EFFECTS OF USING LIVE VERSUS DEAD CRUDE OILS ON UNSTEADY-STATE WATER/OIL RELATIVE PERMEABILITIES

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Introduction

Relative permeability is an important parameter for simulating reservoir performance. To be useful as input data for reservoir simulations, laboratory measurements of relative permeability must be representative of reservoir flow under reservoir conditions. Our first approach to designing the laboratory tests is to duplicate the reservoir conditions in the lab. This approach involves performing tests at reservoir temperature and pressure with live crude oil and brine on preserved cores. Testing at reservoir conditions requires high temperature and pressure equipment, live or recombined crude oil samples, and carefully obtained and handled preserved core samples. Each of these conditions adds significantly to the cost of testing. Although this approach appears conceptually the most representative, the need for all of these conditions is presently undetermined. If any of these conditions can be eliminated or alleviated without the relative permeability values becoming less representative of the reservoir, then considerable cost and manpower can be saved.

The objective of our study was to determine whether relative permeabilities are affected by the use of live as contrasted with dead crude oils. To provide the lab with live crude oils, expensive fluid sampling in the field and/or lab recombination of reservoir gas mixtures and separator oil is necessary. Live oils require special handling in the lab to prevent gas evolution throughout preparation and testing. If the same relative permeability values can be obtained with dead crude oils as with live oils, the use of dead oils can produce significant savings in cost and manpower without losing data quality.

Past studies presented in literature have not dealt with this problem directly, but can shed some insight into the possible effects. In 1973, Rathmell et al. published comparisons of residual oil saturations obtained with live and dead oils.[1] Tests were performed on outcrop rock samples aged in crude oil. Residual oil saturations obtained with live oil at reservoir temperature and pressure were higher than the values obtained with dead oil at room conditions. The study concluded that the live oil changed the wettability obtained by aging the core in dead oil making the core more water-wet. In 1956, Wilson published comparisons of relative permeabilities measured with kerosene on preserved cores at high and low pressures and temperatures.[2] No differences were observed. Kyte et al. in 1961 performed a similar comparison using preserved cores with live crude oils at reservoir pressures and temperatures and with dead refined oils at room conditions.[3] Differences in oil production and in residual oil saturations were observed. Results from Colpitts and Hunter in 1964 agreed with the results from Kyte et al.[4]

Our study was performed using three different reservoir crude oil-rock systems. The reservoir crude oils were matched when possible with a synthetic formation brine based on the composition of the produced formation brine. Preserved cores were available from the same reservoir for two of the systems. In the third system, Berea core aged in the crude oil was used. The unsteady-state waterflood technique was used as the test method because the technique is a fast way of determining both oil and water relative permeability.

Presented in the next section of this report are descriptions of the formation, mineralogy of the cores, and composition of the crude oils. Following this section, procedures of the preparation and testing of the crude oil-rock systems are presented. The results and the discussion of the results including comparisons of production and water-oil relative permeability curves follow that section. Conclusions and recommendations are given at the end.

Description of Cores and Crude Oils

In this study crude oils from three reservoirs were used. The tests performed were divided into three cases each covering a crude oil.

Case I - North Sea Reservoir "A". The reservoir core samples comprising the two composite cores used for Case I are from a formation that is Upper Triassic in age. The environment of deposition is fluvial; the sands occur as discontinuous, low-sinuosity channels. The producing sand is composed of porous sandstone and non-porous, calcite-cemented sandstone. A mineral analysis was performed on two core plugs tested in this study, and the range of values obtained is presented in Table 1. Some basic measurements were performed on the reservoir crude oil used in Case I. Based on laboratory measurements of density of the de-gassed crude oil, the API gravity was about 34^{o}. Liquid chromatographic compound-type analysis was performed on a fresh sample (sample was de-gassed just prior to the chromatographic analyses) of de-gassed crude oil (C15+). The results are given in Table 2.

Case II - Reservoir in France. The reservoir core samples for the composite used in Case II are from a formation that is Triassic in age. The deposition for this formation occurred in a braided stream environment. The grain size is fine to coarse with moderate to poor sorting. Quartz and feldspar overgrowths are common but are not pore filling. Dolomite is abundant and can be pore filling. Mineral analyses were made from core samples from this formation in adjacent wells. An average of core samples from three wells is shown in Table 1. The available crude oil for laboratory testing from this formation was very limited. The gravity of the produced oil is about 37^{o} API. Compositional analyses were made on an oil sample taken from an adjacent well completed in the same formation. The results of the liquid chromatograph are shown in Table 2. The higher percentage of C15+ may be due to more weathering of the oil sample since the oil tested for Case I is known to be a fresh sample (sample was de-gassed just prior to the chromatographic analyses).

Case III - North Sea Reservoir "B". The productive interval for Case III is composed of unconsolidated sandstone. The use of unconsolidated core material would have increased the difficulty in producing reproducible data. A decision was made to avoid non-reproducible results of unconsolidated material such as grain disturbance and inelastic behavior during stress cycles by using Berea as the core material for Case III. The permeability of the Berea used in this study was near the 500 md range (classification used by the quarry). The Berea clay mineralogy presented in Table 1 represents the range for two separate samples not used in the laboratory testing but from the same quarry. The crude oil used in the Case III study had a producing gravity of about 23^{o} API. A separate oil sample from the same well was used in chromatographic analyses.

The results can be compared to the other two oils in Table 2. The higher percentage of asphaltenes is consistent with the heavier density of this oil.

Procedures

The unsteady-state waterflood technique with brine displacing crude oil was used to test composite core samples. The first waterflood on a given composite was initiated with low initial water saturation and live crude oil in the core. After the first waterflood, the core was restored to low initial water saturation by centrifuging. The second waterflood was performed with dead crude oil in the core replacing the live oil. If adjacent core material was available, repeat tests were performed in reverse order (dead oil before live oil). The results were analyzed for water and oil relative permeabilities using the Johnson-Bossler-Naumann (JBN) technique.[5] Comparisons were made based on the oil production and the relative permeability curves.

The detailed procedures and the results are presented as three cases for the three crude oils. Fluid properties are shown in Table 3 for all three cases.

Case I - North Sea Reservoir "A". Following a research applications project, extra crude oil and preserved core samples from North Sea Reservoir "A" were available. The live crude oil was obtained from surface fluid tests. The core plugs were from the same field and were preserved under brine.

Half of the live oil was de-gassed to provide a supply of dead oil. The live oil was de-gassed by flowing through a backpressure regulator set at a pressure above the bubble point. The oil exited the backpressure regulator at atmospheric pressure. The evolved gas was collected. Additional de-gassing was performed by heating the oil to 70°C and subjecting the oil to a vacuum pressure of one half atmosphere for five minutes. The collected gas was combined with the synthetic brine to produce a live brine for the live fluid waterfloods. The synthetic formation brine was a solution of 4.0 wt% of total dissolved solids (TDS) composed of sodium chloride and calcium chloride. Viscosities of the live and dead oils and brines were measured at reservoir temperature of 207°F and pressure of 4000 psi with a capillary tube. As shown in Table 3, this crude oil is not very viscous, and viscous fingering is not expected. Density of the dead crude oil at ambient conditions was measured with a densitometer.

Initially, the cores were flushed with synthetic brine at ambient conditions to remove any drilling fluid filtrate. The effective brine permeability was measured on each core plug. Groups of four plugs to be mounted as composite cores were selected based on the similarity in permeabilities.

Prior to mounting, the cores for the first composite were centrifuged under air to low water and oil saturations at ambient conditions while positioned on spacer plugs. The spacer plugs were used to displace the end effect (high water saturation at the outlet face) that develops during centrifuging. This procedure creates a fairly even saturation distribution in the core plug to be tested. The four core plugs were then mounted end-to-end in a triaxial coreholder. By mounting four plugs end-to-end, an elongated core is produced which reduces the error due to capillary end effects during the waterflood and decreases error in the saturations by increasing the total pore volume. The coreholder sleeve pressure was set such that the net pressure was equal to the net overburden pressure for the reservoir. A short-duration (30 second) vacuum was drawn on the pore space of the core to remove some of the air without evaporating the water. Dead crude oil was injected into the core at a high enough pressure to dissolve the remaining air into the oil. Two pore volumes of dead crude oil were flushed through the core to remove the oil with the dissolved gas and to establish a consistent dead oil in the core. The core was placed in an oven, and the temperature was raised to the reservoir temperature while maintaining constant sleeve and pore pressure. The core was aged in the dead crude oil at reservoir temperature for 19 days. Even though the samples were preserved, the aging period was used to insure the wettability would be constant during the test.

After aging, the core was flushed with live crude oil at reservoir temperature and pressure until the pressure drop across the core was constant which usually occurred within two pore volumes. The effective oil permeability at initial water saturation (koi) was measured with the live oil. The next day the core was flooded with live synthetic brine at reservoir temperature and pressure. The oil production and differential pressure across the composite core were measured during the flood for calculating the relative permeabilities.

Following the waterflood, the water saturation was determined by a brine elution. The brine elution was performed by displacing the chloride based synthetic brine with a nitrate based brine. The formula for the nitrate brine was based on the molar equivalent to the chloride brine in which the cations were the same and the chloride ions were replaced with nitrate ions. Therefore, the nitrate brine had no chloride ions. The nitrate brine was flushed through the core at reservoir temperature and pressure, and effluent was collected in one pore volume increments. Four pore volumes were flushed through the core. The chloride concentration and volume of each effluent sample were measured as well as the chloride concentration of the original synthetic brine. Based on the chloride concentration of the synthetic brine, the chloride concentration of the effluent samples, and the volumes of the effluent samples, the volume of the synthetic brine that was displaced from the core was calculated. This volume was converted to the water saturation of the core after the waterflood. To prevent additional oil production while flushing with the nitrate brine, the flushing was performed the next day after the waterflood to allow saturations to equilibrate, and a very low flow rate was used. The initial water saturation was determined by subtracting the oil production during the waterflood.

After the brine elution, the composite core was flushed with synthetic brine. The pore pressure was reduced to atmospheric pressure, and the composite was cooled to room temperature. The core plugs were dismounted in order to centrifuge to initial water saturation. The orientation of the plugs was noted before dismounting. The cores were centrifuged under air on spacer plugs to low oil and water saturations. The core plugs were remounted in their former order and orientation. The net overburden pressure was set, and a short-duration (30 second) vacuum was drawn on the pore space. Dead crude oil was injected into the core, and two pore volumes of dead oil were flushed through the core. The composite was aged at reservoir temperature for 20 days.

After the aging, the core was flushed with dead crude at reservoir temperature and pressure. The effective oil permeability at initial oil saturation was measured with dead oil. A second waterflood was performed with dead brine. The water volume at the end of the flood was determined by brine elution. The initial water saturation was determined by subtracting the oil production during the waterflood.

To verify the use of the brine elution technique, the water volume at the end of the second waterflood was checked by vacuum distillation. The vacuum distillation was performed by connecting the core to an ice trap outside the oven. The trap was connected to a hand-operated vacuum pump. The connection from the core to the trap and the pump was a closed system such that a vacuum could be drawn on the core. The pore pressure was reduced to atmospheric such that the expelled fluids were caught in the ice trap and the excess pressure was drawn off with the vacuum pump. The sleeve pressure was reduced to maintain a constant net overburden pressure on the core. With the hand pump the pressure was reduced below atmospheric to the vapor pressure of the fluids in the core at the oven temperature. The water and some of the light ends of the oil phase vaporized in the core and moved into the trap. At the cooler temperature of the ice trap the fluids condensed. This process was allowed to continue for several days until the amount of fluids condensing in the trap ceased to increase. The light ends of the oil were removed and the volume of water trapped was determined. Based on the density of the trapped water, the density of the nitrate brine, and the salt concentration of the nitrate brine, the volume of actual brine in the core can be determined from the trapped water volume. Based on density changes in water as a function of temperature from the Critical Tables, the brine volume was adjusted for the change in temperature from reservoir to room conditions.

Following the vacuum distillation, the core was extracted to determine the pore volume. While still mounted in the coreholder, the core was flushed with toluene followed by chloroform to remove the remaining hydrocarbons. Each solvent was flushed through the core until the effluent was clear and colorless. Methanol was the final solvent to be flushed through the core to remove any salts. About ten pore volumes of methanol were injected. Nitrogen gas was used to dry the core. The core while still mounted in the coreholder was subjected to a long-duration (several hours) vacuum, following which white oil was injected into the core with a metering pump at a pressure high enough to dissolve any remaining gases (metered-in pore volume). After accounting for dead volumes in the tubing, valves, and screens, the pore volume was determined from the volume metered in. All saturation determinations were based on this final pore volume measurement.

For North Sea Reservoir "A", a second composite core and enough crude oil were available for a second series of tests. The procedures were basically the same except the waterflood with dead oil in the core was performed before the flood with live oil in the core.

The core plugs for the second composite were flushed with synthetic brine and centrifuged under air as with the first composite. The plugs were mounted into a composite coreholder and dead crude oil was metered-in to the pore space. The core was placed into an oven at reservoir temperature and aged in dead crude oil and a low initial water saturation for 21 days. After aging, the core was flushed with dead crude oil, and the effective oil permeability at initial water saturation was measured. A waterflood was performed with dead synthetic brine at reservoir temperature and pressure. A brine elution was performed to determine the water saturation after the flood. The core plugs were dismounted from the coreholder and centrifuged under air. The plugs were remounted and dead crude oil was metered-in. The composite core was aged at reservoir temperature for 19 days. After aging, the core was flushed with approximately two pore volumes of live crude oil. The effective oil permeability at initial water saturation was measured with the live oil. The next day, a waterflood was performed with live synthetic brine. After the flood, a brine elution and a vacuum distillation were performed. After extracting with solvents, the pore volume was determined by metering-in white oil.

Case II - Reservoir in France. A small amount of crude oil and preserved cores were available after a research applications project for a reservoir in France. The live crude oil was from a separator test, and only enough crude oil was available to perform one series of tests. The core plugs were from the same field and were preserved under brine. The testing procedures for this composite core were very similar to those of the first composite of Case I.

Half of the live oil was de-gassed by first flowing through a back pressure regulator to atmospheric pressure and then applying a half of an atmosphere of vacuum pressure at 70°C for five minutes. The gas collected downstream from the backpressure regulator was used to produce a live synthetic brine. The synthetic formation brine was a solution of 11.5 wt% TDS composed of sodium chloride, calcium chloride, magnesium chloride, and potassium chloride. Only enough crude oil was available to measure the dead oil viscosity at reservoir pressure and temperature. The viscosity value for the live oil was obtained from the lab work on the research applications project (see Table 3). No density measurements were performed on this oil.

The core plugs for the composite were selected based on the initial effective brine permeability. The core plugs were centrifuged under air on spacer plugs to low initial water saturation. Dead crude oil was metered in, and the core was aged at reservoir temperature and reservoir net overburden pressure. During the aging period, several oven failures occurred. Best efforts were made to maintain a constant net overburden pressure during the cooling and reheating. After aging for 34 days in dead crude oil, the core was flushed with live crude oil. The effective oil permeability at initial water saturation was measured with the live crude oil. A waterflood with live synthetic brine was performed two days later. Following the flood a brine elution was performed. The cores were cooled and dismounted. The plugs were centrifuged under air and remounted. Dead crude oil was metered-in, and the core was raised to reservoir temperature with constant sleeve pressure equal to the net overburden pressure of the reservoir. The composite was aged for 10 days with dead crude oil at reservoir temperature. The core was flushed with dead crude oil, and the effective oil permeability at initial water saturation was measured. Four days later the waterflood was performed with dead synthetic brine. After the flood a brine elution was performed followed by a vacuum distillation. After extraction the core was cooled, and the pore volume was measured.

Case III - North Sea Reservoir "B". Following an application project, crude oil was available from the North Sea Reservoir "B". The cores from this reservoir were unconsolidated. To avoid possible reproducibility problems, Berea sandstone was used for the waterflood tests. The use of Berea also provides a test as to how representative this sandstone is for reservoir flow research.

The Berea plugs used for this project were cut from a three-foot rod which was 1.5 inches in diameter. The plugs were extracted first in methanol and then in toluene. The plugs were vacuum dried and saturated with a 5 wt% TDS brine composed of sodium chloride and calcium chloride. A synthetic reservoir brine was not used since a good water sample had not been obtained from the field. The 5 wt% brine was considered adequate for protecting the clays and for performing a brine elution test. The absolute permeability was measured with brine, and two groups of four plugs for two composite cores were selected. Although an arbitrary brine solution and Berea core plugs were used, testing procedures were still performed at pressure and temperature conditions appropriate to the crude oil sample's reservoir.

The live crude oil was developed from stock tank crude oil which was recombined with a synthetic gas. The gas mixture and ratio were the same as were used in the research application project. Half of the live oil was de-gassed at a half of an atmosphere vacuum pressure and 70°C for five minutes. Live 5 wt% brine was produced by combining 200 ml of live crude oil with a liter of dead brine at reservoir conditions. Mixing of the two fluids allowed gas to diffuse from the oil to the brine. The viscosities of live and dead oil and brine were measured with a capillary tube at reservoir temperature and pressure. The results as shown in Table 3 indicated that this crude oil was a higher viscosity oil (by at least one order in magnitude) than the previous oils.

The first four core plugs were centrifuged in air on spacer plugs. The plugs were mounted in a triaxial coreholder, and reservoir net overburden was applied. A short-duration (30 second) vacuum was applied to the pore space of the core, and stock tank crude oil was metered-in the core. About two pore volumes of stock tank oil were flushed through the core. The core was placed in an oven and raised to reservoir temperature at constant net overburden pressure. The core was aged for 45 days.

The core was flushed with dead (de-gassed from the recombined oil) crude oil, and the effective oil permeability at initial water saturation was measured. The next day a waterflood was performed with dead 5 wt% brine. A brine elution was performed with a nitrate brine. Following the brine elution, the composite core was flushed with the original 5 wt% brine and dismounted. The core plugs were centrifuged under air on spacer plugs. The cores were remounted, and the net overburden pressure was reestablished. De-gassed stock tank crude oil was metered-in the core, and the composite core was aged at reservoir temperature for 11 days. The composite core was flushed with live crude oil (from the recombination), and the effective oil permeability at initial water saturation was measured. The next day a waterflood was performed with live 5 wt% brine. A brine elution was performed followed by a vacuum distillation.

A second Berea core plug composite also was tested. This composite core was prepared and tested with North Sea Reservoir "B" oil similar to the first composite but with significant differences in the aging process and times.

After centrifuging to a low initial water saturation, the core plugs for the second composite were mounted, and net overburden pressure was applied. Stock tank crude oil was metered in, and the core temperature was raised to the reservoir value. The core was aged for 71 days. The core was flushed with live crude oil (recombined), and the effective oil permeability at initial water saturation was measured. A combination of equipment failure and holiday time delayed the start of the waterflood. The composite core aged in live crude for an additional 18 days. This composite was the only one aged in live crude oil for more than two days. A waterflood was performed with live 5 wt% brine at reservoir temperature and pressure. A brine elution was performed followed by a flush of dead 5 wt% brine. The core plugs were dismounted and centrifuged under air. The core plugs were remounted, and net overburden pressure was applied. De-gassed crude oil was metered-in the composite. The core was flushed with de-gassed oil, and the effective oil permeability at initial water saturation was measured. In order to maintain the same wettability as with the first waterflood in this composite the time which the dead oil was allowed to stay in the core prior to the second waterflood was minimized. The day after flushing with dead oil, the core was waterflooded. A brine elution followed by a vacuum distillation were performed. A pore volume measurement was performed after the composite core was flushed with solvents and dried.

Results and Discussion

Case I - North Sea Reservoir "A". For the four waterfloods performed on two composite cores from North Sea Reservoir "A", the production data are shown in Figure 1. The production data are expressed as the average water saturation in the core as a function of pore volumes of injected brine. The curves corresponding to the live oil are designated with the solid symbols, while the curves corresponding to the dead oil are designated with the open symbols. The breakthrough of water production at the outlet end of the core is evident as a sharp break in slope in the production curve. The points that are circled represent the breakthrough point as used in the analysis. This graph depicts the breakthrough at lower water saturations (earlier breakthrough) for the two floods with dead oil in the cores. This result is consistent with the less favorable mobility ratio resulting from the higher viscosity of the dead oil relative to the live oil. Data at lower water saturations are obtained after breakthrough for the dead oil as compared to the live oil.

The water-oil relative permeability curves from the North Sea Reservoir "A" are shown in Figure 2. The curves corresponding to the dead oil extend to much lower water saturations than those corresponding to the live oil due to the earlier breakthrough with the higher viscosity dead oil. Only the production and differential pressure data after breakthrough were used to calculate the relative permeability values.

The results for the live and dead oils in the first composite are shown as the solid and open squares respectively. The two sets of relative permeability curves overlap from a water saturation of 50% to 72%. In the overlapping region the difference between the two sets of curves is small with the live oil curves shifted slightly to the left.

The relative permeability curves for the live and dead oils in the second composite are shown as the solid and open triangles respectively in Figure 2. The two sets of relative permeability curves overlap in the saturation range of 57% to 72%. In this overlapping saturation region the difference between the live and dead crude oils is very small for both the water and oil relative permeability curves. For the second composite, the curves with live crude are shifted to the right, which is the opposite direction of the results for the first composite.

The initial saturations for the four waterflood tests are shown as the circled symbols in Figure 2. The direction which the curves with live crude oil shifted away from the curves of the corresponding dead oil correlates directly with the relative values of the initial water saturation. For example, the oil relative permeability curve with the lowest initial water saturation is the dead oil curve from the second composite, and it is shifted farthest to the left. The oil relative permeability curve with the highest initial water saturation is the dead oil curve from the first composite, and that curve is shifted farthest to the right. The two live oil curves had intermediate initial water saturations, and the curves fall in between the dead oil curves. To further define the correlation between the relative permeability curves and the initial water saturation, the curves were plotted against a normalized saturation scale. The normalized saturations were determined by subtracting the initial water saturation for each curve from the face water saturation values in that curve and dividing by 100% minus the initial water saturation (see Figure 3). This normalization procedure forces all of the oil relative permeability curves to start at zero normalized saturation. Therefore, the saturation is a function of the initial hydrocarbon volume (HCV) in the core. As shown in Figure 3, the normalization of the saturations resulted in a tighter grouping of the curves with a separation of only 3% to 4% HCV. This result indicates that the relative permeability curves are more influenced by the initial water saturation than the difference between the live and dead oils. No significant and consistent difference in relative permeability curves was found that can be attributed to whether live or dead oil was in the core during the floods.

A comparison of the water volumes obtained by brine elution was made with the values determined by vacuum distillation for both of the preserved composite cores in Case I. The results are shown in Table 4. The close comparison verifies the use of the two techniques, and the difference in the values are within the differences of the relative permeability curves.

Case II - Reservoir in France. Shown in Figure 4 are the production data expressed as the average saturation from the two waterfloods performed on the one composite from the reservoir in France. As with the previous case, the flood with the dead oil had earlier breakthrough than the live oil. Again, this can be attributed to the higher viscosity of the dead oil creating a less favorable mobility ratio.

The resulting relative permeability curves are shown in Figure 5. The oil and water relative permeability curves for the dead oil extend to much lower water saturations than the curves for the live oil. This greater range of saturations for the dead oil is due to the earlier breakthrough. The live and dead oil curves overlap in the water saturation range of 55% to 70%. For the oil relative permeability curves, virtually no difference was observed between the tests with live and dead oils. For the water relative permeability curves, the curve for the dead oil is shifted considerably higher than the curve for the live oil. Unlike the two composites for the North Sea Reservoir "A", the effective oil permeability at the initial water saturation for this composite core with the live oil is much higher than the value for the dead oil. If the effective oil permeability from the live oil test is used as the reference permeability for the dead oil water relative permeability curve, the water relative permeability curves from both tests match (see Figure 6).

The test with live oil was performed first, and the effective oil permeability at the initial water saturation for the live oil test was much higher than the value from the dead oil test. The reduction in the effective oil permeability is suspected to be caused by disturbance to the core plugs during dismounting and remounting. Apparently, the disturbance reduced the effective oil permeability at high oil saturation, but did not greatly affect the effective water permeabilities at high water saturation. A possible explanation for this occurrence (only by speculation) is the disturbance of water-wet fines on the face of the core plugs. If water-wet fines are lodged in the large pores at the faces of the plugs, the effective oil permeability will be greatly affected, but the effective water permeability will be relatively unchanged. In Figure 6, the difference in the oil relative permeability is about 3% saturation units which is about the same as in Case I. Based on these observations, the difference in the water relative permeability curves in Figure 5 appears to be caused by the lack of reproducibility in the experiments and not due to the difference between live and dead oils.

Case III - North Sea Reservoir "B". Figure 7 shows the production curves for the first Berea composite tested with North Sea Reservoir "B" crude oil. The earlier breakthrough for the more viscous dead crude oil is evident, but the two curves have very different final average water saturation. For both curves the residual oil saturations are high at 40 to 50% which is indicative of strongly water-wet Berea. Apparently, the long aging period with the dead North Sea Reservoir "B" crude oil did not have a very large impact on the natural water-wet wettability of Berea.

For the first composite, the dead oil test was performed first. In the second flood with live oil in the core, an inflection point is apparent in the production curve between 1 and 2 pore volumes of injected brine. Since the precision of the separator for measuring oil production is near 0.01 ml (less than 0.02 %PV), the inflection appears to be greater than the noise in the data. Prior to this point, the live oil curve appeared to be approaching the same final oil saturation as the dead oil curve. Two possible explanations can be offered. First, the flood results may be influenced by viscous fingering since this crude oil had a higher viscosity than the previous oils (see Table 3). Second, the curves may be responding to changes in wettability during the flood. Since the aging process only had a small impact on the wettability of the Berea, small changes in the wettability during the flood could significantly affect the production and relative permeability curves.

The apparent lack of a robust wettability exhibited by the results on the first composite was not present in the results from the preserved cores used in Cases I and II. Preserved cores subjected to short periods of aging with live oil (up to 2 days) did not exhibited the change in relative permeability curves as demonstrated by the Berea composite.

The relative permeability curves for the first composite are shown in Figure 8. The curves clearly show the difference in final oil saturations between the two tests and the inflections in the curves for the test with live oil.

The production curves for the second Berea composite are shown in Figure 9. The live oil test was performed first and is shown in the solid triangles. The (incidental) elongated aging period with live oil after the aging period in dead oil appeared to have had a significant impact on the production. The lack of significant production after breakthrough is indicative of a waterflood on water-wet Berea without viscous fingering. The live oil may have reversed any small wettability changes created by aging in dead oil. Since only the data after breakthrough are used to calculate the relative permeability curves, the relative permeability curves do not cover a very large saturation range.

During the second flood with the dead oil, the core was expected to have the same wettability as during the first flood since the dead oil was in the core for less than 24 hours prior to the flood. The production curve indicates a very different behavior. After breakthrough, the curve has a fairly steep slope and a lower final oil saturation. The resulting relative permeability curves for both live and dead oils are shown in Figure 10.

The resulting relative permeability curves for both composites are shown in Figure 11. None of the curves is consistent with the other. The combination of the North Sea Reservoir "B" crude oil and Berea core plugs did not produce reproducible results. Apparently the crude oil did not establish a robust wettability condition in the Berea cores. This problem was compounded by the possible effects of viscous fingering. No conclusions on the comparative behavior of live and dead oils can be made for this case. Possible future work can treat aging in live oil as a variable to compare to aging in dead oil.

Conclusions

Based on the results of the three crude oils tested in this project we conclude:

1. The unsteady-state (waterflood) tests performed with dead (de-gassed) crude oil in the composite cores had earlier breakthrough (at lower water saturations) of injected brine than tests with the corresponding live crude oil. This result was expected due to the higher viscosity of the dead oil relative to the viscosity of the live oil.

2. The resulting relative permeabilities from tests performed with dead crude oil in the composite cores covered a broader range of saturations than the relative permeabilities from tests performed with the corresponding live oil. This finding was consistent with the earlier breakthrough of injected brine in the tests with the more viscous dead oil.

3. Where the saturation range of the relative permeability curves overlapped, no consistent difference was observed between live and dead crude oils used in preserved cores to determine the relative permeability curves by the unsteady-state technique.

4. Tests performed with Berea cores aged in the North Sea "B" crude oils exhibited effects that may be attributed to the lack of a robust wettability system. The behavior of the oil production for the Berea composites implies that changes in the wettability occurred within hours of contact with different crude oil type (live or dead).

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Table 1
Mineralogy of Formation Samples

North Sea "A" Mineral	Wt %	France Mineral	Wt %*	Berea Mineral	Wt %**
Quartz	54-52	Quartz	57.1		
Feldspar	8-5	Feldspar	13.7	Feldspar	5-3
Plagioclase	24-23	Plagioclase	10.8		
		Dolomite	10.7	Carbonate	2
Illite	2-1	Illite	4.7	Illite	5-2
Chlorite	4-3	Chlorite	1.7	Chlorite	2-1
Kaolinite	1	Kaolinite	0.1	Kaolinite	3-1
Smectite	2-1				
Muscovite	11-7				

* Average for three adjacent wells
** Range for two outcrop samples

Table 2
Gross Compositions of C15+ from
Liquid Chromatography

Sample	EPR Sample No.	%C15+ in Oil	Saturated (% in SOM)	Aromatics (% in SOM)	NSO (% in SOM)	Asphaltenes (% in SOM)
North Sea "A"	160567	72.8	51.4	21.9	22.2	4.6
France*	77164	91.1	56.0	21.5	13.9	8.7
North Sea "B"**	139073	86.0	47.0	28.0	13.0	12.0

* Oil sample from adjacent well
** Separate oil sample from same well

Table 3
Conditions for the Waterfloods

Test Conditions	North Sea "A"	France	North Sea "B"
Reservoir Temperature	207°F	210°F	170°F
Reservoir Pressure	4000 psi	3150 psi	2650 psi
Live Oil Viscosity @ Reservoir Conditions	0.61 cp	2.02 cp	3.36 cp
Dead Oil Viscosity @ Reservoir Conditions	1.77 cp	2.52 cp	11.73 cp
Brine Viscosity @ Reservoir Conditions	0.33 cp	0.38 cp	0.43 cp
Injection Rate	1.8-3.2 mL/min	3.2-4.2 mL/min	2.6-3.1 mL/min
Core Material	Preserved	Preserved	Aged Berea

Table 4
Comparison of Brine Elution
to Vacuum Distillation

Preserved Core	Final Water Volume: Brine Elution (ml)	Final Water Volume: Vacuum Distillation (ml)	Diff. (% PV)
North Sea "A" Composite 1	39.720	40.047	0.6
North Sea "A" Composite 2	41.813	43.714	3.3
France Composite	27.350	27.661	0.8

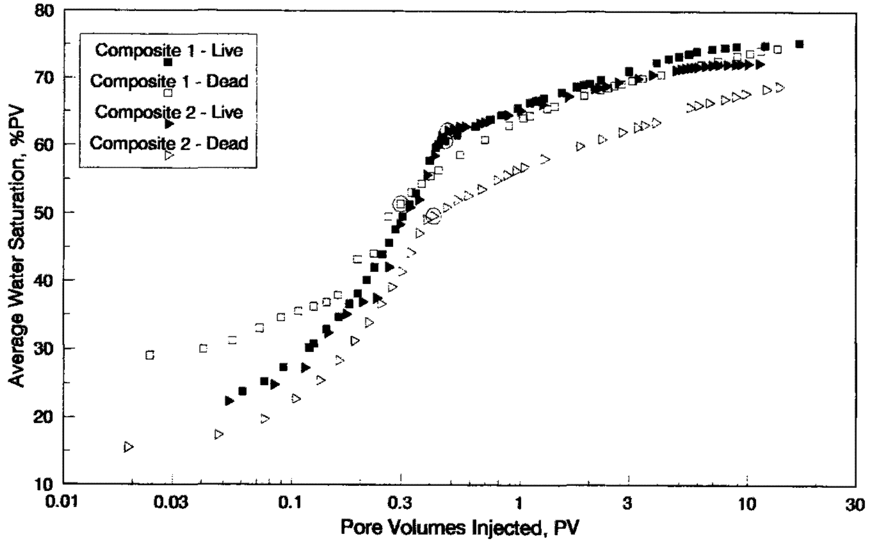

Figure 1. Oil Production During the Waterfloods on Composites from North Sea Reservoir "A".

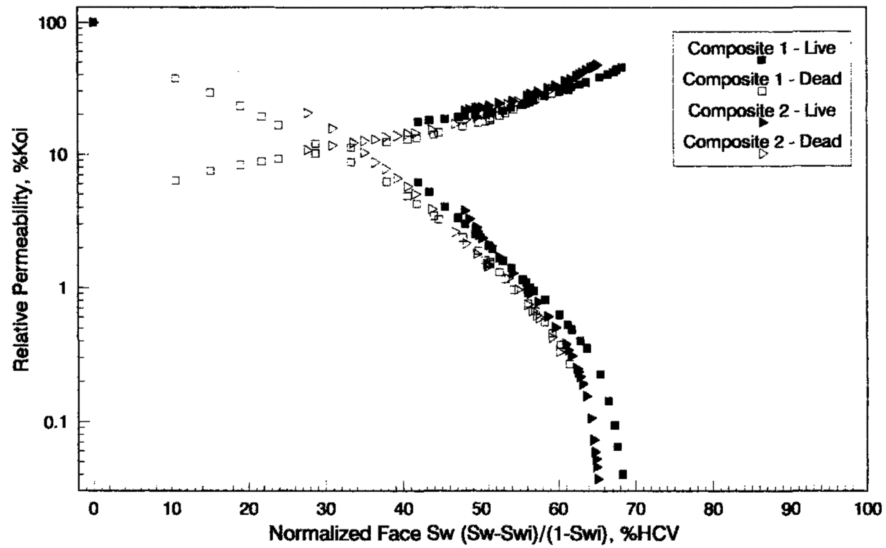

Figure 3. Normalized Results of Waterfloods on Composites from North Sea Reservoir "A".

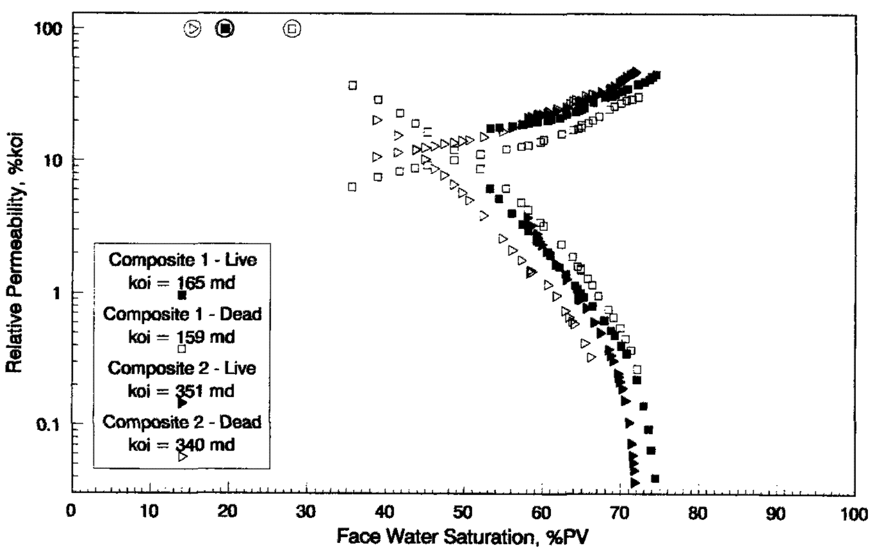

Figure 2. Results of Live Vs Dead Waterfloods on Composites from North Sea Reservior "A".

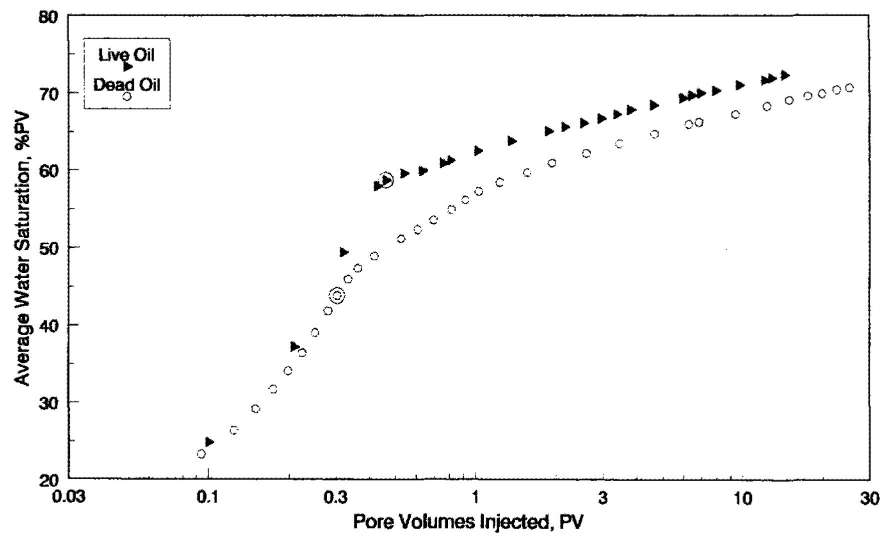

Figure 4. Oil Production During the Waterfloods on Composite from Reservoir in France.

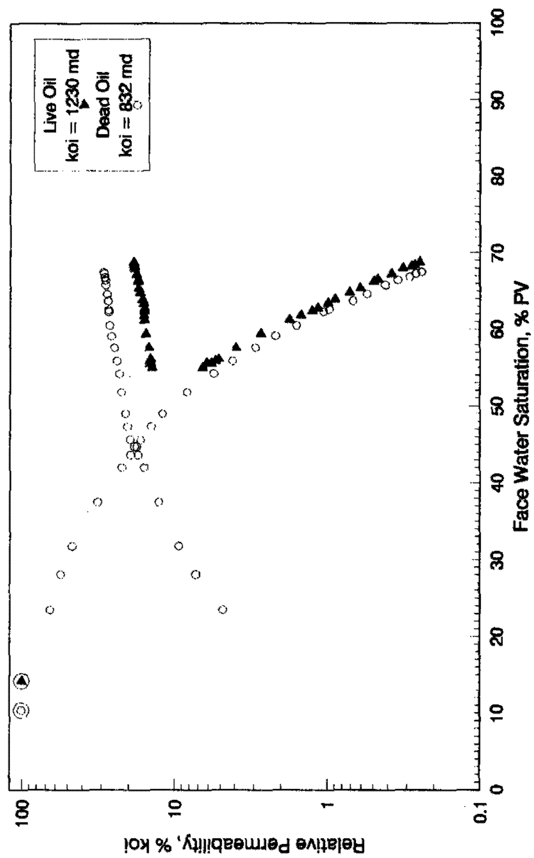

Figure 5. Results of Live Vs Dead Waterfloods on Composite from Reservoir in France.

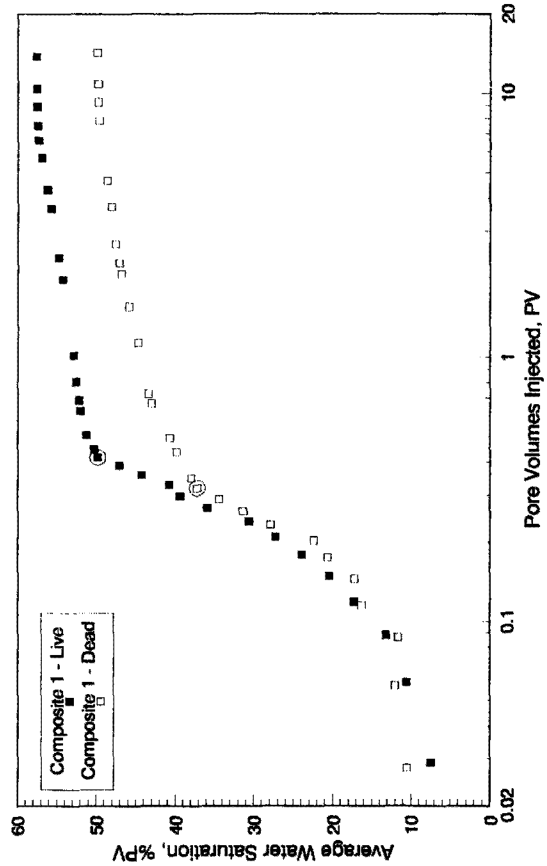

Figure 7. Oil Production During the Waterfloods on Composite No. 1 from North Sea Reservoir "B".

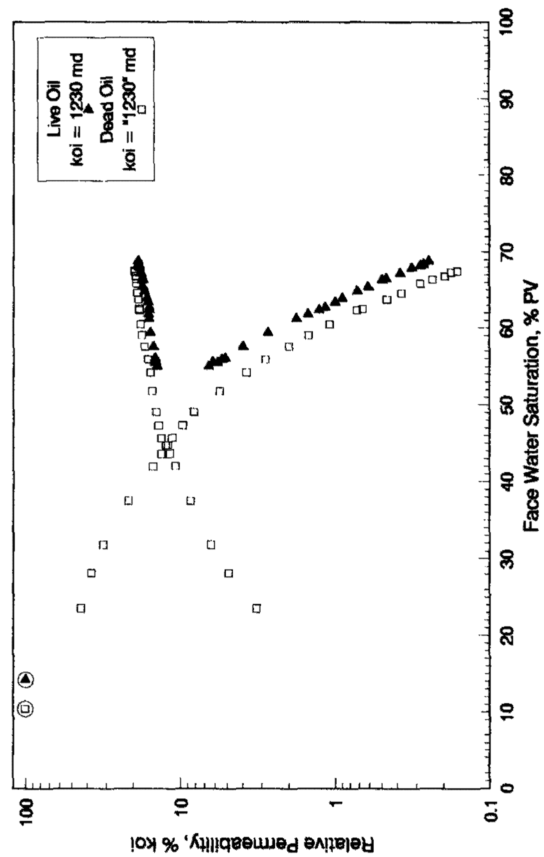

Figure 6. Adjusted Results of Waterfloods on Composite from Reservoir in France.

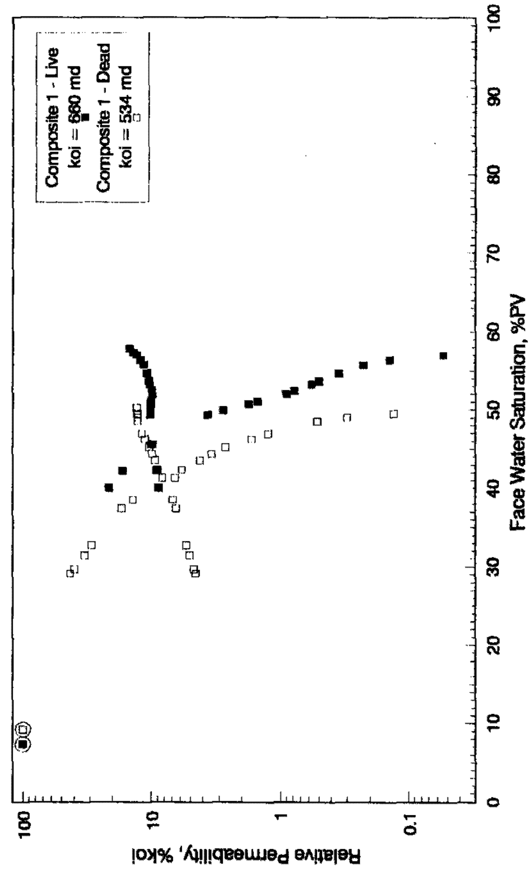

Figure 8. Results of Live Vs Dead Waterfloods on Composite No. 1 from North Sea Reservoir "B".

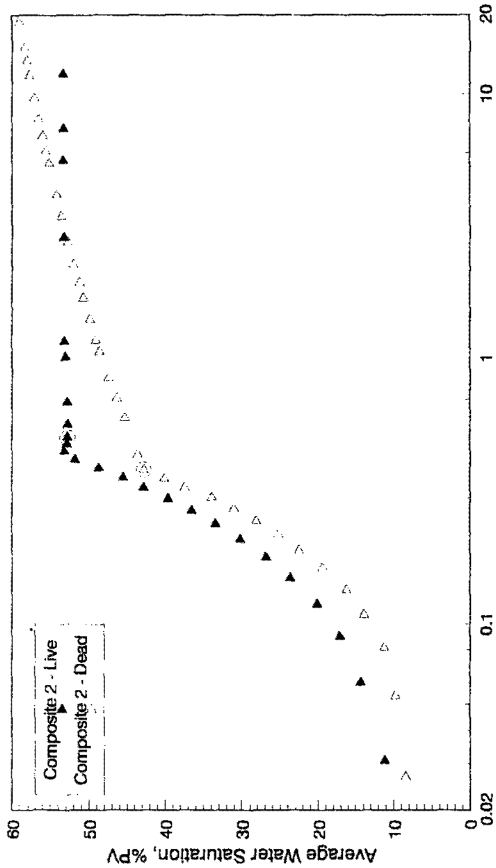

Figure 9. Oil Production During the Waterfloods on Composite No. 2 from North Sea Reservoir "B".

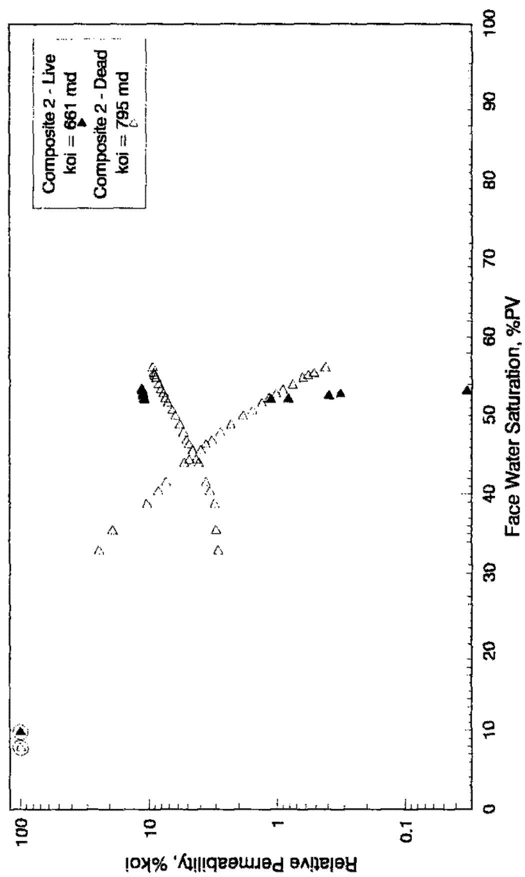

Figure 10. Results of Live Vs Dead Waterfloods on Composite No. 2 from North Sea Reservoir "B".

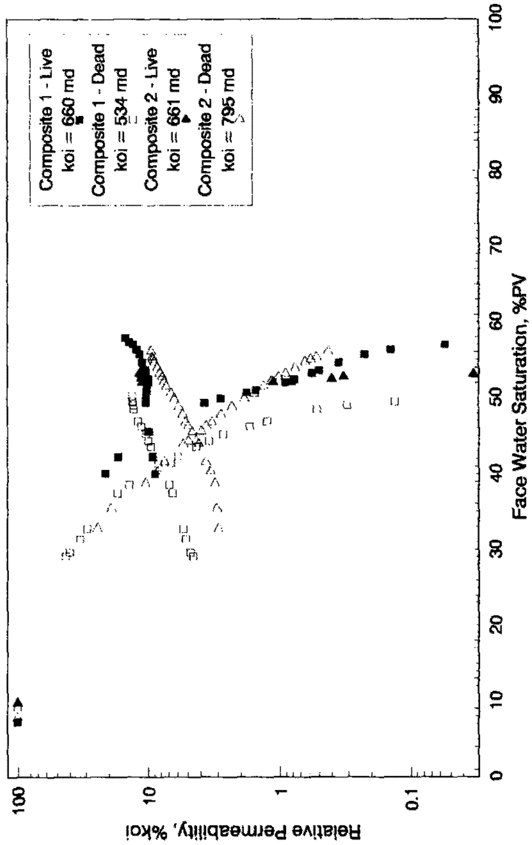

Figure 11. Results of Live Vs Dead Waterfloods on Both Composites from North Sea Reservoir "B".