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The Effect of Wettability on Estimation of Reserves

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ABSTRACT

Estimations of reserves, especially by the volumetric method, is usually undertaken assuming water-wet conditions. However, in South East Asia, some initial reserves estimates have been grossly overestimated. One of the reasons for this, particularly in carbonates reservoirs of this region, is the effect of different wettabilities. Reserves estimation is important at any stage in the production cycle, but in frontier regions such as in South East Asia where initial production costs can be very high, care must be taken. This wettability effect can manifest itself in the form of 100 % oil-wet or mixed or fractional wettability. Petrophysical data is of primary importance to the estimation of volumetric reserves, and an examination of different wettabilities on log and core results is undertaken. The effect of wettability on saturation exponent, cementation exponent and formation factor commonly overlooked until the reservoir production is mature. Capillary pressure and relative permeability can be changed quite substantially with different wetting phases, with subsequent influences on transition zone height, hydrocarbon-water contacts, producibility and residual oil saturation. These changes are discussed with examples from different reservoirs. Reserves estimation is also undertaken by decline curve analysis, material balance, and at times, reservoir simulation. The effects of different wettabilities on these methods of reserves estimation are examined and presented.

INTRODUCTION

Wettability is defined as:

"the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids". [1]

References and figures at end of paper.

The wettability of a fluid/rock system is an integral component of the distribution and behavior of fluids in the reservoir.

Commonly, when a porous medium of uniform wettability that contains at least two immiscible fluids, one of these can be considered as the wetting fluid. In oil bearing reservoirs, the two immiscible fluids are usually oil and water.

Thus, in a static system, or one that is in equilibrium, the wetting fluid will completely occupy the smallest pores and be in contact with a majority of the rock surface, if saturation is sufficiently high. The non-wetting fluid will tend to occupy the centers of the larger pores, and could form globules or "blobs" that extend over several pores [2] (Figure 1).

Many engineers and geologists still believe that all hydrocarbon-bearing reservoirs are strongly water-wet, and most basic reserves estimations are based upon this misconception.

Reservoirs that exhibit some oil-wet characteristics have been described in the literature for over 50 years[3,4,5,6].

For example, Treiber, Archer and Owens in 1972, examined samples from Canada, Iran, Colorado, New Mexico, North Dakota, Oklahoma, Texas, Wyoming and Utah, and determined that 66 percent of the reservoirs were oil-wet [7]. The authors have seen many examples of oil-wet characteristics in various parts of the world, especially in carbonates, although not exclusively.

However, as Anderson states in his excellent treatise[2,8,9,10,11,12] on wettability:

"the large percentage of reservoirs found to be oil-wet is less significant than the general indications that not all reservoirs are water-wet and that the reservoir wettability varies widely".[2]

DETERMINATION OF WETTABILITY

Historically, many different methods have been used to determine and measure wettability. These methods can be roughly subdivided into two : laboratory and in-situ. (see Table 1)

A full description of **laboratory methods** is outside the scope of this discussion, but is undertaken in the series by Anderson.[2]

In-situ methods are more qualitative, and are often site-specific. Very few comparisons between laboratory and in-situ methods have been published, and should be undertaken in a particular reservoir if there is a discrepancy in observed behavior that can be attributed to wettability.

Use of Formation Pressure Data

The application of vertical pressure profiles with the use of high resolution wireline formation testing tools to determine wettability in both oil and gas reservoirs has been described by Desbrahdes et al.[13,14]

Desbrandes claims that the shape of a pressure gradient curve, with sufficient vertical resolution, can indicate qualitatively the wettability of a particular reservoir. If the vertical distance between the free water level and the movable fluid level, permeability, porosity, and fluid interfacial tension are known, Desbrandes states that an average wettability can be determined for both oil and gas reservoirs.

Use of Wireline Log Data

A proposed in-situ method that has not received much exposure is utilizing the difference between flushed-zone and non-invaded resistivities.

The fundamental equation for evaluation of hydrocarbon saturation is the empirically derived Archie[15] equation:

$$S_w = \left(\frac{a \times R_w}{\varphi^m \times R_t}\right)^{1/n} \quad \dots\dots\dots\dots\dots\dots \quad (1)$$

where :

S_w = brine saturation in the porous medium
R_t = resistivity of the porous medium
R_w = resistivity of the 100% brine-saturated formation
n = Archie saturation exponent (commonly $n = 2$)
φ = porosity
m = cementation (porosity) exponent
a = constant (commonly $a = 1$)

With $F = \frac{a}{\varphi^m}$, modifying the Archie equation, in a water-wet reservoir,

in the non-invaded zone

$$R_t = F \times \frac{R_w}{S_w{}^n} \quad \dots\dots\dots\dots\dots \quad (2)$$

and in the flushed zone:

$$R_{xo} = F \times \frac{R_{mf}}{S_{xo}{}^n} \quad \dots\dots\dots\dots\dots \quad (3)$$

It is assumed that the fluids contained in the invaded zone are mud filtrate saturation (S_{mf}), interstitial water (S_{wir}), and residual oil(S_{or}).

If we compare the following two saturation profiles; the first assuming a water-wet system, and the second oil-wet (with $n = 2$).

Water-wet			Oil-wet		
S_{or}	=	10 %	S_{or}	=	40 %
S_{wir}	=	40 %	S_{wir}	=	10 %
S_{mf}	=	50 %	S_{mf}	=	50 %

$$R_{xo(ww)} = \frac{F \times R_{mf}}{0.9^2} \qquad R_{xo(ow)} = \frac{F \times R_{mf}}{0.6^2}$$

Thus in this case,

$$R_{xo(ow)} = 81/36\ R_{xo(ww)} = 2.25\ R_{xo(ww)}$$

In a zone with higher residual oil saturation (as is expected in most oil-wet reservoirs) resistivity of the flushed zone should be significantly higher than the "quick-look" transform of $R_{xo} = F \times R_{mf}$. If the formation factor, F, can be calculated from log analysis in the non-invaded zone, then S_{xo} and an approximate residual oil saturation can be estimated.

Also, utilizing an empirical method described by Pirson and Fraser,[16] if the R_{xo} value is checked with an F factor derived with a known porosity, and it is higher than expected, then a high residual saturation may be present, and possibly an oil-wet component.

Other "quick-look" methods that the authors have used to advantage are:

- calculation of very low water saturation (10 %) from log analysis
- presence of "shows" over a long interval (100 feet). (e.g. the authors have seen over a 500 feet interval that had extensive cuttings "shows", which after comprehensive testing proved to be water-bearing, and later core analysis indicated neutral to oil-wet)

ESTIMATION OF RESERVES

Original hydrocarbons-in-place and reserves are estimated by a number of different methods, depending upon the amount and type of data available. These methods can be divided into two major categories : static and dynamic.

Static methods are basically volumetrics, while dynamic methods include material balance, decline curve analysis, and numerical simulation.

The effect of wettability (in general, increasing oil-wet component) upon each of these methods will be discussed in turn.

Volumetrics

The basic equation for volumetric estimations of hydrocarbons-in-place is:

$$OOIP = \frac{C \times A \times h \times \varphi \times S_o}{FVF} \quad \ldots\ldots\ldots(4)$$

where:

OOIP = original oil in place , STB (S.T.m^3)
C = conversion constant , 7758, bbl/acre (10^6)
A = area of reservoir , acres (km^2)
h = thickness of net pay , ft (m)
φ = porosity , the decimal fraction of void space in the reservoir
S_o = oil saturation (fraction) = 1 - S_{wi}
S_{wi} = initial water saturaion (fraction)
FVF = formation volume factor , Res Bbl / STB (Res m^3 / S.T.m^3)

The variables that are most affected by wettability differences are oil **saturation** (S_o) and **net thickness** (h).

Oil saturation is usually determined by petrophysical methods (log and/or core analysis).

A number of investigators have documented the effect of wettability on the electrical properties of fluid saturated rocks. Most of these studies indicated that the saturation exponent increases as the system becomes more oil-wet.

The relative electrical resistivity of any rock is dependent on the cross-sectional area and the lengths of any conductive paths through the enclosed fluids. A rock that contains a fluid of a particular resistivity is higher than an equal volume of that fluid. This is because the non-conductive rock decreases the cross-sectional area, which is available for current flow, as well as increasing the length of the conducting paths.

This overall conductivity is even further reduced when hydrocarbons (which are non-conductive) are part of the fluid enclosed by the rock. The distribution and location of the different conductive and non-conductive fluids also affect the total resistivity of the rock-fluid system.Not only does wettability affect this fluid distribution, but saturation history is important. (i.e. by capillary effects as well as reduction of hydrocarbon saturation with production).

In a 100 % water-wet system at 100 % S_w, the brine is located on the rock surfaces as well as in all pores. As the oil saturations are increased, the oil is located in the middle of the larger pores. Even at the minimum brine saturation (S_{wir}) the brine is still continuous and can conduct current. Thus the only variations in resistivity is due to the difference in the cross-sectional area that is available for the conduction, rather than the increases in path length or discontinuous brine saturations.

In an oil-wet rock, the oil is distributed both in the pores and on the rock sufaces. At 100 % producible water (i.e. at S_{or} saturation), the conductive path is continuous with n approximately 2.

However, as the oil saturation increases, the brine becomes more discontinuous, until its ability to contribute to electrical conductivity is impaired. Both the cross-sectional area as well as the conductive paths are affected, with the Archie saturation exponent, n, increasing to 10 or more. Lewis [17] suggests that the effect of wettability on the cementation exponent is negligible, whilst the saturation exponent can be significantly different for different wettabili ties. If some of the rock is water-wet and some other sections are oil-wet (i.e. mixed wettability), this change in saturation exponent does not seem to be quite as large [18] (Figure 2).

Little work has been published on the effects of wettability on resistivity in the reservoir (i.e. outside the laboratory). Pirson and Fraser [16] discussed reservoirs that were believed to intermediate or oil-wet, where an "n" of about 3 was thought to be reasonable.

Another feature that is important is that hysteresis of the saturation exponent is large (32 %) for water-wet rocks between drainage and imbibition cycles, whereas this hysteresis is not as prominent in oil-wet cores.

These and other studies have shown that "n" in oil-wet rocks can be significantly higher than the commonly used 2. Lewis found a mean of 4.47 for oil-wet Berea cores.

Graham [19] used a reverse-wetting agent to change the wettability of water wet rock. He found an increase of resistivity of 100 % to 200 % in the cores with reversed wettability. He also confirmed this resistivity increase with field tests.

The formation factor, F, has not been shown to be greatly influenced by changes in wettability, nor has the cementation exponent, "m".

Thus large errors in water saturation could occur if the effects of wettability are not taken into account. For example for a particular case where:

φ = 20 %
R_t = 20 ohm-m
a = 1
m = 2
R_w = 0.1 ohm-m

then,

S_w	n
0.35	2
0.50	3
0.59	4
0.66	5
0.71	6
0.74	7
0.77	8
0.79	9
0.81	10

For a hypothetical field where:

A = 1000 acres
h = 10 feet
φ = 20%
R_t = 20 ohm-m
a = 1
m = 2
R_w = 0.1 ohm-m
FVF = 1.0

If we substitute into the volumetric formula (Equation 1-4), an OOIP of 10.1 million barrels was determined if a saturation exponent (n), of 2 were used, and only 6.4 million barrels if n = 4 (i.e. in an oil-wet reservoir). Thus, a 58 % error could result.

Thus, conventional log analysis is difficult, and very important in rocks that are other than 100% water-wet, as the Archie equation can give non-unique resistivities at the same saturation [20], as well as making significant changes to the saturation exponent, n.

Net thickness (sometimes called net pay) is also estimated by core and/or log analysis and constraints made to eliminate non-productive intervals. These constraints are commonly porosity, water saturation and reservoir quality. Again, the effect of wettability on the calculation of water saturation could be important in the choice of net pay constraints or "cut-offs".

Dynamic Reserves Estimation

The dynamic methods include material balance, decline curve analysis and numerical simulation.

Wettability allowances should not drastically affect results from decline curve analysis, although it is the authors' experience that an oil-wet reservoir is more likely to exhibit hyperbolic characteristics.

The rapid development and industry exceptance of numerical simulation has resulted in simulators becoming a very widely used reservoir engineering tool. In many cases, the results of a simulation study are used as the basis for booking reserves. This practice yields satisfactory reserve estimates if sufficient rock data, fluid data and production data are available to achieve a realistic history match. However, in many cases the preliminary studies are carried out very early in the life of the reservoir. In these cases, it is often necessary for the reservoir engineer to use analogy to other reservoirs when gathering the input data for the simulation. The characteristics of the relative permeability curves used in the reservoir simulation can have a significant effect on the calculated ultimate recovery.

To illustrate this situation, two simulation studies were performed on a 5-spot pattern waterflood with uniform rock and fluid properties. The fluid properties were taken from the Second Comparative Solution Project of SPE [21]. The porosity and permeability were the same as layer four in the test case. The relative permeability curves of a prefentially water-wet rock and a prefentially oil-wet rock were used for the two cases. These relative permeability curves, which were derived from Craig[1] are illustrated in Figures 3 and 4.

The oil-wet curve has typical characteristics of low irreducible water saturation, high residual oil saturation, and a very high terminal K_{rw}. The curves intersect at less than a 50 % water saturation. Conversely, the water-wet relative permeability curve has characteristics of a moderate irreducible water saturation, low residual oil saturation and a low terminal K_{rw}, and have a curve cross-over point greater than 50 %. All of these characteristics must be reviewed when attempting to identify the wetting phase in the reservoirs. Relative permeability curves of different wettabilities are shown in Figure 5. These curves show how the residual oil saturation increases as wettability changes from water-wet to oil wet. Further, this figure also shows that relative permeability to water increases while relative permeability to oil decreases as wettability changes to more oil-wet.

It is a common belief that high residual oil saturations are only found in low quality reservoirs or with viscous low gravity crudes. However, the authors have seen several examples of classic oil-wet relative permeability curves and production behavior in high quality reservoirs and low viscosity crudes.

The results of the 5-spot analysis are presented in Figure 6 and 7, and show that a difference in ultimate recovery of nine percent of the original oil in place at a 98% water cut will be calculated by changing the relative permeability curves. These results are very similar to curves presented by Owens and Archer [22]. The referenced authors carried out calculations on a 20 acre 5-spot water flood using areal sweep efficiencies and injectivities developed by Craig, et al [23] and Caudle and Witt[24].

These different ultimate recoveries could have a significant impact on the economics of a waterflood project and illustrate the importance of wettability on the results of a simulation study.

PRIMARY PRODUCTION PERFORMANCE

The magnitude of the effect wettability has on primary recovery is related to the dominant recovery mechanism in the reservoir. The impact of wettability on ultimate recovery is minimal in the case of a solution gas drive reservoir and increases to a maximum for a water drive reservoir.

The recovery efficiency of a solution gas drive reservoir in reservoir containing a low shrinkage crude oil is relatively insensitive to the wettability of the rock. However, this is not the case for a high shrinkage oil. In a typical oil-wet reservoir, the residual oil saturation can be greater than 30 percent. This has an impact on the recovery efficiency because it takes more stock tank barrels of oil to create the residual oil saturation in an oil-wet rock than in a water-wet rock. It is not uncommon for these factors to be overlooked when estimating reserves for solution gas drive reservoirs.

Many volumetric reservoirs contain bottom water which has a residual oil saturation. This oil can contribute to the system's energy as it contains solution gas which will evolve as the reservoir pressure decreases. This oil is immobile and thus cannot be produced in these circumstances, but the shrinkage associated with the gas coming out of solution could accelerate the pressure decline of the reservoir.

The major effects of wettability on ultimate oil recovery of a gas cap drive reservoir normally occur in combination with a water drive, or a waterflood. In this case, oil may be displaced into the original gas cap thereby creating a residual oil saturation. This could result in significant loss in ultimate recovery. This loss in reserves is at a maximum in an oil-wet rock because of the higher residual oil saturation.

The five spot waterflood discussed previously in this report can also be used to illustrate the effect that wettability has on the performance of a natural water drive. A water drive in a water wet reservoir will recover significantly more of the oil in place than will a similar water drive in an oil-wet reservoir. The lower recovery in an oil-wet reservoir is the result of the high residual oil saturations and the fact that oil-wet reservoirs normally exhibit high water cuts very early in their producing life.

The effect of high water cuts can have a significant effect on the operating economics of an oil field if there is a high cost associated with the disposal of the produced water. This can manifest itself further if the permeability of the reservoir is too low to allow the installation of high volume artificial lift equipment such as electrical submersible pumps or gas lift. In high productivity reservoirs the effect of high water cuts can often be overcome by significantly increasing the daily fluid production from the reservoir. However, this option does not exist in less prolific pools.

SECONDARY PRODUCTION PERFORMANCE

The effect of wettability on waterflood performance is well known and was reinforced by the simulation analysis. The water-wet reservoir recovers more oil in a shorter period of time than does an oil-wet reservoir. These facts become very important when attempting to determine the remaining producing life of a mature waterflood. This is a significant parameter when an operator is attempting to justify further produced water handling facilities in a waterflood.

TERTIARY PRODUCTION PERFORMANCE

Tertiary oil recovery projects such as hydrocarbon miscible floods and CO_2 miscible processes are often carried out in previously waterflooded or water-swept portions of the reservoir. The amount of residual oil which is available for recovery by a miscible process will dictate the success or failure of a project. It is imperative that the reservoir engineer use all the available resources to identify the the end points and shape of the relative permeability curves. Rock characteristics which resulted in an extremely profitable waterflood could produce a disastrous tertiary recovery project.

CONCLUSIONS

- Wettability can have a dramatic effect on the estimation of reserves from initial volumetrics to more detailed production performance predictions. Using common parameters for a water-wet reservoir in an oil-wet reservoir could lead to an over-estimation of oil-in-place and reserves of up to 50 %.

- If an oil-wet reservoir is suspected it is recommended that careful laboratory analysis is undertaken, with native state cores and suitable time periods.

- Wettability should be considered when designing and up grading production facilities.

- All of the wettability identifiers should be analyzed using various techniques prior to initiating a tertiary recovery project.

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Table 1 Wettability Measurement Methods

Laboratory	Quantitative	• Contact Angle • Imbibition and forced displacement (Amott) • US Bureau of Mines (USBM)
	Qualitative	• Imbibition rates • Flotation • Glass slide method • Relative permeability curves • Capillary Pressure curves • Dye absorption • Displacement capillary pressure • Nuclear magnetic resonance
In-situ		• Formation pressures • Wireline logging • Production performance

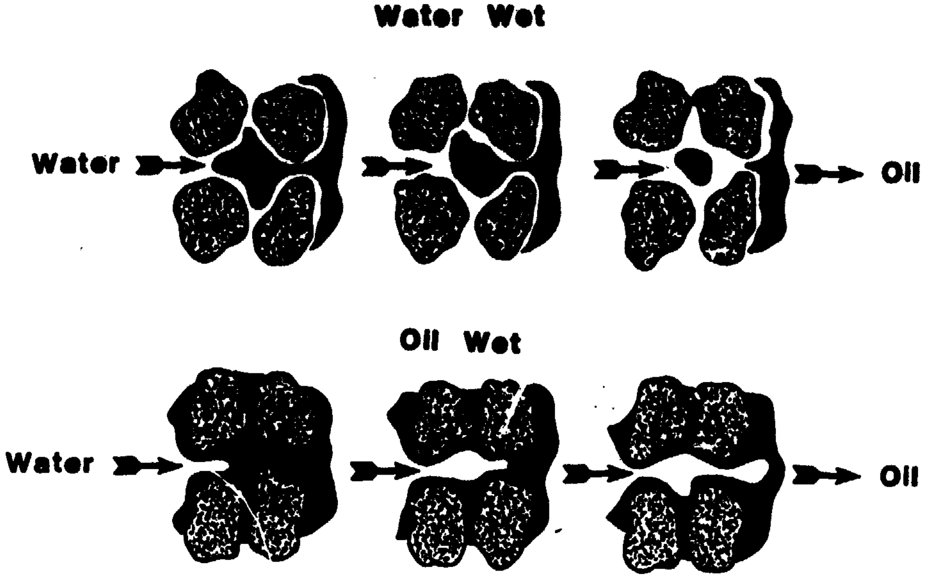

Fig. : 1 FLUID FLOW IN WATER - WET AND OIL - WET ROCK
(After : Ref. 25)

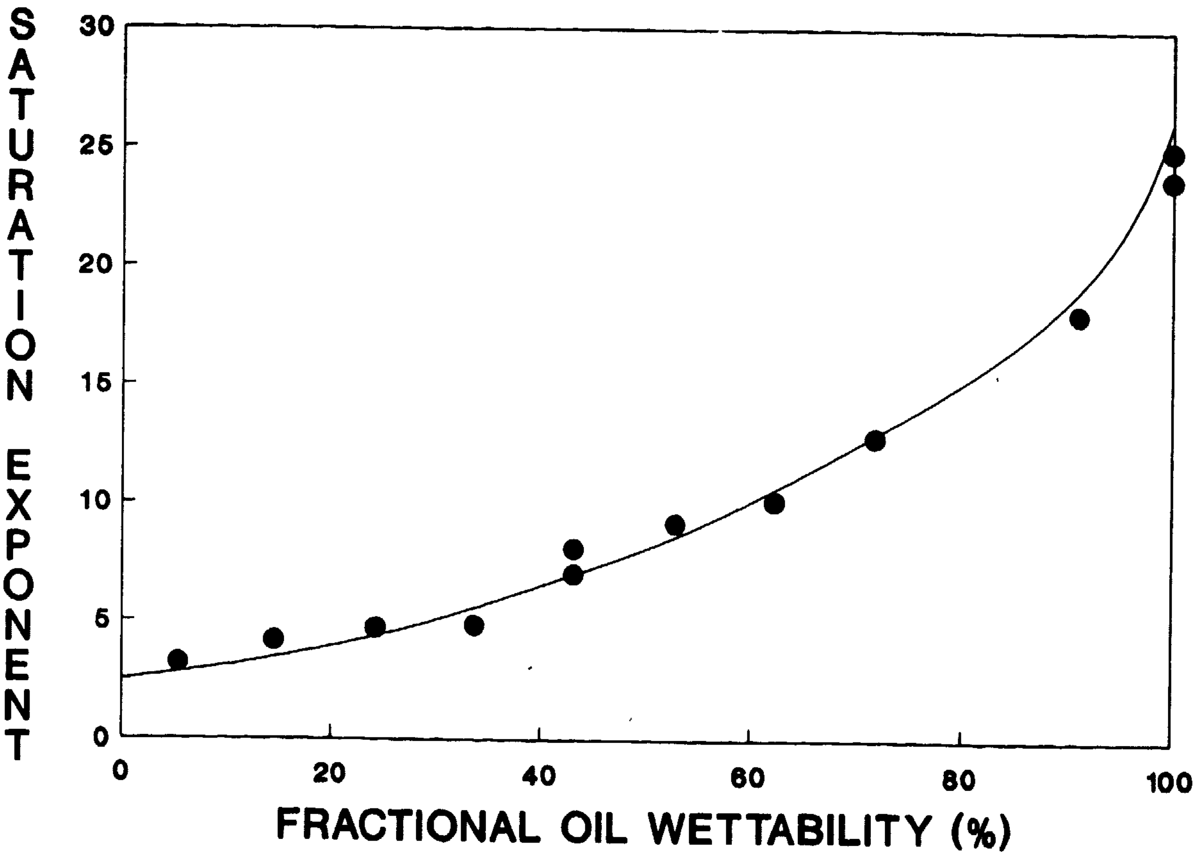

Fig.2:Saturation exponent vs wettability

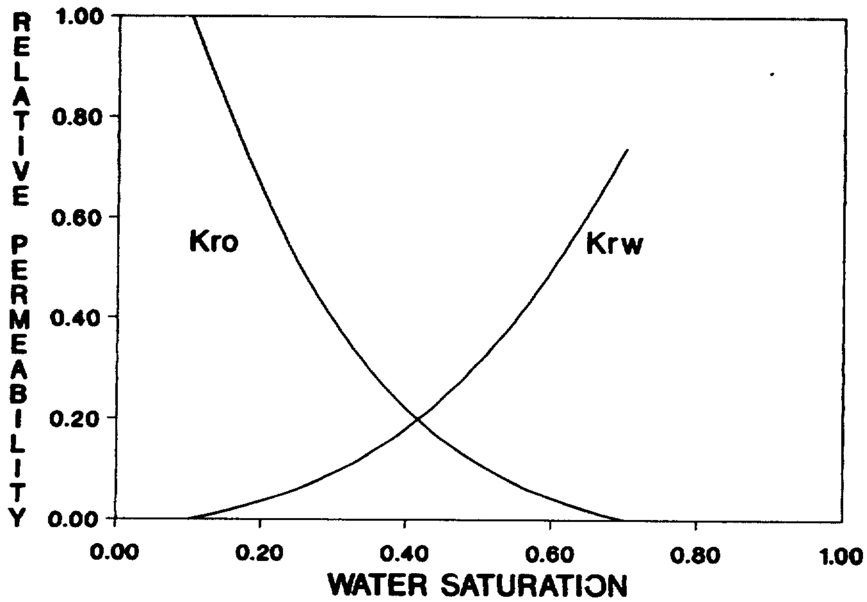

Fig. 3 Oil-wet relative permeability

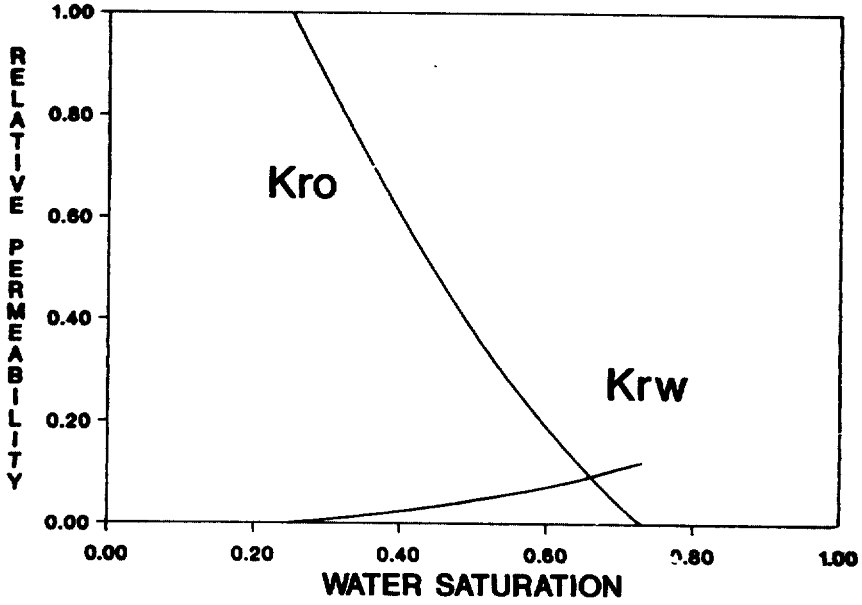

Fig. 4 Water-wet relative permeability

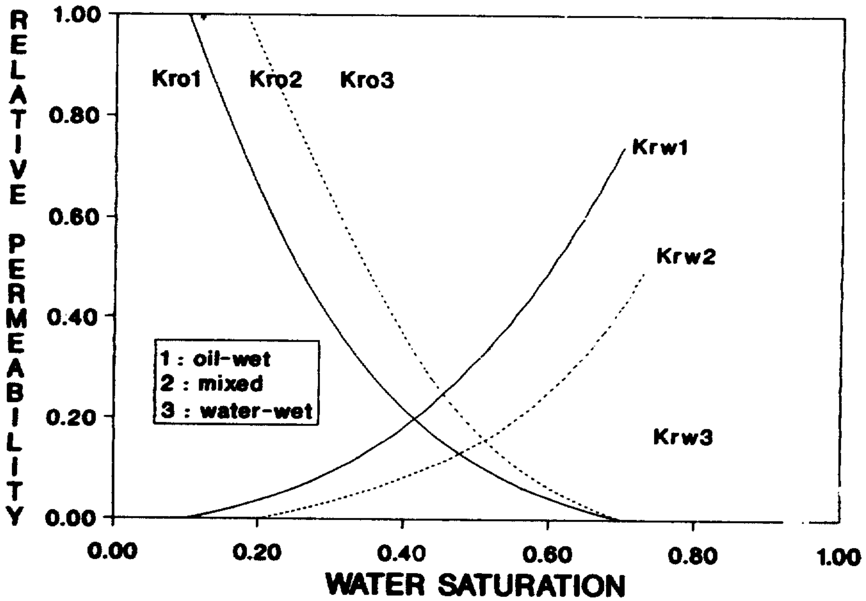

Fig. 5 Relative permeability curves

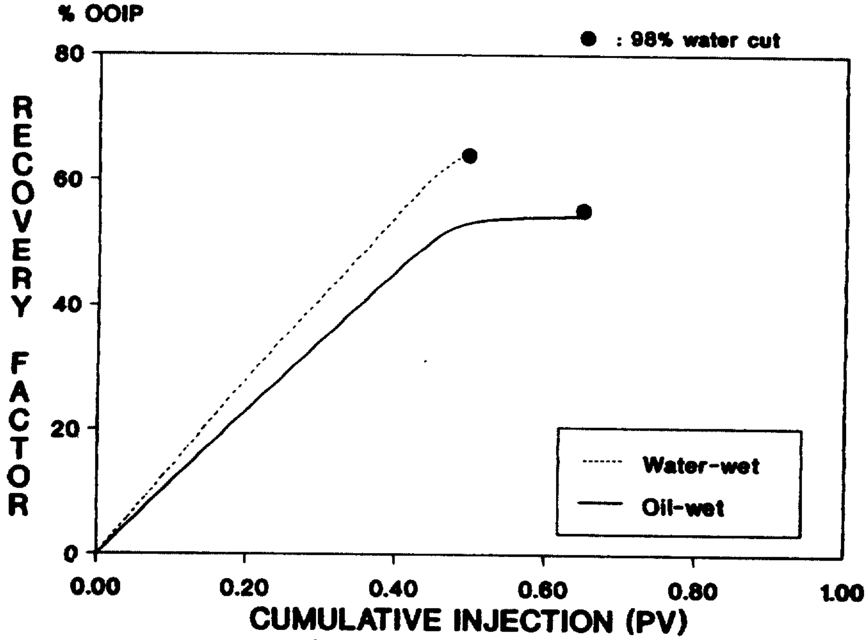

Fig. 6 Recovery factor vs injection

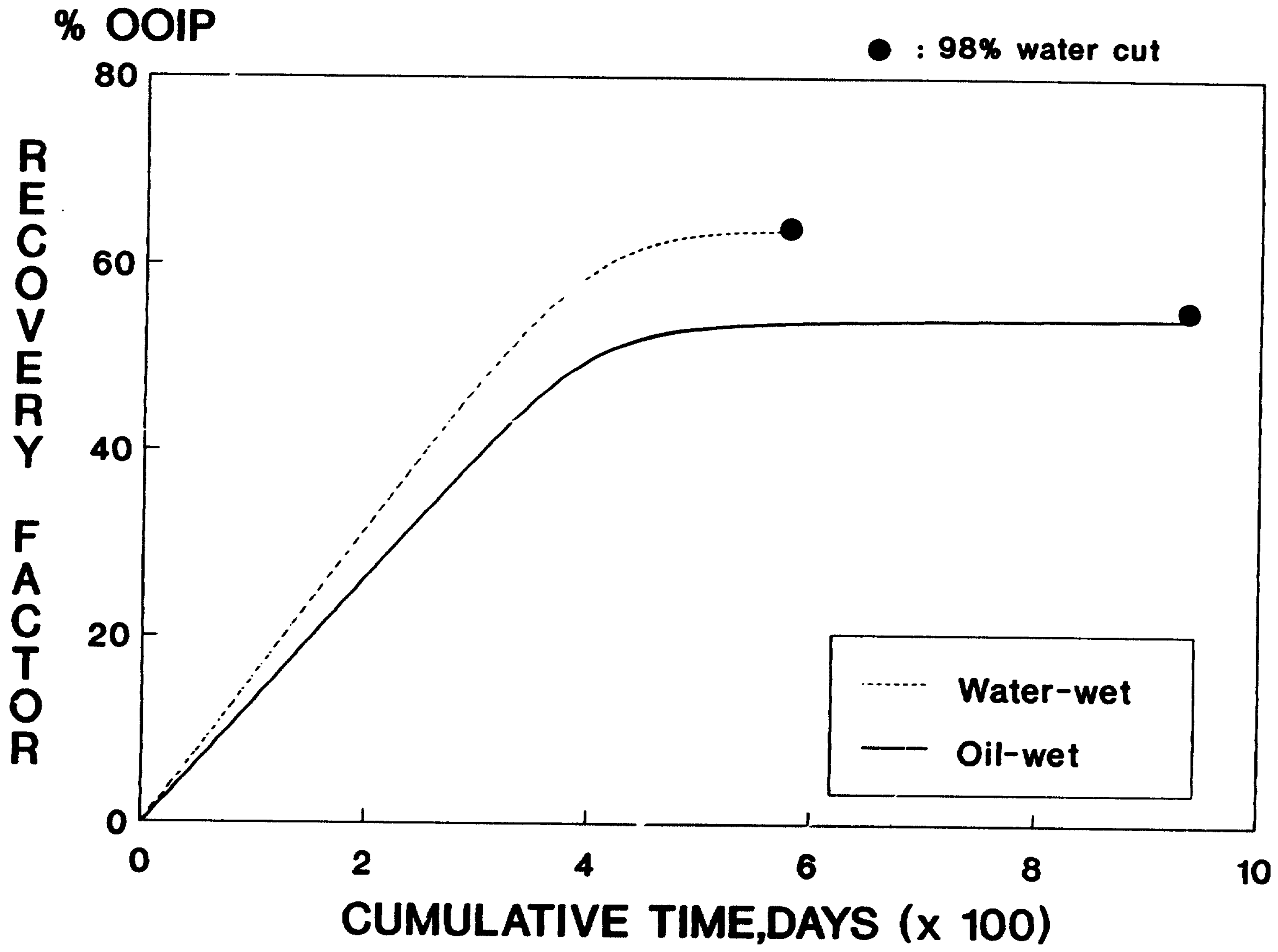

Fig. 7 Recovery factor vs time