PETROPHYSICS OF SHU'AIBA RESERVOIR, SHAYBAH FIELD

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ABSTRACT

Shaybah field is located in the Rub Al-Khali in southeastern Saudi Arabia. The field contains a low sulfur, high API gravity (~ 40^o) crude classified as "Arabian Extra Light" in the Lower Cretaceous Shu'aiba reservoir. Production from this diagenetic limestone reservoir began in July, 1998.

Conventional and special petrophysical tests, such as basic core properties (porosity and permeability), relative permeability, capillary pressure, pore size distribution, and wettability were carried out as part of an overall study to improve the definition of reservoir properties. This study will enable more accurate prediction of reservoir behavior. The data generated significantly impacted reservoir engineering models of the field. The results showed considerable variation in porosity and permeability from well to well and also vertically within the same well. Both reservoir quality index (RQI) and normalized porosity index (NPI) were used to identify different hydraulic units and to capture samples that reflected the overall variability in reservoir engineering properties.

Relative permeability results using composite cores at reservoir conditions indicated considerable oil recoveries with substantial recovery occurring beyond breakthrough. A correlation was developed to estimate the water/oil relative permeability ratio, K_{rw}/K_{ro} from normalized saturation data. The results of modified Amott wettability tests and USBM wettability indices revealed intermediate to water-wet character for the Shu'aiba reservoir with a tendency for increasing water-wet characteristics with depth. Mercury injection tests showed that the Shu'aiba carbonate reservoir could be classified to unimodal and bimodal systems with different capillary character and pore radii varying from 0.5 to 1.5 microns.

INTRODUCTION

Carbonate reservoirs make up about 20 % of the world's sedimentary rocks and contain 40 % of the world's oil. Shaybah field, which is, located in the Rub Al-Khali in southeastern Saudi Arabia represents a premium quality carbonate reservoir. The field contains a low sulfur, high API gravity (~40^o) crude in the lower Cretaceous Shu'aiba reservoir. The reservoir is overlain by a huge gas cap and underlain by aquifer. It is a heterogeneous carbonate formation with five facies (Rudist barrier, fore barrier, back barrier, lagoon, and open platform) due to diagenetic alteration of the original rock fabric.

The need for accurate reservoir characterization is important, not only because of the geologic complexity but also because of the field development methods. Key components of reservoir characterization require understanding of the rock/fluids interactions. The tools that are available for the purpose of reservoir characterization are conventional core analysis data, special core analysis data, geologic information, fluid PVT studies, and numerical reservoir simulation.

The reservoir rock properties that determine hydrocarbon production, the variation in these properties, and how these properties effect the ultimate recovery and fluid flow behavior are still of primary concern. Two examples are the early breakthrough of water in producing wells caused by inefficient displacement due to unfavorable relative permeability relationships, and rapid water advance through a layer with super permeability. Proper remedial strategy for a specific reservoir depends on understanding the factors controlling the fluids. Good core coverage, full use, and analysis of core data are required to characterize the lithofacies changes in Shu'aiba reservoir.

CORE PRESERVATION, SAMPLE SELECTION AND TEST FLUIDS

The handling of core material at the well site and in the laboratory also can be important in preserving wettability.[1,2] In our tests, core material from Shu'aiba reservoir was cut with a KCl brine and packed under de-aerated KCl brine in plastic tubes. Core plugs (1.5 inches in diameter) were cut from the whole core at 0.5-foot intervals. The drilling direction is perpendicular to the axis of the whole core.

Basic core analyses, geological examination, brine permeability at remaining oil saturation, and CT scans were performed as screening tests to assist in sample selection. The screening tests were combined with a review of conventional core data and geological description of the core material to ensure that anomalous samples were not tested. Cores that were fractured, broken, or displayed brine permeability less than 1 millidarcy (md) were excluded from further testing. Wellhead oil from Shu'aiba reservoir was used as the oleic phase; while the aqueous phase was synthetic brine (similar to Shau'aiba brine).

EXPERIMENTAL PROCEDURE

Porosity and Permeability Measurements

All plugs taken for porosity and permeability measurements were cleaned with solvents (toluene, naphtha, and xylene) to remove all soluble hydrocarbon and fluid contaminants. The cleaning processes were carried out using Dean Stark Distillation Unit.

A common method for measuring core porosity is to measure the grain volume using helium porosimeter (Boyl's law) and bulk volume by liquid displacement method or by caliper measurements. The measurement of permeability is accomplished by the application of Darcy's law using gas permeameter apparatus.

Relative Permeability Measurements

The procedure of relative permeability measurements included the use of composite core[4,5] assembled from core material cut with KCl brine and preserved at the well site. The unsteady-state relative permeability tests were conducted at simulated reservoir conditions using recombined (live) and synthetic Shu'aiba brine with the automated flood system (AFS 200).

Oil/Water Capillary Pressure Measurements

Oil/water capillary pressure tests were conducted under reservoir conditions using centrifuge apparatus. Testing was performed by procedures described by Solobod and Chamber.[5] Preserved core plugs were flushed with about 10 pore volumes of synthetic brine to establish residual oil saturation. Samples were placed in the core holders and then kept inside a heating cabinet for temperature equilibrium. The core holders were placed in centrifuge shield and then attached to the centrifuge arm.

Samples were subjected to drainage and imbibition cycles. The volume of each fluid produced at each speed (oil or water) was observed through the top of the centrifuge by means of a transparent lid and a stroboscope which allowed displacement into calibrated collection tubes to be monitored visually. Pore volume of each plug is measured at the end of the experiment after standard cleaning procedure.

Wettability Measurements

Wettabilities of preserved core plugs were measured by modified Amott method[6]. The Amott method combines imbibition and dynamic displacement that performed under ambient condition with simulated formation brine and stock tank oil. The Amott-Harvey wettability index is the displacement-by-water ratio minus the displacement-by-oil ratio. Also, United States Bureau of Mines (USBM) method was used to measure wettability. USBM wettability index is obtained from hysteresis loop of centrifuge capillary pressure curves. The areas under the curves represent the thermodynamic work required for the respective fluids to displace each other. The logarithm of the ratio of the area of oil-displacing-brine (A1) to brine-displacing-oil (A2) is used to identfy the USBM wettability index as follows:

$$\text{USBM Wettability Index} = \log (A1/A2) \qquad (1)$$

Mercury Capillary Pressure Measurements

Mercury injection capillary pressure and pore sizes were measured using a Ruska mercury injection system. The test consists of two runs; blank run (without sample) and a sample run. The readings of blank run represent the compression effects and mercury intrusions into small spaces in the interior part of the apparatus as a result of incremental increase of applied pressure. Each run includes injection test in vacuumed system followed by ejection test. The difference between the blank run and the sample run represent the volume of mercury introduced in the pores during the injection test and the volume of mercury expelled from the pores during the ejection test.

RESULTS AND DISCUSSION

Conventional Core Analysis

A good understanding of porosity (f) and permeability (k) distributions, both within wells and areally, is critical in planning and implementing waterflood in oil reservoirs. Distributions of permeability with depth for two selected wells (A and B) are shown in Figures 1 and 2, respectively. Wide variations with depth and also from well to well are clearly observed. For example, at depth interval of D1 to D2, the permeability values varied between 8 and 178 md in well-A (Figure 1); while they ranged from 9 to 36 md in well-B (Figure 2). Porosity distributions with depth are shown in Figures 3 and 4 for well-A and well-B, respectively. Similar trends of variation of porosity values are also indicated in both wells.

Porosity and permeability data are key to assessment of reserves, potential production, and ultimate recovery. The combination of ϕ and k data in terms of reservoir quality index (RQI) provides a convenient starting point to address the differences between samples and between reservoir zones. The concepts rely on determining two functions[7], RQI and NPI, defined as follows:

$$RQI = 0.0314\sqrt{\frac{K}{f}} \quad \text{...(2)}$$

Where

RQI = reservoir quality index (μm), K = permeability to (md), f = porosity (%).

Normalized porosity index, NPI, is defined as:

$$NPI = \frac{f}{1-f} \quad \text{...(3)}$$

RQI and NPI functions are used to quantify the flow character of a reservoir and provide an association between petrophysical properties at micro and macro levels of tested samples. Using RQI and NPI, a "Flow Zone Indicator" (FZI) is defined as:

$$FZI = \frac{RQI}{NPI} \quad \text{...(4)}$$

A log-log plot of RQI versus NPI for well-A is shown in Figure 5. In this type of plot, samples with similar FZI values lie along a straight line with the value at NPI of equal to FZI. However, point calculations of RQI and FZI did not reveal depth dependence of rock family. Hence, a modified technique was developed by plotting RQI values on a normalized cumulative sum basis versus depth to differentiate between flow zones.

For each individual point the RQI is calculated and the normalized-cumulative sum is plotted versus depth. The technique is based on observing changes in slope on a plot of the normalized-cumulative sum versus depth. The changes in slopes on a plot of the normalized-cumulative sum of the reservoir quality index as a function of depth were observed for core material of Shu'aiba reservoir as shown in Figure 6 for the two selected wells (well A&B). In this figure, the Y-axis is depth while the X-axis is defined by:

$$X_i = \frac{\sum_{x=1}^{i} \sqrt{\frac{Ki}{fi}}}{\sum_{x=1}^{n} \sqrt{\frac{Ki}{fi}}} \quad \text{...} \quad (5)$$

Where

n = total number of data, i = number of data points at sequential steps of calculation

Consistent RQI zones are characterized by straight lines with slope of the line indicating the overall reservoir quality within a particular depth interval. The lower the slope the better the reservoir quality.

Relative Permeability

Relative permeability is a rock characteristic that describes quantitatively the simultaneous flow of two or more immiscible fluids through porous media. This property is important for predicting fluid movement in a reservoir during various recovery processes. The most reliable source is laboratory measurements of relative permeability.

Reservoir condition unsteady-state water-oil relative permeability tests indicated considerable oil recoveries with substantial oil recovery beyond breakthrough.[8]

The relative permeability results suggested a water-wetting core material based on Craig's rule of thumb:[9]

(a) initial water saturations (Swi) were higher than 20 % of PV,
(b) crossover points at which $K_{rw} = K_{ro}$ were greater than 50 %, and
(c) relative permeability to water at residual oil saturation (K_{rw} at Sor) ranged from 25 to 45 percent

These are clearly demonstrated in Figure 7, which shows a typical relative permeability curves for one composite from well-A.

Relative permeability curves have been presented in various forms. If all curves are combined and plotted on the same graph, it is difficult to develop any relationship among them. This is due to very wide range of initial fluid saturations. Therefore, normalization of saturations is one way that these saturations can be reduced to common basis. The normalized saturation is calculated from the following equation:

$$Sn = \frac{Sw - Swi}{1 - Swi - Sor} \quad \text{...} \quad (6)$$

Where

Sn = normalized saturation, Sw = water saturation in the core, Sor = residual oil saturation, Swi = initial water saturation.

Figure 8 is a plot of the water/oil relative permeability ratio (K_{rw}/K_{ro}) as a function of the normalized saturation for all relative permeability data of well-A. Most of the data superimpose except data for composite 2. A recommended approach is to represent the data by a statistically regressed curve. Such a regression that closely approximates the trend of the data was obtained. A total of 202 K_{rw}/K_{ro} versus S_n data pairs from the all core composites were used in the analysis. The resulting equation is:

$$\text{Ln}\,(K_{rw}/K_{ro}) = e^{(25.1Sn-175.18Sn^2+457.01Sn^3-489.65Sn^4+189.56Sn^5)} \quad \ldots\ldots\ldots(7)$$

The correlation of fit is good with correlation coefficient about 0.94. Relative permeability to oil (K_{ro}) can be calculated using equation # 8 based on regression analysis. The correlation coefficient is 0.97.

$$K_{ro} = 16.69 + 172Sn - 734.52\,Sn^2 + 909.49Sn^3 - 364.2Sn^4 \quad \ldots\ldots\ldots(8)$$

Centrifuge Capillary Pressure

Capillary pressure is a major factor in flow through a porous media. Capillary pressure forces are the result of the combined effects of the surface and interfacial tensions of the rock and fluids, the pore size geometry, and the wetting characteristics of the rock matrix. Hence, capillary pressure data can be used to relate the wetting phase saturation with basic core properties of porosity, permeability, and height above the oil-water contact. Furthermore, such information is required for calculation of oil in place at different locations in reservoir.

The results of capillary pressure by centrifuge method showed that there is a general trend of increases in capillary pressure with decreases in permeability. They, also, indicated that the endface brine saturations (Sw*) ranged from 25 to 46 % during drainage cycles. Imbibition cycle endface saturations of 83 to 99 % were observed.[10] Figure 9 shows capillary pressure curves during drainage and imbibition cycles for Shu'aiba reservoir in a USBM wettability format.

Wettability

Wettability is defined as the tendency of one fluid to spread on or adhere to a rock surface in the presence of another immiscible fluid. It has a profound effect on oil recovery produced by waterflood or by water-drive mechanisms. Therefore, it is necessary to determine preferential wettability of the reservoir, whether this be to water, or oil or somewhere between the two extremes i.e. intermediate.

Wettability results obtained by USBM tests and Amott method showed that wettability indices ranged from -0.02 to 0.78. Figure 10 shows the plot of wettability indices as a function of core depth. The wettability indices revealed intermediate to water-wet character with a tendency for increasing water-wet characteristics with depth.

Wettabilty characteristics of Shu'aiba carbonate core material described by K_{rw}/K_{ro} results are in agreement with USBM and Amott results.

Mercury Capillary Pressure and Pore Size Distribution

An essential part of the evaluation of any hydrocarbon bearing carbonate reservoir is the study of pore size distribution of the reservoir rock. The size and distribution of pore throats within reservoir rock control its capillary pressure characteristics, which in turn control fluid behavior in the pore system.

Mercury injection capillary pressure results show that Shu'aiba carbonate materials display unimodal and bimodal distributed pore system as indicated in Figure 11 (well-C). Such distributions reflect complex diagenetic history. Figure 12 presents a plot of cumulative wetting phase saturation vs. the pore entry radius of plugs from Shu'aiba reservoir. It indicates that the median pore radius ranged from 0.5to 1.5 microns It, also shows an increase in pore radius with increased permeability.

CONCLUSIONS

1. High contrast and large differences in basic core properties (K and f) support the complexity of Shu'aiba reservoir.
2. A new technique has been developed to identify intervals with different porosity/permeability relationships. This technique presents reservoir quality index (RQI) as a function of depth and assists in describing reservoir units, which have similar properties.
3. An efficient grouping of special core analyses samples with similar petrophysical properties was obtained using a modified RQI technique.
4. Unsteady-state relative permeability results indicated considerable oil recoveries with substantial recovery occurring beyond breakthrough. A correlation was developed to estimate the water/oil relative permeability ratio, K_{rw}/K_{ro} from normalized saturation data.
5. Modified Amott wettability results and USBM wettability indices revealed intermediate to water-wet character of Shu'aiba reservoir with a tendency for increasing water-wet characteristics with depth.
6. Wettability characteristics of Shu'aiba carbonate material desribed by Krw/Kro results in agreements with USBM and Amott results.
6. Mercury injection tests showed that Shu'aiba reservoir can be classified to unimodal and bimodal pore systems with median pore radius vary from 0.5 to 1.5 microns.

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NOMENCLATURE

A1 : area under drainage capillary pressure curve
A2 : area under imbibition capillary pressure curve
FZI : flow zone indicator (micron)
K : permeability of core plug (md)
K_{rw} : relative permeability to water
K_{ro} : relative permeability to oil
K_{rw}/K_{ro}: water/oil relative permeability ratio
NPI : normalized porosity index
RQI : reservoir quality index (micron)
Swi : initial water saturation
Sor : residual oil saturation
Sn : normalized saturation

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Figure 1: Permeability Distribution Vs. Depth for Well-A.

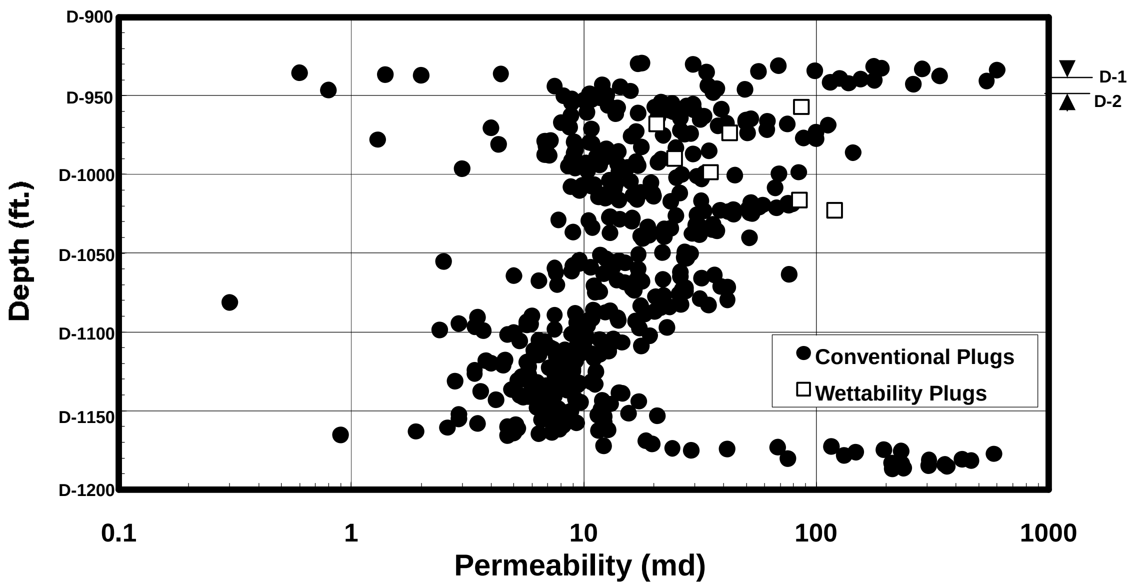
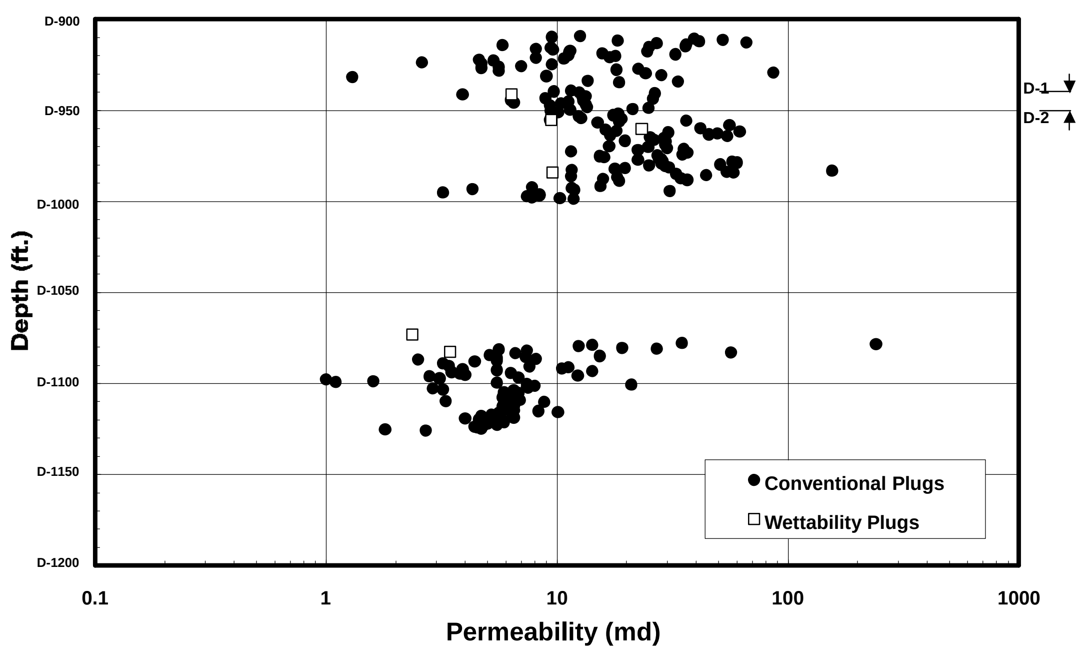


Figure 2: Permeability Distribution Vs. Depth for Well-B.



Figue 3: Porosity Distribution Vs. Depth for Well-A.

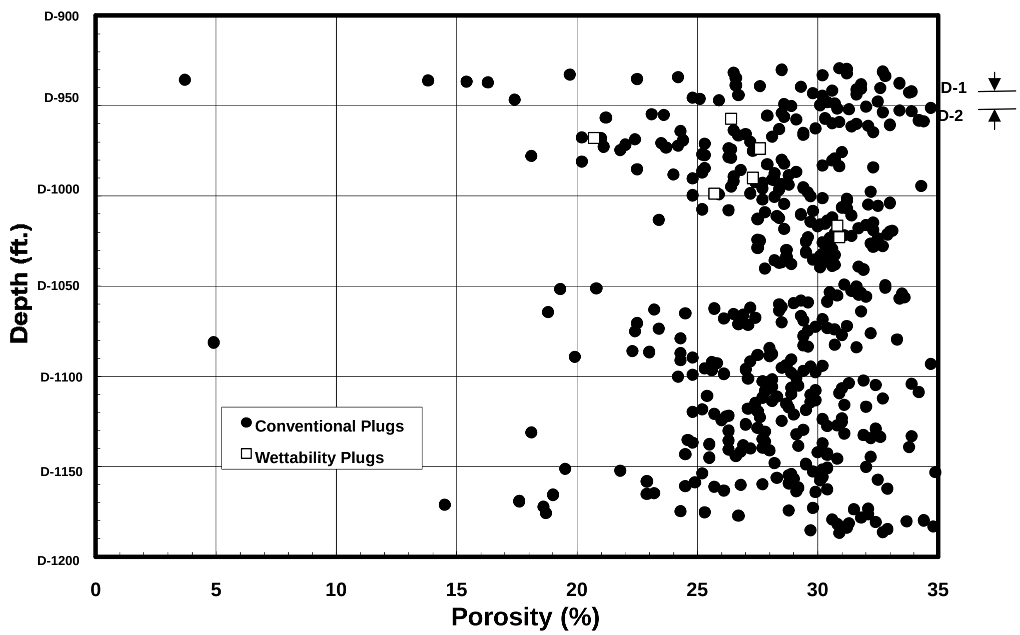


Figure 4: Porosity Distribution Vs. Depth for Well-B.

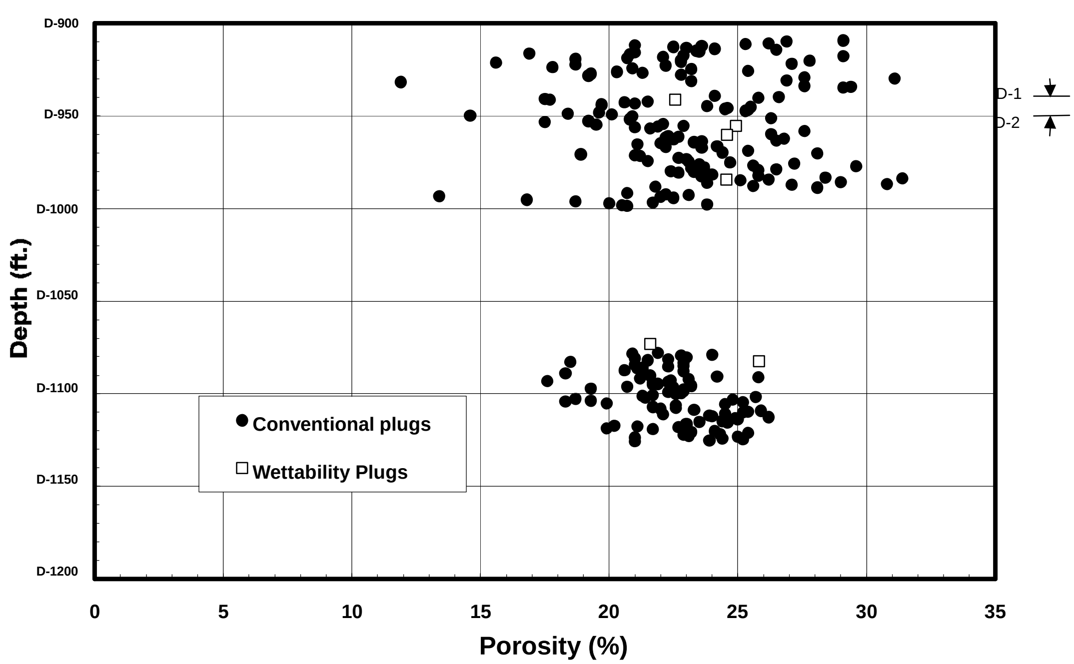


Figure 5: RQI vs. NPI for Well-A Core Plugs.

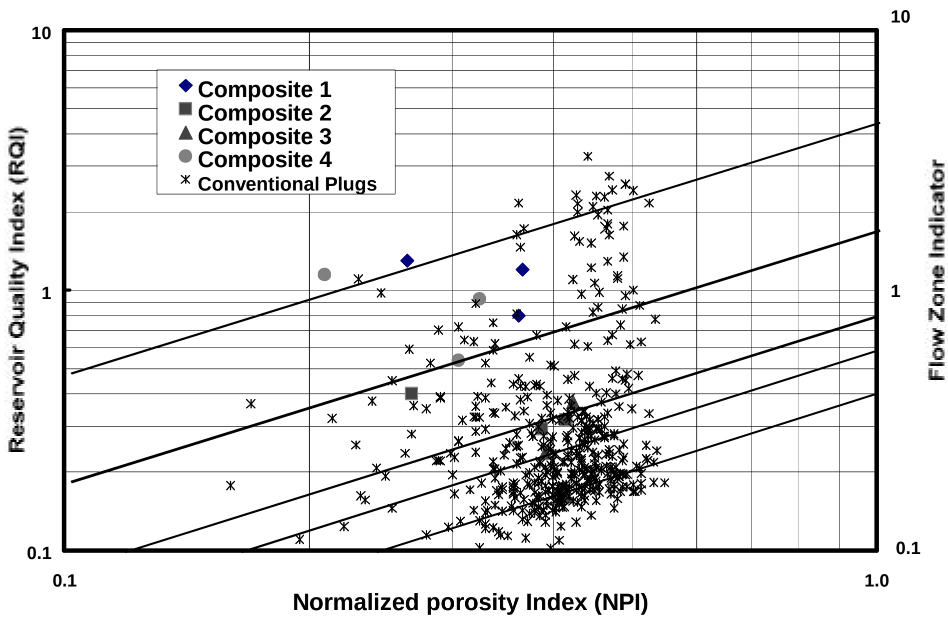


Figure 6: Normalized Cumulative Reservoir Quality Index (RQI) vs. Depth for Well-A and Well-B.

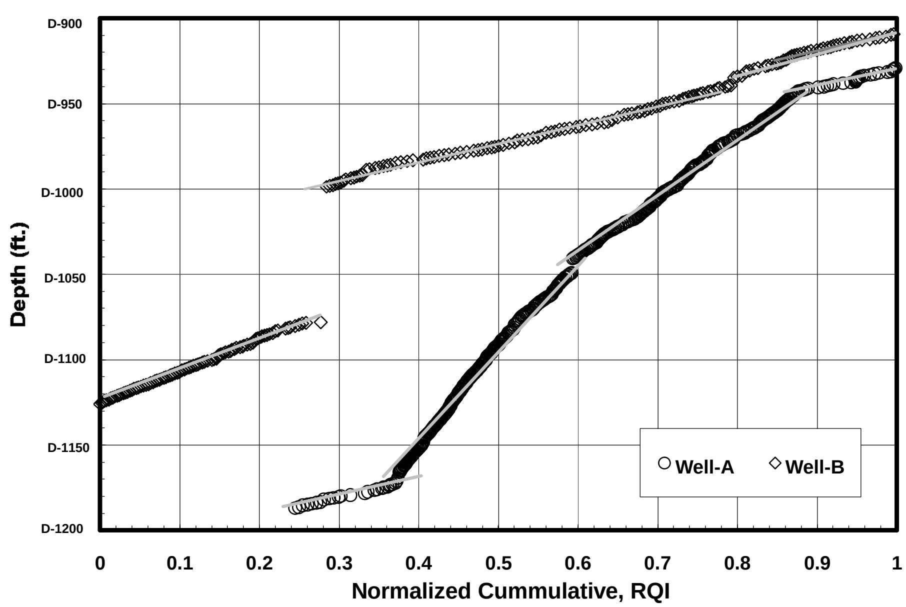


Figure 7: Typical Unsteady-State Oil/Water Relative Permeability Curves, Well-A.

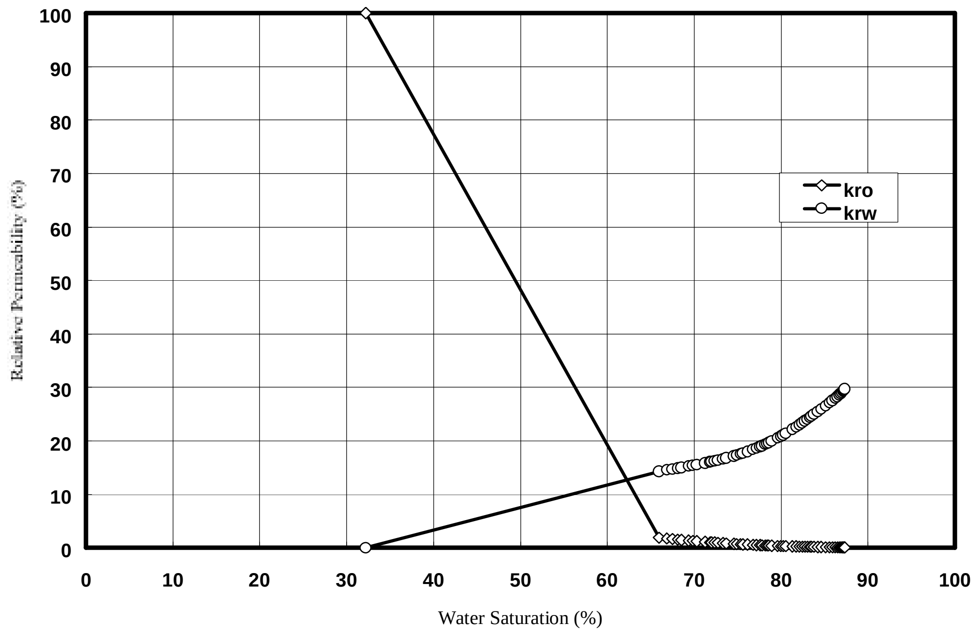


Figure 8: Comparison of all Relative Permeability Ratios as a Function of Normalized Saturation (Well-A).

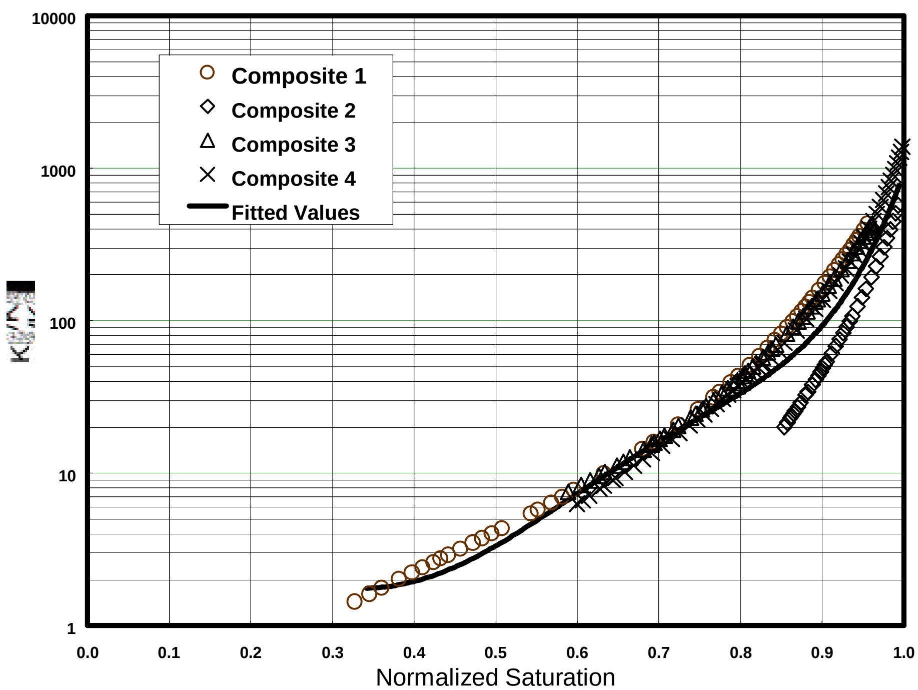


Figure 9: A typical Drainage and Imbibition Curves for Well-A.

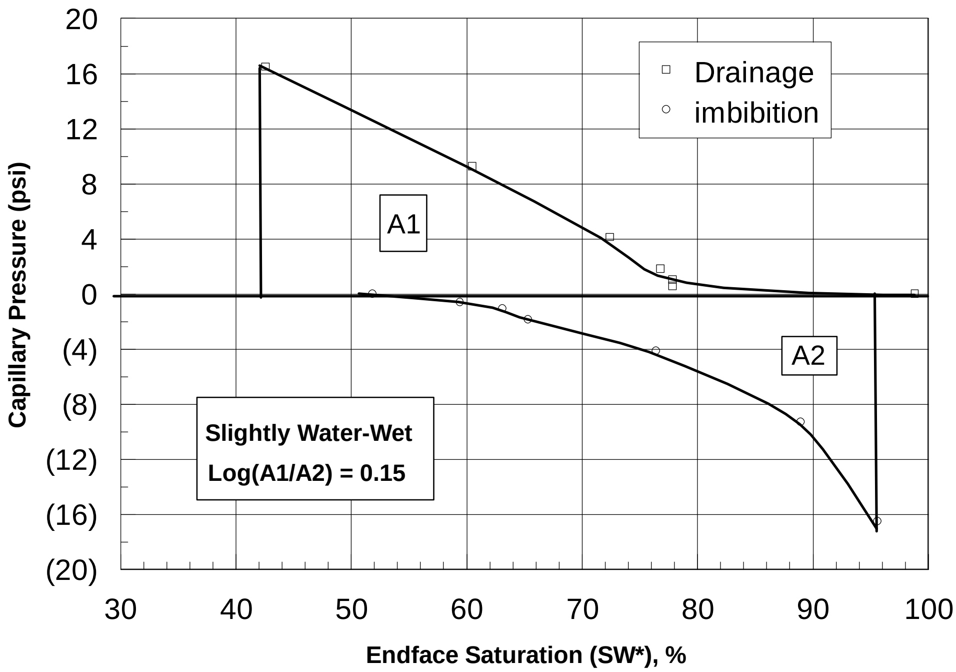


Figure 10: Wettability Indices Distribution for Shu'aiba Reservoir.

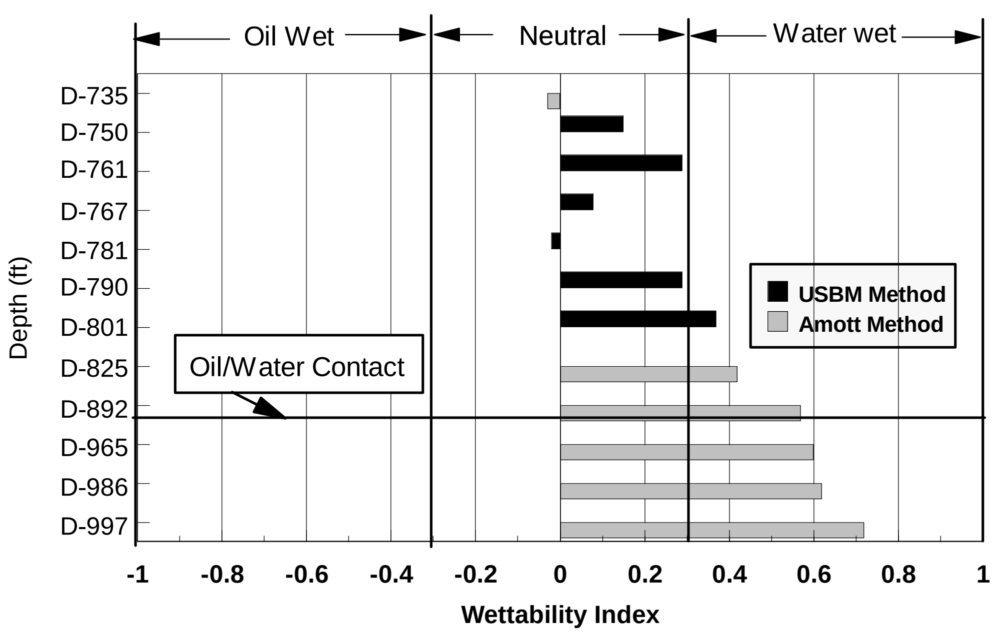


Figure 11: Incremental Wetting Phase Saturation vs. Pore Entry Radius for Well-C.

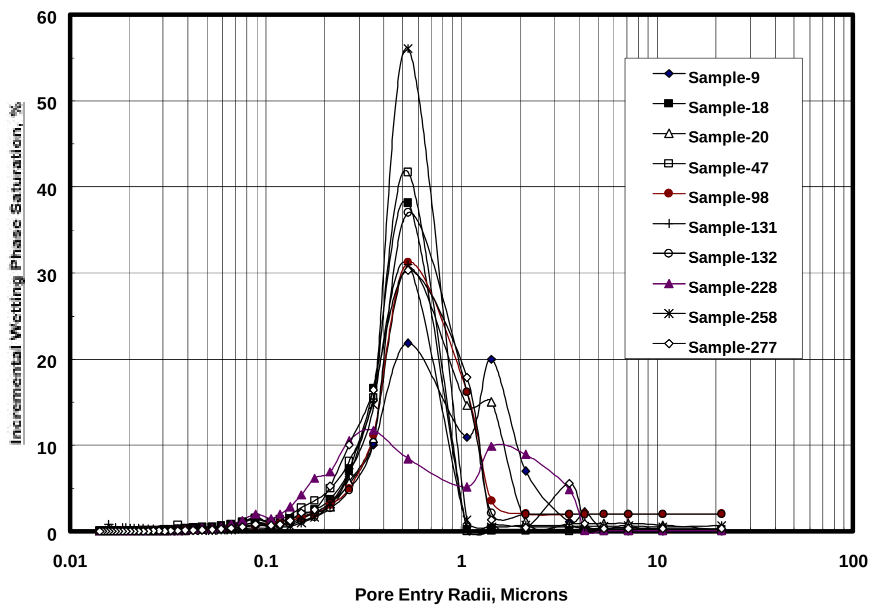


Figure 12: Saturation vs. Pore Entry Radius for Well-C.