SCA2003-13: TWO-PHASE FLOW ROCK-TYPING : ANOTHER APPROACH

Gerald Hamon, Miguel Bennes
Total

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

ABSTRACT

Petrophysical units, also called rock-types, are usually defined to help the reservoir engineers to assign petrophysical characteristics to different zones of a reservoir. Estimate of initial hydrocarbons in place accounts for such petrophysical units which are usually generated, using both single-phase data, i.e. porosity, permeability, and two-phase drainage data (i.e capillary pressure curve) and coupled with sedimentological descriptions. It is then frequently assumed that these rock-types are valid to assign two-phase flow characteristics, such as relative permeability curves, to a reservoir, whatever the recovery process. This paper shows that this assumption is often not correct, using several field examples, including sandstone and carbonate reservoirs. Based on a large number of core flood results, it is shown that the usual rock-typing methods may not capture the actual variability of relative permeability curves. It is also shown that: 1) Multivariate descriptions, including petrophysical characteristics and wettability indicators, should be the basis for the generation of multiphase flow rock-types. 2) Two-phase flow rock-types should be dependent on the recovery process.

Consequences on sampling for coreflood programmes, as well as inputs of simulation models are pointed out.

INTRODUCTION

Multi-phase flow Rock-Typing is usually performed in the industry using two different ways: routinely defined and SCAL defined Rock Types (RT).

Routinely defined Rock Types: Porosity, permeability, grain density, mercury injection capillary pressure curves, are often used as markers of the geometry of rock pore networks. The available data are clustered in subsets having similar flow and storage capacity. These petrophysical groups are then compared to mineralogical data and sedimentological descriptions. The opposite process is also carried out: facies are defined using depositional or diagenetic criteria and then compared to poroperm data. The relationships revealed by these comparisons are used to tie the petrophysical to the geological model. This approach is largely used in combination with log-typing to estimate initial hydrocarbons in place.

High quality core flood tests are often time-consuming and a limited number of tests are usually performed. The selection of samples is an important step to achieve representative Kr curves. Petrophysical groups are usually available at this step and are often used for this selection process: a core flood experiment is generally performed on representative samples of each reservoir quality rock type. This approach is extensively used in the industry [1-3]. It is worth noting that these *a priori* (or routinely defined) Kr rock types are only based on markers of the geometry of the pore system.

SCAL defined Rock Types: Looking at a large Kr data set reveals a different picture. Two-phase relative permeability data often present a wide range of scattering. Once a detailed inspection of experimental conditions and interpretation pitfalls has been carried out, and a significant number of core flood tests have been disregarded, it is our experience that there is still a large amount of scatter. This is confirmed by several studies where high quality results have been selected from a larger set of Kr results [4-6]. Should a pessimistic, intermediate and optimistic set of Kr curves be input separately, the three simulation runs often result in significant differences in reserves. This sensitivity to Kr curves highlights the need to decipher their variability within a reservoir, put in evidence the control parameters, and define *a posteriori* Kr Rock-Types, used to assign relative permeability curves to each zone of a reservoir.

It is generally agreed that two and three phase flow properties are the composite effect of wettability, interfacial tension, pore geometry, fluid distribution and saturation history. This study is focused on recovery processes where interfacial tension and saturation history remain constant. Therefore, it is interesting to observe for each type of recovery process the relation between relative permeability and some indicators of:

- The pore geometry or the pore network topology, such as porosity, permeability, drainage capillary pressure curve, NMR T2 distribution, distribution of pore sizes from visual observation, amount of microporosity, amount of clays and micas and combinations of these parameters
- The wettability, such as initial water saturation, height above contact, amount of Insoluble Organic Carbon (IOC), amount of some other mineralogical components

If acceptable trends of some key features of the relative permeability curves are obtained as a function of these indicators, Kr Rock-Types can then be defined as "units of rock characterised by similar range of pore geometry/topology and wettability indicators resulting in a unique relative permeability-saturation relationship."

In the following, we will offer a brief review of the literature on the relation between relative permeability curves and pore geometry/topology and wettability. In a second part, two sandstone cases and one carbonate case are presented and trends between Kr curves and pore geometry/topology and wettability are demonstrated. The upscaling issue appearing when a detailed description of a reservoir needs to be degraded to comply with coarse grids is beyond the scope of this paper.

The Effect of the Pore Network Characteristics on Relative Permeability Curves

The effect of the pore network characteristics on relative permeability curves has long been studied. Wardlaw and Cassan [7] showed a relation between the mercury recovery efficiency during imbibition and porosity, but none with permeability. Later they measured residual oil saturation on 22 sandstones and 19 carbonates [8], under water-wet conditions, and found a weak correlation between Sorw and porosity or pore throat/pore size ratio. But he pointed out, after observations on glass micromodels that while pore geometry controls trapping in strongly wetted systems, pore geometry appears to be of reduced significance under conditions of intermediate wetting [9]. Chatzis et al. [10] performed waterflood experiments under water-wet conditions, in random packs of equal spheres, heterogeneous packs of spheres with microscopic and macroscopic heterogeneities and Berea sandstone. They concluded that 1) residual oil saturations are independent of absolute pore size in systems of similar pore geometry, 2) well-mixed two-components give the same residual saturations as random packings of equal spheres, 3) clusters of large pores accessible through small pores retain oil, 4) high aspects ratios tend to cause entrapment of oil 5) the role of pore-to-pore coordination number is generally secondary. The effect of the aspect ratio was also highlighted by Roof [11] and Mohanty et al. [12].

Several attempts were also made to correlate two-phase flow results and other rock characteristics for reservoir studies. Some were rather successful [5, 13, 14, 15] whilst other failed [16].

The Effect of Wettability on Oil Recovery and Relative Permeability Curves:

The effect of wettability on oil recovery and water-oil relative permeability curves has received a lot of attention over the past 30 years. Detailed consideration is beyond the scope of this paper. However, it is crucial to highlight that a lot of experimental work illustrated that, for a given sample, and then a given geometry of the pore network, changes in wettability do have a strong influence on oil recovery by waterflooding or water-oil relative permeability curves. Owens and Archer [17] showed very different imbibition water-oil relative permeability curves for the same Torpedo sandstone quality as the oil-water contact angle changes. Later on, through a famous series of studies, Morrow and co-workers and other authors demonstrated that the efficiency of oil recovery by waterflooding on companion samples was extremely sensitive to all parameters which might produce wettability changes. [18-21]. These changes had significant effects on waterflooding efficiency, the highest ultimate oil recoveries were obtained in the neutral wet systems, and the lowest recoveries in the oil-wet systems.

For other types of recovery mechanisms, the influence of wettability was also illustrated. From their work on three phase flow on sandstone and reservoir cores, Schneider and Owens [22] pointed out that rock type appears to have less influence on flow relationships than does rock wetting preference. Keelan and Pugh [23] showed that in a water-gas system, when the rock is not strongly water-wet, lower trapped gas by water displacement is achieved than when gas is displaced by a strongly wetting fluid, such as oil.

This abundance of well-documented studies highlights the observation that the geometry of the pore system is not the only controlling factor of microscopic efficiency.

Wettability Variations Within a Reservoir:

Although a wide range of wetting conditions have been encountered from one reservoir to another as pointed out in many previous studies [6, 24-26], it is usually assumed that this variability is mainly related to variations in oil and brine compositions, temperature, and charges on mineral surfaces. Therefore it is often implicitly assumed that the wettability does not change within a reservoir. In such conditions, attempting to determine in-situ reservoir wettability and to reproduce it during coreflood experiments are the two main issues. But once a good recipe to reproduce reservoir wettability has been achieved, sampling is usually focused on variations of pore network geometry, as the wettability is assumed to be constant throughout the reservoir.

Jerauld and Rathmell [4] showed that the Amott wettability Index of Prudhoe Bay varies from +0.3 near the water-oil contact to –0.1 at the top of the structure. In the same way, samples cored in the upper part of the structure were found to have more oil-wet relative permeability than those taken low in the structure. Hamon and Pellerin [27] illustrated that the water-oil relative permeability of a North Sea sandstone reservoir was also varying with the elevation above the initial water-oil contact and with permeability. The end-point Krw(Sorw) increased from low values downstructure to high values for samples located upstructure. Hamon [28] showed that the wettability index to water decreased upwards, from strongly water-wet (Iw=0.6) near the water oil contact to very weakly water-wet (Iw=0.1), 120 m above the WOC. Okasha et al. [29] showed wettability index varying from –0.02 to 0.4 in the oil zone with a clear tendency of increasing water-wet characteristics with depth in a Saudi carbonate reservoir. Trends in water/oil relative permeability in this reservoir were also in agreement with the evolution of wettability with depth. These four examples illustrate that very large variations of wettability may occur within a reservoir and that the Kr curves may vary accordingly.

RESULTS

Fontainebleau Sandstone :

The Fontainebleau Sandstone is a strongly water-wet outcrop rock. Figure 1 shows that the residual oil saturation after waterflooding of a refined oil is strongly correlated to porosity (or permeability). Figure 1 also shows that the residual gas saturation after waterflooding is even more correlated to porosity [14]. This confirms that there is a good agreement between residual non-wetting saturations achieved during the imbibition process whatever the type of fluids used provided that strongly wetting conditions exist. In such cases, the geometry of the pore network, as reflected by porosity, permeability, mercury injection capillary pressure curves, or other indicators, control the efficiency of the waterflood displacement. These parameters can be rightfully used to generate Rock-Types.

But the strong wettability to water of the Fontainebleau Sandstone can be altered if contact with reservoir crude oils is allowed. A wide range of wetting conditions can be achieved by varying the oil nature, the aging time, the suite of solvents [25,30]. Figure 2 summarises available results and compares the residual oil saturations achieved at water-wet conditions [31] with those at weakly water or oil-wet conditions. When water-wet conditions exist, Sorw is strongly correlated to porosity, but when intermediate or neutral conditions prevail, Sorw is only weakly related to porosity or permeability. Figure 3 shows that both the Amott wettability index and the porosity control Sorw when the rock is no longer strongly water-wet. Sorw decreases as porosity increases and as wettability index decreases. In such a case, it would not be justified to use routinely defined Rock-Types based on porosity or permeability, as they capture only on small part of the variation of Sorw.

This example also illustrates that the Rock-Types should depend on the recovery process. Assume a field with an oil rim underlying a gas-cap. When the gas cap is depleted, the aquifer will encroach into the reservoir and sweep oil and gas. If the oil rim is not strongly water-wet, the RTs used for the water/oil displacement are likely to be poorly defined by indicators of pore geometry whereas those used to describe the water (oil)/gas displacement are likely to be well represented by rock quality indicators (see figure 1). If the oil rim is strongly water-wet, the RTs used for both the water/oil and water (oil)/gas imbibition displacement might be only functions of porosity, or permeability (or a combination) (see Figure 1).

Field Case A:

A series of unsteady-state, primary drainage, gas floods was performed on thirteen long core samples of a West Africa, sandstone reservoir. Gas/oil relative permeability curves in presence of connate water saturation were achieved by history match of experimental data using a coreflood simulator which incorporates viscous, capillary and gravity forces. The Krgo/Krog curves exhibited a significant scatter. Each curve was satisfactorily represented by functional forms, as followed:

$$k_{ro} \propto A S_{oD}^{no} \qquad K_{rg} = (1 - S_{oD})^{ng} \qquad S_{oD} = \frac{S_o}{1 - S_{wirr}}$$

The exponent no of the oil relative permeability, known to have a large effect on the efficiency of oil by gravity drainage, is represented in Figures 4 and 5 as a function of porosity and permeability. There is a very good relationship between the shape of the oil relative permeability curve and porosity, permeability or a combination of both parameters. The oil relative permeability becomes more optimistic as permeability or porosity increases. The oil relative permeability can also be linked to the shape of the capillary pressure curve. If the drainage Pc curve is represented by: $Sw = A.[Pc]^{-l}$, figure 6 shows that there is a good correlation between the shape factor λ of the Pc curve and the shape of the oil relative permeability. When λ is large (sharp pore size distribution) the oil relative permeability curves are rather optimistic, but when λ is small (wide pore size distribution), the oil relative permeability curves are rather pessimistic. This is very similar to what was predicted by the Brooks and Corey equation.

Clearly for this reservoir, the geometry of the pore network, as reflected by porosity, permeability or the the drainage capillary pressure largely controls the gas-oil Kr curves. Classification and clustering of gas-oil relative permeability curves can be performed using one or two of these three parameters as main controls.

A series of unsteady-state, primary imbibition, water floods was performed on sixteen other long core samples of the same reservoir. Samples were cored with water-based mud, preserved, cleaned and restored at reservoir temperature. Water/oil relative permeability curves were achieved by history match of experimental data using a coreflood simulator which incorporates viscous, capillary and gravity forces. The oil/water viscosity ratio is favourable, and the microscopic efficiency of the waterflood hinges mainly on the high water saturation range of the relative permeability curves. Therefore, for the sake of simplicity, we have selected three key parameters to represent the waterflood results: the average water saturation behind the front at water breakthrough, the "residual" oil saturation: Sorw which corresponds to Krow=10^{-4}, and the "endpoint" water relative saturation, Krw(Sorw), which also corresponds to Krow=10^{-4}

There is a significant scatter: Sorw ranges from 0.1 to 0.225, Krw(Sorw) varies from 0.09 to 0.45, and the moveable oil from 0.51 to 0.74. Table 1 shows that neither porosity, nor permeability, nor the shape factor λ of the drainage Pc curve are good indicators of the waterflood performance. NMR T2 distribution was available on nine samples: the correlation between the waterflood performance and some features of the NMR distribution, such as the average T2 or the spread of the distribution were also investigated, as illustrated in Table 1.

Each one of these parameters can correlate satisfactorily with one of the waterflood features: permeability or mean T2s are related to the average Sw behind front, whilst the shape factor λ is linked to the "residual" oil saturation, but none of these parameters alone fully describes the waterflood performance. It was also checked that other features of the drainage Pc curve (Apex, threshold pressure, median pore throat radius) or of the NMR T2 distribution (spread, Clay Bound Water) do not bring more consistency. Comparisons between mineralogical data (amount of quartz, of feldspars, of clays+micas) and waterflood results did not put in evidence any other major control. Finally, neither the description of sedimentological facies nor the layering by reservoir units was found helpful to decipher the scatter of microscopic waterflood performance.

In others words, routinely defined Rock Types based only on classes of porosity, permeability, combination of both or any clustering of features of the drainage Pc curve or of the NMR T2 distribution fail in representing correctly the variability of waterflood results whereas they successfully captured the variability of gas flood results.

This failure to explain the variability of waterflood results with simple indicators of the pore network geometry lies in the absence of wettability indicators in this analysis. Figures 7 and 8 show that Sorw and Krw(Sorw) are both correlated to the height above the initial WOC. Sorw decreases and Krw(Sorw) increases as the elevation above WOC increases. These observations would be consistent with a decreasing wettability to water as the elevation above WOC increases. Downstructure, the rock is rather water-wet: Sorw is large and Krw(Sorw) is low. Upstructure, the rock is weakly water-wet, Sorw decreases and Krw increases.

Clearly in this case, neither indicators of the pore geometry nor the wettability are able to capture alone the variability of waterflood results. Attempts were performed to combine several indicators of the rock characteristics, such as porosity, permeability, amount of clays and micas, shape factor of drainage Pc curve, mean time and spread of T2 NMR distribution and wettability controls such as height above WOC, initial water saturation, amount of Insoluble Organic Carbon (IOC). The number of controlling variables was limited to 3. More than 120 correlations were checked.

Several combinations of variables were found to capture most of the variability of this waterflood data set. It is observed that the incorporation of one wettability indicator always improves the correlations very significantly. Two examples are presented in this paper. The first combination includes the permeability, the shape factor λ of the drainage Pc curve and the height above WOC. The second combination includes the porosity, the mean time of NMR T2s distribution and height above WOC. Figures 9-11 and 12-14 show that the scatter in Sorw, Krw(Sorw) or moveable oil is very well captured by both combinations. Basically, in both cases, two markers of the pore network geometry and one marker of wettability were used. The selected variables might not be the most meaningful but they are the most convenient for input in simulation models, as porosity, permeability, height above contact are always mapped and shape factor or mean T2 might easily be related to sedimentological features, borehole imaging, or some logging results. It is worth noting that the same Rock-Types cannot be used for this field case to describe the gas-oil and water-oil Kr curves.
This field case shows that: multivariate descriptions, including petrophysical characteristics, and wettability indicators, succeed in capturing the actual variability of relative permeability

curves and should be the basis for the generation of multiphase flow rock-types and to populate a fine grid model.

Field Case B:

Light crude oil was displaced by water from 13 samples of a carbonate reservoir. Samples were cored from the same well with water-based mud, preserved, cleaned and restored at reservoir temperature. Design of flood was aimed at minimising the effect of local heterogeneities. Samples were selected to represent the full range of permeability and the main sedimentological facies. Figure 15 illustrates the large scatter of the poroperm plot for all sedimentological facies which is a typical feature of carbonate reservoir. Figures 16 and 17 show that irreducible water saturation is strongly correlated to permeability whereas residual oil saturation is almost independent from permeability or facies. This illustrates that the same Rock-Types cannot be used for the estimate of oil in place (drainage Pc curves) and of reserves (water/oil Krs). Figure 18 shows that, based on this sample selection, the complex pore system of this carbonate reservoir results in a fairly simple overall Krwmax(Sw) relation. Figure 17 shows that the residual oil saturation is rather scattered in the lowermost permeability range whereas it is almost constant for higher permeabilities. The same trend is observed for wettability as a function of permeability: a very weak wettability to water is observed except in the lowermost permeability range (figure 19). This suggests that wettability controls the microscopic performance on this reservoir.

DISCUSSION

The literature review shows that a strong relationship may exist between pore geometry/topology and two phase flow mechanisms. However, it should be pointed out that strongly wetting conditions were always imposed during these studies. In fact, the strong relationship between pore geometry/topology and two phase flow performance mainly holds when strong wetting conditions exist. This conclusion is illustrated by the examples presented in this paper. Residual non-wetting phase saturation by waterflood is strongly correlated to porosity or permeability on water wet Fontainebleau sandstone. Oil relative permeability by gas flood is a function of capillary pressure shape factor for field case A, as gas is likely to be strongly non wetting in this case.

This paper shows that the relations between pore geometry/topology and Kr curves weaken or vanish when the wetting conditions depart from strong preference. This was illustrated by the three examples presented in this paper. In such conditions, our results show that Kr curves reflect the combined effect of the pore system and wettability.

Therefore, it is concluded that use of routinely defined rock-types based only on pore geometry/topology indicators or sedimentological features are irrelevant for core flood sampling or populating a simulation model with Kr curves when strongly wetting conditions do not exist.

Application of this Rock-Typing approach should be limited to aquifer encroachment into a dry gas reservoir. Aquifer encroachment into gas condensate reservoirs may also occur at strong wetting conditions, however field cases were reported where the core samples did not imbibe water, but condensate, indicating that strong wetting conditions to the invading fluid do not always prevail.

This approach should be correct in most cases for gas flooding at irreducible water saturation. Although Kr curves for gas flood were found sensitive to wettability, it seems that they are largely independent of wettability over a large wettability range [32]. But this approach might be misleading for primary depletion, as the nucleation process is sensitive to wettability. Use of predefined rock-types based only on pore geometry/topology indicators or sedimentological feature is not recommended for waterflood Kr's nor for three-phase flow. It is generally agreed that statistically, oil bearing reservoirs are not strongly water-wet [24, 26]. Moreover, there is an increasing evidence that wettability is not constant within a reservoir, but varies according to parameters not directly linked to the geometry of the pore system, such as the elevation above the contact [4, 27-29].

It is worth pointing out two puzzling observations with the use of routinely defined RTs:

- This approach usually prevents any other control of Kr curves to be put in evidence, owing to the scarcity of results and is therefore self-consistent. But in our experience, it is not rare to obtain widely different Kr curves when several samples are selected within a single RT, as illustrated by facies H of field B.
- The choice of rock quality indicators is another issue. The most important features of the pore system controlling the two-phase flow performance have been claimed to be the pore to throat size ratio, the coordination number and the degree of heterogeneity. These features are not widely available and therefore are rarely selected to define rock-types.

Field Case A shows that combining indicators of the pore system and of wettability captures most of the variability of relative permeability curves. Kr Rock-Types can then be defined as "units of rock characterised by similar range of pore geometry/topology and wettability indicators resulting in a unique relative-permeability Saturation relationship" and are easily used to populate the simulation models as long as the key controls can be mapped.

CONCLUSIONS

This paper shows that the usual rock-typing methods, based only on markers of the geometry of the pore system, may not capture the actual variability of relative permeability curves, and particularly:

- Porosity, permeability or pore size distribution might be poor indicators of actual controls for two-phase flow, whatever the technique used to combine them into a rock-type representation
- There is no systematic correspondence between rock-types used to estimate hydrocarbons in place and those required to describe production behaviour,
- There is no systematic correspondence between sedimentological facies and rock-types required to describe production behaviour,

It is also shown that:

- Multivariate descriptions, including petrophysical characteristics and wettability indicators, succeed in capturing the actual variability of relative permeability curves and should be the basis for the generation of multiphase flow rock-types.
- Two-phase flow rock-types should be dependent on the recovery process.

ACKNOWLEDGEMENTS

The authors would like to thank Total for permission to publish this paper.

REFERENCES

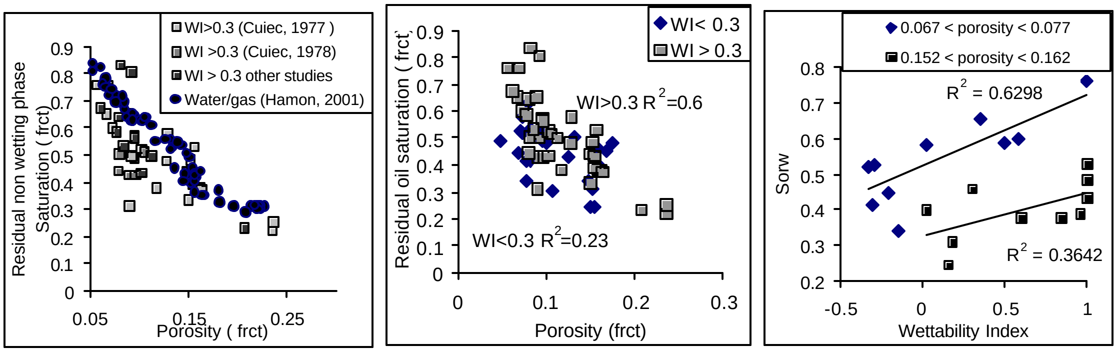
1. Davies, D., Vessell, R., Auman, J.: "Improved Prediction of Reservoir Behavior Through Integration of Quantitative Geological and Petrophysical Data" SPE RE, April 1999.
2. Porras, J., Campos, O.: " Rock Typing: A Key Approach for Petrophysical Characterization and Definition of Flow Units, Santa Barbara Field, Eastern Venezuela Basin" SPE 69458, SPE Latin American Conference, Buenos Aires, Argentina, 2001.
3. Mohammed K., Corbett P.: "How many Relative Permeability Measurements Do You Need ? " Paper SCA2002-03 2002 International Symposium of the Society of Core Analysts, Monterey, CA, 2002.
4. Jerauld G., Rathmell J.: " Wettability and Relative Permeability of Prudhoe Bay: A Case Study in Mixed-Wet Reservoirs" SPE 28756, ATCE , New Orleans, USA, Sept. 1994.
5. Jerauld G.: "Gas-Oil Relative Permeability of Prudhoe Bay" SPE 35718, SPE western Regional Meeting, Anchorage, USA, May 1996.
6. Skauge, A., Ottesen, B.: "A Summary of Experimentally Derived Relative Permeability and Residual Oil Saturation on North Sea Reservoir Cores" SCA 2002-12, International Symposium of the Society of Core Analysts, Monterey, USA, Sept. 2002.
7. Wardlaw, N., Cassan, JP : "Estimation of Recovery Efficiency by Visual Observation of Pore Systems in Reservoir Rocks" Bull. of Canadian Petroleum Geology, 26, N°4, 1978.
8. Wardlaw, N., Cassan, JP : "Oil Recovery Efficiency and the Rock Properties of Some Sandstone Reservoirs" Bulletin of Canadian Petroleum Geology, 27, N°2, 1979.
9. Wardlaw, N.: "The Effects of Pore Structure on Displacement Efficiency in Reservoir Rocks and in Glass Micromodels" SPE 8843, SPE symposium on Enhanced Oil Recovery, Tulsa, OK, USA, April 1980.
10. Chatzis, I., Morrow, N., Lim, H. : "Magnitude and Detailed Structure of Residual Oil Saturation" SPEJ, 23, n°2, 1983.
11. Roof, J. : " Snap-off of oil Droplets in Water-wet Cores" SPEJ, 10, 1970
12. Mohanty, K., Davis, H., Scriven L.: "Physics of oil Entrapment in Water-Wet Rocks" SPE 9406 ATCE, Dallas, Sept 1980.
13. Felsenthal, M : "Correlation of Kg/Ko Data with Sandstone Core Characteristics" Petroleum Transactions AIME, vol 16, 1959.
14. Hamon, G., Suzanne, K: "Distribution of Trapped Gas Saturation in Heterogeneous Sandstone Reservoirs" SPE 71524, October 2001, New Orleans, USA.
15. Coskun, S., Warlaw, N. : " Image Analysis for Estimating Ultimate Oil Recovery Efficiency by Waterflooding Two Sandstone Reservoirs" J.P.S.E. (1995) 12.
16. Felsenthal, M : "A Statistical Study of Some Waterflood Parameters" JPT, Vol 31, 1979.
17. Owens, W., Archer, D.: "The Effect of Rock Wettability on Oil-Water Relative Permeability Relationships" JPT, July 1971.
18. Morrow, N., Lim,H., Ward, J.: " Effect of Crude Oil Induced Wettability Changes on Oil Recovery " SPEFE, 1, 1986.
19. Wang, F.: " Effect of Wettability Alteration on Water-oil Relative Permeability, Dispersion and Flowable Saturation in Porous Media" SPE 15019, SPE Permian Basin oil and Gas Recovery Conference, March 1986.
20. Morrow, N., Ma, S., Zhou, X.: " Characterisation of Wettability and the Effects of Initial Water Saturation and Aging Time on Wettability and Oil Recovery by Waterflooding" 3rd

International Symposium on Evaluation of Reservoir Wettability and its Effect on Oil Recovery", Laramie, WY, Sept. 1994.

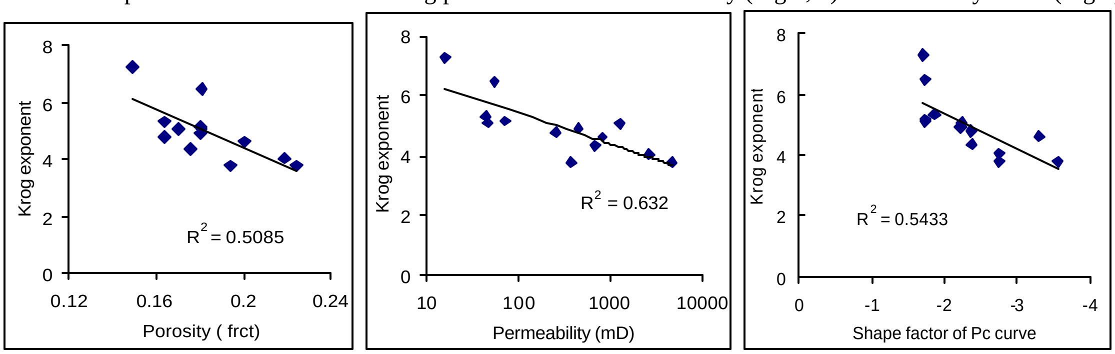
21. Morrow, N., Tang, G., Valat, M.: "Prospects of Improved Oil recovery Related to Wettability and Brine Composition" " Journal of Petroleum Science & Engineering, Vol 20 n°3/4, 1998
22. Schneider, F., Owens, W.: " Sandstone and Carbonates Two and Three Phase Relative Permeability Characteristics" Society of Petroleum Engineers Journal, March 1970
23. Keelan, D., Pugh, V.: " Trapped Gas Saturations in Carbonate Formations", SPE 4535, SPE ATCE Meeting, Las Vegas, USA, Oct. 1973.
24. Treiber, L., Archer, D., Owens, W: " A Laboratory Evaluation of the Wettability of Fifty Oil Producing Reservoirs", SPE 3526, SPE ATCE Meeting, New Orleans, USA, 1972.
25. Cuiec, L: "Study of Problems Related to the Restoration of the Natural State of Core Samples" Journal of Canadian Petroleum Technology, 16, n°4 Oct. 1977.
26. Cuiec, L.: "Rock/Crude Oil Interactions and Wettability: An Attempt to Understand Their Interrelation" SPE 13211, ATCE, Houston, Sept. 1984.
27. Hamon, G.; Pellerin, F.M.: "Evidencing Capillary Pressure and Relative Permeability Trends for Reservoir Simulation", SPE 38898, 1997 SPE Annual Technical Conference and Exhibition, San Antonio, Texas, October 1997.
28. Hamon, G : "Field-Wide Variations of Wettability" SPE 63144, 2000 SPE Annual Technical Conference and Exhibition, Dallas, Texas, October 2000.
29. Okasha, T., Funk, J., Balobaid Y.: " Petrophysics of Shu'aiba Reservoir, Shaybah Field" SCA 2001-03, International Symposium of the SCA, Abu Dhabi, EAU, 2001.
30. Cuiec, L.: "Détermination de la mouillabilité d'un échantillon de roche réservoir" Revue de l'Institut Français du Pétrole, Sept. 1978, vol XXXIII, n°5.
31. Hamon G.:"Scaling-up the Capillary Imbibition Process from Laboratory Experiments on Homogeneous and Heterogeneous Samples", SPE 15852, SPE Europec Conf., London, 1986.
32. Pedrera B., Bertin, H., Hamon, G., Augustin, A. : " Wettability Effect on Oil Relative Permeability During a Gravity Drainage" SPE 77542, 2002 SPE Annual Technical Conference and Exhibition, San Antonio, Texas, October 2002.

	Porosity	Permeability	Shape factor of Pc curve	Mean T2S
Sorw	0.026	0.108	0.416	0
Average Sw at water BT	0.149	0.399	0	0.37
Krw(Sorw)	0.388	0.177	0.132	0.355

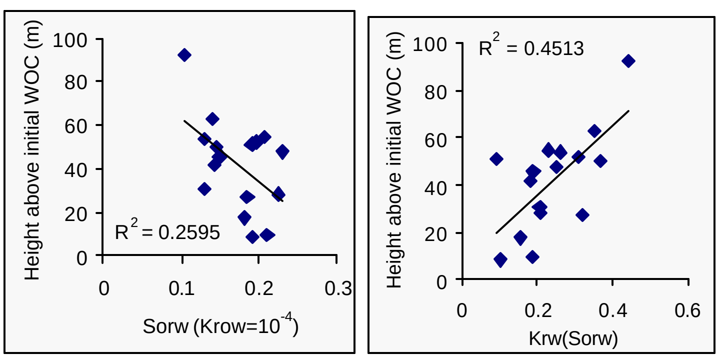
Table 1 : Regression coefficients (R^2) between Sorw, or Average Sw at Water BT, or Krw(Sorw) and porosity, permeability, shape factor of Pc curve



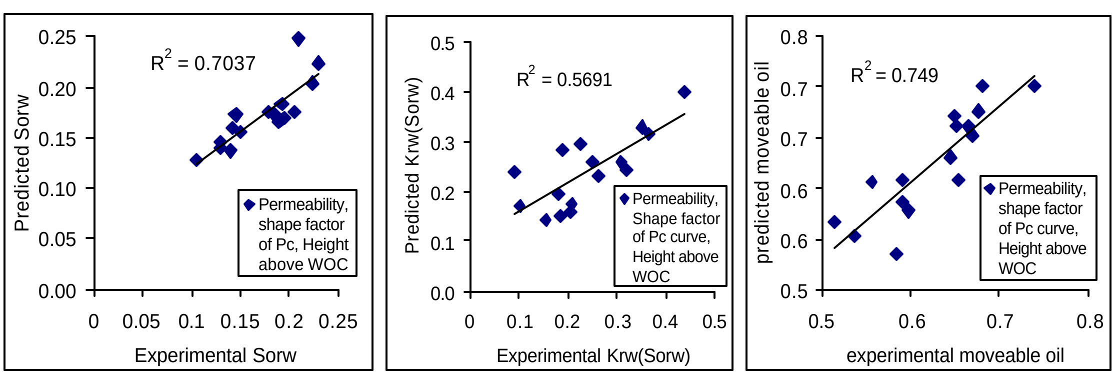
Relationship between residual non-wetting phase saturation and Poro sity (Fig.1, 2) or Wettability Index (Fig 3)



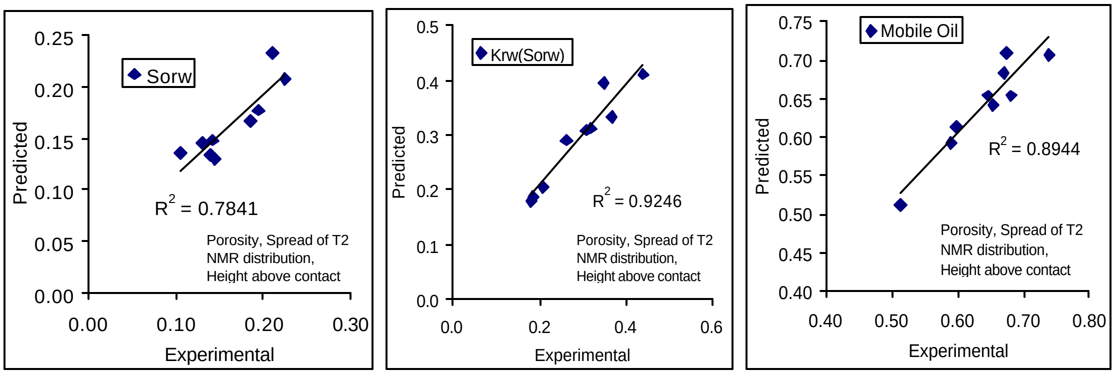
Relationship between oil Corey exponent and porosity (Fig4), permeability (Fig5), shape facor of Pc curve (6)



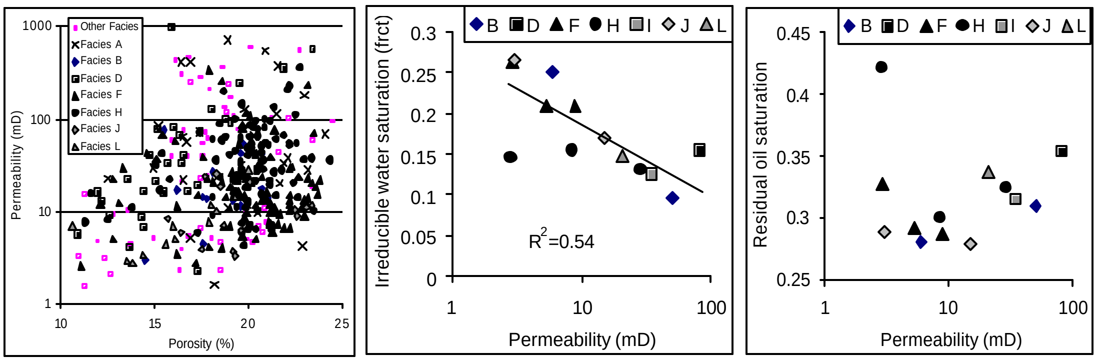
Field A:Relationship between Height above WOC and Sorw (Fig.7)or Krw(Sorw)(Fig.8)



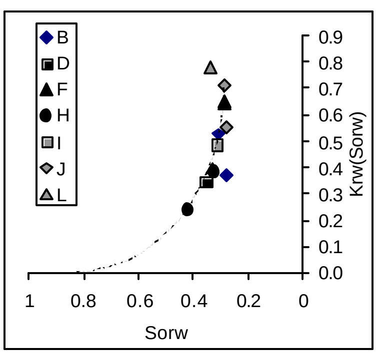
Field A :Multivariate correlations between Kr and rock and wettability indicators (Figures 9, 10, 11)

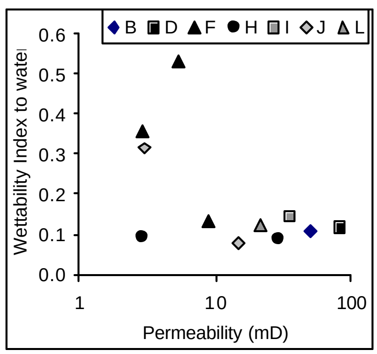


Field A : Multivariate correlations between Kr and rock and wettability indicators (Figures 12, 13, 14)



Field B : Porosity/Permeability plot (Fig.15), Rel ationship between irreducible water saturation (Fig. 16) or residual oil saturation (Fig.17) and permeability.





Field B : Fig. 18 : Relationship between end point Krw and Sorw . Fig. 19) Relationship between Wettability Index and permeability.