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TRANSITION ZONE CHARACTERIZATION WITH APPROPRIATE ROCK-FLUID PROPERTY MEASUREMENTS

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Abstract

In a related paper (Fanchi et al., 1999), the application of rock-fluid properties for estimating recovery of oil from transition zones is discussed. Here, fundamental issues for appropriate selection of rock-fluid properties for characterizing transition zones are addressed. Also, examples of oil mobilization from transition zones in laboratory experiments are provided.

Graphical illustrations are presented to compare and contrast conventional methods for characterizing transition zones with an improved characterization method that requires additional rock-fluid property measurements. Results from laboratory studies of recovery from transition zones are used to demonstrate features of the improved characterization method. These results show that oil in the transition zone is much more mobile and recoverable than is assumed by the conventional approach.

For these laboratory studies, unconsolidated packs of sand, glass beads, and plastic beads were used. The media were varied to observe the effects of wettability and grain size on transition zone properties. It is believed that the variety of media qualitatively represent what would be observed for actual reservoir formations. Local saturations in the transition zones were correlated to gray level of video images of the surface of the packs. The laboratory methods for unconsolidated media could be extended in the future to reservoir rock (having much lower permeabilities) with centrifuge technology.

Introduction

Numerical models for matching historical production and forecasting performance of hydrocarbon reservoirs rely heavily on numerous types of core measurements: porosity, absolute permeability, and formation compressibility, plus capillary pressure and relative permeabilities. Capillary pressure and relative permeability are of primary concern in this paper. Capillary pressure data translate to the hydrocarbon saturation profile as a function of height in a reservoir. Also, gradients of capillary pressures during displacement processes influence movement of fluids. Relative permeabilities provide information on fluid mobility and the amount of hydrocarbon recovery as a function of time.

Conventionally, primary drainage capillary pressure and waterflood relative permeabilities have been used to determine the depth of the lower productive limit of a transition zone, the percentage of hydrocarbon recovery, and the percentage of unrecoverable hydrocarbons from waterflooding. Here, a transition zone is defined as an interval that produces both oil and water during primary recovery. Transition zones affect

volumetric calculations of original oil in place,
simulation of oil recovery for various operational alternatives,
determinations of the spatial distributions of recoverable oil for well placement,
completion interval determinations,
dimensions of the reservoir limits, and
the amount and distribution of unrecoverable oil by conventional methods.

Of particular interest in transition zone characterization are determinations of the top and base of the zone, and the relative amounts of recoverable and residual oil at any elevation within the interval.

When the numerical simulation does not match the fluid production history of a reservoir, it is common practice to adjust the relative permeability data. Numerous reasons are offered for the adjustments. Frequently cited reasons include reservoir heterogeneity, small size of the cores compared to reservoir volume, and inadequacy of numerical models. (Some times, the reasons are even appropriate.)

An alternative approach for improving a simulator match that is especially suited to reservoirs with large oil-water transition zones is suggested by Fanchi et al. (1999). The bottom line of Fanchi et al. (1999) is that oil in a transition zone may be more mobile than conventionally thought. Specifically, rather than being a constant, the residual oil saturation at an elevation in a transition zone depends on the initial oil saturation at that elevation. And more specifically, the residual oil saturation depends on the history of saturation at any elevation.

In the following sections, conventional practice for estimating recovery from transition zones is investigated, and the need for addition rock-fluid property measurements is highlighted. Then, literature relevant to trapped oil relationships is discussed. Trapped oil relationships are important because they show the maximum amount of oil that can be recovered from a transition zone. And then, an approach for obtaining trapped oil relationships from saturation profile experiments is presented. Possible methods for measuring relative permeabilities for transition zones are also discussed. Finally, the need for technology and methods for identifying the saturation history for transition zones is discussed.

Conventional Practice in Reservoir Engineering

Conventional simulators for modeling hydrocarbon production characteristics in a transition zone use drainage (or reducing water saturation) capillary pressure core data and forced imbibition (waterflood, or increasing water saturation) relative permeability core data. Ideally, both sets of measurements are performed on statistically representative core samples from the reservoir. The tests are also ideally performed with reservoir fluids at reservoir temperature and pressure.

Drainage capillary pressure measurements provide several key elements for reservoir analysis. One is the initial water saturation present in the reservoir at discovery. This is also the same saturation used for initializing the waterflood relative permeability measurements. After the drainage capillary pressure data has been converted to reservoir conditions, an oil saturation profile as a function of height in a reservoir can be graphed. Results of the waterflooding tests are often correlated to the oil saturation profile to define the length of the productive oil column and the base of a transition zone as shown in Figure 1. The remaining oil saturation at the end of the waterflooding test, or Sor, is a constant that is applied for the entire reservoir. So, oil saturations in the transition zone that are less than the residual oil saturation at the end of a waterflood test are considered unrecoverable.

The conventional practice, described above, is somewhat dubious because it correlates forced imbibition measurements from the waterflood with drainage capillary pressure results. Though dubious, it is convenient for numerical simulators as presently constructed. The drainage capillary pressure data can be used to establish the transition zone at the start of a waterflood. And, the forced imbibition relative permeabilities contribute to mobilities of fluids.

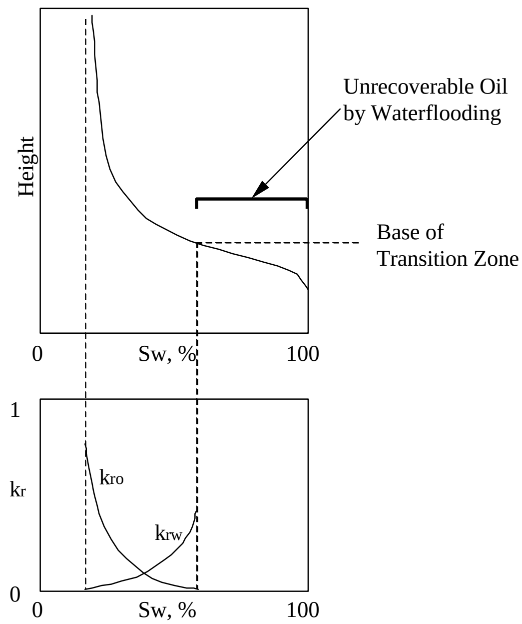

Figure 1. Conventional combination of a drainage capillary pressure relationship (converted to a saturation profile with height) with imbibition relative permeability.

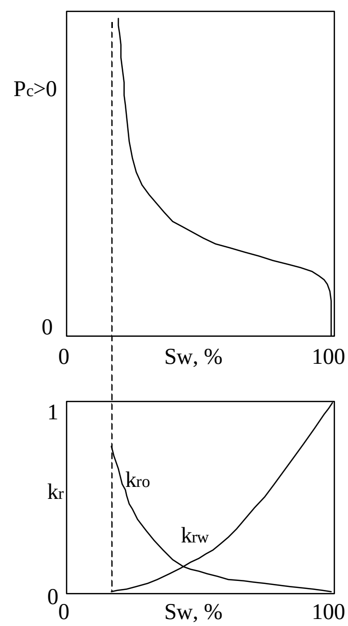

Figure 2. Combination of a primary drainage capillary pressure relationship with primary drainage relative permeabilities.

For describing movement of fluids, it would be more appropriate to combine capillary pressure and relative permeabilities for the same saturation history. For example, drainage capillary pressures with drainage relative permeabilities. This combination is shown in Figure 2. The capillary pressure and relative permeability data in Figure 2 could be appropriate for describing the filling of a water-wet reservoir with oil, or for describing an oilflood of a water-wet core.

A graphical comparison of imbibition capillary pressure and relative permeability core measurements is shown in Figure 3. It is assumed in this figure that the core sample has sustained a primary drainage to low water saturation, such as shown in Figure 2. The imbibition curve moves from high positive capillary pressure values to negative values during imbibition measurements. The combination of these two imbibition core measurements is most suitable for modeling recovery from a waterflood; the influence of the difference between the primary drainage and the imbibition capillary pressure curves on numerically simulated recovery is not clear. Figure 3 shows a relatively high residual oil saturation (about 40%) at the end of waterflooding.

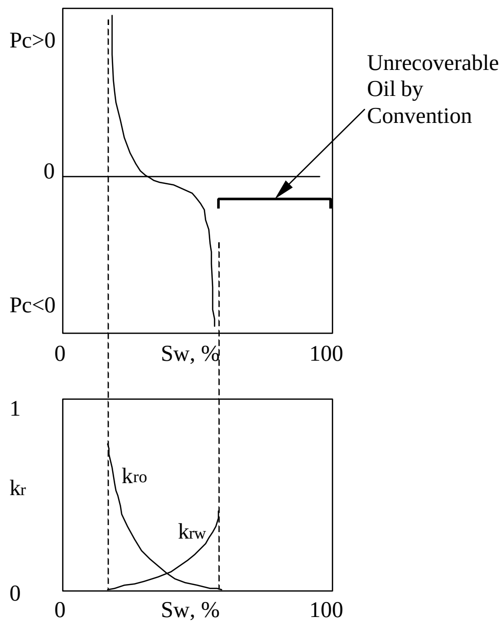

Figure 3. Combination of laboratory measurements of imbibition capillary pressure with imbibition relative permeabilities.

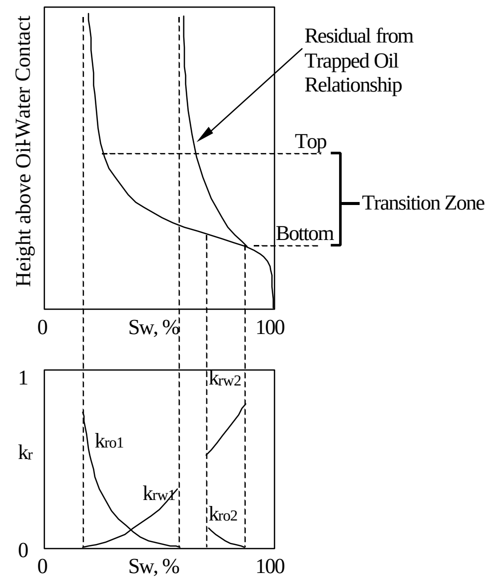

Figure 4. Combination of a drainage capillary pressure relationship (converted to a saturation profile with height) with imbibition relative permeability, enhanced with residual oil saturations that vary according to trapped oil relationships. A suite of relative permeabilities are needed -- just two are shown.

In the discussion of Figures 1, 2, and 3, some of the failings of the conventional approach to analysis of recovery from transition zones have been noted. Perhaps the greatest failing of the conventional approach is the assumption of constant residual oil saturation, regardless of initial oil saturation. As discussed in the following section, several authors have suggested that a lower range of residual oil saturations will be attained depending on the initial oil saturation -- that more oil is recoverable from transition zones than conventional wisdom would indicate.

As discussed below, our recent laboratory experiments verify the suggestions of previous authors. These laboratory results show that in order to characterize oil recoveries in transition zones additional core tests beyond conventional tests are required. Using the oil saturation profile in Figure 1, Figure 4 illustrates potential mobility of oil in a transition zone. Along with residual saturations that vary with position in a transition zone, a spectrum of relative permeability relationships is needed to model the mobility of the liquids. Figure 4 shows a hypothetical trend for relative permeability relationships in the transition zone.

Previous Measurements of Trapped Oil Relationships

Search of the literature has unearthed one reference with actual measurements of trapping relationships for oil (Pickell et al., 1966). There are a number of reports of trapped gas relationships (six are shown in Land, 1968), and some of these relationships have been “extended” as estimates of trapped oil relationships. Morrow reviewed a wide variety of trapping data in 1987.

In 1966, Pickell et al. reported their measurements of mercury-vapor, air-oil(liquid hydrocarbons), and oil-water trapping relationships for one sample of Austin limestone and three samples of Dalton sandstone. Their oil-water results for Dalton sandstone are reproduced in Figure 5. (The trends in Figure 5 are typical of much of the gas trapping data in the literature.) One important and obvious feature of these relationships is that the trapped fluid saturation must be less than or equal to the initial fluid saturation. A second feature of many, but not all, relationships in the literature is that the trapped fluid saturation increases toward an asymptotic value with increasing initial fluid saturation. Pickell et al. found that the trapping relationships for oil and water in water-wet rocks are quite similar to those for mercury-vapor and air-oil tests. Pickell et al. obtained the trapping data for oil-water by saturating the rock samples in a porous-plate apparatus to a desired saturation, and then flooding the sample with water to an endpoint oil saturation.

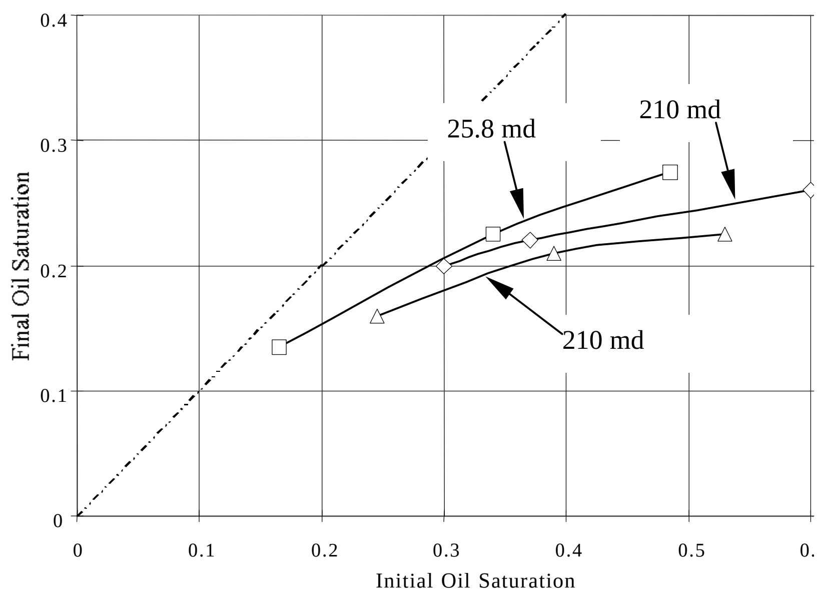

Figure 5. Trapped oil relationship from Pickell et al. (1966)

The procedure used by Pickell et al. for air-oil measurements is easy to implement. First, a clean rock sample is weighed and saturated with a liquid hydrocarbon, such as heptane. Then, the heptane saturation is reduced by evaporation to a desired initial air saturation, as measured by mass of the rock with the heptane. Then, the rock is stored in a sealed bottle for sufficient time to allow saturation equilibrium throughout the sample. Finally, the rock is suspended from a mass balance and immersed in heptane; when imbibition of the liquid is complete, the remaining air saturation is termed the residual saturation. Completion of the imbibition process is identified from a plot of air saturation against time in the liquid. The process may be repeated for increasing initial air saturations. The counter-current imbibition process of Pickell et al. was used by Keelan and Pugh (1973) for studies of the trapping relationships for gas in five types of carbonate.

In 1989, Yuan and Swanson reported trapping relationships derived from APEX (Apparatus for Pore Examination) experiments for samples of Berea and San Andres carbonate. (In APEX experiments, mercury is injected to an evacuated rock sample at very low rates, monitoring the time-dependent pressure during the injection.) The results were compared to counter current imbibition measurements following the procedure of Pickell et al.

Measuring Trapped Oil Relationships from Saturation Profile Experiments

In the discussion below, some background for the experiments is discussed first. Then, the apparatus and procedures for the majority of tests are described. Next, results of the tests are given. Finally, possible directions of future measurements for characterizing the rock-fluid properties of transition zones are considered.

Background. At the start of this research, an experimental approach that could quickly produce data for assessing mobility of oil in transition zones was deemed essential. As there is very little data in the literature to definitely support the hypothesis of residual oil saturations that depend on initial oil saturation, we did not want to expend vast amount of resources to test the idea. It was determined that an experiment in which transition zones could be produced would be most satisfactory. Such an approach could immediately meet the needs of showing if residual oil saturations depend on initial oil saturations, as well as providing data for trapped oil relationships.

It was obvious that producing transition zones with rock of typical reservoir permeability (10 to 1000 md) would require very tall apparatus. So, experiments with unconsolidated media with high permeabilities were selected. Furthermore, previous experiments had shown that fluid saturations in gas-liquid displacements could be rapidly estimated by converting gray levels of video images to saturation with a suitable correlation (Al-Omair and Christiansen, 1998; Al-Modhi and Christiansen, 1998). An experimental plan was then initiated to test the feasibility of this approach.

The very first tests were with packs of glass beads and of sand in a 100-ml burette, about 50-cm tall. As these experiments produced promising results, more formal experiments were developed.

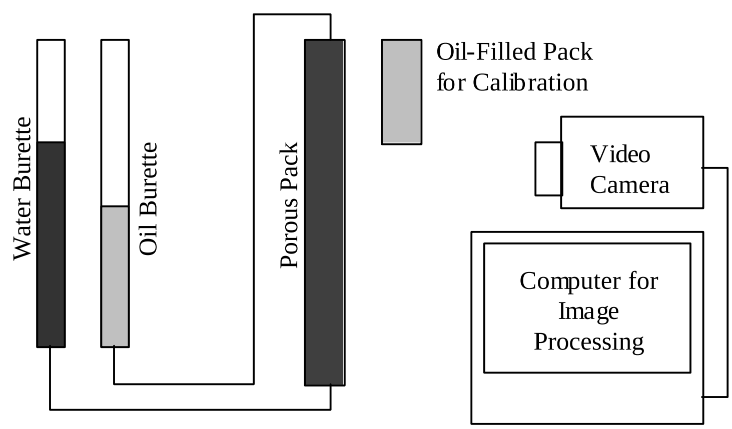

Figure 6. Apparatus for saturation profile measurements.

Experimental Apparatus. The apparatus for the experiments consists of an unconsolidated pack connected to two burettes containing oil and water, a video camera, and a computer for capturing video images. The apparatus is sketched in Figure 6.

The unconsolidated media consisted of spherical glass beads (70-100 mesh), spherical plastic beads (20-40 mesh), and proppant sand (20-40 mesh). The glass beads and the sand were found to be strongly water wet. The plastic beads were strongly oil wet.

The liquids for the experiments consisted of water and nonane. Nonane was chosen because of its low viscosity, low volatility, and availability in the lab. Food dye was used in some experiments for coloring the water. In other experiments, a powdered dye of poorly specified origin was used for dying the nonane. The food dye exhibited little adsorption on the solids. The other dye appeared to leave a very small amount of residual color on the solids.

The unconsolidated media was packed into an 48.3-cm-long acrylic tube (1.27-cm OD x 0.97-cm ID). Caps on each end of the tube allowed for introduction of liquids through a fine wire mesh. The packed tube was mounted vertically on a uniformly white background.

The top of the packed tube was connected to a burette containing nonane. The bottom of the packed tube was connected to a burette containing water. Raising or lowering one or both of the burettes could control position of the oil-water contact. We also considered injecting and withdrawing the oil with a syringe pump. With a pump, motion of the liquid could be maintained easily at low rates. The burette approach was favored because it facilitated calculation of capillary pressures at any point in the medium.

Images of the packed tube could be captured with a video camera at any time during an experiment. Video images were captured and processed with NIH Image software. With this software, sequential images could be compared to determine if a stable profile of gray levels had been obtained.

With the NIH Image software, one can obtain gray level profiles along scan lines selected (by "mouse dragging") on the video image. For our experiments, vertical lines coinciding with the packed tube were selected. The width of the lines can be varied from one to many pixels. We chose widths to obtain averages of gray level for much of the width of the packed tube.

Gray levels from the video images were converted to saturations using a very crude correlation. Adjacent to the packed tube, another short (10-cm length) packed tube was mounted as shown in Figure 6. The porous medium in this tube was fully saturated with nonane. The video gray level of this packed tube provided the 100% oil saturation reference. The bottom of the long packed tube, which was always saturated with water, provided the 100% water saturation reference level. Thus, the gray level correlation consisted of just two points. This crude correlation was sufficient for the qualitative nature of these experiments.

Procedure. At the start of an experiment, the packed tube was saturated with water. This was accomplished by first purging the tube with CO2, then filling with water to displace the CO2. Before proceeding, video images of the tube were examined to check for uniformity of lighting.

Next, the packed tube was connected to the oil and water burettes with flexible and transparent tubing, being careful to avoid introduction of air bubbles into the tubing or packed tube. Then, either the water burette was lowered or the oil burette was raised to force oil slowly into the porous medium packed in the tube. As oil entered the medium, water was withdrawn. The burette movement was slow to avoid high capillary numbers in the displacement process that might lead to difficulties in interpretation of saturation profiles.

In the first experiments, dye was added to the water, and the nonane was clear. In later experiments, the water was clear and the nonane was colored. As will be evident in the results discussed below, it is possible to have either too much or too little dye in the colored liquid.

After moving the burettes 1 or 2 cm to push oil into the medium, some time was allowed for a stable gray level profile to develop. From 1 to 2 hours were required for stabilization. Stabilization was determined from the oil and water levels in the burette and from video images of the packed tube. The oil was moved down in several steps, measuring stable gray level profiles at each step.

The direction of oil movement was reversed when a sufficiently tall oil invasion zone was produced. Stable gray level profiles were measured for each of several steps for injection of water.

Results. Two saturation profiles for an early experiment with the 70-100 mesh glass bead pack are shown in Figure 7. The "Initial" saturation profile is for downward movement of the oil-water contact; the "Final" profile is for upward movement. The depth of penetration of the oil-water contact is readily apparent in the Initial profile at about 26 cm depth. In the Final profile, oil saturation immediately above the Initial oil-water contact approaches zero. While further up the Final profile the saturations depart from zero. The region of zero oil saturation in the Final profile for depths from about 24 to 26 cm is likely erroneous. Excessively high dye concentration in the water may be the cause of this error.

A cross-plot of the Initial and Final saturation profiles of Figure 7 is shown in Figure 8. This figure was produced by plotting the Final saturation (for oil withdrawal) at a pixel in the Final video image against the initial saturation (for oil injection) for the same pixel in the Initial video image. This cross-plot shows many of the expected characteristics of a trapped oil relationship. But, it also includes saturation data that are "irrelevant" to the trapped oil relationship. Specifically, the data in the Final saturation profile above a depth of about 3 cm is irrelevant to the trapped oil relationship, as the oil above this depth is still mobile. The most relevant portion of saturations in Figure 8 is enclosed in a shaded box.

Focussing on just the saturation data in the box of Figure 8, one sees that final saturation are constant at zero for initial saturation from 0 to about 0.07. This data is likely erroneous, resulting from difficulties of seeing residual oil saturation through the water, which was too darkly dyed in this experiment.

While the trend in Figure 8 is promising, we were concerned that the measured saturations could be grossly in error because of the opacity of the dyed water. As a check, it should have been possible to compare the amount of oil injected to the medium (as measured with the burette) to the oil observed with the video image. Unfortunately, several small leaks in this experiment precluded that test.

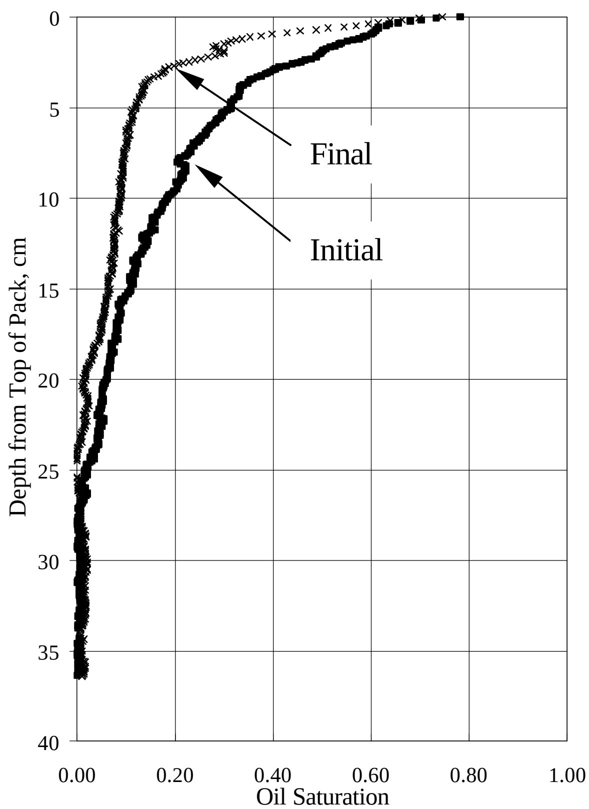

Figure 7. Measured initial and final saturation profiles for 70-100 mesh glass beads.

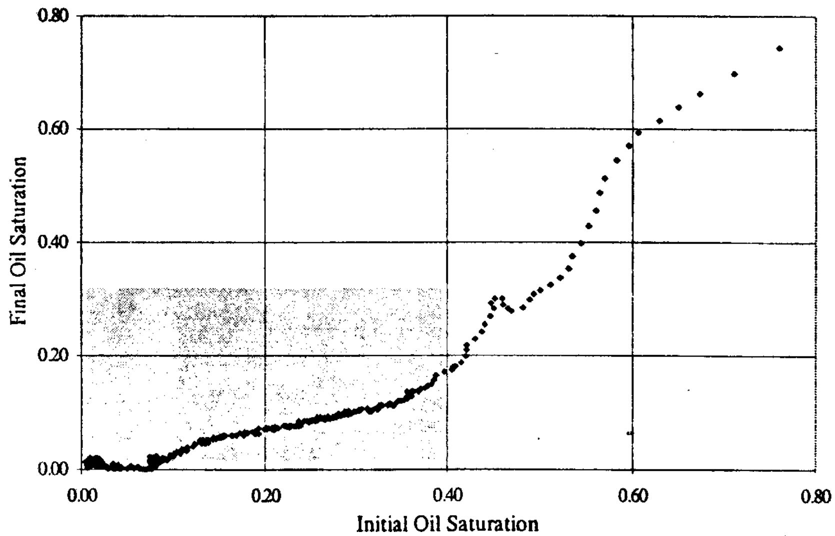

Figure 8. Trapped oil relationship from a cross-plot of profiles in Figure 7.

Initial and Final saturation profiles for an experiment with 70-100 mesh glass beads are shown in Figure 9. These profiles represent Steps 4 and 9 in the experiment. For Steps 1 to 4, the oil-water contact was lowered. For Steps 5 to 9, the oil-water contact was raised. The material balance results for the 9 steps are shown in Figure 10. The amount of oil in the packed medium was underestimated by the video measurements for some of the steps, and overestimated for other steps. For Step 4, the error was about 4%; for Step 9, the error was about 57%. This level of error could possibly be reduced with a more detailed correlation of saturation to gray level. It could be that the correlation for drainage should be different from that for imbibition. However, for most of these experiments, the error was acceptable. The relevant portion of the cross-plot of Initial and Final profiles from Figure 9 are shown in Figure 11. The curve drawn in Figure 11 is intended to show the expected relationship between Initial and Final oil saturations.

In Figure 12, the trapped oil relationship for 20-40 mesh sand is shown with a trendline to facilitate comparison of the two figures. The scatter of the saturations in the trapped oil relationship of Figure 12 may result from the heterogeneity of the gray level for the sand pack. By comparison, the scatter in Figure 11 for the glass bead pack was quite small.

Future Directions. While the above described saturation profile experiments are illuminating, for actual reservoir applications, measurements with reservoir rock are required. For reservoir rock, measurement of trapped oil relationships and relative permeabilities from saturation profiles may be possible with advanced flooding experiments, or with advanced centrifuge. In these experiments, oil would be injected in one direction into a water-saturated rock; then, the flow would be reversed by water injection from the other end of the rock.

The success of the either the flooding approach or the centrifuge approach will depend on the ability to measure local saturations in the rock during an experiment. Measuring saturation profiles in flooding experiments is almost standard practice; profile measurements for centrifuge experiments are uncommon (Chardaire-Riviere et al., 1992).

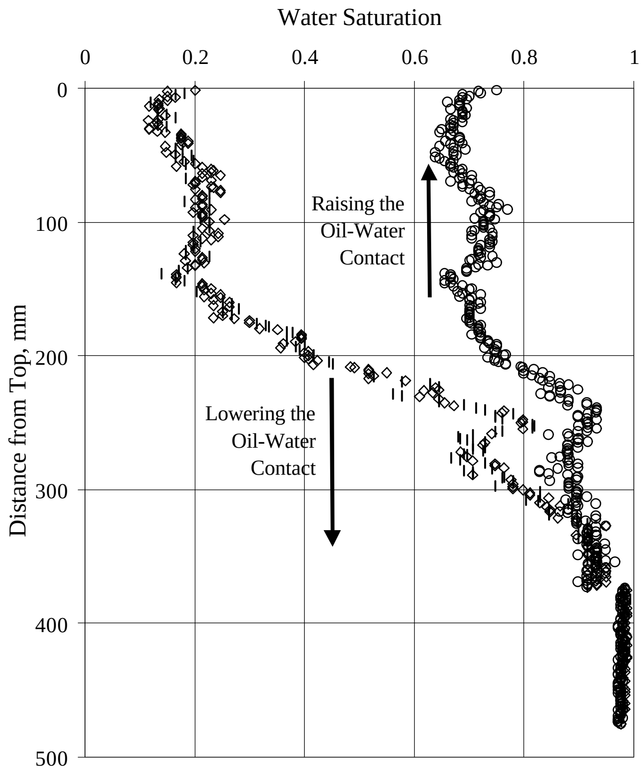

Figure 9. Saturation profiles for lowering and raising the oil-water contact in 70-100 mesh glass beads.

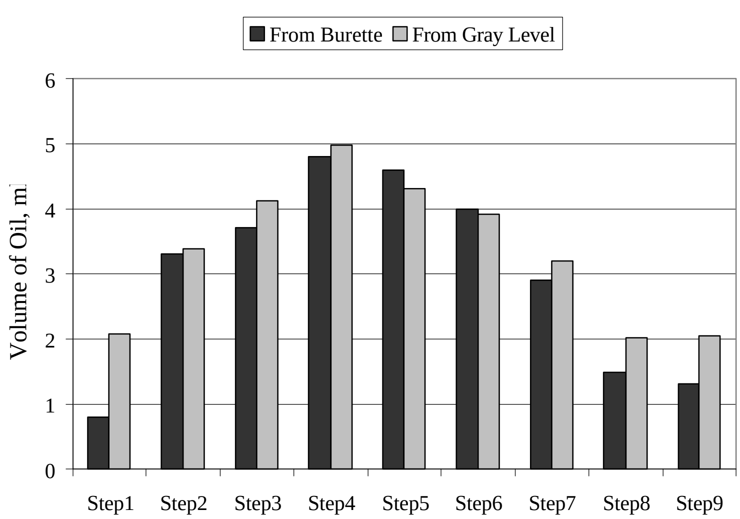

Figure 10. Material balance results for 70-100 mesh glass beads.

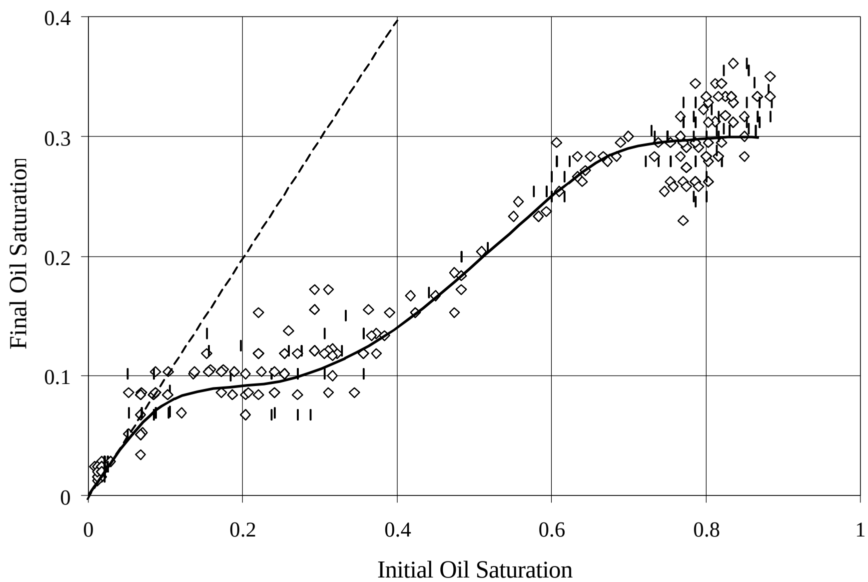

Figure 11. Trapped oil relationship from a cross-plot of profiles in Figure 9. The solid line shows the approximate trend of the data – it is not a fit line. The dashed line is the "45 degree" line.

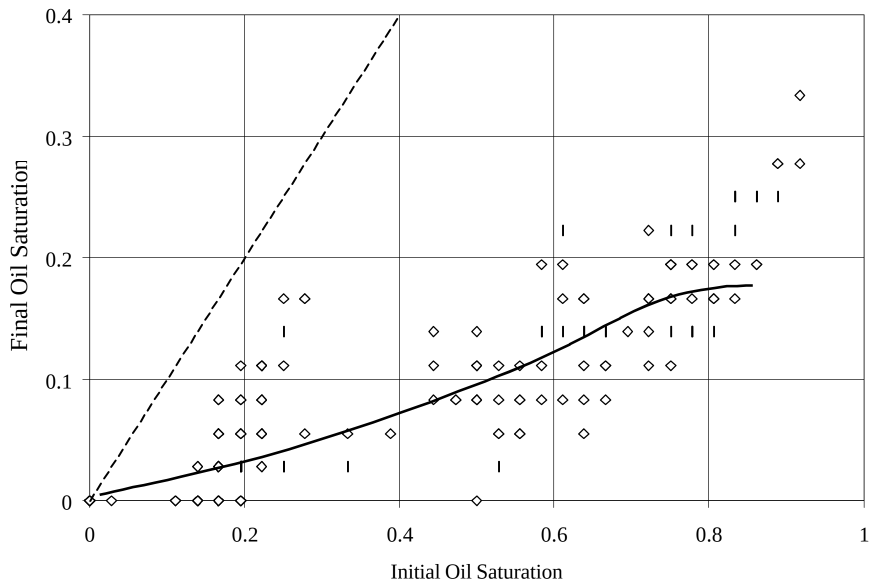

Figure 12. Trapped oil relationship from cross-plot of saturation profiles for an experiment with 20-40 mesh sand. The solid line shows the approximate trend of the data – it is not a fit line. The dashed line is the "45 degree" line.

The profiles for centrifuge experiments could be measured with the video method described above, as implemented by Al-Omair and Christiansen (1998) and Al-Modhi and Christiansen (1998). Researchers in France have used acoustic methods for measuring local saturations in a centrifuge experiment (Chardaire-Riviere et al., 1992). It would also be possible to measure local saturations by quickly removing a sample for CT (Computer Tomographic) Imaging or MR (Magnetic Resonant) Imaging, and then returning the sample to the centrifuge. However, removing and returning a sample during a centrifuge experiment could impart some undesired saturation history on the sample.

In addition to trapped oil relationships, relative permeabilities for reduced initial oil saturations in the transition zone are also needed for numerical simulation. Relative permeabilities could possibly be obtained from history matching (with a numerical simulator modified as suggested by Fanchi et al., 1999) the evolution of saturation profiles in a laboratory test. For centrifuge experiments, the evolving saturation profiles could be obtained as described by Al-Omair and Christiansen (1998) and Al-Modhi and Christiansen (1998). The centrifuge experimental design of Bolas and Torsaeter (1995) and Oyno and Torsaeter (1990) could be very useful for studies of saturation profiles for sequential drainage and imbibition.

The trapped oil relationship could be measured in a controlled manner with porous-plate methods. However, this approach would be very time consuming. It is desirable to attempt to recover relative permeability and capillary pressure information from these experiments as well as the trapped oil relationship.

Need for Reservoir Charging History

While the laboratory data substantiate the need for a trapped oil relationship for modeling of recovery from reservoirs with large transition zones, there remains the challenge of determining the saturation history and current status of the transition zone in any given reservoir so that the appropriate drainage or imbibition data can be applied. (It is important to recognize that "large" does not necessarily mean large in height. The transition zone could be short but spread over a large area, creating a large transition zone volume. See Heymans, 1997.) Some general considerations of the saturation status of hydrocarbon shows are described by Showalter and Hess (1982).

The transition zone in a particular reservoir could reflect a wide variety of hydrocarbon saturation histories. The simplest possible saturation history is drainage of water from the formation as it was charged with oil. But, the history of the transition zone may also reflect movement of oil caused by compression of the formation during burial, or by leaks of hydrocarbons through the reservoir seal if its threshold pressure is exceeded. In another scenario, folding and faulting of an oil-charged stratigraphic trap could allow oil to charge porous and permeable formation below the stratigraphic trap. Methods for determining the top and base of transition zones that have undergone this type of migration history are described by Heymans (1998).

Comparing the observed saturation profile in a reservoir with that predicted from drainage and imbibition capillary pressure measurements is one possible route to determining the saturation history. To compare laboratory results with field results, one must account for reservoir heterogeneity and one must know the elevation at which water-oil capillary pressure is zero. The variations of saturation in a heterogeneous reservoir with changing permeabilities and capillary pressure relationships must be properly analyzed. With data from an RFT (Repeat Formation Tester) tool, the elevation of zero capillary pressure in the reservoir can be estimated. The RFT information can be used also to calculate the capillary pressure at any reservoir elevation. For additional discussion, see Heymans (1998).

Integration of geologic information on burial history with reservoir saturations may lead to a correct picture of the saturation history. Hindle (1997) describes a method for modeling in 3D the history of hydrocarbon migration paths along seals. Craig (1990) describes a hydrocarbon migration path in New Mexico and West Texas as much as 100 miles in length. A reservoir at the end of that trek was charged with hydrocarbon that had spilled under the closures of downdip reservoirs.

As introduced above, a wide variety of transition zone movements can be imagined. So, there is a need to determine just what has led to the current transition zone saturation profile for any particular reservoir while embarking on evaluations of oil mobility in transition zones.

Conclusions

1. Conventional methods of reservoir engineering ignore potential hydrocarbon recovery from transition zones because residual oil saturation is considered constant, independent of initial oil saturation.
2. The literature and our experimental results indicate residual oil saturation depends on initial oil saturation, as summarized in trapped oil relationships. Relative permeabilities will also vary with initial oil saturation.
3. Oil can be recovered by waterflooding when initial oil saturation is lower than conventionally measured residual oil saturation.
4. For estimating recovery of oil from a transition zone, a trapped oil relationship is essential.
5. While there are reports of trapped gas relationships in the literature, there are few reports of trapped oil relationships. And, there are far fewer, if any, discussions in the literature of the dependence of relative permeabilities on initial oil saturation.
6. More core analysis is needed to specify rock-fluid properties for estimating recovery from reservoirs with large transition zones.
7. It is likely that trapped hydrocarbon relationships and their respective relative permeabilities can be obtained with centrifuge technology.
8. Trapped oil measurements with core can help to determine the lowest elevation within a transition zone at which oil can be produced.
9. A geologic model and history of hydrocarbon migration into a reservoir can be useful for understanding saturation distributions and for estimating hydrocarbon mobility in a transition zone.

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