PERMEABILITY TO RESIDUAL WATER SATURATION IN OIL SATURATED PLUGS

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This paper was prepared for presentation at the International Symposium of the Society of Core Analysts held in Abu Dhabi, UAE, 5-9 October, 2004

ABSTRACT

A series of laboratory experiments have been conducted to determine the permeability of brine close to irreducible water saturations with varying rock types, capillary pressures, saturations and permeabilities. X-ray tomography (*CT*) was used in one experiment as a quality assurance measure, visualizing the distribution of the flow of S_{wi} phase in the sample.

Water-saturated plugs attached to a water-wet ceramic membrane were drained by oil to S_{wi}. Oil was then substituted by water at the inlet keeping both the water- and the oil-saturations in the plug constant. This was done in order to allow for water to flow through the plug and the membrane. A subsurface analogue to this laboratory experiment is a hydrocarbon-filled reservoir that is leaking water through a cap rock or a fault – keeping the hydrocarbons in place.

The *CT* scan images showed that, although the overall flow rate was very low, the injected water moved quickly through the S_{wi}-phase. Only a small fraction of the S_{wi} volume contributed to this flow. The *CT* experiment also revealed some experimental artefacts such as spontaneous imbibition and gravity effects, which warrants further investigation.

The result of the experiments verified that water could flow through different core plugs with varying S_{wi} -phase permeability without forcing the oil through the membrane or changing the water saturation. The residual water permeability was dependent on the water saturation (S_{wi}) and the core plug permeability. Lowering the absolute permeability does not give a similar reduction in water permeability at S_{wi}. The water permeability at S_{wi} ranged from 0.02 μD to 1 μD. The absolute permeability for the different plugs ranged from approximately 0.1 mD to 2000 mD.

INTRODUCTION

Hydrostatic pressured hydrocarbon reservoirs will not leak hydrocarbons through the cap rock as long as the pore throats of the cap rock are sufficiently small to prevent hydrocarbons to enter. Within over-pressured systems, the residual water in oil-saturated reservoirs maybe sufficiently mobile to transfer fluid overpressures from the aquifer below the hydrocarbon contact.

Bjørkum et. al [1] discuss the possibility of the water phase in an oil-saturated reservoir to be mobile enough to maintain hydrostatic pressure gradient in the water phase. This publication has prompted discussions regarding the permeability of the water in oil filled reservoir sands [2] and [3] and Teige et. al. (in press) performed a single experiment to measure the permeability of water at residual saturation [4].

Presented here are a series of measurements performed on different rock types to measure the permeability of water close to residual saturation (S_{wi}). For further information see also Teige et al. (subm. *AAPG*) [5].

The S_{wi} in this study is defined as the residual saturation after a capillary pressure drainage process and not as the irreducible saturation where $k_w = 0$ by definition.

EXPERIMENTAL SET-UP AND PROCEDURES

The experimental set-up consisted of a hydrostatic core holder, including one end-piece with two inlets and one end-piece with one inlet, a low permeable porous membrane, an oil reservoir, a water reservoir, and a graduated separator where fluid discharge was collected (Figure 1).

Establishing the S_{wi} was performed by the standard porous plate drainage method using a Keraflux membrane [6]. In this drainage process, oil pressure is set to a target capillary pressure value and water is produced from the plug through the membrane. The core holder was oriented vertically in this stage, with the porous plate at the bottom.

Following the establishment of S_{wi}, the core holder was shut-in and rotated, with the porous plate on top, to simulate an oil reservoir with an overlying cap rock. The oil at the end piece (now at the bottom of the sample) was replaced by circulating water in the end piece. This was done to ensure that only water was pumped through the core in the next stage.

In the last stage of the experiment, the differential pressure was re-applied, this time across the water phase. Water was then supplied into the core holder through the lower inlet, and the water produced out of the upper outlet (through the porous plate) was logged (Figure 2).

CT Scanner Experiment Set-up and Procedure

For the similar experiment conducted in the *CT* scanner, the core holder was laid in a horizontal position due to the orientation of the *CT*-gantry. The core started out saturated with *NaI* doped brine, which would give good X-ray attenuation contrast to the oil phase during the initial capillary drainage to S_{wi}. The second stage of the experiment should visualize the flow of water through the S_{wi} -phase. First the oil in the inlet end piece was quickly displaced by doped brine and pressure maintained, with *CT*-scanning to observe any spontaneous imbibition and redistribution in the core. Finally the doped brine in the inlet was miscibly displaced by un-doped *NaCl* brine and pressure maintained at the inlet of the core. As the un-doped brine flowed through the plug sample and displaced the S_{wi} brine, the *CT*-images would show this as a lowering of attenuation.

In addition, necessary scans were made to be able to give quantitative results; scans of the core sample saturated with doped and un-doped brine and the *CT*-attenuation of all the fluids. The total salinities of the two brines were selected to give identical densities so that gravity effects would not occur during the experiments.

EXPERIMENTAL RESULTS

One Bentheimer Sandstone, one Berea Sandstone and one low-permeable plug from a North Sea Jurassic sandstone reservoir were used. The plugs covered a large range of permeabilities: from 2 D to less than 0.1 mD (Table 1).

The S_{wi} for the Bentheimer plug was established at 5 bar capillary pressure before start of the experiment. A drainage P_c curve had been measured prior to this experiment, Figure 3. The differential pressure applied during the stage where water was flowing through the S_{wi} -phase was 5 bar (same as for the S_{wi} establishment). The permeability of the plug including the membrane was calculated based on the Darcy's law using the measured rate from the outlet. The thickness and permeability of the membrane is known, and is several magnitudes higher than the calculated total permeability. Thereby the membrane contribution could be neglected.

The test on the Bentheimer Sandstone plug was run a second time to check the reproducibility. Both the tests gave similar k_w (at S_{wi}) values of about 0.7 μD. Figure 4 shows produced volume vs. time for the two experiments. The gradient from the linear regression was used as the rate for the permeability calculation.

For the Berea Sandstone and the North Sea reservoir plugs we used three different capillary pressures to establish three different residual water saturations. The purpose was to see if we could find a relationship between S_{wi} and the corresponding permeability to water.

After establishment of each S_{wi} the core holder was turned up side down, with the membrane at the top, and the permeability of the water was measured. Then the core holder was turned back to a normal drainage position and a higher oil pressure was applied before repeating the sequence again. For Berea Sandstone, differential pressures of 1.5, 5 and 10 bars were used. For the low permeable North Sea plug differential pressures of 2.5, 5 and 10 bars were used. A corresponding k_w was calculated based on Darcy's law for each pressure (Table 1).

The drainage capillary pressure curve for the Berea Sandstone and the North Sea Reservoir plugs were not measured in the same experiment due to lack of saturation control when switching between flooding water and applying oil-pressure on the plug sample. Therefore a Mercury-injection test was performed on plug end-trimmings, and a water/oil drainage capillary pressure curve was calculated based on this test. The curves are plotted in Figure 5. The S_{wi} values in Table 1 is therefore based on calculations from the Mercury-injection test and not mass balance during the experiment, except for the Bentheimer Sandstone plug.

Table 1: Summary of the results

	Diff. Pressure or *Pc*	*kl*, mD @ 20bar NCP	*kw* @ *NCP*	Porosity @ *NCP*	*PV*, ml @ *NCP*	"*Swi*" (from *Hg* inj)	*Q*, ml/d	*kw* @ *Swi*, mD	*krw* (base *kw*)
Bentheimer Sandstone	5 bar		1988	0,224	17,98	0,135	0,5553	0,00071	3,27E-07
Bentheimer Sandstone, repeated	5 bar	2554	1988	0,224	17,98	0,135	0,5928	0,00075	3,79E-07
Berea Sandstone		64	22,6	0,156	8,49				
	1.5 bar					0,625	0,2813	0,00107	4,77E-05
	5 bar					0,286	0,1112	0,00013	5,65E-06
	10 bar					0,232	0,0948	0,000054	2,41E-06
North Sea Jurassic reservoir		0,06	0,062	0,073	3,92				
	2.5 bar					0,762	0,0752	0,00017	2,71E-03
	5 bar					0,665	0,0543	0,00006	9,78E-04
	10 bar					0,47	0,0352	0,00002	3,17E-04

*NCP = Net Confining Pressure

We see from the results that the large difference in absolute plug permeability (factor of 30 000) is relatively much smaller for the residual water permeability (factor of 50). The data indicate that the residual water permeability is dependent on both the saturation (P_c curve) and the plug characteristics (porosity and permeability). The relative permeability to the residual water is calculated using the k_w (measured at 100% S_w) as the base permeability. The relative permeability of the residual water is highest for the low permeable plug, reflecting the much higher S_{wi} (Figure 6).

The uncertainties in the data are linked to the following limitations:

- The experiments have been performed on water-wet plug samples, only.
- The residual water saturations were estimated based on Mercury injection data from plug end trimming and the volumes of the residual water saturation are low (higher uncertainty).
- The possible end-effect of spontaneous imbibition that occurred before initialising the water flowing stage.

Results From the Experiment in the CT Scanner

The same Bentheimer Sandstone plug as in previous experiments was used in the *CT*. The experimental set-up in the *CT* scanner had to be in a horizontal position, introducing an extra uncertainty compared to the previous experiments.

The S_{wi} establishment at 5 bar capillary pressure was *CT* scanned (Figure 7). Note the characteristic shape of the S_w-profile in the vicinity of the porous plate/membrane. The drainage S_w was highest near the membrane at the early stage of the drainage. But as the average core S_w becomes lower, the highest S_w is found near the membrane. The explanation could be that at first, the effective k_w of the core is higher than the Keraflux plate which can not drain the incoming water as fast as it is receiving it. Later in the process, the S_w is much lower and the effective k_w of the core is less than in the Keraflux plate and as a result the plate will drain the nearest part of the plug faster than the incoming water. The S_{wi} calculated from the *CT* scan data was 0,113 (compared to 0,135 from the porous plate method).

The next stage was to visualize how the doped water was replaced by un-doped by flowing in the residual water phase. The first observation to be made was how the water-wet and oil-saturated plug would respond to the water, which replaced the oil in the inlet end piece. The same doped brine as in the S_{wi}-phase was used here to be able to follow water/oil saturation changes. As can be expected, there was some spontaneous imbibition of brine and counter current flow of oil around the inlet end piece. This established slightly higher water saturation close to the inlet, which partly redistributed through the sample. After a few days this was repeated with un-doped brine, to be able to follow the miscible displacement in the S_{wi}-phase. By these contacts with brine, the water saturation of the plug had increased slightly to 0.113. As in the previous experiments, the oil in the plug could not escape through the membrane and the inlet was quickly water filled.

The movement of un-doped brine through the S_{wi} -phase was seen as a front of weak reduction of the *CT*-attenuation. The replacement of the doped water reached the far end of the plug at an early stage, after about 1.5% *PV* un-doped brine injected, long before the “front” of un-doped brine could be seen to reach the outlet. This could be observed by a sudden change in *CT*-values in the porous plate (Figure 8). During this period water was slowly being produced through the porous plate, in agreement with the water injected and the changes observed from the *CT* images. The permeability to water at S_{wi} was calculated to be 0.0003 mD. Crosscut *CT*-images along the core sample (constructed from the cross sectional *CT* slices) demonstrate that the residual water moved in pathways within the core (Figure 9). The residual water flow is patchy, where most of the water flows through a few preferred pathways, and most of the S_{wi} -phase do not contribute. Such scattered flow patterns can reflect the natural heterogeneity of S_{wi}-distribution in the core plug. The vertical image demonstrates the effect the presence of the oil in the inlet end piece has on the flow of water. Figure 10 shows the fraction of S_{wi} -brine replaced by injected, as average values for each *CT*-slice as a function of time. The profiles also illustrate the early breakthrough of the injected water. After 5 days of flowing the experiment was ended by increasing the pressure to force an oil breakthrough.

DISCUSSION

The spontaneous imbibition that occurs at the plug ends when changing from oil phase to water has not affected the purpose of the experiments, which was to prove that water could flow through the residual water saturation in an oil-saturated plugs, and further through a porous plate. The spontaneous imbibition was minimized by shortening the fluid replacement time and by vertically positioning the experiments (except for the *CT* experiment). The horizontal position of the *CT* could have reduced the ability of replacing the oil in the inlet end-piece compared to the vertical position This is supported by the possible gravitational effects seen in the *CT* images (Figures 9) indicating that the uppermost part of the end-piece still contains some oil.

The uncertainty in the measured saturation data is relatively large due to the small pore volumes involved, especially for the low permeable North Sea plug. The water saturation established at each capillary pressure step is more uncertain for the Berea Sandstone and the North Sea plugs due to the lack of water/oil capillary pressure data. However, the data appears to be very consistent regarding the S_{wi}-phase permeability variations.

Also a possible uncertainty is that the variability of the sample wettability has not been taken into account However, our current understanding of the micro-porous network suggests that the S_{wi}-phase permeability will only be weakly influenced by wettability since the majority of the flow should be located in the major (water-wet) pathways within the plugs. Reducing the water wetness will predominantly affect the thin water-wet films coating the rock grain surfaces but these films do not contribute significantly to the flow of the S_{wi}-phase in any case [7].

CONCLUSIONS

The work presented in this paper has involved a series of new experiments, the results of which have demonstrated that water, at a range of residual water saturations, is able to flow through a reservoir rock and through a low permeable barrier without leaking oil.

The variation in the permeability to the residual water phase is several magnitudes smaller than the variation in absolute permeability to the samples.

The work has illustrated a relationship between relative permeability to the residual water phase and (a range of) S_{wi} values, which are again a function of the reservoir parameters like capillary pressure, permeability and porosity.

ACKNOWLEDGEMENT

Statoil is acknowledged for giving permission to present this study. Pål-Eric Øren is also thanked for his contribution in discussing the results from the measurements.

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NOMENCLATURE

CT	Computer Tomography
HC	Hydrocarbon
H_g	Mercury
k_l	Klinkenberg corrected gas permeability
k_r, k_{rw}	Relative permeability, relative permeability to water
k_w	Permeability to water
NaCl	Sodium Chlorine
NaI	Sodium Iodine
NCP	Net confining pressure
P_c	Capillary pressure
PV	Pore Volume
Q	Rate
S_w	Water saturation
S_{wi}	Water saturation, residual

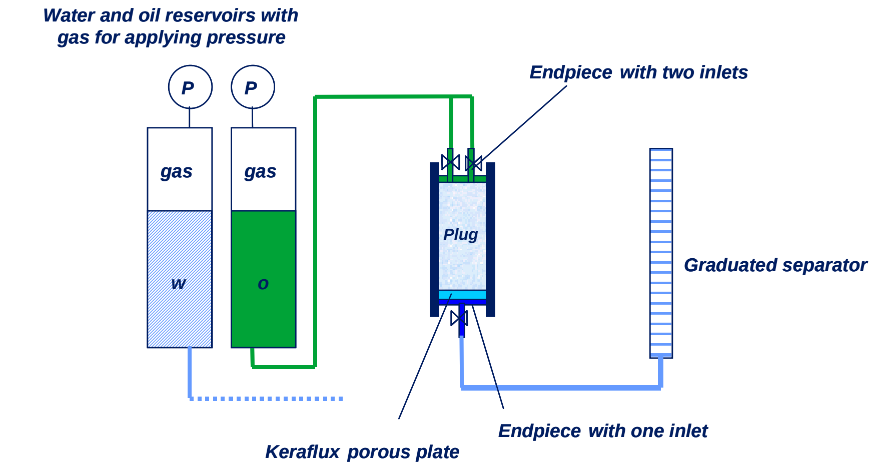


Figure 1: Equipment used in the experiments, here during primary drainage to S_{wi}.

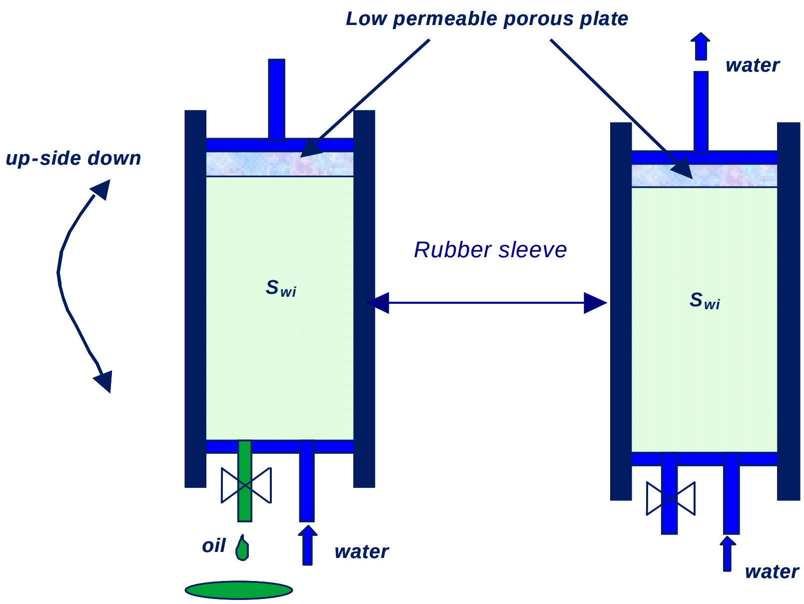


Figure 2: Changing from a capillary pressure drainage set-up to a set-up measuring permeability to the residual water saturation.

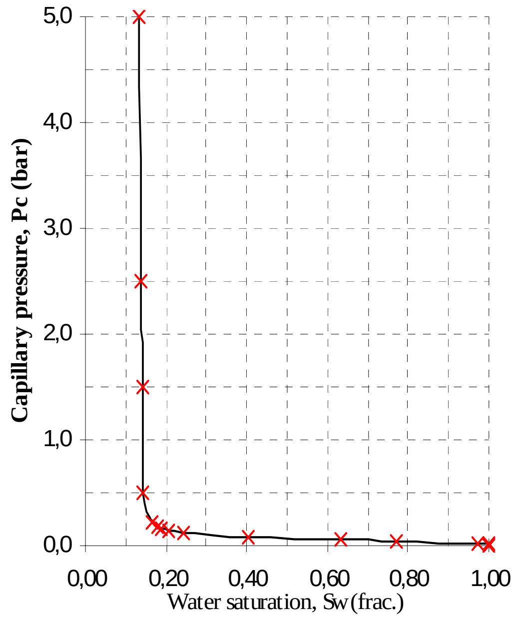


Figure 3: Drainage capillary pressure curve for the Bentheimer Sandstone plug.

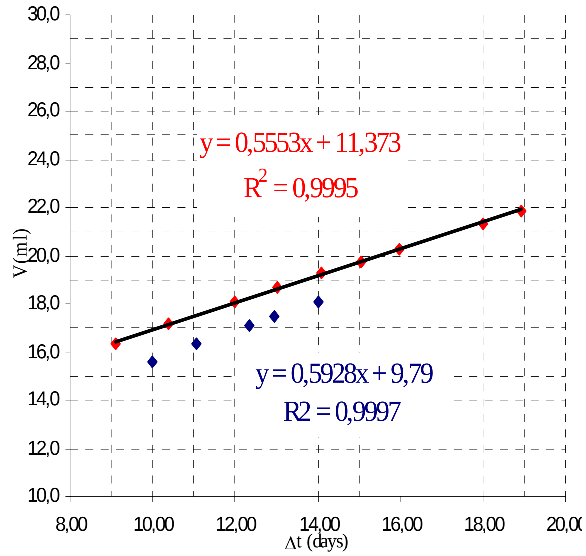


Figure 4: Volume produced during flooding water through the S_{wi}-phase (Bentheimer Sandstone experiments).

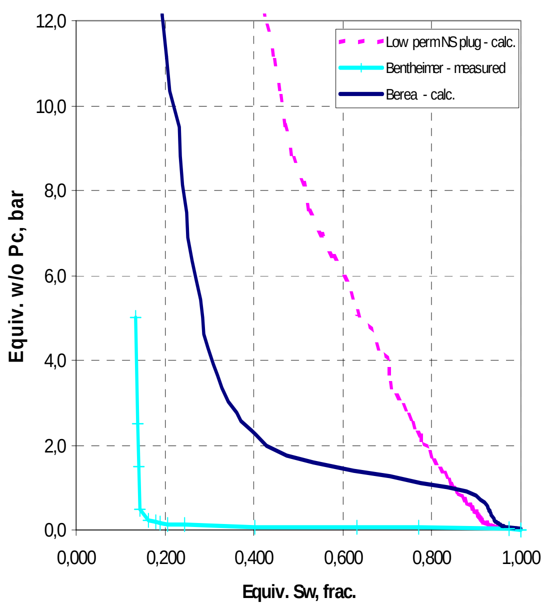


Figure 5: Equivalent oil/water drainage P_c calculated from *Hg*-injection (except for the Bentheimer Sandstone plug in which P_c is measured)

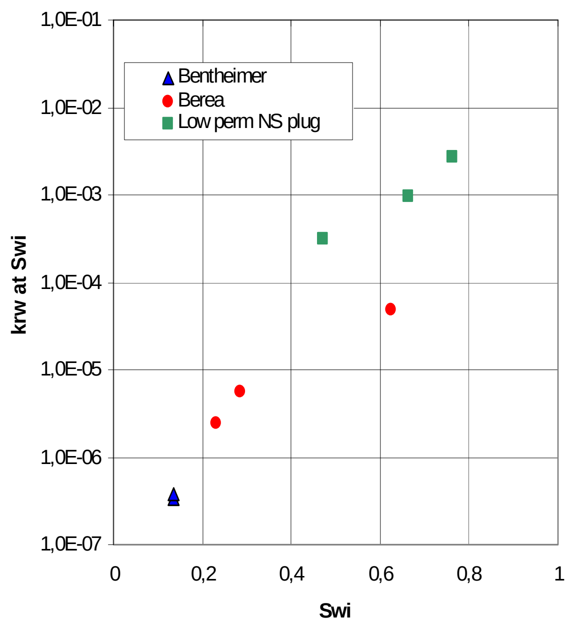


Figure 6: S_{wi} vs. k_{rw} (at S_{wi})

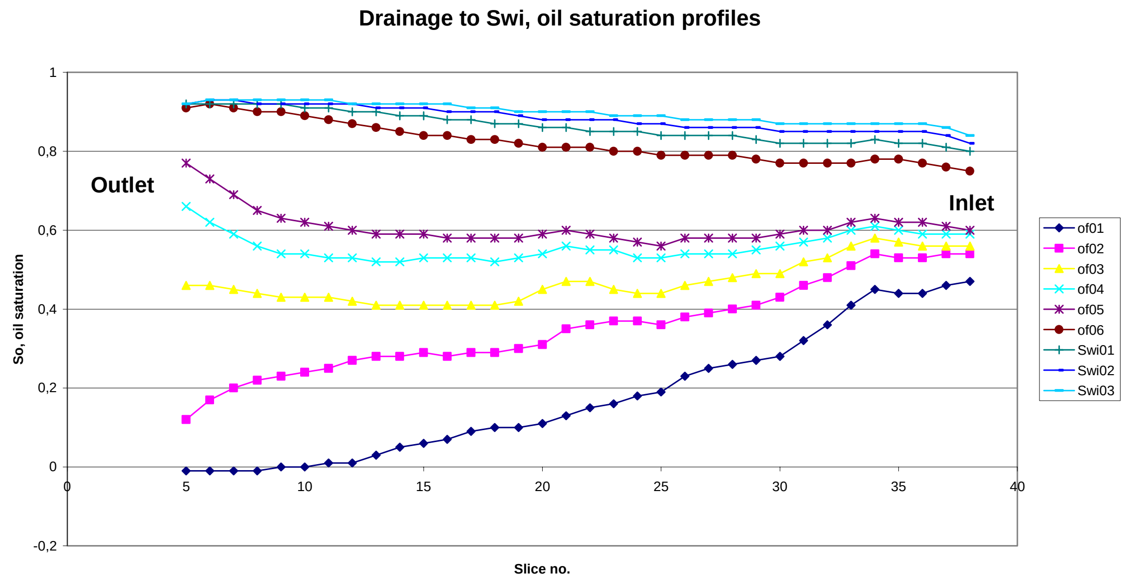


Figure 7: Establishing S_{wi} in the *CT* scanner. The upper most line shows the final oil and water distribution throughout the length of the core plug when the S_{wi} establishment was terminated.

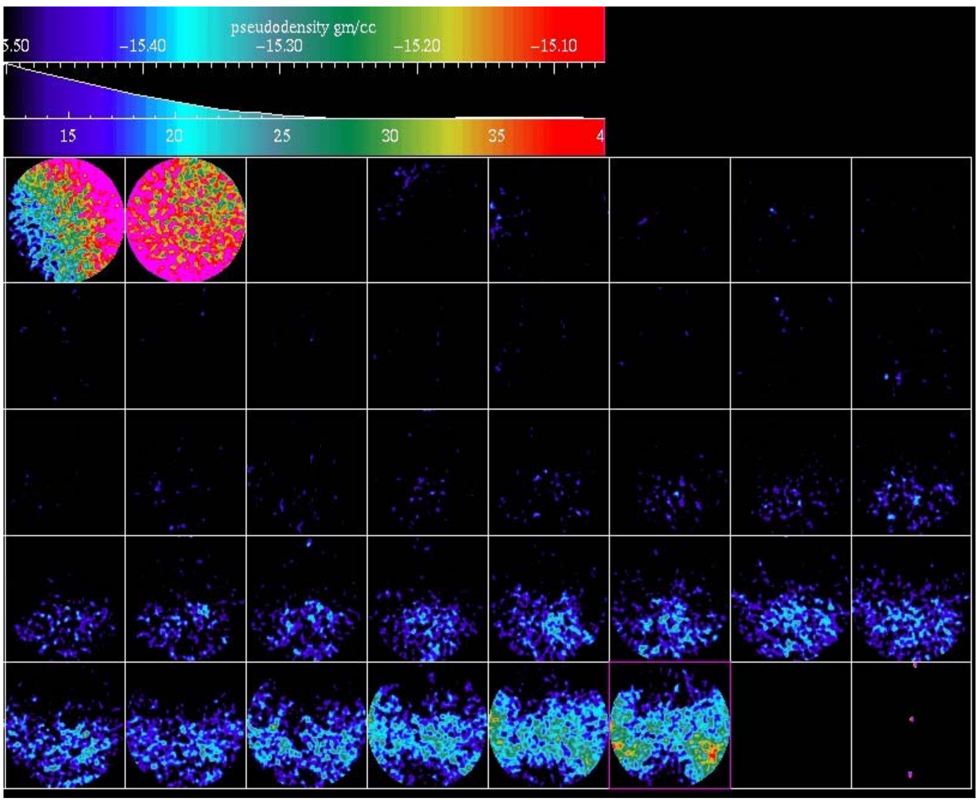
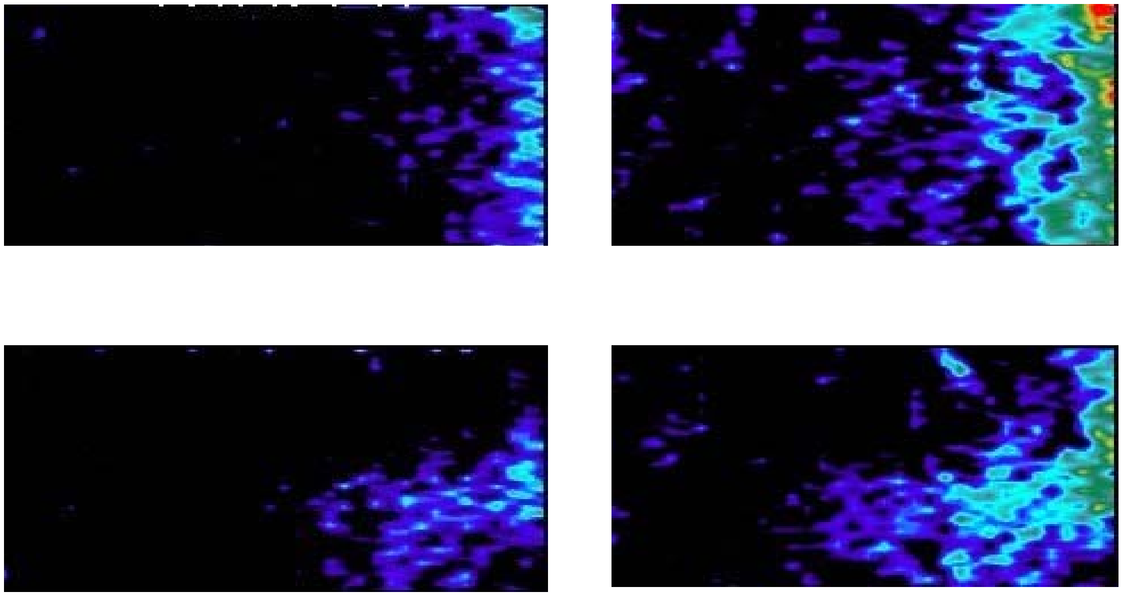


Figure 8: *CT* scan of the doped water phase entering the plug (colour). Upper left corner is the Keraflux Membrane (outlet).



(a) (b)

Figure 9: Images of flow through the S_{wi}-phase along the core at two different times; early (a) and at the end (b). Two perpendicular views at each time: horizontal (top) and vertical (bottom).

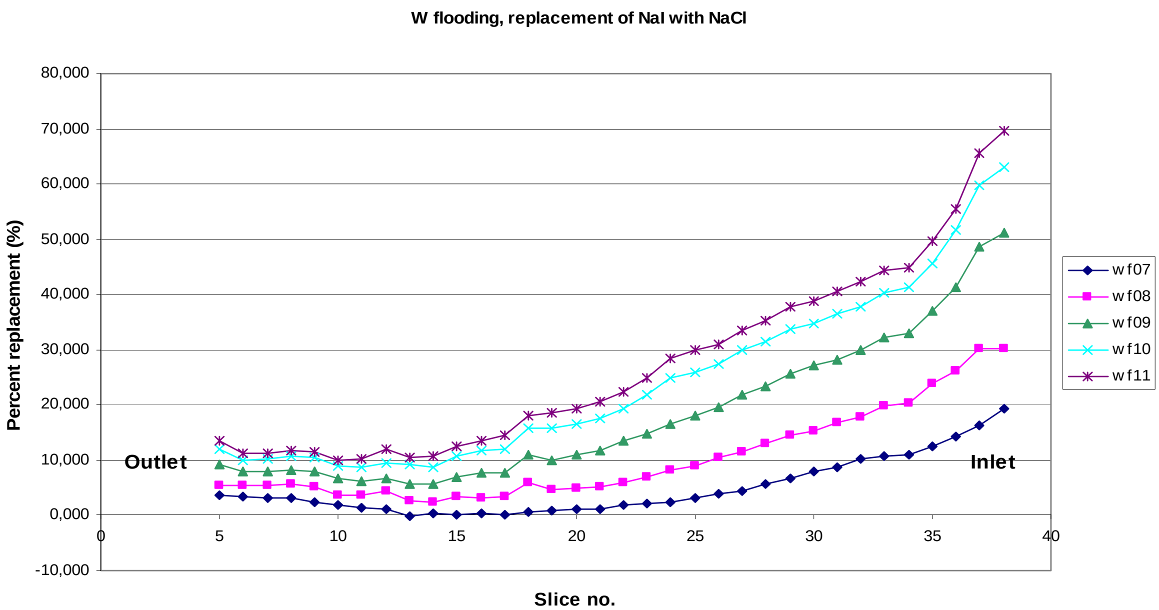


Figure 10: The percent of the S_{wi} -water replaced by doped water during the experiment. The injected water had already reached the outlet after the first scan (wf7), after about 24 hours. The injected water was approx. 1.5% of *PV* (or approx. 15% of the S_{wi}-*PV*)