FORTY COMPARISONS OF MERCURY INJECTION DATA WITH OIL/WATER CAPILLARY PRESSURE MEASUREMENTS BY THE POROUS PLATE TECHNIQUE

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ABSTRACT

Mercury injection is a relatively quick and low cost technique to obtain capillary pressure data. In this paper we address the following question : Can mercury injection data be used to properly estimate oil/water drainage capillary pressure curves representative of the reservoir ?

This question has been discussed in several previous papers, but there is a relative scarcity of relevant experimental data. This paper presents results from forty comparative tests which have been conducted over several years on consolidated core samples originating from the Gulf of Guinea and the North Sea.

Each test consisted in measuring capillary pressure by two different techniques on two adjacent samples. Mercury injection with capillary pressure values up to 1000 bars was used on one sample and a higher cost oil/brine porous plate technique was applied on the adjacent sample. This latter technique consisted in measuring capillary pressure with stock tank oil and brine under stress and temperature. The effective confining stress, the concentration of the brine and the temperature were chosen in order to be representative of reservoir conditions. Such measurements are assumed to be more representative of the actual reservoir oil/water drainage capillary pressure.

Various lithologies were tested : 25 sandstones (either clean, laminated or bioturbated), 10 dolomites (non vuggy and vuggy), 5 limestones. The tested samples had a wide range of permeability and porosity values.

Mercury injection data were scaled to oil/brine conditions with IFT values measured in the laboratory. Comparisons of these scaled data with the porous plate data were then conducted. Results show that mercury injection systematically underestimates water saturation when compared to oil/brine results in the high Pc region. The differences of water saturation between the two techniques were then analyzed per type of facies. This complete set of tests reveals some relationships between mercury injection data and oil/water capillary pressure measurements for oil reservoirs. Local heterogeneities (bioturbations, non-uniform pore access radius distribution, tortuosity) were found to be the main responsible factors to explain these differences in sandstone reservoirs. Oil wettability seems to play an important role in carbonates (especially for limestones). Some general trends, provided in the paper, can help the core analyst to correct its mercury injection data into more representative ones. However, more tests should be carried out to confirm and precise these relations and to point out new ones. Only such relations can justify the use of the low-cost mercury injection technique for Pc studies in oil reservoirs.

INTRODUCTION

Original Oil In Place (OOIP) in oil reservoirs is generally determined from interpretations of well logs. As interpretations of saturations are based on empirical models, they always need to be confronted to representative core measurements of saturations, resistivity index and capillary pressure. Among the methods for measuring capillary pressures of two fluids in core samples, the use of the restored state technique, introduced by Leverett (1941) and Bruce (1947), is probably the most representative one as long as reservoir conditions are respected during the experiments. Several authors have actually shown that capillary pressure measurements are not only dependent on the structures of the porous network but also on many parameters such as rock and oil interactions, water salinity, temperature, confining and pore pressures proving the necessity of measuring capillary pressure curves with actual fluids and under reservoir conditions.

However, among the static methods, the restored state technique under reservoir conditions remains a long and relatively costly technique. The mercury injection method, introduced by Purcell (1949) is still widely used in the oil industry since its cost and rapidity of operation outrun any other technique.

The objective of the paper is to point out and explain the relations between capillary pressure measurements obtained by these two techniques during first drainage. Results are expected to help the core analyst to optimize future Pc core analysis programs in order to find a good compromise between rapidity of operation and the necessity of determining valid saturation data.

LITTERATURE BACKGROUND

Gas/water drainage capillary pressure curves obtained by different techniques have been compared in few papers. Melrose (1990) and Sabatier (1994) found good agreement between centrifuge and porous plate data in the low water saturation region. Results obtained on 12 sandstone samples by Melrose (1991) indicate that water saturations obtained by mercury injection (after appropriate scale up) are lower than saturations obtained by centrifuge or porous plate in the low saturation region (about 4%PV difference). Sabatier (1994) did not confirm these results on six samples (4 sandstones and 2 carbonates). He found a good match between mercury injection and porous plate for 5 out of the 6 samples.

In oil/water systems, very few comparative experiments have been published to our knowledge. Swanson (1985) indicates that differences between mercury and water/oil tests can be often attributed to a lack of equilibrium in the water/oil tests and to the influence of effective stress which can be applied with the porous plate and not with the mercury technique. In Swanson's sandstone example, oil saturation (for a Pc value of 5 bars) was lower than mercury saturation by about 10 %PV. Ninety percent of this difference was due to effective stress and only ten percent was explained by a lack of equilibrium in the water/oil test. However, Longeron (1989) did not get a good agreement between experimental Pc results obtained with different fluid pairs. Bouvier (1991) presented three examples of comparisons between porous plate oil/water data and scaled mercury data. Examples originated from oolitic limestones. At capillary pressure levels corresponding to the invasion of macro-pores, oil saturation was lower than mercury saturation by about 2.5 %PV for two samples. The results of the third sample showed a higher value of oil saturation of about 4 %PV. Bouvier concluded that mercury curves were closed to water/oil curves. Sabatier (1994) and Hamon (1997) pointed out that mercury injection results in lower values of initial water saturation when compared to oil/brine and gas/brine data.

STRATEGY FOR THE FORTY COMPARATIVE TESTS

In order to analyse the forty comparative tests, we focused on the following two parameters :

1- Comparisons of Swi obtained by the two methods for a value of oil/brine Pc of 4 bars. This value was always higher than the Pc value necessary to invade all macro-pores.
$\Delta S = \{Swi\}_{In-situ\ Restored\ State} - \{Swi\}_{Mercury\ Injection}$
Swi is the water saturation measured at an actual or scaled up oil/brine capillary pressure of 4 bars. (See figure 1). ΔS is expressed in fraction (as all saturations in this paper).

2- Comparisons of displacement pressures. The target parameter is the difference :

$$\Delta P = \left\{ Displacement\ \ pressure\ measured\ by\ the\ representative\ \ porous\ \ plate\ method \right\}$$

$$- \left\{ Displacement\ \ pressure\ measured\ by\ mercury\ injection\ \left(scaled\ up\ to\ oil\ /\ brine \right) \right\}$$

In order to ensure validity of the comparative study, the two techniques were applied each time on two adjacent samples cored in the direction of the stratifications. To understand the variations of ΔS and ΔP , the following additional analyses were performed:

- A macrolithological facies was assigned to each sample.
- Percentages of rock minerals were measured through x-ray diffraction experiments.
- Percentages of shale laminations or shale bioturbations were quantified on some shaly samples. These data were obtained through image analysis.
- In order to get a better insight of wettability, some data concerning the oil were collected. Unfortunately, contents of asphaltenes and resins were not available although they are recognized to increase reservoir oil wettability (Cuiec, 1987). An alternative consisted in collecting for each reservoir the ratio $\boldsymbol{r} = \left[\frac{volumic\ weight\ (kg\ /\ dm^3\ )}{molecular\ weight\ \left(g.mol^{-1} \right)} \right]$ of the C_{11}^{+} fraction. This ratio was available from PVT analyses performed on DST samples. This ratio is expected to be a good indicator of the contents of aromatic components and asphaltenes. A high ratio value suggests a relatively high content of aromatics and asphaltenes.
- Brine salinity, reservoir temperature, laboratory interfacial tension measurements were also collected.
- Mercury injection experiments were interpreted into histograms of pore access radius as shown in figure 1. Micro-porosity was defined for bi-modal histograms as the part of porosity which corresponds to access radius lower than Rm (figure 1). Rrs is defined as the smallest pseudo access radius invaded by oil in the restored state experiments. However, the reader should notice that such definition of micro-porosity includes macro-pores that are surrounded by micro-pores. The slope of the Pc curve corresponding to the invasion of macroporosity by mercury was computed (Sl in figure 1). The larger Sl, the more heterogeneous the samples.

EXPERIMENTAL PROCEDURES

Following are brief explanations of the experimental procedures that were used for this study.

1- <u>Porous plate measurements under reservoir conditions</u>

A large core plug (diameter 40mm, length 60mm) is sampled in the direction of stratifications. It is placed in a four electrodes sleeve on a water-wet porous plate which is permeable to brine and not permeable to oil. At the beginning of the experiment the sample is fully saturated with brine and a known positive difference of pressure between the oil and the brine phases is applied $(P_{oil} - P_{brine} = Pc)$. A portion of the brine is expelled and measured during a process of several days. When electrical equillibrium is achieved another higher increment of Pc is applied. Successive increments lead to full knowledge of the drainage $Pc = f\,(Sw)$ and $IR = f\,(Sw)$ curves. The experiment is realized under a temperature representative of the reservoir in a cell where an isotropic confining pressure can be applied. If a pore pressure is used, the confining pressure is set to obtain a representative effective pressure on the sample. Restrictions include a temperature lower than 100°C and a pore pressure lower than 30 bars. The salinity of the brine is the one of the reservoir water. Stock tank oil is used as the displacing fluid after having been filtered and degassed. The placement of oil during first drainage is a one dimensional phenomenon. Continuous electrical measurements during the experiments, enable the detection and prevention of any anomalies such as ruptures of capillary continuity.

Samples are previously cleaned by successive miscible displacements of toluene and isopropanol. Drying is achieved by combination of nitrogen drying and heating. Nitrogen drying is increased for shaly samples whereas drying under temperature is significantly reduced for good preservation of clay structures.

Advantages of the method :
- the method is close to reservoir conditions
- simultaneous measurements of capillary pressure and resistivity index as functions of saturations are obtained
- the method is valid for unconsolidated samples
- measurements of isotropic compressibility can be easily obtained prior to drainage

Drawbacks :
- each step is attained only after several days (in house criterion is that the expelled water must be less than $0.02\,cm^3 / 24\,hours$ during two consecutive days). Drainage experiments typically last between 50 and 120 days. Thickness of the porous plate varies between 2mm and 6.4mm.
- maximum attainable Pc values are around 10 bars
- the technique is costly and cannot be applied on large sets of samples
- cleaning of the samples never results in a completely water wet condition

2- **Mercury injection**

With this method, mercury is injected into an evacuated sample by increments of mercury pressure up to 4000 bars. Equilibrium is achieved very quickly and a full $Pc = f(\,Mercury\ Saturation\,)$ curve can be obtained in less than one day. At the end of drainage, high values of Pc lead to total invasion of the porous medium by mercury. Injection of mercury occurs in three dimensions. For these experiments mercury is clearly the non-wetting phase.
For these experiments, small core plug samples (diameter and length of one inch) were used. They were sampled in the direction of the stratifications. A soxhlet technique with chloroform is used for cleaning. Heating is used for drying. Moderate heating is applied for shaly samples.

Advantages of the method:
- equilibrium is attained after a short period during drainage as the wetting phase (vacuum) does not have to be expelled from the sample.
- high Pc values are attainable
- mercury injection gives a good understanding of the pore networks which can be interpreted into distributions of pore access radius
- It is a low-cost technique
- It gives an equivalent of a purely water-wet system when scaled up to oil/brine.
- The displacing fluid is the non-wetting phase

Drawbacks :
- the method is destructive for the core samples
- it is not representative of the reservoir fluids
- no measurement of resistivity can be made
- the method is not valid for unconsolidated samples

EXPERIMENTAL RESULTS

Forty comparative tests were conducted :
- 25 in sandstone lithologies
- 15 in carbonates

Each test comprised a measurement of oil/brine capillary pressure on a large plug sample and a mercury injection on an adjacent small plug sample.

The «sandstone » family

Conventional measurements of the 25 large core plug samples are represented in figures 2a and 2b. Each sample is named after its originating well. Similar first letters mean that the samples originate from the same cores. One will notice that porosity and permeability are correlated within each sub-family and that for a given porosity value, permeability is lower for bioturbated and laminated samples than for clean medium sandstones. Thickness of laminations and bioturbations is millimetric for the presented samples. They correspond to low resistivity sands intervals. Grain density ranges from 2.65 to 2.7 except for two samples (B1 and B2) which contain about 25 to 30% of siderite which is a heavy mineral (~ 3.94g/cc).

ΔS values were found to be always positive meaning that mercury injection systematically underestimates initial water saturation. They range from zero to 30 %PV.

Let us scan the various explanations for these high values of ΔS :

1- Equilibrium times during oil/water measurements

In oil/water measurements, water is expelled from the sample at each capillary pressure step. As water saturation gets lower, relative permeability of water tends to zero and therefore the equilibrium time tends to infinity (Van Lingen, 1996). On an average, 10 Pc steps were applied for each water/oil porous plate experiment. Each new step was applied after the expelled water flow rate was less than $0.02\, cm^3\, /\, 24\, hours$ during two consecutive days. Full experimental time ranged from 50 to 120 days. For simplicity, let's assume that each step should have lasted ten more days increasing the overall experimental drainage time by an extra 100 days. Let's also assume a constant $0.01\, cm^3\, /\, 24\, hours$ of water flow rate during this extra time. The expelled water would have increased by $0.01 \times 10\, days \times 10\, steps = 1\, cm^3$ which represent about 7%PV for a typical $15\, cm^3$ pore volume. As this phenomenon does not occur with mercury injection into an evacuated sample, the equilibrium time may explain part of the discrepancies between the two techniques. However, it is not likely to be responsible for more than several per cents of pore volume.

1- Natural dispersion

As the experiments are performed on two different samples although they are adjacent, one needs to check that there is no or little local dispersion which could explain the ΔS values. Permeability was measured for each test on both samples under a light confining pressure of 20 bars. Figure 2c shows that variation of permeability is less than 0.2 decades except for three samples (B1, B2 and C) where dispersion reaches 0.7 decades. In the following figures, ΔS values were corrected to take into account this dispersion through the two trends plotted in figure 2d. **At the end of this step, data are no more dependent on local dispersion**.

2- Compaction

Restored sate experiments are performed under effective stress whereas mercury injection is conducted on unconfined samples. As shown in figure 2e, compaction induces a porosity reduction. The permeability reduction could not be recorded during the experiments because of the presence of the porous plate. Porosity reductions average 0.01 fract which corresponds roughly to a maximum permeability reduction of 0.15 decades (figure 2a) and a water saturation increase of 0.02 fraction (figure 2d). Therefore, **compaction is not responsible for the high ΔS values**.

3- Rock textural properties

- **For shaly sandstones, figure 2g reveals a good correlation between ΔS values and the clay content**. The higher the clay content, the larger ΔS . This correlation is even better when the percentage of shaly bioturbations or laminations replaces the content of clay (see figure 2h). This means that not only clay content but also clay structure is correlated to ΔS. There are two exceptions which are « out of trend ». Test L actually involves a friable large sample for the porous plate technique and a cemented sample for the mercury injection. For this latter test, there is a local dispersion which was not detected with conventional measurements but with pictures. The other exception is test B3. The large sample of this test contains a nodule of shaly sand which may explain the relatively low ΔS value when it is compared with samples containing similar content of clay. For the shaly samples, micro-porosity (as defined in figure 1) is poorly correlated to ΔS (see figure 2f). It can be noticed in figure 2i that ΔS does not only correspond to the part of micro-porosity but also includes part of the macro-porosity. This suggests that during the placement of oil in the porous plate experiments, some pore areas full of brine and partly surrounded by clay are trapped. When Pc is high enough to invade these areas, brine patches are disconnected and cannot be expelled.

- For the clean sanstone (either fine or medium) with less than 1% of clay, ΔS **values were found to be correlated to SI values and the cementation factor** (figures 2j and 2k). SI was not included for the E test because the mercury injection was performed in another lab and the computed value of SI was considerably higher than our other in-house values. Therefore, poor confidence was placed on this specific value. Both parameters SI and m are related to heterogeneities. M is often called the tortuosity coefficient. High values of m suggest a tortuous porous medium and high values of SI suggest heterogeneous pore access radii. However test D shows a high value of SI and a low value of m. To explain this « out of tendency » sample, we looked more precisely to its geological descriptions (macro-lithology and thin section). Grain size distribution of the D sample is described as heterogeneous but the geologist noticed that coarser grains were organized in permeable patches (or strata). This can be seen on the 2a plot because permeability is rather high for this test given its porosity. This phenomenon explains the relatively low m value for this test as the organized patches act as good conductors during electrical measurements. Interestingly, one will notice that this test is in the shaly sandstones' trend in plot 2d confirming the bi-modal behavior of the D sample (although it is not shaly at all).
  All these local heterogeneities as well as their organization lead to the trapping of brine during oil placement. The brine can no longer be expelled from the sample which is not the case for its equivalent in the mercury injection technique as vacuum is always replaced by mercury.

- Finally, for clean and well-sorted sandstones, no significant difference in water saturation was found between the two techniques (tests T, AII).

4- Wettability

As presented in figure 2l, ΔS is poorly correlated to ***r*** for any given type of lithology. This suggests that either there is no influence of oil wettability on ΔS values or that the ***r*** ratio is not a good indicator of the asphaltenes contents i. e. a bad indicator of oil wettability. To our knowledge, there is no clear evidence in the litterature of this ratio being a good indicator.

Finally, one will notice the two trends between ΔS and the Archie's exponent of saturation (figure 2n) for the shaly sandstones. Following is a possible explanation: as the percentage of shale bioturbations or laminations increase, the trapping of brine increases leading to higher values of ΔS. Some trapped areas (full of brine) are no more effective for conductivity leading to higher values of n. However, there is a second effect : as the shale content gets larger, the shaly structures responsible for the trapping are more and more connected and form conductive paths. This lowers the n values still giving high values for ΔS.

The displacement pressure estimated during the porous plate experiments was found to be partially correlated to absolute permeability (figure 2o). Differences with the Purcell estimations are slight and maybe related to ΔS values (figure 2p). The difference is less than 100 mbars in most cases. It is delicate to interpret these differences as they are strongly dependent on the scale-up coefficient which was used to scale mercury data to oil/brine data.

The Carbonates

Carbonates were divided into three sub-families : dolomitic sandstones (7 tests), limestones (5 tests) and vuggy carbonates (3 tests). Porosity and permeability are rather well correlated (figure 3a). Grain density values are consistent with the macro-lithological facies (figure 3b). Dispersion between the two samples for each test was studied. It was found to be light enough to compare the data without any correction.

Again, Swi values derived from mercury injection were found to be systematically lower than the ones measured with the porous plate method. Differences range from 0 to 0.18 for the dolomitic sandstones and from 0.11 and 0.28 fraction for the limestones. Compaction induces a light porosity reduction which cannot explain these strong differences. For information, effective confining pressure among the tests range from 50 to 250 bars. Influence of the effective pressure on ΔS values was not significant in this set of data.

Figure 3d reveals that for dolomitic sandstones having a calcite content greater than 17% (tests N2 and NIII1), ΔS values are comparable to those of the limestone tests. The presence of the calcite mineral seems to significantly increase the differences between mercury and porous plate data. The content of dolomite does not seem to affect ΔS values (figure 3e). The exponent of saturation N was found to be greater for the limestone tests compared to the dolomitic sandstones. N ranges higher than 1.9 for limestones. In fact, ΔS are correlated with the exponent of saturation (figure 3f).

Is this phenomenon due to heterogeneities or to oil wettability increased by calcite minerals ? This is a difficult question to answer. All pore access radius distributions are uni-modal but they are more or less dispersed. Figure 3g indicates that limestones are more heterogeneous than dolomitic sandstones. ΔS values also tend to increase with tortuosity (see figure 3h). The effect of oil, through the ***r*** ratio, may suggest that ΔS values increase with this ratio but the range of the ***r*** values is not large enough to be sure of this point (figure 3i). IFT values range from 20 to 25 dyn/cm which is not large enough to notice any significant impact of this parameter. However, a weak correlation with oil viscosity was detected (figure 3j).

The displacement pressure (or threshold pressure) as estimated by the porous plate technique is correlated to permeability (figure 3k). The vuggy carbonates are out of this trend which is consistent with their textural properties (vugs' clusters).

CONCLUSIONS

Scaled up mercury injection data and representative oil/water capillary pressure measurements were compared on adjacent samples. Based on 40 comparative tests originating from oil reservoirs located in the Gulf of Guinea and the North Sea, the following conclusions can be drawn :

1- In all cases, initial water saturations measured at the end of first drainage by the porous plate technique, are systematically comparable or greater than those measured by the mercury injection method. Differences range from 0 to 40 % of pore volume for extreme cases.
2- Compaction (applied in the porous plate method) cannot explain the differences with the unconfined mercury injection experiments.
3- For clean and homogeneous sandstones containing no clay, capillary pressure curves were found to be nearly overlayed.
4- Heterogeneities and tortuosity are likely to lead significant increases of ΔS in sandstones. They probably lead to the trapping of pore areas in the water/oil experiments. Brine can no longer be expelled from these areas.
5- For shaly sandstones, with clay content ranging up to 40%, ΔS increases linearly with the percentage of clay obtained from x-ray experiments. Better correlations were found between ΔS and the percentage of shale laminations or bioturbations meaning that clay content but also clay

structure play a significant role during the oil migration in the reservoir. These structures are more likely to be responsible for the trapping of some areas by oil preventing brine to be expelled.
6- In sandstones, the impact of oil characteristics seems secondary to the previous factors to explain the differences in water saturation above the transition zone.
7- Concerning the carbonates, the larger differences in initial water saturation were found for limestones.
8- Oil characteristics seems to play an important role to explain the Swi differences in carbonates. Increase in oil wettability would lead to greater differences of saturation with mercury data.

The overall study pointed out the interest of mercury injection data to quantify the degree of heterogeneity of rock samples. However, their use in core-log calibration is questionable as they nearly always underestimate water saturation obtained by the porous plate technique. The trends that are provided in the paper to explain these under-estimations should be used VERY cautiously. More of such tests should be carried out to confirm and enrich these trends especially for carbonates. One should also keep in mind that the mercury injection is a 3D phenomenom whereas the placement of oil takes place in 1D for the porous plate technique. The 1D placement may exacerbate the impact of heterogeneities on oil placement when compared to reality resulting in higher water saturations. Another point is that the cleaning procedure for the porous plate experiments does not turn the samples to fully water-wet conditions and that the restored oil wettability may be higher than the actual reservoir one. In such cases the porous plate method would lead to higher water saturation values than the actual ones.

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Figure 1 - Definitions of ΔS, ΔP, Rrs, SI, Rm

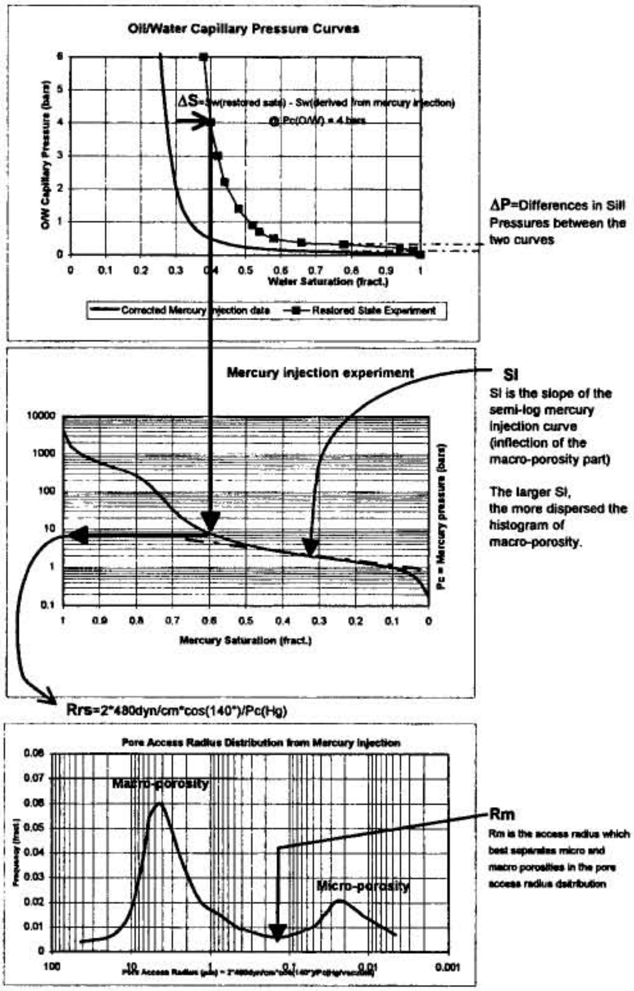

Figure 2a

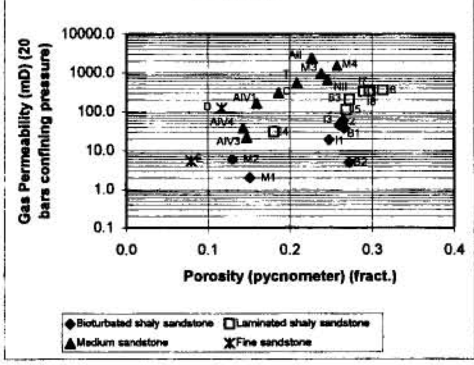

Figure 2b

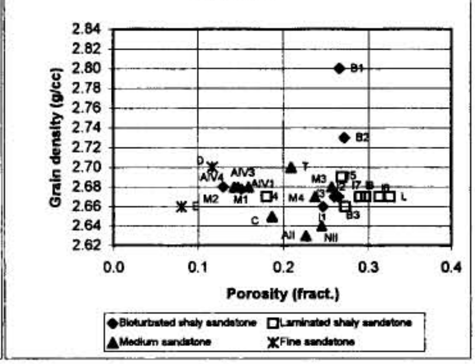

Figure 2c

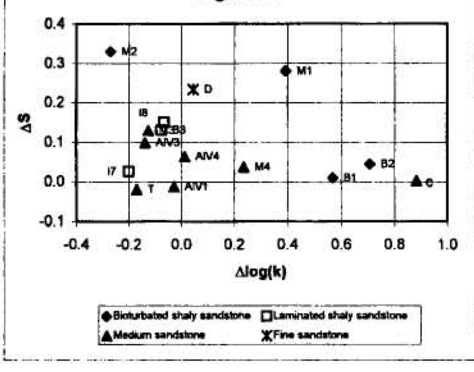

Figure 2d

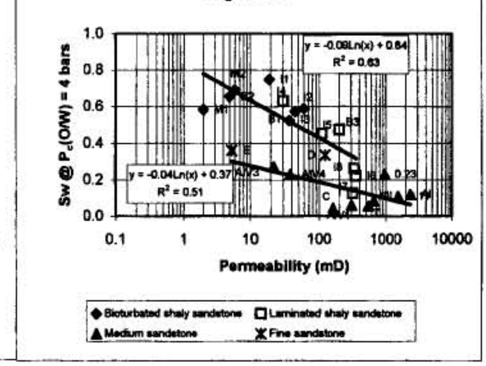

Figure 2e - Compaction on large samples

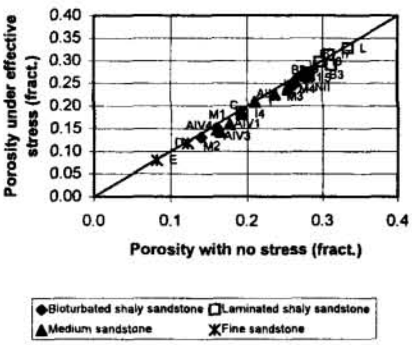

Figure 2f

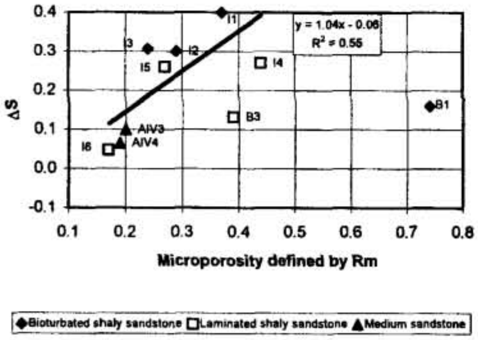

Figure 2g

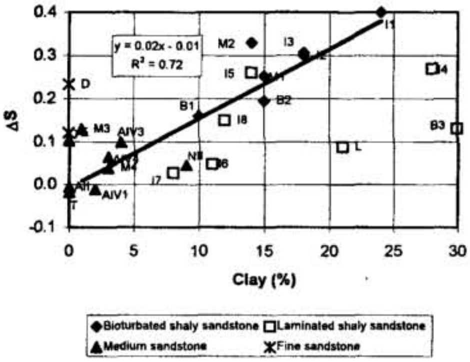

Figure 2h

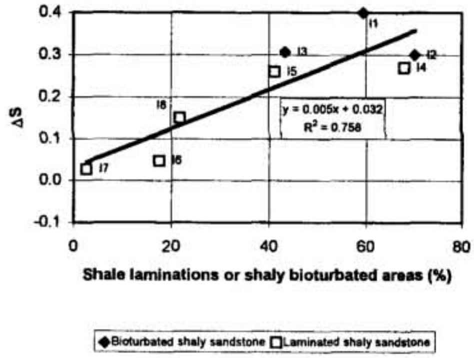

Figure 2i

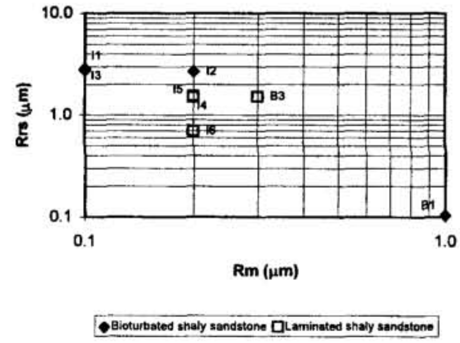

Figure 2j - Samples with less than 1% of clay content

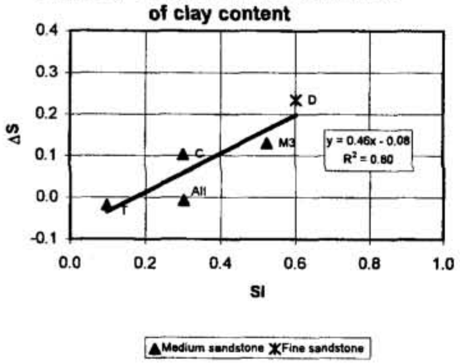

Figure 2k

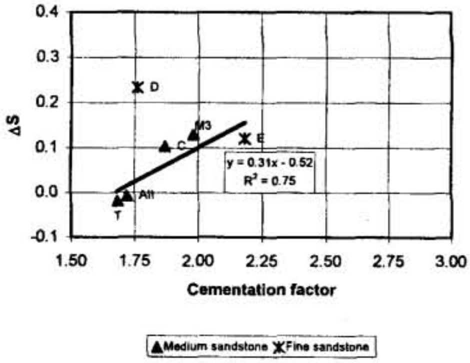

Figure 2l

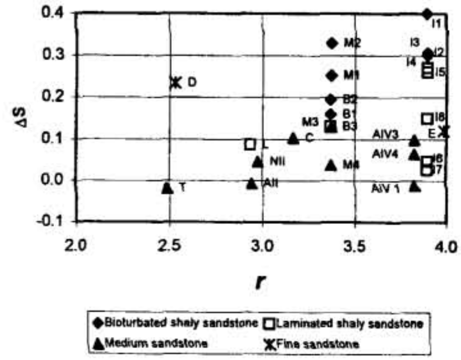

Figure 2m

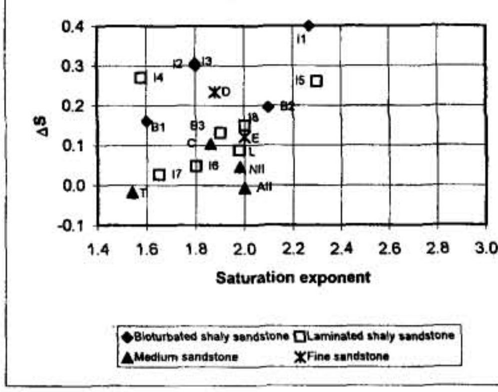

Figure 2n

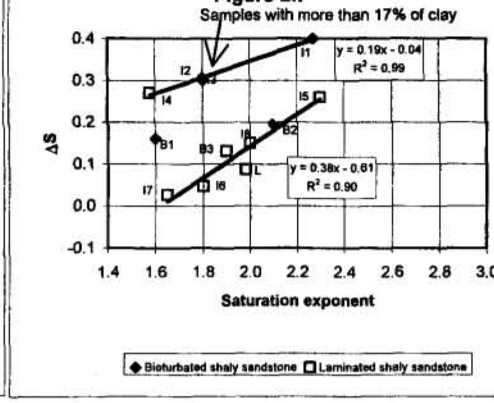

Figure 2o

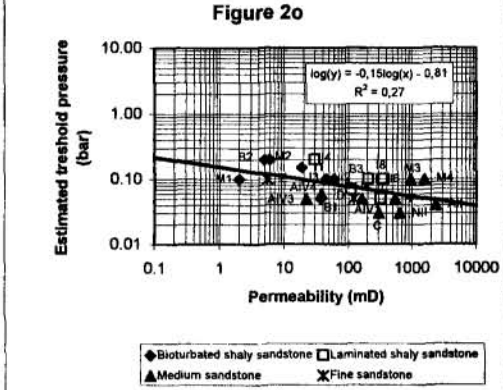

Figure 2p

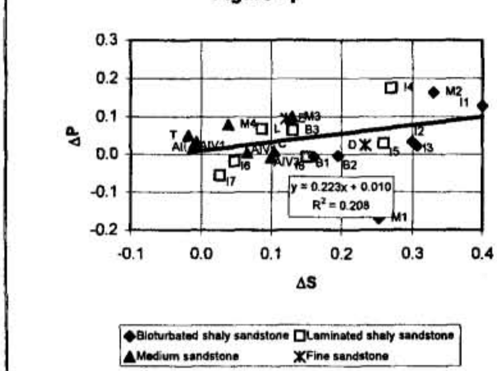

Figure 3a

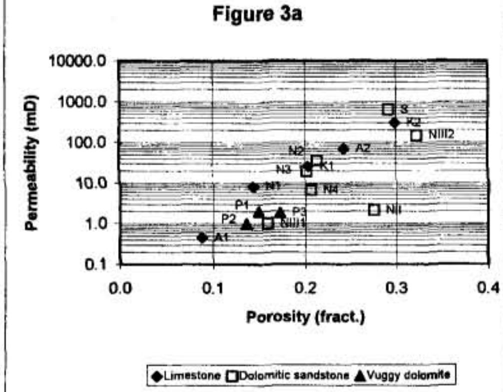

Figure 3b

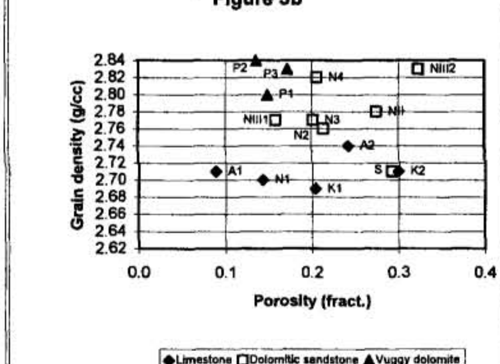

Figure 3c

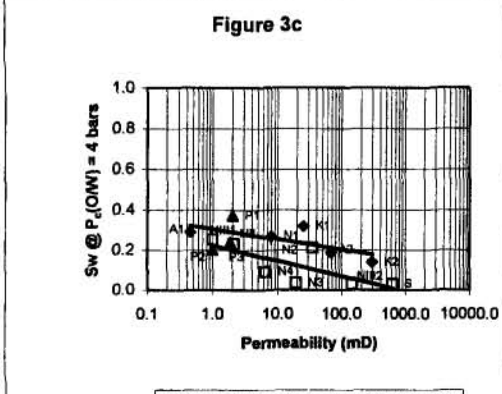

Figure 3d

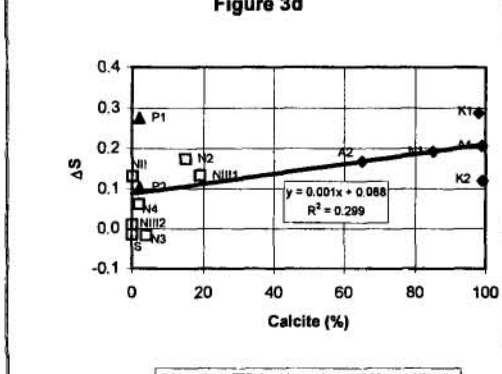

Figure 3e

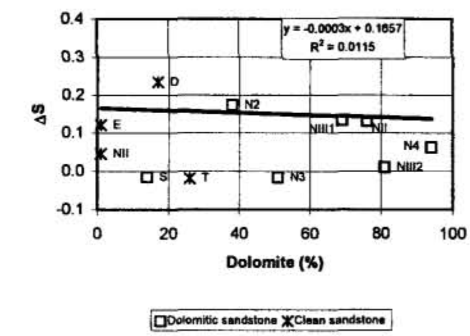

Figure 3f

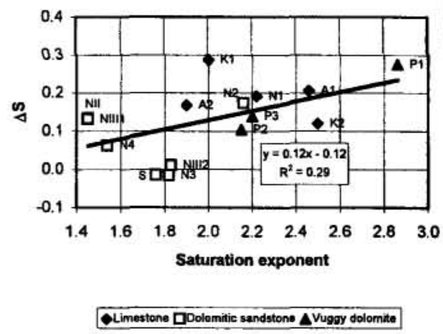

Figure 3g

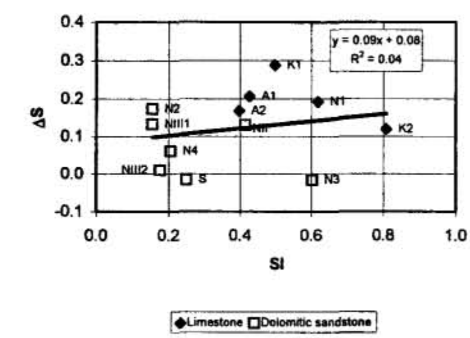

Figure 3h

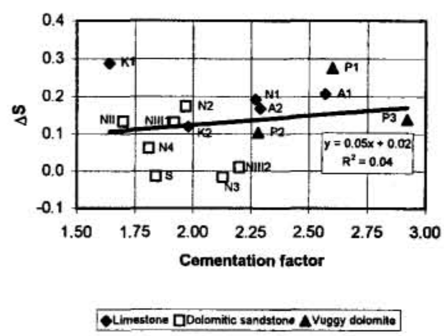

Figure 3i

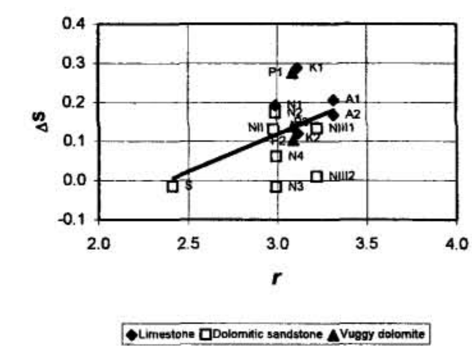

Figure 3j

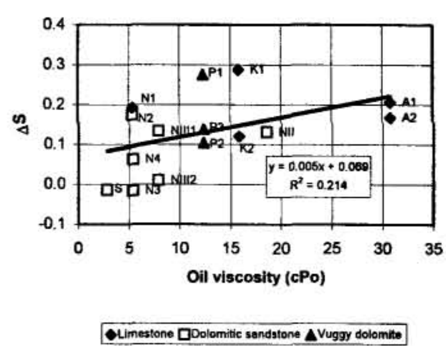

Figure 3k

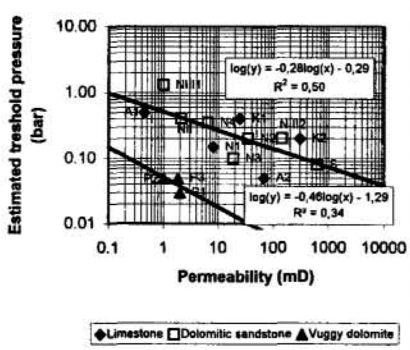

Figure 3l