CASE STUDY OF WATER FLOOD RELATIVE PERMEABILITY MEASUREMENTS FOR TWO MIDDLE EASTERN CARBONATE RESERVOIRS

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ABSTRACT

Major water/oil relative permeability studies have been performed for two Middle Eastern carbonate reservoirs. The data gathered will be used to assess the impact of relative permeability for each rock type in the developed models, and validate the field development plan for possible development options. This case study is concerned with the water flood recovery option. Previous studies have shown significant uncertainty in relative permeability data and end points, and consequently the residual saturations. Water flood (imbibition) measurements were made for a number of rock types covering a permeability range of 0.5mD to 3mD. The paper outlines the field representative laboratory methods used, the recovery data obtained, and implications of the results on field development plans.

Nine water floods were performed in total, comprising six unsteady state (USS) measurements on plug samples and one on a 52cm composite core for Reservoir 1, and one USS measurement on a 27cm composite core and one steady state (SS) measurement on the same composite for Reservoir 2. The water floods were performed with rigorous methods to ensure representative reservoir wettability and also with in-situ saturation monitoring. The relative permeability data were interpreted using the ECL proprietary core flood simulation software, *dyrect*SCAL, in order to correct for capillary pressure artefacts and/or assess the JBN analyses.

Representative and reliable relative permeability data obtained has significantly enhanced the validity of the developed simulation models. Consistency of measured SCAL data is of utmost importance in validation of simulation models and hence better management of reservoir development options.

INTRODUCTION

This paper reports the results of water flood studies performed on two Middle Eastern carbonate reservoirs, Reservoir 1 and Reservoir 2, as part of larger SCAL studies also covering immiscible and miscible gas injection. The objective of the water flood studies was to assess the impact of water/oil relative permeability data and validation of field development plans for possible development options. Various development options were studied to evaluate the optimum scenarios for the subject reservoir zones. Initial options focused on gas and / or water injection as the pressure maintenance fluid, and these were evaluated using a development simulation model with analogue relative permeability curves. The SCAL data used in the development model was old, limited and did not cover all the rock types identified in the static and geological models. Furthermore, the existing data were acquired at ambient conditions and uncertainties existed in initial connate water saturation, wettability of the restored samples and the experimental deficiencies of the original measurements which were performed without in situ saturation monitoring, live oil ageing and were not performed at full reservoir conditions. Also water/oil imbibition capillary pressure data were not measured.

The study objectives were to obtain representative reservoir dynamic data for the reservoir simulation model in order to reduce reservoir model uncertainties.

RESERVOIR DESCRIPTION

Reservoir 1

Reservoir 1 is about 140 feet thick, and shallows upwards from lime mud dominated sediments in the lower 50 feet, to grainstone dominated sediments in the upper 90 feet. Porosity is moderate, ca. 20%, with core permeability values generally less than 10mD, although local permeabilities can be up to 20mD. In the lower section, matrix micro-porosity is dominant and very low permeability results. The upper section is characterized by fining upward poorly sorted intraclastic, bioclastic grainstone beds that can be very coarse grained and locally pebbly, and often with irregular and abrupt bases. These beds, less than 2 to 5 feet thick and arranged in shallowing upwards sets, are packaged between major field-wide and cemented stylolite horizons that define the reservoir sub-zonation.

Reservoir 2

The rock type in question for Reservoir 2 is easily identifiable on wireline logs with high porosity intervals dominated by matrix microporosity with very few macrofauna or macroflora. It consists primarily of rare planktonic forams and fine skeletal debris surrounded by a uniform, chalky lime mud matrix. Porosity varies from 10-30% and permeability from 1-7 mD. The rock type is remarkably homogeneous, of poor-moderate quality reservoir, exhibiting variations due to degree of cementation near dense intervals and partial dolomitization. The porosity system is typically unimodal with little deviation around the characteristic pore throat size peak at 0.60 micron.

Rock type analysis

Three reservoir rock types (RRT) were studied for Reservoir 1 and for Reservoir 2 a single RRT was studied. The original rock typing scheme was based simply on facies description, but with the premise that permeability is controlled by the inter-connected porosity, this scheme was modified early in the project such that the more fundamental rock property of pore throat size distribution was used to characterize rock type.

On this basis samples of similar flow characteristics could be found in different facies types. Subtle differences in the pore throat size curves measured by mercury injection were used to characterize the RRTs. Mercury injection curves with inflection points centred around 1μm were used to define RRT1 and curves slightly lower than 1 μm defined RRT2. RRT3 was lower still. There was significant overlap between RRT's 1 and 2, making the RRT classification a matter of experienced judgement rather than a precise result. Porosity and permeability relationships were also used as an additional guide to rock typing; RRT1 displayed porosity >20% and permeability >1mD, RRT2 displayed porosity <20% and >17% and permeability ≅1mD, and RRT3 was generally <17% porosity and permeability <0.5mD.

LABORATORY PROCEDURES

Core Preparation - Plug samples

Basic properties of the samples used are shown in Table 1. Plugs were cut from preserved whole core samples and homogeneous plugs for relative permeability measurements were selected after CT scanning. Plugs that showed signs of local heterogeneity (vugs, high density inclusions, stylolites, fractures, etc) were omitted from SCAL testing. The plugs were then prepared as follows:

1. The plugs were cleaned by warm solvent flushes of an azeotropic mix, toluene and methanol followed by saturation with synthetic formation brine and measurement of absolute brine permeability. SCAL plugs were never dried prior to relative permeability testing.
2. Plug pore volumes were measured using ISSM techniques by monitoring the miscible displacement of brine with a doped brine.
3. For Reservoir 1, primary drainage relative permeability was measured at 150psi pore pressure and ambient temperature by refined oil displacing brine. (This data was analysed and simulated but its presentation is beyond the scope of this paper.)
4. Plugs were resaturated to 100% brine and then desaturated against a porous plate to representative values of irreducible water saturation (S_{wi}). These were performed individually in core holders and the course of the desaturations monitored by in-situ saturation monitoring (ISSM). Uniform or near uniform saturations were achieved. Similar S_{wi}'s were achieved during the earlier primary drainage relative permeability tests but invariably the viscous displacement for the relative permeability tests (no porous plate) would result in a saturation gradient along the core plug and a distinct retention of water at the outlet.
5. The plugs were transferred to a reservoir condition facility and the refined oil permeability at S_{wi} measured. Following displacement of refined oil with dekalin, then stock tank oil (STO), the samples were raised to full reservoir conditions of approximately 4000psi and 120°C for both reservoirs with a 600 psi overburden pressure. At this stage the samples were flushed with live oil and aged for up to four weeks. Each week the live oil was displaced with fresh live oil and the permeability measured. At the end of the ageing period the live oil permeability

value was then used as the reference permeability for the water / oil relative permeability measurements.

Core Preparation - Composite Samples

Properties of the composites are shown in Table 1. The plugs for the composites of Reservoir 1 and Reservoir 2 were prepared as described above except for step 3 (primary drainages omitted). After step 4 the composites were constructed. No bridging material was used between plugs. The composites were aged as described for the plugs in step 5 above. The composite of Reservoir 1 (compR1) was made up from 10 plugs of a single rock type (RRT 1). The composite of Reservoir 2 (compR2) was made up from 5 plugs of a single rock type.

Un-Steady State Water Flood

Three reservoir condition facilities were used to undertake the measurements on the various samples. The water flood of compR1 was performed as part of a larger miscible gas injection study and consequently was performed without ISSM.

Tests on the plug samples of Reservoir 1 and on compR2 were performed on two other reservoir condition facilities, both equipped with high pressure vessels for storage of live fluids, on-line PVT cells to measure effluent data at full test conditions and ISSM. Core samples up to one foot long could be accommodated in carbon composite core holders. Two high-pressure positive displacement pumps were used (one injecting and one extracting) in order to flood through the core at the required displacement rates. The facilities were equipped with numerous absolute pressure transducers, differential pressure transducers and thermocouples connected to a data logging system. Water flood measurements were performed vertically bottom to top at three injection rates, these being a reservoir rate of around 1ft/day, corresponding to a laboratory flow rate of around 3 mL/h and then two further rates at varying multiples of the low rate (see Table 2 for details). The high rate was chosen such that the maximum pressure drop across the sample was in the order of 250 psi. Live synthetic reservoir brine was used. The water floods were performed directly after ageing, with no depressurisation or movement of the core i.e. the whole process of ageing and water flood was performed sequentially on the same facility.

The initial oil saturation after ageing, flood front saturations and end point saturations were measured by gamma attenuation in-situ saturation monitoring methods [1]. The 100% pore volume doped live synthetic brine and live oil ISSM calibration data were obtained after the water floods were complete, at full test conditions.

Steady State Water Flood

The SS water flood was performed on compR2 at the same conditions as the USS test. As this was exactly the same composite as used in the unsteady state water flood, direct comparisons of the data can be made. After the unsteady state water flood, compR2 was oil flooded to measure secondary drainage K_{rw} and K_{ro}. Despite no porous plate in place a reasonable residual water saturation profile was achieved, although its value (28.0%PV) was not as low as the original S_{wi} (18.1%PV), which was derived from flooding of individual plugs. Due to concern over the effect of initial water saturation on steady state water saturations, a 1-dimensional simulation was performed to investigate the effect. This showed that steady state water saturations achieved at various water fractional flow rates were independent of the starting water saturation, providing the same relative permeability curves was used in the simulation for each starting water saturation. It also required the lowest steady state water saturation to be higher than highest starting water saturation.

The SS test was performed at 1.5ft/day total flow rate (5.2mL/h) which was equal to the low rate used in the USS flood of compR2. The fractional flow rates of water (F_w) used were 1%, 5%, 10%, 20%, 50%, 70%, 90% and 100%. Each fractional flow was left until steady state was reached as judged by the ISSM measurements. The total duration of the steady state flood sequences (not including preparation of the core, ageing and unsteady state testing) was approximately 6 weeks.

RESULTS

Un-steady State Water Flood Results

An objective of the measurements was to provide end point relative permeability data and remaining oil saturation (ROS) data by using rigorous laboratory techniques. These data together with other water flood behaviour parameters for all the unsteady state tests are shown in Table 2. So that the end point data and residual saturations can be compared, the flood rates and pore volume throughput at each rate are also shown. The remaining oil saturations are measured from the ISSM data (except compR1 data) and the end point K_{rw} data are as measured (i.e. not corrected for capillary pressure artifacts). ISSM data was used to quantify saturations in the plug samples and cross-checked with separator measurements. ISSM data generally indicated approximately 5%PV lower ROS's compared to separator readings and this was attributed to the relatively small pore volumes of plugs compared to the relatively large dead volumes of the flow rigs. ISSM data is not affected by dead volume corrections.

All the samples across both reservoirs show a relatively late breakthrough at around 0.6PV and high displacement efficiencies at breakthrough of between 60% to 70%. Only Plug 3 differs slightly from the rest at 0.72 PV injected at breakthrough and a displacement efficiency (DE) of 76% at breakthrough. The recovery profiles from separator readings for compR1 and plug 1 (both RRT 1) are compared in Figure 1. Although the shapes of the recovery curves are very similar, there are differences in the breakthrough time and recovery. This may be due to differences in the samples themselves or due to the inherent accuracy of the larger pore volume of the composite (130mL compared to 18mL.) Note that ISSM data were used to quantify plug saturations for all analyses.

ROS at the end of the reservoir advance rate floods (rate 1) range from 17% to 27%PV for Reservoir 1 and 14.5%PV for Reservoir 2. The ROS at low rate are in some instances high due to capillary retention of the oil phase. This was corrected for by core flood simulation in the final calculation of relative permeability.

At the end of the high rate floods the end point data shown in the tables are generally free of capillary end effects. Only very slight capillary pressure artefacts remained as verified from the ISSM data, therefore the ROS defined by the high through put at the end of the high rate floods were accurate representations of residual saturations. In-situ data for Plug 1 (significant post breakthrough recovery) and Plug 3 (little post breakthrough recovery) are shown in Figures 2 and 3 as examples. At the end of the high rate for Plug 1 a saturation gradient caused by capillary pressure effects still remained along the sample whereas for Plug 3 little end effect remained. For compR2 in-situ profiles at the end of the flood are shown in Figure 4. There was 14.4% PV post breakthrough recovery to the end of the low rate, but from then on there was only a further 3.2%PV recovery to the end of rate 3. The final saturation distributions were very uniform with no end effect.

The remaining oil saturations at the end of rate 3 can be taken as the practical residual oil saturation end points for the samples due to the high throughput and pressure drop the samples had experienced. Thus the displacement efficiencies quoted for rate 3 are effectively the maximum possible for each sample. The displacement efficiency at breakthrough can be compared to the maximum displacement efficiencies and from this is it can be seen that the recoveries at breakthrough ranged from 76% - 89% of the maximum possible recovery. The end point relative permeability data at rate 3 ranged from 0.29 to 0.47 for Reservoir 1 and 0.61 for Reservoir 2.

Unsteady State Relative Permeability Analysis

For Reservoir 1 plug samples and compR2, the production and pressure drop data was first analysed by the JBN technique, but it was clear from the ISSM data that some of the datasets were affected by capillary pressure artefacts, that would result in the JBN K_r curves being suppressed. Therefore the data was simulated using the *dyrect*SCAL method. This novel software has been previously described [2]. Essentially the mathematical representation of the flow variables have been re-formulated in *dyrect*SCAL to allow an independent fit to pressure drop, oil production and in-situ saturation profiles to correct for the effects of capillary pressure, but without the need for an independent measure of imbibition capillary pressure. The resulting water and oil relative permeability curves, shown in Figures 5 and 6 respectively, were equal to or more favourable than the JBN curves, especially so for the oil curves in a number of cases. The JBN data and the core flood simulation data for Reservoir 2 are shown in Figure 7 (together with SS data described later). As expected for this case with no end effect, the simulated data verified the JBN data.

Steady State Water Flood Results

The saturation profiles from the SS test are shown in Figure 8. Also shown on this plot is the end point from the 1.5ft/day USS flood. Note that the final saturation at the end of the SS flood (83.2%PV) compares very closely to the USS saturation which provides reassurance on the ROS achieved. The SS relative permeability is shown in Figure 7 together with the USS core flood simulation, USS measured end points and the oil displacing brine (secondary drainage) end points. As can be seen a very good match between the SS and USS data was observed, enhancing the quality and consistency of data obtained. SS tests allowed acquisition of early flood data, prior to the breakthrough (compared with the USS data), and thus an improved definition of the relative permeability curves.

Imbibition Capillary Pressure

Measured capillary pressure data was not available at the time of core flood analysis, so *dyrect*SCAL simulation/regression calculations were performed as described earlier. These calculations determine P_c', the gradient of the capillary pressure curve. The P_c' curve can be integrated to produce a simulated imbibition P_c curve that is relevant to the actual sample and actual test conditions. The simulated imbibition P_c curves for Plugs 1 – 6 are shown in Figure 9. The derived P_c curves have not yet been compared with measurements.

Wettability Tests

For Reservoir 1, combined Amott/USBM wettability measurements were carried out on a selection of samples that had previously been aged in live oil at full reservoir conditions for 3 weeks. (After ageing, these samples were dekalin and refined oil flooded prior to depressurisation in order to prevent wettability alteration due to heavy end deposition during depressurisation.) The wettability measurements were made at 70°C and ambient overburden pressure, using STO and synthetic brine. The following wettability indices were obtained:

- RRT 1 Amott-Harvey: –0.26 to –0.34, USBM: -0.35 to –0.51
- RRT 2 Amott-Harvey: –0.35 to –0.63, USBM: -0.25 to –0.75
- RRT 3 Amott-Harvey: +0.01 to –0.11, USBM: -0.12 to –0.24

Subsequently, further USBM measurements were made on another batch of samples which were aged in STO at 1000psi for 3 weeks at reservoir temperature. This gave the following wettability results:

- RRT 1 USBM: -1.40
- RRT 2 USBM: -1.48 to –1.68
- RRT 3 USBM: -1.40

For Reservoir 2, combined Amott/USBM wettability measurements were made on a single plug that had been previously aged in live oil in the same manner as reservoir 1 samples. The wettability measurements were made at ambient temperature and pressure, using refined oil. The results for Reservoir 2 show it to be intermediate wet with an Amott-Harvey index of +0.08 and USBM index of +0.05.

DISCUSSION

At the start of the studies it was expected that the samples would show oil wet water flood behaviour, as carbonates tend to be naturally oil wet in nature and the water floods were to be carried out after restoration of reservoir wettability by live oil ageing at full reservoir conditions. The water flood characteristics expected were fairly early breakthrough and a long period of significant post-breakthrough recovery. What was actually seen was a mix between water-wet and oil-wet behaviour; the high breakthrough recovery and sharp increase in water cut post-breakthrough is indicative of water wet core but the post breakthrough recovery and K_{rw} end points ranging from 0.3 to 0.6 is characteristic of intermediate to oil wet behaviour.

The wettability indices measured on the live oil aged samples distinguished between RRT1/2 and RRT3 samples, RRT3 being more intermediate wet than RRT1/2 samples. The USBM indices measured on the samples simply aged in STO did not distinguish between rock type, indicating all samples to be oil wet. The former set of wettability indices are more consistent with the wettability that can be inferred from the water flood characteristics discussed above.

For reservoir modelling a correlation relative permeability with a fundamental controlling parameter such as wettability, pore size distribution or RRT would be desired. The relative permeability data shown in Figures 5 and 6 for Reservoir 1 do tend to show a trend of K_{rw} curve shape with rock type and wettability (although further relative permeability measurements are required to confirm any trends). The wettability indicated by the K_{rw} curves shapes for each RRT has been confirmed with Amott/USBM measurements and further analysis is on-going on this. The trend seen in the K_{ro} curves is less clear and on a log plot, where the low K_r regions are more easily seen, the trend is not so obvious.

The ROS for Reservoir 2 from the SS test was only 2.3% less than that measured on the USS state test at the same total flow rate of 1.5ft/day. This is provides confidence in the measured values and is reassuring that both techniques provide essentially the same result, both in terms of relative permeability and final saturations.

The derived capillary pressure curves are affected by several issues:

- The saturation at which $P_c = 0$ is not fixed.
- The accuracy of the P_c curve diminishes at low saturations where the in-situ data is limited (for these samples with late breakthrough).
- These samples do not exhibit significant capillary end effects. There is therefore little curvature on the end point saturation profiles to define the capillary pressure gradient, leading to uncertainty in the shape of the Pc curve. On-going work is looking at ranges of uncertainty for the data, and considering how these should be presented. Although there are uncertainties in the P_c data derived for intermediate wet samples, we note that the imbibition P_c curve could not be obtained at reservoir conditions (especially the positive part of the curve), other than by difficult and time consuming

experimental methods. In addition, these experimental measurements would not necessarily use the same core as the water flood.

CONCLUSIONS

Representative reservoir conditions and rigorous methods have been used to measure relative permeability and end point saturations. The datasets are consistent with themselves which provides confidence in the data and they are also consistent with wettability measurements and RRT definition. Consistency of the SS and USS tests provides further confidence in the low remaining oil saturations measured. Although the two techniques gave similar results, uncertainty exists in deriving relative permeability curves from USS experiments of intermediate wettability samples (before breakthrough) unless a rigorous core flood simulation approach is used. Use of valid relative permeability data significantly enhances the developed reservoir simulation model, and thus reduces uncertainty in the development options.

ACKNOWLEDGEMENTS

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REFERENCES

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Table 1: Characterisation Data

	Reservoir 1							**Reservoir 2**
	Rock Type 1		Rock Type 2				Rock Type 3	
Plug	CompR1	1	2	3	4	5	6	CompR2
length (cm)	52.00	7.08	7.50	7.21	7.22	7.25	7.40	26.78
dia (cm)	3.74	3.74	3.74	3.74	3.74	3.74	3.74	3.73
Kabs(brine)	1.93	2.53	0.57	1.16	0.61	0.59	0.41	2.71
porosity (%)	22.8	23.2	21.7	21.0	19.2	20.0	20.4	27.9
Swi (%PV)	4.4	3.0	8.5	5.8	12.7	8.3	13.3	18.1
Keo (live oil) (mD)	1.58	2.68	0.58	1.01	0.58	0.51	0.36	2.92

Table 2: USS Water Flood Behaviour Data

	Reservoir 1							Reservoir 2
	Rock Type 1		Rock Type 2				Rock Type 3	
Plug	CompR1	1	2	3	4	5	6	CompR2
Rate 1 (ft/day)	1.00	1.02	1.06	1.13	1.20	1.12	1.09	1.50
PV throughput rate 1	2.0	12.5	11.9	7.8	9.0	8.7	8.4	6.0
PV inj at BT	0.65	0.59	0.60	0.72	0.55	0.64	0.62	0.60
Disp Eff at BT (%)	68.0	60.8	65.6	76.4	63.0	69.8	71.5	74.0
Disp Eff at BT/DE max	n/a	0.76	0.88	0.89	0.80	0.82	0.83	0.86
ROS rate 1 (%PV)	25.0	27.1	24.3	17.4	26.5	17.1	17.4	14.5
Krw rate 1	0.27	0.18	0.23	0.26	0.19	0.21	0.24	0.40
Rate 2 (ft/day)	n/a	6.67	7.07	7.28	7.97	5.22	3.26	9.6
PV throughput rate 2	n/a	12.6	9.9	9.2	12.7	8.2	4.5	10.0
ROS rate 2 (%PV)	n/a	21.5	23.4	15.4	21.3	15.1	16.8	13.3
Krw rate 2	n/a	0.35	0.298	0.35	0.31	0.31	0.25	0.54
Rate 3 (ft/day)	n/a	20.0	21.2	36.4	23.9	18.7	11.6	26.6
PV throughput rate 3	n/a	15.8	17.2	23.2	21.2	15.2	12.7	20.0
ROS rate 3 (%PV)	n/a	19.2	23.4	13.8	18.7	13.7	12.3	11.3
DE (max)(%)	n/a	80.2	74.4	85.4	78.6	85.1	85.8	86.2
Krw rate 3	n/a	0.47	0.309	0.41	0.38	0.39	0.29	0.61

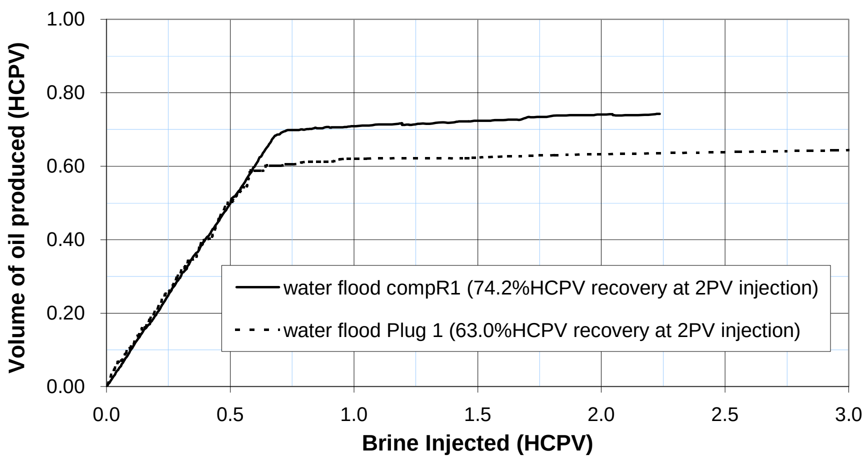

Figure 1: Comparison of Recovery Volume Reservoir 1 Samples

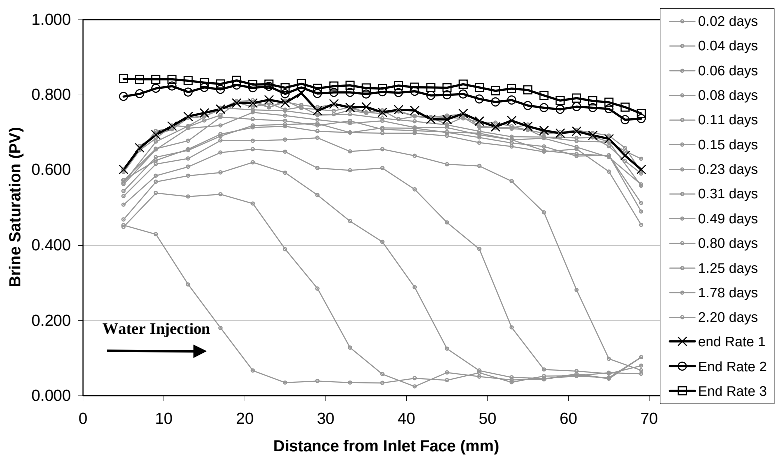

Figure 2: ISSM Profiles for Plug 1

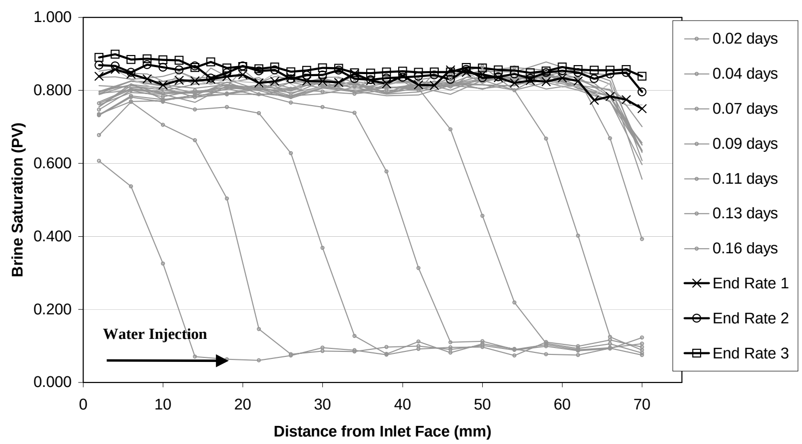

Figure 3: ISSM Profiles for Plug 3

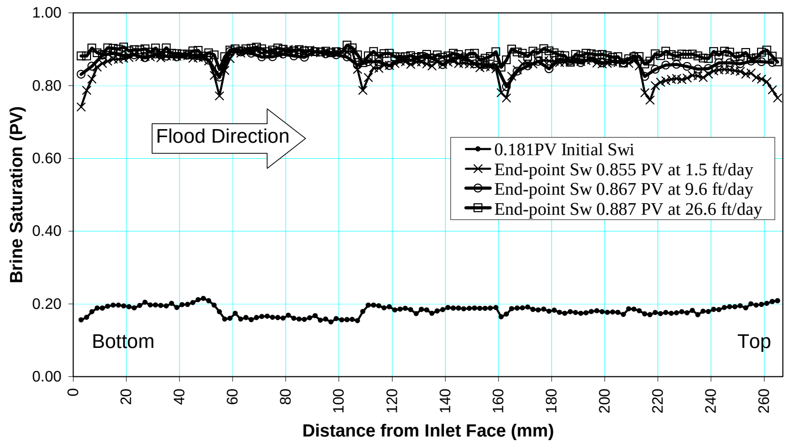

Figure 4: End Point ISSM Profiles for CompR2

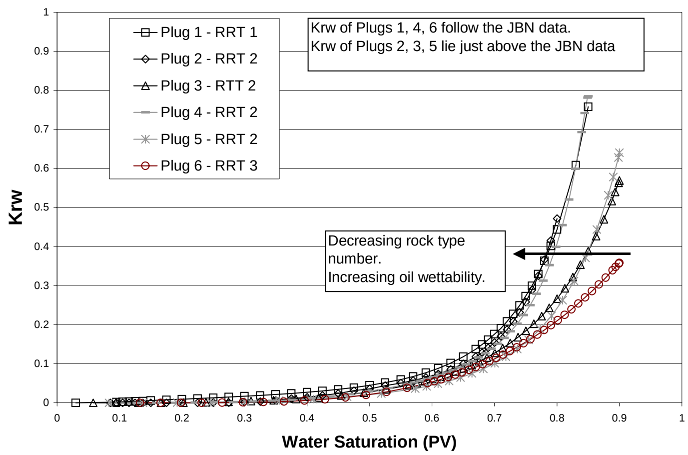

Figure 5: Water Relative Permeability Curves: Reservoir 1 Plugs

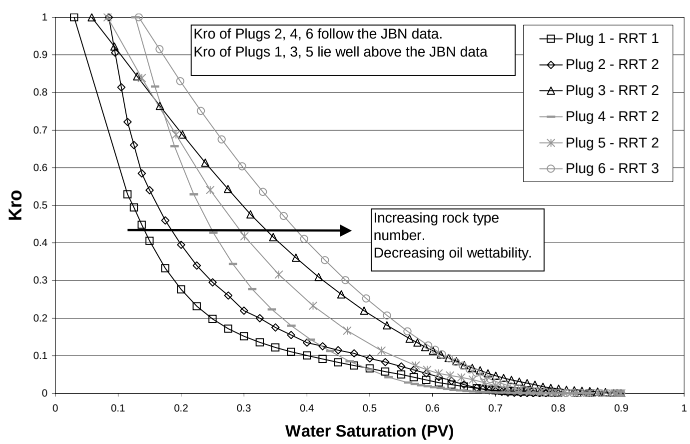

Figure 6: Oil Relative Permeability Curves: Reservoir 1 Plugs

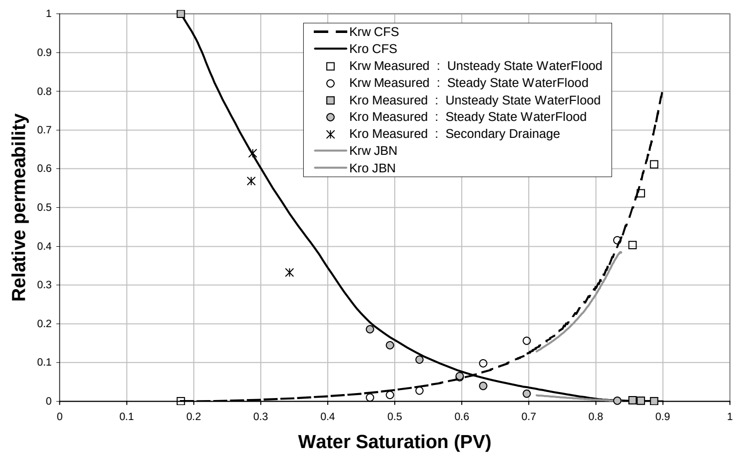

Figure 7: Relative Permeability Data for CompR2

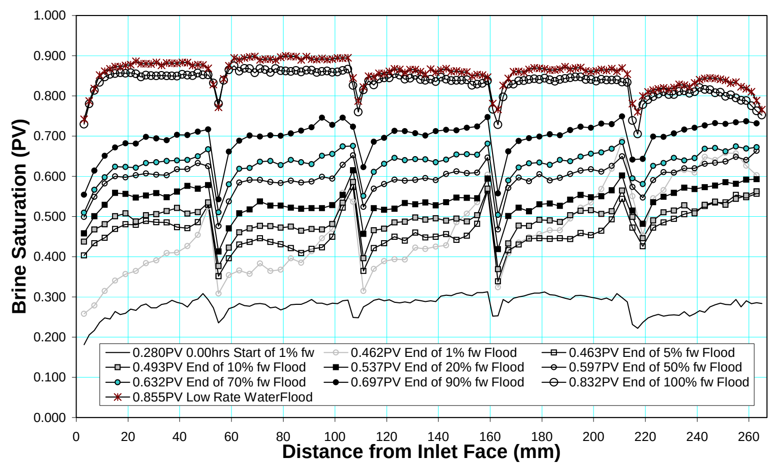

Figure 8: Steady State ISSM Profiles for CompR2

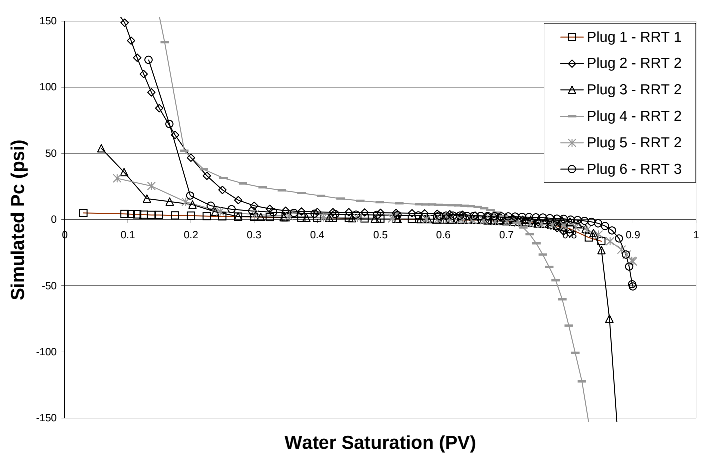

Figure 9: Simulated Imbibition Capillary Pressure Data