IN SITU MEASUREMENT OF RESIDUAL OIL SATURATION

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INTRODUCTION

The accurate determination of residual oil saturation is of critical importance in evaluating the feasibility of applying an enhanced recovery process in a specific reservoir. The economics of the new improved recovery processes are extremely sensitive to the residual oil saturation in place at the beginning of the project and to the conformance expected to be achieved within the project area. This means that both the amount and the distribution of oil remaining in place must be determined to adequately evaluate the potential of the venture.

The only accurate means of determining the residual oil saturation is to measure it in situ within the reservoir zone of interest. In recent years, several methods have been developed to provide this measurement, including analyses of cores cut with a pressure core barrel, various advanced logging techniques, and the single-well tracer test. Each method has certain advantages and limitations, but field experience has shown that some methods are clearly superior to others. However, for some reservoir situations, one method may not provide all the information required to completely define the distribution and amount of remaining oil. These cases might require the application of two or more methods combined with an analysis of all available reservoir data.

This paper will briefly summarize several procedures for determining residual oil saturation and, as pertinent, outline the advantages and limitations of each technique. The single-well tracer method will be described in more detail in terms of two recent field applications.

CONVENTIONAL METHODS FOR ESTIMATING RESIDUAL OIL SATURATION

Traditionally, several methods have been used to *estimate* the residual oil saturation remaining in a reservoir near the end of waterflood; these are the material balance calculation, waterflood calculations based on relative permeability data, and the analysis of saturations in as-received conventional cores. These methods provide merely an approximation of the amount of remaining oil; but results from these methods can sometimes be correlated with more accurate, direct measurement techniques to evaluate the overall distribution of oil remaining in place.

Material Balance Method

This well-known method can be used to estimate the total amount of oil remaining in the reservoir at any stage of depletion. The average remaining oil saturation is calculated from the difference between the volume of oil initially present at discovery and the total volume of oil produced (accounting for pressure changes and shrinkage). The accuracy of this estimate is obviously dependent upon knowledge of reservoir limits, porosity, connate water saturation, and production history. For very old reservoirs, the quality of these data are frequently poor. Even when good quality data are used, this method yields no information about the areal or vertical distribution of oil remaining within the reservoir. However, as will be shown later, the results of this method are still needed even though the true residual oil saturation in depleted zones has been determined by advanced techniques.

Analysis of Conventional Cores

Oil saturations measured in conventional cores as received from a well are of questionable accuracy.[1] Primary sources of error are: (1) flushing of oil by mud filtrate invasion during coring, and (2) expulsion of fluids from the core by gas that expands as the pressure is reduced during surfacing. The gas can be formed by liberation from a high-shrinkage oil, or it may be present in the formation as a free phase. At best, oil saturations measured in cores retrieved in a conventional barrel indicate a lower limit to the possible oil saturation residing in the cored interval.

Waterflood Calculations

Waterflood displacement calculations based on laboratory-measured relative permeability data are useful for estimating the oil saturation distribution behind a waterfront.[2] However, too many variables are unknown to trust that the predicted saturations actually represent the in situ oil distribution in a water-depleted zone. For example, because of reservoir heterogeneities and unknown conformance factors, the throughput of water and oil at any point can seldom be determined. There is always the additional question of whether the core samples used in the measurement of the relative permeabilities are truly representative of rock present throughout the reservoir zone. Further, unknown factors such as gravity drainage or capillary imbibition, not usually accounted for in displacement calculations, may significantly change recovery over that predicted.

ADVANCED MEASUREMENT METHODS

Pressure Coring

The pressure core barrel represents an improvement over a conventional core barrel for obtaining representative samples of resident fluid saturations. This device is designed to prevent expulsion of fluids from the core by gas expansion during surfacing. It contains an assembly that seals the core within a pressure-retaining chamber prior to starting out of the hole. On the surface, the core and its fluid contents are frozen prior to releasing pressure on the core barrel. The cores are kept frozen until they are analyzed in the laboratory. Hagedorn and Blackwell have described the design of the device, the procedures for cutting and analyzing the cores, and the results obtained in several reservoirs.[1] Field applications to determine residual oil saturation have also been reported by other investigators.[3-6] This method has the advantage of providing a vertical profile of oil saturation, which can be very important in highly stratified intervals where vertical conformance may be poor. However, because of the mechanical difficulty in obtaining a good seal in the presence of rock debris, field experience has indicated that there is only a 50 to 80 percent probability of obtaining a sample without losing pressure.

If mud filtrate invades more than about 10 to 15 percent of the core volume, significant uncertainty is introduced into the saturation data even if pressure is retained. For most types of formation rock, mud filtrate invasion can be maintained within acceptable levels by using a properly formulated mud and exercising close control on the pressure overbalance and penetration rate during coring.

Pressure coring can be very expensive if a well must be drilled only to obtain saturation data. However, it is usually employed while drilling wells for further field development. It then represents only a modest incremental expense over the drilling and completion cost.

Log-Inject-Log Procedure

Several investigators have described the use of pulsed neutron capture logging in a log-inject-log procedure for measuring residual oil saturation.[4,6,7,8] In this procedure, the formation interval of interest is logged twice. The first log provides a response from the formation rock, residual oil, and formation brine. Then a bank of water having a different salinity from the formation water is injected to uniformly displace the formation water, and the interval is logged again. The difference in thermal neutron decay response between the two logs can be related to the product of porosity times water saturation, ϕS_w, since the properties of the formation rock and residual oil remain unchanged. If porosity can be measured by an independent method, the residual oil saturation can be computed. In principle, the procedure can give an accurate vertical profile of residual oil saturation.[7,8] However, field experience has shown that the method can be subject to several sources of error.

The radius of investigation of the logging tool is

less than two feet. If the formation brine is not uniformly displaced by the injected water over this region, the procedure will indicate a higher oil saturation than is actually present.[8] In cased holes, uniform displacement may be difficult to achieve, since flow is through a limited number of perforations. Unless vertical permeability is good, flushing between perforations may be poor near the casing. This effect may be a primary reason why many log-inject-log measured residuals appear to be higher than those reasonably expected to exist within the interval tested. Other sources of uncertainty are borehole effects and possible local stripping of oil by injected water.[8,9] Because irregular borehole configurations might be formed by washouts from sand production or formation heaving during production, it has been recommended that only newly perforated intervals be tested.[8] This eliminates as test candidates most existing wells in older fields.

Considering the possible uncertainties in the pulsed neutron capture measurement of ϕS_w and the additional uncertainty in ϕ (from a different measurement), the probable uncertainty in residual oil saturation is ±5 percent pore volume or greater.

Other Logging Techniques

Robinson, et al.,[5] have reported the use of the nuclear magnetism log in a log-inject-log procedure for measuring residual oil. It is subject to uncertainties similar to those mentioned above for other log-inject-log methods.

The carbon-oxygen (C/O) log is a promising technique that does not require the log-inject-log procedure.[10] It can be run in cased holes (perforated or unperforated) or in open holes. The absolute accuracy of this tool for measuring residual oil saturation must still be determined by further field tests. However, it appears capable of measuring saturations within an accuracy of ±5 to ±10 percent pore volume. While it is still subject to irregular borehole effects, it is free of the uncertainty in fluid displacement associated with the log-inject-log procedure.

SINGLE-WELL TRACER TESTS

The theory and test procedure of the single-well tracer method for measuring residual oil saturation have been described previously by Tomich, et al.[11] Results from 11 field applications by Exxon were recently summarized by Bragg, et al.;[12] and Sheely[13] has described tests by CONOCO.

The test is conducted by injecting a bank of primary tracer dissolved in formation water into a reservoir zone that is at residual oil saturation. The primary tracer can be one of several organic acid esters having a significant solubility in both formation water and crude oil. The bank of primary tracer is displaced into the formation by injecting additional water that contains no primary tracer. All of the injected water is tagged with methanol, which serves as a nonreactive material balance tracer. Following injection, the well is shut in to allow partial hydrolysis of the ester to form an alcohol, which is the secondary tracer. Finally, the well is produced and the concentrations of all tracers are measured in the wellhead fluid.

Principles of chromatographic separation are used to relate the residual oil saturation to the difference in arrival times at the wellbore of the primary and secondary tracers. The alcohol (secondary tracer) is almost insoluble in oil, so it travels at a velocity nearly equal to the velocity of the formation water. The ester moves more slowly, since it is partially soluble in the oil and spends a portion of its flow time in the immobile oil phase. The interstitial velocity of each tracer i, $\overline{v_i}$, is related to the water velocity, $\overline{v_w}$, by:

$$\overline{v_i} = \frac{\overline{v_i}}{1 + \beta_i} \qquad (1)$$

where: $$\beta_i \equiv \frac{K_i S_{or}}{1 - S_{or}} \qquad (2)$$

K_i is the equilibrium distribution coefficient of tracer i, defined as the ratio of the tracer concentration in the oil phase to that in the water phase at equilibrium. S_{or} is the residual oil saturation as a fraction of pore volume. Expressions (1) and (2) are incorporated into a computer model that simulates flow of the tracers during the test. Since K_i for each tracer can be measured in the laboratory using reservoir brine and crude oil, the residual oil saturation can be determined by finding the value of S_{or} that gives the best match between predicted tracer concentration profiles and field data. Other parameters included in the simulation are dispersion coefficients, a reaction rate constant, and fluid drift

velocity. Fluid drift is caused by injection and production at wells other than the test well.

Application of this method will be illustrated by two field tests recently conducted for Exxon Co., U.S.A.

Test A

Test A was conducted in a South Texas reservoir zone that had been under a line-drive waterflood for about four years at the time of the test. The test well was located about 700 ft updip from an injection well, and it had watered-out 16 months prior to the test. An electric log of the test well is shown in Fig. 1. The formation had a porosity of 31%, an absolute permeability of 800 md, and a thickness of 37 ft. The reservoir temperature was 141°F.

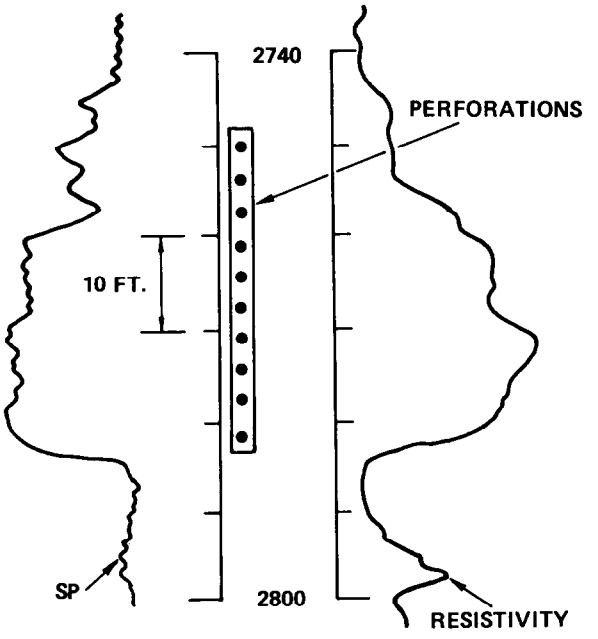

FIG. 1 ELECTRIC LOG OF WELL USED IN TEST A.

Prior to the test, the well was perforated over the entire interval, and then placed on production by gas lift. It produced fluid at a rate of 460 BPD with a 98.5% water cut, indicating that the zone was essentially at residual oil saturation. The test was then initiated by injecting 330 bbl of lease brine tagged with 0.51 volume percent ethyl acetate (the primary tracer). This was displaced into the formation by injecting an additional 770 bbl brine containing no ethyl acetate. All injected brine (1100 bbl) was tagged with 0.5 volume percent methanol, which served as a nonreacting material balance tracer. In addition, the last 100 bbl of brine was tagged with 0.5 volume percent isopropanol as a second material balance tracer. After injection, the well was shut in for 9.5 days to allow part of the ethyl acetate to react with formation water to form ethanol, the secondary tracer. The well was then placed on production, and the concentrations of all tracers were measured in the wellhead fluid as a function of produced volume. Tracer analysis was by gas chromatograph.

In the laboratory, the K-values of all tracers were determined over a range of concentration using samples of brine and crude oil from the test zone. The K-values for methanol, ethanol, and isopropanol were found to equal 0. The ethyl acetate K-value was determined as

$$K_{Et\,Ac} = \frac{3.0}{1 - 0.174\ C_{Ac}} \qquad (3)$$

where C_{Ac} is the brine-phase ethyl acetate concentration in volume percent.

Figures 2 and 3 show the concentration profiles for the tracers. The field-measured concentrations are shown as discrete points. Solid curves denote the concentration profiles predicted by a two-dimensional computer program used to simulate the test. For ethanol, broken curves indicate test sensitivity to residual oil saturation. The best fit of the data (S_{or} of 25% pore volume) was obtained by varying four parameters in the model: the reservoir fluid drift velocity, the dispersion coefficient constant, the reaction rate constant, and the residual oil saturation. Considering all sources of error, the uncertainty in the measured residual oil saturation was estimated to be ±2% pore volume.

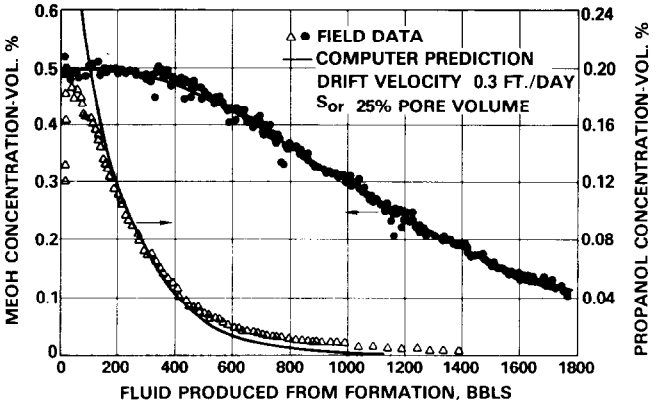

FIG. 2—METHANOL AND ISOPROPANOL CONCENTRATION PROFILES FROM TEST A.

For comparison, the residual oil saturation near the test well was calculated from waterflood displacement calculations. Calculated values ranged from 24 to 29% pore volume, depending upon the volume of injected water assumed to have passed through the zone. So, for this reservoir, waterflood displacement calculations based on relative permeability data were not in great error.

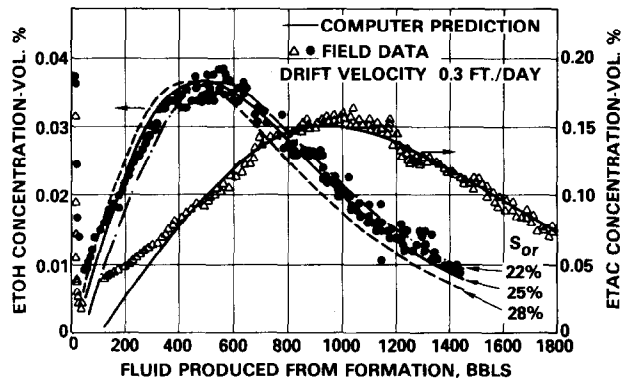

FIG. 3—ETHANOL AND ETHYL ACETATE CONCENTRATION PROFILES FROM TEST A.

Test B

Test B was conducted in a Gulf Coast Frio reservoir being evaluated for infill drilling or tertiary recovery potential. The test well had been watered-out for three years prior to testing. A log of the 37 ft-thick test zone is shown in Fig. 4. The formation had a porosity of 25%, a permeability of 1000 md, and a temperature of 172°F.

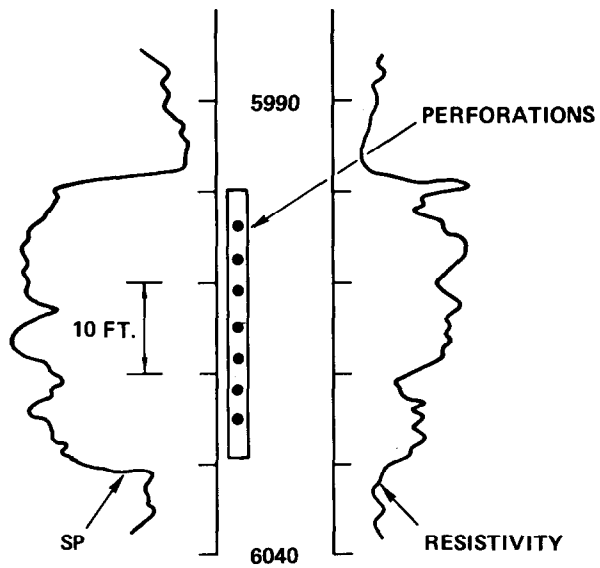

FIG. 4 — ELECTRIC LOG OF WELL USED IN TEST B.

In this test, 400 bbl of brine containing 0.9 volume percent ethyl acetate was first injected, followed by 1200 bbl of brine containing no acetate. All injected brine contained 0.5 volume percent methanol as a material balance tracer. (Here $K_{EtAc} = 8.2$; alcohol K-values = 0.) After a shut-in period of 10.5 days, the well was produced by gas lift, and the concentrations of all tracers in the produced fluid were measured. The concentration profiles of the methanol, ethyl alcohol, and unreacted ethyl acetate are shown in Figs. 5 and 6. An excellent agreement between predicted and measured profiles was obtained for a residual oil saturation of 12% pore volume. The uncertainty in the measured oil saturation is less than ±1.5 percent pore volume, since profiles for 10.5 and 13.5% would bracket the measured profile by a margin exceeding the uncertainty in experimental data.

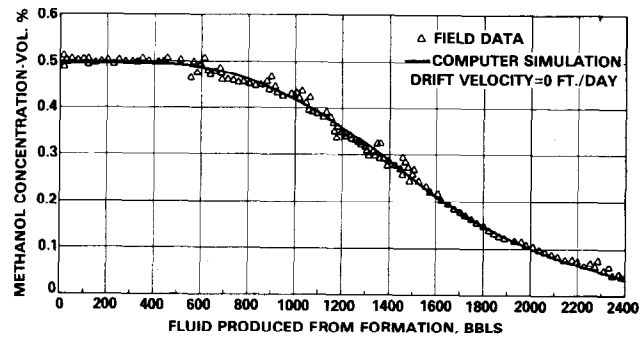

FIG. 5 — METHANOL CONCENTRATION PROFILE FROM FROM TEST B.

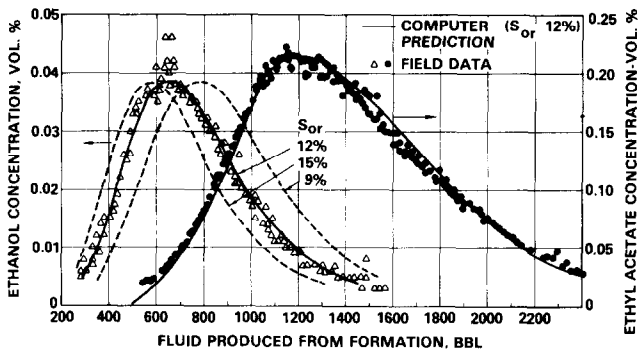

FIG. 6—ETHANOL AND ETHYL ACETATE PROFILES FROM TEST B.

For this reservoir, the residual oil saturation predicted by one-dimensional waterflood displacement calculations was several percent higher than the measured value of 12 ± 1.5 percent. It is

therefore believed that an unexpected factor such as gravity drainage may be aiding recovery.

The tracer test-measured residual oil saturation was used to determine the true displacement efficiency in the reservoir. Based on this displacement efficiency and an observed overall recovery efficiency of 73.3% in the water-invaded region (by material balance), a waterflood conformance of 87.3% was determined. These results indicate that little potential exists in this reservoir for either infill drilling or tertiary recovery, since conformance is relatively high and the residual low.

Advantages and Limitations of the Tracer Method

The single-well tracer test investigates a sample of reservoir pore volume of several hundred or several thousand barrels. It therefore provides a far larger sample than coring or logging methods. The test measures a permeability-thickness weighted average value of residual oil saturation in the waterflooded portion of the interval tested. It does account for different residual oil saturations in strata of different permeabilities, but it cannot reveal the vertical distribution of residual oil. When that is important, another method such as pressure coring or logging can be used in addition to the tracer test to obtain the best overall evaluation of residual oil saturation. Like the log-inject-log procedures, the tracer test should not be run in a fractured well since the true flow profile around the test well cannot be modeled.

TABLE 1 — SUMMARY OF RESERVOIR PROPERTIES AND TEST RESULTS FOR ELEVEN SINGLE-WELL TRACER TESTS CONDUCTED BY EXXON

Parameter	Range
Formation Type	Sandstone, Limestone
Formation Porosity, %	10 -35
Formation Permeability, md	50 - 1000
Formation Thickness, ft	17 - 72
Water Salinity, ppm total solids	4000 - 100,000
Artificial Lift Method	Gas lift, rod pump, Submersible electric pump
Reservoir Temperature, ^{o}F	80 - 210
S_{or}, % Pore Volume	10 - 25
Fluid Drift Velocity, ft/D	0.0 - 2.0
Uncertainty in S_{or}, % Pore Volume	± 1 to ± 5

Field tests have demonstrated that the tracer method provides a reliable and sensitive measure of residual oil saturation. In eleven field tests by Exxon,[12] the uncertainty in the measured residual oil saturation ranged from ± 1 to ± 5 percent pore volume. The uncertainty was greater for tests run in the presence of high reservoir fluid drift. Table 1 summarizes Exxon's tracer test experience.

CONCLUSIONS

1. The single-well tracer method provides an accurate measure of the average residual oil saturation in water-swept reservoir zones. Since it is not sensitive to local wellbore irregularities, the test can be conducted in almost any watered-out well that has not been fractured.
2. For reservoir situations where the vertical distribution of residual oil saturation must be determined in addition to the average value, pressure coring or logging methods should be used in conjunction with the tracer method.

NOMENCLATURE

K_i = equilibrium distribution coefficient for tracer component i, or the ratio of the tracer concentration in the oil phase to its concentration in the water phase at equilibrium
S_{or} = residual oil saturation
S_w = water saturation, fraction of pore volume
$\vec{v}_i$ = local velocity of tracer component i
$\vec{v}_w$ = local interstitial velocity of water
β_i = constant defined by Eq. (2) in text
ϕ = porosity, fraction

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