Some Practical Applications of Recent Core Analysis Advances

by N. V. Williams[1]

ABSTRACT

The Eromanga Basin is Australia's main onshore oil province, consisting of a large number of thin good permeability reservoirs. This basin overlies the Cooper Basin, Australia's main onshore gas province, consisting of many thicker but low permeability gas reservoirs. Both basins often contain stacked reservoirs. In order to identify improvements in core analysis which can be applied to the basins the Operator has conducted a series of experiments using newly or recently developed procedures. Following are some highlights.

(1) Reservoirs which may have leaked
Some Eromanga basin reservoirs are believed to have leaked into overlying reservoirs. For the reservoir which has leaked it is not really valid to compare the log analysis to a drainage capillary pressure curve. Neither does a traditional laboratory imbibition capillary curve exactly describe the process. A new laboratory imbibition procedure was developed which appears to match the log analysis better than drainage data.

(2) Low Invasion Coring
This has become an established procedure in Australia. Many of our reservoirs are well suited to it. In one case we obtained saturations by four different laboratory procedures and compared them to the log analysis, obtaining a somewhat large spread in the various laboratory results.

(3) Transitional Reservoirs
For waterflood and some relative permeability experiments the traditional laboratory procedure of using high capillary pressure (P_c) to achieve s_{wc} then a high flood velocity (or capillary number N) to achieve s_{or} has been shown to produce incorrect results across the Eromanga Basin and has been replaced by a low P_c / low N method, yielding better agreement with log analysis.

(4) Mud Testing on Cores for Formation Damage
Comparison of a particle size distribution from the mud with a pore size distribution from the reservoir has a lot of pitfalls. It doesn't follow that particles much smaller than a pore automatically have the opportunity to enter the pore.

(5) Spreading Experiments
Two suites of experiments were conducted involving waterflooding a core followed by gasflooding it. One suite was run with a positive spreading coefficient, and the other with a negative spreading coefficient. Oil recovery was the same in both cases.

Some of the conclusions in this paper are based on a small number of experiments, owing to cost and time constraints, and further work is desirable.

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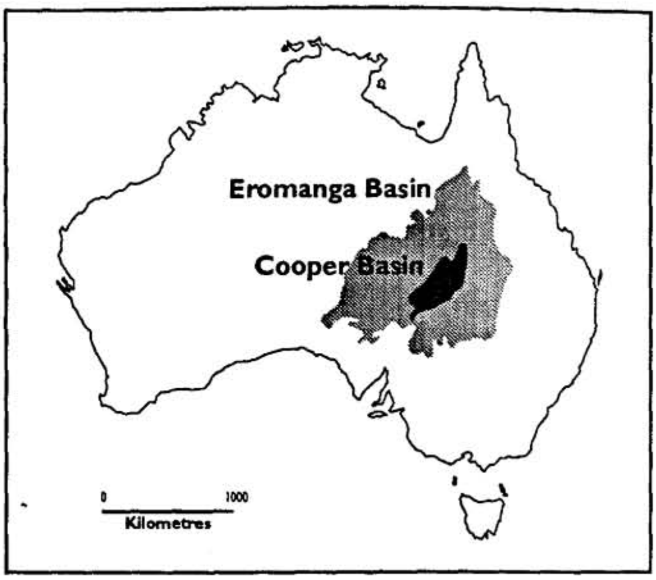


Figure 1 Location of Cooper and Eromanga Basins

INTRODUCTION

Santos operates Australia's most prolific onshore fields, namely the fields in the Cooper and Eromanga basins of Central Australia (see Figure 1), on behalf of various Joint Ventures. The Eromanga, a basin consisting mainly of thin oil reservoirs (see a typical log on the left side of Figure 2), overlies the Cooper, a basin consisting mainly of gas reservoirs. This is a major gas province which supplies the natural gas requirements of 3 of Australia's major cities, Sydney, Adelaide and Canberra. Many of the fields have stacked accumulations.

In the course of routine reservoir management we have conducted a considerable body of special core analysis since 1980. Not having an in house research laboratory we relied on the services and procedures of a number of commercial laboratories. During 1992-1995, in order to identify improvements in core analysis which can be applied to the basins, Santos conducted a series of experiments using newly or recently developed procedures. Following are some highlights.

1. RESERVOIRS WHICH MAY HAVE LEAKED

1.1 The Problem

Some (not all) of the oil reservoirs in the "Namur" sands of the Eromanga basin exhibit the phenomenon of having significant oil saturation below the free water level (FWL) prior to production. This is often associated with the presence of oil in a higher reservoir in the same field. References 1, 2 have demonstrated that the seals of these lower reservoirs are weak and that the lower reservoirs have probably filled to the seal capacity and then leaked. There is no compelling evidence that these reservoirs are oil wet.

Sometimes an ancient free water level (AFWL) can be identified on logs, distinct from the modern FWL which can be seen on both logs and RFT/MDT data. The region in between has oil shows, but flows mainly water on DST.

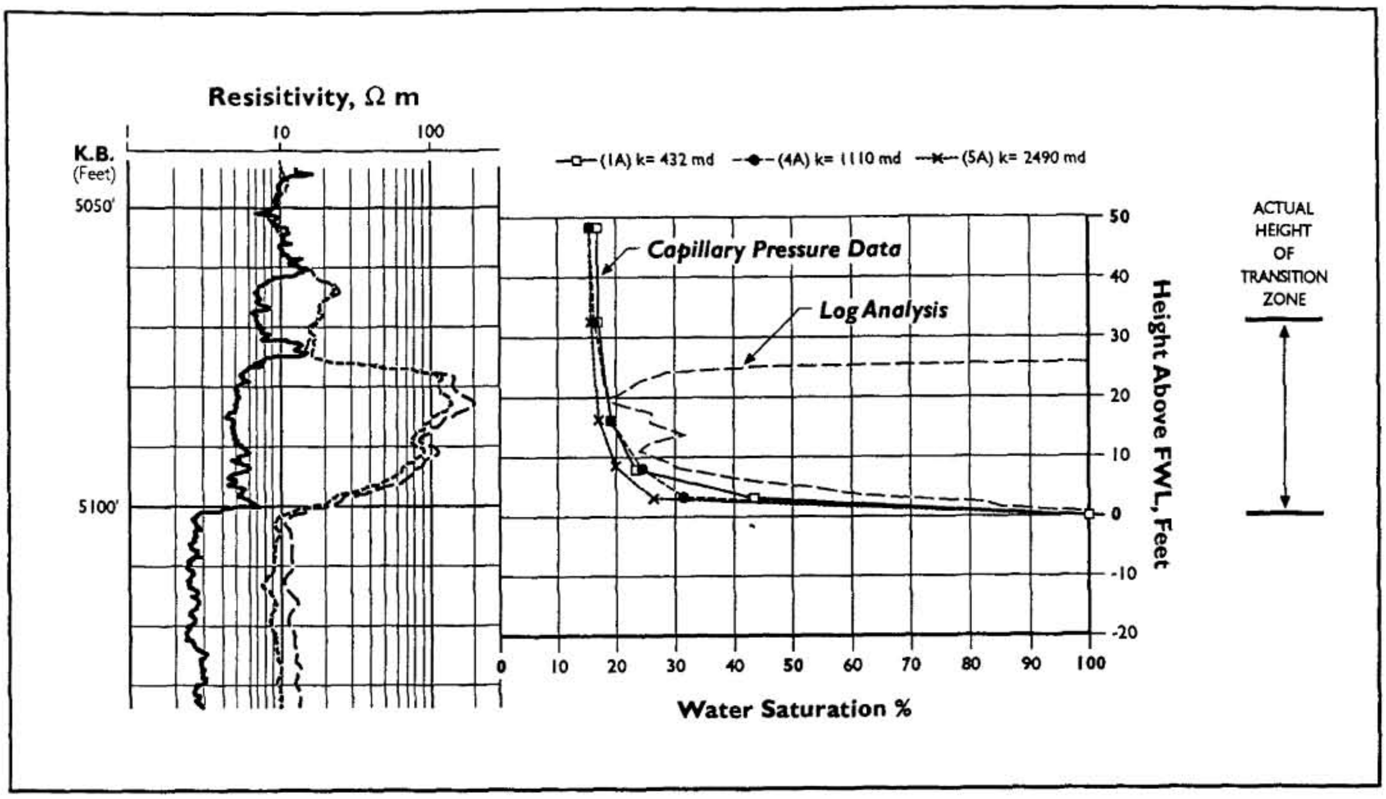


Figure 2 Typical Log Section, Eromanga Basin

The main problem in this situation is that the conventional practice of comparing the log analysis to drainage capillary pressure data is probably invalid. If one sets a drainage curve to start at the modern FWL then all the saturation data between the modern and the ancient FWLs is not generated in the laboratory, so there really is no match of the laboratory data and log analysis except in the low water saturation region far above both FWLs. Alternatively, if one sets a drainage curve to start at the ancient FWL then we get a curve typical of a high permeability sand whereas the log analysis appears to have more the shape of a drainage curve for a low permeability sand, i.e. S_w (logs) >> S_w (laboratory).

The problem is surely that in the reservoir we have an imbibition process whereas in the laboratory there is a drainage process. The log analysis should be compared to laboratory imbibition data.

The next problem is that a traditional laboratory imbibition curve relates to only one point in the reservoir and how S_w changes at that point as the FWL rises. The curve has a typical S-shape and always demonstrates a residual oil saturation (i.e. S_w approaches $1-S_{or}$ as capillary pressure drops). Such a curve will not match the log analysis as it will never yield S_w approaching 100% at the ancient FWL.

1.2 The Approach

It was decided to generate imbibition curves which related to the whole reservoir, in the same way a drainage curve does, instead of relating to just one point. Two core plugs were selected. An estimate was made from the logs of the distance between the ancient and modern FWLs, and this was converted to a change in laboratory capillary pressure ΔP_c. The following sequence of procedures was then conducted:-

* clean plugs and saturate with brine
* bring plugs to a point on a drainage capillary pressure curve in one step
* reduce capillary pressure by ΔPc.

This sequence yields only one point on the imbibition curve for the reservoir so the sequence had to be repeated a number of times to obtain a whole curve.

1.3 The Results

The results are shown in Figures 3, 4 and compared to the log analysis in Figure 5. The imbibition and drainage curves are similar for the lower permeability sample. However for the higher permeability sample, which is a more representative permeability, there is a major change in going from drainage to imbibition. The imbibition curve looks a bit like a low permeability drainage curve and qualitatively this is what we are seeing in the field.

Figure 5 shows that the imbibition data obtained provides a better match to the log analysis than either a drainage curve zeroed at the modern FWL or a drainage curve zeroed at the ancient FWL. The match is not as good as we would like and we attribute this to the formation probably being more permeable than the better of the 2 plugs used. There is also obviously some variation in permeability throughout the formation.

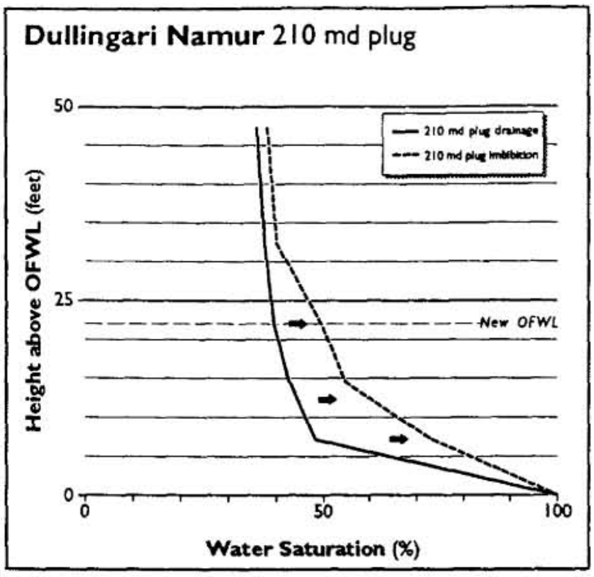


Figure 3 New Imbibiition Curve

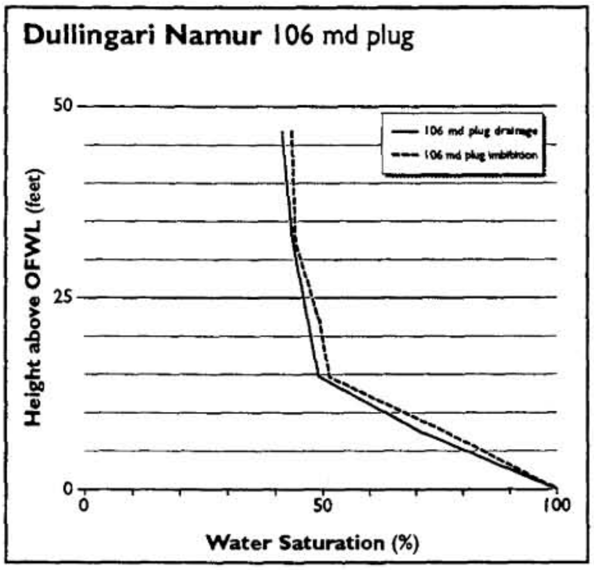


Figure 4 New ImbibitionCurve

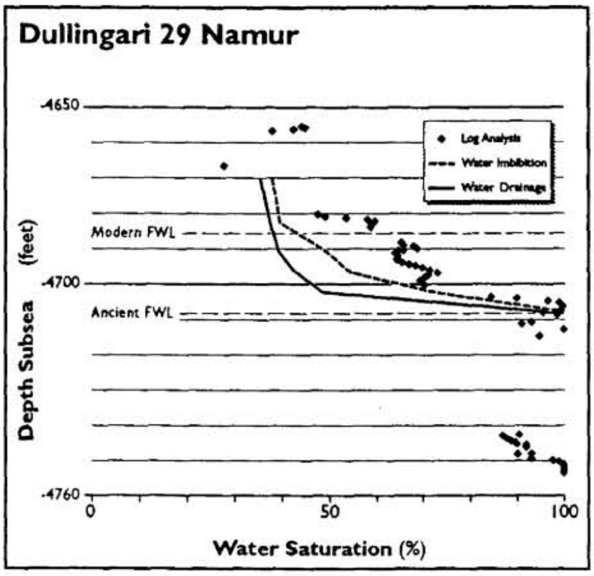


Figure 5 Imbibition Data better than Drainage Data

1.4 The Implications

Obviously this is not a large data set. Nevertheless if these results could be reproduced from a larger data set then some valuable conclusions could be drawn. Tentatively the sorts of issues that emerge are:-

(a) it is probably not generally valid to compare log analysis to drainage capillary pressure curves for reservoirs which have leaked, except far above the transition zone relative to the modern FWL.

(b) Figs 3, 4 imply that there might be oil movement occurring below what are traditionally called oil water contacts (such as S_w = 65%), although strictly we only measured data in this region in Figure 4.

(c) Fig 3 is tending to imply that the bottom sections of reservoirs, even those below the OWC, may be better drained than the top sections.

(d) it appears that the concept of a single residual oil saturation (as obtained from waterfloods) is really too simplistic for detailed modelling of thin transitional reservoirs.

(e) the rise in the level of any particular water saturation, see for example the 65% water saturation, can be quite different to the rise in the free water level, in this case considerably less.

(f) the phenomenon of mobile oil below the free water level can be explained without having to invoke the concept of oil wet rock.

These issues all warrant further investigation and it is not claimed that they have been demonstrated conclusively from this small data set.

2. LOW INVASION CORING (Laboratory Aspects)

2.1 The Objectives

Low invasion cores have been cut in 4 wells in the Eromanga basin. The primary objective was to obtain a sample of uncontaminated connate water from an oil reservoir and measure its resistivity R_w so as to see whether reservoir water is the same as aquifer water. The secondary objective was to obtain direct measurements of water saturation to compare to the log analysis. The Eromanga basin contains shaly sands and fresh waters so the log analysis is very difficult.

2.2 Results

Low invasion coring worked well in the field and the difference between success and failure depends mainly on laboratory procedure. Since the Eromanga basin contains transitional reservoirs we are able to core intervals where water saturation is well above irreducible, which makes it easier to extract the water in the laboratory. Bromide proved to be an excellent tracer and expensive tritium or deuterium were unnecessary.

2.2.1 Measurement of Water Resistivity

From our first low invasion core it was learnt that the laboratory procedure of removing the water by Dean Stark, crushing the core, then soaking it in water to reconstitute the connate water, is unreliable. Crushing the core exposes new rock surfaces and the reconstituted water was quite unusual. We abandoned this procedure and moved to centrifuging for water extraction in subsequent low invasion cores.

From our second low invasion core we successfully obtained samples of uncontaminated formation water from the oil zone by centrifuging. Each plug yielded about 2 to 3 ml of formation water. The resistivity was measured and found to be the same as that of the formation water. The formation was a few hundred millidarcies in permeability and we cored it from 35 feet above the OWC down to below the OWC.

Our third low invasion core was more difficult. The formation was 50-100 md and we cored it more than 100 ft above the OWC so there was much less mobile water in the core. The centrifuge recovery was from 0.1 to 0.3 ml of water from a few plugs, but most plugs yielded no water. Normally the resistivity of such a small sample can only be determined by dilution, which is very inaccurate, however we built special equipment to measure the water resistivity of these small samples and again the connate water resistivity was found to be the same as that of the aquifer water. Results from the fourth low invasion core are still being interpreted.

From the above results we now conclude that everywhere in the Eromanga basin the water in an oil reservoir is the same as the water in the aquifer underneath the reservoir.

2.2.2 Measurement of Water Saturation

Water Saturation was obtained by the following means:-

(a) a large plug through the width of the low invasion core was cut and divided into 5 one inch slices. See Figure 6. The water saturation of the middle slice (plug A) was determined by Dean Stark cleaning.

(b) a 2" plug (plug B) was cut a few inches away from plug A and the water removed by Dean-Stark cleaning then measured.

(c) another 2" plug (plug C - not shown on Figure 6) cut near plugs A and B was centrifuged. Then it was cleaned by Dean-Stark. The water from the 2 steps was added to obtain a total saturation for the plug.

(d) a capillary pressure test was conducted on plug C by the centrifuge procedure (with Hassler/Brunner corrections).

(e) a capillary pressure test was conducted on plug C by the porous plate/cell method at overburden.

(f) Log analysis was performed using a procedure appropriate to freshwater shaly sands.

The above gave us 6 different estimates of S_w and this was done at each of 4 locations in the reservoir. These results are shown in Figures 7-10.

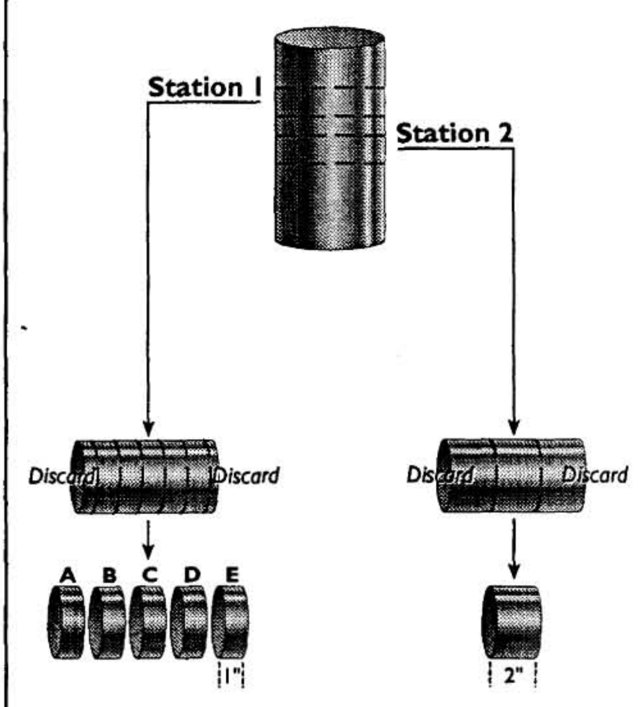
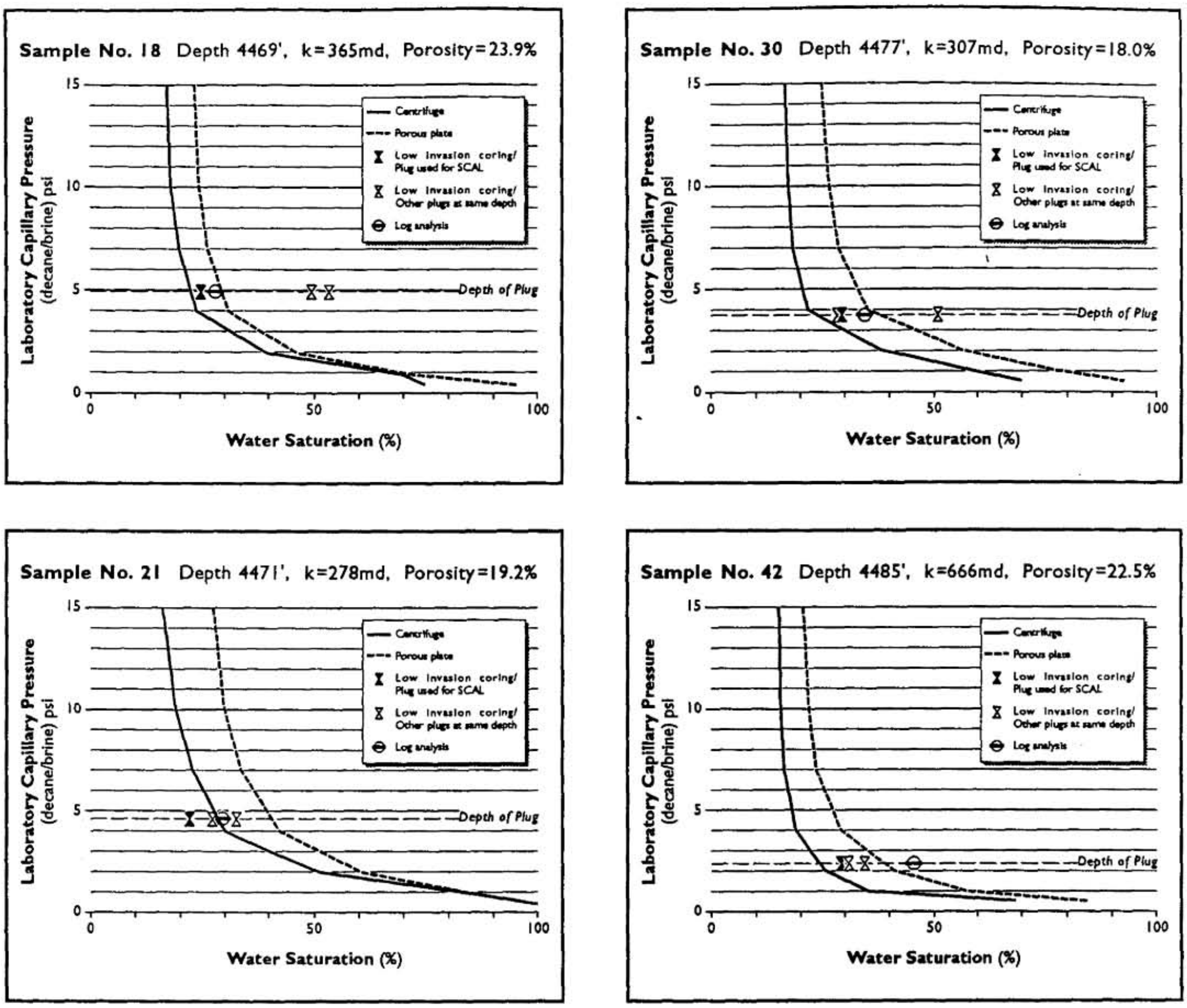


Figure 6 Plugs cut from Low Invasion Core

It is a concern that with 6 estimates of the one thing the range of uncertainty that covers all the 6 estimates is 20% to 30% in saturation units. Although the A,B,C plugs were always within a few inches of each other there was great variation in permeability with very few B, C pairs having similar permeabilities! The differences amongst the saturations of the three plugs are probably mainly governed by permeability differences. The small A plug (only 1") yielded saturation values equally reliable to those from the 2" B plugs.

The two capillary pressure procedures produced results differing by 10%-15% in saturation units. In general we believe the porous plate/cell method is producing more reliable numbers. We see this also in other comparative tests not shown here and are inclined to attribute it to possible shortcomings in the Hassler Brunner correction method, but we have not been able to prove that.

In general the spread in the results from the various measurements is probably indicative of the modest accuracy that is achievable when attention is focussed on one point, whereas usually this sort of data is better for identifying trends. The implications of all the above for log analysis are discussed in reference (3).



Figures 7-10 Comparison of all Water saturation Measurements

3. TRANSITIONAL RESERVOIRS (which have not leaked)

In 1991-92 we conducted a review of the EOR potential of the Eromanga basin where permeabilities are typically hundreds of millidarcies. We were encouraged by the high initial oil saturations (say 80%-90%) and high residual oil saturations (30%-60%) from waterflood that were being observed in the laboratory using laboratory prescribed procedures. We decided to investigate the laboratory procedures more thoroughly.

The first procedure looked at was the determination of residual oil saturation, although it was later realized it would have been better to commence by looking at the determination of initial water saturation. In waterflooding a core to determine the residual oil saturation the laboratories used to like using a particular flow rate through the plug of about 6 cc/min to prevent end effect, even though this effect is only significant in low permeability plugs. This corresponds to a capillary number N generally in the range 10^{-6} to 10^{-4}, much higher than in the reservoir. Keeping all other procedures the same we conducted 3 separate waterfloods at different N values on the same core plug, obtaining much higher residual oil saturation at the lowest value of N, the value closest to reservoir conditions. This was unacceptable as our residual oil saturations were already high.

We then decided to take a more overall view of the experiment and realized that it was pointless to question residual oil saturation without also looking at initial oil saturation. The first reservoir from which some of our test plugs came was very thin and the capillary pressure (P_c) at its crest was about 1.4 psi, which equated to 2.3 psi in laboratory fluids. However the laboratory had brought the plug to "connate" water saturation using a capillary pressure of 120 psi. The preferred practice in the laboratory was to bring plugs to "irreducible" water saturation at the start of a waterflood, irrespective of reservoir conditions. We found that our values of connate water saturation at the start of a waterflood were completely different to the values in capillary pressure tests at a capillary pressure corresponding to that in the reservoir.

Nearly all the Eromanga basin reservoirs are entirely transitional (i.e. within the transition zone of their capillary pressure curves) and there is virtually no rock at irreducible water saturation. We instructed the laboratories to bring plugs to initial water saturation by applying the capillary pressure that prevails in the reservoir. This was done in individual cells at net overburden conditions using a semi-permeable membrane. For our test plug the connate water saturation went from 10% to 40% (experiments 4-13, Table 1). Subsequent waterfloods at low capillary number resulted in a residual oil saturation of 26%, (experiments 6,11, 12), instead of the 42.5% we had obtained previously at low capillary number but starting from irreducible (experiment 2).

It is believed that these phenomena are an example of capillary hysteresis. The higher up the capillary drainage curve a plug is taken the smaller the capillaries and their associated capillary networks that are invaded by oil. These networks become increasingly complicated with the result that the switch from drainage to imbibition sees a greater fraction of oil trapped by the returning wetting phase. The laboratory practice of flooding at very high N values tends to compensate (not necessarily completely) for the practice of bringing the plug to initial water saturation at abnormally high capillary pressures, rather like two wrongs making a right.

The best procedure for obtaining residual oil saturation in our opinion is first to come to initial oil saturation at the capillary pressure that prevails in the reservoir, then to flood at capillary numbers similar to those that prevail in the reservoir (we call this the low P_c/low N method). In the transitional Eromanga reservoirs oil has only entered the pore space at low capillary pressure, i.e. it is only in the biggest pores, and so it is very easily displaced by waterflood.

The above procedures developed on a small number of test plugs were then applied to a larger number of plugs. First we redetermined the connate water saturation in many of the Eromanga basin Namur reservoirs, by applying the reservoir capillary pressure to the plug, and compared the results to the procedure of bringing the plug to irreducible water saturation. The Namur reservoirs are typically only 30 to 40 ft thick. The change in laboratory procedure doubled our average connate water saturation at the top of the reservoir from 15% to 30% and brought the laboratory water saturations into agreement with our log analysis. This also brought the initial oil saturations from waterflood into agreement with our capillary pressure data. (Incidentally, by applying the above procedure at the top of the reservoir it will be valid for both reservoirs which have leaked and those which haven't.)

Next we redetermined the residual oil saturation for a representative group of our reservoirs using the low P_c/low N method and compared the results to those obtained from the traditional laboratory procedure of high P_c/high N. The old procedure appeared to have overestimated residual oil saturation by 5% to 8%. The basin wide average residual oil saturation from 100 measurements using the high P_c/high N procedure was 36%, whereas the average from 15 similar samples using the low P_c/low N method was about 28.5%.

The physics of these oil/water experiments is governed by interfacial tensions, flow rates and viscosities. The reservoir values of these parameters can be reproduced at ambient conditions and hence we consider it adequate to run such experiments at ambient conditions. This would not necessarily apply to 3 phase experiments.

4. MUD TESTING ON CORE FOR FORMATION DAMAGE INVESTIGATION

Underneath the oil rich Eromanga Basin lies the Cooper Basin. Its gas reservoirs are of low permeability, typically some tens of millidarcies. In addition there is a lot of gas reservoired in rock of 1 md and less. Such rocks have a pore size of about 1 micron. We have been investigating our mud systems to see whether they may be damaging these very low permeability rocks. The mud systems have traditionally been bentonite based since temperatures in most of the Basin are too high for polymers.

We have conducted return permeability tests on core but the work is still progressing. In parallel to this work we performed mud particle sizing on the bentonite added to our muds and also on the ground marble recently used in our acidizable muds. The particle size distributions of these two solids were very similar. The major surprise was the massive difference between expressing a particle size distribution by volume and expressing it by number(Figure 11). When the distribution was expressed by volume it gave the impression that our muds contained virtually no particles small enough to enter the formation. When the distribution was expressed by number it became clear that the mud additives contained large numbers of particles that could easily enter the formation provided there was not an effective filtercake.

On comparing the mud particle size distribution to the reservoir pore size distribution (Figure 12) there appeared to be a "perfect mismatch". It does not necessarily follow that the ultrafine mud particles do enter the formation. We examined the outer two or three centimetres of a slice of 1 md core with a scanning electron microscope and could not identify any mud particle penetration. The implication is that the filter cake is "particle effective" i.e. it holds back particles, but this does not necessarily mean it is holding back fluids entirely.

5. SPREADING EXPERIMENTS AT AMBIENT CONDITIONS

Although many aspects of the physics of 3-phase flow cannot be reproduced at ambient conditions, one aspect of 3-phase gas flooding which can be reproduced at ambient is the spreading coefficient. Following published reports (references 4,5,6,7) that residual oil saturation to immiscible gas should depend on the spreading coefficient we conducted one pair of experiments on the same plug

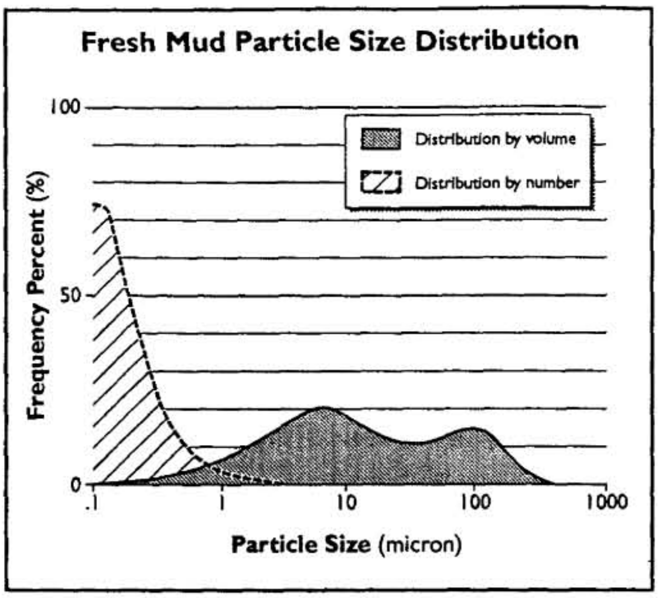


Figure 11 Mud particle size by volume and by number

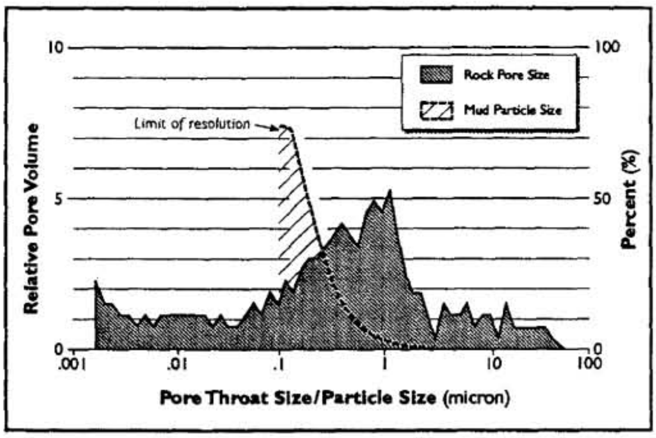


Figure 12 Mud particle size compared to rock pore size

using firstly a positive spreading system and secondly (after plug cleaning) a negative spreading system.

We selected a 500 md plug from the Namur sandstone. The plug was cleaned, brine saturated, and brought to S_{wc} in a porous plate/ cell with a laboratory oil using the capillary pressure in the reservoir (converted to laboratory fluids). It was waterflooded with 2 hydrocarbon pore volumes (HCPV) of water at a capillary number of 10^{-7}. It was then gas flooded in a vertical orientation with 2HCPV of gas at an extremely slow rate (about 0.2 HCPV/day). This rate could only be achieved in the laboratory by injecting gas at 2 cc/hr for 1 hour then ceasing the injection for the rest of the day, however that should give time for gas distribution, spreading and film flow to occur. Finally the plug was gas centrifuged, however the residual oil saturations prior to this step are considered the most meaningful since we are dealing with fairly thin reservoirs. The IFTs for the gas/oil/brine system were measured and the spreading coefficient S was positive (+23). We then cleaned the plug and repeated the whole experiment using a doped brine with S negative (-10). The results were:-

	Positive Spreading System	Negative Spreading System
Connate water saturation at 1.4psi reservoir capillary pressure	41.1%	35.4%
Residual oil saturation after 2 HCPV waterflood at $N = 10^{-7}$ capillary number	25.3%	25.7%
Residual oil saturation after 2 HCPV gasflood at 0.2 HCPV/day	24.2%	22.6%
Residual oil saturation after centrifuging with gas to 25 psi	15.7%	13.3%

Viscosities of oil and water were of the same order of magnitude as those at reservoir conditions so film flow should be at similar rates. The time allocated to the gas injection process compares favourably with the time frame usually used for longer stacks in gravity stable experiments. The water/oil displacement was tested for end-effect and this was found to be negligible.

In general we do not feel that gas floods at ambient conditions are meaningful as the physics is fairly different to that at reservoir conditions. However since the spreading effect can be demonstrated to exist at ambient conditions, and in the absence of rock, we thought that the above procedure should be valid.

We obtained essentially the same residual oil saturation in both cases, after waterflood then gasflood. This is in contrast to previous work by other authors where residual oil was observed to be much lower for a positive spreading system than for a negative spreading system. Previous work was done either on micromodels or on unconsolidated rocks with very unusual properties such as extremely high permeability or extremely high porosity or extremely low connate water saturation.

Tentatively we tend to draw the conclusion that spreading effects may not necessarily manifest themselves in relatively ordinary rocks. However further work on this process would be beneficial to the industry.

Further details of the experimental procedure are in Appendix 1.

6. WETTABILITY AND RELATED ISSUES

A small number of wettability tests have been conducted in the Eromanga Basin yielding strongly water wet results on native state core and neutral to slightly oil wet results on restored state core. We have no other evidence to support the suggestion that any reservoirs may be oil wet. The one reservoir that has tested as slightly oil wet (Dullingari Murta) was probably not representative of the Basin since it is the least transitional, having higher closure and higher permeability than other reservoirs. Nevertheless it was subjected to some comparative testing as shown in the following table:-

	Waterfloods without Wettability Restoration		Capillary Pressure Tests after Wettability Restoration		Waterflood after Wettability Restoration
Plug	D47	D46	D46	D9	D46
Connate Water Saturation %	10	19	19	19	20
Residual Oil Saturation %	44	44	27	21	22

The first conclusion is that water saturation after wettability restoration is the same as that without wettability restoration. This agrees with the data presented in Figures 7-10 where native state measurements of water saturation from low invasion coring appear to exhibit no systematic difference with values from cleaned plugs.

The second conclusion is that there may be scope for residual oil saturation to drop after wettability restoration, but all our other measurements of residual oil saturation in the Basin on cleaned core as summarised in Section 3, are considerably lower than those obtained for this reservoir so any further reduction in s_{or} would have to be small.

All the inferences in this section are presumably very basin specific.

7. CONCLUSIONS

Each of the foregoing sections has its own conclusions. Many of these conclusions are tentative owing to the small number of experiments upon which the conclusions are based. Nevertheless the experiments were painstakingly designed. Looking at them all together it is concluded that there are still many aspects of our technology in need of more fundamental research. Existing core analysis technology is quite powerful provided it is correctly applied, but that is not always the case. There is a need for a better understanding of the physics of core analysis to be disseminated more widely.

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Appendix 1

(A) Coreflood Procedure - Positive Spreading Case

The sample was evacuated and pressure saturated with brine, placed in a cell on a semi-permeable membrane and desaturated with nitrogen to connate water saturation. To remove the nitrogen the sample was then flushed under back pressure with a positive spreading oil prior to a constant rate incremental waterflood performed at a capillary number of 1.37×10^{-7}. Oil production was monitored as a function of hydrocarbon pore volumes (HPCV) throughput. After 2 HCPV throughput a constant rate inert gas injection was performed with incremental recovery of water and oil recorded as a function of gas HCPV throughput. A centrifuge drainage capillary pressure was then performed with humidified inert gas (air) displacing oil and brine.

Details of Gasflood Step

Inject 0.2 HCPV gas at a rate of 2cc/hr (the minimum possible pump rate). Cease injecting. Wait 24 hours.

Repeat the above step until 2 HCPV of gas have been injected.

(B) Coreflood Procedure - Negative Spreading Case

(a) Clean and humidity dry sample.

(b) Re-run porosity and permeability to check sample integrity.

(c) Saturate sample with formation brine doped with butanol (to give negative spreading).

(d) Porous plate desaturation with nitrogen.

(e) Replace nitrogen with oil.

(f) Conduct a waterflood susceptibility at a capillary number of 10^{-7}.

(g) Conduct a low rate gas flood with humidified nitrogen recording production vs PV injection.

(h) Conduct a gas flood using centrifuge as drive mechanism for displacing oil/water.

BIALA #7 NAMUR CORE FLOODS, PLUG 5R

(k_{air} = 660 md, Ø= 26% at overburden)

Experiment Number	Type of Experiment	Method	Laboratory Cap Pressure used to reach "connate" Water Saturation (psi)	"Connate" Water Saturation (%)	Differential Pressure used for Water Flood (psi)	Residual Oil Saturation after Water Flood (%)	Residual Oil Saturation after Inert Gas Flood (%)	Capillary Number N	Non Wetting Phase in Lab	IFT in Lab
1	relative permeability		120	10.1	6	26.6	-	6.9×10^{-6}	ONDINA/I	23
2	waterflood		120	10.1	2*	42.5	30.0	8.7×10^{-7}	"	23
3	waterflood		120	10.1	25.5	25.7	19.3	6.4×10^{-5}	"	23
4	single point cap pressure oil/brine	ppco	2.3	41.4	-	-	-	-	HEXANE	51.1
5	2 point cap pressure oil/brine	ppco	5	39					HEXANE	51.1
6	waterflood		5	39	0.1	25.8	-	4×10^{-9}	ONDINA/I	23
7	mobilization		5	39	incr to 126 in stages	23.8	-	incr to 1×10^{-3} in stages	ONDINA/ ISOPAR	23
8	2 point cap pressure, air/brine	cent	3.3, 7	52, 39					AIR	72
9	end effect test		3.3, 7	52, 39	end effect negligible over range N = 4×10^{-9} to 1×10^{-5}					
10	single point drainage cap pressure air/brine	ppco	7	36.8					AIR	72
11	imbibition cap pressure	ppco	4.6, 2.3, 0		-	29.9	-		AIR	72
12	1pt cap press + water flood	ppco	2.3	43.4		26.0	-	4×10^{-9}	DECANE	50.6
13†	2 pt cap pres sand water flood	ppco	1.15	42.0		32.7		4×10^{-9}	DECANE	50.6

Notes: *max res cap pressure = 1.4 psi; assumed res IFT = 30 dyne/cm*
ppco = porous plate/cell at overburden.

† *results of experiment 13 considered unreliable*

Lines marked ———— *represent the end of a series of 1 or more experiments, ie. plug then cleaned*

* *no flow initially at 0.255 psi*