SOME OBSERVATIONS ON THE CAPILLARY PRESSURE HYSTERESIS USING THE ULTRACENTRIFUGE

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ABSTRACT

The use of centrifuge technology for the determination of capillary pressure characteristics of reservoir rocks has received increasing attention in the recent decades. In recent experiments it has become evident that the hysteresis observed in the centrifuge experiments is different than the hysteresis observed in the traditional porous plate measurements. More specifically, the value of the "irreducible" wetting phase saturation seems to shift between the first drainage cycle and the second drainage cycle. This phenomenon was studied in some detail in our laboratory. Approximately sixty (60) core plugs were tested under a variety of conditions which included crude and refined oils at room and reservoir temperatures. The cores used were Berea sandstone, Baker dolomite and plugs from various carbonate pinnacle reefs of Western Canada. The tests were conducted using reservoir core that was in both native and restored state. It was found that the widest hysteresis occurred when crude oil was used. The hysteresis was more significant in carbonates than in sandstones. This can be only partially attributed to the fact that the carbonates have significantly smaller pore volumes (i.e. a higher expected experimental relative error). However, the trends on clean carbonates (Baker dolomite) are opposite to the ones of reservoir rock. Also, there seems to be no significance on the effect of saturation history (i.e. whether or not the displacement was single or multi step).

INTRODUCTION

The measurement of the capillary pressure characteristics of a rock / fluid system and its incorporation into the characterization of a given reservoir is a complicated and often controversial process. The centrifuge is a tool that provides an easy and fast way of estimating wettability and capillary pressure characteristics.

Dean Stark extraction technique. Toluene was used as the primary hydrocarbon solvent while methanol and acetone were used as salt and water solvents respectively. The samples were then saturated with a synthetic formation brine and brought to initial water condition through a primary drainage by the use of the ultracentrifuge. The samples were then aged under crude oil at ambient temperature for a period of 1,000 hours to restore the original wetting properties. In the case of the native-state tests, core samples were drilled from cores that were preserved under formation brine. Drilling was done using formation brine. To insure that there was no air or solution gas in the samples, vacuum was applied while the samples were kept under brine. The samples were thus brought to the same initial condition as in the restored-state case.

The combined Amott/USBM procedure was used for the assessment of wettability. Drainage and imbibiiton capillary pressure curves were also obtained (Nikakhtar *et al.*, 1993). All tests were performed using synthetic formation brine and "dead" crude oil from the pool at reservoir temperature. The analysis of the raw centrifuge data for capillary pressure was done by using a computer program that calculates the best fit for a given set of data (Ruth and Wong, 1990).

RESULTS AND DISCUSSION

In most cases the first cycle drainage was done in a single step to reduce the total experimental time. However, a series of "native" state samples were run under multistep first and second drainage cycles specifically to identify any differences in the the whole drainage curve (as opposed to the irreducible wetting phase saturation alone). Some of these tests are shown in Figures 4 and 5. The curves of Figure 4 are all from the same well, identified as Well I and they come from the Rainbow Keg River reefs of the North Western Alberta. The curves of Figure 5 are coming from the same pool but from a different well. It can be clearly seen from both figures that there is considerable hysteresis between first and second cycle drainage, but the difference in the irreducible water saturation between the two cycles is not consistent. In many cases the second drainage irreducible water saturation is lower than that of the first drainage, while in others the opposite holds. This dependency did not seem to correlate with porosity or permeability.

In Figure 6 the residual water saturation after the first drainage cycle is plotted against the residual water saturation after the second cycle. A large number of samples have been included in this figure that cover a wide variety of experimental conditions. All the "native" core samples are included along with a large number of restored state core samples from the same and other pools. For comparison purposes, the results from samples of Berea sandstone and Baker dolomite are also presented. With these samples, the tests were performed using both crude oil and refined oil at both reservoir temperature and room temperature. When refined oil was used, both at reservoir and room temperature, the shift of the irreducible water saturation was very small. This small shift is considered within the experimental error of the system. The shift was larger when crude oil was used. Both Berea and Baker cores exhibited significant shift to lower irreducible water saturation in the second drainage. This was opposite to all the "restored" core samples, which consistently gave much higher irreducible water saturation in the second drainage than in the first. Yet the "native" state core samples were divided, with some having higher irreducible water saturation in the first cycle and some giving higher irreducible water saturation in the second cycle. This behaviour was too consistent to be a coincidence.

An attempt was made to correlate hysteresis with other sample properties. Plots were prepared of the difference between the first and second cycle residual water saturation as a function of various properties. The most significant of these plots are presented next.

Figure 7 shows the difference of the residual water saturations (Sw at the end of the second drainage less Sw at the end of the first drainage) versus the USBM index. Although the data are scattered, it is clear that there is a monotonic trend indicating that the difference decreases as the sample becomes more and more water wet. A large positive difference of the parameter [Sw(2)-Sw(1)] was observed at large negative USBM numbers, which decreased to a small negative difference as the USBM index increased to a large positive value.

The same trend was observed when the saturation difference was plotted against the Relative Displacement Index - RDI (Figure 8). RDI is defined as the difference of the Amott index to water minus the Amott index to oil. The trend remained when the saturation differences were plotted against the Amott index to water (Figure 9). When the same differences were plotted against the Amott index to oil (Figure 10), the trend disappeared.

From the above analysis it was evident that either the wettability is being alterred with cycle, or that the fluids follow different paths while penetrating the core with each cycle. The argument that wettability shifts with cycle would be consistent with other literature information (see for example the review in Nikakhtar *et al.*, 1993). In general, the restoration process made the core samples from the pinnacle reefs less water wet. On the contrary, multiple cycles made Berea and Baker cores more water wet. This observation cannot be explained at this moment.

There was no particular correlation between the saturation difference and the wettability numbers, or porosity and permeability of the "native" state samples. The best correlation was with the formation depth of the plug. It is shown in Figure 11. The samples that had negative saturation difference were all taken from the oil bank zone, while the samples with possitive saturation difference were taken either from above the gas / oil contact or below the water / oil contact. The contacts were the current contacts at the time when the well was drilled and core was cut. This indicates that saturation history in the reservoir may play a much more important role than initially anticipated. Further work is needed in this direction to confirm these findings.

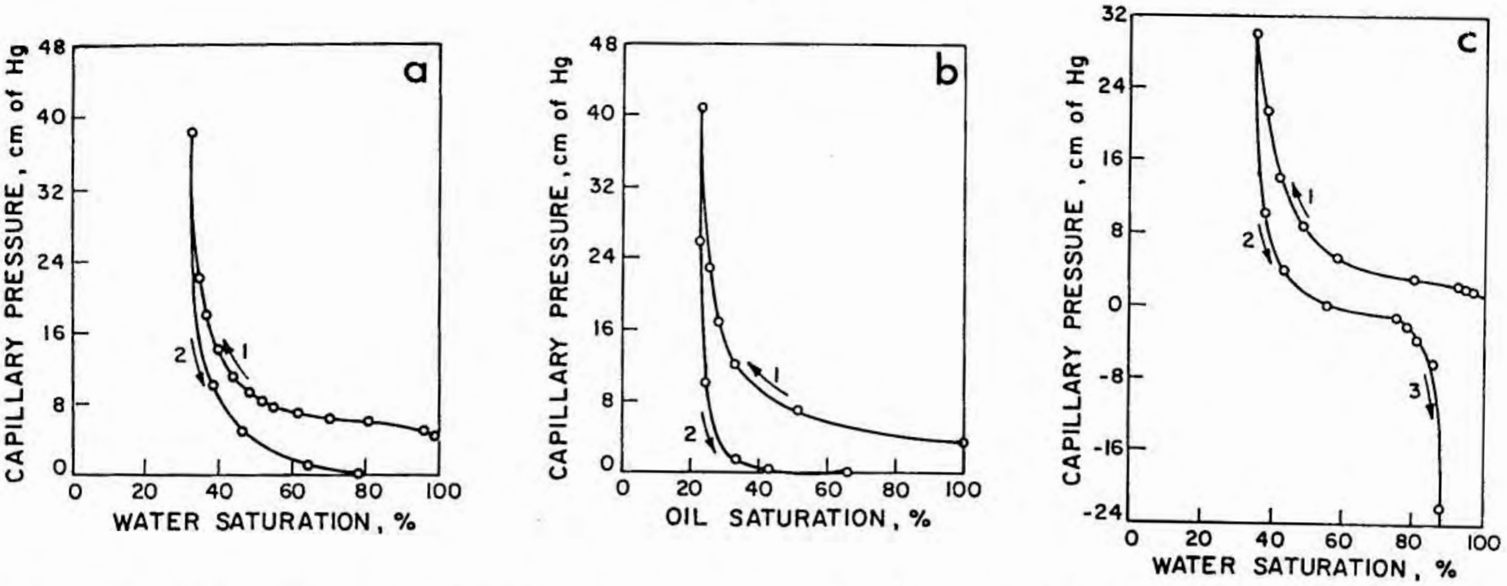

Figure 1: Capillary pressure characteristics of systems with different wettabilities: (a) Venango water-wet rock, (b) Tensleep oil-wet rock, (c) Berea fractional wettability rock (from Killins *et al.*, 1953).

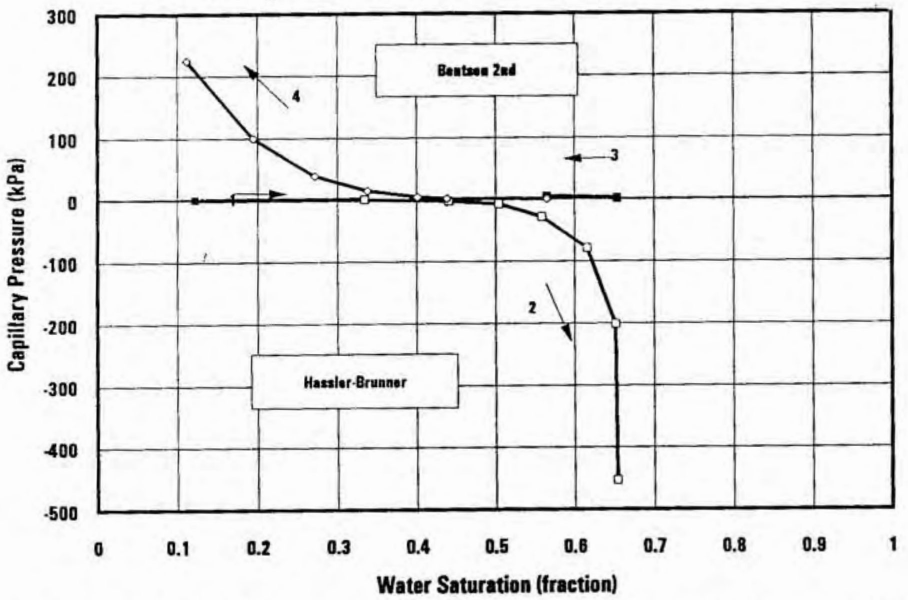

Figure 2: Capillary pressure curve as derived from the centrifuge experiments.

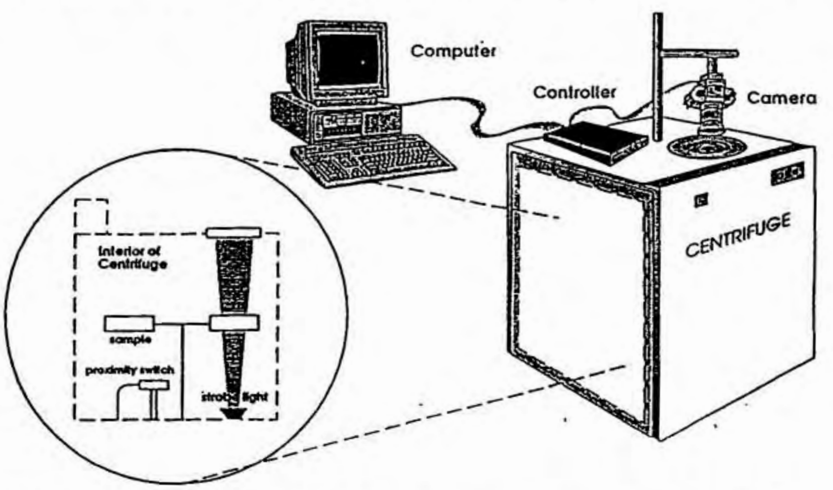

Figure 3: Schematic of the ultracentrifuge apparatus.

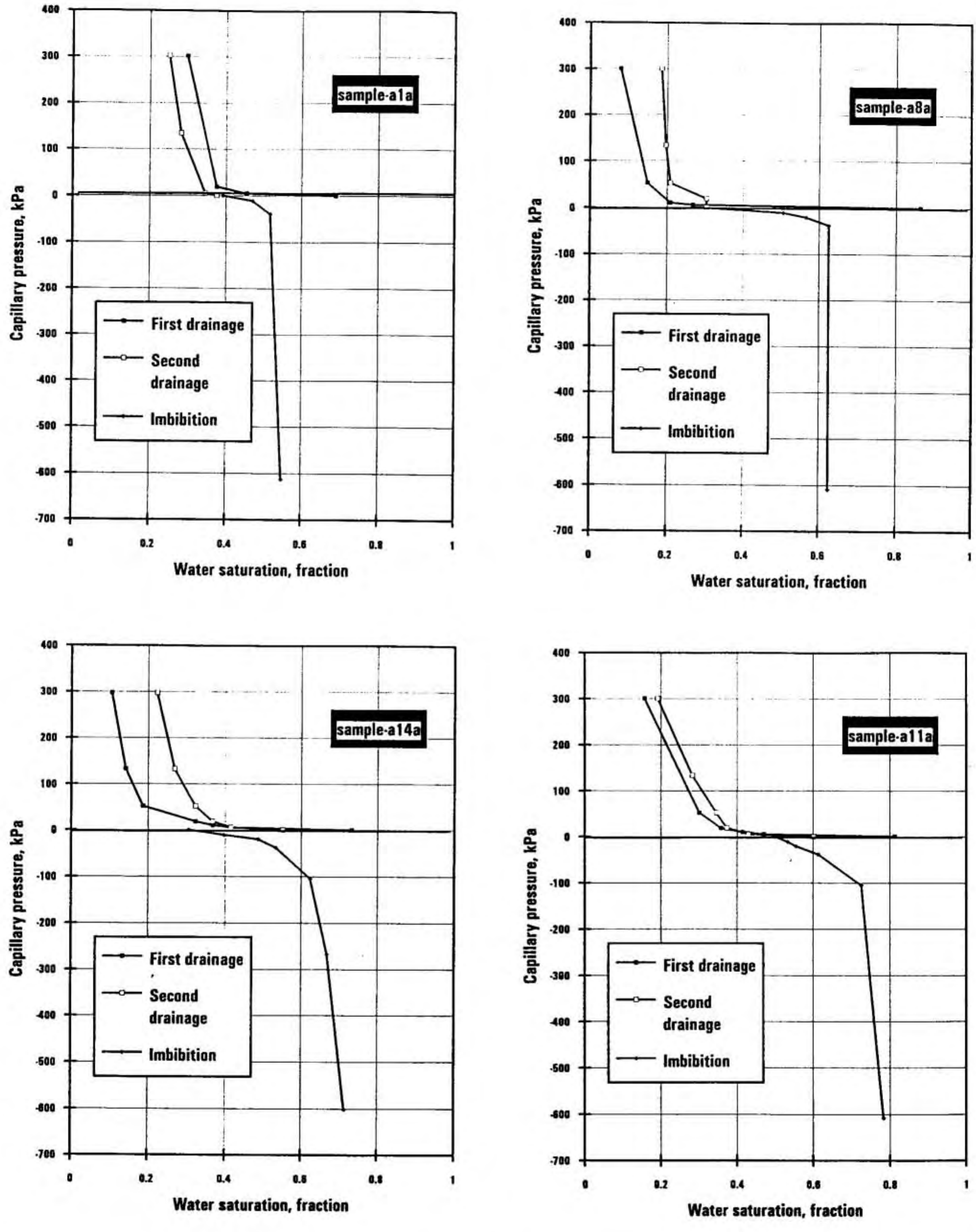

Figure 4: Primary and secondary drainage curves from plugs of well I using the centrifuge.

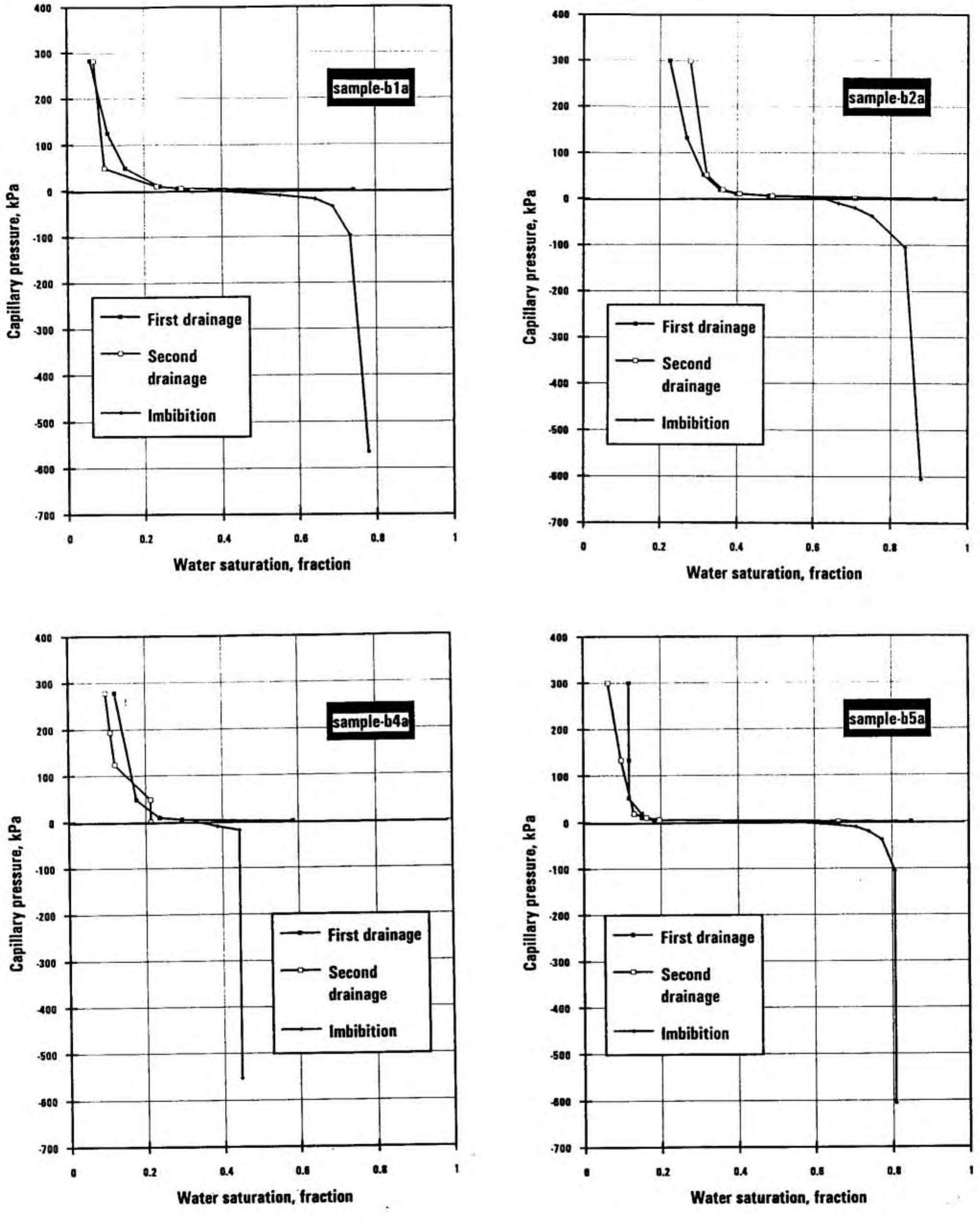

Figure 5: Primary and secondary drainage curves from plugs of well II using the centrifuge.

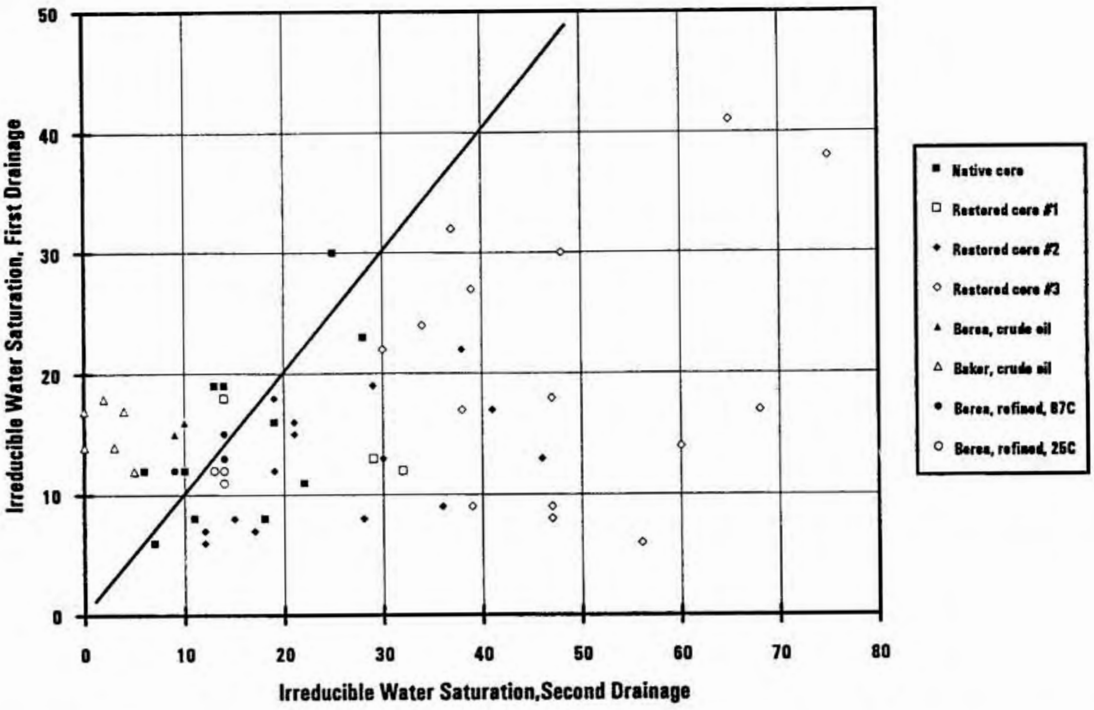

Figure 6: Irreducible water saturation for second drainage plotted against the irreducible water saturation for the first drainage.

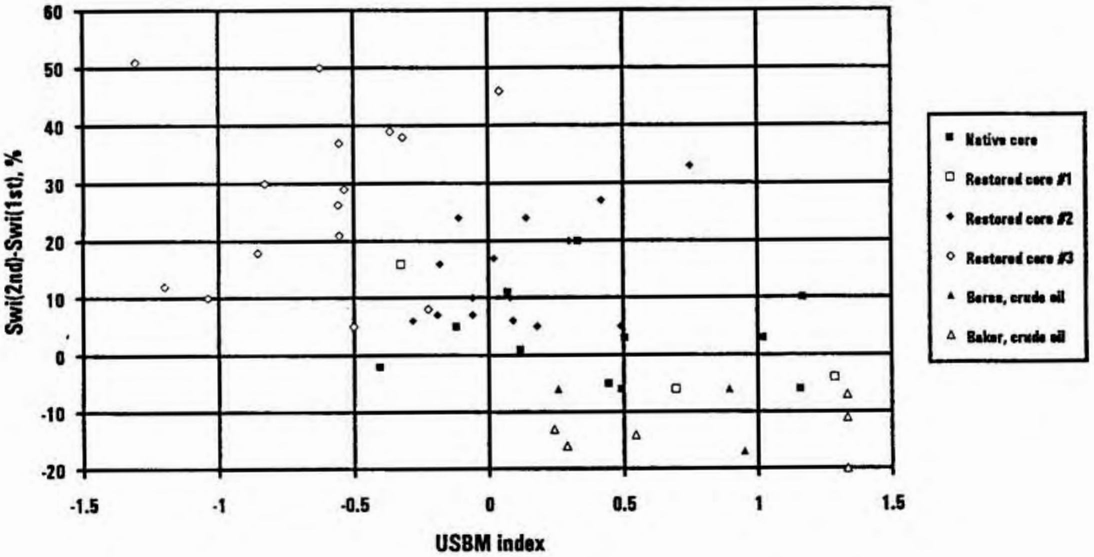

Figure 7: Irreducible water saturation difference plotted against the USBM index.

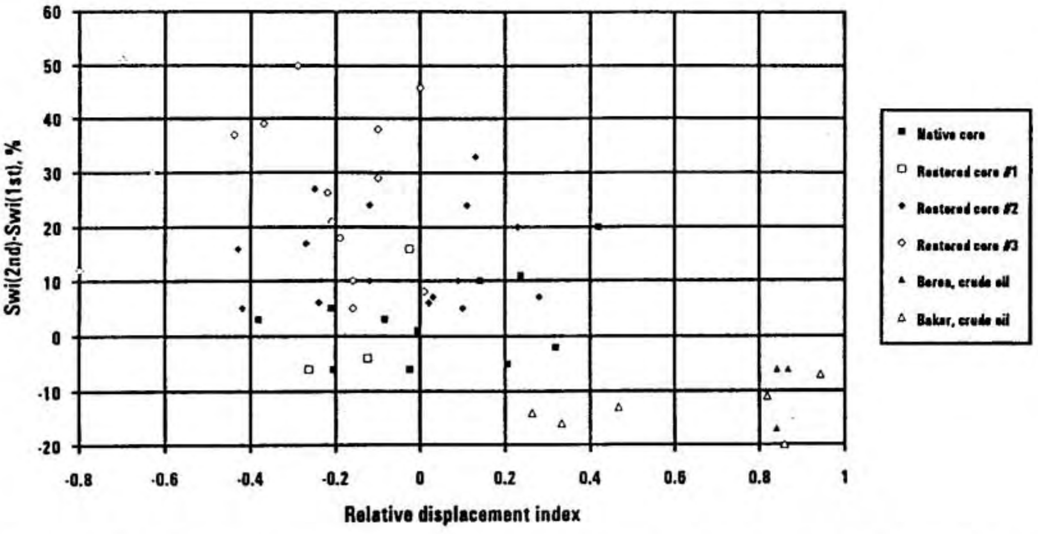

Figure 8: Irreducible water saturation difference plotted against the relative displacement index.

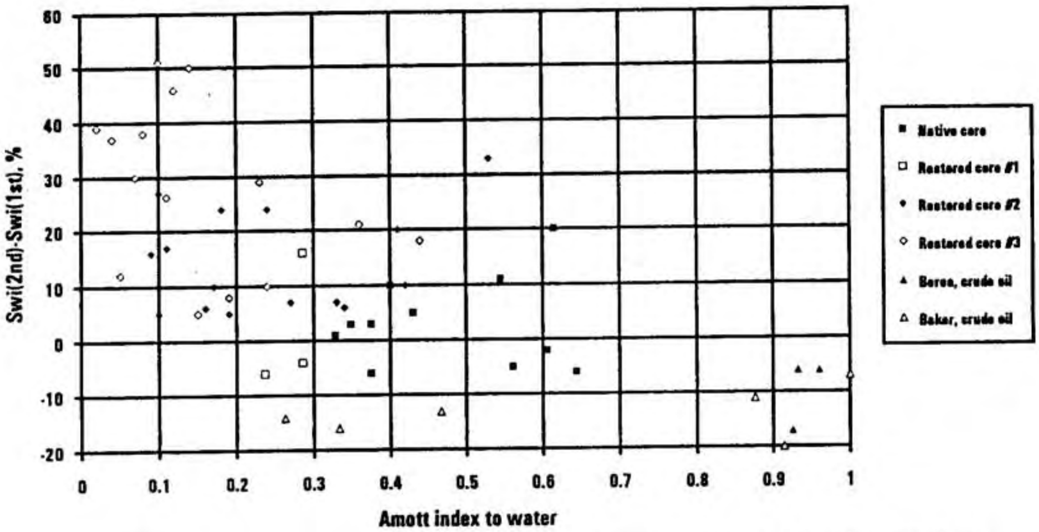

Figure 9: Irreducible water saturation difference plotted against the Amott index to water.

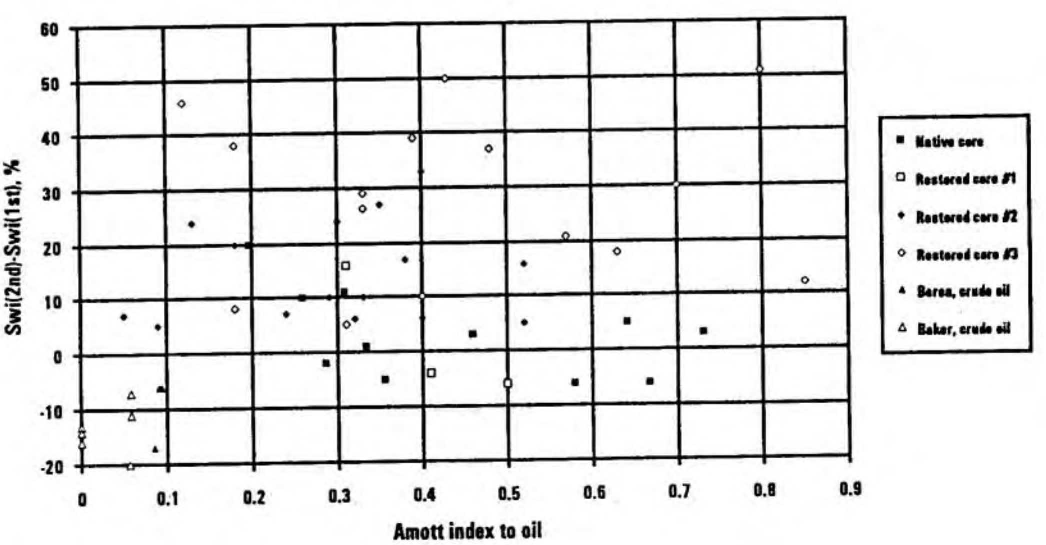

Figure 10: Irreducible water saturation difference plotted against the Amott index to oil.

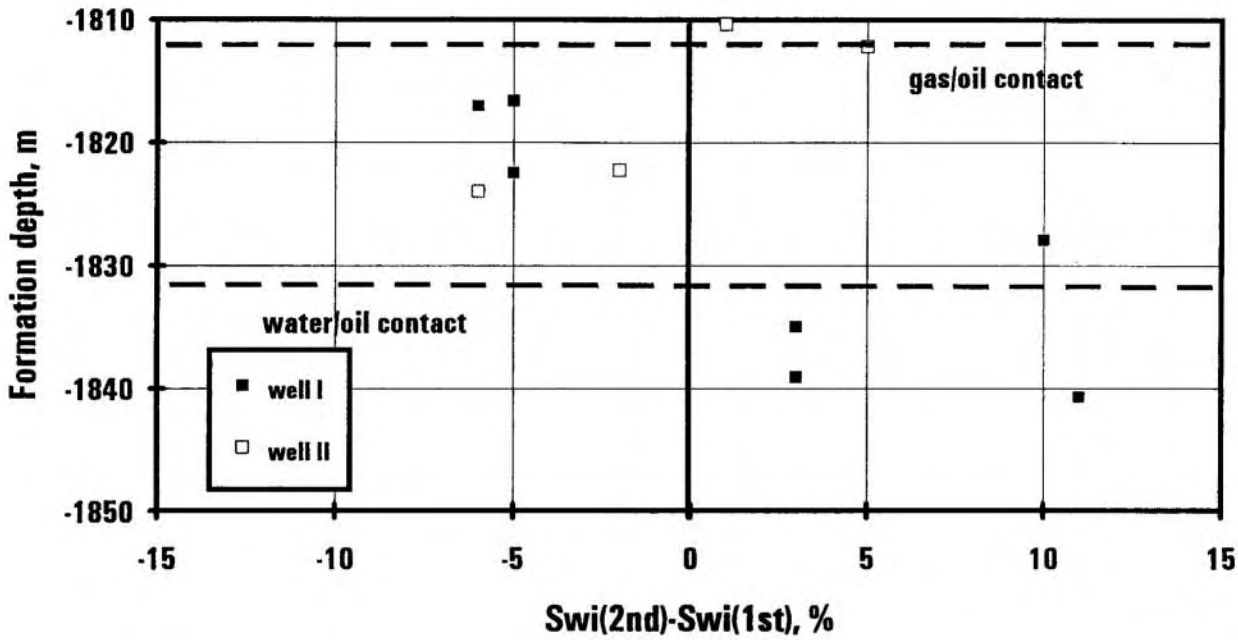

Figure 11: Irreducible water saturation difference plotted against depth of formation for the "native" state core plugs.