EXPERIMENTAL INVESTIGATION OF FACTORS AFFECTING LABORATORY MEASURED RELATIVE PERMEABILITY CURVES AND EOR

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ABSTRACT

Relative permeability curves are a fundamental input to reservoir models which provide the only way to predict the subsurface fluid flow behaviour. There is still much controversy surrounding the factors affecting the measurement of relative permeability curves in the laboratory, and to achieve an optimum enhanced oil recovery mechanism in petroleum reservoirs, we need a better understanding of the flow characteristics, which is greatly affected by fluid-rock and fluid-fluid interactions. These interactions directly control rock wettability, capillary pressure and relative permeability curves.

This study deals with different laboratory experiments in order to investigate the possible effects of several factors, including fluid system properties, rock types and measurement conditions and/or procedures, on the measurement of relative permeability, displacement efficiency and therefore the enhanced oil recovery applications and the practical significance of these factors. Laboratory core-floods and centrifuge experiments were conducted on sandstone and carbonate cores to assure a measurement of valid flow behaviour. Drainage and imbibition relative permeabilities in two phase system were measured and handled. Sensitivity analysis for fluid properties, lithology types and measurement conditions were done by using a core-flood simulator with history matching to properly account for capillary pressure effects and to establish the validity of different scenarios of measurements by the technique used and then study the flow behaviour with the investigated parameters.

Results were compared with previously achieved investigations. There was a correlation between fluid system properties, residual saturations and relative permeability end points. Remaining oil saturations from laboratory measurements might be too high due to experimental procedures and capillary end effect .The effect of wettability was also observed and discussed, since, in most cases, residual oil saturations were increased and relative permeability to water was decreased as the samples tend to be water wet. The laboratory investigations of relative permeability curves should be conducted at conditions as closely as possible to reservoir conditions in order to achieve reliable and accurate results. An improved oil recovery can be achieved by controlling the composition and properties of the fluid system and their reactions with the geological system.

INTRODUCTION

Relative permeability curves are fundamental for the analysis of reservoir problems. They are directly related to various production procedures during the field development. During the measurement of relative permeability curves, there are many challenges which must be taken into account such as the effects of changes in fluid properties at reservoir conditions and heterogeneity in the reservoir. Laboratory core experiments are the main tool for studying these properties for scientific and practical applications.

In laboratory flow tests, it is necessary to simulate in the experiments all the factors of importance which influence the flow in the reservoir to assure a measurement of valid flow behaviour. These factors have been studied by many investigators and may include; wettability characteristics of the system, reservoir temperature and pressure, fluid properties such as viscosity, density and salinity, fluid flow rate, interfacial tension. These factors also have an effect on residual saturations, displacement efficiency and enhanced oil recovery.

Previously, it has been shown that brine salinity can be very important in water flooding process. Laboratory tests indicated that residual oil saturation obtained at the end of water flood test depends on the salinity and/or viscosity of the brine used. There are many published data in the literature showing that water flood recovery is dependent on the composition, especially the salinity, of the injection brine. Jadhunandan and Morrow (1995) and Yildiz and Morrow (1996) published papers on the influence of brine composition on oil recovery. The effect of oil viscosity and viscosity ratio on relative permeability curves have been investigated and studied extensively by many authors including Leverett, Tzimas et al, Dong and Dullien. Wettability of the system has a significant effect on relative permeability and oil recovery. A water-wet system will exhibit greater primary oil recovery, but the relationship between primary recovery and wettability has not been developed. Emery et al., Kyte et al and Donaldson et al. studied the wettability of core samples. The results showed that as the system becomes more oil-wet, less oil is recovered at any given amount of injected water.

Laboratory procedures such as flow rates can significantly affect relative permeability curves. At sufficiently low flow rates, microscopic flow behaviour should always be capillary dominated if the system has a strong wetting preference. The effect of interfacial tension can also be significant. If the experimental flow rate is high and the interfacial tension is small, the capillary forces become less significant and slugs of both fluids may begin to flow through the same network of pores.

This work’s objectives were to study and investigate the probable effect of several parameters on water-oil relative permeability curves and residual oil saturations. Comparisons of different measurement conditions and lithology types were also made.

EXPERIMENTAL PROCEDURES

In this study, water flooding and centrifuge methods were used to measure relative permeability curves. In addition to that, wettability tests (USBM and/or Amott/Harvey) were conducted using core materials with different lithology types taken from different reservoirs. These core materials have a wide permeability range from less than one mD to more than 500 mD. The porosity range was between 5 % and 34 %. Different types of fluids were used to conduct these tests. A wide range of oil viscosities, from 1 to more than 30 cp, were used in these experiments. Oil/water viscosity ratio was in the range of 1 to 30. Several brine salinities ranging from 8,000 ppm to 230,000 ppm were also used.

One of the objectives of this study was to evaluate the effect of reservoir fluid properties on relative permeability curves and residual saturations. A sensitivity analysis of several reservoir fluid types was made at different measurement conditions (ambient and reservoir conditions). The water phase was brine with more than ten different concentrations. For the oil phase, a range of different properties were used. Before conducting the relative permeability tests, it was essential for the core samples to be at representative conditions, initial water saturations, which match the height above the oil water contact in the reservoir. Initial water saturations were achieved by oil flood at different flow rates using different kinds of oils.

Having the samples at initial water saturations, these samples were placed in a relative permeability measurements apparatus. The measurement conditions were set as required and monitored. The obtained data were used to calculate relative permeability curves using a two-phase 1D black-oil simulation model with history matching. This software is used for analyzing single SCAL experiments as well as several SCAL experiments simultaneously. In addition to that, samples with different lithologies were selected to perform centrifuge capillary pressure in two different cycles (drainage and imbibition). The selected samples were placed in Beckman Ultracentrifuge vessels under oil or water and the conditions were set as required and the obtained data were processed.

The wettability of the samples was measured by two methods; Amott/Harvey and USBM techniques. In the case of USBM method, multi-point imbibition and drainage curves to end point saturations were performed by centrifuging and the area under the curves were used to calculate the USBM wettability index. For the Amott/Harvey method, two spontaneous imbibition measurements and two forced displacement measurements were conducted. The Amott water index, Iw, and the Amott oil index, Io, were calculated and combined to give the Amott–Harvey index which describes the wettability of the rock.

The procedures covered oil-water experiments. Both imbibition and drainage cycles were handled and a comparison of a variety of flow properties was made. Other factors which may have an impact on relative permeability curves such as IFT and flow rates were taken into account and examined. The data analysis and interpretation were performed by a 1-D core flood simulator where different scenarios of core flooding with different phases of reservoir fluids can be performed through simulation and/or estimation. Simulation is forward simulations of a multi-phase flow experiment, while estimation utilizes an optimization routine to history match the experimental data obtained in the laboratory. Several correlations were used and tested for their validity to history match the experimental data. This was done through a sensitivity analysis of several cases. These correlations are summarized in Table 1. The selected correlation in each case depends on the type of the experiment that is being analysed. Figure 1 shows an example of history match of oil production and pressure drop and the generated relative permeability curves for one of the studied samples (carbonate sample).

RESULTS AND DISCUSSION

In this section, the results and the interpretation of the data which were obtained from the experimental work will be introduced. The selected samples for this study were taken from different hydrocarbon basins including sandstone and carbonate rocks. These samples represent different formations covering a variety of depositional environments such as fluvial channel, distributary channel, shelf and reef. The datasets are also a mixed suite of rock fabrics and composition. The petrophysical properties, routine core analysis, (porosity, air permeability and grain density) were measured for all of the samples. The statistical analysis of these properties showed that the samples have a porosity range from 5 % to 34 % and a permeability to air range from 0.234 to 551.0 mD.

Core-flood Analyses and Interpretation

About eleven oils and fourteen brine salinities were used to investigate the effect of fluid properties and measurement conditions on relative permeability curves and residual oil saturations. These properties include oil viscosity and density, brine salinity/density and viscosity, IFT and temperature. The properties of these fluids and the main results of residual and initial saturations, as an average for each reservoir, are given in Table 2.

The experimental results from relative permeability tests in this work are also included in Table 2. This table shows the average endpoint saturations of oil and water. Oil and water permeabilities at the endpoints are also listed for each reservoir. The water relative permeabilities at residual oil saturations were plotted as a function of oil/water viscosity ratio for different salinity values in Figure 2. This figure shows a relation between Krw@Sor and oil to water viscosity ratio. In this figure the multiple dots for each color represent samples with same oil/water viscosity ratio, so each color represent a group of samples with specific oil/water ratio. It can be seen that as the oil viscosity (or higher oil/water viscosity ratio) increases, the Krw@Sor decreases. In the viscosity ratio range from 1 to 10 most of the samples gave high krw@sor, on the other hand when viscosity ratio becomes more than 10 most of the samples gave low krw@sor. The general trend of this figure was compared with other published data and there was a similar trend. The effect of oil viscosity on residual oil saturations is shown in Figure 3. This figure shows that as the oil viscosity increases, residual oil saturations increases. Several values for the oil viscosity have been used to study their effect on Sor, these oil viscosities were used with different brine salinities, so for each group of samples, represented with different color, a specific oil and brine were used. In the case of lowest oil viscosity, six samples were used some of them showed an increased Sor with high oil viscosity and others showed a decrease in Sor, this can be due to the nature of the rock samples (sample heterogeneity), wettability and the interaction between the two fluids and the rock. These results were in a good agreement with other published data. The effect of oil and water viscosities was also investigated by a 3D plot as shown in Figure 4. In this figure the average value of residual oil saturation, Sor, for each reservoir were plotted against oil and water viscosities. From this figure it can be seen that, residual oil saturations increases with increasing both oil and water viscosities. However, the effect of oil viscosity is more obvious on residual oil saturations than water viscosity. Figure 5 shows a relationship between residual oil saturations and the mobility ratio. In this figure, although there is a spread in the data, the residual oil saturations, both from centrifuge and flooding experiments, were increased when the mobility ratio is increased. The reason why there was no clear trend in this figure might be due to the assumptions of stable displacement front in conventional water flood theory which might not be applicable in all cases especially in the case of heavy oil reservoirs.

The effect of reservoir conditions was also investigated. Figures 6 and 7 show how the fractional flow curves changed and/or shifted by changing the temperature. The measurements were conducted at three different temperatures, 25, 45 & 75 C^o, for high and low salinity brines. These figures show that the effect of temperature is not consistent in both salinity cases, it was obvious that this effect can be significant on some samples and can be neglected on others. The low salinity brine clearly shifts the fractional flow curve to the right, while in the case of high salinity brine the water fractional curves at 45 C^o and 75 C^o shifted to opposite directions relative to 25 C^o curve. These observations can be attributed to the associated lithology of the samples and the interactions between the fluid system and the rock.

Centrifuge Capillary Pressure

In general, the residual oil values from centrifuge tests are lower compared to flooding experiments. In the case of high viscosity, it would be difficult to achieve the residual oil saturations which were achieved by centrifuge in a water flood test because the differences in the displacement mechanism. The capillary and gravity forces control the residual oil from centrifuge, while viscous forces are not important. During a water flood, fingering and by passing the oil phase could cause a higher residual oil. From the laboratory measurements it was noticed that water relative permeability at S_{or} decreases with increasing residual oil, as expected, and becomes very low for high S_{or}. Also the flow rate used in the lab should be carefully designed to achieve accurate results and to minimise any possible errors in the initial and residual saturations.

USBM & Amott/Harvey Wettability

The other parameter which has an influence on relative permeability and residual saturations is wettability. The effects of wettability on residual oil saturations for the studied reservoirs are shown in Figures 8 and 9. Figure 8 shows that, for USBM wettability indexes ranging between 0.0 and 0.6, residual oils were varied from 0.20 to 0.60. In general, the data indicates that, $S_{or}@K_{rw}$ increases and $K_{rw}@S_{or}$ decreases as the system changes from zero USBM wettability index (intermediate wet) towards water wet. This observation was similar to Amott/Harvey index shown in Figure 9. In both cases shown in Figures 8 and 9 there is an indication that residual oil saturation is usually low when the core samples have neutral wettability, which is neither water-wet nor oil-wet. On the other hand, residual oil saturation tends to be high at strongly water wet conditions.

Calculation of Relative Permeability Curves by History Matching

In order to get a good relative permeability results, history matching of the experimental data through a number of forward simulations were made. This was performed on the data obtained from the lab using a commercial 1D core flooding simulator. An example of the history matching of oil production, pressure drop and the generated relative permeability curves for one of the studied samples is shown in Figure 1. This figure shows a comparison of the relative permeability curves for different fluid systems. This figure shows that the fluid properties such as viscosity and salinity have an influence on oil-water relative permeability curves and residual saturations.

The general trend is that, with increasing oil viscosity, residual oil saturation increases while irreducible water saturation decreases. Both oil and water relative permeability curves shift to lower values with increasing oil viscosity. These observations were more obvious in the case of high μo/μw ratio and less when the viscosity of the two fluids gets close to each other (μo/μw=1). Also, it was observed that the salinity has a little effect and sometimes this can be neglected on the irreducible water saturations.
In this work different correlations were used to history match the laboratory data. The most used ones were Corey and LET for relative permeability and Skjaeveland and LET for capillary pressure. These correlations, listed in Table 1, were used to obtain the real endpoints from the laboratory measured data. It was observed that, residual oil saturations from laboratory measurements are higher than the history match data. On the other hand, the K_{rw}@S_{or} values from laboratory measurements are lower.

The Effect of Different Parameters on Oil Recovery

In this study, the effect of many parameters on the recovery of crude oil during water flooding was investigated. Sensitivity analyses of fractional flow curves were made and compared as shown in Figures 10 and 11. These figures show two examples of these analyses. In these investigations different properties were used for the fluid system to generate different values of the mobility ratio between the existing fluids in the reservoir. Figure 10 shows an example of the effect of brine salinity on residual fluids and oil recovery. This figure shows a relationship between three different values of brine salinity and residual oil saturation. From this figure it can be seen that residual oil saturations generally decreases when low salinity brine is used. This is due to the fact that the interaction between low salinity brine and the rock samples depends on the composition of the fluid system (water and oil) and in general low salinity brines when injected into the samples work to change the initial wettability of the rock to more water wet wettability and this results in an increased oil recovery and less residual oil saturations.
Another investigation is shown in Figure 11. This figure compares three different cases of the fractional flow curves and how they are affected and shifted by changing the properties

of both oil and water. From this figure it can be seen that the efficiency of a water flood depends greatly on the mobility ratio of the displacing fluid to the displaced fluid, the lower this ratio the more efficient the displacement. This means that ultimate recovery efficiency will be obtained if the ratio is so low that the fractional flow curve has no inflection point. Also it can be seen that the effect of oil viscosity on these curves and thus on the drive mechanism is more obvious in the case of low salinity system. In general, it can be said that fractional flow curves are very sensitive to many parameters and a great care should always be taken when studying these curves.

CONCLUSION

The main results can be summarized as follows:

- When the oil viscosity increases, residual oil saturations generally increase and relative permeability to water decreases.
- Generally the end point water relative permeability data do not vary significantly with salinity variations.
- At the same injection flow rate and with the same water phase, relative permeabilities were a function of oil viscosity in the oil viscosity range studied.
- Generally, residual oil saturations were decreased when low salinity brine was used.
- The effect of wettability was clearly observed. In most cases, residual oil saturations were increased and relative permeability to water was decreased as the samples tend to be water wet and/or strongly water wet. On the other hand, residual oil saturations usually low, when the core samples have neutral wettability.
- Water fractional flow curves and thus oil recovery were affected by many parameters including the properties of the fluid/rock system and measurement conditions.
- The effect of oil viscosity on water fractional flow curves was more significant in the case of low salinity systems.
- The effect of temperature on water fractional flow curves was not consistent in the cases of low and high salinity systems.
- Laboratory investigations of relative permeability curves should be conducted at conditions as closely as possible to reservoir conditions.
- Residual oil saturations obtained from laboratory measurements can be higher than the real values. This depends on the measurements conditions and procedures.
- An improved oil recovery can be achieved by controlling the composition and properties of the fluid system and their reactions with the geological system.

With the results from these investigations, a complete picture of the relationship between different flow parameters and relative permeability curves can be developed and applied.

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Table 1. Different Correlations Used for Relative Permeability and Capillary Pressure Calculations.

Relative Permeability	**Capillary Pressure**
Corey	Skjaeveland
Chierici	Burdine
Burdine	Bentsen and Anli
Sigmund – McCaffery	LET – Primary & Secondary Drainage
LET	LET – Imbibition

Table 2. Summary of Fluid Properties and Experimental Results

Reservoir No	***Brine Salinity, ppm***	***Viscosity of Oil, cp***	***Viscosity of Brine, cp***	***μ_o/μ_w***	***Average S_{wi},%***	***Average S_{or},%***	***Average K_o@ S_{wi}, mD***	***Average K_w @ S_{or}, mD***
1	8000	6.850	0.922	7.431	20.365	43.210	20.401	13.120
2	9000	7.120	0.855	8.327	12.040	41.625	20.410	13.120
3	12000	12.12	1.023	11.85	17.971	37.848	103.64	29.771
4	22000	3.583	0.918	3.903	22.978	22.948	4.9190	1.7475
5	60000	1.691	1.111	1.522	18.010	22.221	23.440	4.3320
6	85000	32.00	1.172	27.31	12.454	34.456	207.50	56.698
7	110000	1.867	1.263	1.478	18.450	25.338	11.509	5.1605
8	115000	1.500	1.090	1.376	30.520	46.722	1.7255	0.5015
9	120000	3.516	1.116	3.151	25.525	34.598	10.618	1.0285
10	160000	1.876	1.271	1.476	19.550	28.877	9.5540	7.4320
11	168000	4.696	1.290	3.642	18.658	30.275	3.5470	0.6480
12	180000	4.697	1.350	3.479	9.2800	31.504	1.7180	0.5011
13	208000	1.500	1.470	1.022	44.950	36.255	0.0450	0.0066
14	220000	3.583	1.891	1.895	22.978	22.948	2.4510	0.5300

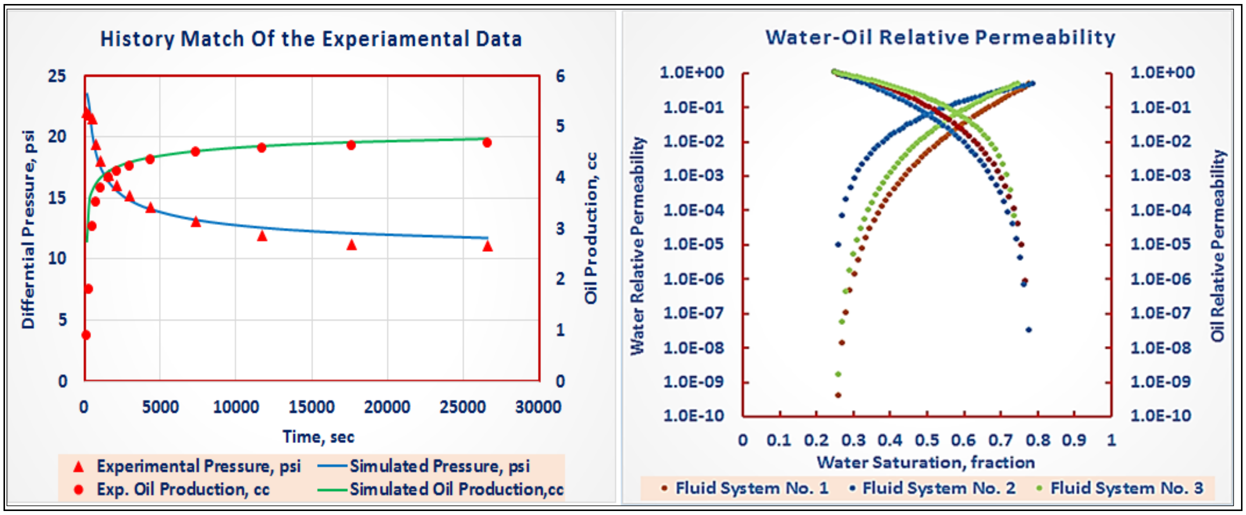


Figure 1. Sensitivity Analysis of Relative Permeability Curves for a Carbonate Sample.

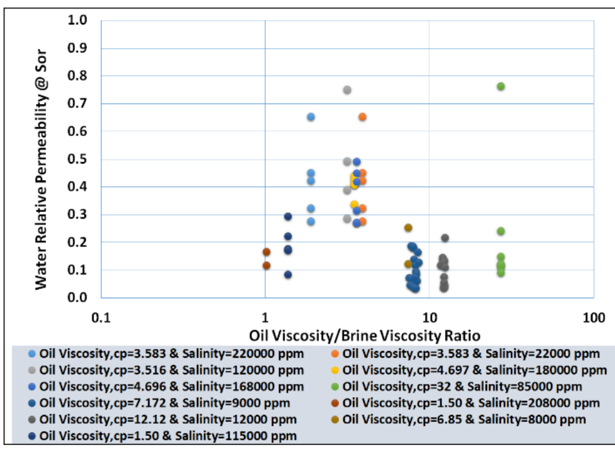


Figure 2. Water Relative Permeability Vs Oil/Water Viscosity Ratio

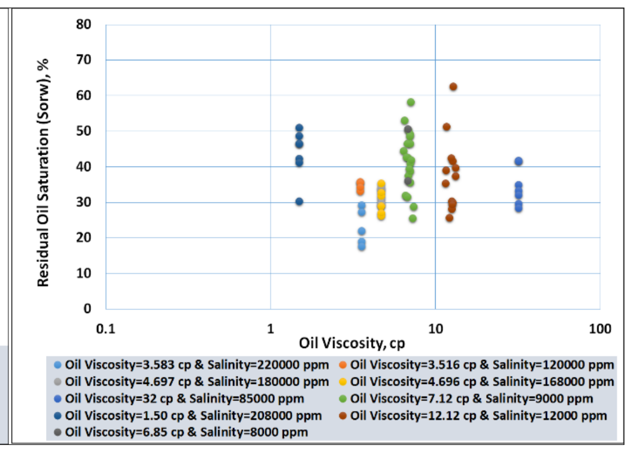
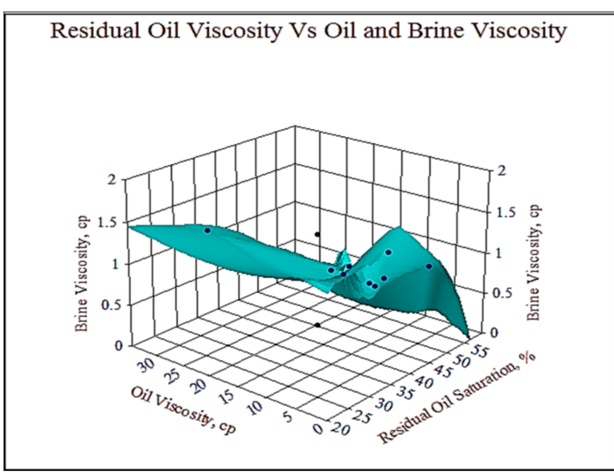


Figure 3. Residual Oil Saturation Vs Oil Viscosity



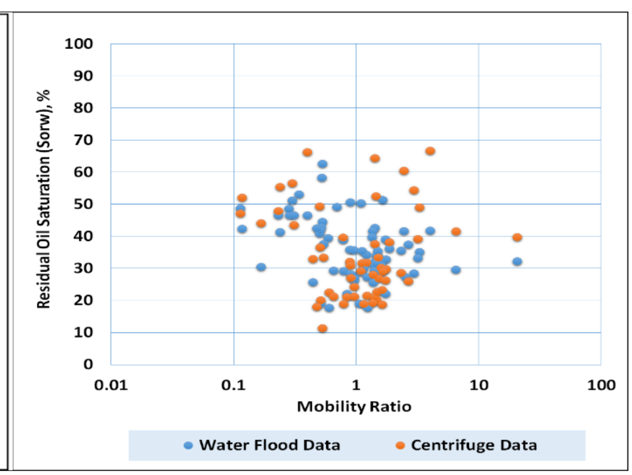
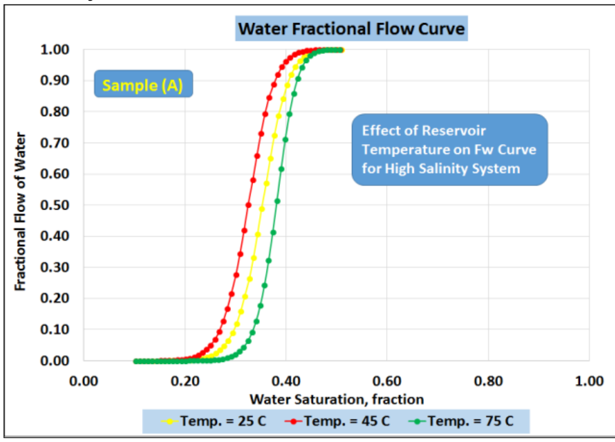
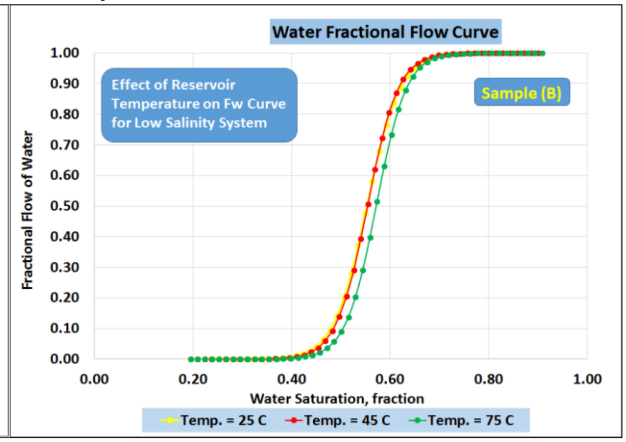


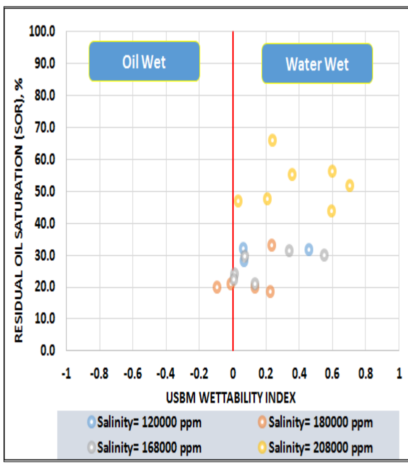
Figure 4. Residual Oil Saturation Vs Oil and Water Viscosity

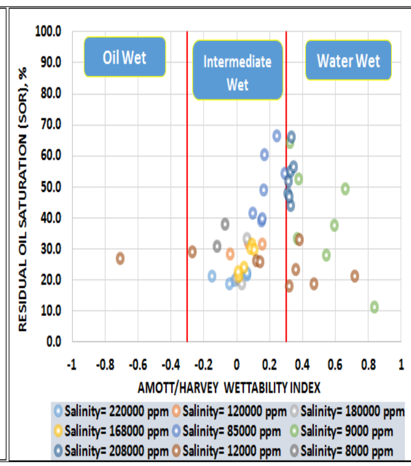
Figure 5. Residual Oil Saturation as A Function of Mobility Ratio

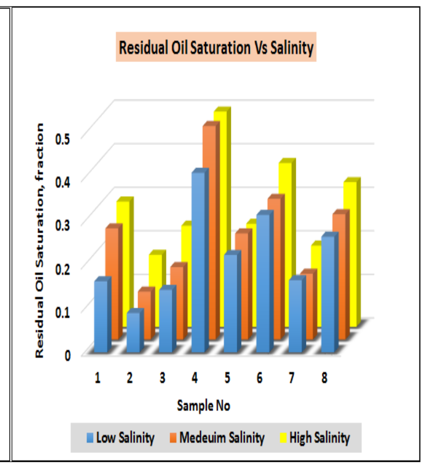




Figures 6 & 7. The effect of Reservoir Temperature on Water Fractional Flow Curves for High Salinity and Low Salinity Systems







Figures 8 & 9. Sor vs USBM & Amott/Harvey Indexes.

Figure 10. Effect of Salinity on Residual Oil Saturation.

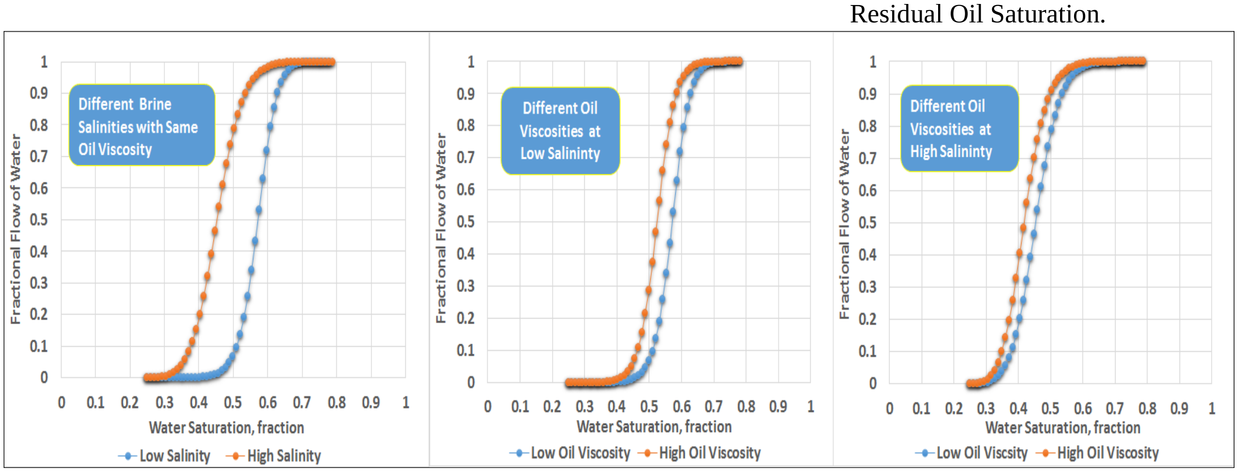


Figure 11. Effect of Fluid Properties on Water Fractional Flow Curves; Different Brine Salinities with Same Oil Viscosity, Different Oil Viscosities @ Low Salinity and Different Oil Viscosities @ High Salinity.