

# **SCA2003-46: THE CHARACTERISTICS OF RELATIVE PERMEABILITY CURVES IN CHEMICAL FLOODING BY PORE SCALE NETWORK MODELING**

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## **ABSTRACT**

EOR processes that feature polymer flooding, surfactant flooding, or ASP compositional flooding, require relative permeability data to calculate the flow behavior in reservoir engineering calculations and numerical simulation of reservoir performance. The present work deals with a dynamic pore scale network model where the porous medium is represented by a regular pore geometry, and aims at the evaluation in the change of two-phase flow properties induced by the introduction of chemical flooding factors, such as interfacial tension reduction and water viscosity enhancement. Both the non-wetting and wetting phase relative permeabilities vary with the chemical flooding factors. The injection of polymer reduces water relative permeability over the entire saturation range. The relative permeability is greatly affected by interfacial tension values. Both water and oil relative permeability curves were found to shift upward as interfacial tension is reduced. They tend to become linear with saturation as interfacial tension reaches ultra-low value.

## **INTRODUCTION**

As world oil reserves dwindle, the development of EOR techniques to maximize recovery is of great importance. Methods such as chemical flooding, miscible flooding, and thermal recovery involve altering the mobility and/or the interfacial tension between the displacing and the displaced fluids. Means for increasing tertiary oil recoveries from previously waterflooded viscous oil reservoirs are receiving added attention today as a result of industry-wide efforts to improve the oil producing rates and reserves. The flow behavior in chemical flooding differs from that of conventional water and oil; it depends upon interfacial tension, viscosity, and flow rate as well as the rock properties of pore size distribution and wettability. The mechanism of two-phase flow in porous media in chemical flooding has been a subject of wide controversy.

The concept of relative permeability was introduced to describe simultaneous flow of fluids in a porous medium by an apparently simple modification of Darcy's equation. To evaluate

the potential magnitude of improved recovery and economics of prior chemical injection, there is a need for relative permeability data for use in performance evaluation calculations.

Many studies have shown that the presence of polymer and/or surfactant in water phase had a significant and consistent effect. Mathematical model studies provide a reliable means for evaluating potential benefits of chemical flooding. However, such studies require input data that permit the model to simulate the physical process that may occur in the reservoir. With the increased use of mathematical reservoir simulators to predict recovery from different EOR processes, the need to model the various flow properties, especially relative permeability, becomes important.

The present work deals with a dynamic pore scale network model where the porous medium is represented by a regular pore geometry. The objective of this study was to investigate relative permeabilities during chemical flooding. By the dynamic pore scale network modeling, the relative permeability alteration due to typical chemical factors were investigated. It has to be emphasized that the goal in this paper is not to directly reproduce experimental situation with actual parameters, but rather to investigate the phenomenology of the problem for a test configuration. It showed that the dynamic pore scale network model, which gives an insight for flow mechanism, is a promising tool.

## **DYNAMIC PORE SCALE NETWORK MODEL**

Pore-scale network models have been used to describe a wide range of phenomena from capillary pressure characteristics to three-phase relative permeability curves. The void space of a rock is described as a lattice of pores connected by throats. The pores and throats are assigned some ideal geometry and rules are developed to determine the multiphase fluid configuration and transport in these elements.

Pore-scale network models can be categorized into two kinds: quasi-static and dynamic. In the quasi-static model, it was assumed flow at an infinitesimal flow rate where the viscous pressure drop across the network is negligible and capillary forces completely control the fluid configurations. In chemical flooding, the approximation of quasi-static displacement is not valid. For example, very large pressure gradients are found in flows involving polymers, and in surfactant flooding, the very low interfacial tension reduces the capillary forces.

Dynamic models relax the condition that the capillary number is small. The effects of viscous forces are modeled through the explicit computation of the pressure field in the network.

Koplick and Lasseter <sup>[1]</sup> present a dynamic network model for two phase flow, which allowed for the advance of several menisci during a time step. Equal fluid viscosities were assumed. Lenormand *et al.* <sup>[2]</sup> simulated the dynamics of drainage on 100×100 two

dimensional networks and showed the existence of three basic domains, namely capillary fingering, viscous fingering, and stable displacement, within which the fluid patterns remain unchanged. They noted that due to capillary pressure, the system of equations used to solve the pressure at each node became non-linear. Whereas previously reported work<sup>[1]</sup> consisted of replacing the nonlinear problem with a sequence of linear problems. Lenormand *et al.* approximate directly the solution to the non-linear problem, using a relaxation technique.

Dias and Payatakes<sup>[3]</sup> used a pore and throat model that had a throat geometry that varied sinusoidally between the adjacent pore sizes. The effects of stranding, breakup, coalescence, and shape of ganglion for both favorable and unfavorable viscosity ratios were first simulated by them. The issue of steady-state ganglia dynamics was further addressed in a paper by Constantinides and Payatakes<sup>[4]</sup>, who calculated the relative permeabilities as a function of capillary number, viscosity ratio, and coalescence factor.

Another dynamic two-phase model of drainage was developed by Blunt and King<sup>[5][6]</sup> with the purpose of studying the effect of viscous and capillary forces on relative permeabilities for 2-D and 3-D networks. Their simulations showed that drainage relative permeability may be a function of both viscosity ratio and capillary number. Chaouche *et al.*<sup>[7]</sup> and Haghghi *et al.*<sup>[8]</sup> developed a dynamic network model similar to the one of Blunt and King to study drainage in heterogeneous media.

Vizika *et al.*<sup>[9]</sup> investigated the role of viscosity ratio during forced imbibition and found that it affects residual oil saturation significantly even for low capillary number. Pereira *et al.*<sup>[10]</sup> developed a model for drainage dominated three-phase flow. Their simulations agreed with micromodel work by Øren and Pinczewski<sup>[11]</sup>. Mogensen and Stenby<sup>[12]</sup> had developed a dynamic model of imbibition that accounted for the flow of wetting fluid in the corners, as well as allowing for ganglion to be mobilized.

In this paper, a two-dimensional network model with triangular lattice of spherical pores connected by cylindrical throats is used. The coordination number is 6 (See Fig.1). The pore throat and pore body radii are described using a probability distribution given by a special case of Weibull distribution,

$$f(x) = \frac{r - r_{min}}{(r_{max} - r_{min})^2} \exp\left(\frac{(r - r_{min})^2}{(r_{max} - r_{min})^2}\right) \quad (1)$$

where  $r$  represents the pore throat radius,  $r_{min}$  and  $r_{max}$  define the minimum and maximum sizes respectively. The distribution of the pore radius is shown in Fig.2. In this model, we assume that the pore throat radius is uncorrelated. Throat lengths are all set to an input specified value. So the pore and throat volumes can be calculated.

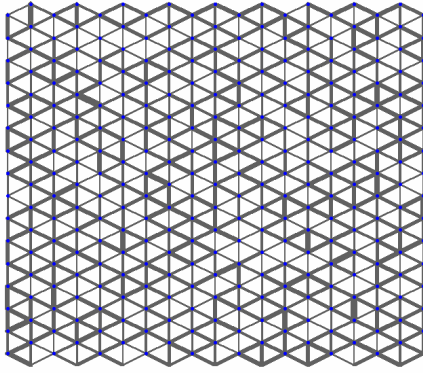


Figure 1 Schematic of the pore scale network model ( $z=6$ )

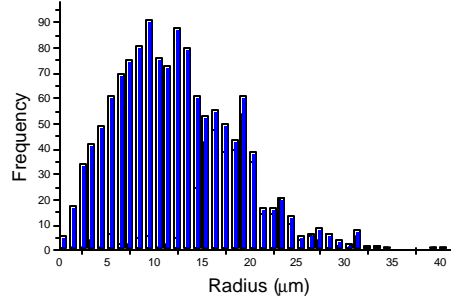


Fig. 2 Pore radius distribution

We calculate the wetting phase pressure by applying volume conservation in each pore:

$$\sum_{j=1,m} q_{ij} = 0 \quad (2)$$

where  $q_{ij}$  is the volumetric flow rate flowing from pore  $i$  to adjacent pore  $j$  and is obtained from a Darcy-type law in each pore-throat element as:

$$q_{ij} = \frac{\mathbf{p}r_{ij}^4}{8A\mathbf{m}_j} (p_i - p_j - P_c)^+ \quad (3)$$

where  $P_c = \frac{2\mathbf{s} \cos \mathbf{q}}{r}$  is capillary pressure across the pore throat between nodes  $i$  and  $j$ . In

this equation, the + denotes the positive part; means that  $q_{ij} = 0$  as long as  $(p_i - p_j < P_c)$ ,

otherwise the expression of  $q_{ij}$  is the one of a biphasic Poiseuille flow in a tube with a pressure jump at the interface. The wettability of the pore surface was set to water-wet by set the contact angle less than  $90^\circ$ . The heterogeneity of wettability was not considered in this paper, so the contact angle for all throats were set identical.

## RESULTS

### Relative Permeability in Surfactant Flooding

The effect of surfactants in enhanced oil recovery systems is of great interest to those concerned with designing cost effective processes to recover residual oil after waterflooding. The effect of interfacial tension on relative permeability curves has received increasing treatment in the petroleum literature. Leverett<sup>[13]</sup> reported a small but definite tendency for a water/oil system in unconsolidated rocks to exhibit 20 to 30% higher relative permeabilities if the interfacial tension was decreased from 24 to 5 mN/m. Muga<sup>[14]</sup> studies interfacial tension values varying from 5 to 40 mN/m. Although his systems were artificial, clean, and very idealized, a decrease in the relative permeability ratios with decreasing interfacial

tension could be deduced from the displacement data.

More significant effects would be expected for very low interfacial tension. Talash<sup>[15]</sup> presented oil and water relative permeability curves for various low tension formulations. The relative permeabilities for both phases increased with the decreasing interfacial tension at a given water saturation. Though the residual oil saturations decreased. The irreducible water saturation did not seem to be affected. The lack of equilibration between the systems in the unsteady-state displacement experiments was manifested in the continual release of oil globules with large volumes of throughput. Gillian *et al.*<sup>[16]</sup> provided limited relative permeability data for some low-tension systems. They hypothesized that in a low-tension flood the oil relative permeability curves shifted toward higher water saturation and that the ultimate residual oil saturation was reduced to zero. The aqueous wetting phase relative permeability was not affected. Batycky *et al.*<sup>[17]</sup> examined steady-state relative permeability data for three interfacial tension levels (50, 0.2, 0.02mN/m). Their data show a reduction in the irreducible brine saturation with decreasing interfacial tension. Bardon *et al.*<sup>[18]</sup> evaluated the effect of low interfacial tension on gas/oil permeability curves. Their results show that the residual oil saturation and relative permeability are affected strongly by low interfacial tension.

The ratio of viscous to capillary forces is defined by a capillary number

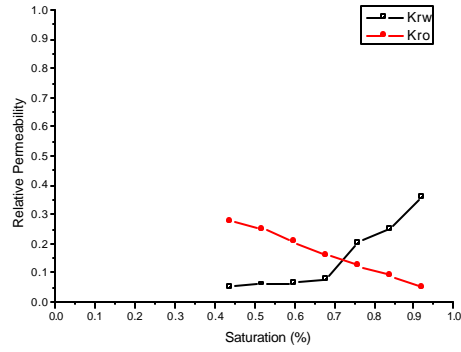
$$N_c = \frac{\mathbf{m}q}{\mathbf{s}} \quad (4)$$

where  $\mathbf{m}$  is the viscosity of the injected phases,  $q$  is the flow rate and  $\mathbf{s}$  is the interfacial tension. Taber<sup>[19]</sup> defined capillary number in terms of the pressure drop between two points, the flow length, and the interfacial tension. He concluded that as this ratio increases to a specified value the residual oil saturation was reduced significantly. Melrose and Brandner<sup>[20]</sup> indicated that as the capillary number rose to a value of  $10^{-4}$ , the microscopic displacement efficiency, which account for the residual saturations to both water and oil, increased. The effects of capillary number on the recovery of residual oil are given by Chatzis and Morrow<sup>[21][22]</sup>, showing a decreasing residual saturation to both oil and water.

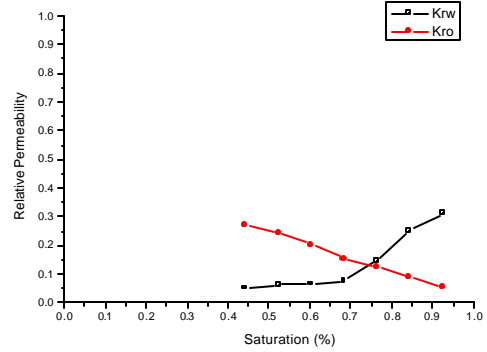
To sum up, the assumption that relative permeability are function only of fluid saturations and saturation histories is not sufficient to accurately describe observed chemical flooding behavior. So many endeavors were performed to determine the relative permeabilities at specified chemical flooding circumstance. Amaefule *et al.*<sup>[23]</sup>, Fulcher *et al.*<sup>[24]</sup> developed a relative permeability model based on their experimental data by regression analysis. In their model the relative permeabilities are the function of saturation, interfacial tension, fluid viscosity and the residual saturation. The residual oil saturation was modeled as a function of the capillary number and the irreducible water saturation was a function of interfacial tension.

In this work, we are seeking to reveal the function between relative permeability and

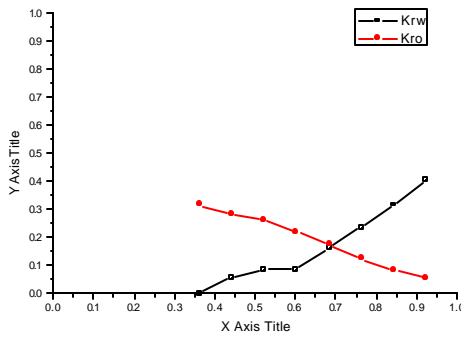
interfacial tension by numerical methods. With the help of a dynamic pore-scale network model, the competition between the viscous forces and the capillary forces can be illustrated. Six virtual surfactant flooding scenarios were investigated using this network model with different interfacial tensions in the range of  $2.0 \times 10^{-1}$  mN/m to as small as  $5.0 \times 10^{-4}$  mN/m.



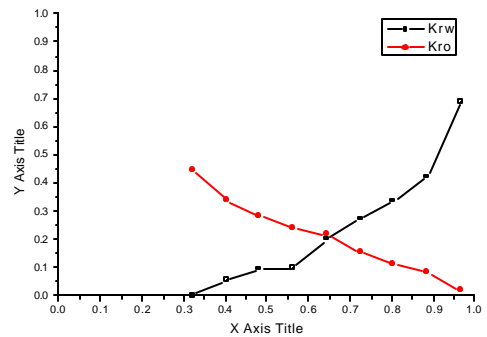
a.  $s = 2.0 \times 10^{-1}$  mN/m



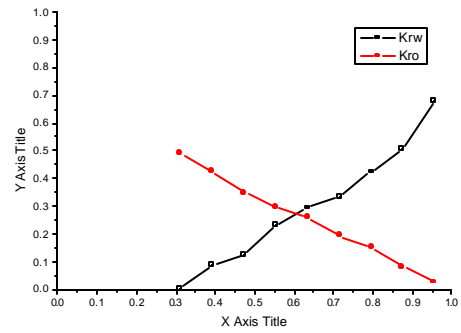
b.  $s = 5.0 \times 10^{-1}$  mN/m



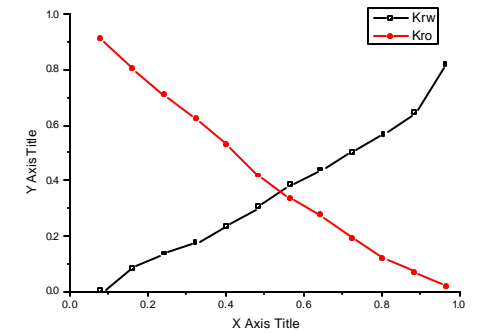
c.  $s = 5.0 \times 10^{-2}$  mN/m



d.  $s = 2.0 \times 10^{-2}$  mN/m



e.  $s = 2.0 \times 10^{-3}$  mN/m



f.  $s = 5.0 \times 10^{-4}$  mN/m

Fig. 3 Simulated relative permeability curves with different interfacial tension values

The relative permeability curves from different interfacial tension systems are given in Fig. 3. It is seen from Fig. 3a and Fig. 3b that for interfacial tension above  $10^2$  mN/m, the changes of

relative permeabilities were negligible. But larger increase were observed for interfacial tension below  $10^{-2}$  mN/m for both phases, as shown in Fig. 3c, Fig. 3d, Fig. 3e and Fig. 3f. It shows that when the interfacial tension decreases, the relative permeabilities of oil and water increase. When the interfacial tension continues to decrease to values as low as  $10^{-4}$  mN/m, the curves tend toward linearity, as shown in Fig. 3f.

### **Relative Permeability in ASP Flooding**

Great attention has also been given to chemical flooding processes using alkali, polymer and/or surfactant because the oil recovery can be greatly improved by synergistic action of these 2 or 3 chemicals. Meanwhile the used quantity of expensive surfactant can be reduced even 10 times by using cheaper alkali agent so that the method will be of great prospect. The surfactant increases the capillary number by reducing the interfacial tension. Polymers improve the mobility ratio by enhancing water viscosity. The alkali is used to prevent adsorption onto the rock of the other components, and to stimulate the production of natural surfactants from crude oil.

Compared to the experimental or numerical investigation on the relative permeability in surfactant flooding, the relative permeability in polymer flooding and ASP flooding were rare. Many experimental studies have investigated the resulting effect of a polymer injection on two-phase flow in porous media. All the studies indicate a selective action of the polymer with significant reduction in relative permeability to water with respect to the relative permeability to oil, which is often referred as the disproportionate permeability reduction (DPR). Schneider *et al.*<sup>[25]</sup> had measured polymer/oil relative permeability data by steady-state procedures on a suite of 18 outcrop and formation core samples. The observation in these studies was that the presence of polymers in the water phase had a significant and consistent effect, lowering water relative permeability over the entire water saturation range. Zitha *et al.*<sup>[26]</sup> and Barreau *et al.*<sup>[27]</sup> demonstrated the effect of polymer adsorption on the relative permeability. The group of Seright<sup>[28]</sup> had published many papers which interpreted the DPR phenomenon by different mechanisms, such as polymer retention, partitioning of fluids leading to segregation of oil and water within the porous media; lubrication effect of the polymer reducing pore wall roughness of the solid matrix; enhancement of water wettability due to adsorption of hydrophilic molecules.

In this work the interplay of the viscosity and interfacial tension were considered. A series of dynamic pore scale network simulations were realized with selected viscosity ratio (oil viscosity (cp)/ water viscosity (cp)) and interfacial tension values. For the purpose of simplicity, three viscosity ratios were considered, as 30/50, 30/30 and 50/30. The interfacial tension decreased from  $1.0 \times 10^{-1}$  mN/m to  $1.0 \times 10^{-4}$  mN/m.

Figure 4 shows the simulated relative permeability with the synergistic effect of viscosity and interfacial tension. The values of interfacial tension were  $1.0 \times 10^{-1}$  mN/m,  $1.0 \times 10^{-2}$  mN/m,  $1.0 \times 10^{-3}$  mN/m and  $1.0 \times 10^{-4}$  mN/m for Fig.4a to Fig.4d. respectively. It is shown that at higher interfacial tension values, as shown in Fig. 4a and Fig.4b, the effects of viscosity ratio are negligible. The relative permeability curves almost overlapped. With the decrease of interfacial tension, as shown in Fig. 4c and Fig. 4d, the effects of viscosity ratio were significant. At low viscosity ratio, *i.e.* more viscous water, the water phase relative permeability had larger reduction. The oil relative permeability curves also decreased with water viscosity enhancement, but the reduction was relatively smaller when compared to the reduction in water relative permeability. In the high water saturation range,  $S_w > 70\%$ , the reduction of oil relative permeability was insignificant, thus indicating that at high water cut stage, the impact of viscosity upon oil flow can be neglected.

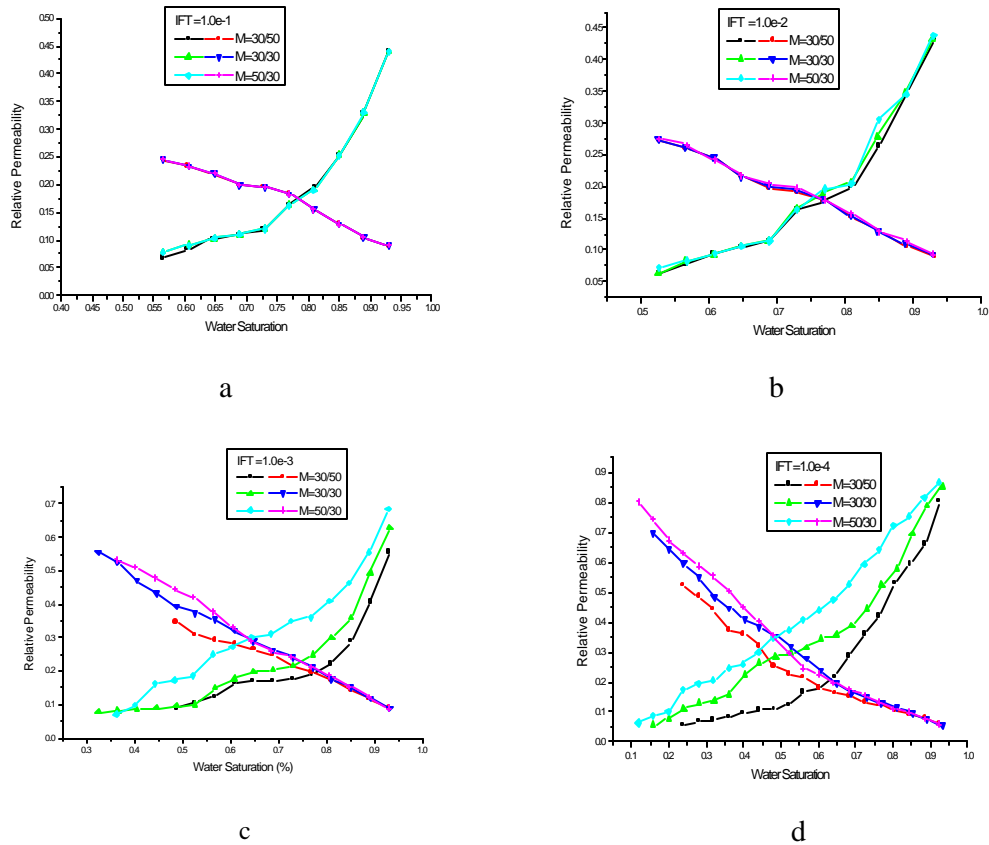


Fig. 4 Simulated Relative permeability with the synergistic effect of viscosity and interfacial tension



## Effect of interfacial tension and Viscosity ratio upon Breakthrough Average Saturation

The irreducible water saturation and residual oil saturation are two important parameters in relative permeability curve. The correlation curve between residual oil saturation and capillary number became the most important guidance for the EOR practice, but the correlation between breakthrough saturation and interfacial tension and viscosity ratio were not well known. This correlation was obtained base on more than 40 simulation results. The breakthrough saturation had some relation with the displacement pattern.

In the pore-scale network modeling, four oil/water viscosity ratios were used, 3, 1, 0.6, and 0.3. At every viscosity ratio step, ten interfacial tension values were considered, decreasing from  $1.0 \times 10^1$  mN/m to  $1.0 \times 10^{-4}$  mN/m. Figure 5 presents the water breakthrough average saturation as a function of IFT for various values of viscosity ratio.

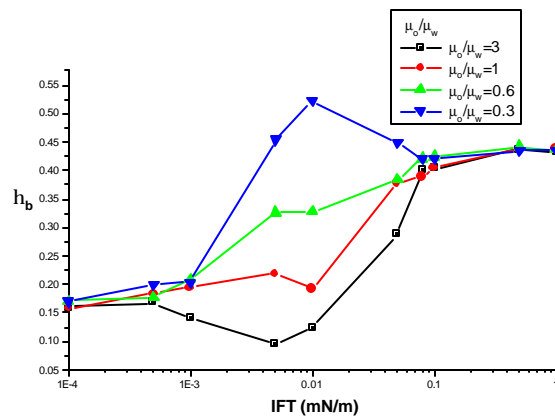


Fig. 5 The correlation between water breakthrough saturation and interfacial tension and viscosity ratio.

With the decrease of the interfacial tension, the breakthrough average water saturation decreases, in accordance with previous results. In the higher and lower interfacial tension range, i.e. interfacial tension  $> 0.1$  mN/m and interfacial tension  $< 0.001$  mN/m, the effects of viscosity ratio were negligible. But in the interfacial tension range from 0.1 to 0.001 mN/m, the relationship between interfacial tension and breakthrough saturation was not monotonous any more. The viscosity ratio will alter the curves strongly. When the viscosity ratio was high, in the interfacial tension value from 0.1 to 0.001 mN/m, the breakthrough saturation decreased with the decrease of the interfacial tension sharply, then it increase slowly, shown as squares and circles in Fig. 5. Inversely, when the viscosity ratio was low, the water viscosity was high, the breakthrough average water saturation curve increased and then decreased with a reduction of IFT values, shown as triangles in Fig. 5.

The low breakthrough saturations imply fingering, while the high breakthrough saturation imply weak fingering, and a stable displacement. In chemical flooding the sweep efficiency

was improved mainly due to the mobility control, as in polymer flooding, where the microscopic efficiency improved mainly by the injection of surfactant solution. In the ASP composition flooding, the coupling of surfactant and polymer may be counteracting upon breakthrough. In Fig.5, the effect of polymer only act at some specified interfacial tension range.

## CONCLUSIONS

In this brief paper, we have shown that the dynamic pore scale network model can reproduce the relative permeability for chemical flooding characterized by low interfacial tension and enhanced water viscosity. It was shown that the relative permeability for both oil and water increases with the decrease of interfacial tension, especially for interfacial tension below  $10^{-2}$  mN/m. The trends of simulated result were in good agreement with experimental results reported in ref.[23], [24]. The synergistic effect of viscosity ratio and interfacial tension upon relative permeability and breakthrough saturation were demonstrated by the numerical simulations. The problem needs further work due to its complexity. The success of the dynamic model provides some hope that our studies based on pore-scale network modeling will have implications for chemical flooding practices.

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