Effect of Displacement Pressure on Oil–Water Relative Permeability for Extra-Low-Permeability Reservoirs

Qing Liu, Keliu Wu,* Xiangfang Li, Bin Tu, Wen Zhao, Minxia He, Qiukai Zhang, and Yunfei Xie

ABSTRACT: The oil–water relative permeability is an important parameter to characterize the seepage law of fluid in extra-low-permeability reservoirs, and it is of vital significance for the prediction and evaluation of the production. The pore throat size of extra-low-permeability reservoirs is relatively small, and the threshold pressure gradient and capillary pressure cannot be negligible.

In this study, the oil–water relative permeability experiments with three different displacement pressures were carried out on the same core from the extra-low-permeability reservoir of Chang 4+5 formation in Ordos basin by the unsteady experimental method. The results show that the relative permeability of oil increases, while the relative permeability of water remains unchanged considering the capillary pressure and oil threshold pressure gradient compared with the JBN method. As the displacement pressure enlarges, the relative permeability of oil and water both increases; the residual oil saturation decreases, therefore the range of the two-phase flow zone is improved. Moreover, the isotonic point of water–oil relative permeability curves moves to the upper right region, and the reference permeability improves as well with the increasing pressure.

1. INTRODUCTION

Extra-low-permeability reservoir plays a significant role in the energy industry, and it is an important strategic resource for oil and gas reservoir exploration and development in China.1 Waterflooding is a widely used development method for extra-low-permeability reservoirs and to enhance the oil recovery efficiency by keeping/improving the formation pressure and exert the displacement imbibition. The oil–water seepage law is strongly different from the traditional Darcy’s law, where the fluid can flow with the displacement pressure greater than a certain value, which is known as the threshold pressure. The oil–water relative permeability plays a crucial part in the study of seepage characteristic and productivity prediction.2,3

The most essential difference between the seepage characteristics of extra-low-permeability reservoirs and conventional reservoirs is that the seepage laws in extra-low-permeability reservoirs no longer conform to the classic Darcy’s law, which has been verified by many scholars.1–6 Huang7 introduced a typical seepage law curve of extra-low-permeability reservoirs. The fluid in the porous medium of extra-low-permeability reservoirs can flow until the displacement pressure gradient exceeds a certain critical value of the pressure gradient, which is the true pressure gradient.

The methods to determine relative permeability are divided into empirical, analytical, and laboratory ones.8 The most common and convenient methods are the steady-state method and the unsteady state method.9–12 The steady-state method has the characteristics of long experimental time, complex operation, and low efficiency, especially for the extra-low-permeability reservoirs, while the unsteady state method is more convenient, efficient, and widely used.13,14 Johnson et al., Bossler et al., and Navman et al. used the Buckley–Leverett equation to derive the classical JBN model to calculate the oil–
water relative permeability curve. However, the method ignored the influence of gravity, threshold pressure gradient, and capillary pressure on the relative permeability.25 The pore throat of extra-low permeability is small, with the scale ranges from micrometer to nanometer. Due to the strong solid—liquid force, the seepage behavior of fluid does not comply with Darcy’s law, and it is a nonlinear flow process with the threshold pressure gradient.16,17 The capillary pressure is inversely proportional to the pore throat radius, and cannot be ignored for the extra-low-permeability reservoirs.16–20 Therefore, the threshold pressure gradient and capillary pressure must be taken into consideration when using the unsteady state method to obtain the oil—water relative permeability.

The oil—water two-phase permeability is affected by many factors such as pore network structure, wettability, fluid properties, interfacial tension, and displacement speed. Many factors are artificially uncontrollable except the displacement speed which has a great impact on the fluid flow for extra-low-permeability reservoirs.21–23 Pirson et al. concluded that the relative permeability is not rate-sensitive during the drainage process.24 Ehrlich et al. indicated that relative permeability is independent of flow rate with the steady state method.25 Heaviside et al. and Huang et al. studied the influence of displacement speed on the relative permeability curve, and it cannot be ignored when the end effect is robust.26,27 Lv et al. used the capillary number to characterize the impact of displacement rate on the unsteady phase permeability curve. The residual oil saturation decreases and the water—oil relative permeabilities both increase with the increasing capillary number, while the common permeability point moves to the upper right.28 Alizadeh et al. carried out experiments to study the flow rate effect on the relative permeability, and results showed that the relative permeability curves of water and its endpoints were not affected by the flow rate, but the relative permeability of oil decreases at a low flow rate.29 Lei et al. believed that the displacement rate affects the relative permeability curves by the cross-sectional effect caused by capillary pressure.30 The studies about relative permeability with flow rate mentioned above are conducted on the middle and high-permeability cores (\( k > 50 \times 10^{-3} \mu m^2 \)); however, the effect of displacement pressure on the seepage for the extra-low-permeability reservoirs needs further investigation. The error can be reduced to carry out the experiment on the same core of extra-low-permeability reservoirs caused by the core microstructure.

During the waterflooding development process of the actual ultralow permeability reservoirs, the displacement pressure gradient at different positions of the reservoir between the injection well and production well is quite different due to the varying flow rate and seepage resistance. Experimental results and the production performance of the waterflooding development in the actual oil field both indicate that the formation pressure gradient is great in the near-well zone, and it is small in the zone far away from the injection and production wells. In addition, the displacement pressure gradient at the same location varies at different production stages. It is unreasonable to apply a set of relative permeability at different locations and at different times in the numerical simulation.31

Capillary pressure is the pressure difference across the interface of two immiscible fluids and always exists during the flow process in a porous medium. In addition, it is correlated with pore throat size, rock wettability, fluid viscosity, and other factors. Moreover, the capillary pressure is inversely proportional to the pore throat radius, so it cannot be negligible for the oil—water system in extra-low-permeability reservoirs and plays an important role in the performance of the waterflooding.32

In this work, the experiment of the oil—water relative permeability curves is conducted under different displacing pressures, and the results and discussions are given. To exactly obtain the oil—water relative permeability curves for extra-low-permeability reservoirs, the displacement pressure in the experiment is determined by considering the effect of capillary pressure curve and threshold pressure gradient, and a model for the oil—water relative permeability is proposed by considering the end correction during the experiment data processing. This work will provide a reliable oil—water relative permeability curve, which is helpful to improve the accuracy of the production prediction by the numerical simulation for the extra-low-permeability reservoirs.

2. ANALYSIS OF VARIOUS EFFECT FACTORS ON THE SEEPAGE

2.1. Threshold Pressure Gradient. There are two main reasons for the existence of a threshold pressure gradient in extra-low-permeability reservoirs. One is the small size of the pore throat in the extra-low-permeability reservoirs. The threshold pressure gradient becomes very large when the pore throat radius decreases, and the flow of the fluid becomes more difficult. The threshold pressure gradient decreases rapidly with the increase of pore throat radius, and gradually approaches a certain value in the pores with a large pore throat radius.32,33 The second one is the boundary layer, which is the liquid adsorption layer on the rock particles surface due to the interface interaction between the solid and the liquid in micro-nano-scale pores.34,35 The starting resistance of fluid near the boundary layer is greater than that in the bulk fluid; in addition, the presence of a boundary layer on the solid surface makes the pore throat radius smaller. The thickness of the boundary layer is related to many factors, such as fluid properties, pore throat size, displacement pressure gradient, and so on.36

Nuclear magnetic resonance (NMR) is a common method to measure the pore structure of rocks. The working mechanism of NMR is based on relaxation mechanism and petrophysical measuring principle. The transverse relaxation time \( T_2 \) is proportional to the pore throat radius \( r \) when the water-saturated rocks is under a uniform magnetic field,37 which is established as eq 1; moreover, the relaxation rate \( \rho_2 \) and pore shape factor \( F_2 \) could be approximated as constants; thus, it is possible to calculate the pore throat radius distribution from the NMR \( T_2 \) spectra. Figure 1 presents the distribution of pore throat radius of cores with different permeabilities of extra-low permeabilities. With the decrease in permeability, the average pore throat radius decreases, resulting in an increase in the threshold pressure gradient, and a high displacement pressure is required to allow the fluids to flow. The main pore throat radius distributes at 0.2–0.6 \( \mu m \) for the core permeabilities of 0.34 \( \times 10^{-3} \) and 0.67 \( \times 10^{-3} \mu m^2 \), less than 1.0 \( \times 10^{-3} \mu m^2 \); but distributes at 0.4–1.1 \( \mu m \) for the core permeabilities of 1.02 \( \times 10^{-3} \) and 2.23 \( \times 10^{-3} \mu m^2 \).

\[
T_2 = \frac{1}{\rho_2 F_2 r}
\]
However, the capillary pressure of extra-low-permeability reservoirs ($k = 2.47 \times 10^{-3}$ and $1.26 \times 10^{-3}$ $\mu m^2$) is far greater, and the capillary pressure decreases much faster with the increase of water saturation at the small saturation.

The effect of capillary pressure on the water saturation should be considered at the outlet end surface of the hydrophilic extra-low-permeability cores for the oil–water relative permeability experiment. The hysteresis of the water phase causes an increase in the water saturation at the outlet section, and the phenomenon is called the end effect. The end effect can be eliminated when the displacement pressure or displacement speed satisfies the $\pi$ theorem for the unsteady experiment of medium-high and low-permeability reservoirs. However, the capillary pressure of the extra-low-permeability reservoirs is relatively large, and the end effect cannot be ignored. Thus, the oil–water relative permeability must be corrected by considering the end effect.

2.3. Displacement Pressures. The fluid in the porous media can flow until the displacement pressure gradient becomes greater than the threshold pressure gradient of the pore throat. According to the relationship between the threshold pressure gradient and the pore throat radius, the influence of the displacement pressure on the reservoir seepage can be analyzed. Permeability is an important parameter to macroscopically characterize the seepage characteristics, and it can be calculated by eq 3. Permeability $k$ is a function of flow rate and displacement pressure. The measured permeability for the same core is different under varying displacement pressures, and it strongly depends on the core pore throat distribution due to the effect of the threshold pressure gradient.

As shown in Figure 3, the pore throat has the main distribution range between $r_2$ and $r_3$, and the threshold pressure gradient decreases with the increase of pore throat radius. Besides, the displacement pressures $\Delta p_1$, $\Delta p_2$, and $\Delta p_3$ correspond to the pressure gradients $p_1$, $p_2$, and $p_3$ respectively. Only the fluid in the radius $r > r_1$ of pore throat can flow at the displacement pressure $\Delta p_1$, and the proportion of the all fluid in the core is 55%, so the corresponding permeability is $k_1$ which is relatively low. As the displacement pressure increases to $\Delta p_2$, the available pore throats range expand, and the fluid that can flow reaches 55%, and the permeability enlarges to $k_2$ because the main distribution radius of the pore throat is $r_2 < r < r_1$. Furthermore, the permeability increases to $k_3$ at the displacement pressure $\Delta p_3$, and the volume of additional pore throats is 25%. The fluid in the large pore and pore throat is available to flow at the low pressure, which occupies a little space. A mass of fluid became available when the displacement pressure is larger than the threshold pressure of the main distribution radius of the pore throat, and the permeability increases a lot relatively. The threshold pressure gradient of the remaining undeveloped fluid is very large, so the needed displacement pressure is great, but the additional fluid that can flow is small. The increasing speed of permeability reduces with the increasing displacement pressure.

The formulation of permeability of seepage considering the threshold pressure gradient is expressed as

$$k = \frac{\mu L}{A \nabla p - G} \quad (3)$$
3. EXPERIMENTAL SECTION

3.1. Cores and Fluid Properties. The water-wet sandstone cores of the experiment are obtained from Chang 4+5 in Ordos Basin, China, and the properties are listed in Table 1. The permeability of the core is the water permeability measured at the full water saturation state with a high displacement pressure. The oil is the mixture of crude oil and diesel oil in a 1:2 ratio, with a viscosity of 1.97 mPa·s and a density of 0.838 g/cm³ at room temperature. The water is formation water, with a salinity of 37.84 g/L as water type of CaCl₂ and pH of 5.6. The water viscosity and density are 0.89 mPa·s and 1.0 g/cm³ at room temperature, respectively.

3.2. Experimental Condition and Apparatus. The unsteady-state method is used to measure the oil−water relative permeability in the experiment. The apparatus of the experiment is shown in Figure 4. The experiment is conducted at the room temperature of 25 °C, and under the effective overburden pressure of 18.0 MPa match the formation conditions. The key point of the experiment is to obtain the relative permeability curve with different displacement pressures. The critical pressures are determined to be 4.65 and 6.17 MPa, respectively, according to the Chinese industry standard of GB/T 28912-2012. Besides, combined with the capillary pressure of the experimental core, the displacement pressures of the experiment are determined to be 1.5, 3.1, and 5.0 MPa for core 1 and 2.0, 4.5, and 6.3 MPa for core 2.

3.3. Experimental Procedure. The relative permeability experiment has the following steps. (1) The oil in the core is washed and the formation water is saturated after vacuum treatment. (2) The irreducible water saturation is established with the oil flooding method. First, a low displacement pressure of 0.5 MPa was used for the oil flooding and then the displacement pressure gradually increased until no water was produced. Finally, the core mass was measured and the irreducible water saturation was calculated. (3) The reference permeability, which is the oil permeability under irreducible water condition, and then the oil−water separator.

Figure 3. Distribution schematic diagram between the threshold pressure gradient, permeability, and pore throat radius. (a) Distribution of pore throat radius, (b) relationship between threshold pressure gradient and pore throat radius, and (c) relationship between permeability and displacement pressure.

Table 1. Core Properties of Experiment

| cores no. | length (cm) | diameter (cm) | porosity (%) | permeability (x10⁻³ μm²) | critical pressure (MPa) |
|-----------|-------------|---------------|--------------|--------------------------|------------------------|
| 1         | 5.23        | 2.50          | 14.3         | 2.47                     | 4.65                   |
| 2         | 5.10        | 2.50          | 12.8         | 1.26                     | 6.17                   |

Figure 4. Apparatus of the oil−water relative permeability: (1) pump, (2) water storage tank, (3) oil storage tank, (4) valve, (5) pressure transducer, (6) core holser, (7) confining pressure pump, and (8) oil−water separator.
is injected at the displacement pressure of 1.5 MPa for the waterflooding until no oil is produced. The injection pressure, oil flow rate, and water flow rate were recorded. According to the measured data, residual oil saturation, oil and water relative permeability, and other parameters can be calculated. (6) The core is cleaned and dried after the above displacement procedure and confirm that the physical properties of the core are almost unchanged. Change the displacement pressure to 5.0 MPa to repeat steps (2)–(5).

4. MODELS OF OIL AND WATER RELATIVE
PERMEABILITY

4.1. JBN Method. The JBN method is Johnson E. F., Bossler D. P., and Nauman V. O. derived from Buckley–Leverett equation for the relative permeability calculation. However, it ignored the effect of gravity, threshold pressure gradient, and capillary pressure. It would be more accurate for medium- and high-permeability reservoirs.

The models to deal with the experimental data are expressed as

\[ f_o = \frac{dQ_o}{dQ(t)} \]  
\[ I = \frac{Q(t)}{Q_o} \frac{\nabla p_o}{\nabla p(t)} \]  
\[ k_{ro} = f_o \frac{d[1/(Q(t))]}{d[1/Q(t)]} \]  
\[ k_{rw} = k_{ro} \frac{\mu_w}{\mu_o} \left( 1 - f_o(S_w) \right) \]  
\[ f_w = \frac{v_w}{v} \]  

The capillary pressure is expressed as

\[ P_c = P_o - P_w \]  

The mass conservation equations of the oil and water phases during the waterflooding process for one-dimensional homogeneous reservoirs are expressed as

\[ \frac{\partial S_o}{\partial t} = -\phi \frac{\partial}{\partial x} \left( k_{ro} \frac{\partial P}{\partial x} \right) \]  
\[ \frac{\partial S_w}{\partial t} = -\phi \frac{\partial}{\partial x} \left( k_{rw} \frac{\partial P}{\partial x} \right) \]

The model of oil and water relative permeability is obtained by jointly solving the motion equations and the mass equations.

The models of the relative permeabilities of water and oil are expressed as

\[ k_{rw} = \frac{\mu_o(1 - f_w)}{k_{ro} \frac{\mu_w}{\mu_o} + \frac{\phi}{\phi_w} \frac{d\phi}{dS_w} + G_w - G_o} \]  

The water saturation gradient at the end section of the core can be obtained by the following equation

\[ \frac{dS_w}{dx} \bigg|_{x=L} = -\frac{Q^2}{A\phi L} \left( \frac{df_w^2}{dQ} + \frac{d^2f_w}{dQ^2} \right) \]  

4.3. End-Effect-Corrected Model. For the experiment measuring the relative permeability with low displacement pressure, the end effect must be taken into account, otherwise it will cause large errors. For hydrophilic cores, the end effect can be reduced by increasing the displacement pressure. Therefore, the capillary pressure at the outlet section reduces, while the capillary pressure at the inlet section increases. By means of intermittent displacement, the fluid at the outlet section is redistributed and the end effect is reduced. Besides, the influence of the end effect can also be reduced by conducting the three-section core experiment. Qadeer et al. established the correct model for the oil and water relative permeability by introducing the dimensionless ratio of the end effect. In other words, they first achieved the dimensionless terminal flow rate (eq 20) and then obtained the correction coefficients of the oil and water relative permeability (eqs 21 and 22), and finally obtained the actual oil and water relative permeability by considering the end effect. This model is easy to apply, and the error is small.

The dimensionless flow rate is expressed as

\[ R_D = \frac{L\mu q}{A\phi \sqrt{K \phi}} \]  

The correction coefficients of oil and water relative permeability are expressed as

\[ \frac{k_{ro}}{k_{ro,true}} = 0.14 + 0.062R_D - 1.2 \times 10^{-3}R_D^2 \]
5. RESULTS AND DISCUSSION

5.1. End-Effect Correction. The end-effect correction can reduce the error caused by the capillary pressure on the outlet, and the influence of capillary pressure is great when the displacement pressure is low. In this section, take the relative permeabilities of core 1# with displacement pressure of 1.5 MPa and core 2# with displacement pressure of 2.0 MPa as examples to illustrate the end effect.

The oil–water interfacial tension is set as 20 mN/m, and the flow rate is the initial oil flow rate, so the dimensionless velocity is calculated, and then the correction coefficient of oil and water relative permeabilities is obtained. The oil and water correction coefficients are 0.852 and 0.786, respectively, for core 1# and 0.832 and 0.791, respectively, for core 2#.

\[
\frac{k_{iw}}{(k_{nw})_{true}} = 0.85 - 0.0025 R_D - 7 \times 10^{-5} R_D^2
\]  

The relative permeability curves without and with the end-effect correction are shown in Figure 5. According to the Chinese industry standard of GB/T 28912-2012, the effect of the oil–water interfacial tension is set as 20 mN/m, and the flow rate is the initial oil flow rate, so the dimensionless velocity is calculated, and then the correction coefficient of oil and water relative permeabilities is obtained. The oil and water correction coefficients are 0.852 and 0.786, respectively, for core 1# and 0.832 and 0.791, respectively, for core 2#.

Figure 5. Comparison between relative permeability curves without and with end-effect correction. (a) Relative permeability curves for core 1# and (b) relative permeability curves for core 2#.

Figure 6. Relative permeability curves of oil and water considering the capillary pressure and threshold pressure gradient. (a–c) Relative permeability curves with the displacement pressures of 1.5, 3.1, and 5.0 MPa for core 1#, respectively. (d–f) Relative permeability curves with the displacement pressures of 2.0, 4.5, and 6.3 MPa for core 2#, respectively.
capillary pressure on the outlet is small when the displacement pressure is bigger than the critical pressure. It is noted that the oil and water relative permeabilities with the end-effect correction are bigger than that without the end-effect correction and the difference with the relative permeability measured with the pressure greater than the critical pressure. The end-effect correction could reduce the influence of capillary pressure on the core outlet.

5.2. Effect of the Threshold Pressure Gradient and Capillary Pressure. 5.2.1. Relative Permeability Curves. The influences of capillary pressure and threshold pressure gradient are considered in the model of the oil−water relative permeability. The threshold pressure gradient for the oil phase is 0.017 MPa/m, and the water phase threshold pressure gradient is ignored because it is relatively small compared to oil phase. The capillary pressure curves are applied with a permeability of 1.26 × 10^{-3} and 2.47 × 10^{-3} μm² as shown in Figure 2. The existing relative permeability model and the end-effect-corrected method are used to obtain the oil−water relative permeability curves considering the capillary pressure and the threshold pressure gradient, respectively. The results are shown in Figure 6. According to the model of relative permeability (eq 17), it can be seen that the capillary pressure has no effect on the relative permeability of water. The model shows that the relative permeability of oil increases under the effect of the capillary pressure, and this is because the capillary pressure causes imbibition during the displacement process. The water in the large pores replaces the oil in the surrounding small pores under the influence of the capillary pressure, so that the volume of the mobile oil increases, resulting in the increase in the relative permeability of oil. The relative permeability of oil decreases when the threshold pressure gradient is considered, while the relative permeability of water does not change because the water threshold pressure gradient is taken as zero in this work. When the capillary pressure and the threshold pressure gradient both are considered, the relative permeability of oil increases and the relative permeability of water decreases. Moreover, the isotonic permeability point moves to the upper right region, and the corresponding water saturation of the point is larger than 50%, which indicates that the cores are hydrophilic.

5.3. Influence of Displacement Pressure. 5.3.1. Flow Rate Curves. The experiment is carried out with constant pressure, and the flow rate at the core outlet is different as time progresses because of the distribution of water and oil in the core. The flow rate versus time curves with different displacement pressures are drawn according to the experimental results, as shown in Figure 7. When the water begins to be injected into the core of irreducible water saturation, only oil flows out, and the water flow rate is zero, and the initial oil flow rate raises with the increasing of displacement pressure. With the development of waterflooding, water begins to flow out from the macropores or the microfracture of the pore scale, and then the oil flow rate decreases. At the end, the oil flow rate is zero but the water flow rate increases to a certain value. The final liquid flow rate increases with the increasing of displacement pressure in a certain range. The larger the displacement pressure, the bigger the volume of the available
pores is; so, the oil recovery is higher and the residual oil saturation is lower.

5.3.2. Relative Permeability Curves. The oil and water relative permeability curves under different displacement pressures are compared, which are shown in Figure 8. It can be seen that as the experiment displacement pressure increases, the range of the two-phase zone increases, and the residual oil saturation decreases. The relative permeabilities of oil and water increase and the isotonic point moves to the upper right region. It is noted that the distribution of the pore throats is complex in extra-low-permeability reservoirs, and the threshold pressure gradients of the fluid in different scale pore throats are significantly different. The displacement pressure required for fluid in large pore throats is small but large for fluid in small pore throats. As the displacement pressure increases, the range of the pore throat sizes that allow the fluid to flow increases so that the residual oil saturation decreases, and the oil recovery factor enhances, as shown in Table 2.

The reference permeabilities measured with different displacement pressures are shown in Table 2. The reference permeability increases with the raising of pressure. Due to the uneven distribution of pores and pore throats, the corresponding capillary pressures are quite different, and the amount of fluid that can be activated to flow by different displacement pressures is also significantly different, which results in different reference permeabilities with different displacement pressures.

6. CONCLUSIONS

In this paper, the relative permeability and seepage laws of the Chang 4+5 extra-low-permeability sandstone, Ordos Basin, China, were experimentally analyzed. The main conclusions are as follows:

(1) The threshold pressure gradient and the capillary pressure cannot be ignored during the seepage process for the extra-low-permeability reservoirs, and their effects increase with the decrease of permeability. The capillary pressure not only affects the fluid seepage characteristics but also strengthens the end effect on relative permeability in the experiment.

(2) There are two water-wet cores from Chang 4+5 for the relative permeability experiment. Three different displacement pressures were used to test the relative permeability on the same core, and 1.5, 3.1, and 5.0 MPa were conducted for core 1, 2.0, 4.5, and 6.3 MPa were used for core 2.

(3) The effects of the threshold pressure gradient and capillary pressure are considered; the relative permeability of oil increases, while the relative permeability of water is unchanged.

(4) As the displacement pressure increases, the range of the two-phase zone increases, and the residual oil saturation decreases; moreover, the relative permeabilities of both oil and water increase, and the isotonic point moves to the upper right region and the reference permeability increases.

(5) The pore throat size is relatively small and its distribution is uneven in extra-low-permeability reservoirs. The fluid volume in the pores and the pore throats activated to flow by different displacement pressures is quite different, which results in the different see page characteristics and permeabilities obtained under different displacement pressures.

Table 2. Data and Results of the Experiment for the Two Cores

| core # | permeability of core ($\times 10^{-3}$ μm$^2$) | irreducible water saturation (%) | displacement pressure (MPa) | reference permeability ($\times 10^{-3}$ μm$^2$) | residual oil saturation (%) |
|--------|--------------------------------|---------------------------------|----------------------------|--------------------------------|--------------------------|
| 1      | 2.47                           | 43.7                            | 1.5                        | 0.76                           | 34.9                     |
|        |                                |                                 | 3.1                        | 1.59                           | 25.7                     |
|        |                                |                                 | 5.0                        | 1.93                           | 22.4                     |
| 2      | 1.26                           | 53.2                            | 2.0                        | 0.33                           | 26.5                     |
|        |                                |                                 | 4.5                        | 0.74                           | 20.4                     |
|        |                                |                                 | 6.3                        | 0.92                           | 16.3                     |

Figure 8. Relative permeability curves obtained with different displacement pressures. (a) Relative permeability curves for core 1# and (b) relative permeability curves for core 2#.

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|--------|--------------------------------|---------------------------------|----------------------------|--------------------------------|--------------------------|
| 1      | 2.47                           | 43.7                            | 1.5                        | 0.76                           | 34.9                     |
|        |                                |                                 | 3.1                        | 1.59                           | 25.7                     |
|        |                                |                                 | 5.0                        | 1.93                           | 22.4                     |
| 2      | 1.26                           | 53.2                            | 2.0                        | 0.33                           | 26.5                     |
|        |                                |                                 | 4.5                        | 0.74                           | 20.4                     |
|        |                                |                                 | 6.3                        | 0.92                           | 16.3                     |

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NOMENCLATURE

- \( \nu \): flow velocity of fluid, \( 10^{-6} \) m/s
- \( k \): permeability of core, \( 10^{-3} \) \( \mu m^2 \)
- \( \mu \): viscosity of fluid, \( \text{mPa}\cdot\text{s} \)
- \( V_p \): displacement pressure gradient, MPa/m
- \( G \): threshold pressure gradient, MPa/m
- \( G_o \): threshold pressure gradient of oil phase, MPa/m
- \( G_w \): threshold pressure gradient of water phase, MPa/m
- \( L \): length of core, cm
- \( A \): sectional area, cm²
- \( q \): quantity of flow, m³/s
- \( \nu_o \): oil velocity, \( 10^{-6} \) m/s
- \( \nu_w \): water velocity, \( 10^{-6} \) m/s
- \( k_{o,\text{measured}} \): measured relative permeability of oil, fraction
- \( k_{w,\text{measured}} \): measured relative permeability of water, fraction
- \( \mu_o \): oil viscosity, \( \text{mPa}\cdot\text{s} \)
- \( \mu_w \): water viscosity, \( \text{mPa}\cdot\text{s} \)
- \( p_o \): pressure of oil phase, MPa
- \( p_w \): pressure of water phase, MPa
- \( p_c \): capillary pressure, MPa
- \( f_o \): fractional flow of oil, fraction
- \( f_w \): fractional flow of water, fraction
- \( \phi \): porosity, fraction
- \( t \): time, s
- \( S_o \): oil saturation, fraction
- \( S_w \): water saturation, fraction
- \( Q_{p,\text{inj}} \): pore volume multiples of cumulative injected water
- \( Q_o \): pore volume multiples of cumulative oil production
- \( \rho \): corrected relative permeability of oil, fraction
- \( \rho_{w,\text{true}} \): corrected relative permeability of water, fraction

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