RECONCILIATION OF CORE AND LOG RESIDUAL OIL SATURATION THROUGH APPLICATION OF IN-SITU SATURATION MONITORING

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ABSTRACT The residual oil saturation (Sor) of a North Sea sandstone reservoir has been measured by two different techniques. Log analysis of a zone swept by vertical water flow from the aquifer yielded a range of values. Carefully performed core analysis using in-situ saturation monitoring has provided an independent check on residual oil saturation. By examining petrophysical parameters, taking saturation hysteresis into account, reconciliation of log and core Sor has been achieved. Application of the results using a Land-type[1,2] approach to describe dependence of Sor on intitial oil saturation (Soi) furnishes high quality input data for reserves calculations and numerical reservoir simulation. In-situ monitoring of oil and water saturation within core samples was achieved through measuring the attenuation of X-rays. Water saturation (Sw) measurements accurate to 1-2 saturation units were obtained in 2mm contiguous slices down the length of the core over a 30 second scanning period. This detailed, real time saturation profile measurement can identify uneven and therefore unrepresentative initial water saturation (Swi) and Sor profiles. The technique can also identify instability in the flood front due to rock heterogeneities or viscous fingering. Since Sw measurement is made in-situ, it is inherently less prone to the errors suffered by traditional volumetric techniques. The accuracy of this residual oil saturation measurement therefore gives confidence in the values obtained and shows consistency with log-derived Sor.

INTRODUCTION

The calculation of hydrocarbon saturation in a reservoir from well log data requires the knowledge of the formation water resistivity (Rw) and two Archie parameters (assuming a=1) : the cementation factor (m) and the saturation exponent (n). Formation brine resistivity can be obtained from several sources, ranging from direct measurement, produced water samples to analogy with neighbouring field data. It can also be estimated using cross-plotted log data, either given the cementation factor or if a known aquifer of varying porosity can be assumed. The cementation exponent can be obtained using the same technique. Although laboratory measurements to obtain it are often of great value, a reliable value of m is found using log data if there is little mineralogical or pore morphological difference between the aquifer and the oil leg. The one rock electrical parameter which cannot be derived solely from log data is the saturation exponent.

The assumption that 'n' equals 2.00 can lead to significant error in the calculated hydrocarbon saturation. In addition, the assumption that a saturation exponent measured during the primary drainage cycle is the same as that measured during a different drainage or imbibition cycle can similarly lead to inaccurate estimation of Sw. Longeron (1990)[3] gives a thorough discussion of the literature relevant to the effect of saturation history on the Archie saturation exponent. No consensus seems to appear in the literature but it is evident from Longeron's work on sandstones that most probably, for a given water saturation, n is lower in the primary imbibition cycle than during the primary drainage cycle.

Conceptually, this makes sense. Consider the case of a water wet sandstone. It is generally accepted that pore throats are the major controlling factor for electrical resistivity in clean sandstones. In the primary drainage cycle, a significant proportion of the cross-section of the pore throat is taken up by non-conducting hydrocarbon. After imbibition, the water wet character of the system results in isolated, snapped-off residual hydrocarbon. This implies that the pore throat cross-section is likely to be 100 % water. The resistivity under such conditions would therefore be lower than that measured at the same water saturation on the primary drainage cycle. This will therefore result in a lower saturation exponent at residual hydrocarbon saturation.

This paper seeks to show the value of accurate core analysis as a tool for reservoir description. Too often core analysis results are 'normalised' to bring them into line with log analysis. This paper hopes to demonstrate that, given confidence in the core analysis data, the combination of core and log information can yield more about the reservoir than either on their own.

A well drilled in a producing field in the Central North Sea encountered a zone which had experienced water influx from the aquifer. Log analysis using long-established Archie parameters and brine resistivity resulted in a relatively low residual oil saturation. Relative permeability core data using rock material from the swept zone implied a higher value. Reconciliation has been achieved by recognising that it is better to examine the assumptions and techniques used in deriving each number, rather than assuming that the log analysis must be correct and the core data adjusted accordingly.

DESCRIPTION OF RESERVOIR

The subject field of this study is located in the Central North Sea, and contains a stratified reservoir of Palaeocene age. It has been producing close to its plateau rate for over 5 years. Recently a well was drilled which encountered a section of reservoir which had experienced vertical water influx from the aquifer, providing a rare opportunity to assess the residual oil saturation behind an advancing water front on a reservoir scale. The reservoir has been characterised thoroughly over the years since its discovery, and its petrophysical properties are well established.

In order to predict the behaviour of the reservoir accurately, representative rock relative permeability and residual oil saturation relationships should be determined. An examination of the data available for the field in question showed that these were uncertain due to the varying techniques used and the vintage of the Special Core Analysis data available. A new study using core from the subject well was commissioned to resolve the issue, employing recent advances in core analysis techniques.

The reservoir transition zone in the original, primary drainage condition is relatively thin (approximately 15 feet) but contains a significant proportion of the initial oil in place. For this reason, it was decided to obtain data that could furnish a Land[1,2] type correlation, relating initial to residual oil saturation. This would then allow the application of Sor data determined from one Swi to predict the value for different initial water saturations. To this end, samples of differing permeability would be chosen and a single capillary pressure used to attain Swi. After measurement of residual oil saturation, a single point modified[2] Land coefficient value can be determined from:

$$C = \frac{Soi}{Sor} - 1$$

LOG ANALYSIS

A standard complex lithology option is used to analyse the well logs from this field. The cementation factor has been established by both core analysis (at reservoir net overburden) and by Pickett[4] plots of data from below the field-wide oil-water contact. Formation brine resistivity is also well defined from produced water analysis and confirmed by a Pickett Plot using the cementation factor from Advanced Rock Properties measurements. The reservoir contains a succession of fairly clean sands separated by thin but laterally extensive sealing shales. The clay volume of the sands is calculated from a neutron-density cross plot and from the gamma ray response. The neutron-density data is also used to calculate the porosity. Water saturation is calculated using the Indonesian equation in conjunction with the established values of m and n. The routine log analysis for part of the subject well is shown in Figure 1. The original oil-water contact can clearly be seen, as can the swept and unswept zones. A saturation exponent of 1.98 was used and the residual oil saturation in the upper half of the swept zone is calculated to be 0.20.

In considering the relative permeability results, a log analysis Sor of 0.20 seems low. Even disregarding the actual Sor values from the water flood tests, the low end point Krw implies significant water wet behaviour. Such a system should have a relatively high residual oil saturation. Given the confidence in the core analysis data, the log interpretation was re-examined to see if any of the input data could be in error.

The cementation factor and brine resistivity data have been

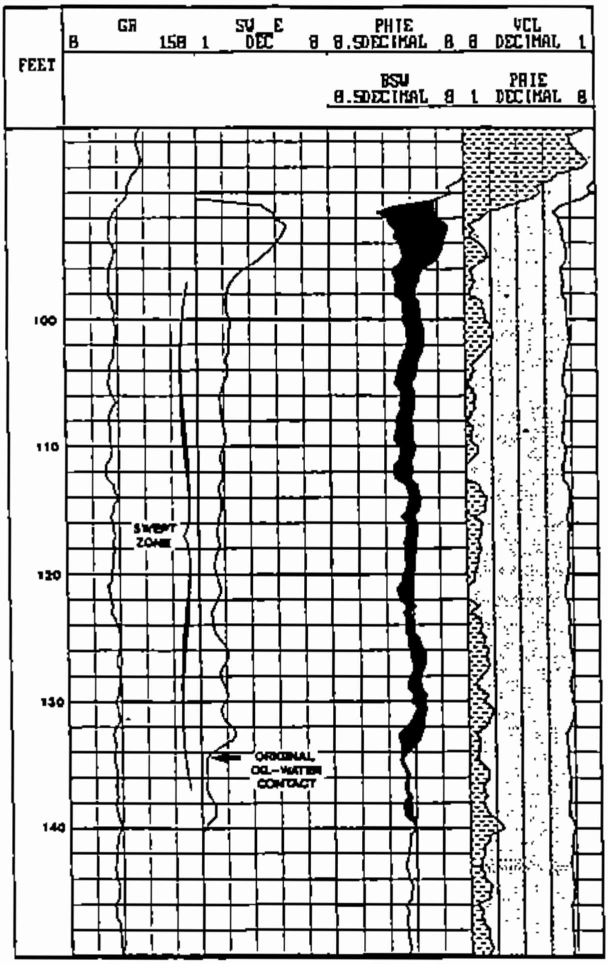


FIGURE 1 : WELL LOG DATA

consistently verified in each well drilled on the field. The raw log data and the subsequent environmental corrections were also verified. However, the same saturation exponent had been used for the oil zone and the swept zone. Saturation history had not been taken into account. Data from the literature (Longeron, 1990) suggests that the saturation exponent is lower on the primary imbibition cycle at Sor than on the primary drainage curve. The reduction seemed to be significant: n decreased from around 2.0 to 1.7 or less. It was decided to examine the effect of varying the saturation exponent on the calculated value of residual oil saturation. The results can be seen in Table 1. The residual oil saturation from core analysis is in the range 0.23 to 0.29, averaging 0.26. It is evident that invoking hysteresis in the saturation exponent accounts for the majority of the discrepancy between log and core values. The numbers do not coincide exactly, but the two data sets have been effectively reconciled.

Table 1: Effect of n on Sor

SATURATION EXPONENT	RESIDUAL OIL SATURATION
1.6	0.249
1.7	0.235
1.8	0.223
1.9	0.212
2.0	0.204

EXPERIMENTAL PROCEDURES

Mild Miscible Flush Cleaning and Brine Saturation

The preserved core plugs were individually flushed with 3 - 5 pore volumes of toluene at a flow rate of 10 cm^3/hr, and then soaked overnight with toluene filling the pore spaces. The toluene was replaced by flushing with 3 - 5 pore volumes of methanol at a flow rate of 10 cm^3/hr, and soaked overnight with methanol filling the pore spaces. The toluene and methanol flush and soak process was repeated. Methanol was replaced by flushing with synthetic formation brine and the core plugs were then soaked overnight with brine filling the pore spaces. The brine filled core plugs were pressure saturated to 60 bar for 4 hours, and then the pressure was slowly released. The saturated weight of each core plug was measured in air, and then measured whilst the core plug was immersed in brine.

X-ray Computerised Tomography (C.T.) Scanning

The samples were stored under brine in plastic containers and wrapped in bubble wrap plastic to prevent movement. Both longitudinal and transverse CT scans were taken for each sample. Four samples were identified with minimal heterogeneities present.

Desaturation to Initial Water Saturation (Swi) and Flush Saturation with Oil

The core plugs were placed in a porous plate cell housed in a temperature controlled environment and desaturated using humidified air as the displacing phase at a pressure of 15 psig. This pressure was selected to desaturate the samples to a water saturation representative of that above the original transition zone. A paste of diatomaceous earth, kaolinite and brine, separated from the core plug by a brine soaked filter pad was used to obtain good capillary contact with the porous plate. After a period of 21 days, to allow saturation equilibrium to be established, the partially saturated core plugs were removed from the cell and weighed. Saturation equilibrium was confirmed by monitoring the weight of brine effluent from the porous plate. The partially saturated core plugs were stored under matched viscosity oil (isopar). They were then individually loaded into hydrostatic core holders and flushed at 10 cm^3/hr with this oil and a back pressure of 200 psi, ensuring that the pressure drop in the oil phase (ΔP_{oil}) was less than or equal to 2/3 of the equivalent oil brine capillary pressure. This prevented water mobilisation.

Unsteady-State Waterflood Using In-Situ Saturation Monitoring by Attenuation of X-rays (SMAX™)

The analysis technique used to perform the unsteady state relative permeability experiment involved in-situ saturation monitoring by the attenuation of X-rays. In-situ saturation monitoring has been used throughout the industry for a number of years and its importance in relative permeability measurements is well documented. Heaviside et al used a system based upon gamma rays[5] although other workers have also used X-rays[6].

The SMAX technique relies upon obtaining a contrast between X-ray attenuation of two fluid phases present in the rock. In order to obtain a sufficiently high contrast between the attenuation of the two phases a dopant, such as iododecane for the oil phase, must be used. The linear track unit and X-ray equipment enable measurements to be taken in the form of counts every 2 mm along the sample (ie total counts recorded in a pre-set 'gate' time for each slice). The counts were converted to water saturations once the system had been calibrated at the end of the test sequence. Initially however, the data were presented in graphical form as log of the total counts per 2 mm slice versus time. Each 2mm slice took 1 second to scan.

The samples, at Swi, were loaded into a Hassler type core holder in the SMAX system, and a 400 psig net confining pressure applied. The samples were flushed at 10 cm^3/hr with doped matched viscosity oil. Flushing continued until a stable X-ray attenuation profile had been achieved. The permeability to oil at irreducible water saturation was determined. An X-ray scan was performed which indicated a uniform saturation profile along the sample. The unsteady state waterflood was carried out using a synthetic formation brine and a flow rate of 4 cm^3/hr. X-ray scanning was performed continuously in order to monitor changes in saturation due to oil production. The pressure differential was also logged continuously until oil production ceased. To minimise system compressibility the flood was run at a pore pressure of 200 psi. Once a stable final water saturation had been achieved, the flow rate was increased to 400 cm^3/hr (bump flood). This was done to evaluate oil mobility and hence water wetness of the core. Strongly water wet rocks show little oil production at the bump rate.

Calibration

Calibration requires the X-ray attenuation to be measured with the sample in-situ, 100 % saturated with X-ray blocking fluid, (in this case iododecane doped oil), and also when 100 % saturated with non X-ray blocking fluid, (undoped brine). At the end of the waterflood test, the sample was flush cleaned in-situ with methanol, followed by toluene. The toluene was displaced with the doped oil, and a scan made of the sample. This gave the attenuation value when the sample was at zero % Sw (C_{100}), 100 % doped fluid). Specific permeability to oil was then determined. The sample was flush cleaned with toluene followed by methanol. The methanol was displaced with synthetic formation brine (which is non X-ray blocking) until the pressure differential across the sample was stable indicating that the sample was 100 % water saturated. The sample was scanned to give a calibration point (C_0) with the sample 100 % water saturated, (zero % doped fluid). Specific permeability to brine was determined. Saturations are calculated as follows :

$$\mathbf{Sw = (Log\ (C_x) - Log\ (C_{100})) \;/\; (Log\ (C_0) - Log\ (C_{100}))}$$

Where: C_x represents intermediate counts.

RESULTS

Base data for samples A through D are given in Table 2 along with water flood end point data. Plots have been provided to illustrate the progress of the flood front and saturation profile throughout the flood for sample A. Data for this sample were consistent with that for the others.

Figure 2 shows the displacement of undoped oil with doped oil. The counts start at a high value and gradually decrease until a stable low value is established. The uniformity of the data confirmed the absence of any significant heterogeneities.

Relative Permeability Summary

Sample ID	Breakthrough	After 1 Pv	End	End
A			Flood	Bump
Kw	49	106	180	350*
Krw	0.04	0.09	0.15	0.29*
Sw Avg.	0.69	0.72	0.74	0.79
Sor	0.31	0.28	0.26	0.21
C.L	0.77	1.44	1.82	2.57

* Due to non - incremented bump

Sample ID	Breakthrough	After 1 Pv	End	End
B			Flood	Bump
Kw	12	24	28	29
Krw	0.05	0.09	0.11	0.11
Sw Avg.	0.71	0.72	0.73	0.74
Sor	0.29	0.28	0.27	0.26
C.L	0.96	1.22	1.36	1.43

Sample ID	Breakthrough	After 1 Pv	End	End
C			Flood	Bump
Kw	52	119	160	160
Krw	0.04	0.09	0.12	0.12
Sw Avg.	0.70	0.71	0.71	0.71
Sor	0.30	0.29	0.29	0.29
C.L	1.40	1.58	1.76	1.77

Sample ID	Breakthrough	After 1 Pv	End	End
D			Flood	Bump
Kw	18	96	165	167
Krw	0.01	0.08	0.13	0.13
Sw Avg.	0.70	0.75	0.77	-
Sor	0.30	0.25	0.23	-
C.L	0.32	1.87	2.22	-

C.L = Land's Coefficient = ((1-Swi)/Sor) - 1

Base Data Summary

	Swi	Ko @ Swi	Kair	Porosity
Sample ID	(frac.)	mD	mD	frac.
A	0.26	1227	1467	0.26
B	0.37	262	336	0.24
C	0.20	1395	1560	0.27
D	0.25	1282	1330	0.28

Table 2

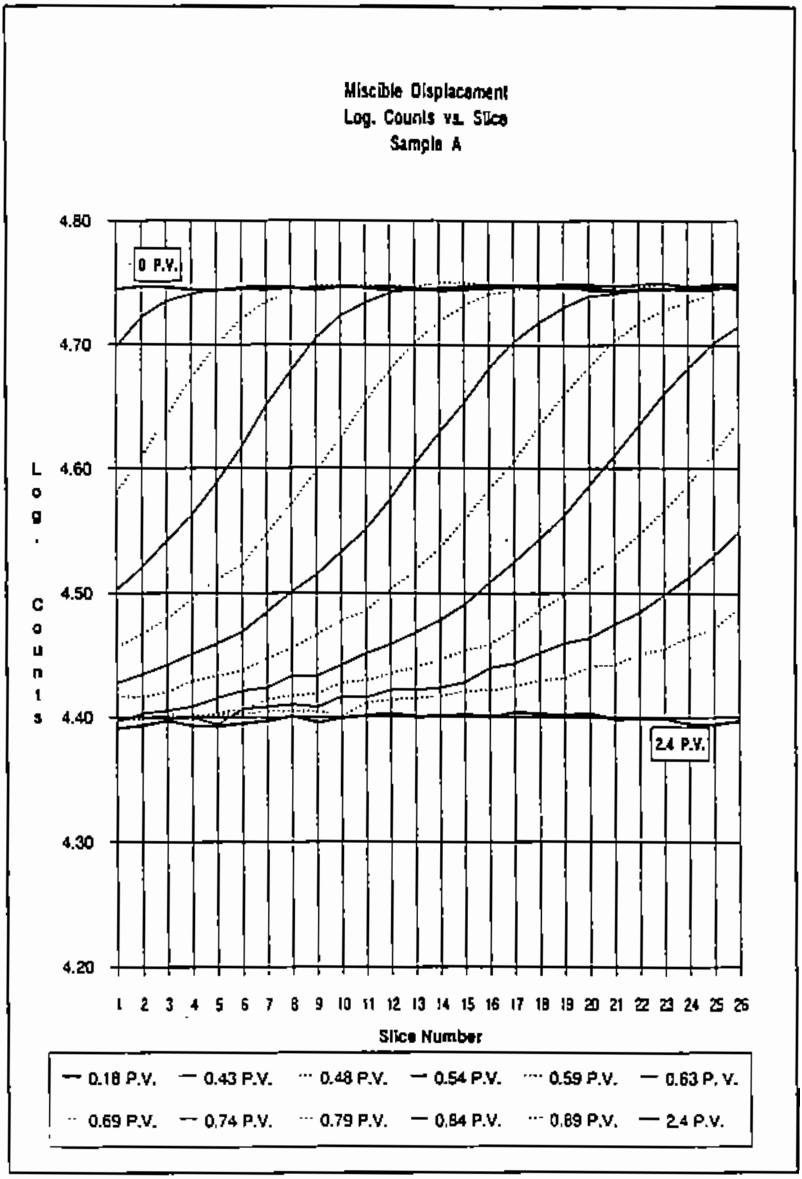

Miscible Displacement
Log. Counts vs. Slice
Sample A
0 P.V.
2.4 P.V.
4.80
4.70
4.60
4.50
4.40
4.30
4.20
Log. Counts
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26
Slice Number
0.18 P.V.
0.43 P.V.
0.48 P.V.
0.54 P.V.
0.59 P.V.
0.63 P. V.
0.69 P.V.
0.74 P.V.
0.79 P.V.
0.84 P.V.
0.89 P.V.
2.4 P.V.

Figure 2

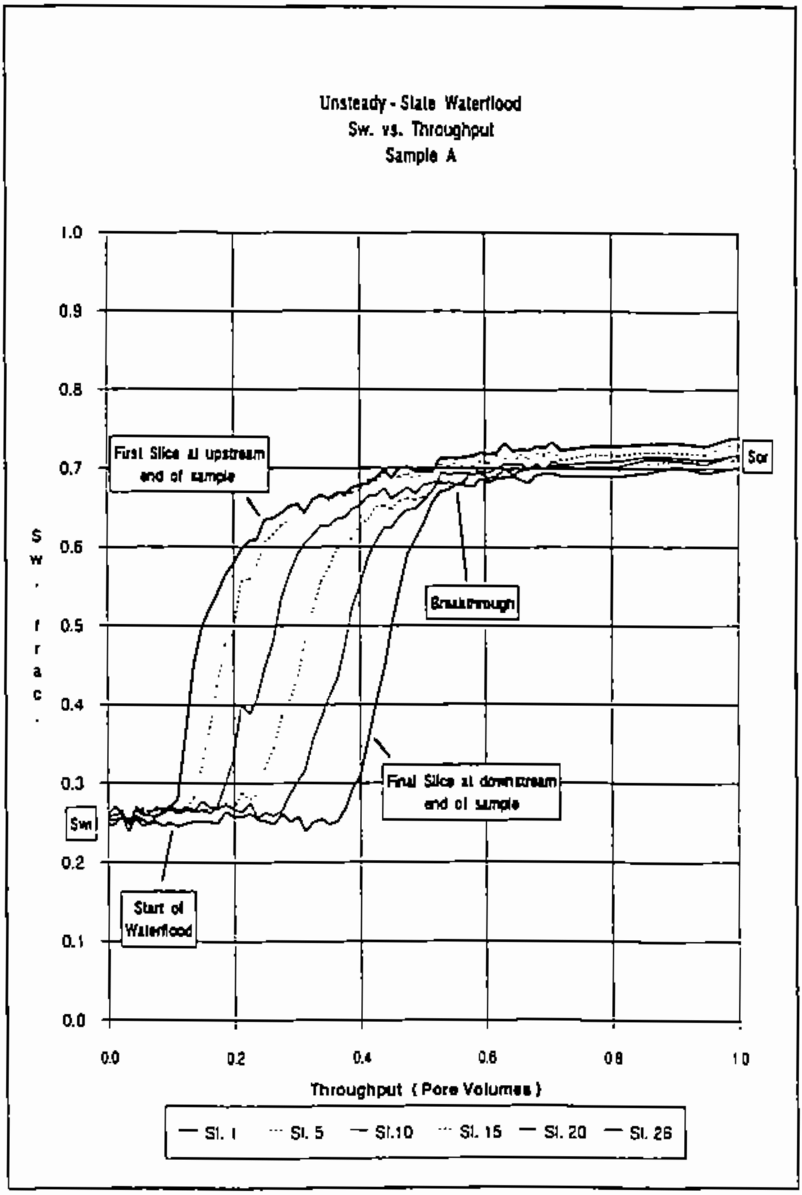
Figure 3 shows the progress of the flood front through the sample for six slices. The curves for each slice are parallel, indicating the progression of a stable front. A stable flood front satisfies the requirements for data which are used to calculate relative permeability according to Johnson et al[7]. The greater the rate of change of water saturation versus throughput at any position within the core, the more efficient the water displacement.

The even saturation profiles observed in Figure 4 are indicative of the homogeneity of the core plug. They also indicate the absence of capillary pressure end effects, which may result in uneven profiles at the beginning and end of the flood. Breakthrough occurs when the shock front reaches the end of the core. Note that the water saturation at the core outlet can increase before breakthrough due to spontaneous imbibition ahead of the shock front.

DISCUSSION

The waterflood data set shows consistently low end point water relative permeability (0.11 - 0.15), despite the samples having been cleaned using a mild miscible solvent technique. Oil production after breakthrough was very low, ranging from 0.01 to 0.06 pore volumes. Both observations indicate water wet behaviour. The range of residual oil saturations, 0.23 to 0.29 (averaging 0.26) is also consistent with this water wet characterisation. The original log-derived residual oil saturation, in the light of such consistency seems low.

However, rather than dismiss the core data out of hand (or 'normalise' it) the question that must be addressed is which figure is more likely to be correct. On one hand, over cleaning a core sample can make it too water wet, resulting in an Sor which is too high. On the other hand, the log data had been analysed using a saturation exponent relevant to the primary drainage cycle rather than one appropriate to the circumstances encountered. Given that the cleaning technique used in plug preparation was very mild, and did not include a drying stage prior to water flooding, then it is unlikely to have induced an unrepresentative wettability. If the core analysis results are believed, then the accuracy of the measured residual oil saturations means that the log-derived values must be in error. Since the subject reservoir has been characterised so thoroughly in the past, then hysteresis in the saturation exponent is the most likely



Unsteady - State Waterflood
Sw. vs. Throughput
Sample A
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
S w , f r a c .
First Slice at upstream end of sample
Sor
Breakthrough
Final Slice at downstream end of sample
Swi
Start of Waterflood
0.0
0.2
0.4
0.6
0.8
1.0
Throughput (Pore Volumes)
Sl. 1
Sl. 5
Sl. 10
Sl. 15
Sl. 20
Sl. 26

Figure 3

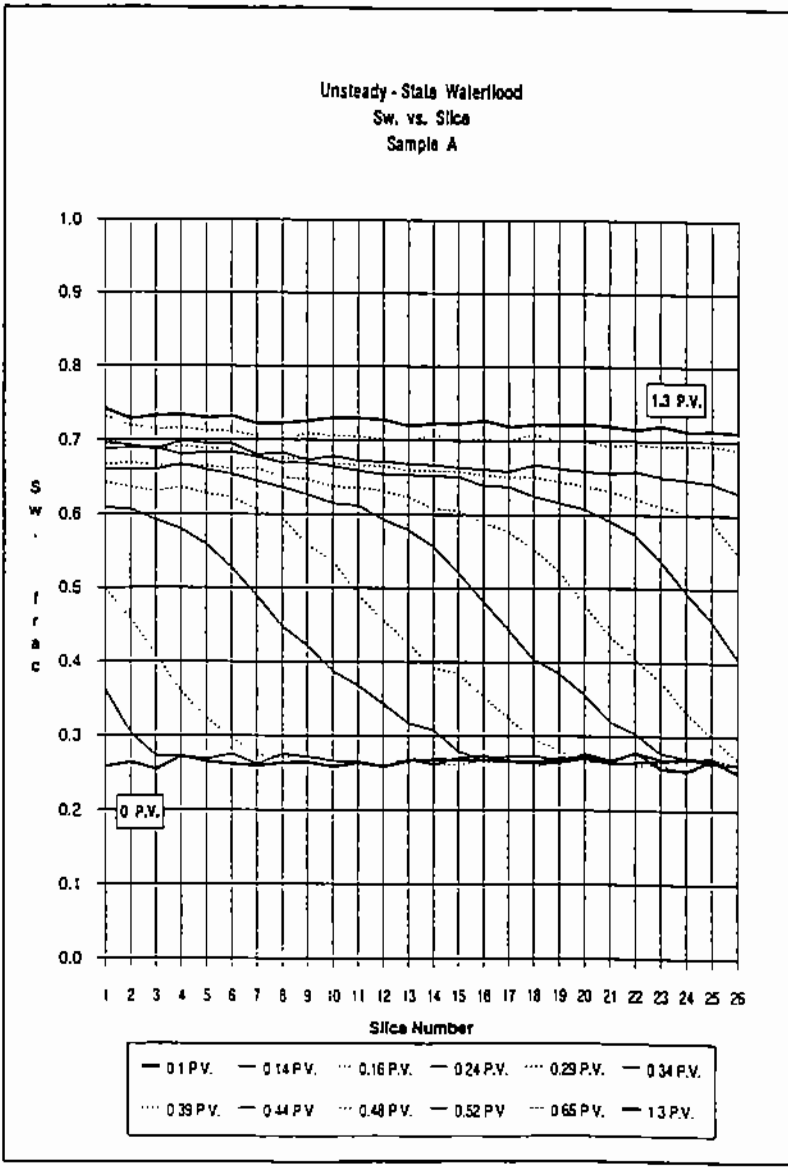

Unsteady - State Waterflood
Sw. vs. Slice
Sample A
1.3 P.V.
0 P.V.
Sw, frac
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26
Slice Number
0.1 P.V. 0.14 P.V. 0.16 P.V. 0.24 P.V. 0.29 P.V. 0.34 P.V.
0.39 P.V. 0.44 P.V. 0.48 P.V. 0.52 P.V. 0.65 P.V. 1.3 P.V.

Figure 4

explanation.

Previous literature supports the reduction of saturation exponent in order to account for hysteresis effects and in doing so effectively reconciles the two data sets. The application of modern, high quality core analysis has therefore been demonstrated and hopefully the advances in core analysis technology will lead to better utilisation of core data in the future.

CONCLUSIONS

1 The use of high quality core analysis data has resulted in improved reservoir description and an appreciation of the sensitivity of log results to saturation hysteresis effects.

2 X-ray CT scanning has proved a useful screening technique for the selection of plug samples for relative permeability testing. In-situ sample saturation observed during miscible flushing can also be used to indicate sample homogeneity.

3 The samples appear to be significantly water wet as shown by the following ;
  - End point permeability to water was found to be low.
  - Post breakthrough production during the water floods was low.
  - Production on the 'bump' flood was low.

4 The water wet nature of the rock material is consistent with reservoir conditions and fluid composition. The discrepancy between log and core derived residual oil saturation is therefore believed to be predominantly due to the unrepresentative saturation exponent values assumed and used in the original log analysis.

5 Since there are many wells in the field and the formation water is well characterised, the values of brine resistivity and cementation factor used are thought to be reliable. The saturation exponent used in the flushed zone is thought to be in error due to hysteresis effects. Use of a lower value (supported by some earlier experimental evidence in the literature) allows effective reconciliation of the data set.

NOMENCLATURE

C	Number of X-ray Counts logged in 1 second
CL	Land Coefficient
n	Saturation Exponent
Sw	Water saturation (fractional)
Swi	Initial water saturation (fractional)
Swirr	Irreducible water saturation (fractional)
So	Oil saturation (fractional)
Soi	Initial oil saturation (fractional)
Sor	Residual oil saturation (fractional)
Kw	Brine permeability (mD)
Krw	End point brine relative permeability (fractional)

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