RATE SELECTION FOR WATERFLOODING OF INTERMEDIATE WET CORES

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ABSTRACT

The effect of flow rate on water-oil relative permeability has been analysed from unsteady state waterflood displacements performed on intermediate-wet sandstone reservoir cores. The experiments performed consist for each core of a full cycle drainage and imbibition, giving wettability indices and capillary pressure characteristics. Thereafter several water floods were performed at different flow rate, and finally a second wettability test to ensure that the wetting was still unchanged after several cycles of flooding and resaturation to initial water saturation for each flood. In the displacements, saturation profiles along the cores showed little capillary end effects.

Several methods, both analytical and different simulation approaches have been applied in order to derive relative permeability. The best match of the production data is generally obtained by inverse approach optimisation on capillary pressure and relative permeability simultaneously. The estimated capillary pressure from match of the core floods is shifted towards more positive values than the direct measured imbibition capillary pressure. The results show that the derived relative permeability is influenced by capillary pressure even at rather high flow rate. We recommend low rate displacement analysed by simulation and including capillary pressure as the best method to estimate relative permeability for intermediate wet cores.

INTRODUCTION

The effect of flow rate or pressure gradient on relative permeability and end point saturation has been a controversial subject in special core analysis.[1] Some authors believe that the effect of flow rate is simply an "end effect" developed during core floods. The discontinuity in saturation at the end-face of the core causes a net capillary force to persist in the porous medium, and this force tends to prevent the wetting phase from being produced. The accumulation of the wetting phase at the outlet end of the sample creates a saturation gradient along the core that influences the relative permeability measurements. The obvious solution to the errors in relative permeability would be to get "true" data from high rate experiments.

There is no question about the fact of capillary end-effects, and the use of corrections. But is the decreased capillary influence obtained by increasing flow rate sufficient to explain the rate effect? The authors find several troublesome questions arising from the "capillary effect" argument. Why is the experimental data in the literature so inconclusive?[1] If the capillary correction is valid, can the same argument hold independent of wettability of the core? Data from intermediate wet cores[2] have shown unexpected effects of flow rate such as more dispersed fronts at higher rate, and end-point saturation uniformly distributed even at ultra low flow rate. If the solution to "true" relative permeability is high rate floods, simulation that includes or corrects for capillary pressure, should give the same relative permeability independent of rate. The results on water floods are again inconclusive,[1,2] and we find literature data difficult to evaluate, as the uncertainty of the derived relative permeability is usually not reported. Previously in our laboratory, studies have been made of rate effects on gas-oil drainage[3] and water-oil steady state displacements,[4] where covariance analysis have been applied to describe the accuracy in the relative permeabilities.

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The objectives of this study were to use intermediate-wet cores and test for any change in wettability before and after core flooding experiments. The relative permeability was calculated by an inverse approach that allows confidence intervals to be included. This provides an important check as to whether changes with rate are within or outside the statistical uncertainty.

Intermediate wet cores cover a large variation from weakly water wet to weakly oil wet, and involve fractional and mixed wettability. As our experiments only cover a limited type of the vast possible variation of intermediate wettability, we will be cautious in generalising the results. The capillary pressure varies for the different groups of intermediate wet cores, even for the same wettability index.

EXPERIMENTS

The experiments were performed on single core plugs with permeability in the range of 20-600 mD, see Table 1. The core material was selected because earlier special core analysis studies had shown little effect of core cleaning with toluene/methanol solvent. Fresh and cleaned cores gave similar wettability, and repeated cleaning did not change the wetting properties as measured by Amott tests.

We used single plugs to avoid possible local end effects caused by butting core pieces into a composite core. The sandstone cores had earlier been found to maintain an intermediate wet state even after cleaning and new flooding experiments. The sequence of experiments consisted of a USBM wettability test, followed by three core floods at different rate. Between each flood, the cores were cleaned with toluene/methanol and resaturated by drainage to initial water saturation. All experiments were done at ambient temperature. After the three waterfloods a spontaneous imbibition test was repeated to check for possible change in wettability (see Table 2). After all core floods have been made a new spontaneous imbibition test and full cycle capillary pressure measurement will be performed. If the spontaneous imbibition was reproduced we have assumed that the wetting state of the cores have been preserved, see Figure 1b.

The viscosity of the brine and oil was about 1 cp. All experiments were performed in a gravity stable manner, using constant rate. After a low rate flood i.e. when production had ceased, the flow rate was increased to a higher rate (bump rate), Table 3. The end point relative permeability for each rate step was obtained by stepping down the flow rate and measuring the differential pressure after it had stabilised.

SCALING OF CORE FLOOD EXPERIMENTS

In the literature, the Rapoport and Leas scaling group[5] has often been used to select the rate of water flood. The scaling coefficient was extended to water floods in mixed wet cores by Haugen,[6] who found that a scaling coefficient of less than 0,1 was required for stabilised flow. The term "stabilised 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 stabilised flow. It is not obvious that a stabilised flow region exists in all the different wettability situations. As L is large in a reservoir, stabilised flow is always expected, except near wells. As an example, if the objective is to find rate-independent residual oil saturation, a stabilised flow region may be one of the rate selection criteria. The Rapoport and Leas[5] scaling group is defined as:

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

units: (L=cm, μ_w=mPa s, v=cm / min)

A dimensionless form for the Rapoport and Leas number has been suggested by Lake[7]:

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

Lake[7] found that a N_{RL} of 3 corresponded to a scaling group of 1 in Rapoport and Leas data.[5] The advantage of the dimensionless number is that it also includes permeability of the rock. For small N_{RL}, capillary pressure (Pc) will cause shock waves to spread out. The limit of rate criteria above which relative permeability is negligibly affected by capillary forces in a 1-D water – oil displacement, when the core is water wet, is N_{RL} equal to 3.

Capillary desaturation defines a limit for when the residual oil saturation becomes a function of the capillary number. A critical capillary number for similar North Sea sandstone cores as the one used in this study has been found to be $N_{c,c}=1x10^{-6}$ (ref. 8).

An even more restrictive lower-range flow rate criteria aimed at eliminating end effects was proposed by Sigmund and McCaffery.[9] An upper limit for the flow rate may be the onset of viscous instability (discussed by Peters and Flock[10]) or by the critical capillary number as mentioned above. We have used σ = 50 mN/m and $\cos\theta$ = 1 in our calculations, due to lack of knowledge of the actual contact angles in these core floods. In selecting a flow rate for the imbibition process, the Rapoport and Leas criterion is easily met, and the mobility ratio is favourable especially as the displacement is gravity stable.

RELATIVE PERMEABILITY ESTIMATES

At the start of a test sequence a full cycle USBM wettability measurement was performed. Fig.1a shows the capillary pressure for forced imbibition of water and oil. The wettability indices are reported in Table 2. Core B, the most permeable core, ended-up at higher water saturation after secondary drainage. The imbibition capillary pressure is a fixed input in the simulations. However, in some simulations both capillary pressure and relative permeability are estimated. An example of spontaneous imbibition is shown in Figure 1b. The spontaneous imbibition prior and after six core floods are in good agreement.

We have selected the cores A, B, and E for further analysis because initial water saturation is more closely restored and wettability better preserved than for the two other cores. The three selected cores also represent variation in wetting state and rock permeability. The reason for variation in initial water saturation in some of the experiments, see Table 3, was variation in applied differential pressure during primary oil drainage.

Core floods at different flow rate show variation in oil recovery (see Fig. 2). The more water-wet core initially gave a minimum in oil recovery; thereafter, oil recovery increased with rate. Heaviside et al.[14] found that oil recovery increased with flow rate in a study of relative permeability for water wet cores. The results showed that residual oil saturation depended on flow rate, but was independent of core length. The results for our core A only deviate from this trend at low rate. However, the two studies are not directly comparable, because core A is not strongly water wet, the wettability index being about 0,5.

The other four cores were closer to intermediate wettability than Core A. Qualitatively, all cores showed similar change in recovery with rate, but deviated from the behaviour of the more water-wet core. The recovery is highest at the next to lowest rate. From other studies of intermediate wet cores[2,15] it has been recommended that reservoir rates be used to achieve field-representative residual oil saturation and relative permeability. The trend in recovery with rate found in this study is more complex, and it is not obvious as to which rate will be representative of microscopic displacement efficiency in the reservoir.

The endpoint water relative permeability increases with flow rate for all cores (Fig. 3), similar to observations in other studies of intermediate wet cores.[2,15] The trend is consistent with the argument of reduced capillary retention at high rate. The remaining oil saturation is also included in Figure 3. It is seen that the variation in remaining oil saturation does not govern the variations in endpoint water relative permeability. This means that effect of flow rate on end point saturation is different to that for end- point permeability.

The oil production (core A) at water breakthrough generally follow the same trend as for total recovery; production after breakthrough is, in nearly all cases, significant. This confirms that the results differ from strongly water-wet behaviour. The historical sequence of the experiments may influence the wettability and thereby the shape of the oil production curves. The second and third highest rates for Core B of 5,4 cc/hr and 54 cc/hr both show a gradual change in fractional flow after water breakthrough.

The best match of production and differential pressure is achieved by a spline fit.[11] Spline representation is also more flexible than, for example, a Corey-curve[12] fit. Figure 5 shows a good history match of both production and differential pressure for the high rate experiment on core A.

Figures 6 and 7 show relative permeability from different estimation methods. The analytical value of k_{ro} (neglecting P_c)[13] is lower than k_{ro} with capillarity included even at very high flow rate. In order to compare different methods for estimating relative permeability, the oil relative permeability at irreducible water saturation is set equal to unity. In an unconstrained history match, we would have preferred to link the simulations to measured values of the endpoint oil relative permeability. (Don't understand this point.) The experimental endpoint oil permeability at initial water saturation was close to unity for most experiments.

The variation given by different methods of estimating k_{rw} is much less for core A at high flow rate, indicating that analytical JBN relative permeability is closer to relative permeability estimates that include capillary pressure. One conclusion would be that capillary pressure had little influence at high rate; however, the simulations estimate a high capillary pressure(Figure 10). The confidence intervals for capillary pressure from the high rate flood are still rather narrow, and do not overlap the static measured capillary pressure. This means that capillary pressure still have an influence at high rate, and the estimated capillary pressure change with flow rate. It is not possible to get a match of the high rate floods with static measured capillary pressure. At low rate, in-situ saturation profiles are used in the matching procedure. Figure 8 show a good match between simulations and experiments. The water displacement front is dispersed even though the experiments were gravity stable with water being injected from the bottom of the core.

The effect of rate on relative permeability for core A is shown in Figs. 9, 11, and 12. Water relative permeability increase systematically with flow rate. The changes are clearly outside the confidence intervals. Oil relative permeability shows more complex variation with flow rate. The changes are again beyond the limit of the confidence intervals, and therefore can not be neglected. Figure 10 shows the change in P_c estimated from spline representation. The capillary pressure is in best agreement near P_c=0, as expected. At low flow rate the capillary pressure is closer to the experimental measured static capillary pressure.

Figure 13 shows k_{ro} and k_{rw} for core B at a flow rate of 6 cc/hr. As for the more water-wet core A, k_{ro} is underestimated by JBN analysis. The spline and Corey representation are in good agreement. Effect of rate on oil production from core B is seen in Fig.14. The highest production, at BT and final recovery, are achieved at the lower flow rates.

We were not able to simulate the flooding experiment (core B) with the highest flow rate by any of the different methods. The critical capillary number for this core flood was above the expected critical value (10^{-6}) for these sandstone cores. The differential pressure continued to increase after water breakthrough. For the other experiments, oil relative permeability was found to increase with rate; k_{rw} also showed an increase in relative permeability with rate. (Fig. 15). Mohanty and Miller[15] found that oil relative permeability decreased with increasing rate at the early part of the experiment, but increased with rate after 1 pore volume had been injected. In our estimate of oil relative permeability, k_{ro} increased with rate, but the oil relative permeability curves are restricted by the assumption that k_{ro} = 1 at initial water saturation.

Fig. 16 shows the estimated capillary pressure from a Corey fit on relative permeability, but with the flexibility of a spline fit to the P_c. All cases had similar capillary pressure, but the estimated P_c deviate from the measured static P_c.

Core E showed less variation in oil production from experiments at different flow rate, (Fig.17). Even with little effect on oil production, the water relative permeability increased systematically with increased flow rate (Figure 18). The oil relative permeability shows a more complex trend with flow rate, as was observed for the other intermediate-wet core (B).

CONCLUSIONS

- Relative permeabilities calculated analytically from unsteady state measurements give underestimates because results are still influenced by capillarity.

- Estimated capillary pressure from core floods is found to increase with rate

- Water relative permeability increases with rate for intermediate wet cores

- Oil relative permeability increases with rate for more water-wet cores, and also varies with rate for the more intermediate-wet cores, but the variation with rate is more complex.

- The results show that the derived relative permeability seems influenced by capillary pressure even at high flow rate.

- Remaining oil saturation, estimated residual oil, and oil production are all influenced by flow rate

We recommend the use of low flow rate and inclusion of capillary pressure in estimation of relative permeability as the best approach to obtaining data for intermediate wet cores.

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NOMENCLATURE

k	=	permeability, mD	P_c	=	capillary pressure, kPa
k_{ro}	=	oil relative permeability	q	=	injection rate, cc/hr or cc/min
k_{rw}	=	water relative permeability	S_{OR}	=	residual oil saturation, fraction
L	=	core length, cm	u	=	superficial velocity, cm/min
N_c	=	capillary number	v	=	interstitial velocity, cm/min
$N_{c,c}$	=	critical capillary number	μ_w	=	water viscosity, cp, mPa.s
N_{RL}	=	Rapoport and Leas Number	ϕ	=	porosity
Δp	=	pressure drop, kPa	σ	=	interfacial tension, mN/m
PV	=	pore volume, ml	θ	=	contact angle

Table 1. Core properties

		A	B	C	D	E
Length	(cm)	4.76	4.70	4.70	4.66	4.69
Diameter	(cm)	3.79	3.79	3.79	3.78	3.79
Petrophysical measurements						
Porosity, f_{He}	(frac.)	0.171	0.190	0.241	0.241	0.242
K(gas) Klinkenberg corrected	(mD)	22.3	637	104	103	104
Water permeability, kw	(mD)	20.6	534	107	98.1	96.4
Wettability indexes						
WI_{Amott}		0.56	0.22	0.29	0.37	0.38
WI_{usbm}		0.55	0.24	0.14	0.24	0.32

Table 2. Wettability checked before the waterflooding experiments, and after several waterfloods

Wettability index	A	B	C	D	E
Spontaneous imbibition frac. (prior)	0.25	0.12	0.19	0.23	0.23
Spontaneous imbibition frac. (after 3 floods)	0.21	0.17	0.22	0.41	0.31
Spontaneous imbibition frac. (after 6 floods)	0.21	0.13			

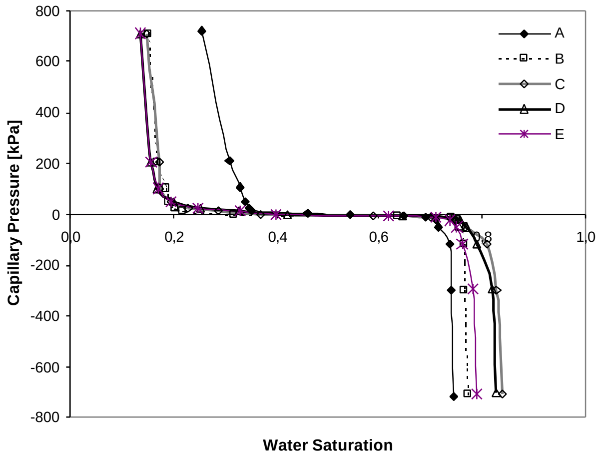

Figure 1a Capillary pressure (forced water imbibition (neg. part) and secondary oil drainage (pos. part))

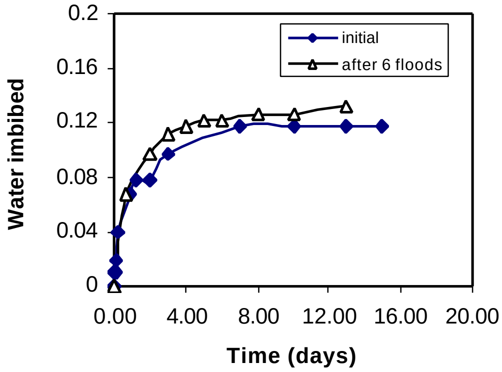

Figure 1b Spontaneous imbibition core B

Table 3. Waterflood experiments, initial and end point saturation, endpoint relative permeability

CORE		A	B	C	D	E
Rate 1	cc/min	**0.01**	**0.05**	0.02	0.01	**0.02**
Swi	frac.	**0.32**	**0.22**	0.21	0.25	**0.23**
Sor	frac.	**0.26**	**0.28**	0.32	0.29	**0.34**
Krw		**0.02**	**0.04**	0.04	0.03	**0.08**
Rate increase	cc/min	**0.57**	**8.0**	4.0	3.9	**3.8**
Sor	frac.	**0.24**	**0.27**	0.23	0.28	**0.32**
Krw		**0.05**	**0.14**	0.26	0.12	**0.18**
Rate 2	cc/min	**0.09**	**0.10**	0.02	0.02	**0.24**
Swi	frac.	**0.31**	**0.18**	0.29	0.19	**0.23**
Sor	frac.	**0.31**	**0.28**	0.31	0.30	**0.26**
Krw		**0.07**	**0.05**	0.16	0.04	**0.17**
Rate increase	cc/min	**1.33**	**8.0**	4.0	3.9	**3.9**
Sor	frac.	**0.28**	**0.28**	0.16	0.29	**0.19**
Krw		**0.14**	**0.18**	0.30	0.15	**0.34**
Rate 3	cc/min	**0.5**	**0.5**	0.05	0.24	**0.5**
Swi	frac.	**0.30**	**0.23**	0.20	0.19	**0.21**
Sor	frac.	**0.30**	**0.21**	0.28	0.32	**0.30**
Krw		**0.05**	**0.16**	0.04	0.09	**0.16**
Rate increase	cc/min		**8.0**	4.0	3.9	**3.8**
Sor	frac.		**0.18**	0.21	0.29	**0.28**
Krw			**0.25**	0.21	0.15	**0.16**
Rate 4	cc/min	**0.5**	0.5	0.5	0.24	**0.8**
Swi		**0.32**	0.30	0.22	0.26	**0.20**
Sor		**0.30**	0.35	0.26	0.24	**0.30**
Krw		**0.10**	0.33	0.23	0.23	**0.20**
Rate increase	cc/min	**1.66**	8.0	5.0	3.9	**3.8**
Sor		**0.29**	0.33	0.24	0.17	**0.28**
Krw		**0.15**	0.56	0.45	0.44	**0.22**
Rate 5	cc/min	**0.9**	**1.7**	0.9	08	0.8
Swi		**0.32**	**0.25**	0.18	0.31	0.36
Sor		**0.23**	**0.26**	0.28	0.25	0.27
Krw		**0.11**	**0.16**	0.29	0.14	0.09
Rate increase	cc/min	**1.1**	**8.0**	4.0	3.9	3.8
Sor		**0.23**	**0.25**	0.25	0.25	0.25
Krw		**0.11**	**0.17**	0.33	0.14	0.10
Rate 6	cc/min	**1.66**	**5.0**	2.5	2.4	**2.4**
Swi		**0.28**	**0.22**	0.24	0.29	**0.24**
Sor		**0.19**	**0.29**	0.25	0.29	**0.25**
Krw		**0.11**	**0.17**	0.25	0.16	**0.22**
Rate increase	cc/min		**8.0**	4.0	3.9	**3.8**
Sor			**0.29**	0.23	0.28	**0.25**
Krw			**0.17**	0.27	0.16	**0.23**

* data in **BOLD** is used in comparative study (selected from each series, the experiments with similar Swi)

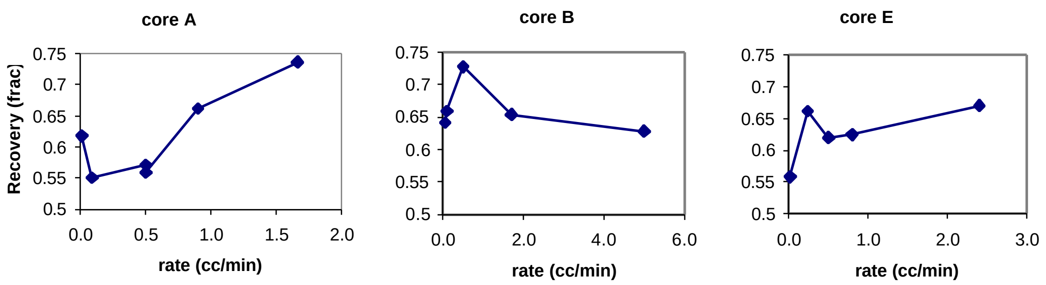

Figure 2 Oil recovery versus flow rate for the cores A, B, and E

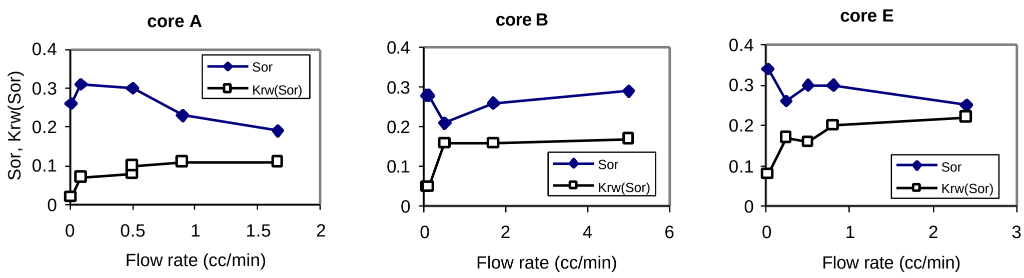

Figure 3 Remaining oil saturation and endpoint water relative permeability for core A, B, and E

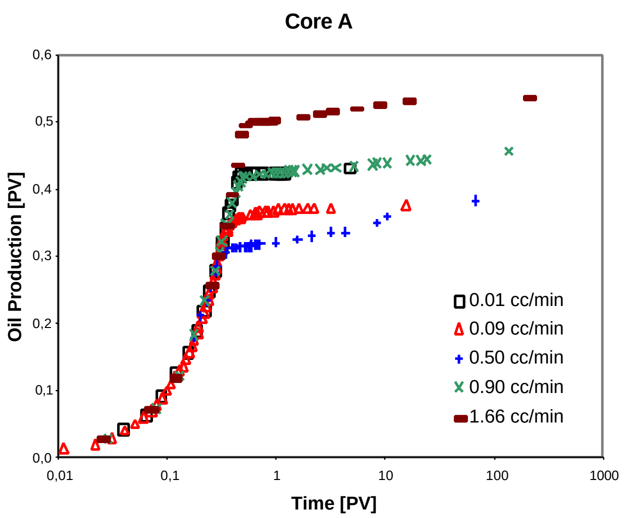

Figure 4 Oil production versus log time for core A at different flow rates

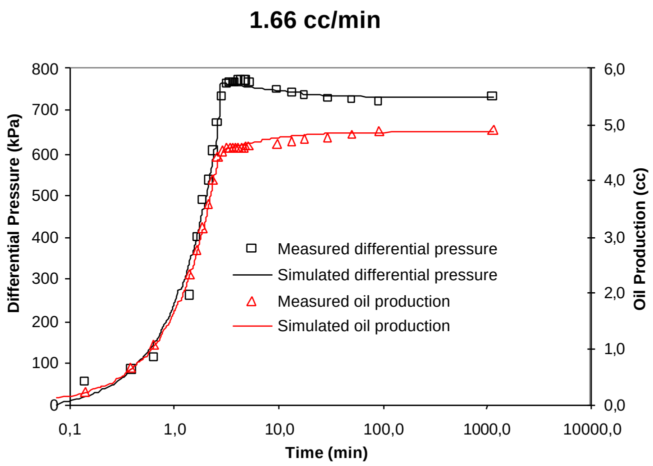

Figure 5 History match of production and differential pressure for core A at flow rate 1.66 cc/min

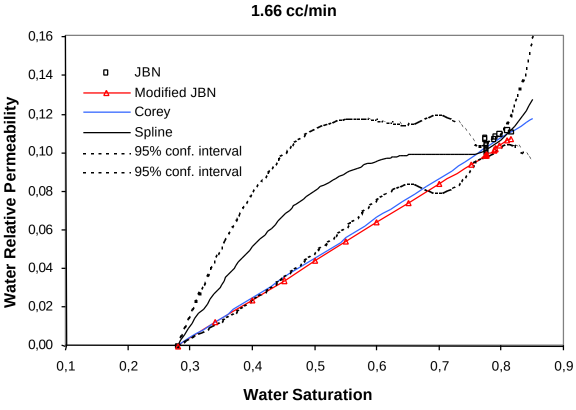

Figure 6 Water relative permeability estimated by different methods (Core A, rate=1.66 cc/min)

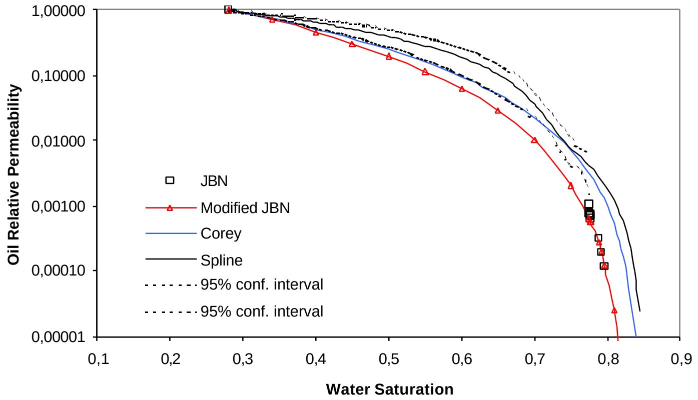

Figure 7 Oil relative permeability estimated by different methods (Core A, rate=1.66 cc/min)

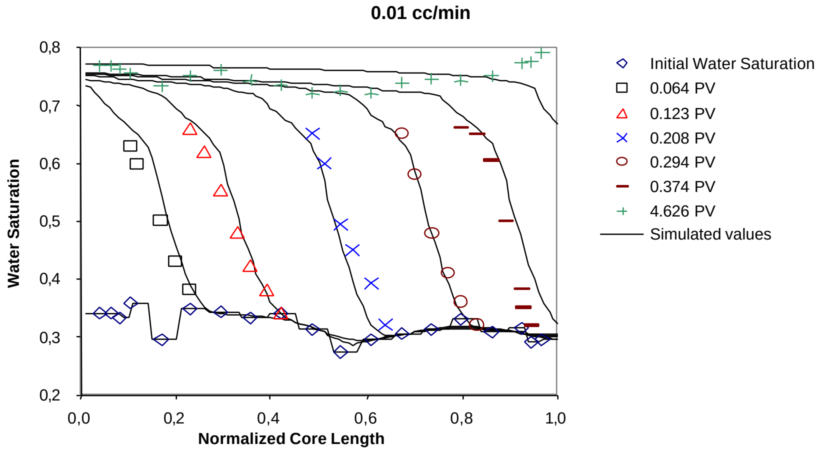

Figure 8 History match of in-situ saturation profiles (core A, rate=0.01 cc/min)

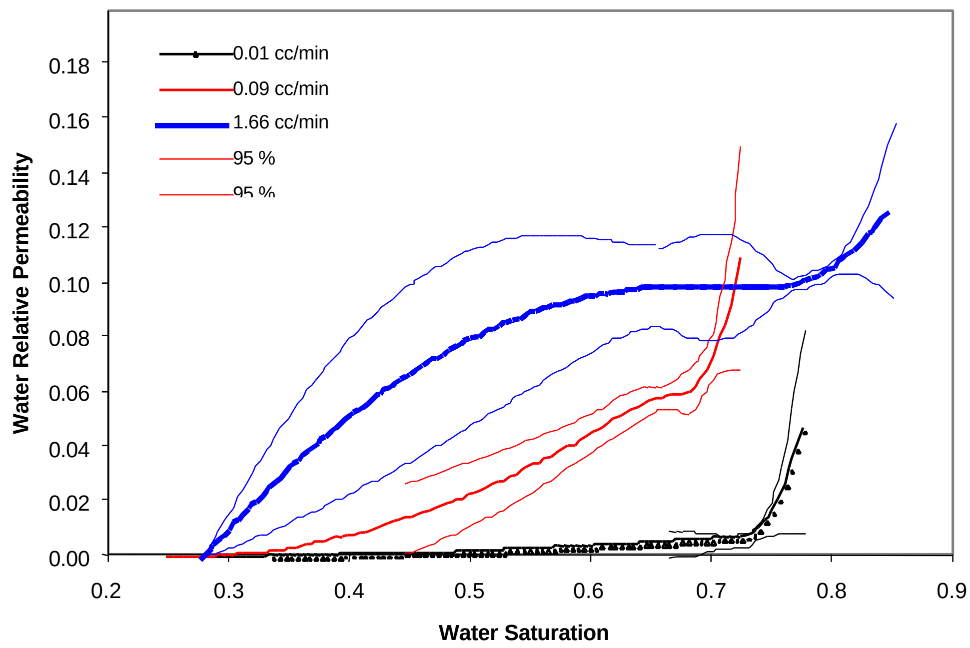

Figure 9 Water relative permeability from spline estimates at different rates, core A

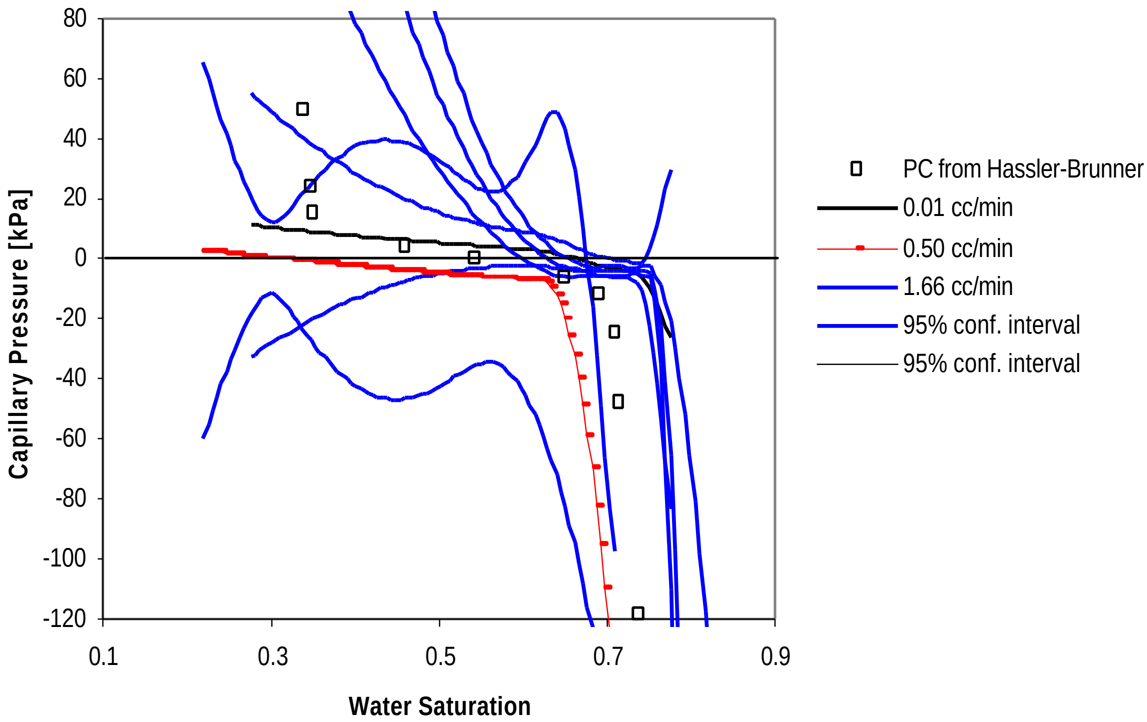

Figure 10 Capillary pressure from spline estimates at different rates, core A

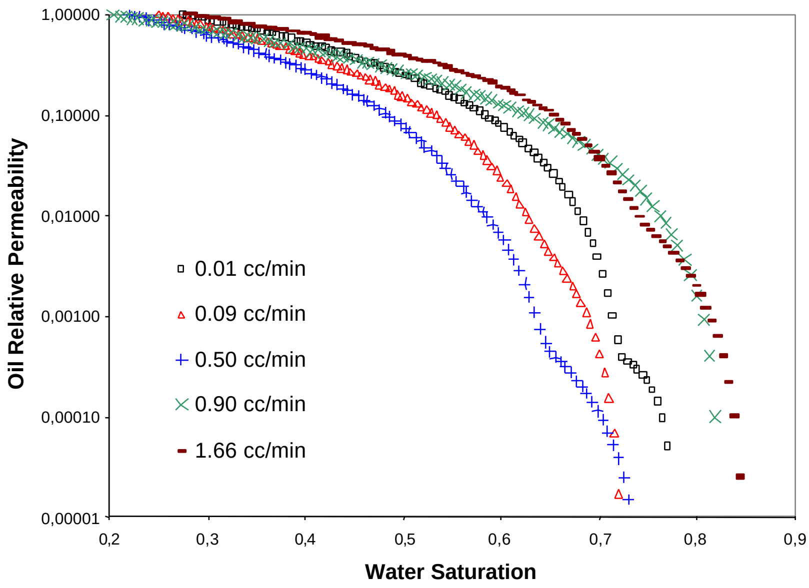

Figure 11 Oil relative permeability from spline estimates at different rates, core A

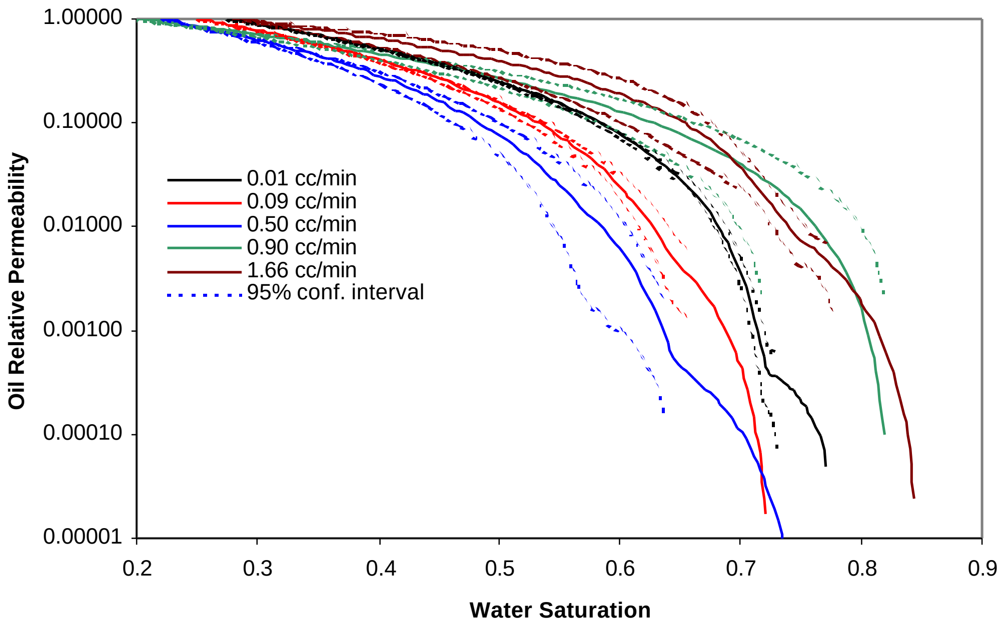

Figure 12 Oil relative permeability from spline estimates at different rates, core A including confidence intervals from covariance analysis

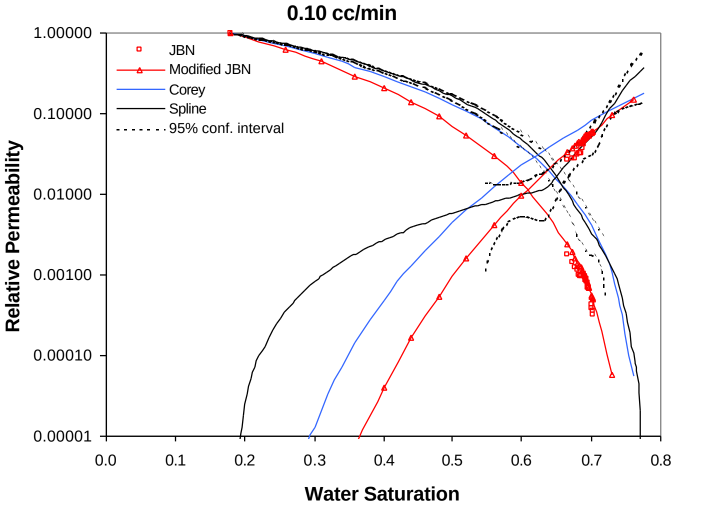

Figure 13. Water and oil relative permeability estimated by different methods (Core B, rate=0.10 cc/min)

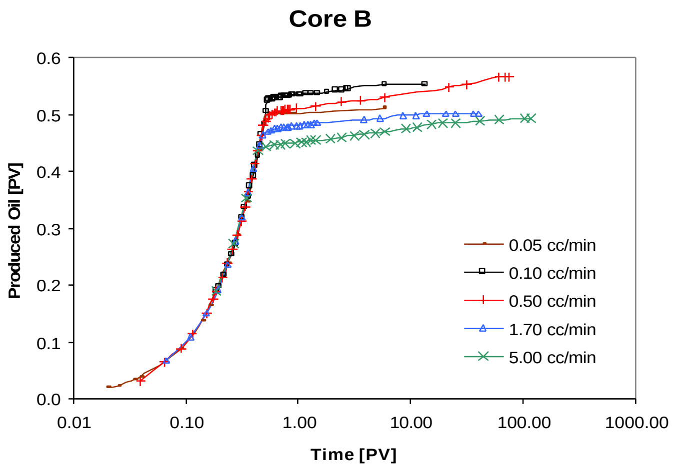

Figure 14. Oil production versus log time for core B at different flow rates

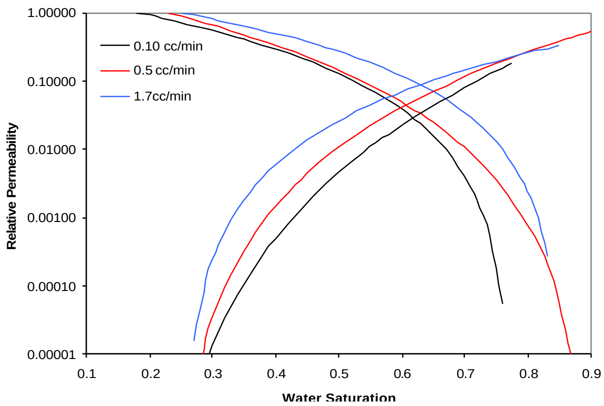

Figure 15. Relative permeability at different rate from history match using Corey fit, core B

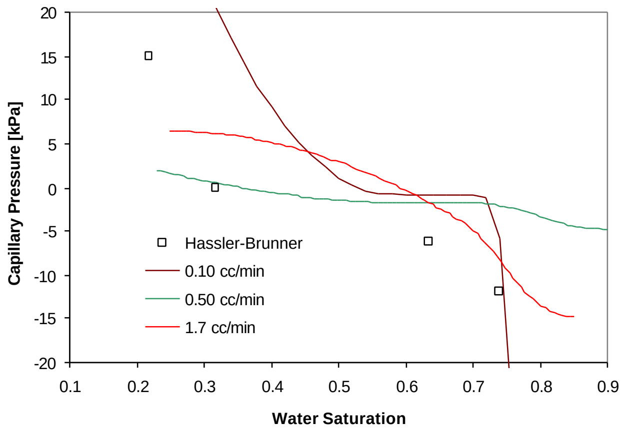

Figure 16. Capillary pressure estimates from history match at different rates, Core B

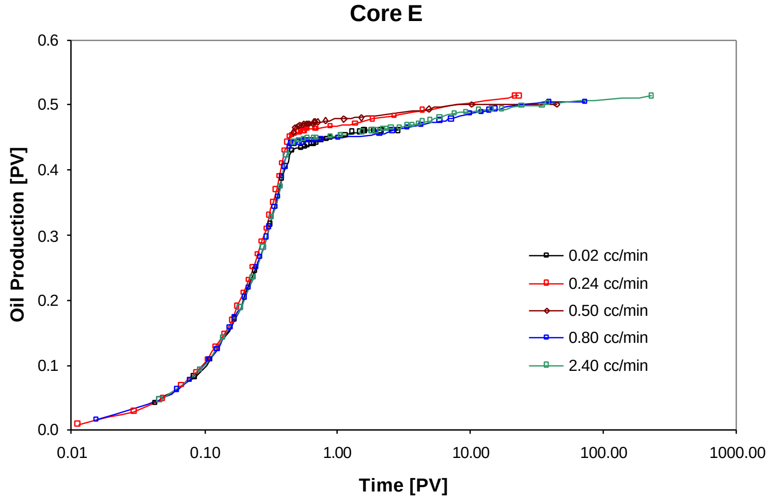

Figure 17. Oil production versus log time for core E at different flow rates

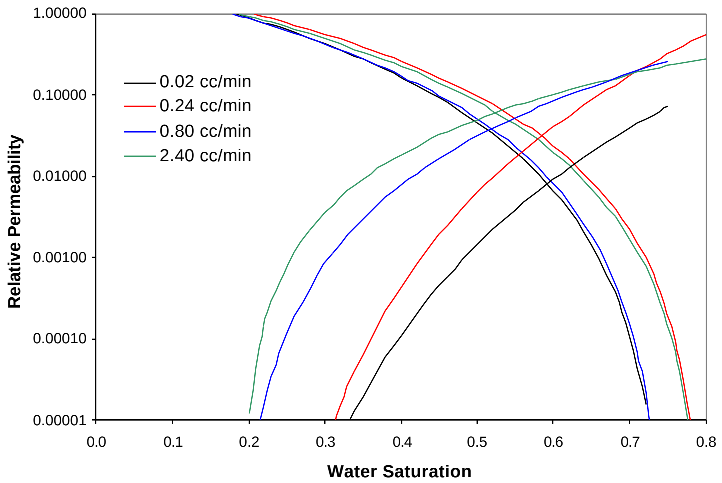

Figure 18. Relative permeability at different rate from history match using Corey fit, core E

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