INVESTIGATION OF WETTABILITY EFFECTS ON CAPILLARY PRESSURE, AND IRREDUCIBLE SATURATION FOR SAUDI CRUDE OILS, USING ROCK CENTRIFUGE

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The main task of a petroleum reservoir engineer is to produce oil and gas reservoirs with maximum economic rate and reaching the ultimate recovery. Reservoir evaluation processes need a reservoir description as completely and accurately as possible using a variety of methods from seismic and well testing to logging, cuttings analysis and coring. These methods present the engineer with a valuable and wide range of scales of information to well evaluate the reservoir and control its performance and improve oil recovery. The main goal of core analysis is to reduce uncertainty in reservoir evaluation processes created by the uncertainty degree in the input parameters at the different levels from reserve estimate level to the enhancement of reservoir performance level. In order to reach these targets, the exact determination of certain petrophysical properties are necessary such as rock porosity, relative permeability, water saturation, and capillary pressure at all stages of reservoir life and rock wettability. Predicting reservoir wettability and its effect on fluid distribution and hydrocarbon recovery remains one of the major challenges in reservoir evaluation and engineering. Current laboratory based techniques require the use of rock-fluid systems that are representative of in situ reservoir wettability. Several parameters like relative permeability's, residual saturations, and capillary depressurization curves change with the wettability state of the reservoir. In addition all these parameters, can greatly impact oil recovery. Thus, there is a need to relate all these parameter to wettability state of the reservoir [Anderson, 1986].

In this study, irreducible oil saturation and capillary pressures using rock centrifuge measurements for Berea Sandstone rock samples and Saudi oils will be tested during drainage and imbibitions cycles by varying each time the wettability of the tested samples by using different Saudi oils (Heavy, Medium, and Light). The capillary pressure for the aged samples will be measured again by the rock centrifuge. Hence, the changes in capillary pressure curve before and after wettability alteration will be obtained. Hence, wettability, capillary pressure, initial fluids saturation, will be correlated for Saudi reservoirs.

Keywords: *Wettability, Capillary Pressure, Irreducible Saturation and Relative Permeability*

1. INTRODUCTION

Wettability Definition

Wettability is defined as the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids. In other words wettability of reservoir rocks is the actual process by which a liquid spreads on (wets) a solid substrate or surface [Anderson, 1986].

Wettability Classification

The wettability of fluid/rock system can range from strongly water-wet to strongly oil-wet. When the rock has no strong preference for either oil or water, the system is said to be neutral (or intermediate) wettability. Besides strong and neutral wettability, there are two different types of wettability such as *fractional wettability*, and *mixed wettability* [Anderson,1986].

Wettability Measurement Techniques

Many different methods have been proposed for measuring the wettability of a rock/fluid system. They include quantitative methods such as contact angles, imbibition and forced displacement (Amott), and USBM wettability method. The contact angle measures the wettability of a specific surface, while the Amott and USBM methods measure the average wettability of a core [Anderson, 1986].

Changes in the wettability of cores have been shown to affect electrical properties, capillary pressure, waterflood behavior, relative permeability, dispersion, simulated tertiary recovery, irreducible water saturation (IWS), and residual oil saturation (ROS) [Anderson, Oct. 1987].

Effect of wettability on capillary pressure

The capillary pressure/saturation relationship depends on the interaction of wettability, pore structure, initial saturation, and saturation history. No simple relationship exists that relates the capillary pressure determined at two different wettabilities. Therefore, the most accurate measurements are made with cores that have native reservoir wettability [Anderson, Oct. 1987].

In a uniformly wetted porous medium, pore geometry effects and the extremely rough surface of the porous medium make the capillary pressure curve insensitive to wettability for small contact angles (less than about 50є for drainage capillary pressure curves and less than about 20є for spontaneous-imbibition capillary pressure curves). When the porous medium has fractional or mixed wettability, both the amount and distribution of the oil-wet and water-wet surfaces are important in determining the capillary pressure curve, residual saturation, and imbibition behavior. Imbibition also depends on the interaction of wettability, pore structure, initial saturation, and saturation history. Because of these interactions, there is a large range of contact angles where neither oil nor water will imbibe freely into a uniform wetted reservoir core. In contrast, it is sometimes possible for both fluids to imbibe freely into a core with fractional or mixed Wettability [Anderson, Oct. 1987].

When oil and water are placed together on a surface, a curved interface between the oil and water is formed, with a contact angle at the surface that can range from 0 to 180 º. By convention, the contact angle, θ, is measured through the water. Generally, when is between 0 and 60 º to 75 º, the system is defined as water wet. When is between 180 ° and 105 to 120 °, the system is defined as oil-wet. In the middle range of contact angle, a system is neutrally or intermediately wet [Anderson, Oct 1986].

Effect of Wettability on Relative Permeability

The wettability of a core will strongly affect its waterflood behavior and relative permeability. Wettability affects relative permeability because it is a major factor in the control of the location, flow, and distribution of fluid in a porous medium. In uniformly or fractionally wetted porous media, the water relative permeability increase and the oil relative permeability decrease as the system becomes more oil-wet. In a mixed-wettability system, the continuous oil-wet paths in the larger pores alter the relative permeability curves and allow the system to be water flooded to very low residual oil saturation (ROS) after the injection of many PV's of water. The most accurate relative permeability measurements are made in native-state core, where the reservoir wettability is preserved [Anderson, Nov. 1986].

Wettability Alteration by Surfactants

A surfactant is a polar compound, consisting of an amphiphilic molecule, with a hydrophilic part (anionic, cationic, amphoteric or nonionic) and a hydrophobic part. As a result, the addition of a surfactant to an oil-water mixture would lead to a reduction in the interfacial tension. In the past time, the surfactants were used to increase oil recovery by lowering IFT. Later on, due to the difficulty of initiating imbibition process in oil-wet carbonate rocks, many researchers have focused on how to alter the oil-wet carbonate to water-wet by using surfactants. The most successful method reported is the surfactant flooding in the presence of alkaline. There are a number of mechanisms for surfactant adsorption such as electrostatic attraction/repulsion, ion-exchange, chemisorption, chain-chain interactions, hydrogen bonding and hydrophobic bonding. The nature of the surfactants, minerals and solution conditions as well as the mineralogical composition of reservoir rocks play a governing role in determining the interactions between the reservoir minerals and externally added reagents (surfactants/ polymers) and their effect on solid-liquid interfacial properties such as surface charge and wettability [Babadagli, 2003].

METHOD USED FOR MEASURING CAPILLARY PRESSURE

Centrifuge Method Description

Hassler and Brunner (1945) presented the basic concepts involved in the use of the centrifuge by relating the performance of a small core in a field of high acceleration [Singhal, 1976].

If the cylindrical core of length L is subjected to an acceleration $ac = -\omega^2 r$ where ω angular velocity of the centrifuge and r is the distance from the axis of rotation, then from the following equation:

$$\frac{\partial p_c}{\partial z} = (\rho_o - \rho_w) \tag{1}$$

We have

$$\frac{\partial p_c}{\partial r} = \Delta\rho a_c \tag{2}$$

Given the boundary conditions show in Figure 1, the differential equation can be solved by simple integration

$$P_c = \int_{r2}^{2} \Delta\rho a_c \, dr \tag{3}$$

$$P_c(r) = -\int_{r2}^{2} \Delta\,\rho\omega^2 r dr \tag{4}$$

The capillary pressure at the outer face of the core is zero, $Pc(r2) = 0$, so

$$P_c(r) = \frac{1}{2}\Delta\,\rho\omega^2 (r_2^2 - r_1^2) \tag{5}$$

and for a continuous phase, the capillary pressure at the inner face of the core is

$$P_{cL} = p_c(L) = \frac{1}{2}\Delta\rho\omega^2(r_2^2 - r_1^2) \qquad (6)$$

Now, the main purpose is to relate the capillary pressure and saturation *S* for a given core which gives the saturation in the core at equilibrium with the capillary pressure, *S = S(Pc)* [Dake, 1978]

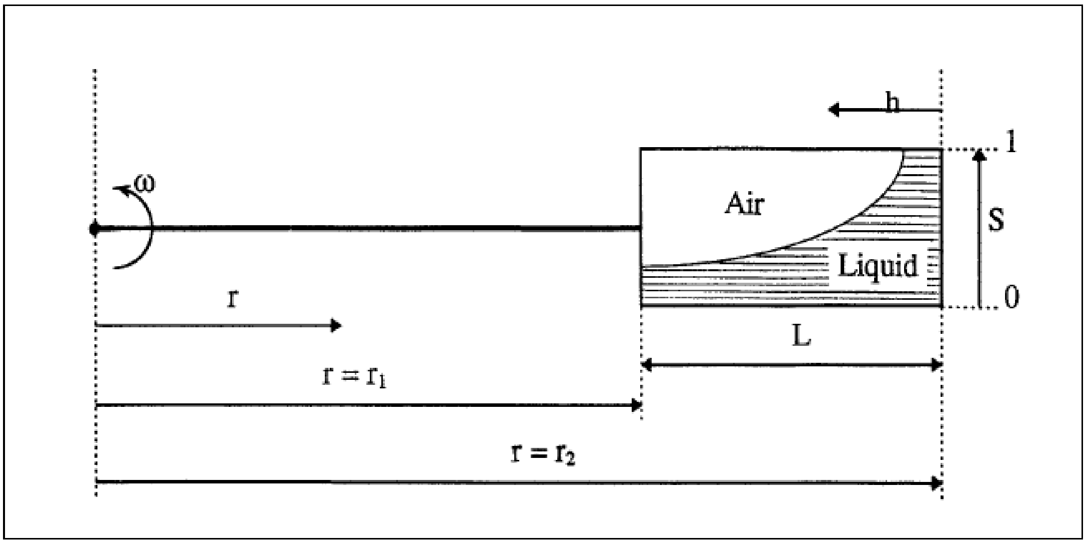

Figure 1. Schematic diagram of a core in a centrifuge
and its boundary conditions [After Singhal 1976]

The saturation at a distance *h* above the outer face of the core can not be measured directly. However, the average saturation, which is the ratio of remaining liquid volume after production to pore volume, can be written as:

$$\bar{S} = \frac{1}{(r_2 - r_1)} \int_{r_2}^{r_1} S(r)\,dr \qquad (7)$$

We will have a relationship of saturation as a function of capillary pressure, *S = S(Pc)*, so Eq. (7) can be expressed as follows by changing integration variable *Pc (r2) = 0* and *Pc (r1) = PcL*

$$\bar{S} = \frac{1}{(r_2 - r_1)} \int_{0}^{P_{cl}} \frac{S(P_c)\,dP_c}{-\Delta\rho\omega^2 r} \qquad (8)$$

An expression for r is obtained from Eq. (5)

$$r = r_2 \sqrt{1 - \frac{P_c}{\frac{1}{2}\Delta\rho\omega^2 r_2^2}} \qquad (9)$$

$$\bar{S}=\frac{1}{(r_2-r_1)\Delta\rho\omega^2 r_2}\int_0^{p_{cl}}\frac{S(P_c)dP_c}{\sqrt{1-\frac{P_c}{\frac{1}{2}\Delta\rho\omega^2 r_2^2}}} \quad (10)$$

and with mathematical manipulation it becomes

$$\bar{S}P_{cl}=\cos^2(\frac{\alpha}{2})\int_0^{p_{cl}}\frac{S(P_c)dP_c}{\sqrt{1-\frac{P_c}{1-\frac{P_c}{P_{cl}}sin^2\alpha}}} \quad (11)$$

Where

$$\cos^2(\frac{\alpha}{2})=\frac{1}{2}(1+\cos\alpha)=\frac{r_1+r_2}{2r_2} \quad (12)$$

$$\sin^2\alpha=1-\cos^2\alpha=1-\frac{r_1^2}{r_2^1} \quad (13)$$

Eq. (11) can not be solved so simply for the unknown function *S*. For small values of α (small core sample), the acceleration gradient along the core can be neglected [10].

Assuming $r_1/r_2=1$, then $\cos^2(\frac{\alpha}{2})=1$ and $\sin^2\alpha=0$.

Eq. (11) is then reduced to

$$\bar{S}=\int_0^{p_{cl}}S(P_c)dP_c \quad (14)$$

Or in differentiation form

$$S_L=\frac{d}{dP_{cL}}(\bar{S}P_{cL}) \quad (15)$$

In this method the cores is saturated with water (or oil) and rotated at increasing speed. The speed is increased in steps, and average fluid saturations at each speed is calculated from observation of liquid produced. The liquid volume is read with a stroboscope while centrifuge is in motion, and the speed of centrifuge is increased stepwise. When the run is over the cores are removed and weighed.

The value of P_{cL} for each centrifuge speed are then computed from Eq. (6), and the average saturation for each core is obtained from the dry and saturated weights and the corresponding pipette reading. From these data a smooth curve is prepared for each core. Figure 2a shows a typical *cL SP* as a function of P_{cL} and points indicated on the curve are first, second and third speed. The value of saturation that goes with each value of P_{cL}, which now represents the capillary pressure, is obtained from this curve by graphical differentiation according to Eq. (15). A typical plot of P_c as a function of S is shown in Figure 2b.

A complete capillary pressure curve by this method may be obtained in a few hours, and several samples are run simultaneously. The method is claimed to be accurate, to reach equilibrium rapidly, give good reproducibility, and is able to produce high pressure differences between phases [Singhal 1976].

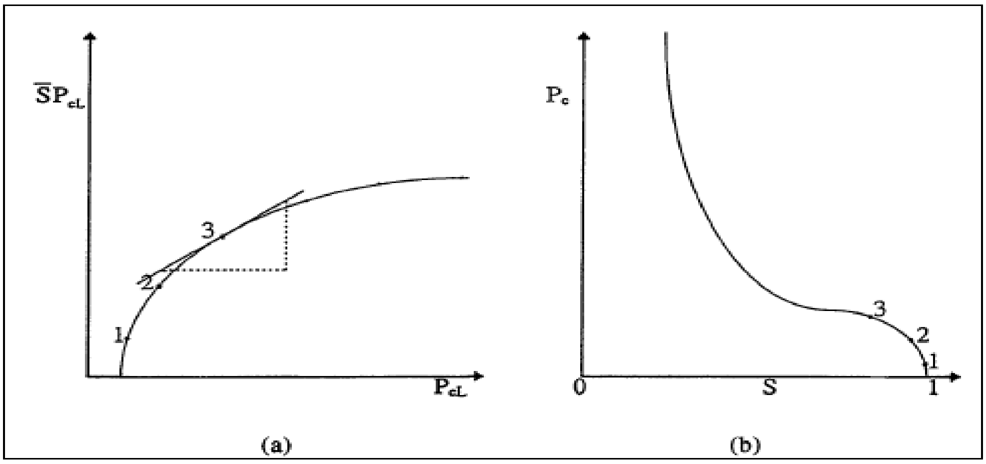

Figure 2. Graphical Differentiation of $\bar{S}\,P_{cL} - P_{cL}$ curve (a) to determine $S - P_c$ curve (b) [After Singhal 1976]

RESULTS AND DISCUSSION

Results of Gas Permeability Measurements

Gas permeability was measured to predict the equivalent liquid permeability by using Klinkenberg method. Table 1 shows the resulted gas permeability for the used rock samples.

Table 1

Gas Permeability for used Samples

Core	Porosity	Ka (md)
A	20.12	386
B	19.19	381
C	19.29	275

Results of Liquid Permeability Measurements

Absolute liquid permeability's for the three cores were measured using Liquid Permeameter by using brine at four different rates vs. pressure difference. A rang of 250 to 365 md was estimated for the tested rock samples. Samples B and C have almost the same permeability of about 360 md. The permeability's were obtained from the resulted slope of plotting q versus ΔP, where $K = slope \times \mu$.

Tables 2, 3, and 4 and Figures 3, 4, and 5 show the resulted data of liquid permeability for the tested rock samples, whereas these Tables and Figures show that the sample A and B are almost have the same permeability.

Results of Capillary Pressure Measurements

The results of the drainage and imbibition process using rock centrifuge method that mentioned the last chapter for the test rock samples are listed in Tables 5, and 6. Due to the difference in oil compositions of the used crude oils (Arab-light, Arab-Medium, and Arab-heavy), there are marked changes in the capillary curves of the drainage cycles for the tested samples. Similarly, these marked changes between the capillary curves during the ambition cycles were occurred.

Table 2

Liquid permeability for Sample A

Sample	Q, cc/min	Q, cc/sec	DP, psi	DPcorr. psi	DP, atm	μ, cp
A	2	0.0333	0.4	0.4166	0.0283	1.07
	4	0.0667	0.73	0.7465	0.0508	1.07
	6	0.1	1.41	1.4263	0.097	1.07
	8	0.1333	2.18	2.196	0.1494	1.07

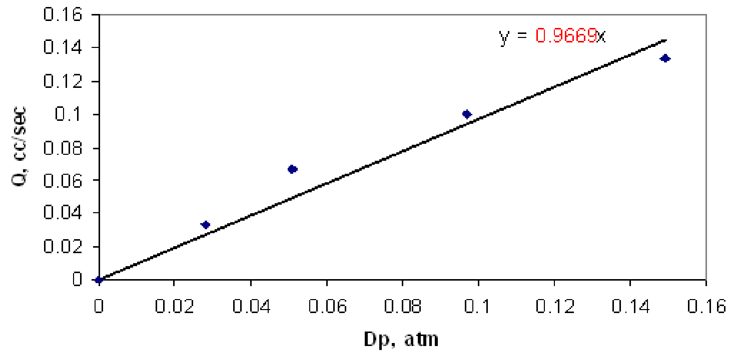

Figure 3. Flow Rate vs. Pressure Difference for Sample A

Table 3

Liquid Permeability for Sample B

Sample	Q, cc/min	Q, cc/sec	DP, psi	DPcorr. psi	DP, atm	µ, cp
B	2	0.03333	0.64	0.65651	0.04466	1.07
	4	0.06667	1.68	1.6962	0.11539	1.07
	6	0.1	3.74	3.75558	0.25548	1.07
	8	0.13333	3.74	3.75558	0.25548	1.07

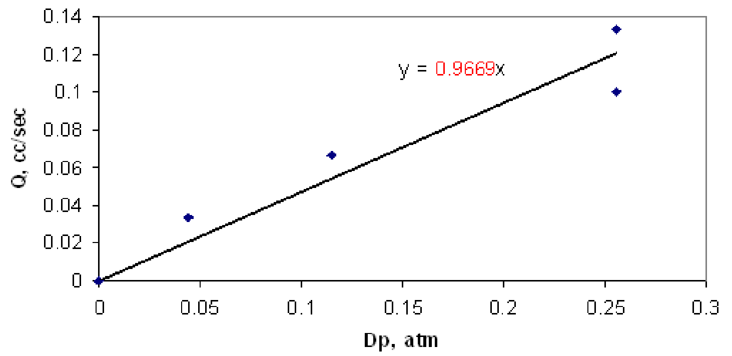

Figure 4. Flow Rate vs. Pressure Difference for Sample B

Table 4

Liquid Permeability for Sample C

Sample	Q, cc/min	Q, cc/sec	DP, psi	DPcorr. psi	DP, atm	μ, cp
C	2	0.03333	0.86	0.87644	0.05962	1.07
	4	0.06667	1.81	1.82616	0.12423	1.07
	6	0.1	2.14	2.15606	0.14667	1.07
	8	0.13333	2.84	2.85585	0.19428	1.07

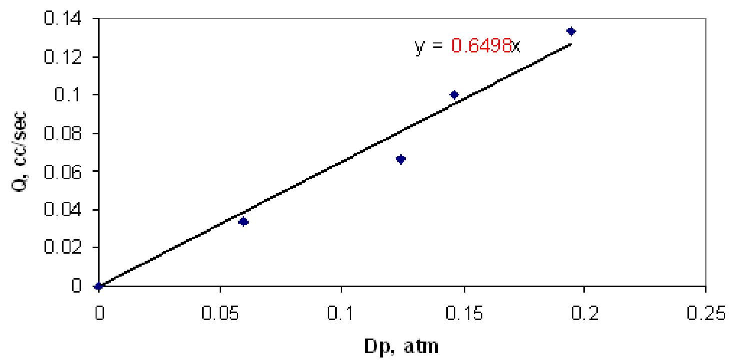

Figure 5. Flow Rate vs. Pressure Difference for Sample C

Wettability versus Capillary Pressure

Practically, heavy oil has higher asphaltene concentrations than light oil. The presences of these asphaltene or polar components concentrations in crude oil can adsorb on mineral surfaces and alter their wetting properties. However, there are several distinct mechanisms by which a crude oil can alter rock wetting characteristic. Therefore, oil compositional characteristics are needed that related directly to these mechanisms, such as acid and base numbers. Due to a complete analysis of used crude oil not available the judgment on the rock/oil wetting system was done by the variations on the irreducible water saturations during the drainage cycle of the capillary curve and on the residual oil saturation at the end of the imbibition cycle of the capillary pressure curve.

To draw a clear relationship between the capillary pressure, water saturation, and water saturation two stages should be investigated. These stages are Drainage and Imbibition. In the drainage stage the speeds of centrifuge ranged from 700 to

6000 RPM. The capillary pressures and water saturations of the drainage cycle listed in Table 5. Arab Light, Arab-Medium, and Arab-Heavy crude oils were used in samples A, B, and C respectively. From this table and Figure 4 it is clear that sample C (heavy crude oil) has the highest irreducible water saturation among the other two samples. Whereas, drainage cycle means increasing the wetting-phase saturation from its maximum to the irreducible minimum by increasing the capillary pressure from zero to a large positive value, therefore, used fluid (Arab–heavy) in sample C change the wettability of this sample toward oil wet.

Wettability versus Oil Recovery

In Imbibition Stage 16000 RPM speed of the centrifuge was reached for recording the volumes of oil removed from the rock sample. The capillary pressures and oil saturations of the imbibition cycle (that represent water flood cycle) listed in Table 6. This Table and Figure 4 show that Sample C has the highest residual oil saturation, which means low recovery factor. Practically, as the wettability of a system ranges from water-wet to oil wet the breakthrough and economical Sor increase, so oil recovery decreases. The economical Sor is lower than the breakthrough saturation, and the different between the two gradually increases, so that there is a longer period of simultaneous oil and water production. Small amounts of oil are produced for a long time after breakthrough; therefore, the economical Sor depends on the number of PV's of water injected. The decrease in oil mobility at high oil/water viscosity ratios cause a decrease in the oil recovery at breakthrough and increase in the period of oil and water production for cores of any wettability. On the other hand, there will be a high oil recovery at breakthrough and little subsequent oil recovery even in a strongly oil-wet core when the oil/water viscosity ratio is very favorable. However, a waterflood in an oil-wet or intermediate-wet core is always less efficient than the waterflood in a water-wet core at the same viscosity ratio

Table 5

Capillary Pressures and Saturations of the Samples -Drainage Stage

Speed	SwA L	pcLA	SwB M	PcLB	SwC heavy	PcLC
700	1	0.635	1	0.585	1	0.504
900	0.9465	1.049	0.9442	0.967	0.946	0.834
1200	0.8394	1.865	0.8883	1.718	0.946	1.482
1300	0.8394	2.189	0.8883	2.017	0.892	1.74
1400	0.8394	2.538	0.6092	2.339	0.892	2.018
1600	0.7858	3.315	0.6092	3.055	0.837	2.635
1800	0.7323	4.196	0.4416	3.867	0.837	3.335
2000	0.6252	5.18	0.3858	4.774	0.783	4.118
2700	0.3575	9.441	0.3858	8.7	0.675	7.504
3500	0.1969	15.865	0.2741	14.619	0.404	12.61
4000	0.1969	20.721	0.2741	19.094	0.295	16.47
4500	0.1434	26.225	0.2183	24.166	0.241	20.845
5000	0.0898	32.377	0.2183	29.835	0.241	25.735
5500	0.0898	39.176	0.2183	36.1	0.241	31.139
6000	0.0898	46.623	0.2183	42.962	0.241	37.058

Table 6

Capillary Pressures and Saturations of the Samples - Imbibition Stage

Speed	**SwA**	**SoA**	**P_{cL}A**	**SwB**	**SoB**	**P_{cL}B**	**SwC**	**SoC**	**P_{cL}C**
700	0.24126	0.75874	-1.4972	0.21831	0.78169	-1.7246	0.08984	0.91016	-1.8693
950	0.24126	0.75874	-2.7577	0.21831	0.78169	-3.1765	0.08984	0.91016	-3.4429
1200	0.29546	0.70454	-4.4001	0.27414	0.72586	-5.0683	0.14338	0.85662	-5.4934
1300	0.29546	0.70454	-5.164	0.27414	0.72586	-5.9482	0.14338	0.85662	-6.4471
1400	0.29546	0.70454	-5.989	0.27414	0.72586	-6.8985	0.14338	0.85662	-7.4771
1600	0.29546	0.70454	-7.8224	0.27414	0.72586	-9.0102	0.14338	0.85662	-9.7661
1800	0.29546	0.70454	-9.9002	0.27414	0.72586	-11.404	0.14338	0.85662	-12.36
2000	0.29546	0.70454	-12.222	0.27414	0.72586	-14.078	0.14338	0.85662	-15.259
2700	0.29546	0.70454	-22.275	0.27414	0.72586	-25.658	0.14338	0.85662	-27.81
3500	0.29546	0.70454	-37.431	0.27414	0.72586	-43.115	0.19692	0.80308	-46.732
4000	0.34966	0.65034	-48.89	0.27414	0.72586	-56.314	0.25045	0.74955	-61.038
4500	0.34966	0.65034	-61.876	0.27414	0.72586	-71.272	0.25045	0.74955	-77.251
5000	0.40386	0.59614	-76.39	0.32998	0.67002	-87.991	0.30399	0.69601	-95.372
5500	0.40386	0.59614	-92.432	0.32998	0.67002	-106.47	0.30399	0.69601	-115.4
6000	0.40386	0.59614	-110	0.32998	0.67002	-126.71	0.35753	0.64247	-137.34
6500	0.40386	0.59614	-129.1	0.32998	0.67002	-148.7	0.35753	0.64247	-161.18
7000	0.40386	0.59614	-149.72	0.32998	0.67002	-172.46	0.35753	0.64247	-186.93
7500	0.45806	0.54194	-171.88	0.38581	0.61419	-197.98	0.35753	0.64247	-214.59
8000	0.45806	0.54194	-195.56	0.38581	0.61419	-225.26	0.41107	0.58893	-244.15
9000	0.45806	0.54194	-247.5	0.44165	0.55835	-285.09	0.41107	0.58893	-309
10000	0.51227	0.48773	-305.56	0.44165	0.55835	-351.96	0.46461	0.53539	-381.49
11000	0.56647	0.43353	-369.73	0.49748	0.50252	-425.87	0.51815	0.48185	-461.6
12000	0.59357	0.40643	-440.01	0.5254	0.4746	-506.83	0.51815	0.48185	-549.34
13000	0.62067	0.37933	-516.4	0.55332	0.44668	-594.82	0.59846	0.40154	-644.71
14000	0.64777	0.35223	-598.9	0.58124	0.41876	-689.85	0.59846	0.40154	-747.71
15000	0.67487	0.32513	-687.51	0.60915	0.39085	-791.91	0.652	0.348	-858.34
16000	0.72907	0.27093	-782.24	0.66499	0.33501	-901.02	0.65275	0.34725	-976.61

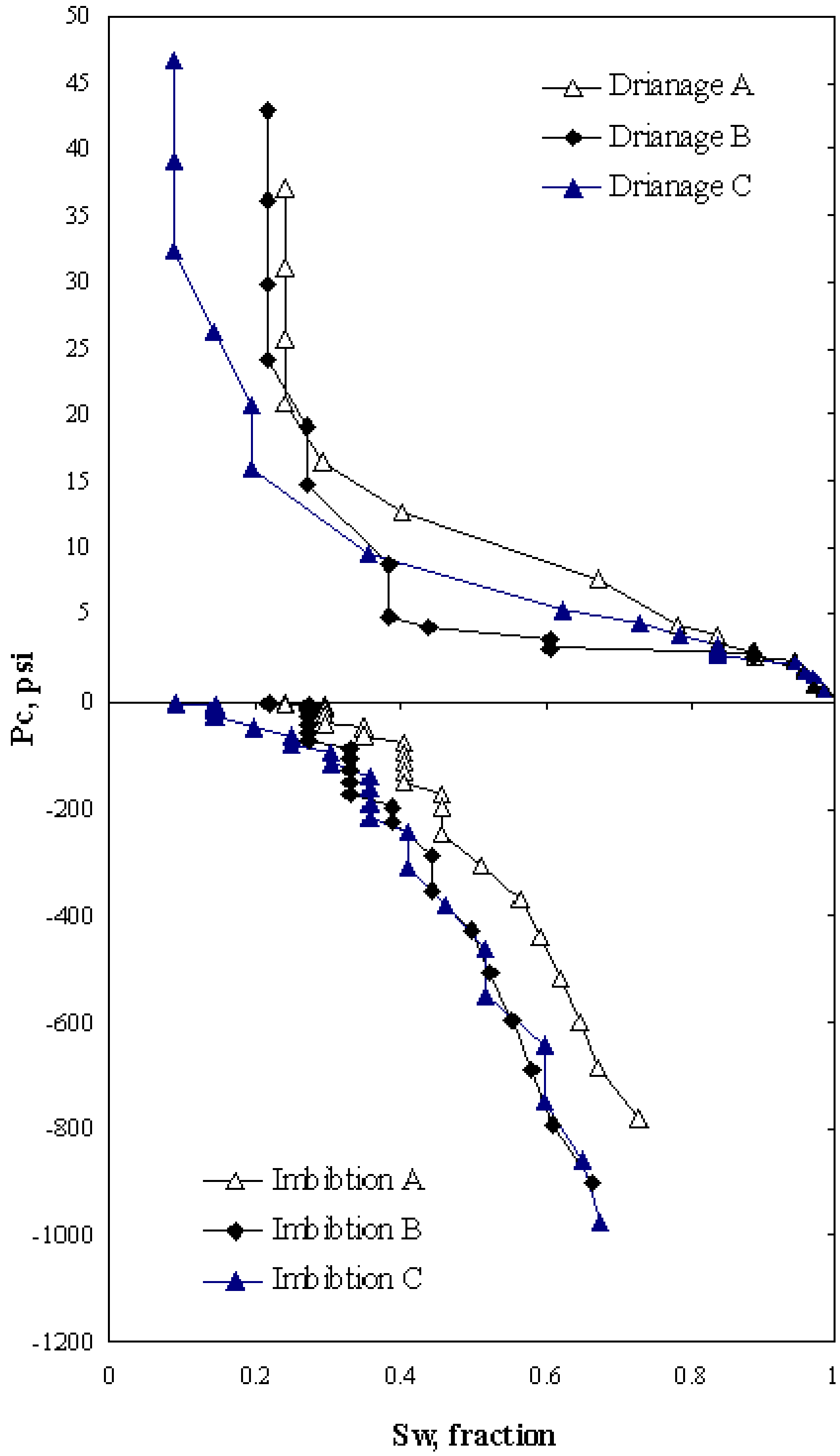

Figure 5. Capillary Pressures vs. Saturations at Drainage and Imbibition cycles

CONCLUSIONS

1. Changing the wettability cause a change in capillary pressure curve.
2. The irreducible water saturation reached at about 50 psi capillary pressure value equivalent to 6000 RPM rock centrifuge during the drainage cycle using synthetic Saudi formation brine and Saudi oil fluid pair.
3. The residual oil saturation reached at about 980 psi capillary pressure value equivalent to 16000 RPM rock centrifuge during the imbibition cycle using synthetic Saudi formation brine and Saudi oil fluid pair.
4. Residual oil saturation depends on the rock/fluid wetting characteristic, whereas it markedly increase by alteration the reservoir wettability from oil wet to water.

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