RELATIVE PERMEABILITY, CAPILLARY PRESSURE AND USBM WETTABILITY INDEX DETERMINATION IN A HIGHLY ASPHALTENIC OIL RESERVOIR

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ABSTRACT

Most of the troubles concerning determination of water-oil relative permeability and capillary pressure of reservoir rocks arise from discrepancies in the wettability of studied reservoir and measured laboratory data, which makes the results unreliable and doubtful. In core study experiments, when live reservoir oil is out of reach, dead crude oil is mainly used to establish reservoir wettability. But most of the times it is unusable for relative permeability and capillary pressure experiments.

In this study the effect of using highly asphaltenic dead crude oil on the relative permeability, capillary pressure and USBM wettability index experiments was investigated by applying the "restored-state" approach. The tests were performed on some core plug samples of a carbonate reservoir from the South-West of Iran. Due to asphaltene and resin precipitation and clogging in the pore spaces no representative results were obtained, hence, buffer solvent was injected into the samples to remove the bulk of crude oil before using synthetic mineral oil for performing the experiments. The recorded data from relative permeability experiments were simulated by Sendra core flow simulator and compared with conventional Jones and Roszelle calculation method. Both USBM and Craige rules of thumb showed oil-wetness characteristics.

NOMENCLATURE

P_C: capillary pressure
ω: angular velocity
r: distance from center of rotation
r_e: distance of core outlet face from center of rotation
$\Delta\rho$: density difference of fluids

INTRODUCTION

Relative permeability and capillary pressure data are of paramount importance for simulation and prediction of a reservoir performance. In order to be useful as input data for reservoir simulation, their measurements in the laboratory must be representative of the reservoir conditions. The first approach to designing the laboratory tests is to replicate the reservoir conditions in laboratory. This approach involves performing the tests at reservoir temperature and pressure with live reservoir crude oil and brine on preserved reservoir rocks.

Performing the tests at reservoir conditions requires high temperature and pressure equipment, live reservoir fluids, and carefully obtained, handled and preserved core samples. Each of these conditions adds significantly to the cost and duration of the tests. For example, the most representative capillary pressure and wettability index data are obtained by using the porous plate technique under reservoir conditions which is very expensive and time-consuming. Although this approach appears conceptually the most representative, the need for all of these conditions is presently undetermined. If any of these conditions can be eliminated or alleviated without these data becoming less representative of the reservoir, then considerable cost, time and manpower can be saved [1].

In this study the "restored-state" approach was used for establishing the wettability of reservoir core samples prior to the relative permeability, capillary pressure and USBM wettability index determination. Hence, the samples must undergo a cleaning procedure to reach water-wet state and then to be aged in crude oil at irreducible water saturation (S_{wi}).

The most representative ageing method is using live oil at reservoir conditions. However many researchers stated that the difference in results between live and dead crude oils at reservoir conditions was not significant [2]. In case of lacking live oil, dead crude oil has mostly been recommended in the literature [1, 2]. In this study due to restrictions of providing live oil and funding resources, dead crude oil was used for establishing irreducible water saturation and ageing prior to performing the experiments.

RESERVOIR CRUDE OIL AND ROCK PROPERTIES

The dead crude oil of the candidate well contained high amount of asphaltene, resine and metals like vanadium and nickel. The SARA test showed presence of 20w% of resine and 10.4w% of asphaltene in this dead crude oil. Asphaltene precipitation has been known to have strong effects on the permeability reduction. The crude oil was centrifuged prior to using for the experiments.

3 carbonate core plugs with different ranges of porosity and permeability from a candidate well were selected to perform relative permeability and capillary pressure experiments. Their petrophysical properties are presented in table 1.

EXPERIMENTAL PROCEDURES

The core plug samples were cleaned by toluene in the soxhlet which leaves them water-wet. After cleaning, drying and measuring petrophysical properties of the samples, they were evacuated and saturated with de-aired simulated formation brine of 240,000 PPM under 3000 psi pressure for 48 hours. Then the samples were emerged in brine in a sealed airtight desiccator for 10 days to reach ionic equilibrium.

For relative permeability experiments the plug samples were loaded in a hydrostatic core holder and brine permeability of each sample was determined. Measurements were performed by injecting the brine at three different appropriate flow rates through core plugs. The centrifuged dead crude oil was then injected into the samples at reservoir temperature of 85ºC and very low flow rate (0.03 cc/min) which was increased gradually. Throughout the test the effluent fluids were collected in precise graduated glass-wares and two phases were separated by centrifuging. After establishing the irreducible water saturation, dead oil was injected with a low flow rate. The injection pressure was ever increasing which we believe that it is as a result of wettability changing and plugging the pores by flocculated asphaltene and resin.

The centrifuge experiments were firstly performed by using dead crude oil at elevated temperature of 65°C which was the limitation of the apparatus. After ageing the samples at 1000 psi pore pressure and reservoir temperature of 85°C for 30 days, water-crude oil imbibition and secondary drainage tests were performed. The results showed unrepresentative imbibition and secondary capillary pressure curves (figures 1-3). A very dense layer of resin and asphaltene was also formed on the plug faces due to centrifuging at high speeds.

Removing precipitated asphaltene and resin:

Asphaltenes are originally organic matters considered to be polyaromatic hydrocarbons, consisting primarily of aromatic and aliphatic groups (approximately 89% by mass) and heavy compounds rich in carbon of low hydrogen content, and with high concentration of heteroatom and metals. Deposition of asphaltene from crude oil is widely believed to alter reservoir wettability toward an oil-wet condition. Because oil recovery efficiency for a given reservoir typically declines as the reservoir becomes more oil-wet in character, deposition of asphaltenes may have an adverse impact on ultimate oil recovery [3].

Presence of asphaltene in the crude oil reduces effective hydrocarbon mobility by blocking the pore throats, altering the formation wettability toward oil-wet, due to adsorbing onto the rock surfaces, and increasing hydrocarbon viscosity by nucleating water in oil emulsions [3, 4].

The flocculation of dispersed asphaltene and resin and further their precipitation in the pore throats of the core samples can impede successful relative permeability and capillary pressure measurements by significantly decreasing the effective oil permeability at irreducible water saturation (S_{wi}) condition and during the tests. When asphaltene flocculation occurs in the rock matrix, some asphaltenes may drop out in the pores because of their large size; the flowing fluid may carry others until they arrive simultaneously at the pore throats to bridge and reduce effective permeability.

The crude oil inside the pore spaces of core samples was displaced by 5 to 7 pore volumes (PV) of Decahydronaphthalene (Decalin) at 85°C. Decalin has the formula of $C_{10}H_{18}$, with density of 0.8816 g/cm^3 and viscosity of 2.5 cp at ambient conditions. When Decalin is used to displace the crude oil from the aged core samples, mainly the bulk volume of crude oil is removed, and the polar components adsorbed on the rock surfaces which alter the wettability stay in place [1-4]. The Decalin flush separates refined oil from crude oil which might otherwise cause asphaltene deposition, which in turn would cause unrealistic wettability [3]. This procedure avoids precipitation of asphaltenes and other possible effects on adsorbed components that might result from direct displacement with mineral oil. Pure solvents like Pentane or Heptane, distillation fractions (i.e. kerosene) or light crude oils can induce asphaltene precipitation if are added to a crude oil of low stability [1, 3].

Decalin was then slowly displaced by 5 to 7 PV of Carnation mineral oil with dynamic viscosity of 18.45 cp at ambient condition, with gradually decreasing the core holder temperature to ambient condition. Having the viscosity ratio of oil to brine at reservoir conditions (5.15/0.5=10.3) and the viscosity of brine at ambient condition (1.61 cp), Carnation oil was prepared for relative permeability experiments.

Relative permeability experiments: Conventionally, relative permeability is determined in the laboratory by UnSteady-State (USS), Steady-State (SS), or Centrifuge methods. In this study constant pressure displacement (or USS) method was employed. The USS method of determining relative permeability has the advantage over the SS method, as it is a much quicker way of determining relative permeability curves. This method is thought to most closely represent the reservoir displacement process.
After flushing the aged core plugs with Decalin and further displacing by Carnation mineral oil, the effective oil permeability at S_{wi} condition was obtained. Its value was used as base permeability for all the relative permeability analyses. Prepared salt water was then injected at proper constant injection pressure. Oil and water effluents together with time and pressure data were recorded. The experiment was continued until no more oil was produced. The relative permeabilities, ignoring gravity and capillary end effects, were calculated using graphical technique developed by Jones and Roszelle [5], which is based on Buckley-Leverett theory.

Centrifuge capillary pressure experiments: Capillary pressure (P_C) characteristics of reservoir rocks affect the flow and distribution of fluids within the reservoir. It is one of the most important measurements that can be made because it relates reservoir rock and fluid properties and mostly expressed as a function of water saturation. Conventional centrifuge method is the most common way of P_C curves determination. In a centrifuge experiment, the pressure difference between two phases or the capillary pressure at any point is determined by the angular velocity (ω). In the centrifuge with angular velocity of ω at hydrostatic equilibrium, P_C at radius (r) is equivalent to the difference in hydrostatic pressure between the phases occupying the pore spaces of the sample such that:

$$Pc_{(r)} = \frac{\Delta\rho.\omega^2}{2}(r_e^2 - r^2)$$

In performing the capillary pressure measurements with centrifuge using dead crude oil, a thick layer of asphaltene and heavy components was formed. Aggregation and film formation are likely driven by polar heteroatom interactions, such as hydrogen bonding, which allow asphaltenes to absorb, consolidate, and form cohesive films at the oil-water interface [6]. This event was the reason for unreliable water-oil imbibition and very high threshold pressure in secondary drainage capillary pressure tests and establishing higher amount of S_{wi} comparing to primary drainage tests (figures 1-3).
Due to plugging the pore spaces of plug samples by precipitated asphaltene and resin, imbibition and secondary drainage P_C curves were not correct. Therefore the plug samples were flushed by 5 to 7 PV of Decalin in the core holder at 85°C, followed by injecting Carnation oil to replace the bulk of Decalin. The injection pressure of Decalin into the samples was surveyed periodically to make sure of proper plugging removal. The rest of capillary pressure processes, namely water-Carnation oil imbibition, spontaneous imbibition, Carnation oil-water secondary drainage, and air-Carnation oil drainage were performed at ambient conditions.

Wettability determination: Reservoir wettability is a significant controlling factor in oil recovery efficiency because of its influence on location, distribution, and flow characteristics of the reservoir fluids. The USBM and Amott indices are quantitative measurements of wettability that are derived mainly from the imbibition and secondary drainage capillary pressure curves. In the USBM method, a system is considered strongly water-wet or oil-wet if the index is near +1 or -1, respectively.
The USBM test compares the work necessary for one fluid to displace the other. It has been shown that the required work is related to the area under the P_C curve. For example, if the water wetting is strong enough, most of the water will spontaneously imbibe into the core, and the area under the brine-drive curve will be very small. The areas beneath the P_C curves are calculated by integration. The USBM wetting index is obtained by the logarithm of the ratio of the area beneath the secondary drainage capillary pressure curve to the area beneath the imbibition capillary pressure curve.
In wettability determination using dead crude oil, spontaneous sections were performed in glass imbibiometers at 65ºC and forced sections by a high temperature ultracentrifuge. Spontaneous imbibition/drainage was left until there was no

production for 24 hours. The volume of expelled fluids in the spontaneous phases was monitored periodically.

The adsorption of heavy components of crude oil is suspected to take place predominately in largest pores, containing thin films of bound water [7]. Therefore in spontaneous oil imbibition large amount of water is expelled whereas a film of heavy components covered the large pore surfaces.

Table 1
Petrophysical properties of studied core plug samples.

Sample ID	L (cm)	D (cm)	Porosity (%)	K_{air} (mD)	Density (gr/cm^3)	Archie classification
1	5.039	3.789	10.23	1.684	2.70	I/II,A
2	5.096	3.799	14.75	3.807	2.71	II/I,A/B
3	5.134	3.800	18.57	3.337	2.68	II,A/B

Table 2
The results of relative permeability experiments.

Sample ID	K_w (mD)	S_{wi} (%)	$K_{Carnation\ oil}$ @ S_{wi} (mD)	Injection Pressure (psi)	S_{or} (%)	End point K_{rw} @ S_{or} (mD)
1	0.455	16.4	0.305	600.0	36.1	0.514
2	1.422	16.0	1.017	410.0	30.0	0.595
3	1.929	15.4	1.020	645.0	32.5	0.637

Table 3
The results of centrifuge capillary pressure experiments (sp.: spontaneous).

Sample ID	water-crude oil					water- Carnation oil				
	First drainage S_{wi} (%)	Sp. water imbibition (%)	S_{or} (%)	Sp. oil imbibition (%)	Secondary drainage S_{wi} (%)	Sp. Water imbibition (%)	S_{or} (%)	Sp. oil imbibition (%)	Secondary drainage S_{wi} (%)	USBM Wettability Index
1	16.0	3.1	19.7	23.2	25.0	2.3	10.4	60.0	17.3	-1.0
2	9.3	1.5	18.1	29.4	35.6	1.1	10.1	48.0	16.4	-0.6
3	15.5	1.9	15.9	21.0	47.2	2.8	9.2	49.0	25.9	-0.6

RESULTS AND DISCUSSION

Quantitative and qualitative wettability determination by USBM and Craige rules of thumb respectively showed oil-wet characteristics of these studied core plugs. Whereas P_C curves of crude oil-water tests were not reliable, P_C curves of Carnation oil-water tests were used for determination of USBM wettability index (figures 1-3). Due to high oil tendency of the core samples, oil was imbibed almost half of the core plugs pore volume spontaneously.

The estimated oil production and water production matched well with recorded experimental data from constant pressure water displacement of the samples in Sendra core flow simulation software (figures 4-6). LET model [8] was used for relative permeability and Skjaveland model was used for capillary pressure estimation. Whereas the test procedure was constant pressure water flooding, the fluids were considered uncompressible, although applying compressible fluids in the software yielded a very low compressibility.

Relative permeability curves were also calculated from conventional Jones and Roszelle graphical technique [5], which matches well with those estimated from software. It can be inferred that displacement processes were not affected by the end effect problem. The reason for obtaining high S_{or} values is that in oil-wet reservoir rocks oil flows with more difficulty through pore channels and throats. Consequently, water channels through larger pore throats and bypasses some of the oil.

Comparing imbibition and secondary drainage capillary pressure curves from crude oil-water and Carnation oil-water shows the need of more force for production of the same amount of oil/water during imbibition/drainage cycles of crude oil-water which is due to plugging the pore throats and higher IFT between crude oil-water than Carnation oil-water.

The carnation oil-water secondary drainage curve has not reached to the same S_{wi} value as the first drainage Pc curve. This could be as a result of hysteresis, water entrapment and oil/water measurement discrepancies during the tests, whereas approximately 10% of water was expelled during air-oil drainage process.

CONCLUSIONS

Most of the times when live reservoir oil is out of reach, dead crude oil is used for relative permeability and capillary pressure experiments, but precipitation of asphaltene and resin must be considered. It causes unreliable effective oil permeability and unrepresentative capillary pressure curves. If so, a buffer solvent, normally Decalin, should be used for crude oil displacement prior to injecting synthetic oil.

Some of the benefits of using synthetic oil in SCAL studies are much lower cost and duration of the tests, safer test conditions and need of lower pressure and temperature equipments.

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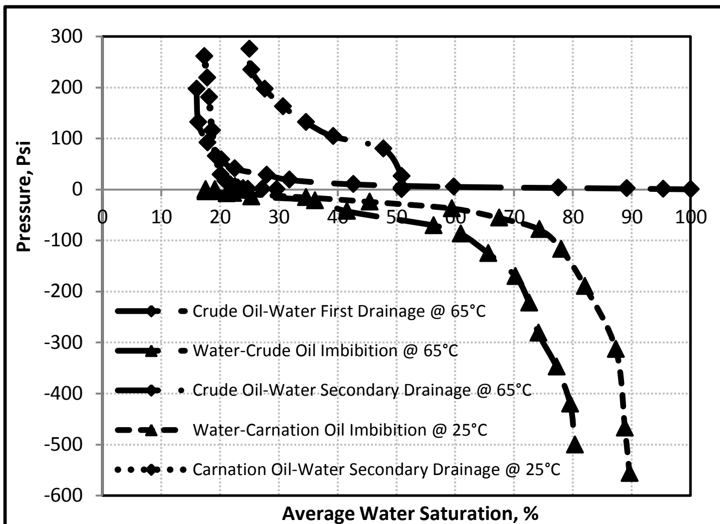

Figure 1
Centrifuge capillary pressure curves of sample 1.

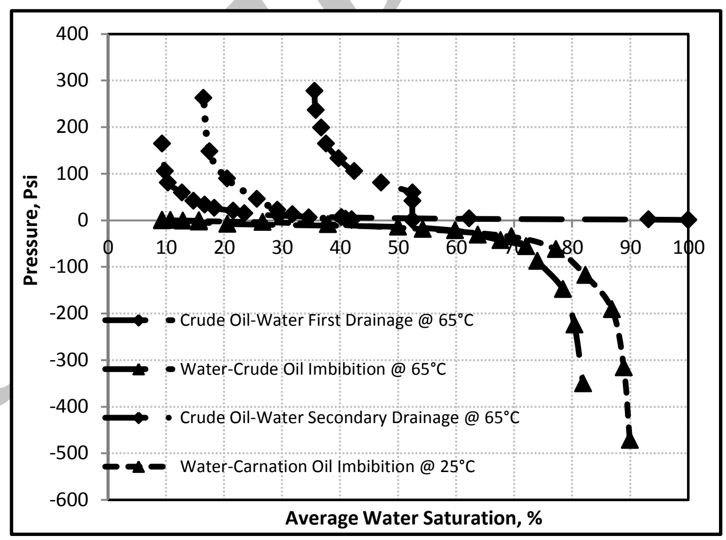

Figure 2
Centrifuge capillary pressure curves of sample 2.

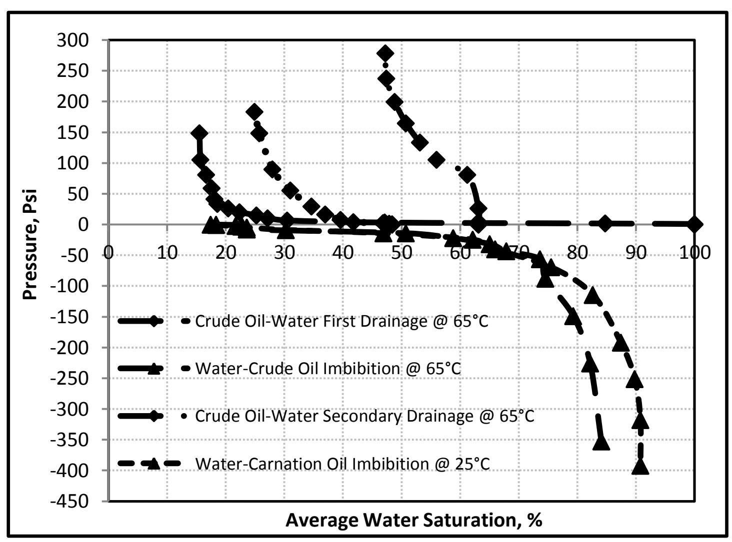

Figure 3
Centrifuge capillary pressure curves of sample 3.

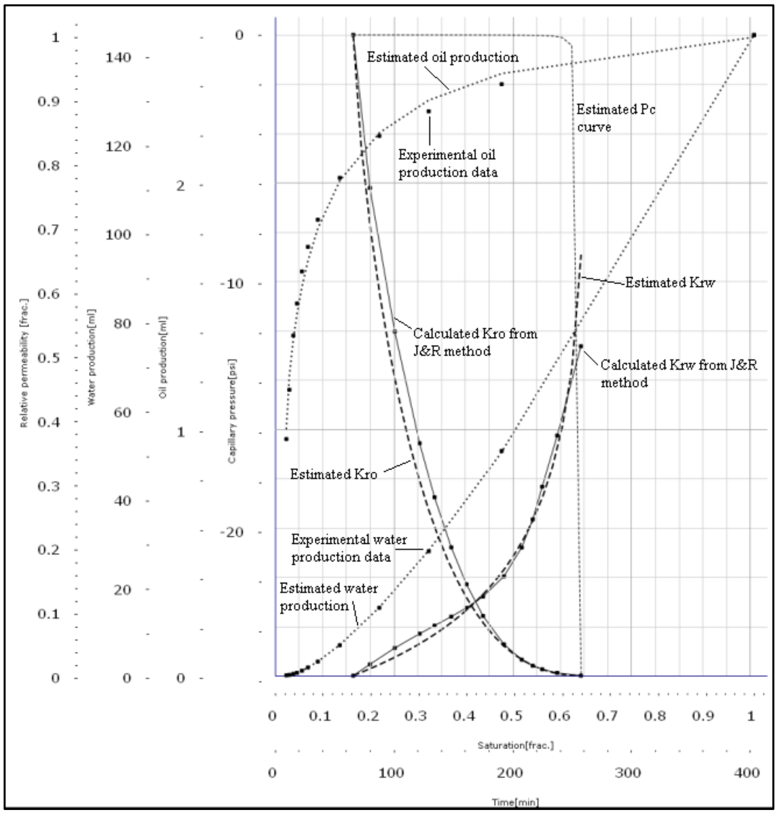

Figure 4
Water-oil relative permeability curves of sample 1.

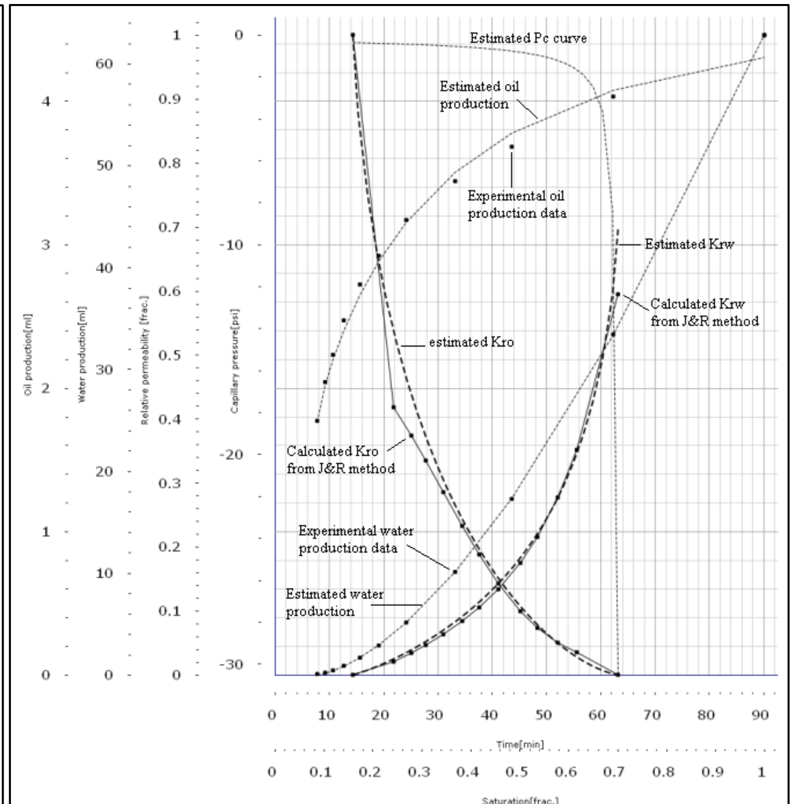

Figure 5
Water-oil relative permeability curves of sample 2.

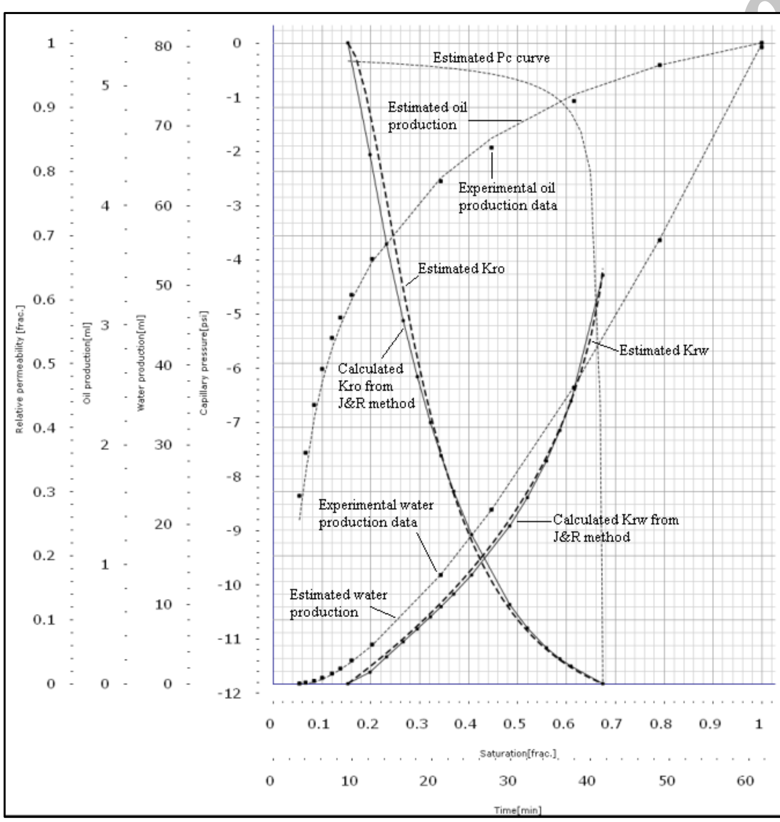

Figure 6
Water-oil relative permeability curves of sample 3.

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