RATE EFFECTS ON WATER-OIL RELATIVE PERMEABILITY

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This paper presents a systematic investigation of the effect of flow rate on measurements of water-oil relative permeability using the steady-state method. Imbibition relative permeabilities were measured for a mixed-wet sandstone core and a water-wet sandstone core. In both cases, the measured relative permeability curves were independent of flow rate. Interstitial velocities ranging from 2 ft/day, representative of flowing rates in the reservoir, to 39 ft/day, representative of flow rates typically used in laboratory experiments, were used in this study. For the range of flow rates, the oil curves differed from the average by a maximum of ±3 saturation units, and the water curves differed by a maximum of ±2 saturation units from the average.

INTRODUCTION

Relative permeability is an important parameter in reservoir simulations when determining producible reserves and estimating ultimate recovery. Thus, laboratory measurements of relative permeability should be representative of flow behavior in the reservoir. Ideally, laboratory corefloods should duplicate the low rates of flooding processes in the field away from the wellbore. However, using low flow rates in laboratory experiments presents several difficulties, including long test times, low pressure drops which are difficult to measure accurately, and experimental artifacts such as capillary end effects.

Discontinuities in capillary pressure at the ends of the core, characterized by increased pressure drop and retention of the wetting phase as described by Richardson et. al.,[1] have been observed and are well documented in the literature. To overcome the influence of these end effects, flow rates higher than those characteristic of flooding processes in the reservoir are often used in laboratory measurements of relative permeability. Rapoport and Leas[2] described the use of a scaling factor based on the core length, flow rate, and fluid viscosity to determine a minimum flow rate for which viscous forces will dominate capillary forces and end effects become negligible. Using high flow rates also presents other advantages, such as shorter test times and larger measurable pressure drops. However, the question remains as to whether or not relative permeability measurements obtained from laboratory corefloods using high flow rates are representative of the low rate flooding processes in the reservoir.
Evidence in the literature regarding this question is sparse. Several papers discuss flow rate effects, but actually refer to the effect of flow rate on the magnitude of capillary end

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effects in the core. In this paper, a systematic investigation of the effect of flow rate on relative permeability measurements is discussed. Oil and water imbibition relative permeabilities were measured at several flow rates. The imbibition process here refers to increasing water saturation, regardless of the wetting phase. In these experiments, the steady-state method was used, allowing the effects of capillary pressure to be taken into account directly, without depending upon simulations or analytical models for interpretation of the data. Accounting for capillary pressure experimentally avoids the difficulties often encountered in using simulations to match production data, such as proper incorporation of capillary pressure into the model and verifying uniqueness of the derived relative permeability curves. If not taken into account properly, the additional pressure drop caused by capillary end effects can lead to an underestimation of relative permeability.

DESCRIPTION OF EXPERIMENTS

Experimental Apparatus

Relative permeability measurements were made using the steady-state coreflood method. Measurements were made for two wettability cases: a mixed-wet sandstone and a water-wet sandstone. The details of the cores are described later. The tests were conducted using a steady-state recirculating relative permeability system similar to the one described by Braun and Holland.[3] The system, shown in Figure 1, allows tests to be conducted with live crude oil at reservoir conditions.

The system is equipped with a linear x-ray scanner, which can determine the average in situ fluid saturation at any location along the core during an experiment. As the x-ray scanner travels along the length of the core, a saturation profile can be obtained. The x-ray scanning system can perform scans every 2 mm, revealing the presence of experimental artifacts, such as end effects or capillary discontinuities at plug junctions. Measurements can be obtained at a rate of 1 scan/second, allowing the observation of transient events.

Mixed-Wet Core

Experiments were initially performed on Berea samples aged to a mixed-wet state to provide a homogeneous mixed-wet composite core. Newly cut Berea sandstone plugs were first cleaned with a sequence of solvents to remove any contaminants from the mineral surfaces. The plugs were then saturated with a 4.6% salinity synthetic brine and centrifuged to low water saturation. To obtain mixed-wettability, the plugs were then aged in Loudon crude oil for 10 weeks at a temperature of 73^{o}F, the approximate temperature of the Loudon reservoir. Spontaneous imbibition and USBM tests performed on a companion plug prepared in the same manner as the plugs used in the composite confirmed that the aging process was effective in altering the wettability from strongly water-wet to mixed-wet. The USBM index of the companion plug was -0.10.

After aging, the plugs were assembled into a composite core. A long composite was used in the experiments to minimize the influence of capillary end effects. By placing the plugs end to end in a rubber sleeve, a composite measuring 30.0 cm in length and 3.86 cm in diameter was constructed. The rubber sleeve had multiple pressure taps spaced 5.08 cm apart for internal pressure measurements, as shown in Figure 2. The composite was placed in an aluminum coreholder, and a net confining pressure of 1,500 psi was applied hydrostatically with a white oil in the annulus. The composite had a porosity of 20.6%. The experiments were conducted with degassed Loudon crude oil ($\mu_o = 7.25$ cp) and synthetic brine ($\mu_w = 0.979$ cp) at 73°F.

Water-Wet Core

The next set of experiments were performed with field core plugs, which conveniently demonstrated water-wet characteristics. (Preserved cores from the field exhibited water-wet characteristics in spontaneous imbibition, USBM, and relative permeability measurements with live crude oil.) To ensure that a water-wet state was established, the plugs were first cleaned by injecting a sequence of solvents. The water-wet nature of the extracted core was concluded from the similarity between relative permeability curves measured on the extracted composite core and those that had been previously measured on the same composite when the plugs were initially preserved.

In preparation of the experiments, the plugs used in the composite were first saturated with a 7.8% salinity brine and centrifuged to low water saturation. As in the construction of the mixed-wet composite, the plugs were confined in a rubber sleeve with multiple pressure taps spaced 5.08 cm apart, creating a composite core that measured 25.4 cm in length and 3.76 cm in diameter. The composite was placed in an aluminum coreholder, and a net confining pressure of 3,000 psi was applied hydrostatically with a white oil in the annulus. The composite had a porosity of 27.1%. The experiments were conducted at 73°F with Sontex 70 ($\mu_o = 19.7$ cp) and a synthetic brine ($\mu_w = 1.03$ cp) matching the composition of the reservoir brine. The fluids were chosen to match the viscosity ratio of the reservoir crude and brine. Before use, the Sontex 70 was filtered through a silica gel column to remove polar components.

Experimental Procedure

Water and oil imbibition relative permeabilities were measured for the mixed-wet and water-wet composites using four injection rates: 0.1 cc/min, 0.3 cc/min, 0.8 cc/min, and 2 cc/min. These injection rates, q, are equivalent to interstitial velocities, v, of 2 ft/day, 6 ft/day, 16 ft/day, and 39 ft/day as defined by the expression

$$v = \frac{q}{\phi A}$$

where ϕ is the porosity and A is the area of the composite core. These rates were chosen to represent the range of typical field rates to typical laboratory rates. The use of monotonically increasing or decreasing flow rates was avoided to obtain results that would be independent of the direction of change in flow rate. In addition, some of the tests were repeated, to obtain a measure of the repeatability of the results.

For each wettability case, the tests were conducted on a single core over several months. After assembly, each composite was waterflooded to residual oil saturation and then oilflooded to establish an initial water saturation. An effective oil permeability, $k_{o,iw}$, of 416 mD was measured for the mixed-wet composite, and a $k_{o,iw}$ of 632 mD was measured for the water-wet composite. These values of $k_{o,iw}$ were used as the reference permeabilities in determining relative permeabilities for each core. For each subsequent steady-state test, the core was oilflooded in the same manner to establish directly comparable initial conditions in the core, and an effective oil permeability was measured before the experiment. The initial water saturations that were established for the mixed-wet core differed by a maximum of ±2 units from the average. For the water-wet core, the initial water saturation established before each test differed from the average by ±1 unit. The flow rates used in these tests, the order in which they were conducted, and the initial water saturations established after each oilflood are summarized for the mixed-wet and water-wet composites in Table 1 and Table 2, respectively.

The steady-state tests were conducted by simultaneously injecting water and oil into the core until conditions in the cored stabilized. The water saturation in the core was then increased by increasing the water fraction while decreasing the oil fraction to maintain a constant total injection rate during the test. The water saturation was increased in 8 steps, and the fluid fractions that were used are summarized in Table 3. After the system reached steady-state at each fluid fraction, the saturations in the core were determined from an x-ray scan of the composite and verified by material balance calculations. Examples of in situ saturation profiles measured on the mixed-wet composite are shown in Figure 3 and Figure 4. The accuracy of the material balance is typically within ±2 saturation units. A similar resolution was achieved with the x-ray scans by replacing 4.6 wt.% of NaCl with NaI in the brine composition for all of the experiments. In effect, the NaI improved the contrast between the oil and brine phases in the x-ray measurements.

During the experiment, pressure drops across the internal pressure taps, as well as the total pressure drop across the composite, were measured. Relative permeabilities were calculated using Darcy's law, and are referenced to the $k_{o,iw}$ measured at the start of the sequence of tests as described above. The influence of capillary end effects was removed from the data by using only the portion of the core that was identified to be free of end effects, as shown in Figure 3 (obtained at 2 ft/day) and Figure 4 (obtained at 39 ft/day). (As expected, the end effects are more extensive in the test conducted at 2 ft/day than in the test conducted at 39 ft/day.) The fluids saturations were determined by averaging the in situ saturation profile over this region of the core, and the corresponding relative permeabilities were determined from the pressure drop across the internal pressure taps located over the same region. The resulting relative permeability curves are discussed in the next section.

DISCUSSION OF RESULTS

Mixed-Wet Experiments

The properties of the mixed-wet composite and the fluids used in the experiments are summarized in Table 4 and Table 5, respectively. The measured relative permeability curves are shown in Figure 5. The legend indicates the chronological order of the tests from the first (top) to the last (bottom). Interstitial velocities ranged from 2 ft/day to 39 ft/day, and a second test at 2 ft/day was conducted at the end. The test at 2 ft/day was conducted twice to obtain an estimate of the repeatability of the results. The curves have not been smoothed and show a straight line interpolation between the fractional flow points that were used in each steady-state test.

To evaluate the effect of flow rate on relative permeability, the entire curves should be considered. The water relative permeability curves are very similar at every flow rate. For all of the flow rates, the curves deviated from the average by less than ±2.5 saturation units. Comparing the measured oil relative permeability curves for all of the flow rates, the curves differ slightly. Upon closer inspection, the shift in the curves can be seen to be a result of the chronological order of the tests, rather than an effect of flow rate. The later an experiment was performed in the sequence of tests, the more the oil relative permeability shifted to a slightly higher water saturation. Although the core was aged for 10 weeks, the conditions in the core appear to continue to slowly change over the 3 months during which the experiments were conducted. Taking an average through the data spread, the maximum difference of the curves from the average is ±3 saturation units. Since the difference in the curves measured at the different flow rates is on the same order as the measurement accuracy, the conclusion can be drawn that measurements of both oil and water imbibition relative permeability using the steady-state method are independent of flow rate for mixed-wet sandstones for the range of flow rates used in these experiments.

Water-Wet Experiments

The rock and fluid properties for the water-wet experiments are summarized in Table 6 and Table 7, respectively. Figure 6 shows the water-oil imbibition relative permeability curves that were measured on the water-wet composite for all of the flow rates tested. Again, the legend indicates the chronological order in which the tests were conducted, from the first (2 ft/day) to the last (16 ft/day). Interstitial velocities varied from 2 ft/day to 39 ft/day. As in the results for the mixed-wet composite, these curves have not been smoothed.

Again, in evaluating rate effects, the entire relative permeability curves should be compared. For every flow rate, the water relative permeability curves nearly duplicate each other, deviating from the average by less than ±1 saturation unit. The oil relative permeability curves differ slightly, exhibiting a difference of ±2.5 saturation units from the average. The difference in the measured curves at the different flow rates is on the same order as the accuracy of the measurements. Therefore, these results show that, when using the steady-state method, measurements of relative permeability obtained at flow rates typically used in laboratory tests produce the same results as those obtained at flow rates representative of field rates. Clearly, in this flow range, oil and water imbibition relative permeability for water-wet sandstones are independent of flow rate when measured with the steady-state method.

CONCLUSIONS

Using the steady-state method, experimental measurements have shown that water-oil imbibition relative permeabilities are independent of flow rate for mixed-wet and water-wet sandstones. Since tests conducted at high flow rates are less susceptible to experimental artifacts, using flow rates higher than those characteristic of reservoir flooding processes are preferred for laboratory measurements of relative permeability. If in situ saturation measurements are unavailable for determining the extent of capillary end effects, using high flow rates will ensure that viscous forces are larger than capillary forces, and relative permeabilities will not be underestimated.

In these experiments, relative permeabilities were determined from a direct application of Darcy's law. The influence of capillary pressure was removed from the data by using only the portion of the core that was unaffected by capillary end effects in the calculations. The unaffected region was identified by using x-ray in situ saturation measurements and internal pressure taps along the core. Thus, any actual flow rate effects could be distinguished from capillary end effects.

Research investigating additional issues is currently in progress. One area of investigation is the effect of flow rate on relative permeability measurements for oil-wet sandstones. A study using the unsteady-state method for obtaining relative permeability measurements is also in progress. In this study, coreflood simulations are being used to properly account for capillary pressure effects. With the results from these additional studies, a complete picture of the relationship between flow rate and relative permeability will be developed.

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NOMENCLATURE

ϕ = porosity (%PV)
μ_o = oil viscosity (cp)
μ_w = brine viscosity (cp)
A = area (cm^2)
f_o = oil fraction
f_w = water fraction
k_g = gas permeability (mD)
$k_{o,iw}$ = effective oil permeability at initial water saturation (mD)
$k_{ro,w}$ = oil relative permeability (% $k_{o,iw}$)
k_{rw} = water relative permeability (% $k_{o,iw}$)
PV = pore volume (cc)
q = total injection rate (cc/min)
S_{wi} = initial water saturation (% PV)
v = interstitial velocity (ft/day)

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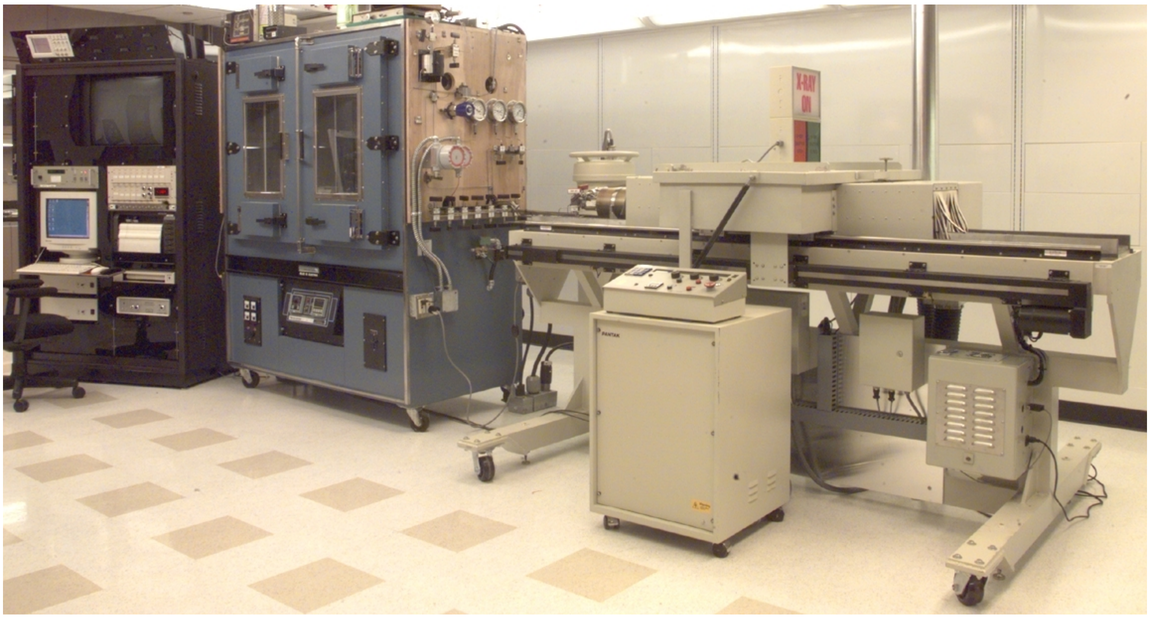

Figure 1. Reservoir conditions steady-state relative permeability system with a linear x-ray scanner.

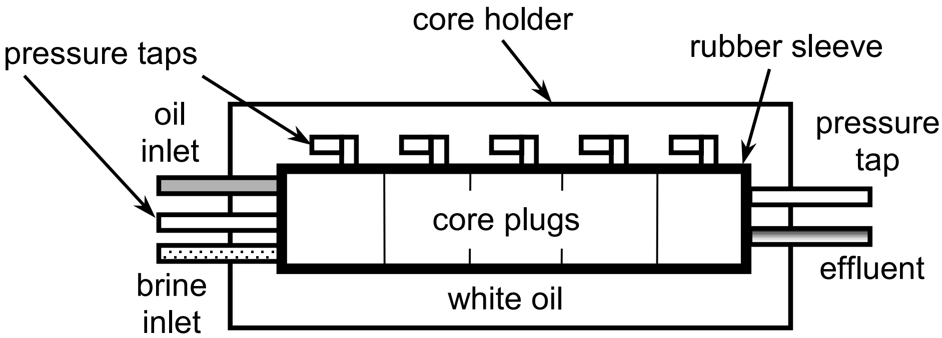

Figure 2. Schematic of a composite core.

Table 1
Summary of Steady-State Tests on Mixed-Wet Core

v (ft/day)	S_{wi} (% PV)
2	16.7
39	14.5
6	17.6
16	20.0
2	17.0

Table 2 Summary of Steady-State Tests on Water-Wet Core	
v (ft/day)	S_{wi} (% PV)
2	18.0
39	19.4
6	19.9
16	19.7

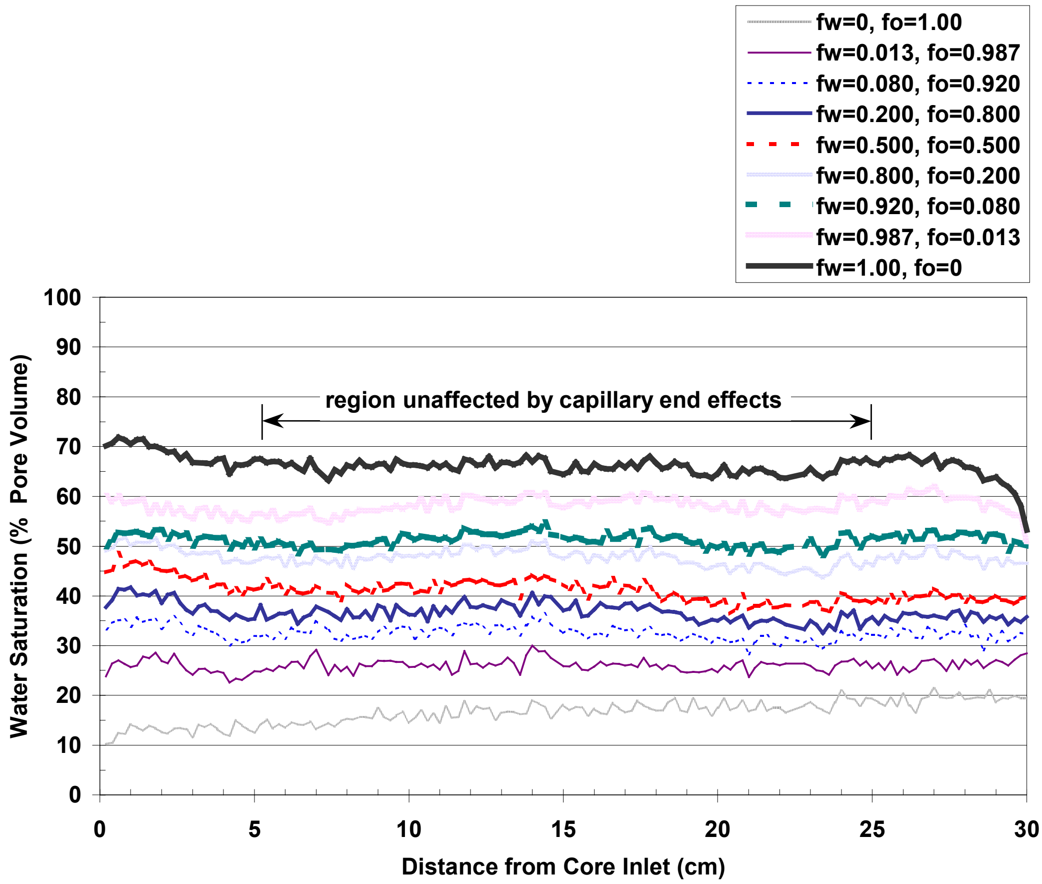

Figure 3. Example of in situ saturation profiles obtained during a steady-state imbibition relative permeability test at 2 ft/day on the mixed-wet composite core.

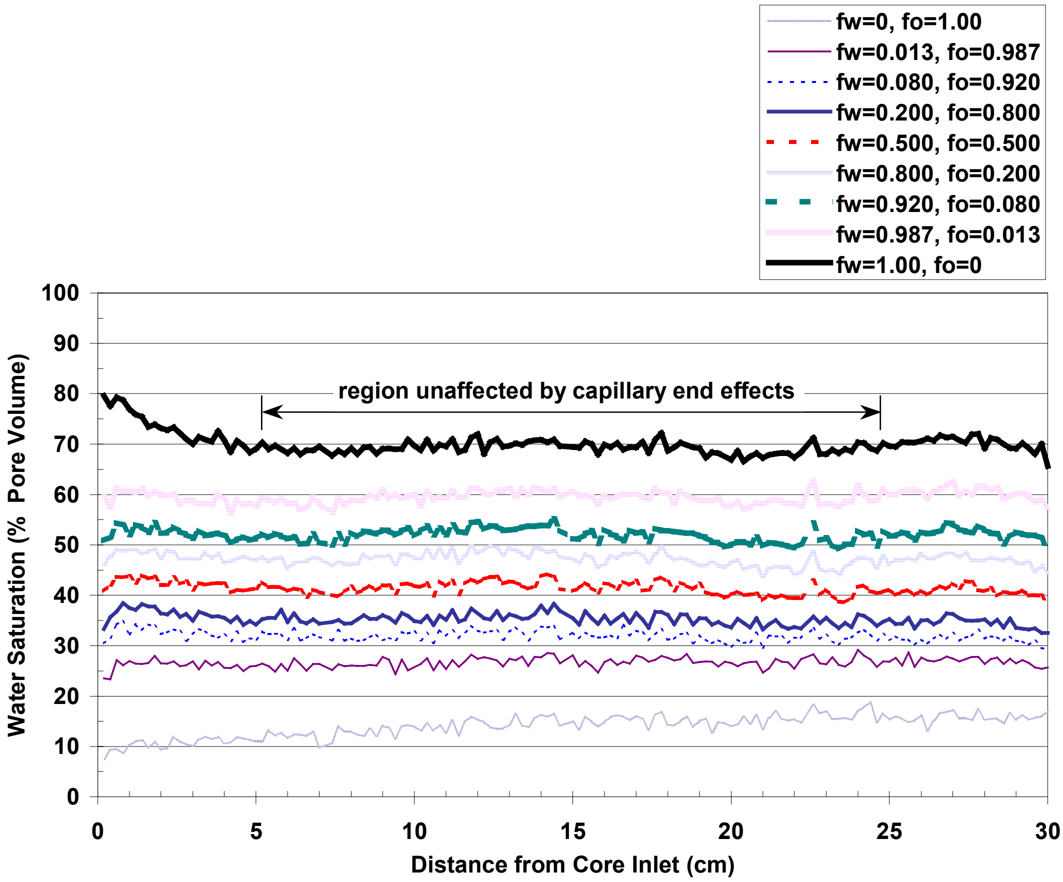

Figure 4. Example of in situ saturation profiles obtained during a steady-state imbibition relative permeability test at 39 ft/day on the mixed-wet composite core.

Table 3 Steady-State Relative Permeability Fractional Flows	
f_w	**f_o**
0	1.00
0.013	0.987
0.080	0.920
0.200	0.800
0.500	0.500
0.800	0.200
0.920	0.080
0.987	0.013
1.00	0

Table 4 Properties of the Mixed-Wet Composite Core	
Length (cm)	30.0
A (cm^2)	11.7
PV (cc)	72.2
ϕ (% PV)	20.6
$k_{o,iw}$ (mD)	416
k_g (mD)	474
Net confining stress (psi)	1500

Table 5 Fluid Properties in Mixed-Wet Experiments (73°F)		
Property	**Brine**	**Loudon Crude**
Density (g/cc)	1.03	0.839
Viscosity (cp)	0.979	7.25

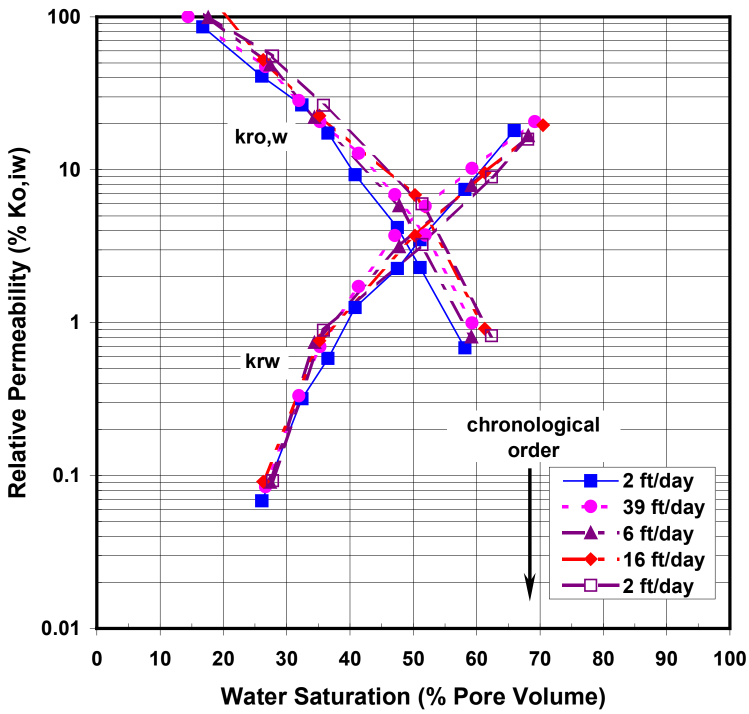

Figure 5. Steady-state water-oil imbibition relative permeability measured at several flow rates for a mixed-wet sandstone core.

Table 6 Properties of the Water-Wet Composite Core	
Length (cm)	25.4
A (cm^2)	11.1
PV (cc)	77.3
ϕ (% PV)	27.1
$k_{o,iw}$ (mD)	632
k_g (mD)	839
Net confining stress (psi)	3000

Table 7 Fluid Properties in Water-Wet Experiments (73°F)		
Property	**Brine**	**Sontex 70**
Density (g/cc)	1.06	0.841
Viscosity (cp)	1.03	19.7

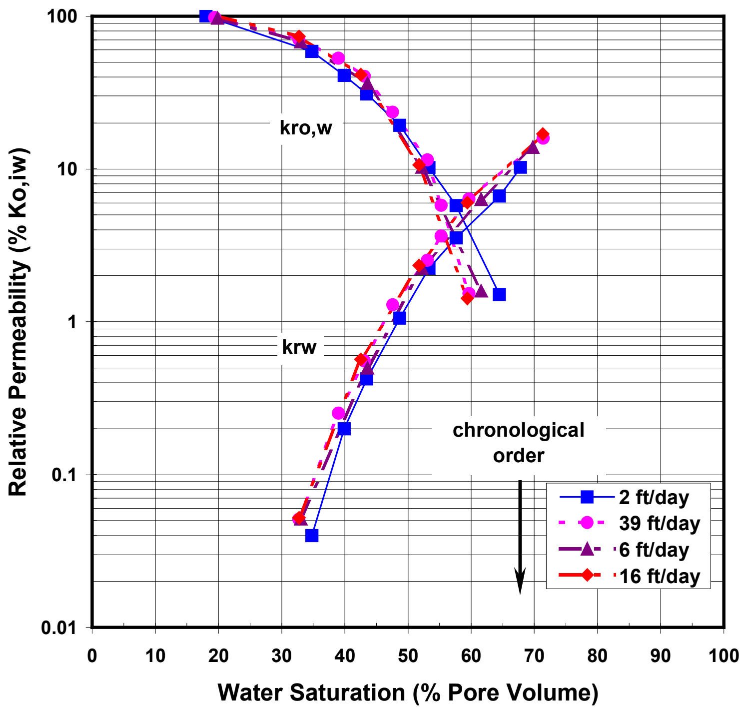

Figure 6. Steady-state water-oil imbibition relative permeability measured at several flow rates for a water-wet sandstone core.

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