EFFECT OF OIL VISCOSITY ON WATER/OIL RELATIVE PERMEABILITY

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This paper was prepared for presentation at the International Symposium of the Society of Core Analysts held in Austin, Texas, USA 18-21 September, 2011

ABSTRACT
This work presents an investigation on the effect of oil viscosity on residual oil saturation and water relative permeability endpoint. A number of water/oil relative permeability measurements were performed using steady state, unsteady state and centrifuge methods. Experiments were conducted on core material from viscous/heavy oil fields. Viscous crude oil and refined lab oils were used to study the effect of oil viscosity on residual oil saturation, Sorw, and the corresponding relative permeability to water, Krw(Sorw). Results were compared with field data from the Statoil SCAL database and literature data.

Data indicates that there is a correlation between the oil viscosity and residual oil saturation and water relative permeability end point. Increasing oil viscosity reduces the Krw(Sorw) and increases Sorw. Micromodel experiments also show a different fluid distribution during water / oil displacement and distribution of residual oil depending on the oil viscosity

The remaining oil saturation from laboratory measurements might be systematically too high due to experimental artefact, capillary end effect and early termination of the experiment, especially when using heavy/viscous oil. Similarly the Krw(Sorw) may be systematically too low. We suggest using history matching (core flood simulating) or extrapolated Kro-curves to residual oil when reporting the measured lab data. The effect of wettability on the observed results is also discussed.

INTRODUCTION
Heavy oil development is becoming more important due to continuous decline in conventional oil reserves. Reservoir simulation model of water flooding in some heavy oil fields show high sensitivity to the water/oil relative permeability input, especially the water relative permeability curve. Low values of Krw(Sorw) in full field model simulators for heavy oil fields have been reported in some publications [1,7].
There are two different views in the literature about the effect of oil viscosity on water/oil relative permeability. Some authors claim that the oil viscosity does not have an effect on water/oil relative permeability [8-10]. While other researchers have shown the dependency of residuals and relative permeability curves on the oil viscosity [11-14].

Leverett et al [8] investigated the effect of viscosity variation of an oil-water mixture on relative permeability of compacted sands. He found no systematic variation in relative permeability when the oil viscosity was varied from 0.31 cp to 76.5 cp and the water phase viscosity was varied from 0.85 to 32.2. Dullien[12] suggested that if one of the fluids is very viscous, then viscosity ratio could be an important parameter affecting the relative permeability. Abrams[13] waterflooding experiments on sandstone and limestone core material showed that residual oil saturation would increase with increasing the oil/water viscosity ratio. Wang et al[14] investigated the effect oil viscosity on water/oil relative permeability. They measured water/oil relative permeability in a wide range of oil viscosity from 430 to 13550cp. Their results showed that both oil and water relative permeability curve shifted to lower values with increasing the oil viscosity. Residual oil saturation increased linearly with the log value of oil viscosity.

The objective of this study was to investigate the effect of viscosity on residual oil (Sorw) and water relative permeability end point at Sorw in water/oil system. Relative permeability experiments were performed on core and fluids from viscous oil reservoirs using steady state, unsteady state and centrifuge methods. Some USBM wettability measurements were also conducted. Results are compared to other data in Statoil and also published data.

EXPERIMENTAL PROCEDURE

Using core materials from heavy/viscous oil reservoirs, relative permeability and USBM wettability tests were conducted on restored and fresh plugs. Core materials were unconsolidated high permeability sandstone from three different heavy oil reservoirs (A, B and C in **Table 1**). Different types of oil from live to dead crude oil and laboratory oil were used to conduct the tests. Oil viscosity in these experiments were covering a wide range of viscosities from 1 to 5290 cp. Oil/water viscosity ratio was in the range of 1 to 6780.

Plug Preparation and Establishing the Initial Conditions

Restored state samples were cleaned by hot solvents, oven dried and 100% saturated with brine. Then they were drained to Swi by crude oil injection and were aged for two weeks.

Fresh state plugs were flushed with brine to displace any mud filtrate which might have invaded the pore space. Lab oil was then injected to displace the brine.
For experiments performed with crude oil/live oil, lab oil was displaced with injecting crude/live oil. For USBM wettability and centrifuge relative permeability, centrifugation was used to establish the initial saturation. After establishing the initial conditions, wettability and relative permeability tests were conducted.

Unsteady State Relative Permeability

Water flood was performed by injecting brine at constant rate while recording differential pressure and produced oil and water. The water floods were continued until a produced water/oil ratio of 10000 or greater was obtained. Effective permeability to brine at Sorw was determined. Unsteady state water/oil relative permeability curves were calculated using JBN method. Prior to terminating the brine injection, flow rate was raised to produce a bump flood.

Steady State Relative Permeability

Water fraction was increased in 7 steps from zero to one. Differential pressure and oil production were measured and relative permeability was calculated with Darcy law under each steady state fraction. Similar to unsteady state, the water rate was increased at the end of the steady state test. .

USBM Wettability

A multi point imbibition curve to Sorw was performed by centrifuging the samples under brine. Displacement tests at each pressure was continued until the volume of oil displaced was unchanged for a period of at least 8 hrs. Then a multi point drainage curve to Swi was performed by centrifuging the samples under oil (Similar to forced imbibition of water). USBM wettability index was calculated for each sample using the formula: USBM wettability Index= log (A1/A2). A1 and A2 are areas under oil displacing water curve and brine displacing oil curve, respectively.

Plugs specifications, preparation, experimental methods and conditions are given in **Table 1**. Most of these tests were performed at reservoir temperature.

RESULTS AND DISCUSSION

Experimental results for relative permeability and wettability tests from this work are included in **Table 1**. Water relative permeability at residual oil is plotted as a function of oil/water viscosity ratio in **Figure 1**. It shows a relation between Krw(Sorw) and oil/water viscosity ratio. Increase in oil viscosity (or higher oil/water viscosity ratio), reduces the Krw(Sorw). These data are compared with other data in Statoil and published data[1-7, 14-19] in **Figure 2** as a function of oil viscosity. Published data are from different sources: field performance reports, case studies and experimental measurements. There is a large variation in both Statoil and published data sets, but they follow the same trend.

Figure 3 shows the residual oil saturation, by experimental method in this work, as a function of oil/water viscosity ratio. There is a relation between Sorw and $\mu o/\mu \omega$; residual oil increases as the viscosity difference increases.

Sorw values from this work, other data sources in Statoil and published data[1-7, 14-19] are plotted in **Figure 4** as a function of oil viscosity. This figure shows a good agreement between the different sets of data.

Conventional waterflood theory is based on assumptions of a stable displacement front. This might not directly be applicable to heavy oil reservoirs. To see the relation between residual oil and mobility ratio, **Figure 5** was plotted. The following equation was used to calculate the mobility ratio:

$$M=\left[\frac{Krw(Sorw)/\mu w}{Kro(Swi)/\mu o}\right]$$

Similar to **Figures 3&4**, this plot shows that residual oil increases as mobility ratio increases.

Residual oil values from centrifuge tests are lower compared to flooding experiments for a given reservoir (**Figure 3**). The residual oil achieved by centrifuge might not be possible to reach in a real case under high viscosity ratio (or high mobility ratio) since the displacement mechanism is different. Balance between capillary and gravity forces controls the residual oil from centrifuge, while viscous forces are not important. During a waterflood, fingering and by passing the oil phase could cause a higher residual oil. Therefore one can speculate that Sorw achieved by centrifuging will not be representative of the ultimate Sorw that can be achieved by waterflooding in the lab or in the field.

The effect of wettability on residual oil value for the three reservoirs is shown in **Figure 6.** The oil/water viscosity ratio in the wettability tests varied from 1 to 1900. It can be seen that for USBM wettability indexes ranging between -0.3 and 0.4, residual oil is varied from 0.16 to 0.24. The data indicates little effect of wettability on Sorw for these viscous oil systems. However, in these wettability tests some samples were restored, some were fresh and they come from different reservoirs and different types of oil were used **(Table 1)**. This makes it difficult to conclude on effect of wettability on the observed results and it is an area for further investigation.

Micromodel studies with heavy oil at reservoir conditions[20] have shown that when water flooding a water-wet pore system, there is no water fingering, in spite of a high viscosity difference between water and oil. Water could move through a thin water layer (or film) on the pore walls which would result in low relative permeability to water. No oil filled pores would be bypassed and residual oil saturation would in the form of trapped oil in middle of pores. The observation is in line with other micromodel studies using conventional oil for water-wet system[21]. Micromodel studies[21] in oil-wet system using conventional oil showed that when water flooding, some of the oil filled pores surrounded by narrow pores were completely by passed, creating residual oil ganglia. General observations[22-24] suggest that Sorw would increase and Krw(Sorw) decrease as the system changes from non-water wet towards water-wet. It is a possibility that the main cause of the trends of Sorw and Krw(Sorw) observed in **Figures 1-5** are due to wettability differences; with the higher reservoir oil viscosity giving a more water wet system.

The relation between Krw(Sorw) and Sorw for the tests performed are shown in **Figure 7**. Also included are published data[1-7,14-19] of Sorw and Krw(Sorw) from waterflooding of viscous oil systems. Although there is a spread in the data, Krw(Sorw) decreases with increasing Sorw, as can be expected, and becomes very low for high Sorw.

Extrapolating and History Matching Lab Data

A core flood experiment with heavy oil is complicated and should be designed carefully in order to produce good relative permeability results. In many cases core samples taken from heavy oil fields with high permeability are unconsolidated and need special handling. Permeability changes due to core damage could be an issue. Establishing initial water saturation (Swi) in heavy oil systems needs special consideration to avoid generating emulsions. Emulsification can also occur during water flooding. Reservoir oil samples themselves can contain significant amounts of water as emulsion.
Experimental artefact such as capillary end effect (the hold up of the preferentially wetting phase at the outlet), unstable displacement and incomplete tail production when conducting relative permeability measurements by flooding would result in high residual oil from lab experiments. Similarly measured Krw(Sorw) could be low. Analytical techniques or history matching the production and pressure data should be used to correct the error to some extent.

History matching was performed on some of the unsteady state waterflood tests, using a commercial 1D core flooding simulator (Sendra). But it was not possible to obtain a good history match. **Figures 8** shows an example of history matched results for oil/water viscosity ratio of 213.

In this work, an analytical solution by extrapolating the Kro curve to Kro=0 (Corey or LET type) was used to obtain the “true” endpoints from the laboratory core flood data. Extrapolated Sorw and Krw(Sorw) have been plotted versus the lab measurements in **Figures 9**, respectively. Sorw data from lab measurements could be up to 0.12 (saturation units) higher than the extrapolated residual oil. Similarly measured Krw(Sorw) could be systematically lower than the extrapolated value, up to 0.15. All the Statoil data used in this study of the effect of viscosity ratio on end points were extrapolated Sorw and Krw(Sorw). However for the published data, it was not documented whether data have been history matched or other modifications have been performed to obtain limiting endpoints. We always recommend using history matching or extrapolated Krw and Kro-curves to residual oil when reporting the measured lab data.

CONCLUSIONS

A number of experiments have been performed using material from heavy/viscous oil reservoirs and comparison made with other Statoil viscous oil data and literature data. Oil/water viscosity ratio was in the range of 1 to 6780 for these experiments. Results suggest that for high viscosity systems:

- Residual oil saturation after water flooding generally increases with increasing oil viscosity
- Relative permeability to water at residual oil decreases with increasing oil viscosity and increasing residual oil saturation

- Wettability and pore scale flow mechanism are likely to be the main contributors for the observed end point trend with viscosity. Further investigation is needed to conclude on the results.
- Remaining oil saturation from laboratory measurements could be systematically too high and the corresponding Krw(Sorw) may be systematically too low. Extrapolated Kro-curves to residual oil should be used when reporting the measured lab data.

ACKNOWLEDGEMENTS

The authors would like to thank Statoil ASA for permission to publish the results of various SCAL studies entailed in this paper. International Research Institute of Stavanger for conducting some of the experimental work is also acknowledged.

NOMENCLATURE

K: permeability, mD
Krw(Sorw): water relative permeability end point at residual oil saturation
Krw(Sorw)*: extrapolated water relative permeability end point at residual oil saturation
Kro(Swi): oil relative permeability at initial water saturation
M: mobility ratio
Sorw: residual oil saturation after water flooding
Sorw*: extrapolated residual oil after water flooding
Swi: Initial water saturation
ϕ: porosity, fraction
μo: oil viscosity at reservoir conditions, cp
μw: water viscosity at reservoir conditions, cp

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Table 1. Specification of the conducted relative permeability experiments and experimental results.

Sample No./ Reservoir	Test conditions	K, mD	Krw(Sorw) exp	Krw(Sorw)*	Sorw exp	Sorw*	μo, cp	μo/μω	USBM	Mobility ratio
1 A	USS, restored plug, crude oil, 34ºC	12700	0.15	0.18	0.50	0.48	5290	6782		1221
2 A	USS, restored plug, crude oil, 34ºC	11700	0.17	0.25	0.44	0.41	5290	6782		1696
3 A	USS, restored, crude oil, 93ºC	19960	0.28	0.30	0.27	0.26	68	213		64
4 A	USS, restored, crude oil, 93ºC	22900	0.31	0.34	0.26	0.24	68	213		72
1 B	USS, fresh, res cond, 41ºC	3791	0.51		0.33	0.30	80	113		
2 B	USS, fresh, res cond, 41ºC	3958	0.47		0.31	0.26	80	113		
3 B	USS, fresh, res cond, 41ºC	2612	0.18	0.22	0.28	0.28	80	113		25
4 B	USS, fresh, res cond, 41ºC	2757	0.18	0.22	0.23	0.23	80	113		25
5 B	USS, fresh, res cond, 41ºC	2300	0.22	0.25	0.22	0.21	80	113		28
6 B	USS, fresh, res cond, 41ºC	5105	0.15	0.22	0.24	0.22	80	113		25
7 B	USS, fresh, res cond, 41ºC	8126	0.25	0.28	0.23	0.11	80	113		32
8 B	USS, fresh, res cond, 41ºC	10039	0.08	0.16	0.27	0.25	80	113		18
9 B	USS, fresh, res cond, 41ºC	5105	0.14	0.13	0.28	0.29	80	113		15
10 B	USS, fresh, res cond, 41ºC	12528	0.09	0.21	0.30	0.23	80	113		24
11 B	USS, fresh, res cond, 41ºC	8528		0.23	0.37	0.29	80	113		26
12 B	USS, fresh, res cond, 41ºC	8947	0.22	0.44	0.33	0.26	80	113		50
13 B	USS, fresh, res cond, 41ºC	7429	0.00	0.17	0.33	0.27	80	113		19
14 B	USS, fresh, res cond, 41ºC	3520	0.17	0.19	0.34	0.31	80	113		22
15 B	USS, fresh, res cond, 41ºC	5220	0.34	0.41	0.28	0.23	80	113		46
16 B	USS, fresh, res cond, 41ºC	4153	0.23	0.26	0.29	0.23	80	113		29
17 B	USS, fresh, res cond, 41ºC	4637	0.20	0.25	0.29	0.25	80	113		28
18 B	USS, fresh, res cond, 41ºC	2554	0.28	0.30	0.37	0.29	80	113		34
19 B	USS, fresh, res cond, 41ºC	4911	0.20	0.20	0.32	0.26	80	113		23
1 C	SS, restored, lab oil, ambient	1398	0.83	0.81	0.18	0.17	1	1		1
2 C	USS, restored, lab oil, ambient	1398	0.83	0.82	0.17	0.13	1	1		1
3 C	USS, restored, res cond, 37ºC	1398	0.23		0.39		480	632		0
4 C	Centrifuge relperm, restored, lab oil, ambient	7210	0.48	0.48	0.15	0.15	31	29		14
5 C	Centrifuge relperm, restored, lab oil, ambient	9383	0.46	0.46	0.07	0.07	31	29		13

6 C	Centrifuge relperm, restored, lab oil, ambient	3376	0.18	0.18	0.05	0.05	31	29		5
7 C	Centrifuge relperm, restored, lab oil, ambient	9432	0.21	0.21	0.19	0.19	15	20		4
8 C	Centrifuge relperm, restored, lab oil, ambient	5587	0.28	0.28	0.07	0.07	15	20		6
9 C	Wettability, lab oil, restored, 37ºC	6637	0.94	0.94	0.21	0.21	1	1	0.31	1
10 C	Wettability, lab oil, restored, 37ºC	9101	0.60	0.60	0.17	0.17	1	1	-0.11	1
5 A	Wettability, fresh, crude oil, 49ºC	607			0.20	0.20	1180	1903	0.42	0
6 A	Wettability, fresh, crude oil, 49ºC	……			0.24	0.24	1180	1903	-0.18	0
7 A	Wettability, fresh, crude oil, 49ºC	4260			0.23	0.23	1180	1903	0.42	0
8 A	Wettability, fresh, crude oil, 49ºC	607			0.17	0.17	1180	1903	0.12	0
9 A	Wettability, fresh, crude oil, 49ºC	12500			0.21	0.21	1180	1903	0.01	0
10 A	Wettability, fresh, crude oil, 49ºC	4260			0.16	0.16	1180	1903	0.04	0
11 B	Wettability, fresh, refined oil, 41ºC	7033			0.20	0.20	100	141	-0.32	0
12 B	Wettability, fresh, refined oil, 41ºC	5584			0.20	0.20	100	141	-0.34	0
13 B	Wettability, fresh, refined oil, 41ºC	11680			0.21	0.21	100	141	-0.28	0
14 B	Wettability, fresh, refined oil, 41ºC	14201			0.22	0.22	100	141	-0.16	0
15 B	Wettability, fresh, refined oil, 41ºC	5396			0.20	0.20	100	141	-0.11	0
16 B	Wettability, fresh, refined oil, 41ºC	8406			0.22	0.22	100	141	-0.10	0

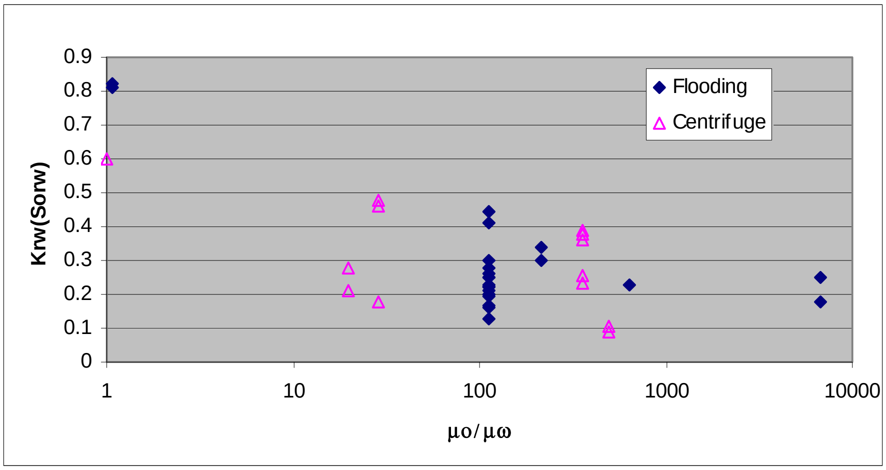

Figure 1. Water relative permeability at residual oil versus oil/water viscosity ratio.

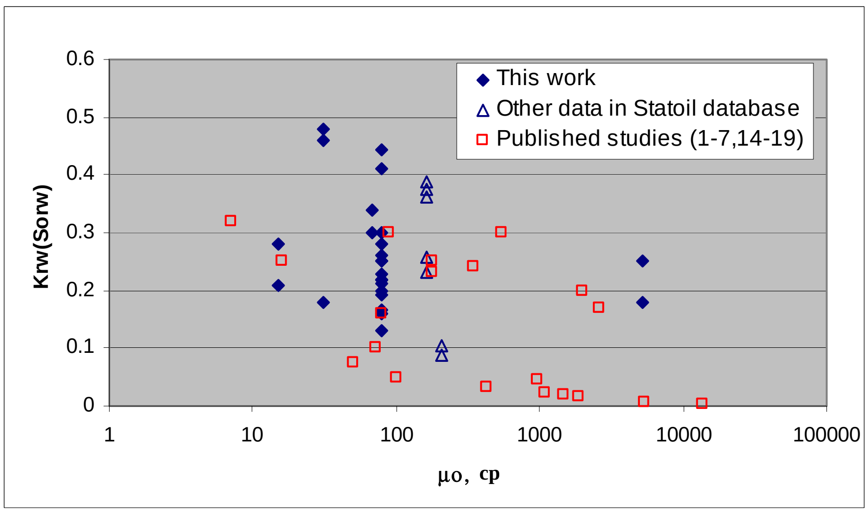

Figure 2. Water relative permeability at residual oil versus oil viscosity.

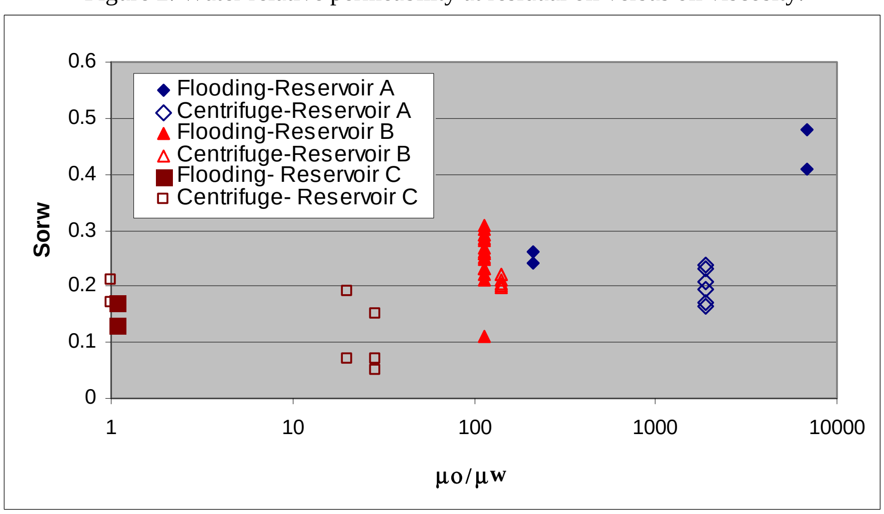

Figure 3. Residual oil versus oil/water viscosity ratio.

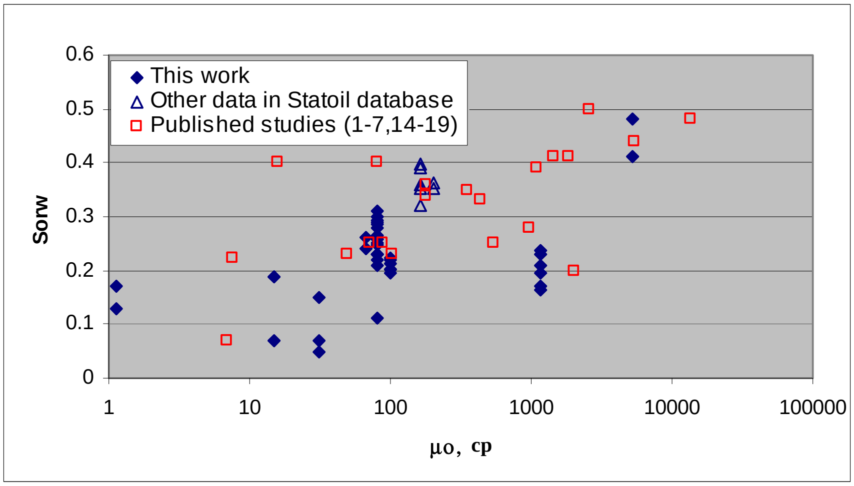

Figure 4. Residual oil versus oil viscosity.

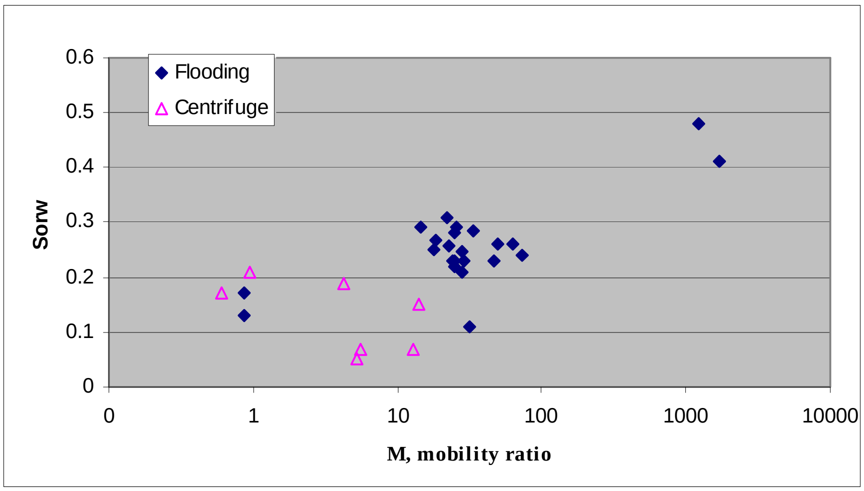

Figure 5. Residual oil as a function of mobility ratio.

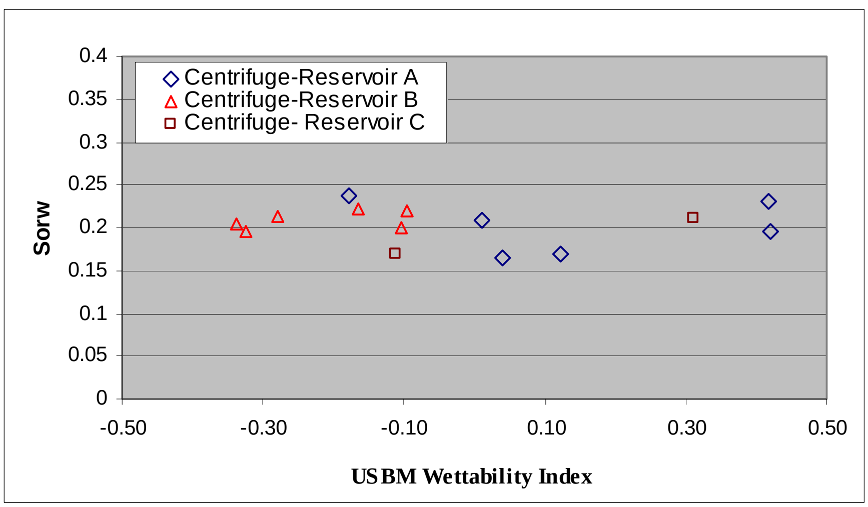

Figure 6. Residual oil versus wettability.

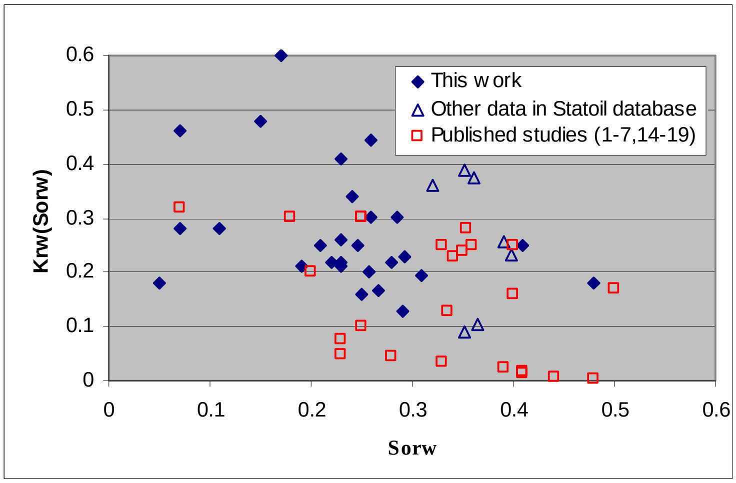

Figure 7. Water relative permeability at residual oil vs. residual oil.

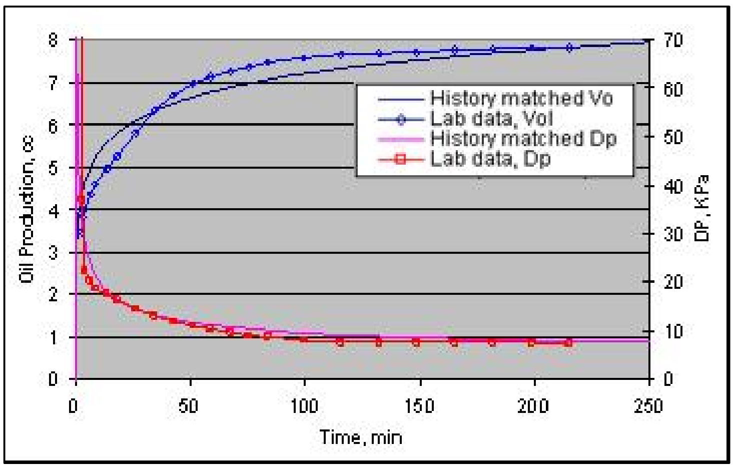

Figure 8. Comparison the history matched production/pressure with experimental data, $\mu o/\mu w$=213 cp.

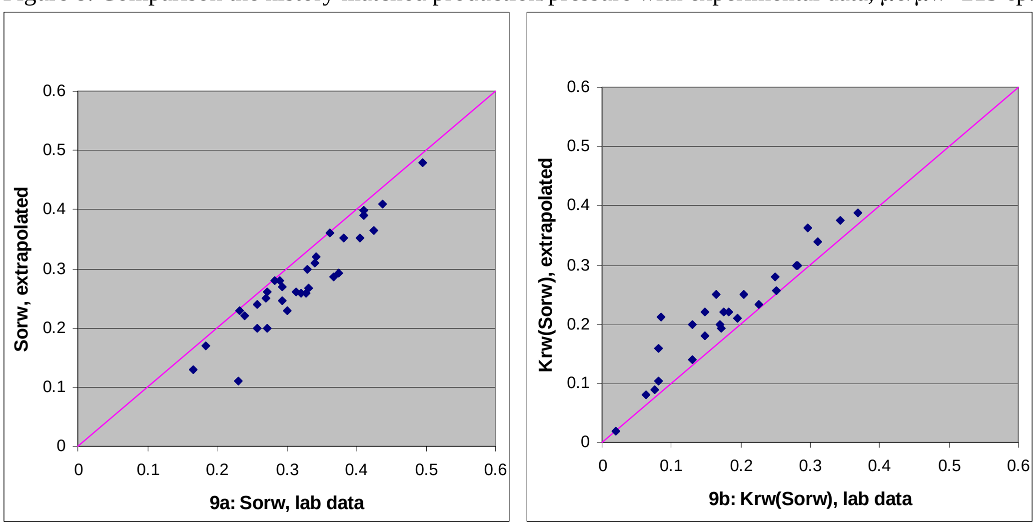

Figure 9. a) Extrapolated residual oil versus residual oil from lab measurements. b) Extrapolated water relative permeability at residual oil versus lab measured values.