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The Influence of Interfacial Tension on Water/Oil Two-Phase Relative Permeability

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Abstract

Water-oil relative permeability characterizes two-phase flow and displacement processes, and its functional form is difficult to determine in a particular reservoir study. Adding various chemical agents into the displacing aqueous phase during alkaline-surfactant-polymer combination chemical flooding in oil production significantly changes interfacial tension (σ) on water-oil interfaces, and also increases the degree of difficulty in measuring such changes in the laboratory or field. To overcome the limitations of the existing laboratory measurements of relative permeability (which are applicable only for high ranges of interfacial tension [e.g., $\sigma > 10^{-2}$ mN/m], we present a comprehensive experimental study of two-phase relative-permeability functions in much lower, more realistic interfacial tension water-oil systems. In particular, we have (1) develop an improved steady-state method of measuring water-oil relative permeability curves; (2) proven that a critical interfacial tension value (σ_c) exists such that interfacial tension has little impact on relative permeability for $\sigma > \sigma_c$, while if $\sigma < \sigma_c$, relative permeabilities to both water and oil phases will increase with decreasing interfacial tension; and (3) shown that a logarithmic relationship exists between water-oil two-phase relative permeability and interfacial tensions. The experimental results reported here and conceptual models proposed here will be useful for feasibility studies, optimal designs, and numerical simulations of different chemical flooding operations in oil reservoirs.

Introduction

With simultaneous increasing demand for oil and large decreases worldwide in newly discovered oil reserves in the past few decades, more efficient development of oil and gas from existing reservoirs, using enhanced oil recovery (EOR) methods, has received greater attention, in the energy industry. As a result of industry-wide efforts to improve oil recovery rates, many EOR techniques have been developed and applied to various oil fields. In general, EOR methods, such as chemical flooding, miscible flooding, and thermal recovery techniques, rely on altering the mobility and/or the interfacial tension (IFT) between the displacing and displaced fluids to improve sweep or displacement efficiency. Among the various EOR approaches developed, chemical flooding, with various chemical surfactants added into injected fluids, is among the most promising, cost-effective, and widely used methods.

To evaluate such chemically enhanced EOR approaches for their efficiency or suitability to a given reservoir, investigators resort to quantitative studies of laboratory experiments and field applications, requiring many physical parameters. Among these parameters and correlations, water-oil two-phase relative permeability is perhaps the most important constitutive relation that characterizes two-phase flow and displacement processes in porous media. Because of the additional interactions between fluid (water and oil) phases, chemical components, and solid porous rock, flow behavior within chemical flooding is in general more difficult to characterize than that within oil displacement in conventional water flooding. Even with the significant progress made in understanding chemical flooding over the past few decades, it remains a challenge to quantitatively assess such flow behavior. It is even more difficult to predict whether this technique can be successfully applied to a given field condition. One of the primary difficulties is the lack of physical insight or constitutive correlations (e.g., relative permeability curves) for describing mutual effects or interplay between phases during chemical flooding processes, a deficiency that hinders quantitative analysis (such as numerical modeling studies) of laboratory or field studies.

The primary goals in reservoir EOR operations are to displace or mobilize more remaining oil from existing formations than can be achieved using conventional waterflooding techniques. Remaining oil left in reservoirs after long-time recovery operations is normally discontinuously distributed in pores. From the viewpoint of fluid flow mechanics, there are two main forces acting on residual oil drops: *viscous* and *capillary* forces. Microscopic displacement efficiency with an EOR method depends on the relative influence or ratio of these two forces, which is often described by defining a capillary number[1] as the ratio of viscous forces and capillarity:

$$N_c = \frac{\mu_w V_w}{\phi \sigma_{wo}} \qquad (1)$$

where N_c is the capillary number; μ_w is the viscosity of aqueous or displacing phase; V_w is the flow rate of the displacing phase; ϕ is the effective porosity of formation; and σ_{wo} is the water-oil interfacial tension. Another useful parameter for quantitative analysis of oil recovery operations is the microscopic displacement efficiency (E_m), defined as:

$$E_m = \frac{1 - S_{or} - S_{wc}}{1 - S_{wc}} \qquad (2)$$

where S_{or} is residual oil saturation and S_{wc} is residual saturation.

Using experimental results, Fulcher et al.[2] show that changes in the capillary number have a significant effect on the residual oil saturation of the system. The interfacial tension between crude oil and *in situ* brine ranges normally from 20 to 30 mN/m under normal reservoir conditions, and the capillary number is at about 10^{-6} for general water flooding reservoirs. The residual oil saturation or microscopic displacement efficiency of about 40% can be reached. As the capillary number rises to 10^{-2}, however, the residual oil saturation could be lowered to near zero and recovery efficiency could theoretically be close to 100%. One efficient way to increase capillary number is adding surfactants to displacing fluids during chemical flooding operations, which could significantly reduce the interfacial tension to as low as 10^{-3} mN/m (equivalent to a four-orders-of-magnitude increase in capillary number). This will increase the capillary number to above a value of 10^{-2} for an optimal oil recovery result [1]. At the same time, water-phase relative permeability at residual oil saturation after waterflooding will continuously increase as the capillary number increases.[2]

By altering interfacial tension between water-oil (water-gas or oil-gas) phases, surfactants can cause significant changes in two-phase flow behavior. To understand the process, many researchers have studied relative permeability with flow systems involving change in interfacial tension. Among the earlier efforts, Talash[3] presented a modified Naar-Wygel equation exponential function to describe the relationship between relative permeability and normalized saturation under low interfacial tension conditions. By comparing with laboratory measurements, the modified model was found to fit well for relative permeability curves near the two ends of saturation ranges, but not well for the middle portion of the curves.

Lawson and Hirasaki[4] found that two-phase water-oil flow and displacement behaved very differently with or without adding a surfactant. They showed that concentration, adsorption onto the rock, and partitioning of surfactants into the oleic phase all affected relative permeability curves. Asar and Handy[5] measured relative permeability curves for two-phase flow of "oil" (methane, ethane, or kerosene) and gas (nitrogen) under different interfacial tension, ranging from 0.033 to 30 mN/m. Based on shapes and extrapolations of measured relative permeability curves under different interfacial tension, they predicted that the relative permeability curves would become two diagonally straight lines (i.e., relative permeability equal to saturation) at zero interfacial tension. This argument or prediction has received wide acceptance and has even been extended for flow in a water-oil system.

In addition, several studies indicate that there may exist a crucial interfacial-tension value below or above which impact of interfacial tension on relative permeability is very different. This hypothesis has been confirmed by results from investigating a low interfacial-tension water-oil system [6] and a low-interfacial-tension oil-gas system.[7] Both studies found that relative permeability curves changed significantly with interfacial tension lower than 0.04 mN/m. For this low range of interfacial tension, their model appeared to fail. Using relative permeability curves measured from consolidated sandstone cores, Torabzadeh and Handy[8] further categorized flow systems into relatively high interfacial tension systems, with $\sigma > 20$ mN/m, and relatively low interfacial tension systems, with $\sigma < 0.19$ mN/m. They considered that these were the two distinguishing zones of interfacial tension in which relative permeability had different characteristics. Kumar et al.[9] carried out more experimental studies, classifying interfacial tension into three ranges for the relationships of residual oil or water saturation versus interfacial tension. For high interfacial tension with $\sigma > 1.0$ mN/m, residual saturations are independent of interfacial tension and are functions of temperature only. However, under lower interfacial tension (0.15 mN/m $< \sigma <$ 1.0 mN/m) and an ultra-low tension system with $\sigma < 0.150$ mN/m, two-phase residual saturations behave differently as functions of both temperature and interfacial tension.

To overcome well-known difficulties in measuring relative permeability curves under low interfacial tension, several attempts were made, involving either increasing viscous forces in displacing fluids or increasing the capillary number.[2, 10, 11] However, a large increase in the viscosity of the displacing, aqueous phase may lead to too great a decrease in displacing rates or mobility. On the other hand, very high flow rates will cause small rock solids or particles to migrate. As a consequence, those approaches cannot in general achieve the capillary-number ranges appropriate for normal surfactant chemical flooding.

In addition to the effects of fluid saturation, interfacial tension, and temperature, relative permeability is also affected by pore structure or porous medium characteristics. To describe these effects, researchers have devoted considerable effort towards deriving closed-form equations to correlate these factors with relative permeability functions.[12, 13, 14] A number of studies have been carried out regarding two-phase flow and displacement processes under different interfacial tension values.[5, 7, 11, 15, 16, 17, 18, 19] The majority of these studies, however, were performed for either *oil-gas* or *water-gas,* not for *water-oil* two-phase systems. Secondly, the ranges of interfacial tension covered in these investigations were limited mostly to 10^{-1} to 40 mN/m (or higher than 10^{-2} mN/m). In addition, few studies have been conducted for the effect of interfacial tension on relative permeability as a result of adding surfactants into water-oil systems. This is mainly because it is difficult to conduct such experiments and measurements (i.e., involving low interfacial tension) under

laboratory conditions, owing to the complexity in chemical-property effects and their variations, such as chemical reactions and adsorption.

In a parallel development in recent years, extensive studies from laboratory to field applications have been carried out in China for large-scale EOR projects. In the 1990s, field pilot tests were carried out, using the alkali-surfactant-polymer combinational flooding approach, at several oil fields in China. As part of the field-application effort, laboratory studies of low-interfacial-tension relative permeability for water-oil systems were also conducted. Using a dynamic method, Wang et al.[20] and Lu et al.[21] measured end values of relative permeability and remaining residual oil saturation for low interfacial tension water-oil systems. They showed the effects of water-oil interfacial tension on the end values of relative permeability under transient displacement. To avoid the large, undesirable effect of nonequilibrium adsorption of surfactants on relative permeability, Ye et al.[22] attempted to use a steady-state method for measuring end relative-permeability values and made some useful findings regarding the effect of interfacial tension on residual oil saturation. However, no complete relative permeability curves were obtained from that study because of the difficulties encountered in their measurements.

To fill the large gap between research and application regarding water-oil relative permeability under different interfacial tension conditions, this paper presents a detailed experimental study on the effects of low interfacial tension on two-phase relative permeability in water-oil systems. In particular, we present an improved steady-state method for measuring water-oil relative permeability curves. The experimental results indicate that there may exist two critical interfacial tension values that separate ranges of interfacial-tension effects on relative permeability and residual oil saturations. In addition, based on two-phase experimental data from sandstone cores, a two-phase relative permeability model is proposed to correlate water-oil two-phase relative permeability with interfacial tension as well as saturations. The experimental results and proposed relative permeability model will be useful for numerical simulation and other quantitative studies of surfactant-enhanced chemical flooding operation in reservoirs.

Experimental Procedure and Method

To eliminate the effects of complex chemical processes occurring at water-oil interfaces on measurements, we adopted a steady-state method for measuring water-oil relative permeability within a low-interfacial-tension system. The steady-state approach ensures that equilibrium is reached for partitioning of chemical agents between water-oil phases and rock solids of adsorption.

Water-Oil System.

Oil Phase: To make experiments as well as measurements repeatable, the oil used in this study is called "model oil," consisting primarily of straight-chain hydrocarbon, extracted commonly from petroleum lubricant fluids through systematical treatment of removing light-hydrocarbon, wax, and volatile components, and adding hydrogen. The treated oil is a colorless, odorless, nonvolatile, nonsurfactant with a

viscosity of about 1 cp. Also, it has stable chemical properties that will not change rock wettability, cause precipitation, or form colloids in cores.

Aqueous Phase: Brine, consisting of 5,000 mg/L of NaCl (sodium chloride), is used in the water-oil system as the aqueous phase. Using high-NaCl-concentration brinescan reduce, or even eliminate, the possible effect of existing clayey minerals of sandstone cores on capillary numbers in experimental results. Fluid mixtures with low interfacial tension used in EOR operations are usually composed of various chemical additives. When interfacial tension is lower than 10^{-1} mN/m for most fluid systems, different levels of emulsification will occur. This makes it difficult to measure relative permeability curves. To resolve this problem, many different combinations of chemical mixtures are tested in this study, with the finalists screened and selected by the following criteria:

1. They enable ultralow interfacial tension (~10^{-3} mN/m) with both the model oil and crude oil from reservoirs.

2. The degree of emulsification has little impact on measurements of water and oil saturations, in repeated use and after frequent flushing of cores.

Chemical components of the surfactant chosen for this study are: 2SY+NaCl (0.5%wt)+NaOH (sodium hydroxide). Here, 2SY stands for alkyl benzene sulfonate, the main component of the surfactant, which in China is a widely used surfactant for chemical flooding mixtures in the laboratory.

Cores.

Sandstone cores for the experiment are made from outcrops located in Sichuan, China. These outcrop samples are well consolidated and have intermediate permeability ranges, which make them suitable for study of water-oil flow and displacement processes under different interfacial tensions. Table 1 lists the basic properties of the 1-inch diameter cores used in this study. The main reason for using these outcrop cores is that the sandstone contains little (less than 1%) clayey or swollen materials, such as kaoline and chlorite. In addition, rock solids of the cores show only a very weak adsorbing effect with the chemicals selected, which helps to minimize or avoid interference between chemicals and clayey minerals in measurement and analysis of flow behavior.

Table 1. Parameters of core samples used in experiments

Sample No.	Core Length (cm)	Effective Porosity	Permeability ($10^{-3}\mu$ m^2)
1-2	6.530	0.135	228
1-1	6.522	0.140	237
1-4	6.554	0.135	228
1-3	6.487	0.135	256
3-2	6.521	0.135	276
2-1(fired)	6.558	0.131	273
2-3	6.453	0.134	263
2-4	6.474	0.133	281
11-4	5.030	0.179	252
3-1	6.426	0.142	333
3-3	6.541	0.135	246
11-2	4.987	0.191	168
11-3	5.048	0.195	255
3-4	6.517	0.134	226

All the cores are thoroughly cleaned with liquid detergents to be strongly water wet. After cleaning, they are dried completely in an oven at 105°C until no change in weight is observed.

Measurements and Instruments.

The experimental setup, instrumentation, and procedure of this study are shown in Figure 1. During experimental measurement of relative permeability curves using the steady-state method, we used two pumps (Quizix) to regulate injection, displacement, and recycling of water and oil. Confining pressures within the cylindrical space were controlled by a separate manual hydraulic pump. In addition, several electromanometers with different measurement-scale ranges were employed to measure pressures at the inlet and outlet ends. Water and oil saturations were estimated by a mass-balance calculation using the scaled glass water-oil separator of Figure 1. A tensometer (TX500C) was used for measuring interfacial tension.
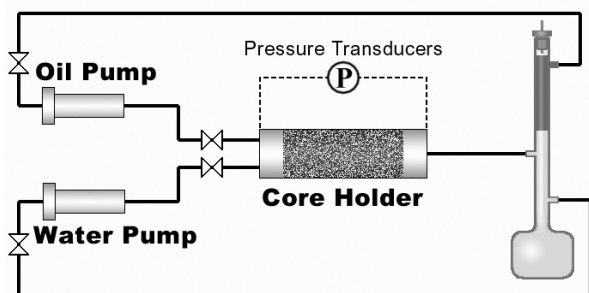

Figure 1. Schematic diagram of the apparatus and experimental setup

Measurement of Relative Permeability.

To account for the time needed for adsorption to reach equilibrium between chemicals and cores (i.e., to eliminate nonequilibrium sorption effects), a steady-state method was adopted in this study for measurement of relative permeability curves. In addition, only the cores with strong water wettability were selected, as determined by spontaneous imbibition indexes.

The experiments were conducted as follows. First, all the selected cores were fully saturated with a brine having a sodium chloride concentration of 4,500 mg/L. Then, water-phase permeability at zero oil saturation was measured from these 100% brine-saturated cores. To assure reaching adsorptive equilibrium between chemicals and cores at different saturations, we determined the first value of water saturation (i.e., a beginning minimum value of water saturation for the experiment) after more than two days of continuous injecting and recycling of the fluids through the core. By varying ratios of water and oil-injection rates at pumps, we adjusted oil saturation to increase gradually. Once a new steady state was reached, all parameters were measured and recorded, and relative permeability values for water and oil phases were then calculated at steady-state Darcy flow.

There are a total of five fluid systems (Table 2) used in this study, covering five different ranges of interfacial tension.

Table 2. Flow rate and fluid parameters used in experiments

Sample No.	Flow Rate (ml/min)	Aqueous Phase Viscosity (cp)	Interfacial Tension (mN/m)
1-2	0.1	1	34.2 (Basis water and oil system without surfactant)
1-1	1.0	1	
1-3	0.1	10	
1-4	1.0	10	
3-2	0.1	1	10^{0}
2-1(fired)	0.1	1	
2-3	0.1	1	10^{-1}
2-4	0.1	1	
11-4	0.1	1	
3-1	0.1	10	
3-3	0.1	1	10^{-2}
11-2	0.1	1	
11-3	0.1	1	
3-4	0.1	1	10^{-3}

Results and Discussion

Surfactant-Flooding Characteristics and Interfacial Tension.

As shown in the experimental results, there exists a certain correlation between residual oil saturation and water-oil interfacial tension under different surfactant concentrations within fluid systems. With the selected water-wetting cores under laboratory temperature conditions, for example, there appear to be two crucial values (σ_{C1} and σ_{C2}) observed for interfacial tension (Figure 2). When $\sigma > \sigma_{C1}$ (= 3 mN/m, the first or high crucial point), residual oil saturation of the water flooding remains at about 0.40. This residual saturation value of 0.40 seems to be unvarying with increases in interfacial tension within this range. On the other end of the curve, as shown in Figure 2, residual oil saturation is also kept as a low-level constant for $\sigma < \sigma_{C2}$ (= 0.01 mN/m). For the intermediate values of interfacial tension (i.e., $\sigma_{C1} < \sigma < \sigma_{C2}$), however, Figure 2 shows that residual oil saturation rapidly decreases with decreasing interfacial tension. In other words, displacement efficiency increases significantly with decreasing interfacial tension.

The relationship between residual oil saturation and interfacial tension, under the different interfacial tension of this study's core-fluid system, can be further quantified using a regression analysis. Fitting and statistical analysis of experimental data yields the following expression:

$$S_{or} = \frac{\sigma_{wo}^{1.5}}{A\sigma_{wo}^{1.5} + B} \quad (r^2 = 0.9995, F_{stat} = 5517) \quad (3)$$

where A and B are constants related to cores and experimental conditions (A = 2.432, B = 0.1154, fitted from our experimental data), and r and F are the correlation coefficient and F-test of statistics, respectively. As shown in Figure 2, the results of using Equation (3) (labeled as "fitted") match the experimental data points well.
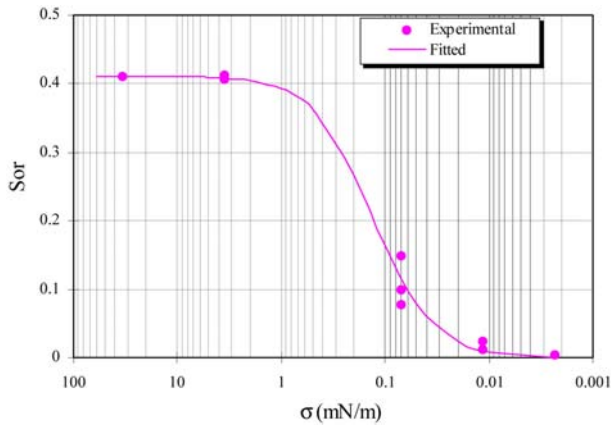
Figure 2. Experimentally determined residual saturations as functions of the interfacial tension

Relative permeability characteristics are observed to be very different under the different interfacial tension of the studied water-oil systems. Figure 3 shows the experimental results of water-oil relative permeabilities and their variations under different values of interfacial tension at a constant saturation of $S_w = 0.5$. Note that when $\sigma > \sigma_{C1}$ (= 3 mN/m), water relative permeability is at about 0.08, and that oil relative permeability is at 0.2 at the water saturation value of 0.5. The two relative permeability values are almost constants over this range of interfacial tension. In contrast, relative permeabilities to both phases increase continuously as interfacial tension decreases when $\sigma < \sigma_{C1}$. In general, the rate of increase in the water relative permeability appears larger than that of oil relative permeability within the low range of interfacial tension.
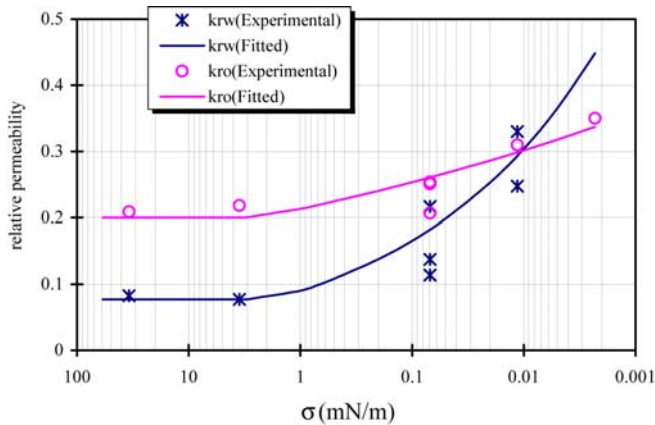

Figure 3. Water-oil relative permeability as a function of the interfacial tension at water saturation of 0.5

After fitting many sets of experimental data, we obtained the following equation for describing water and oil relative permeability curves versus interfacial tension at $S_w = 0.5$:

$$k_{rw}(S_w=0.5)=\exp[A_w+B_w\ln(\sigma_{ow})] \quad (r^2=0.7443, F_{stat}=11.65) \quad (4)$$

and

$$k_{ro}(S_w=0.5)=\exp[A_o+B_o\ln(\sigma_{ow})] \quad (r^2=0.7405, F_{stat}=11.42) \quad (5)$$

where $k_{rw}(S_w=0.5)$ is relative permeability to water phase at water saturation of 0.5; $k_{ro}(S_w=0.5)$ is relative permeability to

oil phase at water saturation of 0.5; and A_w, B_w, A_o, and B_o are constants related to cores and experimental conditions. Note that the results in Figures 2 and 3 are consistent with the trends found in the literature.[15]

Normalized Relative Permeability.

To analyze two-phase flow and displacement processes in various water-oil systems with different interfacial tension, we need complete relative permeability curves, not just their end values. Figure 4 presents such relative permeability curves, determined from our experimental measurements for two-phase flow, subject to different interfacial tensions. Because the aqueous phase contains different amount of surfactants, significant differences exist in interfacial tensions among the two-phase fluid systems. As a result, relative permeability curves obtained for different interfacial tensions not only have very different end values, but also have very different shapes. This makes it difficult to compare and analyze experimental results for different interfacial tensions.
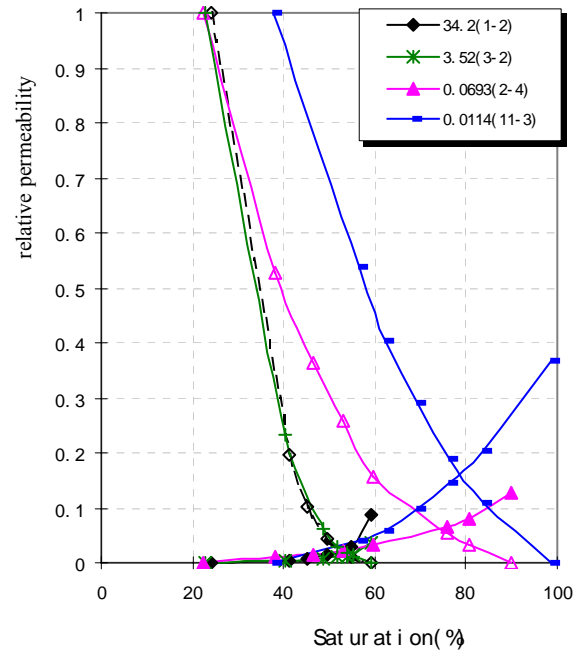

Figure 4. Water-oil relative permeability curves for different interfacial tension values (Note: legend of 34.2(1-2), 34.2 for interfacial-tension value and 1-2 for Sample #)

Experimental data can be analyzed using the following normalized parameters and functions.[23] Normalized water saturation is defined as:

$$S_w^* = \frac{S_w - S_{wc}}{1 - S_{wc} - S_{or}} \qquad (0 \le S_w^* \le 1) \quad (6)$$

Normalized relative permeability to water phase is defined as:

$$k_{rw}^* = \frac{k_{rw}}{(k_{rw})_{S_{or}}} \qquad (0 \le k_{rw}^* \le 1) \quad (7)$$

and normalized relative permeability to oil phase is defined as:

$$k_{ro}^* = \frac{k_{ro}}{(k_{ro})_{S_{wc}}} \qquad (0 \le k_{ro}^* \le 1) \quad (8)$$

where S_w^* is the normalized wetting, aqueous phase saturation; k_{rw}^* is the normalized aqueous-phase relative permeability; k_{ro}^* is the normalized oil-phase relative permeability; $(k_{rw}^*)_{S_{or}}$ is the aqueous-phase relative permeability at residual oil-water saturation; $(k_{ro}^*)_{S_{wc}}$ is the oil-phase relative permeability at connate water saturation; and S_{wc} is the connate water saturation.

Figure 5 displays the normalized relative permeability curves for two-phase flow, using the same results as in Figure 4 for different interfacial tensions. It appears from Figure 5 that after normalization, only small differences appear in both oil and water relative permeability curves for $\sigma > \sigma_{C1}$. Significant changes in normalized relative permeability curves occur as interfacial tension changes when $\sigma < \sigma_{C1}$.
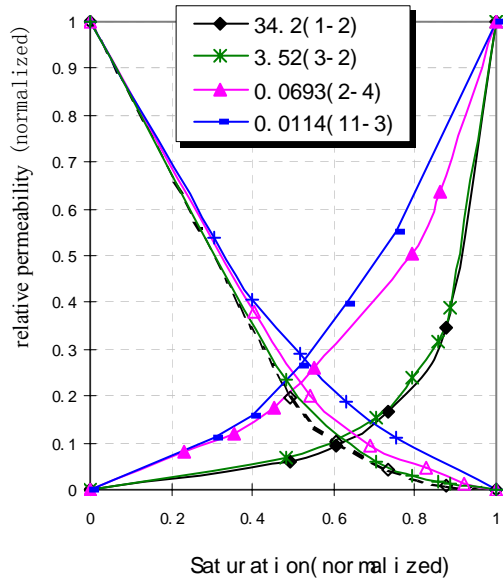

Figure 5. Normalized water-oil relative permeability curves for different interfacial tension values (Note: legend of 34.2 (1-2), 34.2 for interfacial-tension value and 1-2 for sample #)

Relative Permeability Model for Low Interfacial Tension.
Many studies [2, 9, 24] shown that water-oil relative permeability for two-phase flow systems is a function of fluid saturation, rock-pore characteristics, temperature, interfacial tension, and capillary number. Even though a number of different forms of relative permeability functions have been proposed, the simple exponential equation has been among the most widely used relationships in reservoir simulation.[25] In our experiment, water and oil viscosities and displacement rate remain constant. Therefore, relative permeability from our experiments is considered as a function of saturation, interfacial tension, and properties of core pores only. Based on the experimental measurements, we select the following two-phase-flow relative permeability models:

$$k_{rw} = m_w \left(S_w^*\right)^{n_w} \quad (9)$$

and

$$k_{ro} = m_o \left(1 - S_w^*\right)^{n_o} \quad (10)$$

where m_w and m_o are coefficients of water and oil relative permeability functions, respectively; and n_w and n_o are exponential constants or indexes of water and oil relative permeability functions, respectively.

Note that m_w is the water relative permeability at $S_w^* = 1$ and m_o is the oil relative permeability at $S_w^* = 0$, respectively. By definition, we have $m_w = (k_{rw}^*)_{S_{or}}$ and $m_o = (k_{ro}^*)_{S_{wc}}$. Therefore, the normalized formula can be derived from Equations (9) and (10) as

$$k_{rw}^* = \left(S_w^*\right)^{n_w} \quad (11)$$

and

$$k_{ro}^* = \left(1 - S_w^*\right)^{n_o} \quad (12)$$

The two exponential indexes, n_w and n_o, are found to be related with interfacial tension and pore size distribution parameters, λ_w and λ_o[13], as

$$n_o = n_o(\sigma_{wo}, \lambda_o) \quad (13)$$

and

$$n_w = n_w(\sigma_{wo}, \lambda_w) \quad (14)$$

Using a statistical analysis for the experimental data obtained with different interfacial tension, n_w and n_o have been estimated as listed in Table 3.

Table 3. Exponential indexes of relative permeability functions, calibrated using the experimental data

σ (mN/m)	n_w	n_o	Sample Number
Basis water-oil system	4.428	2.289	4
10^0	4.298	2.148	2
10^{-1}	2.788	1.749	4
10^{-2}	1.940	1.639	3

Let us further discuss the role played by interfacial tension in impacting relative permeability curves. A recent study with an artificial neural network model[26] indicates that for a given fluid system, relative permeability functions are closely related to the following groups of fluid and rock parameters:

$$\sigma_{wo}S_{wc}, \; \sigma_{wo}S_{or}, \; \ln(\sigma_{wo}), \; \text{and} \; \ln(\mu_w/\mu_o/\sigma_{wo}) \quad (15)$$

where μ_o is the viscosity of oil phase. Although neural network modeling cannot provide a closed-form function in general, it could help reveal the interrelationship between these parameters within two-phase flow permeability functions for a given fluid-rock system.

Based on our experimental data and curve-fitting results in Table 3, the particular relations between exponential constants and interfacial tension can be written as:

$$n_o(\sigma_{wo}, \lambda_o) = 0.1960 \times \log(\sigma_{wo}) + 2.006 \quad (r = 0.9911) \quad (16)$$

and

$$n_w(\sigma_{wo}, \lambda_w) = 0.9371 \times \log(\sigma_{wo}) + 3.807 \quad (r = 0.9975) \quad (17)$$

Accordingly, the two-phase relative permeability model, Equations (11) and (12), has the form:

$$k_{rw}^* = \left(S_w^*\right)^{[0.9371 \cdot \log(\sigma_{wo}) + \lambda_w]} \quad (18)$$

and

$$k_{ro}^* = \left(1 - S_w^*\right)^{[0.1960 \cdot \log(\sigma_{wo}) + \lambda_o]} \quad (19)$$

where λ_w and λ_o are constants for water and oil relative permeability, respectively, for the same rock type. The two parameters, λ_w and λ_o, should be determined from pore properties of core samples, dependent on pore size distribution, tortuosity, and phase distribution within pores (wettability). With the sandstone outcrop cores associated with the fluids of this study, curve fitting of the experimental data leads to $\lambda_w = 3.807$ and $\lambda_o = 2.006$.

Figure 6 displays the relationships between the two exponential indices and interfacial tension. As shown in Figure 6, interfacial tension has a small effect on n_w and n_o, when $\sigma > \sigma_{C1}$ (3mN/m); whereas for $\sigma < \sigma_{C1}$ (3mN/m), both water and oil exponential indices decrease with the decrease in interfacial tension. However, the index, n_w, for the water phase decreases at a much larger rate. This is consistent with the observation of different relative permeability behavior for different ranges of interfacial tension, separated by their crucial values.
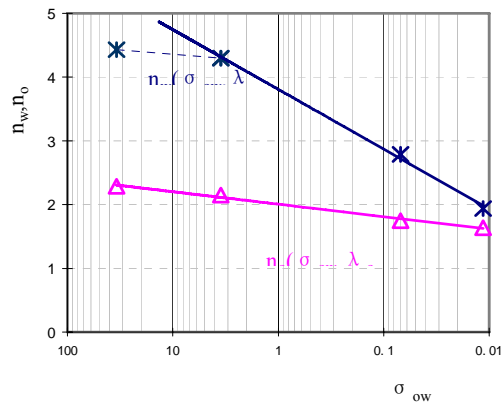

Figure 6. Correlations between interfacial tension and exponential indexes, n_w and n_o

It appears that as interfacial tension decreases, two exponential indices also decrease. This will make both water and oil relative permeability curves tend to be straighter. As shown in Table 3 and Figure 6, the exponential indices are still not close to one, even with a very low value of interfacial tension ($\sigma = 0.01$ mN/m). Therefore, the corresponding relative permeability curves are still not yet straight lines.

Summary and Concluding Remarks

This paper presents an experimental study of two-phase relative permeability functions in a low-interfacial-tension water-oil system. By analyzing the experimental data, the following results and conclusions can be drawn:

An improved steady-state method for measuring relative permeability data has been developed. This new steady-state method (with the designed experimental system) can be used to measure complete relative permeability curves under low interfacial tension accurately and efficiently.

There appears to exist two crucial values or points (σ_{c1} and σ_{c2}) in interfacial tension that characterize interfacial-tension effects on relative permeability and residual oil saturation for the systems of fluids and porous media used in this study.

Residual oil saturation tends toward zero as interfacial tension is reduced as low as $\sigma = 10^{-2}$ mN/m from $\sigma = 3$ mN/m. In addition, relative permeability curves for both water and oil phases become less curved, i.e., straighter with decreasing interfacial tension. For $\sigma > 3$ (σ_{c1}) mN/m, interfacial tension shows little impact on both residual oil saturation and relative permeability values for water and oil at $S_w = 0.5$. For $\sigma > \sigma_{c1}$, two-phase flow and displacement can be handled as normal brine-oil flow. However, once $\sigma < \sigma_{c1}$, two-phase flow behaves very differently, and the effects of interfacial tension must be considered in relative permeability models. As interfacial tension decreases to lower than the second crucial point (i.e., $\sigma < \sigma_{c2}$), relative-permeability-curve shapes will continuously change, even though residual oil saturation and relative permeability values at $S_w = 0.5$ will hardly change at all.

The experimental data and our analysis of the data indicate that relative permeability for the low-interfacial-tension water-oil system is described by a function having the form:

$$k_r = S_w^{* \, A \log \sigma_{wo} + \lambda}.$$

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