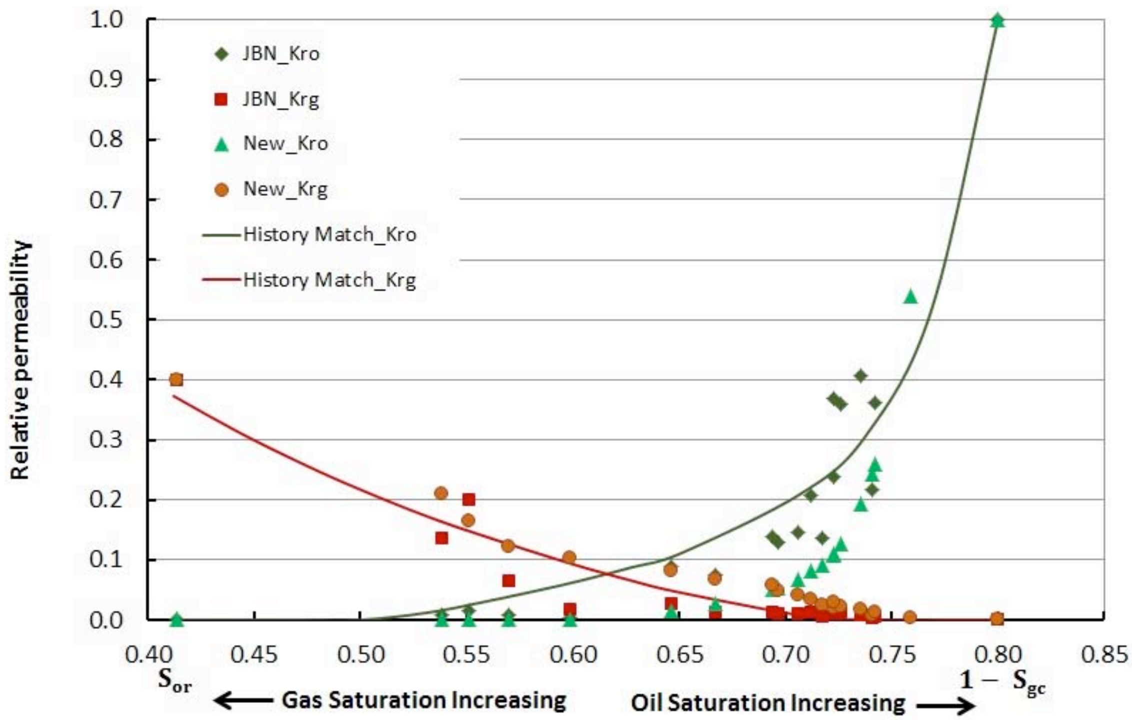

Figure 2 Gas-oil relative permeability results

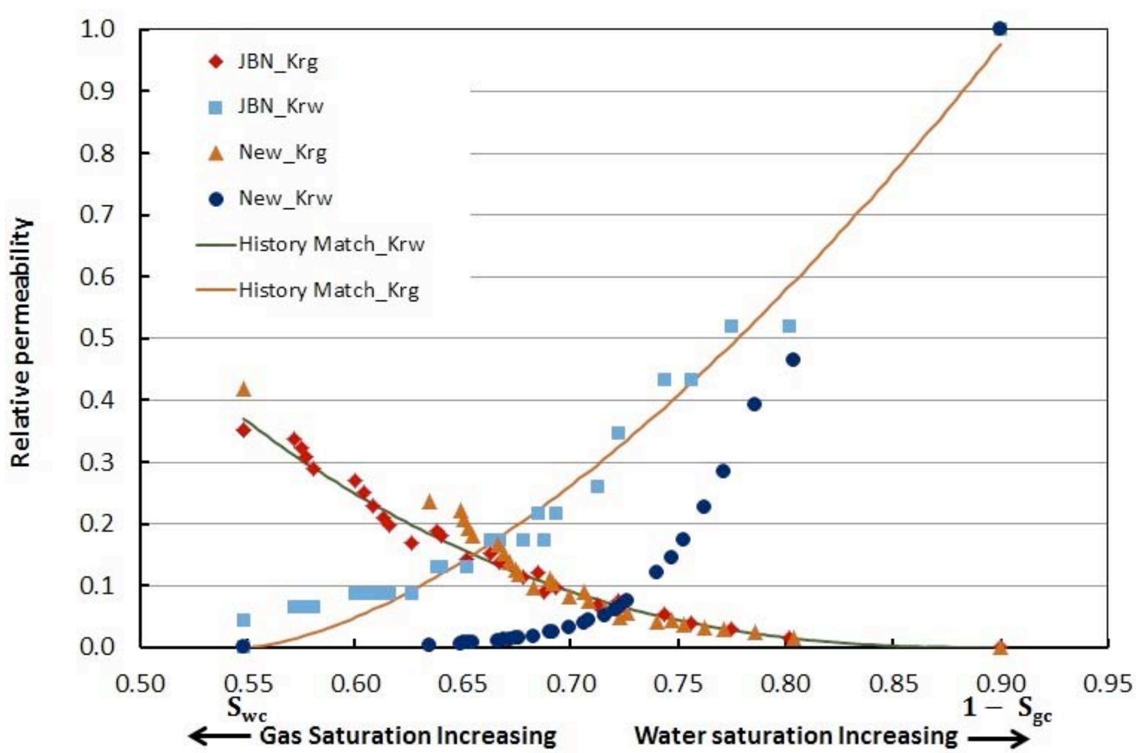

Figure 3 Gas-water relative permeability results

CONCLUSIONS

In this research, the new analytical relative permeability interpretation method is verified through comparison with the JBN method and numerical method for same displacement experiments. The new method is examined as an alternative method for gas-liquid displacement experiment interpretations, showing a lower liquid relative permeability than JBN method. It applies fractional flow theory under constant pressure boundary and also reduces the errors associated with numerical differentiation used in other analytical methods such as JBN method. Further experiments are need for accuracy verification.

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