IMPROVEMENTS OF COREFLOOD DESIGN AND INTERPRETATION USING A NEW SOFTWARE.

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ABSTRACT :

A new software package (CAROPT) has been developed for the interpretation of relative permeability experiments. In CAROPT the flow functions (i.e. relative permeabilities and capillary pressure) are adjusted in an optimisation procedure until the experimental observations are matched as closely as possible by numerical simulations of the experiments. CAROPT is designed for the interpretation of unsteady-state , steady-state and centrifuge experiments. The software performs two types of linear error analysis for the assessment of uncertainties arising from errors in the experimental data. The first type is an error bar calculation for the individual points on the flow function curves. The second type results in a complete set of «optimistic» and «pessimistic» relative permeability curves. In the present paper, we demonstrate the field of application of the software using real examples including experimental design and advanced interpretation :

1. In Steady-State experiments, standard interpretation methods are time consuming because long stabilisation time are required and because they do not account for capillary effects. CAROPT was used to find an experimental design that optimises accuracy on both flow functions over a wide range of saturation and cost of the experiment.
2. It is commonly accepted that Unsteady-State waterfloods should be performed under field rate, especially when mobility ratios are unfavourable, in order to prevent unstable displacement. The experiments are usually followed by bumps to satisfy the Rapoport criterion and check the existence of an end effect. It has been observed on very permeable samples (1-10 Darcy) through in situ saturation measurements, that field rates can lead to strong saturation variations along the core even in homogeneous samples. CAROPT was used for the interpretation of experiments performed on unconsolidated samples using both an homogeneous and an heterogeneous model. The impact of the heterogeneity on the flow functions is demonstrated and the use of saturation profiles for flow functions determination is highlighted.

INTRODUCTION :

Relative permeabilities are an important issue for the assessment of the recovery of an oil field. Three different experimental techniques are currently used in SCAL laboratories : Unsteady State, Steady State and centrifugation. Interpretation techniques have been developed to calculate analytically the relative permeabilities curves when capillary effects are negligible like the JBN method for the Unsteady-State experiment. When the capillary effects have a significant influence, solutions of the problem become much more complex. Another approach is to use a simulator to solve the non-linear partial differential equations describing the flow mechanism within the core. Flow functions are the input parameters of the simulation and oil production and/or pressure drop the output data. We need then to solve the inverse problem that is find the parameters that give the best match between the simulation and the experimental data. This method also known as parameter estimation consists in the following steps :

- The first step consists in the formulation of the inverse problem as an optimisation problem with an objective function defined as the weighted sum of squares of the differences between the measured and the simulated data. A numerical optimisation algorithm is used to find the solution and the corresponding flow functions.
- The second step consists in a sensitivity analysis that determines a confidence interval based on errors in the measured data. At this stage, the question of the uniqueness of the solution of our problem is considered(1). A different approach consists in calculating for a required resolution on each parameter, the CTB coefficients (Contribution of an observation) to check whether the parameter is identifiable or not (2).

Elf Exploration Production has developed a program called CAROPT that links an in-house simulator Z2C to a commercial optimisation package developed at Stanford University called Npsol. Previous works on the main features of CAROPT and its use for flooding experiments interpretation have been published (3). Since, CAROPT has been upgraded to account for heterogeneity in capillary pressure curves and extended to all kind of experiments performed in our laboratory (Steady-State, Centrifuge). The error calculation module has been improved to allow calculation of error curves according to various criteria (Break-Through, Recovery).
The main topic of this paper is to focus on some applications of this software in water flooding experiments interpretation. In the first part, we illustrate how CAROPT can be used for the optimal design of a Steady-State experiment. In the second part, we give a concrete example of how using CAROPT in a complex interpretation of water-oil flooding where cross-bedding heterogeneity is accounted for.

PART I: DESIGN OF A STEADY-STATE OIL/WATER IMBIBITION

Traditional Steady-State experimental designs like the Penn State method are widely used in the core analysis laboratories. They usually consist in injecting both displacing and displaced phases at different fractional flow in a saturated core and wait for stabilisation (pressure drop and/or saturation changes). High rates are used to minimise the end effect. Hence capillary pressure is not taken into account in the interpretation methods which suppose a uniform saturation along the core at the equilibrium. The relative permeabilities are then calculated using the direct application of the Darcy law in each phase. However, those methods present several drawbacks : Stabilisation can be very long to achieve and thus not cost effective. Capillary pressure effects are indeed minimised but the influence on the interpretation method can not be assessed. To avoid this, some authors have proposed more complex interpretations (4) in order to take the end effect into account, but this requires separate capillary pressure measurements and more stabilised steps (with varying total rates). Parameter estimation is an alternative method, which avoids the main drawbacks of classical design with analytical interpretation:

- Transient flows are taken into account and long stabilisation times are no longer required.
- Both flow functions can be determined simultaneously in a unique experiment.

Urkedal (5) has proposed an experimental design for the oil/water drainage case. But we are not aware of any investigation that has been performed for oil/water imbibition which is of bigger interest for reservoir engineering. However, the results obtained by Urkedal are interesting because they confirm some intuitive considerations :

- When the experimental design includes only changes in fractional flow, the parameters can not be well estimated if the capillary pressure is not negligible.
- When experimental design includes at the end of the experiment increases of the total rate, it is possible to determine both the relative permeabilities and the capillary pressure by modifying the ratio between the viscous and the capillary forces. Those results have been widely demonstrated for Unsteady-State experiments (1-3) and were extended to Steady-State by Urkedal for a drainage oil/water flood.

However, this design, as it will be shown later is not sufficient in the case of an oil/water imbibition because the bumps will modify the balance between the viscous forces and the negative capillary forces only. It is thus not possible to get information either on the positive branch of the capillary pressure curve or on the relative permeability at the corresponding saturation. We propose a new experimental design including total rate variations at low water fractional flow that allows relative permeability calculations over the entire range of saturation.

Validation of an experimental design : First a synthetic case is studied to help in choosing an experimental design. The core properties were chosen as given in table IIa. The flow functions were chosen as representative of an intermediate wet case (see Fig II 1-2). Three experimental designs A,B & C (table IIb) were studied. For each, a linear covariance analysis was performed and error bars were calculated using relevant error estimates for the oil production and pressure drop. The results are given in Fig II 1 & 2. The error bars are joined to allow an easy comparison between the different designs (some curves are superimposed):

- As expected, the design A is not adapted to give both flow functions except in the medium saturation range where the capillary effects are negligible.
- Scenario B gives better results especially in the high saturation region where the bumps are performed. This clearly shows the benefit of those bumps. The accuracy on both flow functions and capillary pressure at low water saturation remains poor. This design corresponds to the design proposed by Urkedal (5) for an oil-water drainage.
- Scenario C gives the best estimation over the entire range of saturation.

Use of the experimental design : Following the recommendations of the experimental design study, a water-oil imbibition was performed on a carbonate sample. The core properties are given in table IIc. The design was chosen as in table IId. An interpretation was performed using CAROPT. The flow functions with error bars are given in Fig II8&9. The numerical capillary pressure was compared to measurements by restored state performed on a nearby plug (Table IIc). A few points were available because after Swi was reached, the capillary pressure was directly dropped to zero. Negative capillary pressure used were quite large resulting in a rapid increase in water saturation. As one can see:

- There is a good agreement between numerical and experimental Pc for the end point saturation (Swi-Sorw). Swi was higher for the plug because the maximum capillary pressure used was limited to 6 bars (12 bars for the full size sample).
- The experiment was designed in such a way that both positive and negative capillary pressure could be determined accurately. As shown by the error bars, the 0 capillary pressure point then could be found with a good accuracy under such conditions. This is confirmed by the experiment since both saturation are very close (0.53 & 0.56).

Some authors have questioned the interest of measuring flow functions at low saturation since they will play only a small role in the frontal flow mechanism occurring in the reservoir. In fact, positive capillary pressure could have a significant effect on the upscaling process by increasing the cross flow between the layers of the grid block.

PARTII HETEROGENEOUS CORE FLOOD INTERPRETATION

Heterogeneity is a key aspect in the determination of the relative permeabilities determination. A good sampling strategy for SCAL measurements usually consists in selecting one core sample per rock type, assuming the uniqueness of the flow properties in the entire reservoir for that particular rock type. Nevertheless, other petrophysical parameters (permeability, porosity, end point saturation, capillary pressure curves) are seldom homogeneous for the entire core. Honarpour (6) has shown, comparing relative permeabilities for both cross and parallel to the flow laminated bedding that another key parameter is the structure of the heterogeneity itself. Many papers have been published in the past, investigating the impact of the heterogeneity distribution and magnitude on the relative permeabilities determination. Some of them have limited their work to heterogeneity in porosity/permeability. Others have tried to go further by integrating heterogeneity in flow functions (capillary pressure (7) and relative permeabilities (8)) through the use of different initial water and residual oil saturation given by in-situ measurements. Both cross-bedding and parallel bedding were studied. This approach was nevertheless limited by the large number of parameters required to represent the flow functions,which is very time consuming with the optimisation process. Thus, a strong hypothesis had to be made by considering a unique relative permeability and capillary pressure function vs a normalised water saturation calculated using the end point saturation. The major improvement of this approach lies in the fact that simulated saturation profiles can better recreate the non monotonic variations along the core. This was not possible considering heterogeneities only in permeability. This method appears to be a comprehensive way of accounting for the heterogeneity of a core. This is the case for example when the scale of the layering is low compared to the dimension of the core and when the contrast in heterogeneity is high (small scale laminae). In that particular case, the core is made up pieces of various rock types and significant initial water saturation distribution resulting in significant wettability changes. According to our experience, this appears to be the case only for a few reservoirs. In most cases, the permeability distribution within the core usually varies in a range 1-3 SU. Since capillary pressure curves are not permeability normalised functions (contrary to relative permeabilities), they will also vary the same way. Nevertheless, initial water saturation established under high capillary forces will vary in a range 1-3 SU along the core and thus can be considered uniform.

At the core analysis laboratory of Elf Exploration Production, samples used for waterflooding experiments are cored vertically over the maximum possible diameter and length in the preserved zone of the core. This sampling strategy results in dealing with pore volumes between 80 and 250 cc reducing the relative uncertainties in dead volumes. Another consequence is the cross bedding structure of the heterogeneity.

An important remark has to be made at this stage. Most of the SCAL laboratories usually work on horizontally plugged samples stacked together to increase the length of the core. Saturation profiles have shown in that case that there are large saturation variations at the interfaces between the plugs indicating discontinuities in the porous medium. As a result, in both cases the interpretation will have to cope with cross-bedding heterogeneities and the flow process should be considered 1D. This is the main assumption in what follows. An important issue here will be to check whether this permeability distribution has an important impact or not on the flow mechanism taking place in the porous medium. In fact, the impact of heterogeneity strongly depends on the equilibrium between the capillary and the viscous forces at the core scale.

Cross bedding heterogeneity (influence of the capillary pressure) : We consider an unsteady-state waterflood on a composite core made up two plugs stacked together with different permeabilities (case a1) and both different permeabilities and capillary pressure curves (case a2 - Figure III1). Figure III2 shows the saturation profiles along the core for both cases at two different rates. For case a1, the saturation profile changes monotonically. For case a2, a jump is observed at the interface between the two plugs. When the rate is increased, the magnitude of the jump is reduced. This "inner effect" is caused by the discontinuity of the porous medium whereas the pressures in both phases are continuous. The continuity in capillary pressure at the interface will create a saturation jump. At a high flow rate, if residual oil saturation for both capillary pressure curves are close, no saturation jump will be observed. The magnitude of the jump for a given core will depend on the magnitude of the viscous forces compared to the capillary forces. This phenomenon was detailed by Langaas (9). In a similar way that the end effect influences the calculation of relative permeabilities, the "inner effect" will lead to wrong relative permeabilities if not properly accounted for. The synthetic experimental data (oil production and pressure drop) of case a1 and a2 were then history-matched using an homogeneous model to assess the impact of both kind of heterogeneity. Fig III3 shows the corresponding relative permeabilities. The case where capillary pressure curves are different shows much higher discrepancies from the true curves than the case where only heterogeneity in permeability is considered. Langaas showed that when the capillary pressure was scaled with a Leverett function, the impact of the heterogeneity for a given rate increased as the permeability increased i.e. high permeable samples are more subject to saturation gradients than low permeable samples. This is a very important observation. In an imbibition process, no obvious scaling of the capillary pressure with permeability has been identified, but people usually agree that the dependence of the capillary pressure with permeability will be weaker than for a drainage process. Thus, the observation made above can be extended to an imbibition process. Our laboratory is dealing more and more with unconsolidated cores from deep offshore. Their permeabilities range between 1 and 10 Darcy. The previous observations make us aware of the necessity to integrate the heterogeneity in the interpretation process. This is corroborated by our observations of the in situ saturation profiles which show a strong heterogeneous behaviour.

Heterogeneity characterisation: To achieve a realistic heterogeneous interpretation it is necessary to quantify the heterogeneity of the core. Several methods are currently used by the laboratories :

- Miniprobe test which gives a surface mapping of the permeability of the core.
- Gamma ray profiles can be used to determine porosity along the core. Permeability vs porosity plots correlation plots are then used to calculate permeability along the core.

In unconsolidated sands, none of those methods are available because mini probe can be performed on consolidated samples only and because permeability-porosity correlations are seldom observed. After cleaning we perform a tracer test to discard samples with along to the flow bedding heterogeneities because they have the bigger impact on the interpretation of Unsteady-State flooding (10) and can not be modelled in the simulator because of the restriction to a 1D grid. Furthermore, we have developed a method to quantify cross bedding heterogeneities using the drainage process for initial water saturation setting. The method consists in injecting at a high rate (100 cc/hr) a high viscous oil (Marcol 172 : 75 cpo) into the sample saturated with water and recording the evolution in the pressure drop with time until the breakthrough is reached. The interpretation method is detailed in Appendix II. Some hypothesis have to be made :

- The viscous forces are high compared to the capillary forces. The previous remark has pointed out that this may not be always the case, especially when the permeability is very high. But given the viscosity of the oil (75 cpo) and the high injecting rate, this assumption is usually correct. It is possible to check its validity by comparing the pressure jump observed as the oil reaches the inlet face and the overall increase in pressure drop before the breakthrough.
- The displacing front in the sample is assumed to be very sharp (high viscosity ratio).
- Permeabilities in both phases are close: In a drainage process after cleaning, the sample has been rendered water wet. Thus, oil permeability at connate saturation is very close to the absolute brine permeability. Since the viscosity ratio is very high (75), the front will be very sharp.

The permeability is calculated, using time as a parameter :

$$\boxed{K(t) = \frac{Q^2(\mu o - \mu w)}{A^2 \phi (1 - Swi) \cdot \left(\frac{\partial \Delta P(t)}{\partial t} \right)}}$$

See APPENDIX Part I

Experiment : A waterflooding experiment was performed on an unconsolidated sand sample from a deep water reservoir. The characteristic of the sample are given in table IIIb as well as the properties of the fluids used. The wettability was found intermediate wet according to restored state capillary pressure measurements on the same field. During the drainage process, the DP was recorded (Figure III 4). The method previously described was used to calculate the variation in permeability along the flow direction axis (see table

IIIc). In fact, since water is still produced after the breakthrough, the permeability increases and it is necessary to scale the permeabilities found for each layer in order to be consistent with the overall permeability measured for the sample once irreducible saturation is reached and after ageing.

The waterflooding imbibition was performed at field rate. Once the oil production was stabilised, the water rate was increased several times till no additional oil was produced (bumps). The experimental data were the oil production, the pressure drop along the core and in-situ saturation measurements using gamma ray. Since long counting times are required by the gamma ray technique to achieve sufficient accuracy in the saturation measurement, dynamic profiles before breakthrough were discarded because they were measured with less counting times. A good agreement was observed between the average saturation within the core calculated by material balance and gamma ray (within 2 SU). In the following we will only consider the stabilised profiles performed at the end of each rate step, respectively 20cc/hr, 40 cc/hr and 80 cc/hr (Figure III6). The oil is trapped in the lower permeability layers. At high rate, the saturation profiles become uniform on the entire length of the core. The initial water saturation is similarly uniform (see profiles). Thus, the following conclusions can be made :

- Permeability changes along the core.
- Residual oil saturation changes are also observed, as a consequence of the discontinuity in capillary pressure functions.
- When the inner effects are squeezed by the viscous forces (last bumps), the saturation are uniform along the core, indicating that the asymptotic values of the capillary pressure curves are the identical i.e. residual oil saturation are the same.
- The same observation can be made on the measured connate water saturation established at a high flow rate (high viscous forces).

As a consequence, since end point saturation are identical, the problem should be modelled by a single relative permeability curve. Different capillary pressure curves should nevertheless be used to account for the discontinuity observed in the porous medium.

Parameter estimation : In this part, we discuss the parameter estimation procedure that is used to find the relative permeabilities of the core. Here we mean by parameters the relative permeabilities and the different capillary pressure functions. The sample was initially divided into 9 segments of different permeabilities. It would be possible to assign one capillary pressure function to each zone but that would result in a large number of parameters and slow convergence of the software. So we decided to make some grouping in order to reduce the number of capillary pressure curves to 2.

- Pc1 was assigned to the low permeability zone(<5D).
- Pc2 was assigned to the high permeability zones(>5D).

No hypothesis was made neither on the shape of the capillary pressure functions nor on their scaling with the permeability. The parameters used for the interpretation are made up two capillary pressure curves and a relative permeability function.

The gridding was refined at the boundaries between the different zones (where the saturation changes sharply) to avoid numerical dispersion.

A first interpretation was performed with an homogeneous model. The matched relative permeabilities (figure III8) were used to initialise the heterogeneous model. The capillary pressure curve was scaled at 2D for Pc1 and 7D for Pc2 using a Leverett function. Those parameters will be used later for a sensitivity analysis. A direct run was performed. Saturation profiles were simulated and compared to the true profiles. We give both rough and 1cm scale averaged simulated profile in Figure III6. As one can see, the capillary pressures used recreate well the heterogeneity observed on in situ measurements. The saturation profiles help in validating the rock type grouping previously made.

At this stage, we have to perform a sensitivity analysis to check if the different parameters will be identifiable and see the impact of the saturation profiles in reducing uncertainties. Error bars were calculated with the following error on the experimental measured data : DP (1 mbar), oil production (0.5 cc), saturation profiles (3 SU). In a first calculation the saturation profiles were taken into account with a smoothing of 1cm along the. In a second run, they were removed. The comparison of the error calculation on the parameters shows:

- Parameters at low water saturation will not be identifiable. This is an obvious result for unsteady-State waterfloods. As a result, few parameters will be used in the corresponding region and the capillary pressure will be locked to zero at initial water saturation because positive values will not be identifiable.
- The saturation profiles help to reduce the uncertainties on the parameters at high water saturation. Hence profiles will be used in the optimisation process with the averaging option.

Results: The result of the parameter estimation process in the heterogeneous case shows:

- The use of saturation profiles gives a better match to the measured data than in the homogeneous case, especially saturation profiles (Figure III7).
- The capillary pressure curves matched (Fig III9) are relevant since they seem to correlate with the permeability of the segment.
- The matched relative permeabilities curves for both the homogeneous and heterogeneous model are significantly different and the dispersion is far above the estimated error on the parameters (Figure III8). The comparison between both curves shows that the oil relative permeability is underestimated and water permeability curve is sharpened when the heterogeneity is not accounted for, leading to pessimistic recovery but optimistic break through.

CONCLUSION :

- A new design for Steady-State experiments is proposed in the case of a water/oil imbibition flooding which gives better accuracy than the previous methods over the entire range of saturation and allows positive imbibition capillary pressure determination.
- We have emphasised that cross-bedding heterogeneities are impossible to avoid in the cores used for SCAL experiments. Thus, we have developed and validated a simple technique that allows the determination of the 1D permeability along the core sample using the data measured during the drainage process.

- We have demonstrated the impact of heterogeneity in capillary pressure on the calculation of relative permeabilities. This impact increases as the permeability of the core increases.
- We have compared homogeneous and heterogeneous interpretation of a water oil flooding experiment performed on an unconsolidated sand with in situ saturation measurements. The parameter estimation process was much improved by including saturation profiles. The quality of the matching of the observed data (pressure drop, oil production and saturation profiles) was much improved when heterogeneity was accounted for.

NOMENCLATURE :

A: Core section.
L: core length.
Q: rate.
Sw : Water saturation.
ϕ : Porosity.
μ : Viscosity.

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APPENDIX PART I

Table IIa		Table IIb								
		Design A			Design B			Design C		
		T (min)	Qo (cc/hr)	Qw (cc/hr)	T (min)	Qo (cc/hr)	Qw (cc/hr)	T (min)	Qo (cc/hr)	Qw (cc/hr)
	Core	0	30	0	0	30	0	0	120	0
Length (cm)	24.5	5000	29.7	0.3	5000	29.7	0.3	1000	120	0.3
Diameter (cm)	5	10000	27	3	10000	27	3	5000	60	0.3
Phi (frac)	30	15000	15	15	15000	15	15	10000	29.7	0.3
Swi (frac)	0.255	20000	3	27	20000	3	27	15000	27	3
Ko(Swi) (mD)	1000	25000	0.3	29.7	25000	0.3	29.7	20000	15	15
		30000	0	30	30000	0	30	25000	3	27
					35000	0	70	30000	0.3	29.7
					40000	0	180	35000	0	30
								40000	0	70
								45000	0	180

Figure II 1 : Comparison of the error bars for different designs

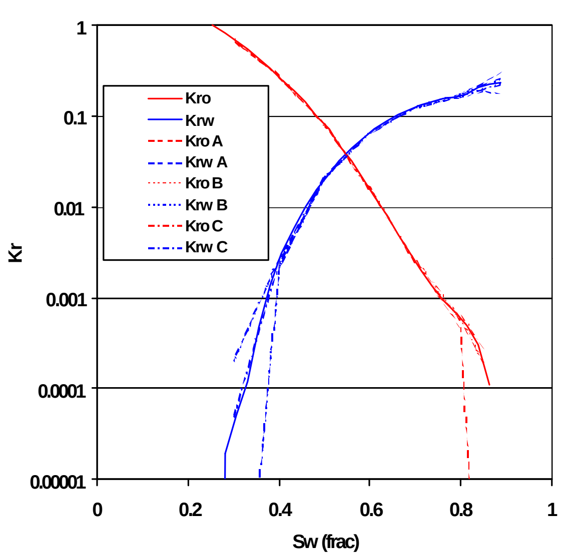

Fig II 2 : Error bars on capillary pressure for different designs

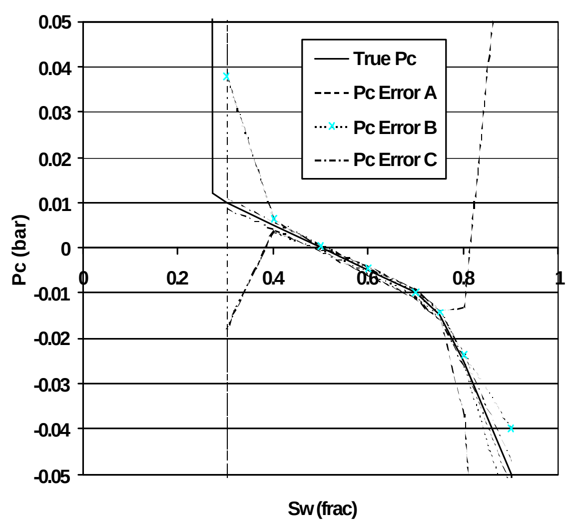

Table IIc			Table IId		
	Full Size	Plug	T (min)	Qo (cc/hr)	Qw (cc/hr)
Length (cm)	23.5	5.13	0	100	0.1
Diameter (cm)	5	3.984	11510	10	0.1
Phi (frac)	14.7	17.2	21090	9	1
Kg (mD)	10	40	22920	5	5
Rhos (g/cc)	2.72	2.706	26925	1	9
Swi (frac)	0.27	0.31	29770	0.1	10
Sor (frac)	0.28	0.26	37200	0	10
			47030	0	30
			51430	0	90

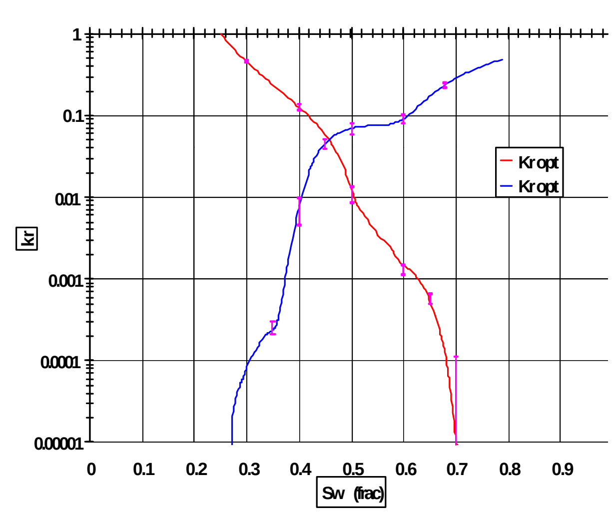

Figure II 8 : Relative permeabilities with error bars

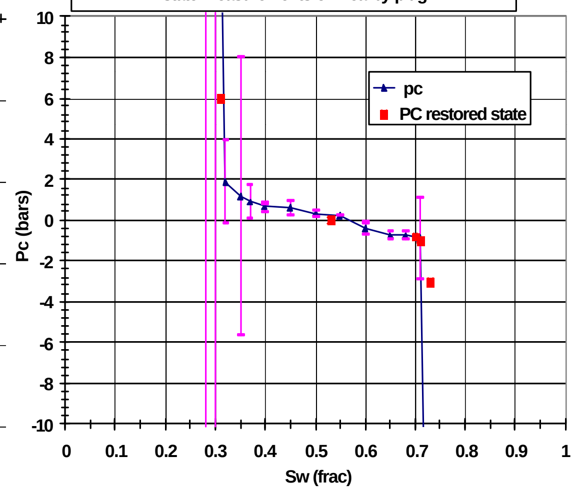

Figure II 9 : Comparison between numerical Pc and restored state measurements on nearby plug

APPENDIX PART II : Heterogeneity mapping :DP(t) is the pressure drop across the core. If the capillary pressure is neglected and if we assume that the displacement is piston like, DP can be written as the sum of the DP in the water phase (inlet-front) and the DP in the oil phase (front-outlet):

$$DP(t) = \int_0^{Xf} \frac{Q.mo}{A.K(x)}.dx + \int_{Xf}^{L} \frac{Q.mw}{A.K(x)}.dx$$

(1) where Xf designates the position of the front

$$Xf = \frac{Q}{A.f.(1-Swi)}.t \quad (2) \qquad \frac{\partial DP(t)}{\partial t} = \frac{Q}{A.f.(1-Swi)}\left(\frac{Q.mo}{A.K(xf)} - \frac{Q.mw}{A.K(xf)}\right)$$

$$K(t) = \frac{Q^2(mo-mw)}{A^2.f.(1-Swi).\left(\frac{\partial DP(t)}{\partial t}\right)}$$

We have a relation between K and Xf.

Case a1	1st but	2nd but	Case a2	1st but	2nd but
Length (cm)	10	10	Length (cm)	10	10
Diameter (cm)	5	5	Diameter (cm)	5	5
Porosity (%)	30	30	Porosity (%)	30	30
Swi (%)	25.5	25.5	Swi (%)	25.5	25.5
Ko (Swi) (mD)	1000	5000	Ko (Swi) (mD)	1000	5000
Capillary pressure	Pc1	Pc1	Capillary pressure	Pc1	Pc2

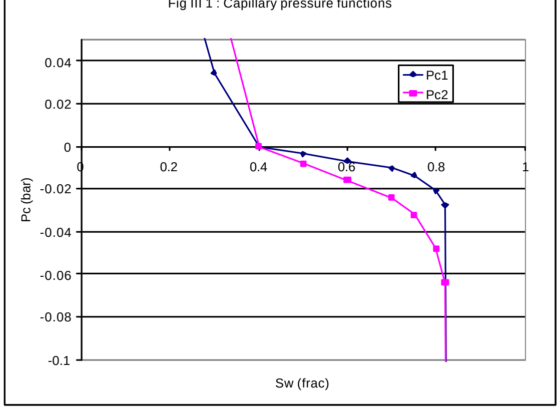

Fig III 1 : Capillary pressure functions

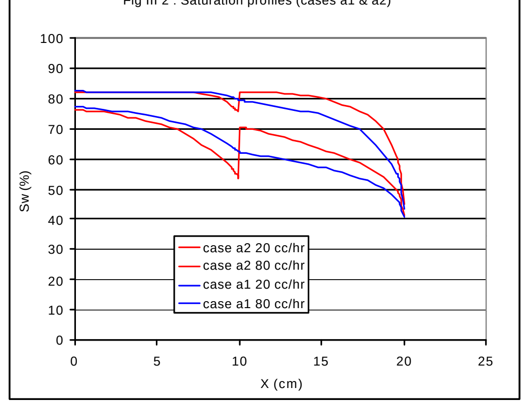

Fig III 2 : Saturation profiles (cases a1 & a2)

Figure III 3 : Effect of the heterogeneity on the relative permeabilities case a1 & a2

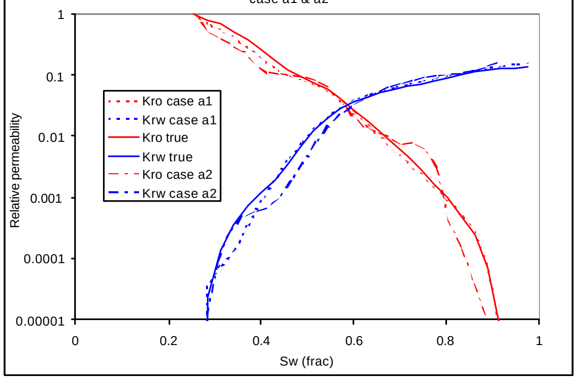

Figure III 4 :Pressure drop logging during drainage

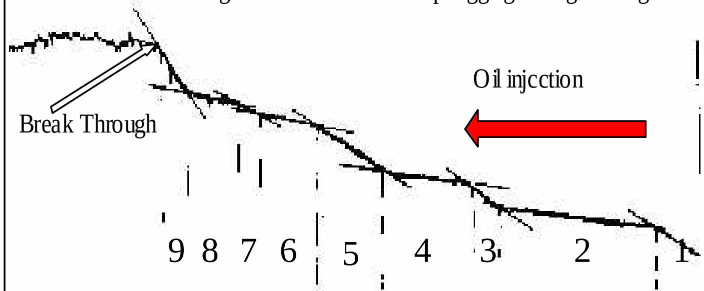

Table III b : Experiment

Core	Length (cm)	23
	Diameter (cm)	5
	Phi (%)	29.6
	Swi(%)	15.8
	Ko(Swi) (mD)	5700
Fluids	Temperature (°C)	65
	Oil viscosity (cpo)	6.3
	Oil density (g/cc)	0.98
	Water viscosity (cpo)	0.659
	Water density (g/cc)	1.03

Table III c : Permeability vs X

X(cm)	K(x) (mD)
2	4200
9	9000
10.5	4000
14.5	10000
16.5	4500
18.5	7500
19.5	4200
21.5	7000
23.0	2500

Figure III 6 : Comparison between experimental & simulated profiles without matching

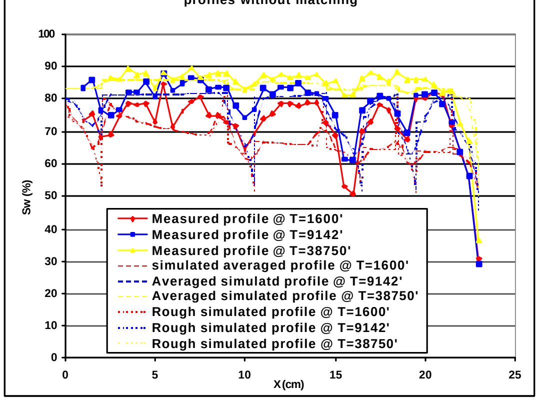

Figure III 7 : Comparison between experimental & simulated profiles after matching

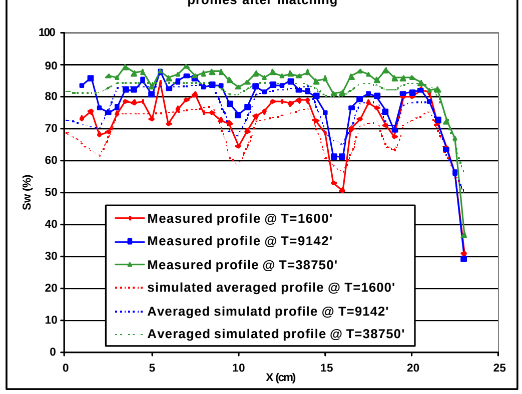

Fig III 8 : Relative permeabilities for both homogeneous & heterogeneous interpretation

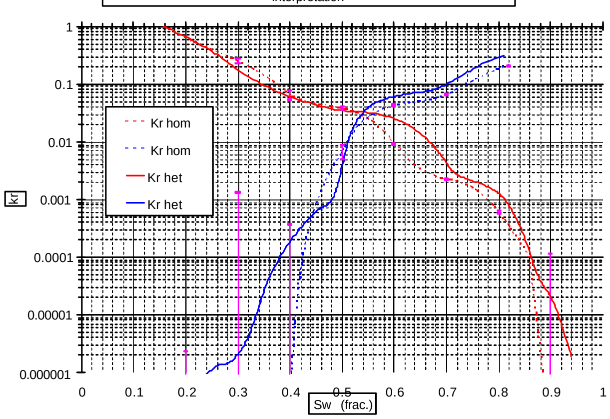

Fig III 9 : Capillary pressure for both homogeneous and heterogeneous interpretation