IMPROVING THE EVALUATION OF PETROPHYSICAL PROPERTIES FOR UNCONSOLIDATED SANDS

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ABSTRACT

The importance of inter-bedded turbiditic sand formations and its reservoir production potential is widely recognized. The reservoir quality of thin laminated units is often very good and can contribute a significant amount of the reservoir production. Logging and interpretation methods can lead to an underestimation of hydrocarbon reserves or, in extreme cases, even missing these reservoir zones. Core data, when available, play an important role in the characterization of these laminated sands. However, some of these formations are unconsolidated or very poorly cemented, so core plugs are very difficult to obtain.

The aim of this paper is to assess the type and quality of data that can be obtained from synthetic core plugs, built from loose turbiditic reservoir sands, following a novel experimental procedure. The synthetic plugs were prepared with the material, mineral compositions, from the cores. They were then loaded into the multi-sample pressure cell and overburden stress cycles applied to investigate the effect of hydrostatic pressure on porosity, formation factor and water permeability. The loading-unloading stress cycles produce large hysteresis in these properties. On the other hand, the cementation exponent is almost constant.

The results obtained at the end of the stress cycle were compared with data from ten core plugs, which after some initial tests lost their integrity (became loose sand) and were afterwards used to prepare synthetic core plugs. An excellent agreement was found for porosity, formation factor, and cementation exponent; while a fair agreement was also found for permeability. These synthetic plugs were also used to measure some additional petrophysical properties such as NMR (T_2 distribution and cut off), gas-brine capillary pressures and resistivity index. The results show that this new laboratory methodology can be used to obtain and predict reliable petrophysical properties for poorly consolidated sands to improve reservoir evaluation.

INTRODUCTION

The potential for hydrocarbon production from inter-bedded formations has become apparent over the last few years. Their sequence with beds of sand and shales ranging from the centimetre to metre scale commonly constitute the main reservoir, and many of them are poorly cemented or even unconsolidated. Core recovery in unconsolidated reservoirs can be problematic given the formation’s limited cohesive strength. In addition to careful wellsite preservation and stabilisation, the most critical steps are the plugging and handling of such delicate materials. In the laboratory and during all core analysis procedures special care is required and very often core plugs are lost at some stage before the results can be obtained.

The determination of petrophysical data from this disturbed type of material is required for log calibration and desired for reservoir engineering studies. Permeability-porosity relations can be obtained from formations with similar characteristics [1]. However, analogs representing the variation from layer to layer are extremely difficult to find. Thus, it is desirable to obtain the data directly from disturbed core plugs for the formation and layers/beds of interest.

The origin the samples used in this paper is from deepwater in the Mediterranean Sea, from the Lower Pliocene. These reservoirs, which are usually prolific in the region, comprise turbiditic sands and associated shales deposited in a basin floor fan system. The sands were supplied via a number of submarine canyons, which cut back into the Pliocene shelf. It is likely that the fans were deposited at a relative sea level low-stand. Sand deposition ceased as sea level rise drowned the sand dispersal system. The canyons are now buried beneath thick Plio-Pleistocene claystones forming the reservoir seal.

This paper presents a methodology to improve the characterisation of such formations by using routine and special core analysis data and the identification of laminated turbiditic sands by using synthetic core plugs, built from loose reservoir material.

EXPERIMENTAL APPARATUS AND PROCEDURE

The test rig consists of a multi-sample core holder where up to five rock samples can be simultaneously tested [2]. The samples were enclosed in Viton sleeves, with flow lines and electrical circuit. The pore pressure system consists of two fluid interface units, one used to introduce brine (permeability measurements) or gas for drainage. The second unit is used to monitor the pore volume or the volume of brine displaced from the samples. The multi-sample experimental rig was used for the measurement of variation of pore volume, electrical resistivity and permeability with confining stress. Gas drainage experiments were also performed in the multi-sample core holder, which was used to determine resistivity index and capillary pressure curves.

Test procedure

The synthetic core samples were prepared from unconsolidated loose reservoir sands following a novel procedure, developed at Imperial College, which is based on a previous technique pioneered by X.D Jing [3]. The synthetic samples were saturated with simulated formation brine and placed in a multi-sample cell. Then the samples underwent two loading and unloading pressure/stress cycles from 500 psi to 1800 psi. Pore volume and resistance change during the stress cycles were measured. The permeability to brine at various hydrostatic pressures was measured for each sample. The core samples where then removed from the cell, the bulk volume determined by Archimedes (buoyancy) and the NMR T_2 relaxation at full brine saturation measured. Selected samples were drained using a porous disk with nitrogen under a hydrostatic overburden pressure of 600 psi. At each capillary pressure equilibrium point the displaced volume and resistivity across the sample were measured, allowing the simultaneous measurement of both capillary pressure and resistivity index curves. NMR T_2 distributions were also measured at irreducible water saturation. This allowed the verification of the irreducible water saturation and the determination of the T_2 cut-off value.

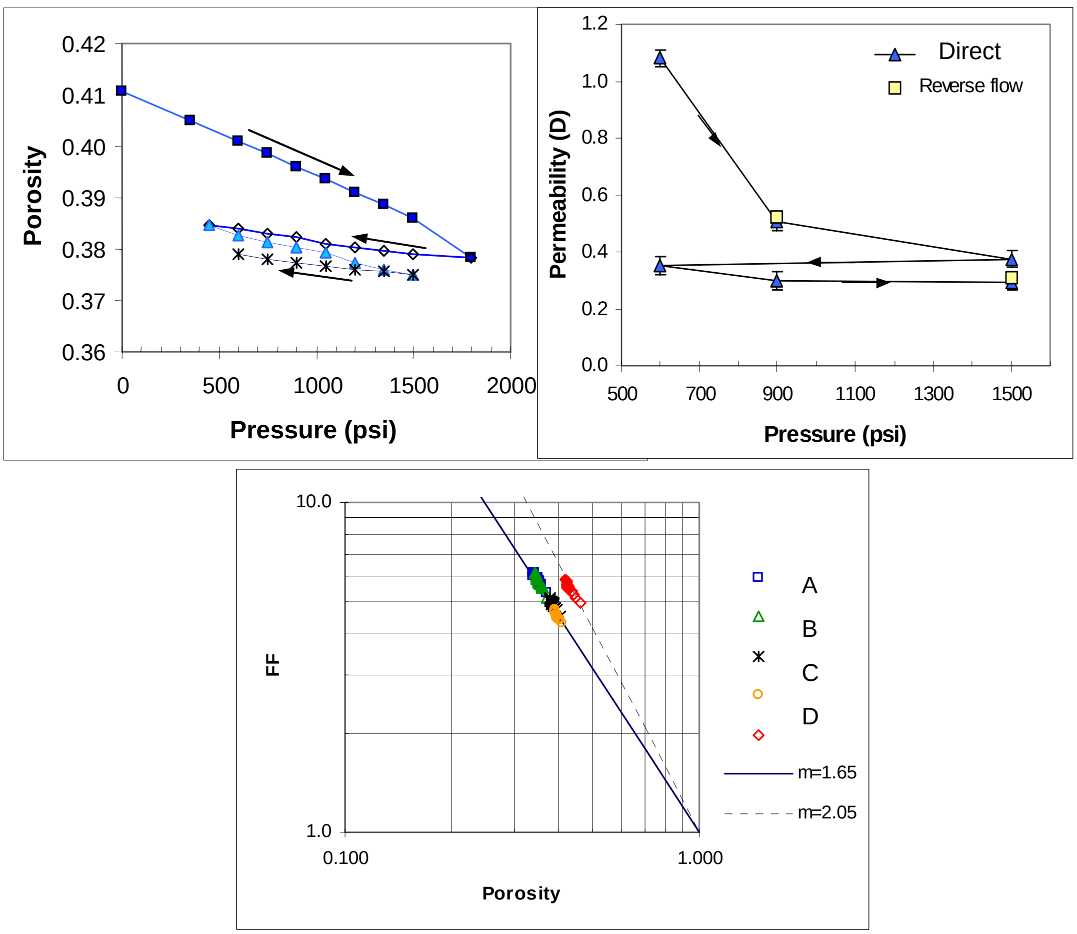


Figure 1. Effect of hydrostatic stress on porosity, permeability and formation factor for a brine saturated synthetic plug, during two loading and unloading cycles.

NMR T_2 relaxation measurements were performed in a Resonance Instruments MARAN 2 spectrometer at ambient pressure and 34.0 ^oC. The methodology for obtaining the T_2 distributions from the CPMG echo-train and parameter settings used has been reported elsewhere [4].

EXPERIMENTAL RESULTS AND DISCUSSION

Effect of hydrostatic stress

Porosity, electrical resistivity and permeability have been monitored during the stress cycles. The change hydrostatic confining pressure leads to hysteresis effects as shown in Fig.1. The observed hysteresis in porosity and resistivity is in agreement with previous observations in shaly sands and sandstones [5]. Due to space reasons only the data for one sample will be presented in this section.

Porosity and brine permeability, Fig. 1A and 1B, decreases with confining pressure, presenting a large hysteresis during the first loading cycle, and decreasing in the following cycle. During the stress cycles, the formation factor increased while porosity decreased with confining pressure, thus resulting in almost constant Archie cementation exponent, Fig 1C.

It is worth noting that some samples presented a large permeability variation during preliminary tests (the first loading cycle), which may be due to the movement of fine grains or clays. When the flow direction was reversed a different value of permeability was obtained after a long transient time. The effect of flow direction becomes negligible during the second loading cycle, so these values were measured in further tests. Fine migration and the effect of stress on permeability have been previously reported for unconsolidated sands in the Gulf of Mexico [6, 7].

Comparison of basic properties

The synthetic plugs were prepared with the material from the cores that lost their integrity (became loose sand, see figure 2) after some initial tests. Thus, some data was available from a service laboratory for the original cores. In order to verify the methodology used for the preparing of the synthetic plugs the porosity, cementation exponent and permeability obtained at the base confining pressure (600psi at the start of the second loading cycle) was compared to the initial core plug data. The comparison is presented in Figure 3. It is worth pointing out that as some of the initial core plugs lost their integrity during measurement not all the initial data is available, thus different number of points are plotted in Figure 3(A)-(C). The agreement between porosity and cementation exponent is very good. The permeability of the synthetic plugs correlates well with the core values.

Figure 2. Loose sand material used to prepare the synthetic plugs.

However, their value is lower, within a factor of five of the original core permeability, possible due to the segregation of fines and clay material.

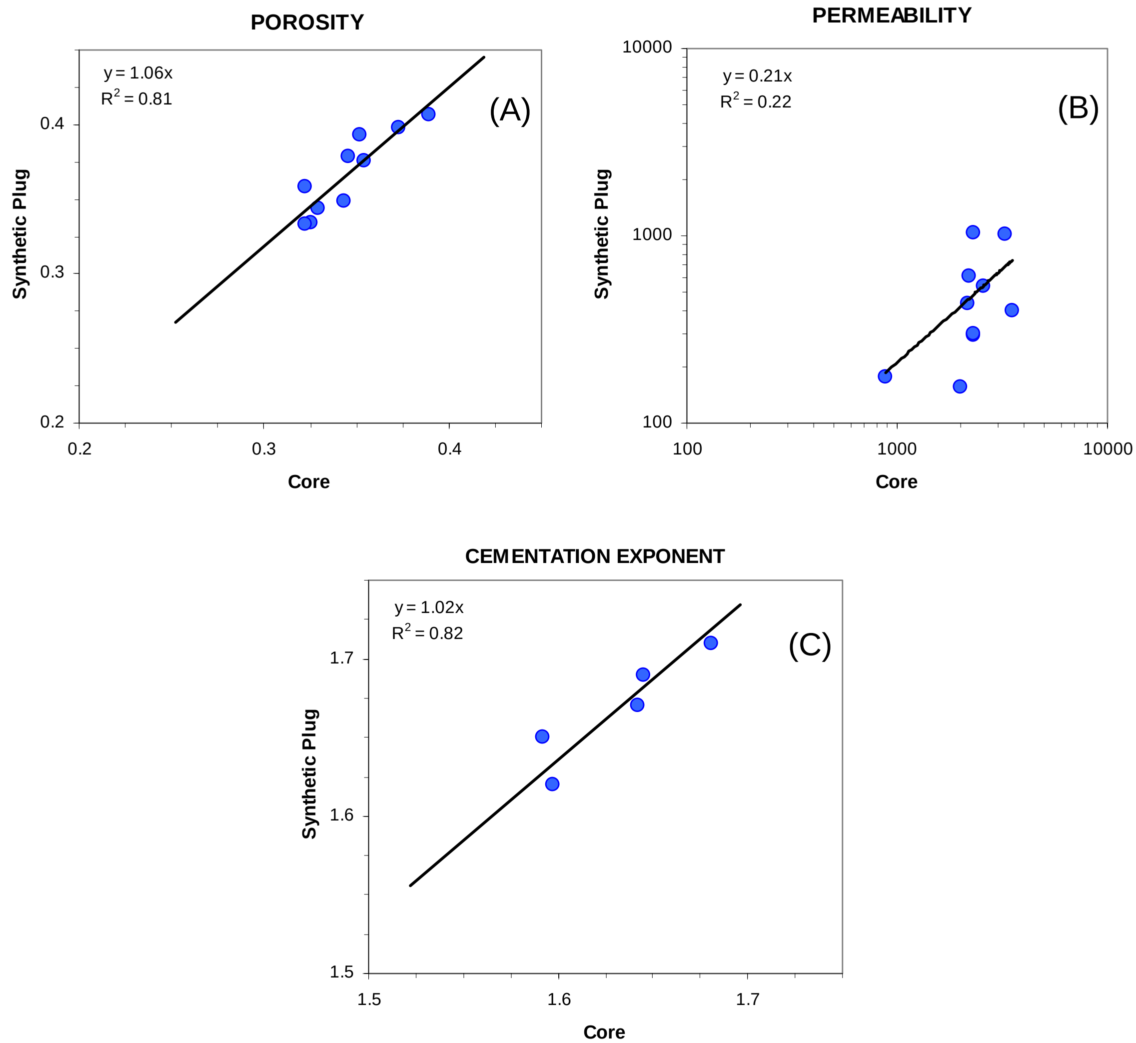
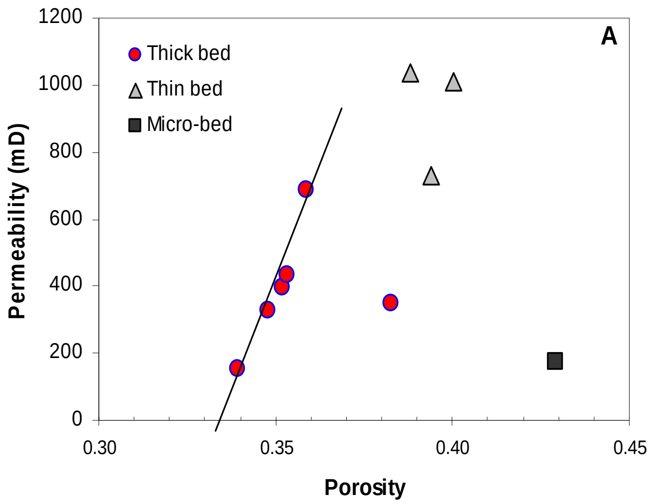


Figure 3. Comparison between core plug porosity (A), permeability (B), and cementation exponent (C) and the respective values from synthetic plugs.

Figure 4 shows porosity-permeability and porosity-cementation exponent crossplots for all the synthetic samples at the base confining pressure. When the data for the ten samples are compared the differences between bed sizes becomes apparent, and different trends can be observed for thick and thin beds with the exception of one sample. It is worth noting that the plugs from thin beds in general seem to have better reservoir quality.



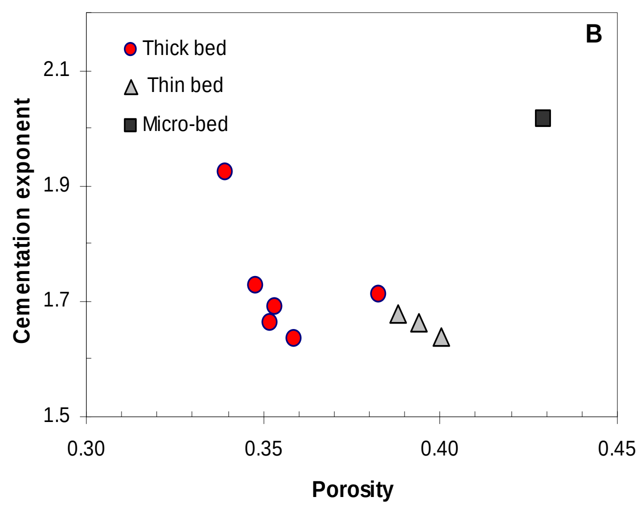


Figure 4. Porosity-permeability and porosity-cementation exponent crossplots at the base confining pressure of 600 psi.

Petrophysical properties from NMR measurement on synthetic plugs

NMR is a rapid and non-destructive tool that can provide an indication of the pore size distribution within the rock. The T2 distributions can be interpreted to provide other petrophysical properties. The NMR results allowed the verification of the porosity after compaction, which was within 2.5 p.u. of the porosity determined under stress. The T2 distributions for the synthetic plugs studied are shown in Figure 5 and they have been grouped according to their NMR characteristics. All the samples present a signal below 10 ms suggesting the existence of different amounts of clay-bound water and therefore an indication of clays. Two different groups exist for the thick layers: one have the main peak at ~ 60 ms for (Fig.5 A) and the other have the main peak ~110 to 150 for (Fig 5 B). The latter group is associated with the larger and uniform grains within sand-rich laminae, which probably control the flow. However, a decrease in the distribution at longer times (larger pores) is observed as the clay bound water increases, suggesting that the changes in cementation exponent and permeability are due to the presence of clays. On the other hand the thin beds, with the exception of sample J, which contains thin clay lamina, have similar characteristics to the second group of thick beds.

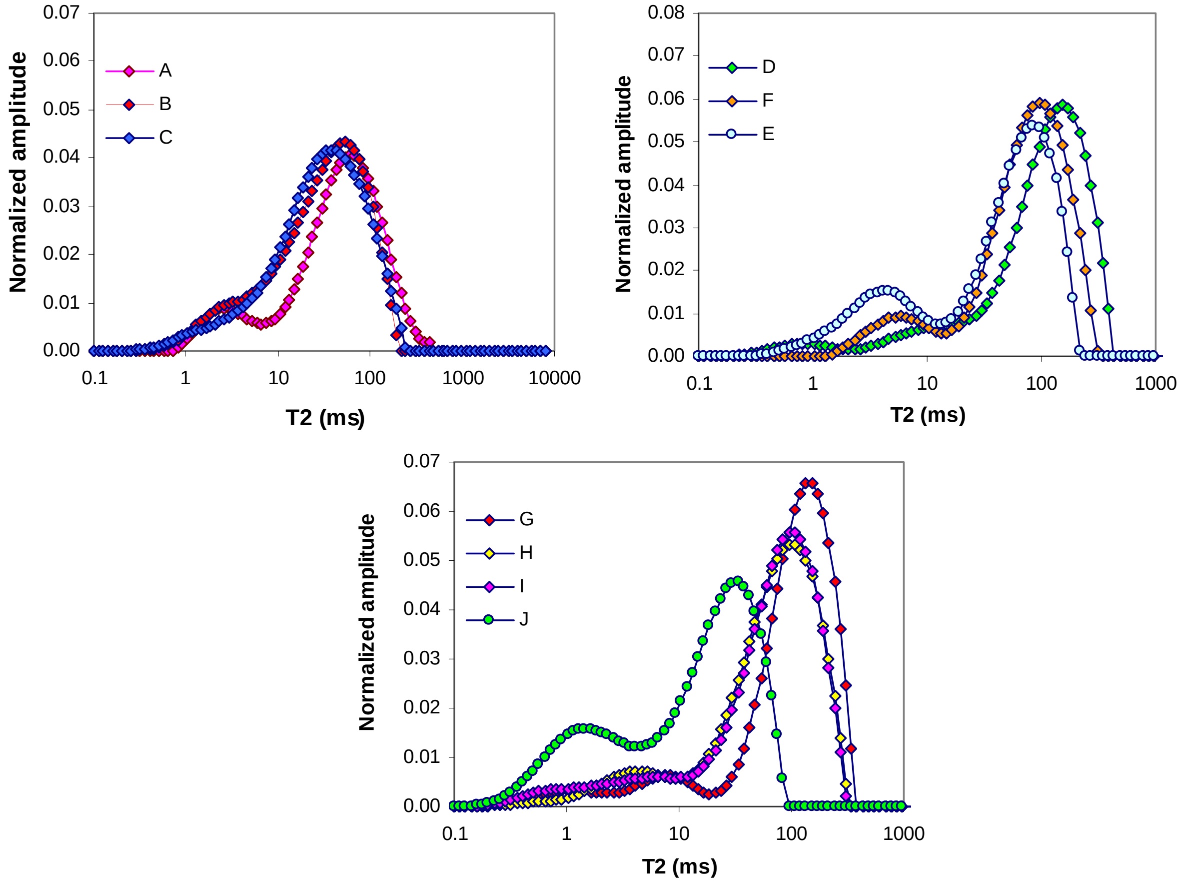


Figure 5. NMR T_2 relaxation data for compacted and brine saturated samples.

The permeability can be modeled from the NMR response following the traditional models of Coates [8] and Kenyon [9]. However, a poor overall match was obtained for these models, possibly due to a lesser influence of the porosity and the characteristics of the T2 distributions. A combined model that includes both the ratio of free fluid (*Ffi*) to bound fluid (*Bvi*) and the T_2 geomertic mean (T_{2m}) gave a better correlation. The best match is obtained with the equation:

$$\boldsymbol{K}(\boldsymbol{md}) = \boldsymbol{C}\left(\frac{\boldsymbol{Ffi}}{\boldsymbol{Bvi}}\boldsymbol{T}_{2\boldsymbol{m}}\right)\cdot\left(\frac{\phi}{10}\right)^2 \qquad (1)$$

The modeled permeability for the synthetic core plugs is plotted in Figure 6.

Selected samples were desaturated with gas under capillary equilibrium, and the T2 distributions of the drained samples were measured. The results were also used to establish the irreducible water saturation. The values obtained from NMR measurements agreed very well with the value calculated from a material balance. The cut-off was derived from the cumulative T2 distribution of the fully saturated sample and irreducible water saturation. This cut-off is used to separate the capillary bound (Bvi) and free fluid volume (Ffi) and it ranged between 7.1 and 9.8 ms, which is much lower than the traditional cutoff of 33 ms.

The NMR response of fully saturated samples can be also used to obtain the drainage capillary pressure. The methodology proposed by Grattoni et al. [10] was used here to obtain the capillary pressure of three samples and the results are presented in Figure 7. The model predicts reasonably well the irreducible water saturation at maximum capillary pressure and the drainage capillary pressure curves show a very good agreement.

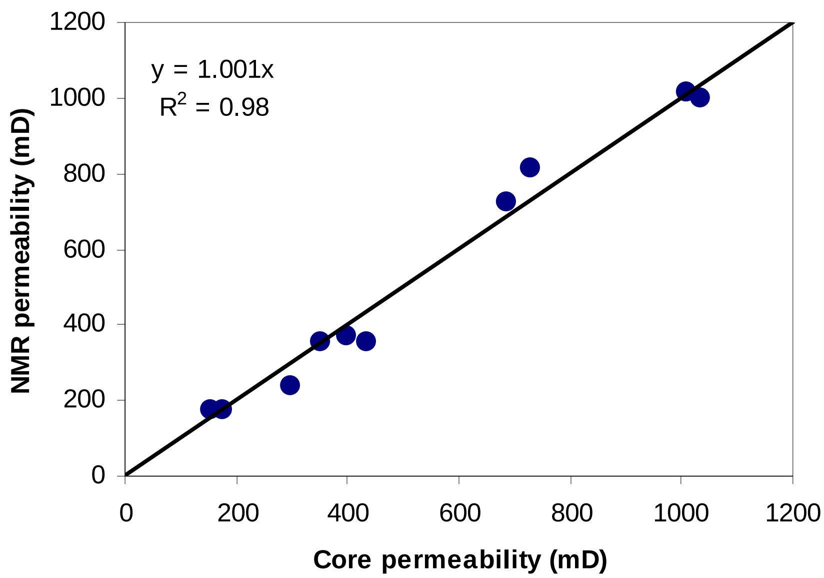


Figure 6: Modeled NMR permeability against synthetic core plug permeability.

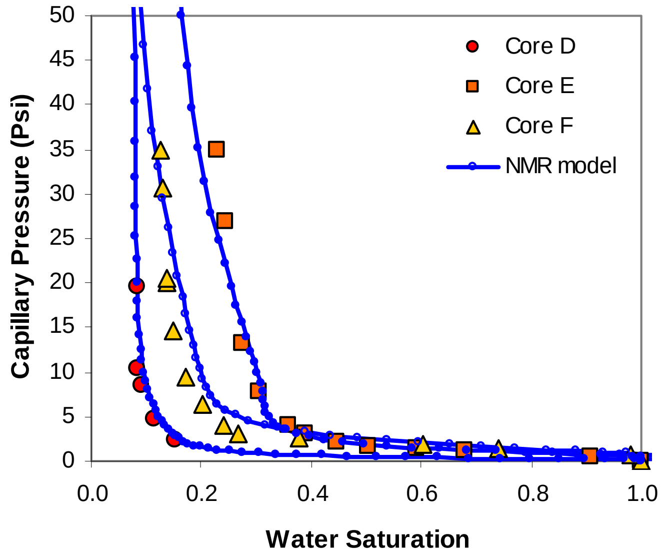


Figure 7. Experimental air-brine drainage capillary pressure curves and NMR derived curves.

CONCLUSIONS

- A methodology to develop synthetic core plugs with built from loose (unconsolidated) reservoir material was developed and tested.
- The porosity and Archie's cementation exponent determined from these synthetic plugs present very good match to the available original core data, while the permeability provides an acceptable match.
- The synthetic core plugs were also used to measure some special core analysis data and correlate several properties from NMR measurements.
- The use of this methodology can improve the characterisation of turbiditic unconsolidated sands and formation evaluation.

ACKNOWLEDGEMENTS

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