SCA2003-34: INVESTIGATION OF THE OIL SATURATION OF THE SWEPT ZONE OF THE HARDING FIELD, UKCS

J Williams & K Sincock, BP Exploration
P Mitchell, Integrated Core Consultancy Services

This paper was prepared for presentation at the International Symposium of the Society of Core Analysts held in Pau, France, 21-24 September 2003

ABSTRACT

Harding is an Eocene sandstone field located in the Central Graben of the UKCS. Production started in 1996 and has so far produced approximately 40% of reserves. Production has led to the development of a well defined swept zone above the original oil water contact, but determination of the remaining hydrocarbon in this zone remained problematical

Analysis of the swept zone by wireline data, standard Archie parameters and aquifer brine salinity led to an over estimate of remaining oil saturation. This is partly due to swept zone wells being horizontal, the vertical propagation of the induction log and the position of the oil in the pore space; and partly due to the true salinity of the swept zone water (a mixture of aquifer and injected waters).

A core was cut through the swept zone, to provide water extracts for direct swept zone water resisitivity measurement, and fresh core material for Archie parameter measurement. Remaining oil saturation in the swept zone could not be measured directly from the core due to the necessity to use synthetic oil based mud for drilling operations, and because of gas drive expulsion of oil from the core during tripping out of the well.

A Special Core Analysis study was performed to replicate the in-situ environment of measurement to determine the appropriate Archie parameters for estimation of the remaining oil saturation in the swept zone. The results of the study showed a clear directional electrical anisotropy and a range of Archie parameters. Log interpretation using appropriate Archie parameters and Rw has led to a better understanding of remaining oil saturation in the swept zone; and suggests that the reservoir is being swept more effectively than previously thought.

INTRODUCTION

Well 9/23b-A21 was planned as a water injector well in the swept zone of the Harding Field. As penetrations of the swept zone in the mature field are rare, this presented an excellent opportunity to evaluate the remaining oil saturation in the Harding swept zone. However, oil saturation could not be measured directly from the core in this well due to the use of synthetic oil based mud and due to the potential of gas drive of trapped gas during tripping. Oil saturation had therefore to be determined indirectly by wireline log data calibrated to core from conventional and special core analysis. An innovative Special Core AnaLysis (SCAL) programme was designed to replicate reservoir conditions as close as possible so as to determine the influence of these factors on down-hole measurements.

OBJECTIVES

The objectives of the study therefore were to:

- Determine the most representative porosity, ‘a’, ‘m’ an ‘n’ values for the Archie equation to better estimate oil saturation in the swept zone from wireline or LWD data
- Determine and apply the most appropriate salinity for the swept zone.

WELLSITE CORE PROGRAMME

The Harding reservoir formation is an unconsolidated multi-Darcy sandstone. All coring, tripping, surface handling, plugging & preservation were all performed using soft sediment procedures to ensure that reservoir representative materials were available for all lab tests.

Drilling mud was optimized for coring, and the mud water phase was labeled using a tracer (Deuterium Oxide). Plug samples were cut from the center of the large diameter (5.25 inches) core at the wellsite to ensure that core water extracts were minimally contaminated, and that uncontaminated swept zone water properties could be defined. Analysis of the sample plugs showed that all three plugs used in these tests had negligible contamination

CORE ORIENTATION AND PLUGGING

Prior to retrieving the sealed core from the core sleeves, the core was X-rayed to help in the orientation of the any subtle sedimentary features that were present. The massive nature of the Harding sandstone often makes orientation difficult. On retrieving the core though, sufficient sedimentary features were visible to orientate the core for plugging to proceed in the desired orientation. Paleomagnetic orientation measurements were also conducted, and the results of these confirmed core orientation.

Two vertical plugs were cut parallel to in-situ $Sigma_v$ rather than perpendicular to the core surface at each sample depth (Figure 1). The well was highly deviated but not horizontal so care was taken to plug at the correct angle. One plug was cut horizontally, perpendicular to $Sigma_v$. This was to be used to determine whether packing and loading have any effect on the determination of formation resistivity factor.

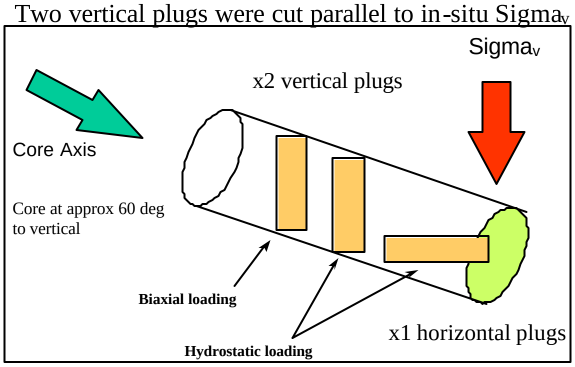


Figure 1 Plug orientation

POROSITY AND FRF 'M'

Assumptions

For porosity and formation resistivity factor 'm' determination at reservoir stress conditions the following parameters were used to represent the current conditions in the Harding flushed zone.

•Depth = 5895 feet TVD BRT
•Pore pressure = 2574 psi
•$Sigma_h$ = 4035 psi
•$Sigma_v$ = 5061 psi

The plugs were loaded and cleaned prior to measuring porosity and FRF at ambient conditions (Figure 2). One set of vertical plugs were then subjected to biaxial stress, with $Sigma_v eff$ applied in the vertical direction and $Sigma_h eff$ in the horizontal direction as shown below.

•$Sigma_h^{eff}$ ~ 1500 psi
•$Sigma_v^{eff}$ ~ 2500 psi

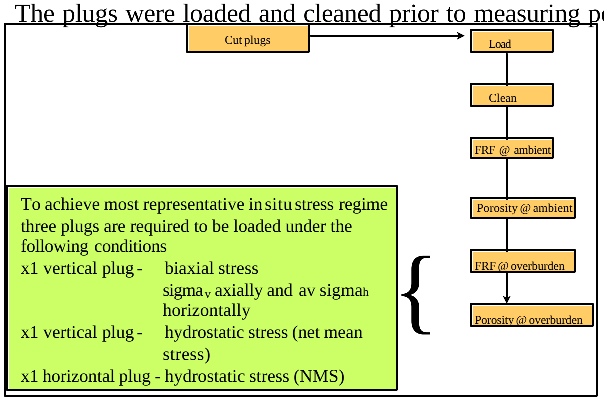


Figure 2 Analysis Flow diagram: Porosity and FRF 'm'

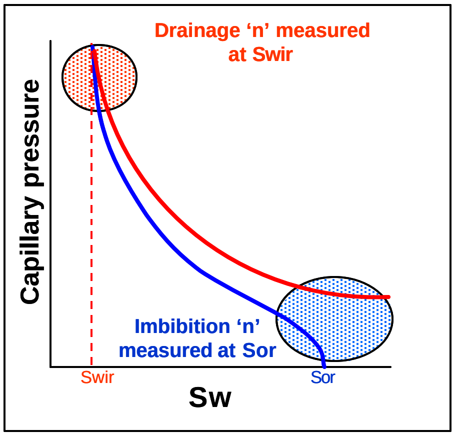
For the biaxial tests, cells had approximately 500 psi applied hydrostatically then loaded differentially to the respective biaxial pressure conditions. For the hydrostatic tests the cells were subjected to a net mean stress of 1825 psi.

Results

The results of the porosity and formation resistivity factor tests at overburden stress conditions showed the formation to be relatively isotropic with respect to these parameters. The reduction in porosity in both the vertical and horizontal plugs was very similar at between 0.955 and 0.963 of ambient values. The value of cementation factor 'm' from the formation resistivity factor tests varies from only 1.756 at ambient conditions (400 psi) to 1.721 at in-situ conditions.

RESISTIVITY INDEX 'N'

Reservoir resistivity index measurements are generally performed during drainage cycle capillary pressure tests and represent the filling of the reservoir and conditions at Sw_i. However to establish the resistivity index and hence saturation exponent 'n' of a swept leg of a reservoir as occurs in the Harding Field, these tests should be performed at conditions more representative of those in the reservoir under water advance. To do this the plugs have to be taken to Sw_i and then waterflooded (Figure 3).



To replicate reservoir conditions as close as possible, resistivity index measurements were performed only on the plugs cut vertically and were placed in a vertically orientated core holder.

Plugs were then re-confined and heated to simulated reservoir conditions (a temperature of 60°C with a hydrostatic confining stress of 4500 psi and 2600 psi pore pressure).

Figure 3 Conditions of resistivity index measurements

The plugs were then cleaned thoroughly at overburden conditions and totally saturated with live brine (brine composition was designed to replicate the chemistry of recovered samples from within the swept zone).

Full saturation profiles were determined during all tests using Gamma Saturation Monitoring (GASM). The technique infers fluid saturation from the contrast in γ-ray attenuation between oil and water. An exponential decay relationship exists between the transmission of gamma rays and material thickness. The coefficients of this relationship are complex but relate broadly to material density. Dopants are used in the aqueous phase to increase the density contrast with the oil phase. The transformation between the two extremes of 100% water saturation and 100% oil saturation amounts to the replacement of a certain thickness of one phase by the other. The logarithm of count-rate at some intermediate saturation relates linearly with fluid saturation. If the transmission of gamma rays has been determined at the 100% saturation extremes, then the transmission through the sample at any point between can be scaled to give a direct measure of saturation.

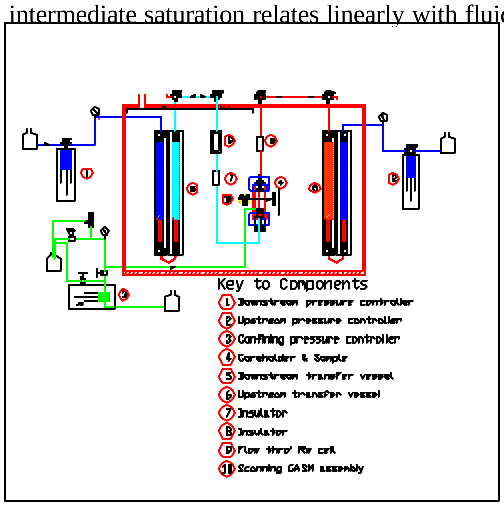


Figure 4 Schematic of the Equipment

All measurements took place at full reservoir conditions and using approximate reservoir water advance rates in an attempt to correctly replicate both in-situ wettability, and the magnitude and distribution of remaining oil after water flooding .

A schematic of the equipment used is shown in Figure 4. The equipment incorporates a γ-ray source/detector assembly which is scanned continuously along the core during desaturation to measure the saturation profile. The pressure controllers, which use refined fluids, are interfaced to the live fluids using transfer vessels containing liquid metal alloy.

The brines and oil used were recombined with synthetic separator gas to replicate in-situ fluids.
The plugs were then de-saturated to initial low water saturation conditions in equilibrated pressure steps still under overburden conditions, using live crude from a re-constituted oil sample. The final de-saturation pressure was commensurate with original height above FWL of the respective plugs. In the imbibition process water of similar composition to that of the swept zone was flowed at constant rate through the membrane to 'remaining oil saturation'. Saturation distribution was determined by GASM throughout the imbibition cycle (Figure 5).

It was also important to consider the ageing criteria for resistivity index measurements to be as representative as possible. The plugs were allowed to age between each pressure step until cessation of resistivity and saturation changes, which are considered the most rigorous indicators of equilibrium. Both of these parameters were routinely monitored throughout the process. The flow rate for the imbibition cycle was maintained as close as possible to estimated reservoir advance rate. For a 3" x 1.5" plug, a flow rate of 4cc/hr = 1 ft/day reservoir advancement was used.

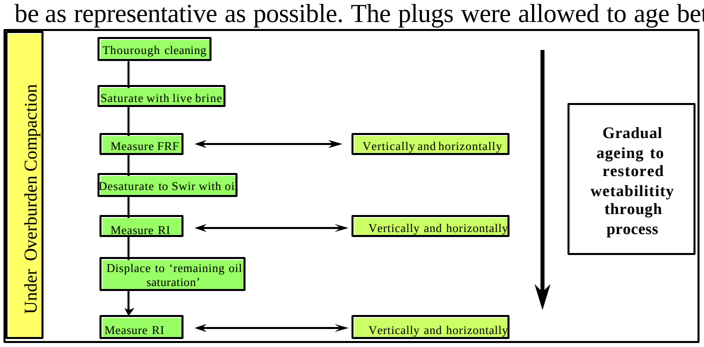


Figure 5 Analysis flow diagram: resistivity index

The tests also set out to determine the effect that the remaining oil had on resistivity index in the swept zone. To check for directional anisotropy, resistivity measurements were made along the plugs in the normal manner, and also across the plugs using specially designed electrodes. It was hypothesisied that remaining oil droplets could be preferentially trapped in the attics of the pores, creating an electrical anisotropy between the vertical and horizontal planes. (Figure 6)

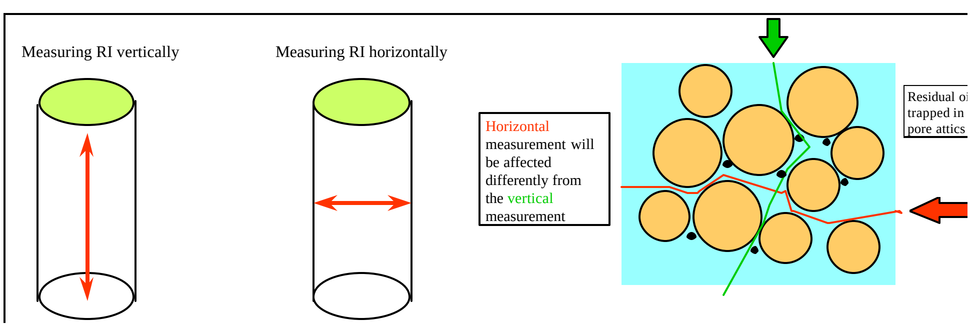


Figure 6 Measurement of Resistivity Index

Results

The resistivity index results show a difference in saturation exponent values between the drainage cycle measurements at Sw_{ir} and the imbibition cycle at So_r. They also show clear electrical anisotropy at conditions of So_r caused by the presence of residual oil in pore attics. This anisotropy is the difference in resistivity index and hence saturation exponent 'n' between the directional measurements R_V versus R_h along and across core plugs respectively.

These results demonstrate that the use of a saturation exponent measured under drainage conditions at irreducible water saturation (S_{wir}) will under estimate Sor if used to evaluate the swept zone, e.g. 'n' for Sample 3 at Sw_i is 2.27 but its respective 'n' measured at So_r horizontally is 1.749. At 1ohm m and 30% porosity this is a difference of 5.5 saturation units. (Table 1)

Table 1 Table of Results

Sample	Depth	Drainage			Imbibition		
	(feet)	Sw	Horiz	Vert	Sw	Horiz	Vert
1	8268	0.088	2.183	2.105	0.712	1.697	2.891
3	8289	0.0531	2.271	2.214	0.703	1.749	2.191
4	8301	0.061	1.844	2.089	0.756	1.782	2.262

The appropriate saturation exponent for swept zone or the residual leg of an oil column should therefore be measured at So_r in the imbibition cycle and in the appropriate directional measurement according to the relative hole angle of the well being evaluated.

The results demonstrate the robustness of the measuring technique by the relative consistency of the saturation exponent value at Sw_i, where it would be expected that little electrical anisotropy would be in effect.

APPLYING THE RESULTS

The findings of this study can be applied to ensure the appropriate Archie parameters are applied to the Harding field and in respect to reservoir fluid and well path inclination of producers and injectors alike.

In a vertical or near vertical well an induction log is inducing a current in the formation perpendicular to the wellbore, i.e. horizontally (Figure 7). In a reservoir at Sw_{ir} there will not be a significant electrical anisotropy due to the consistency of the fluid effects in the pores. However in a swept zone the effects can be significant.

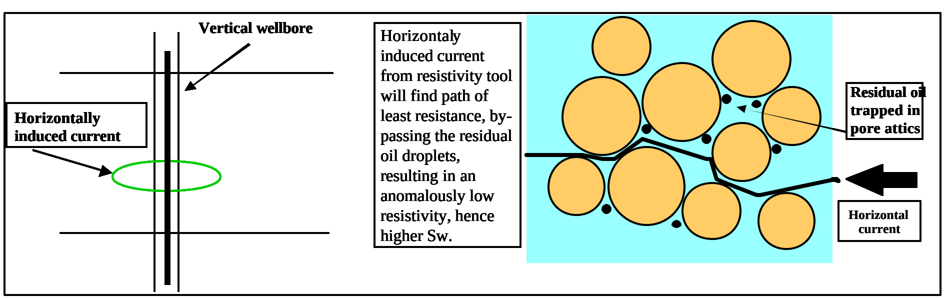


Figure 7 Electrical path of an induced current in a reservoir around a vertical well

The residual oil is buoyed in the attics of the pores. As the current travel along the path of least resistance, the buoyed oil will have a minimal effect on the current, resulting in a lower than expected Rt for the swept zone (or zone of residual oil). To account for this effect in the Archie equation it is appropriate to use the resistivity index measured under conditions of So_r rather than conventionally the 'n' measured at Sw_i with the additional requirement of measuring the plug horizontally, as described above, to simulate the in-situ conditions in which the log data is acquired in (Figure 8).

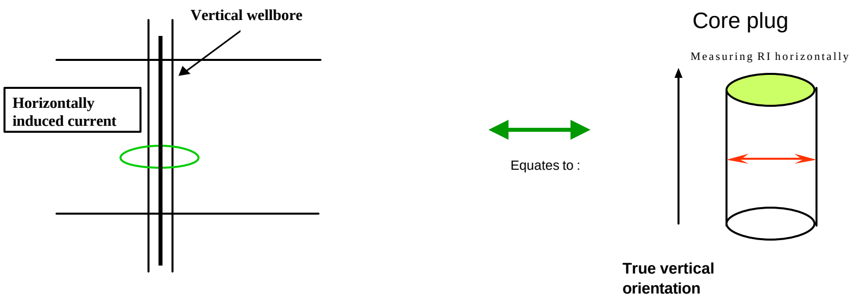


Figure 8 The appropriate measurement direction for a vertical well

The high values of saturation exponent derived from the measurement of resistivity index along the plugs in the vertical direction are assumed to be derived from the increased resistivity caused by the residual oil being trapped in the attics of the pores (Figure 9)

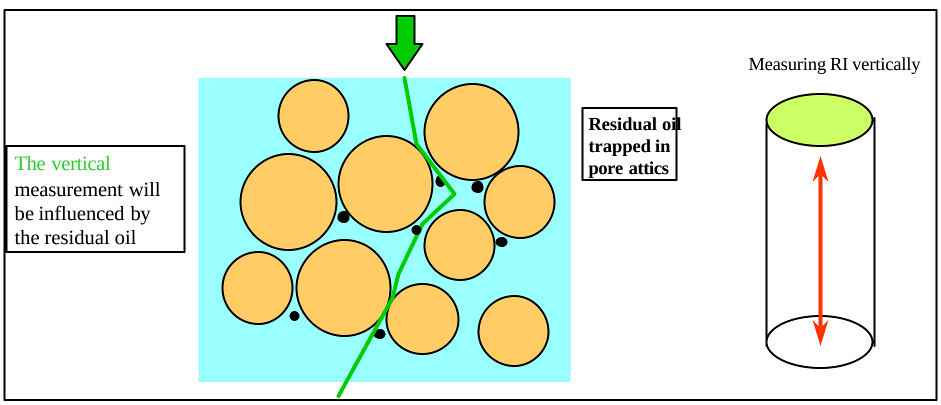


Figure 9 Electrical path of the vertical resistivity index measurement.

For a horizontal or high angled well in the swept zone (or in the residual oil leg) a similar effect will be evident in the measurement of formation resistivity with the induction tool. Formation resistivity will be more affected by the buoyed residual oil in the pore spaces because of the large vertical component to the induced current compared to that of the vertical well. However the resistivity measurement in the horizontal well will have a horizontal component to it as well and therefore a singular vertical component 'n' value may not be the most appropriate value to use (Figure 10).

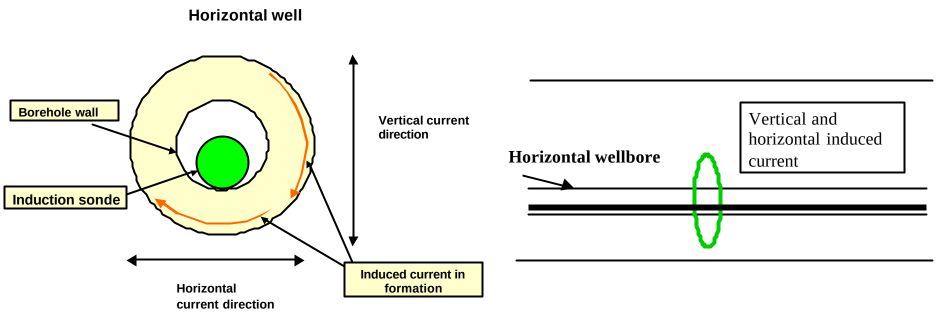


Figure 10 Mixed electrical path components in a horizontal well case.

This anisotropy effect should be addressed in the Archie parameter determination in some way. One technique that may be used is regularly used in inversion modelling where the vertical and horizontal components are combined in the following manner.

$$'n' = \sqrt{n_v * n_h} \qquad \text{Equation 1}$$

Where n_v is the vertical measured saturation exponent and n_h is the horizontal measurement for either drainage or imbibition measurements. This technique takes into account the vertical (Rv) and horizontal (Rh) components of the current path induced in the formation around a horizontal borehole by an induction tool as expressed below.

$$R = \sqrt{R_v * R_h}$$

The following is a listing of which components should be used in which situations (Figure 11). Saturation exponent measured under these respective conditions will be different due to the fluid distribution in the pore spaces.

Well type	Reservoir zone	Swept zone/residual leg
Vertical or near vertical well	Drainage n_h	Imbibition n_h
Horizontal or high angle well	Drainage $'n' = \sqrt{n_v * n_h}$	Imbibition $'n' = \sqrt{n_v * n_h}$

The drainage curve measurement at Swir represents the reservoir zone and the imbibition curve measurement at Sor represents the swept zone or residual oil leg. The appropriate value should be used in the respective cases.

Figure 11 Appropriate saturation exponents in the Archie equation

For the Harding Field, the appropriate saturation exponents have been assigned to the various different reservoir zones as defined by their fluid content as shown below (Figure 12).

	Vertical well	Horizontal well
Reservoir	Range n = 1.84 – 2.27 Average n = 2.1	Range n = 2.089 – 2.214 Average n = 2.136
Swept zone	Range n = 1.697 – 1.782 Average n = 1.743	Range n = 2.191 – 2.891 Average n = 2.448
Aquifer	Little effect on Sw regardless on n	Little effect on Sw regardless on n
Residual oil leg Aquifer	Range n = 1.697 – 1.782 Average n = 1.743 Little effect on Sw regardless on n	Range n = 2.191 – 2.891 Average n = 2.448 Little effect on Sw regardless on n

Figure 12 Assignment of appropriate saturation exponents.

EFFECT OF SWEPT ZONE SALINITY

Fluid samples from the swept zone were collected in the 9/23b-A21 well and are tabulated in Figure 13. Water was extracted from the core by centrifuge techniques and also larger volumes were recovered with the RCI tool. The salinity measured from the fluid recovered from the RCI tool is quite consistent, whereas the variation in salinity measured from water extracted from core is quite a large. The water recovered from the RCI tool is higher than any fluid recovered from the core. This compares to an aquifer brine resistivity of 0.055 ohm m at 140 F from brine analysis of approx 68,000 ppm tds NaCl equivalent.

Sample	Depth	Type	Ω.m at 20 C	140 F	
1 inner	8266'5.5"	Spun core	0.152	0.0716	
3 inner	8269'4"	Spun core	0.145	0.0686	
4 inner	8272'2"	Spun core	0.152	0.0720	
6 inner	8275'2"	Spun core	0.169	0.0798	
8 inner	8278'2"	Spun core	0.147	0.0695	
10 inner	8281'2"	Spun core	0.138	0.0650	
12 inner	8284'2"	Spun core	0.149	0.0705	
14 inner	8287'2"	Spun core	0.146	0.0688	
16 inner	8290'2"	Spun core	0.155	0.0730	
18 inner	8292'2"	Spun core	0.140	0.0659	
20 inner	8296'2"	Spun core	0.135	0.0640	Lowest
23 inner	8299'4"	Spun core	0.152	0.0719	
24 inner	8302'2"	Spun core	0.152	0.0718	
26 inner	8305'2"	Spun core	0.146	0.0689	
28 inner	8308'1"	Spun core	0.160	0.0757	
30 inner	8311'1"	Spun core	0.163	0.0770	
32 inner	8314'3"	Spun core	0.154	0.0726	
35 inner	8317'3"	Spun core	0.156	0.0736	
37 inner	8320'2"	Spun core	0.177	0.0835	
183475	8343.5	RCI	0.186	0.0877	Highest
188900	8355.3	RCI	0.183	0.0862	
188467	8355.3	RCI	0.180	0.0848	

Figure 13 Swept zone brine resistivity from core and RCI tool

COMBINING THE RESULTS

Using the full range of salinity in the Archie equation Sw in the swept zone, there is a greater variation in Sw than derived from variation in the saturation exponent. (Figure14). However the results show a decrease in the original So_r due to the application of the more appropriate saturation exponent in the Archie equation. The four cases shown below comprise of the following parameters:

Case	n	Rw
Low Rw, Low ‘n’	1.958	0.064
Low Rw, High ‘n’	2.215	0.064
High Rw, Low ‘n’	1.958	0.088
High Rw, High ‘n’	2.215	0.088

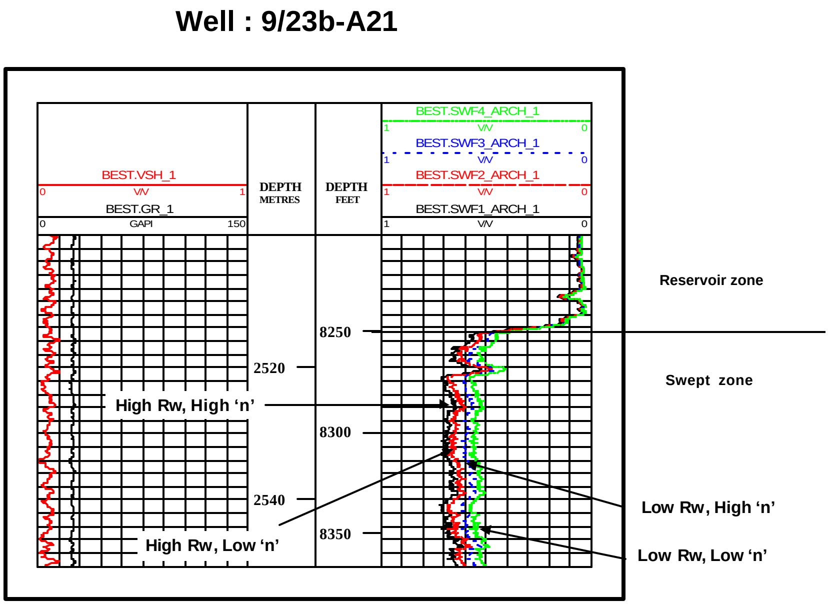


Figure 14 Comparison of parameters in Archie equation

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Case 4 the High Rw and High 'n' best tie the Sw's at which the resistivity index measurements were conducted and are therefore considered the most appropriate parameters to use. The calcula ted Sw's displayed in Figure 14 appear to be more influenced by the variation in Rw than by the variation of 'n' values.

CONCLUSIONS

The investigation concludes that the resistivity index results show a difference in saturation exponent values between the drainage cycle measurements at Sw_{ir} and the imbibition cycle at So_r. They also show clear electrical anisotropy at conditions of So_r caused by the presence of residual oil in pore attics. The SCAL results show that the drainage 'n' at Sw_i is the most appropriate saturation exponent for the main reservoir section with little variation in values between a vertical and horizontal measurement and that the saturation exponent for the swept zone should be determined at the end of the imbibition cycle and the appropriate orientation of measurement should be determined by the relative bearing of the well path.

It also shows that there is a significant range in salinity of the brine in the swept zone and that the most appropriate combination of saturation exponent is the highest derived Rw and the highest 'n' which tie the SCAL results most accurately.

ACKNOWLEDGEMENTS

The authors would like to thank Kerr McGee, Canadian Natural Resource and BP for permission to publish this paper. I would like to acknowledge Aubrey Hewson, formerly of the Harding team, for his help and encouragement, Stephen Willson and Lindsay Kaye for his advice and guidance.