

# INCLUDING CAPILLARY PRESSURE IN SIMULATIONS OF STEADY STATE RELATIVE PERMEABILITY EXPERIMENTS

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## **Abstract**

Two series of steady state core floods have been performed on composite reservoir core material. The rock material was from a water wet sandstone, with a permeability of 100 mD. The core flood experiments include two-phase water-oil drainage and imbibition processes, and in addition three-phase steady state experiments.

Usually, relative permeability is calculated from steady state experiments neglecting capillary pressure. The two-phase drainage and imbibition experiments were modeled using a steady state simulator. Relative permeability including and excluding capillary pressure were estimated. Relative permeability showed considerable differences even though the selected flow rate for the experiments was within the standard scaling criteria for water flooding. Water relative permeability was not distinctly affected by capillarity. The critical rate for neglecting capillarity in these experiments has been estimated for the two-phase drainage and imbibition type steady state experiments.

Oil and water relative permeability from the three-phase steady-state experiments have been compared to the data from the two-phase steady-state experiments. Both oil and water relative permeability was generally affected by three-phase flow. The water relative permeability was considerable lower for three-phase flow compared to two-phase water-oil. The oil relative permeability was higher for three-phase flow compared to two-phase water-oil, and the three-phase residual oil saturation was found to be substantially lower than the two-phase residual oil saturation.

## **Introduction**

Measurement of relative permeability by the steady state technique allows one to calculate relative permeability directly using Darcy's law. The differential pressure and saturations are recorded, using a pseudo-equilibrium criterion, of constant phase flow rate in and out of the core, and constant saturations along the core. The experimental equipment must be designed to give good material balance, and due to the complexity of the high quality experimental set-up only a few laboratories have this capacity. For more detailed discussion of experimental methods for relative permeability measurements we refer to

references (1-4), and for more details about high quality steady state experimental set-up, see references (5,6).

The steady state method has the advantage that it is capable of defining relative permeability over a broader saturation range than other methods, like flooding (unsteady state) or centrifuge. Compared to unsteady state a shock front is avoided in steady state, though, small saturation shocks may exist when the ratio of injected phases is changed. Usually a composite core is required to improve the accuracy of saturation and differential pressure measurements. The limited length of the core material used in core analysis may cause boundary effects to arise, i.e. capillary end-effects that distort the calculated results. Data from steady state experiments reported in the literature are often calculated by neglecting capillary pressure. This is justified either by applying the Penn State method<sup>7,1,2</sup> or by selecting a flow rate that falls within the standard scaling criteria for water flooding<sup>8,9</sup>. Scaling criteria for water flooding aims at defining a total flow rate interval between capillary influence and viscous instability. The rate criteria are usually argued from the work of Rapoport and Leas<sup>8</sup>.

In this study the experiments were designed according to the standard approach<sup>8,9</sup> and relative permeability was initially calculated neglecting capillary pressure. Later on, the steady-state experiments have been reinterpreted using a steady state simulator<sup>10</sup> to history match the measured pressure drops and saturations, including the capillary pressure.

### ***Experimental procedure***

The core material was from a shallow marine sandstone formation located in a North Sea oil reservoir. The porosity was 29.9% and the absolute permeability to water was in the range of 100 mD. The sandstone cores used was water wet. The shape of the imbibition capillary pressure curve, which is shown in Figure 1, shows a strong spontaneous imbibition, and indicates the water wet behavior. The core used in the steady state experiments was a composite core, consisting of two core elements. The properties of the cores are shown in Table 1. The water applied was filtered synthetic brine saturated with N<sub>2</sub> and the oil was n-decane with a purity of 95% saturated with N<sub>2</sub>. The gas applied in three-phase experiments was N<sub>2</sub>. Fluid properties are listed in Table 2.

Two series of steady-state experiments were performed on the core, denoted A and B. Tables 3 and 4 outline the injection scheme, and the initial and final saturations of each experiment in both series. The steady-state series include both two-phase and three-phase experiments. The steady state displacements were conducted by applying a constant total injection rate throughout the experiment, whereas the injection rate of each fluid phase was varied in steps. The pressure drop was monitored and the computer initiated a new step when the pressure drop was constant within experimental error for six sequential five-minute intervals. The total injection rate applied in all displacements was 1 ml/min. Bump floods of higher rates were performed at the end of a steady state series in some of the sequences. In the steady state experiments in series B, the magnitude of the incremental

steps from one injection fraction to the next was varied in order to ensure the best possible scatter of steady state measurements over the saturation range.

Prior to both series of experiments, the plug was cleaned with (a) toluene, (b) 50/50 mixture of toluene and methanol, (c) methanol and (d) isopropanol. Then 1 pore volume of 0.5% mixture of NaCl and distilled water was injected into the plug, succeeded by several PV's of synthetic brine. Finally the core was drained down to irreducible water saturation by high viscosity synthetic oil, Marcol 172, which was thereafter replaced by n-decane.

The experimental set-up applied for the steady state, is similar to what has been reported earlier<sup>6</sup>, and consists of six pumps (Quizix type) that operate in pairs, one pair for each fluid. One pump injects fluid into the core, and the other pump withdraws fluid from the acoustic three-phase separator. Another separator, a two-phase acoustic monitored separator, filled with water and gas is connected to the three-phase separator in order to minimize the pressure variations that occur during shifts from one pump to another. The set-up is mounted in an air bath in order to maintain a constant temperature.

A computer conducts the entire experiment automatically, based on user defined stability criteria. The injection fractions are thus changed automatically when the three-phase separator records a constant fluid volume and the pressure transducer records a constant  $\Delta p$  over a preset defined time. All experiments were performed at 20 bars backpressure and 40°C. All displacements were conducted in a gravity stable manner. The core was sealed in Teflon tape and aluminum foil, and placed in a rubber sleeve that contracts upon heating.

### ***Selecting flow rate***

In steady state core experiments porous end-pieces are often applied in order to avoid capillary effects at the boundary of the porous media (see Penn-State method<sup>7</sup> and other references<sup>1,2</sup>). Another alternative used to eliminate capillary end-effects in steady state experiments is to use a composite core (increase core length) and high flow rate. As we have applied the last approach flow rate selection becomes a concern. Rapoport and Leas scaling group<sup>8</sup> has been extensively used to define the rate of water flood. The scaling coefficient was extended to water floods in mixed wet cores by Haugen<sup>9</sup>, who found that a scaling coefficient of less than 0,1 was required to have stabilized flow. The term "stabilized flow" refers to flow where the shape of the front does not change with time. The effect of capillary pressure in core floods is to spread the front, but at the same time there is a wave sharpening effect because of the convex-upward shape of the fractional flow curve. These two effects tend to balance and make the wave approach an asymptotic limit or stabilized flow. It is not obvious that there exist a stabilized flow region in all the different wettability situations. As  $L$  is large in a reservoir stabilized flow is always expected, except near wells. In steady state the need for stabilized flow seems very restrictive, as shock fronts should not be dominant. But as an example, if the objective is to find rate-independent residual oil saturation a stabilized flow region may be one of the rate selection criteria.

The Rapoport and Leas<sup>8</sup> scaling group is defined as:

$$L \mu_w v \quad (1)$$

units: (L=cm,  $\mu_w$ =mPa s,  $v$ =cm / min)

A dimensionless form of the Rapoport and Leas number has been suggested by Lake<sup>11</sup>:

$$N_{RL} = (\phi / k)^{1/2} [(\mu_w u L) / (k_{rw} * \phi \sigma \cos\theta)] \quad (2)$$

Lake<sup>11</sup> found that a  $N_{RL}$  of 3 corresponded to a scaling group of 1 in Rapoport and Leas data<sup>8</sup>. For small  $N_{RL}$ , capillary pressure ( $P_c$ ) will cause shock waves to spread out. The upper limit rate criteria for relative permeability to be negligibly affected by capillary forces in a one-dimensional water – oil displacement, when the core is water wet, is  $N_{RL}$  equal to 3. The injection rate applied in the experiments presented in this paper falls within the standard scaling criteria for water flooding, and applied a capillary number,  $N_c = 7 * 10^{-7}$ . The reported range for  $L \mu_w v$  is 0.1 to 1 cm<sup>2</sup>cp/min, and corresponding  $N_c$  range from  $10^{-4}$  to  $10^{-8}$  to avoid residual oil to become a function of rate (references<sup>11,12</sup>). The critical capillary number for similar North Sea sandstone cores has been found to be  $N_{c,c} = 1 * 10^{-6}$  (ref. <sup>13</sup>). The flow rate used corresponds to  $N_{RL} = 4.6$ . Another even more restrictive lower range flow rate criteria aimed at eliminating end effects has been proposed by Sigmund and McCaffery<sup>14</sup>. An upper limit for the flow rate may be the onset of viscous instability (discussed by Peters and Flock<sup>15</sup>) or by the critical capillary number as mentioned above. We have used  $\sigma = 50$  mN/m and  $\cos\theta = 1$  in our calculations.

For the drainage process, with this core material and fluids, there is no flow rate range where viscous instability and limiting capillary effects both could be avoided. Selecting a flow rate for the imbibition process, the Rapoport and Leas criterion is easily met, and the mobility ratio is favorable. However, for the drainage process, it becomes more difficult to avoid capillary end effects (Sigmund and McCaffery criteria<sup>14</sup>) as it requires a minimum flow rate of 13 cc/min. The mobility ratio for drainage is unfavorable and indicates viscous instability even at low rates (criteria from Peters and Flock<sup>15</sup>). The drainage flow rate is also on the limit where  $S_{or}$  starts to become a function of  $N_c$ .

The arguments presented above refer to discussion of shock fronts, and the relevance of these arguments may be questioned for small saturation changes in the steady state process. However, we like to comment that the use of high flow rate in steady state to avoid capillary end-effects still leaves some questions of possible instability and  $S_{or}$  variation with flow rate. To our knowledge these questions about rate effects on steady state relative permeability have not been addressed.

## **Experimental results and discussion**

### ***Two-phase steady state***

The core material appears rather water wet, and results are compared to other studies of water wet or weakly water wet rock. The relative permeability given in Figures 2-5 was calculated by straightforward application of Darcy's law to each phase. The two-phase measurements consisted of two types of steady state experiments: drainage, meaning the oil injection fraction was increased and the water injection fraction was decreased, and imbibition in which the water injection fraction was increased and the oil injection fraction was decreased.

Figure 2 show the relative permeability calculated for imbibition processes in both steady state series. Figure 3 show the relative permeability for secondary drainage experiments in both steady state series. Both figures confirm that data are nicely reproduced in the two experimental series.

Possible relative permeability hysteresis is described in Figures 4 & 5 comparing oil and water relative permeability respectively, from imbibition and drainage experiments in both steady state series. The secondary drainage oil relative permeability is generally lower than imbibition relative permeability at the same saturation, in agreement with data from Braun and Holland<sup>17</sup>. Very little hysteresis between imbibition and primary and/or secondary drainage is seen for the water phase. These results are similar to other results on outcrop and reservoir cores<sup>2,16-20</sup>.

### ***Three-phase steady state***

The three-phase measurements consisted of the following experiments: G1A and G1B, where two-phases were injected, the gas injection fraction was increased and the water injection fraction was decreased. Similar, O2A and O3B, where the oil injection fraction was increased and the gas injection fraction was decreased. For other experiments, see Table 3. The two first experiments G1A and G1B could be regarded as drainage experiments, as gas is regarded to be the non-wetting phase in this three-phase situation. These experiments may involve a double drainage process if gas displaces oil and oil displaces water. The remaining three-phase experiments are neither true drainage nor true imbibition experiments.

Figure 6 compares water relative permeability from the three-phase drainage experiments (oil and water is displaced by gas) to the two-phase drainage experiments (water is displaced by oil). Water relative permeability data from three-phase experiments overlap the two-phase data. The data show that drainage water relative permeability in this comparison seems dependent on the water saturation only. An argument in favor of this observation could be that water is mostly in contact and drained by oil in both these two-, and three-phase steady state experiments. The water relative permeability seems not affected by the fact that oil is simultaneously displaced by gas in the three-phase flow experiments.

Figure 7 compares water relative permeability from two-phase experiments where oil is displaced by water (imbibition), to three-phase experiments where oil is displaced by both gas and water. Water relative permeability data from three-phase experiments do not overlap the two-phase data. Three-phase water relative permeability is reduced and seems not merely dependent on the water saturation, but depends on the other saturation of the other phases present. Similar observations have been seen in other unsteady state and steady state three-phase flow experiments<sup>17-20</sup>.

Figure 8 compares oil relative permeability from two-phase experiments where oil is displaced by water, to three-phase experiments where oil is displaced by both gas and water. Oil relative permeability data from three-phase experiments do not overlap the two-phase data. The results show that oil relative permeability is increased in three-phase situations.

Figure 9 compares oil relative permeability from two-phase experiments where oil displaces water, to three-phase experiments where oil displaces both gas and water. The oil relative permeability data at low oil saturation from three-phase experiments seems to be higher than the two-phase data, indicating that oil relative permeability in all processes are increased for three-phase flow at low oil saturations.

In summary, the results in Figures 7, 8 and 9 show that oil relative permeability derived from three-phase experiments is larger than from two-phase experiments at low oil saturation, whereas the opposite seems true for water relative permeability. The residual oil saturation was lower in the three-phase than in the two-phase experiments. These observations agree with core flood results on water-wet outcrop cores<sup>18-20</sup>. The trends are more pronounced for series B than for series A because more gas is introduced into the system in series B. It should be noted that all three-phase relative permeability data are calculated neglecting capillarity. It was not possible to include capillary pressure in an appropriate manner.

### **Simulation procedure**

All two-phase steady-state experiments were modeled using a semi-analytical steady state simulator<sup>10</sup>. The simulator was applied to interpret the measured data with account for gravity and capillary forces. The capillary pressure curve was measured separately and used as input to the simulator along with measured pressure drops and saturations. The relative permeability was determined through an iterative procedure where the pressure drops and saturations were matched. Saturation profiles along the core length were generated at each time step. The simulation runs deliver two sets of relative permeability, one where capillary pressure is included, and one where capillary pressure is neglected.

A rate dependency study was undertaken with the simulator. Each of the two-phase experiments was history matched applying different rates. The measured pressure drops were scaled linearly with the rate. This implies that the system was assumed to obey

Darcy's law. The capillary pressure curves shown in Figure 1 were used as fixed input for all simulations.

### **Simulation results and discussion**

Figure 10 show the relative permeability curves obtained by history matching experiment O2B (second oil flood in series B). In addition six different rates: 0.5, 1, 2, 4, 8 and 16 ml/min were simulated to investigate the influence of flow rate. The pressure drop was scaled according to the flow rate by Darcy's law. The relative permeability from each rate excluding capillary pressure therefore coincides, and relative permeability including capillarity differs according to capillary influence on relative permeability calculations. Figure 10 reveals that oil relative permeability is affected by capillarity at rates less than 4 ml/min, corresponding to  $\Lambda\mu v = 16 \text{ cm}^2\text{cp}/\text{min}$  or  $N_{\text{RL}} = 18$ . Water relative permeability seemed much less affected by capillarity in this drainage type process. The results from similar simulations performed on the two other steady state drainage experiments have verified these results.

Figure 11 show the saturation profile along the core in experiment O2B, for the six different rates. The profile is displayed at the end of the drainage experiment where the injected oil fraction,  $f_o = 99\%$ . Figure 11 confirms the results in Figure 10, i.e. the assumption of uniform saturation distribution is a reasonably good approximation for injection rates above 4 ml/min. At rates less than 4 ml/min, an end-effect seems to be present. The critical capillary number for drainage has been found from earlier studies<sup>21</sup> to be higher than  $6 \times 10^{-5}$ , and the  $N_c$  would be well below that limit. However, as mentioned earlier, these rates are clearly above the limit for the viscous instability criteria, but these simulations cannot investigate this matter.

Figure 12 show the relative permeability curves obtained by history matching experiment W2A (second water flood in steady state series A). Also here we applied six different rates: 0.5, 1, 2, 4, 8 and 16 ml/min to investigate rate effects on relative permeability by simulations. The figure reveals that oil relative permeability is affected by capillary pressure at rates less than 2 ml/min, corresponding to  $\Lambda\mu u = 8 \text{ cm}^2\text{cp}/\text{min}$  or  $N_{\text{RL}} = 9$ . Capillarity has a less pronounced effect on the water relative permeability. The results from similar simulations performed on the four other steady state imbibition experiments have verified these results, and trends for both oil and water are in agreement with analytical corrections for capillary pressure on steady state relative permeability<sup>22-23</sup>.

Figure 13 shows the saturation profile along the core in experiment W2A, for the six different rates. The profile is generated at the beginning of the imbibition experiment where the injected water fractional flow,  $f_w = 10\%$ . Towards the end of the experiment, the saturation profile is reversed as water in an imbibition experiment is retained near the inlet at high water injection fractions. Figure 13 confirms the results in Figure 12. At rates less than  $N_{\text{RL}} = 9$ , a small end-effect is present, and at rates above  $N_{\text{RL}} = 9$  the water saturation profile is flat throughout the core length. At this total flow rate we are on the borderline versus critical capillary number, ( $N_{c,c} = 1 \times 10^{-6}$ ).

## Conclusions

The following conclusions are based on experiments and simulations performed on composite cores consisting of water-wet reservoir sandstone.

- Relative permeability showed considerable shift when capillary pressure was included even though the selected flow rate for the experiments was within the standard scaling criteria for water flooding.
- Neglecting capillary effects led to an underestimate of oil relative permeability.
- Relative permeability hysteresis was more pronounced for the oil phase (non-wetting phase)
- In oil-water steady-state imbibition, oil relative permeability is affected by capillarity at rates corresponding to a Rapoport and Leas number of  $N_{RL} < 9$ .
- Drainage oil-water steady state showed that relative permeability was affected by capillarity at  $N_{RL} < 18$ . For these experiments there seems to be no windows of rates that satisfy criteria of eliminating capillary influence and viscous instabilities.
- Three-phase steady state results show:
  - (a) oil relative permeability derived from three-phase steady state experiments is larger than two-phase oil-water at low oil saturations.
  - (b) drainage process water relative permeability seems unaffected of two- or three-phase flow, while three-phase imbibition water relative permeability is reduced.
  - (c) residual oil saturation is lower in the three-phase than in the two-phase experiments.

## Nomenclature

$f$  = injection fraction

$k$  = permeability, mD

$k_{ro}$  = oil relative permeability

$k_{rw}$  = water relative permeability

$L$  = core length, cm

$N_c$  = capillary number

$N_{c,c}$  = critical capillary number

$N_{RL}$  = Rapoport and Leas Number

$\Delta p$  = pressure drop, atm

$PV$  = pore volume, ml

$P_c$  = capillary pressure, atm

$q$  = injection rate, ml/min



$S_{or}$  = residual oil saturation, %, fraction  
 $u$  = superficial velocity, cm/min  
 $v$  = interstitial velocity, cm/min  
 $\mu_w$  = water viscosity, cp  
 $\phi$  = porosity  
 $\sigma$  = interfacial tension, mN/m  
 $\theta$  = contact angle

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Table 1 Properties of composite core

Exp. Series	Length1 [cm]	Length2 [cm]	Length Tot [cm]	Diam [cm]	PV [ml]	K <sub>abs</sub> [mD]	K <sub>o</sub> (S <sub>wi</sub> ) [mD]
A	8.86	9.09	17.95	3.71	57.9	107	162
B	8.86	9.09	17.95	3.71	57.9	93	168

Table 2 Fluid properties

Fluid	Density [g/cm <sup>3</sup> ]	Viscosity [cp]
Synthetic brine	1.000	0.721
n-decane saturated with N <sub>2</sub>	0.700	0.691
N <sub>2</sub>	0.165	0.023

Table 3 Summary of steady state experiments, I = increasing, D = decreasing

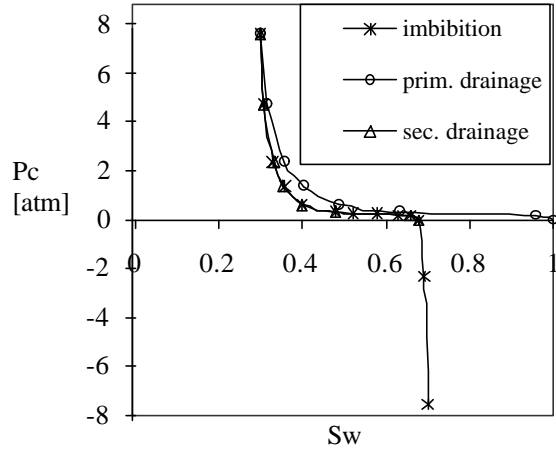
Experiment		Injection fractions		
A	B	fw	fo	fg
W1	W1	I	D	-
O1	O1	D	I	-
W2	W2	I	D	-
	O2	D	I	-
	W3	I	D	-
G1	G1	D	-	I
O2	O3	-	I	D
3F	3F	I	D	I

Table 4 Average saturations at beginning and end of all steady-state experiments

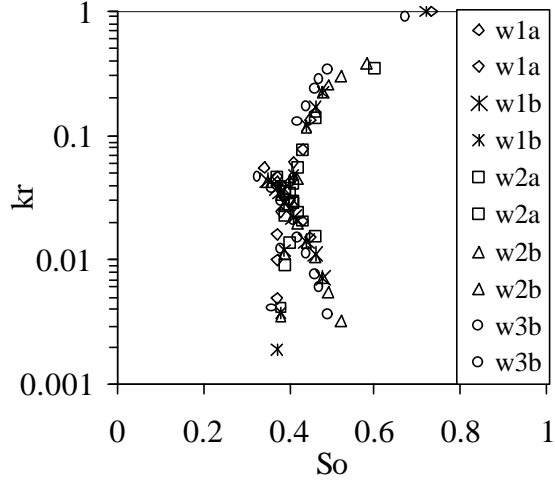
Exp.	Saturations [%]											
	Sw				So				Sg			
	A		B		A		B		A		B	
	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End
W1	27	66	28	65	73	34	72	35	0	0	0	0
O1	66	40	65	42	34	60	35	58	0	0	0	0
W2	40	63	42	65	60	37	58	35	0	0	0	0
O2	-	-	65	33	-	-	35	67	0	0	0	0
W3	-	-	33	67	-	-	67	33	0	0	0	0
G1	63	49	67	45	37	26	33	23	0	24	0	31
O2	49	35	45	32	26	65	23	68	24	0	31	0
3F	35	61	32	65	65	26	68	14	0	13	0	21

Table 5 Min. flow rates to neglect capillarity.  $L_{\mu v}$  is the Rapoport-Leas scaling factor.

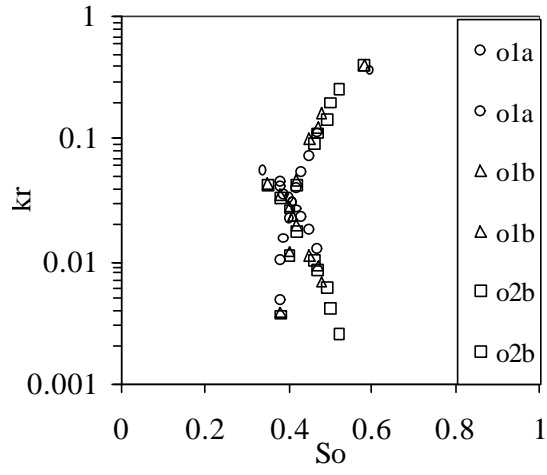
Experiment	W1A	W1B	W2A	W2B	W3B	O1A	O1B	O2B
q [ml/min]	2	2	2	2	1-2	4	3-4	4
$L_{\mu v}$ [cm <sup>2</sup> cp/min]	8	8	8	8	4-8	16	12-16	16



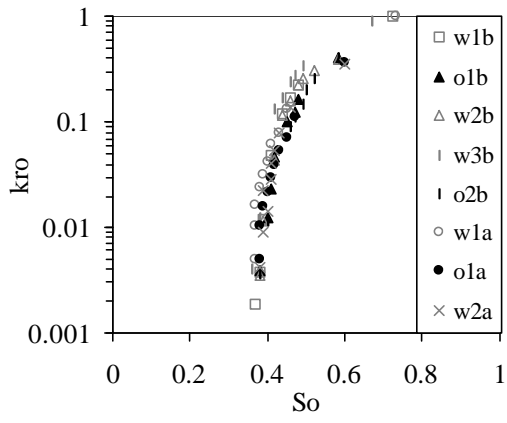
**Figure 1** Capillary pressure for the reservoir cores.



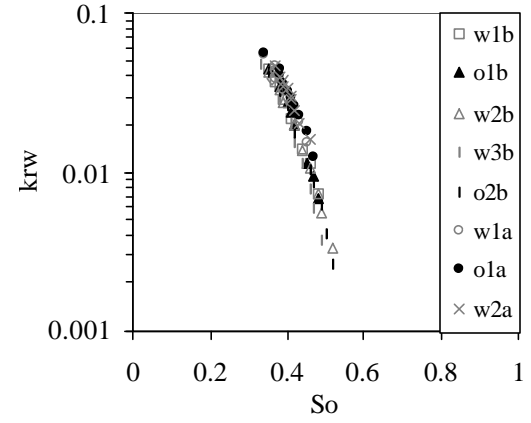
**Figure 2** Steady state imbibition relative permeability.



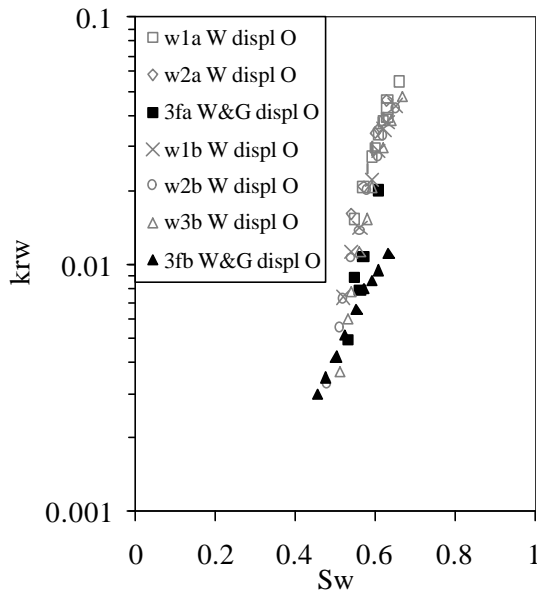
**Figure 3** Drainage process relative permeability.



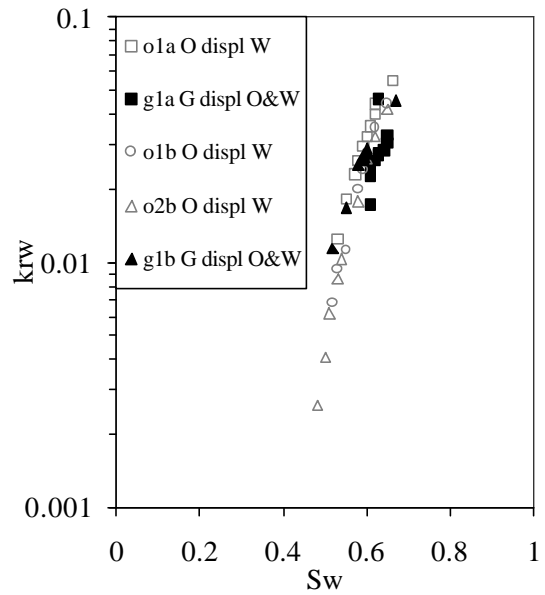
**Figure 4** Oil relative permeability, (both drainage and imbibition).



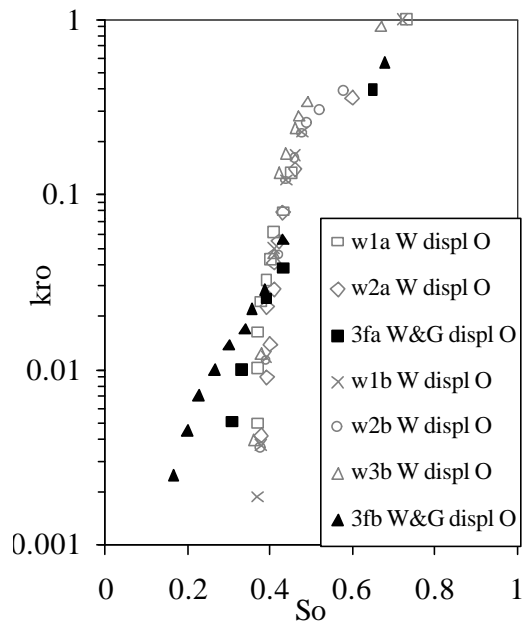
**Figure 5** Water relative permeability (both drainage and imbibition).



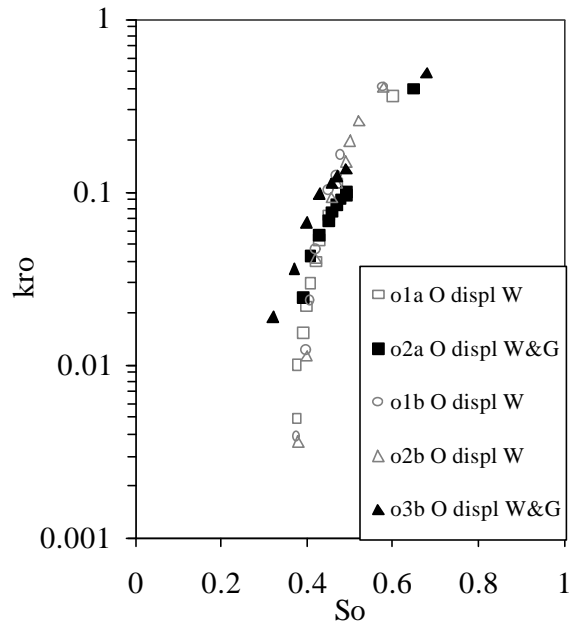
**Figure 6** Two- and three-phase water relative permeability, for decreasing  $S_w$  processes.



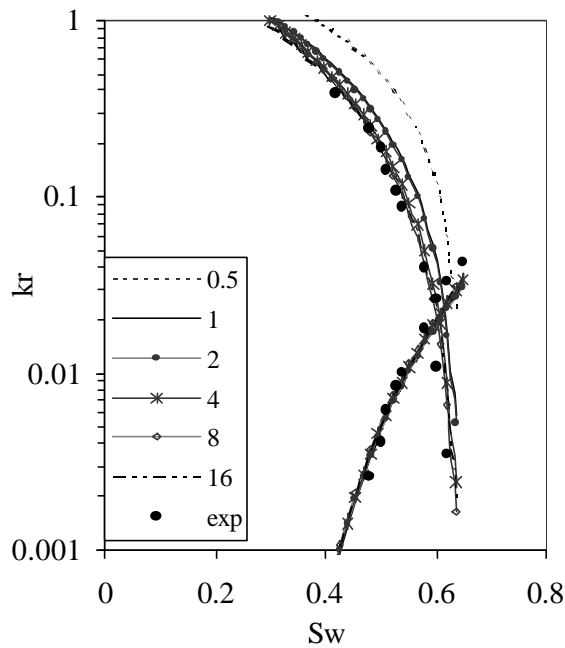
**Figure 7** Two- and three-phase water  $k_r$  for increasing  $S_w$  processes.



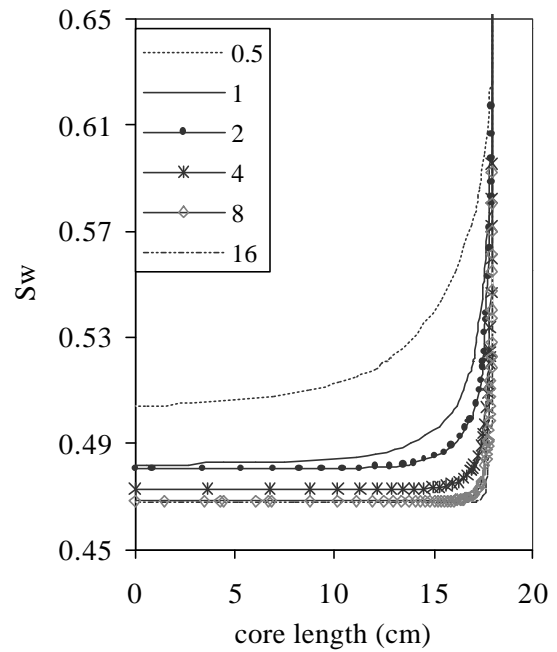
**Figure 8** Two- and three-phase oil relative permeability, for decreasing  $S_o$  processes.



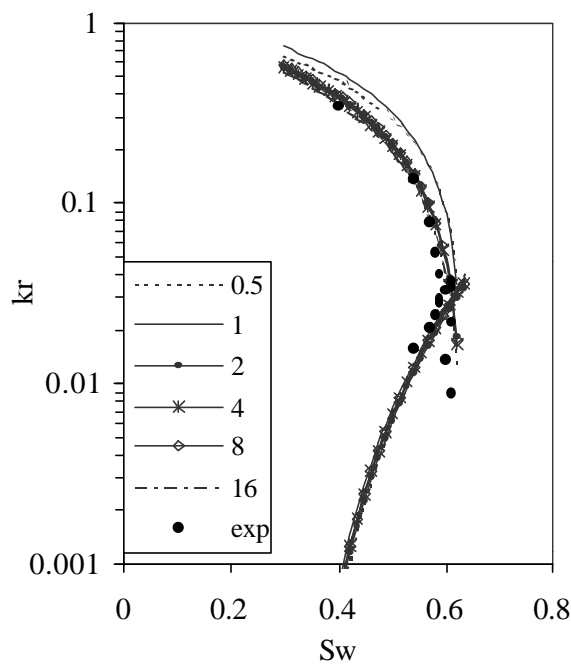
**Figure 9** Two- and three-phase oil  $k_r$  for increasing  $S_o$  processes.



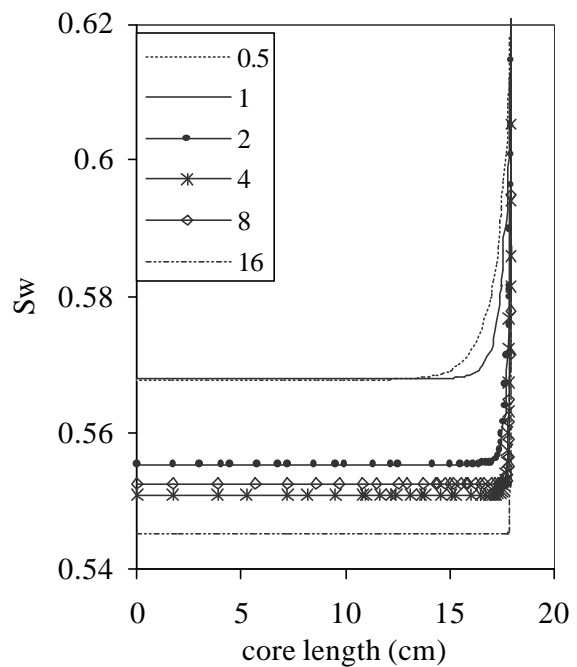
**Figure 10** O2B history-matched and simulations at different total flow rate: 0.5-16 ml/min.



**Figure 11** Saturation profiles at  $f_0=0.99$  for exp. O2B simulation including  $P_c$ .



**Figure 12** W2A history-matched and simulations at different total flow rate: 0.5-16 ml/min



**Figure 13** Saturation profiles at  $f_w=0.1$  for exp. W2A simulation including  $P_c$ .