COMPARISON OF THREE METHODS OF RELATIVE PERMEABILITY MEASUREMENT

by

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ABSTRACT

Relative permeability curve shapes of granular carbonate cores from a Middle Eastern reservoir were comparable regardless of the conditions and methods of measurement. However, variations among the tests in flow rate, viscosity ratio and pore volumes of water injected did affect residual oil saturation. Thus, this research confirms the importance of reservoir condition relative permeability measurement because of the significant impact of test conditions on residual oil saturation. The three types of measurements were: ambient condition unsteady-state, ambient condition steady-state, and reservoir condition unsteady-state. This study provided a unique opportunity to compare relative permeabilities from these different methods on the same core. All data were from first cycle waterfloods on restored-state core. The rock/fluid interaction was oil-wetting in character. Although the residual oil saturation varied, the shape of the relative permeability curves from the three methods were similar. In addition, a new equation was developed for normalizing relative permeability curves, which accounts for the different residual oil saturations of the various samples.

INTRODUCTION

To assist in simulation studies, i.e. history matching and performance forecasting, relative permeabilities were measured on core from this Middle Eastern reservoir. No freshly cut core was available for this study. Thus, it was necessary to restore older, unpreserved core to its original "native-wettability" (Wendel, et al., 1985; Gant and Anderson, 1986; Cuiec, 1975; Cuiec, 1977). This was accomplished by cleaning the core to a water-wet state, saturating the sample with a synthetic formation brine, flushing the sample with dead reservoir crude, and aging the sample at reservoir temperature for 1000 hours.

In many cases, restored-state analysis is the only way to get representative data. There are three major reasons why it is often necessary to measure relative permeabilities on "restored-state" rather than "native-state" core.

1. The only available core was not properly preserved.

2. The core's wettability was altered due to interaction with drilling fluids.

3. The core is on the wrong flood cycle (due to waterflooding or flushing during coring) and the results are affected by hysteresis.

Old, Unpreserved Core

Often times the only core that is available for analysis is old core that was not properly preserved. Because of the expense or time involved, it may not be possible to obtain a fresh, carefully preserved core. In such cases, an old, unpreserved core may be available as a substitute. Unfortunately, because of loss of light ends or deposition and oxidation of heavy ends, the wettability of the core may be altered (Treiber, et al., 1972; Richardson, et al., 1955). Thus, this core would be unsuitable for "native-state" measurement, and would have to be measured "restored-state."

Core With Altered Wettability

Research by Sharma and coworkers (1987; 1988) has shown that most drilling fluid components alter rock/fluid wettability, even those that have traditionally been regarded as bland components. They have found this to be true both for oil-based and water-based mud. That leaves us with lease crude as the potential drilling fluid of choice. Safety concerns aside, however, even crude oil as a drilling fluid would probably be exposed to air, possibly altering the oil's wetting characteristics. Even with a bland drilling mud, hysteresis in relative permeability measurements often makes "native-state" analysis inappropriate.

Core on the Wrong Flooding Cycle

Because of hysteresis in relative permeability measurements it may be desirable to conduct restored-state analysis even on fresh core. Numerous studies in the literature have identified the phenomenon of relative permeability hysteresis (Josendal, et al., 1952; Levine, 1954), and Patel and coworkers (1985) have shown evidence that it exists in the reservoir. Hysteresis in relative permeabilities can take two forms, flooding phase dependence and cycle dependence. Flooding phase dependence means, results are different when relative permeabilities are measured during an oilflood than when measured during a waterflood. Cycle dependence means, results are different when initially relative permeabilities are measured on a waterflood cycle, then the sample is oilflooded back to irreducible water saturation (S_{wi}), and then relative permeabilities are measured again on a second cycle waterflood. The second cycle waterflood results are different than the first cycle waterflood results.

Because of relative permeability hysteresis, only data from a first cycle waterflood accurately represents the reservoir waterflood. Obtaining core that has not already been through the first cycle waterflood is difficult. The reservoir may be under active water drive or waterflood, or if a water-based mud is used in drilling, the core will have been flushed with water during coring. In either case, the core when it reaches the laboratory will already have gone through a first cycle waterflood, thus "native-state" analysis would be on the wrong cycle.

During coring, the core is usually flushed by mud filtrate. Normally, when "fresh-state" core plugs are taken at the laboratory they are then flushed with brine to remove mud filtrate (continuing the first cycle waterflood). The core plugs are then flushed back to S_{wi} with oil, and the relative permeability measurements are then made on a second cycle! So, no matter to what lengths we've gone to preserve "native-wettability," the measurements are made on the wrong cycle and are affected by hysteresis. Our experience shows that these hysteresis effects are more significant than minor alterations in wettability, especially for the non-wetting phase. The wettability restoration process, on the other hand, simulates the initial oil migration into the reservoir, and subsequent relative permeabilities are measured on a first cycle waterflood.

Cycle dependent relative permeabilities are why we recommend "restored-state" analysis, even for fresh core, in most instances. We recommend using a bland mud for coring, because the absence of wettability altering compounds will leave the core easier to clean. We also carefully preserve the core, again, because the core will be easier to clean if it is not exposed to oxygen or allowed to dry out.

Much work has been published in the literature concerning the effect of temperature on relative permeability (Honarpour, et al, 1986). However, the published data are contradictory. For example, some studies indicate a strong temperature effect (Edmonson, 1965), while other studies indicate no temperature effect (Miller and Ramey, 1985). Likewise, there have been some studies published comparing the steady-state and unsteady-state methods of relative permeability measurement. Again, these data are contradictory, with some studies showing significant differences (Amaefule and Handy, 1982) between the two methods while other studies show agreement (Johnson, et al., 1959) between the two methods.

In light of the historical controversy concerning measurement methods, for this study relative permeabilities were measured three different ways on restored-state core. The three different methods were: 1) unsteady-state at ambient conditions, 2) steady-state at ambient conditions, and 3) unsteady-state at reservoir conditions. Since each test was run on a separate sample, we have a comparison of the methods on geologically similar plugs, rather than identical plugs.

ROCK AND FLUID PROPERTIES

The relative permeability measurements were made on core plugs from a granular limestone from an oil field in the Middle East. Table 1 summarizes the pertinent rock and fluid properties.

Table 1. Rock and Fluid Properties

Porosity	20 - 26%
Permeability	9 - 26 md
Irreducible Water Saturation	5 - 10%
Rock Type	Granular Limestone
Fluid Gravity	32° API
Reservoir Temperature	230° F
Reservoir Pressure	3000 psia
Gas Oil Ratio	400 scf/stb

A porosity-permeability crossplot for the core plugs is shown in Figure 1. In general the core plugs possessed similar properties. Procedures for restoration to native wettability and for the three different measurement methods are described in the following sections.

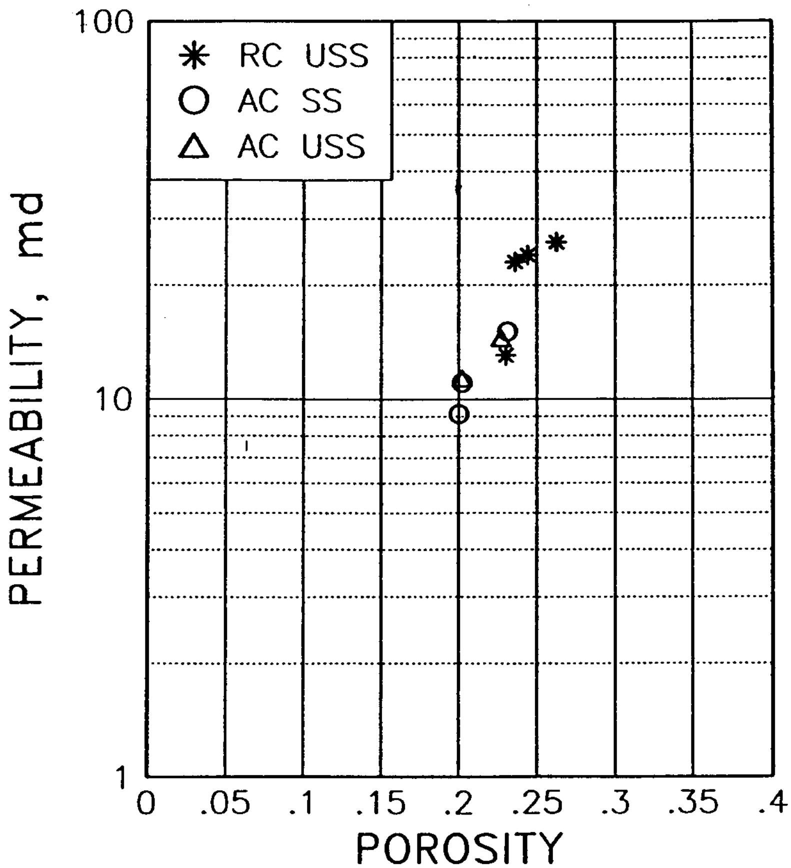

Figure 1. Air permeability versus porosity.

PROCEDURES

Restoration of Native Wettability

To restore native wettability, the plugs were first cleaned by cycles of carbon dioxide saturated methanol, followed by carbon dioxide saturated toluene. Subsequent USBM wettability tests (Donaldson, 1981) confirmed that the core was clean and water-wet. After the plugs were cleaned, they were placed in a Hassler-type core holder, confined at approximate reservoir overburden pressure, evacuated, then saturated with a synthetic, filtered formation brine. The cores were then flushed with filtered (0.22 micron) and degassed crude oil from the reservoir.

> **Note:** Care was taken in obtaining the crude oil sample to insure that nothing was added to the crude (demulsifiers, etc.), and that the crude oil's exposure to air was minimized.

Approximately ten pore volumes of crude oil were flushed through the sample, driving the core plug to S_{wi}. The plugs were then submerged in crude oil in a pressure vessel with a 100 psig cap of methane. The vessel was then placed in an oven at the reservoir temperature of 230°F and allowed to age in the crude oil for 1000 hours. While some researchers have shown that wettability equilibrium can sometimes be established in a shorter period of time (Cuiec, et al., 1979), based on other research (Hjelmeland and Larrondo, 1986) we have determined 1000 hours of restoration to be sufficient. After restoration, relative permeabilities were measured by three different methods.

Unsteady-State Ambient Condition Measurement

The unsteady-state ambient condition relative permeability measurements were made at Conoco's Production R&D facility in Ponca City, Oklahoma. After restoration, the plugs were placed in a Hassler-type core holder with 2500 psi confining pressure. Additional water was displaced from the plugs by flushing them with approximately 10 pore volumes of Blandol®, a refined mineral oil with a viscosity of 25 centipoises. This was done so that low values of S_{wi}, comparable to field values, could be established. The Blandol® was then miscibly displaced with 0.8 centipoise decane. Oil permeability at irreducible water saturation (K_o @ S_{wi}) was then measured with decane.

The plugs were then waterflooded at a constant injection rate of 10 ml/minute. During the flood, the pressure drop across the core and the volume of decane produced were automatically measured. The data, consisting of water injected, pressure drop, and decane produced, were then analyzed using a modification of the technique of Johnson, Bossler and Naumann (1959).

Steady-State Ambient Condition Measurement

The steady-state ambient condition relative permeability measurements were made at the Tulsa, Oklahoma facility of Core Laboratories Inc. After restoration, each sample was loaded into a hydrostatic core holder and flushed down to S_{wi} with a 20 centipoise refined mineral oil. The sample was then flushed with Isopar-L, which has a viscosity at room temperature of 1.5 centipoise. The Isopar-L was then miscibly displaced by a mixture of Isopar-L and iododecane. The iododecane is used to attenuate X-rays during the flow tests so that saturations can be calculated. Using the Isopar-L/iododecane mixture, K_o @ S_{wi} was measured.

Each sample was then loaded into an aluminum Hassler-type core holder, between two Berea Sandstone mixing headers, which had previously been flushed to S_{wi} with the Isopar-L/iododecane mixture. A mixture of oil and synthetic formation brine was then flowed through the core at various ratios (water flow rate increasing, oil flow rate decreasing) until finally only water was flowing through the core. Flow was continued at each ratio until equilibrium was attained as determined by a constant pressure drop and X-ray scan profile. X-ray attenuation scans were made at each equilibrium point so that saturations could ultimately be determined. Effective permeabilities were calculated from Darcy's law, using the flow rates, fluid viscosities, plug dimensions and the measured pressure drops. Corresponding fluid saturations were determined from the X-ray measurements.

Unsteady-State Reservoir Condition Measurements

After restoration, a sample was loaded into a hydrostatic core holder with a 3400 psi overburden. With a back pressure of 300 psi, degassed crude oil was injected into the sample. The system temperature was then raised to 230°F, and three pore volumes of recombined reservoir fluid were injected to displace the dead crude. The sample was allowed to equilibrate overnight, then an additional two pore volumes of reservoir fluid were injected and K_o @ S_{wi} was measured.

Synthetic reservoir brine was injected until a 99.9 percent water-cut was observed. Water relative permeability at residual oil saturation (K_{rw} @ S_{or})

was then measured. During the test, water production, gas production, oil production, and pressure drop were monitored and unsteady-state relative permeabilities were calculated using the technique of Johnson, Bossler and Naumann (1959).

RESULTS

Table 2 summarizes the relative permeability results from the three methods.

Table 2. Summary of Waterflood Relative Permeabilities

Sample No.	Swi % PV	Ko @ Swi md	Sor % PV	Krw @ Sor	Oil Displaced % OOIP
Ambient Condition Unsteady-State (AC USS)					
1	6.3	8.3	2.5	1.16	97.3
2	4.9	6.0	11.2	0.80	87.5
Averages	5.6	7.2	6.9	0.98	92.4
Ambient Condition Steady-State (AC SS)					
3	6.8	9.7	19.4	0.43	79.2
4	7.2	7.1	21.6	0.46	76.7
5	6.9	6.3	14.3	0.49	84.6
Averages	7.0	7.7	18.4	0.46	80.2
Reservoir Condition Unsteady-State (RC USS)					
6	10.0	8.3	24.9	0.37	72.3
7	9.0	8.5	21.0	0.48	76.9
8	10.0	9.6	24.2	0.53	73.1
9	8.0	4.8	29.2	0.52	68.3
Averages	9.3	7.8	24.8	0.48	72.7

Relative Permeabilities at Low Water Saturations

In unsteady-state relative permeability measurements no data are available between S_{wi} and the breakthrough saturation. Likewise, in steady-state relative permeability measurements no data are available between S_{wi} and the average saturation established for the first injection ratio of water and oil. Table 3 contains the average saturation at the first measurement point available for each of the three methods.

Table 3. Average Water Saturations for First Data Point

Method	Average Water Saturation For First Data Point
Ambient Condition Unsteady-State	57%
Ambient Condition Steady-State	29%
Reservoir Condition Unsteady-State	40%

The relative permeability curves for each of the methods are drawn in over the entire saturation range. However, Table 3 shows that the relative permeability values are unknown at the lower saturation ranges. As a matter of practicality the curves are "eyeballed" in between S_{wi} and the first data point. Thus, comparisons of the curves at the lower saturation ranges are dependent on the subjective way in which we choose to draw the curves. Before comparing all of the results, we will first examine the individual results from the three different methods.

Ambient Condition Unsteady-State

Figure 2 shows the relative permeability curves for the two ambient condition unsteady-state samples. The curves are relative to K_o @ S_{wi}, as are all of the relative permeability curves presented in this paper. The relative permeability curves display an oil-wet character. Using Craig's rules of thumb (1971): the curves have very low values of S_{wi}, the crossover point (where the oil and water relative permeabilities are equal) occurs at a water saturation less than 50%, and the curves show a high value of K_{rw} @ S_{or}. In fact, one of the curves is actually off the graph and goes to a value of 1.16 for K_{rw} @ S_{or}.

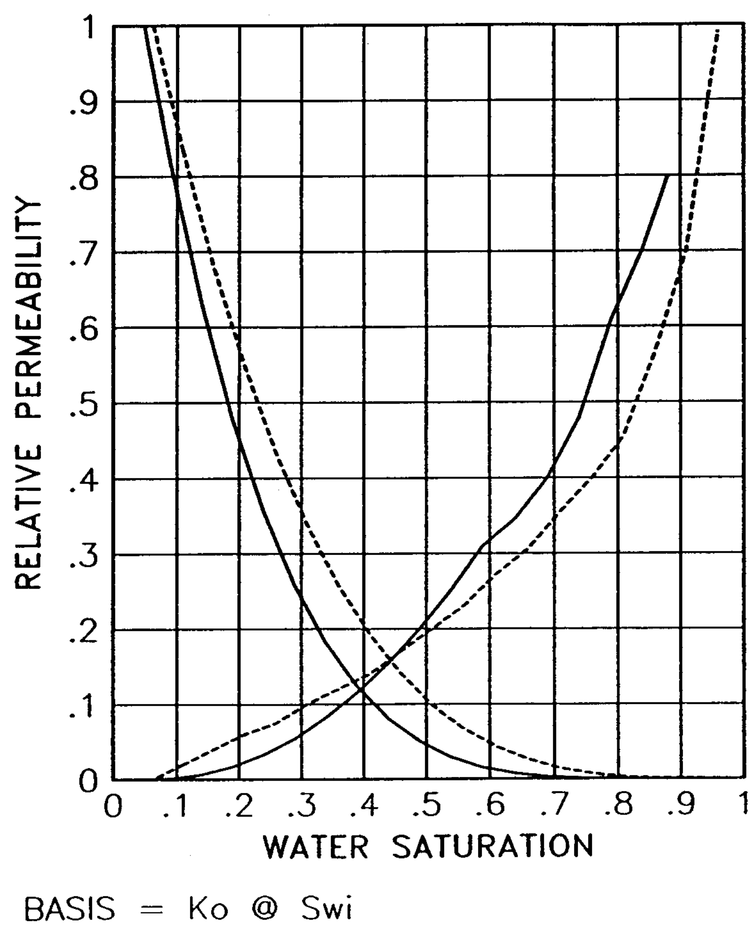

Figure 2. Ambient condition unsteady-state relative permeabilities.

Ambient Condition Steady-State

Figure 3 shows the ambient condition steady-state relative permeabilities. Again, there is some scatter in the data, and the curves for the most part are oil-wet. Note, however, that the S_{or} values are not as low, and the K_{rw} @ S_{or} values are not as high as for the ambient condition unsteady-state measurements.

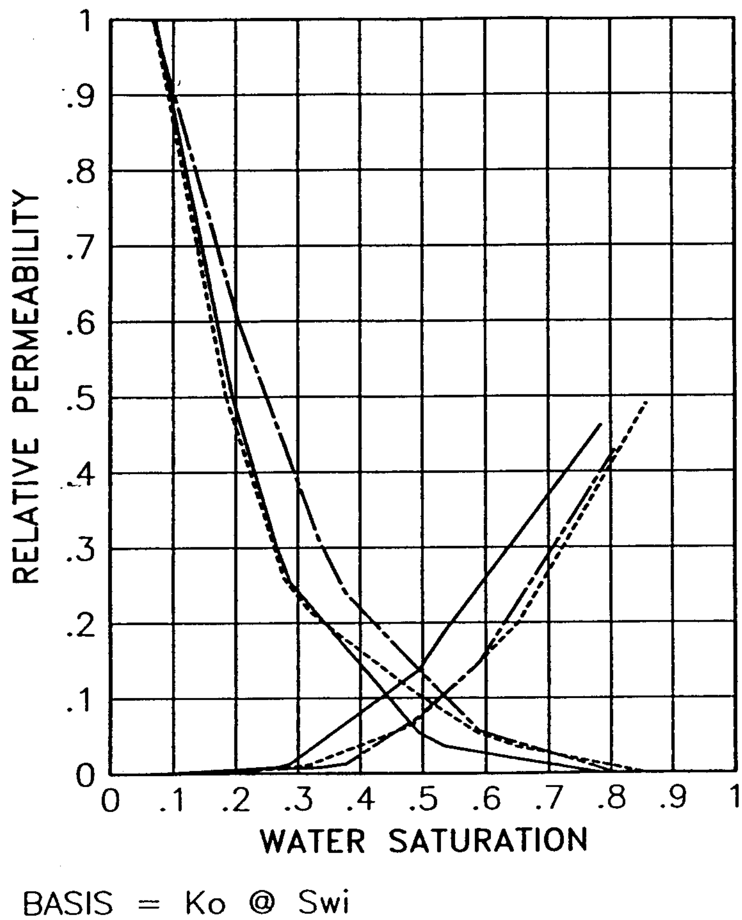

Figure 3. Ambient condition steady-state relative permeability.

Reservoir Condition Unsteady-State

The reservoir condition unsteady-state relative permeabilities are shown in Figure 4. There is some scatter in the data and, again, the curves appear oil-wet in nature. Note, that like the ambient condition steady-state measurements, the reservoir condition data have higher S_{or} values, and lower K_{rw} @ S_{or} values than the ambient condition unsteady-state curves.

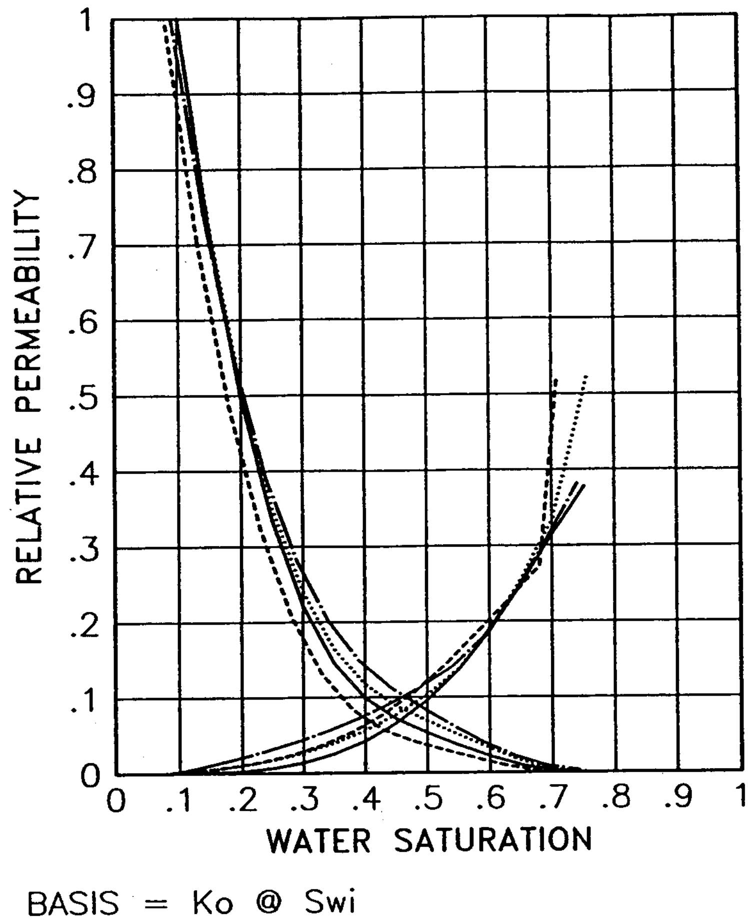

Figure 4. Reservoir condition unsteady-state relative permeabilities.

COMPARISON OF ALL THREE METHODS

The wettability of the rock/fluid pairs, as estimated from the relative permeability curves, is the same for all three methods. This indicates that the mineral oils used in the ambient condition tests (Blandol and Isopar) did not alter the wettability of the restored-state core. Results from all three methods will now be compared. Since there are so many curves, the oil and water curves will be compared separately.

Oil Relative Permeability Curves

Figure 5 shows all of the oil relative permeability curves for all three methods. While there is some spread among the curves, they generally have the same shape, with different values of S_{or}. At this point, remember that these are not repeat tests on the same exact piece of rock, but rather, rocks from the same formation that are mineralogically similar. Therefore, the major differences among the curves can probably be attributed to differences in rock characteristics. Also, the differences in S_{or} correlate well with differences in test conditions, as will be explained later.

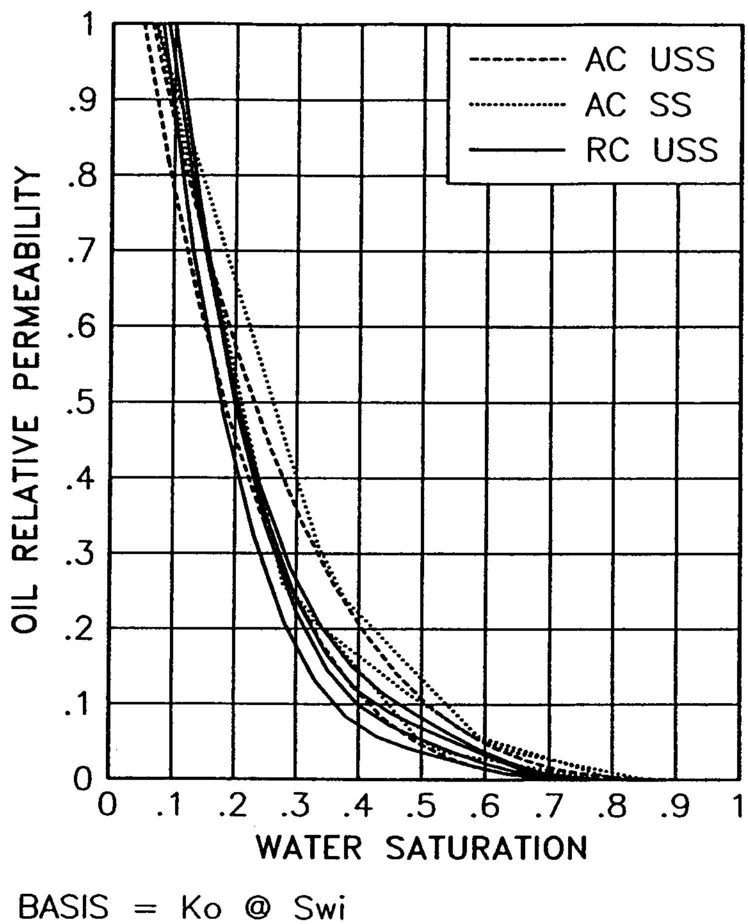

Figure 5. Oil relative permeabilities.

Water Relative Permeability Curves

All of the water relative permeability curves for all three methods are shown in Figure 6. Again, there is some spread in the data. The ambient condition unsteady-state results generally give a slightly higher value of water relative permeability at a given saturation. The results from the other two methods essentially overlap.

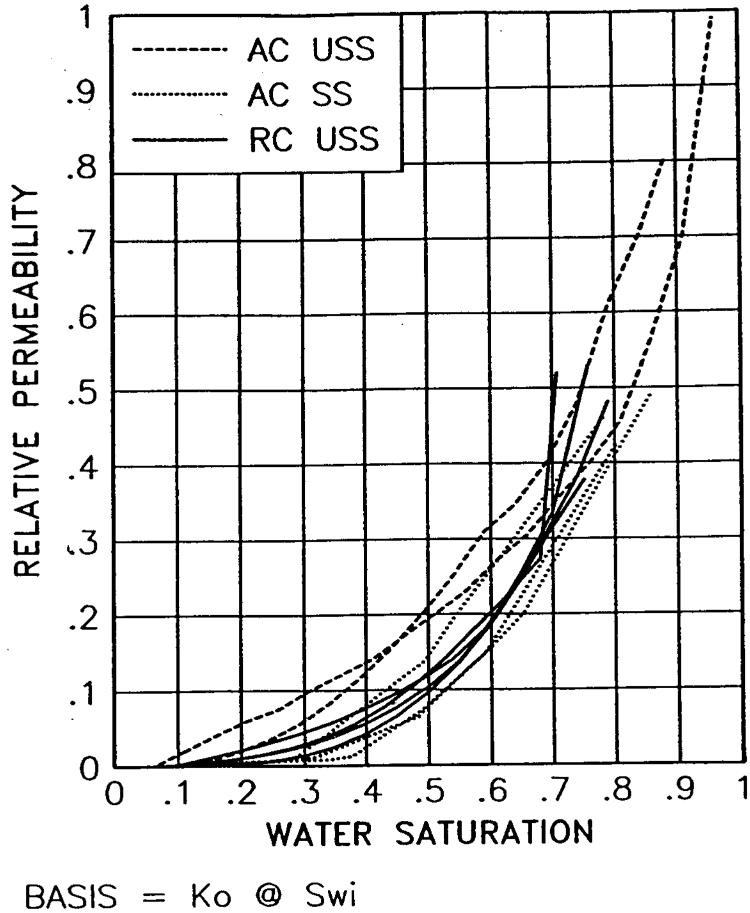

Figure 6. Water relative permeabilities.

Generally the curve shapes are similar for the three methods of measurement with the main differences being in S_{or}, and K_{rw} @ S_{or}. Differences in experimental conditions, as discussed below, have lead to the different S_{or} values.

FACTORS AFFECTING RESIDUAL OIL SATURATION

The factors affecting S_{or} have been investigated and reported in the literature (Abrams, 1975). These factors include fluid viscosities, flow rate and interfacial tension (IFT). The effect these factors have are: 1) The higher the flow rate the lower the S_{or}. 2) The larger the viscosity ratio (μw/μo) the lower the S_{or}. 3) The higher the water viscosity, the lower the S_{or}. 4) The lower the IFT, the lower the S_{or}. Table 4 summarizes the differences in experimental conditions for the three methods.

Table 4. Differences In Experimental Conditions

Test	Viscosities, cp Oil	Viscosities, cp Water	Viscosity Ratio(μw/μo)	Flow Rate, ml/min	Oil
AC USS	0.8	1.0	1.25	10.0	Decane
AC SS	2.0	1.0	0.50	3.3	Isopar/Iododecane
RC USS	0.725	0.27	0.37	2.0	Reservoir Crude

The flow rate for the steady-state test is the final flow rate when only water was being injected at the end of the test. The higher flow rate, larger viscosity ratio, and higher water viscosity of the ambient condition unsteady-state test explains their lower S_{or} values. The lower water viscosity, and lower flow rate of the reservoir condition unsteady-state tests are consistent with their higher S_{or} values. Therefore, the differing values of S_{or} are due to the different experimental conditions.

Abrams (1975) published a paper where he correlated an expanded capillary number with S_{or}. The higher the Abrams' number, the lower the S_{or} for a given rock. Table 5 contains Abrams' expanded capillary number for the various methods.

Table 5. Values of Abrams' Number

Method	Abrams' Number	Average Sor, %PV
Ambient Condition Unsteady-State	250×10^{-7}	6.9
Ambient Condition Steady-State	47×10^{-7}	18.4
Reservoir Condition Unsteady-State	7×10^{-7}	24.8

These numbers correlate with the general trend in the S_{or} values from the three methods. The ambient condition unsteady-state tests have the largest Abrams' number, and the lowest average S_{or}. Correspondingly the reservoir condition unsteady-state tests have the smallest Abrams' number, and the highest average S_{or}.

Based on Abrams' work we would expect only a 5-10 saturation % difference in S_{or} for this range of Abrams' number. In addition to differences in Abrams' number, different volumes of throughput probably help explain the rather large differences in S_{or}. Particularly for an oil-wet rock like this, the final oil saturation achieved during a flood is largely dependent on how much water has flowed through the core. Table 6 shows the approximate pore volumes of water injected during each of the three different tests.

Table 6. Approximate Pore Volumes Injected

Method	Pore Volumes Injected	Average Sor, %PV
Ambient Condition Unsteady-State	120	6.9
Ambient Condition Steady-State	40	18.4
Reservoir Condition Unsteady-State	18	24.8

There were significant differences in the number of pore volumes injected for the three different methods. The combination of the differences in Abrams' numbers (ratio of capillary to viscous forces) along with differences in pore volumes injected caused the differences in S_{or}. While the values of S_{or} vary, in general, the curve shapes are very similar over most of the saturation range. Labastie and coworkers (1980) found a similar phenomenon while varying flow rate in relative permeability experiments. They found that while S_{or} changed with flow rate, in general, curve shape remained the same.

SELECTION OF APPROPRIATE RESIDUAL OIL SATURATION

The reservoir condition tests were selected as the best model for field performance. These tests most closely approximate the field conditions both in terms of flow rate and viscosity ratio and, also, the number of pore volumes injected. Averaging the reservoir condition results we come up with an S_{or} of 24.8%.

NORMALIZING OF THE RELATIVE PERMEABILITY CURVES

If core plugs are of similar wettability, similar lithology and similar pore structure, and they have similar S_{wi} values, it is reasonable to expect that they would have similar relative permeability curves. To compare the relative permeability curves on an equivalent basis, the curves need to be normalized. The standard method of normalizing relative permeability curves uses the following equation (Schneider, 1987):

$$S_w^* = \frac{(S_w - S_{wi})}{(1 - S_{wi} - S_{or})}$$

This method starts and ends all the curves at normalized saturations of 0.0% and 100.0%, respectively. Figure 7 shows two sets of data from each of the three measurement methods, normalized with the standard method. Comparing Figure 7 with Figure 6 we see that this normalization technique actually spreads the water relative permeability curves further apart. By making all of the curves start at 0% normalized saturation we are making the assumption that they all have similar S_{wi} values. Examining Table 2, we see that this is a fairly reasonable assumption in that all the plugs had similar S_{wi} values. However, forcing all the curves to end at a normalized saturation of 100% is making the assumption that they all have the same S_{or} value. Examining Table 2, again, we see that this assumption is not valid. Because of differences in test conditions and differences in pore volumes injected, the different methods gave substantially different S_{or} values.

To take into account varying S_{or} values, a new equation was developed for normalizing relative permeability curves. The new equation starts all the curves at a normalized saturation of 0.0%, and extends them to a final saturation of $(1 - S_{or})$:

$$S_w^* = \frac{(S_w - S_{wi})(1 - S_{or})}{(1 - S_{wi} - S_{or})}$$

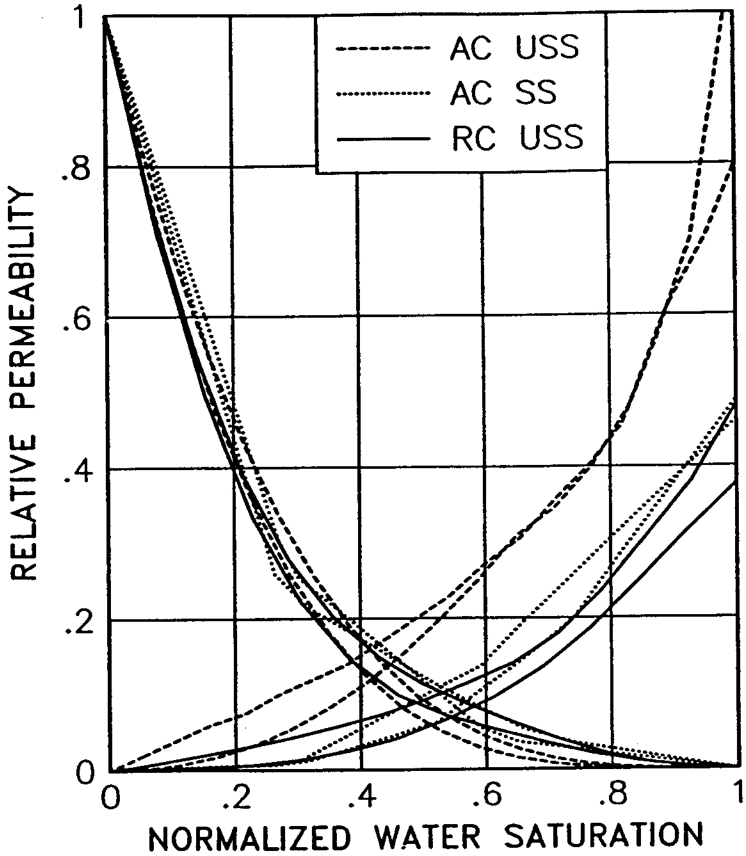

Figure 7. Curves normalized by the standard method.

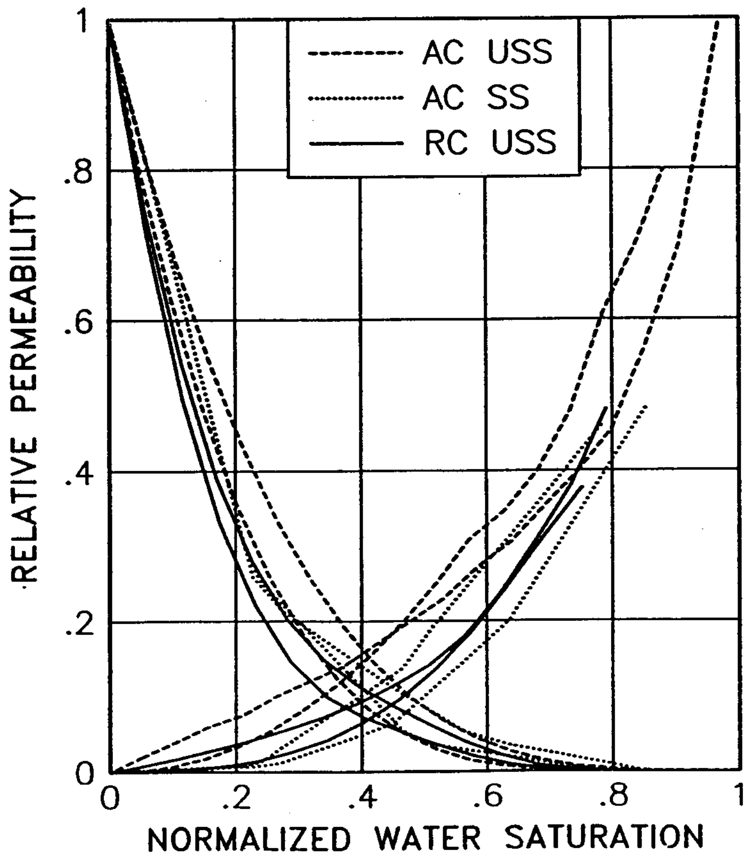

Figure 8. Curves normalized by the new method.

Figure 8 shows the curves normalized with the new method. Comparing Figure 7 and Figure 8, we see that overall the new method gives considerably less scatter among the curves. For cases where there is significant variation in S_{or}, we have found the new method a superior way of normalizing relative permeability curves, resulting in less scatter.

CONCLUSIONS

1. The shapes of the relative permeability curves were comparable for the three measurement methods.

2. Because of variations in test conditions the three methods gave different values of S_{or} and K_{rw} @ S_{or}, demonstrating the importance of measuring these parameters at reservoir conditions.

3. A new method of normalizing relative permeability curves has been introduced that takes into account the different S_{or} values that are obtained under varying test conditions.

4. The mineral oils used in the experiments did not alter the wettability of the restored-state core.

This study was not a detailed parametric study conducted on many combinations of rock and fluid, thus, the conclusions of this study are not universally applicable. However, the conclusions are probably applicable for reservoirs with similar properties.

ACKNOWLEDGEMENTS

I am grateful to Ken Weissenburger, Jeff Meyers, and Andre Bouchard for their review of the manuscript. I also thank the management of Conoco Inc., for permission to publish the paper.

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