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Relative Permeability Measurements on Heterogeneous Samples

A pragmatic approach

by

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Abstract

Over the years, the reliability of measured flow parameters like relative permeability and residual oil has significantly increased. As a consequence, the impact of Special Core Analysis (SCAL) data on field development planning has become more apparent. A drawback is that current measurement technology requires the samples to be homogeneous. Usually, an X-ray CT scanner is used to screen samples to reject heterogeneous samples. It is our experience, however, that rejection rates can be as high as 90%. This poses the question as to when data obtained on homogeneous samples can still be representative for the reservoir.

Three situations occur:

1) If heterogeneity in the reservoir is much larger than the scale of the sample, a distribution of homogeneous samples will allow for representative data. A reservoir simulator will then be used for averaging the data.
2) If heterogeneity is much smaller than the scale of the sample, the sample will appear to be homogeneous and the standard procedures are adequate. In effect Nature will carry out the averaging during the flooding experiments.
3) If heterogeneity is on the scale of the samples, the measurement results will be severely affected by the incidental heterogeneities and it is not clear how the data should be interpreted.

The proposed method, to address the third situation depicted above, starts-out by defining a statistically representative sample set to characterise a heterogeneous reservoir unit. Then on each sample in the set, a Steady-State experiment needs to be conducted in which the pressure drop is measured in each flowing phase independently. This is achieved by using water-wet filters in the tubings connecting to one differential pressure transducer and oil-wet filters in the tubings for a second transducer.

Results will be presented of computer simulations of such experiments, assuming various types of heterogeneities. We compare these results with simulations on the field scale. We demonstrate that by careful design of the flow experiments, the measurements should be representative of the flow in the reservoir. Therefore, the distribution of the relative permeabilities obtained in the measurements on all samples in the selected set, is representative of the distribution of the relative permeabilities in the reservoir. This distribution, rather than just averaged curves, should then be used as input for reservoir simulation to predict field performance of heterogeneous reservoirs.

1. INTRODUCTION

Particularly in the last 5 years or so, the technology for the measurement of Special Core Analysis (SCAL) flow parameters has seen a strong development in the industry, leading to significantly more reliable data for relative permeability, capillary pressure and residual oil saturations. Apart from increased measurement precision, this technology development is based on the use of a flow simulator for the design and the interpretation of the flow experiments [1]. Measurement artefacts, such as the inevitable interference between capillary and viscous forces in any flow experiment, are accounted for. In this way, the produced data are not only more

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reliable, but often rather different from the results of a standard analysis. Generally, mobility of oil at low oil saturations is larger than established with conventional analysis and modern residual oil saturations often are 10 saturation units lower than “standard” data [2]. This has a significant impact on predicted field performance, particularly later in the field life. In our experience, predicted ultimate recovery can be increased by 10% or more.

A serious drawback of current measurement technology is the requirement that the rock needs to be homogeneous. The reason for this is built into the design of all SCAL flow experiments as used in the industry today: the UnSteady-State or Welge method [3], the Steady-State method [4], and the Centrifuge method [5, 6]. Interpretation by simulation takes care of measurement artefacts, but does not change the basic experimental design. Usually, an X-ray CT scanner is used to screen core to reject heterogeneous parts. It is our experience, that rejection rates can be as high as 90%. Then, if only 10% of the rock can be used for measurements, one is faced with the question whether data obtained from the selected homogeneous material still can be representative for the heterogeneous reservoir.

Three situations occur:

1) If heterogeneity in the reservoir is much larger than the scale of the core, a distribution of homogeneous plugs will allow for representative data. A reservoir simulator will then be used for averaging the data.
2) If heterogeneity is much smaller than the scale of the core, the rock will appear to be homogeneous and the standard procedures are adequate. In effect Nature will carry out the averaging during the flooding experiments.
3) If heterogeneity is on the scale of the core, the measurement results will be severely affected by the incidental heterogeneities and it is not clear how the data should be interpreted.

This paper addresses the third situation, for two phases only. Before we present our approach to measurements on heterogeneous core plugs, we would like to review briefly how incorrect flow parameters can impact on field development planning, particular in heterogeneous reservoirs. This is discussed in Section 2. Subsequently, in Section 3, we present a cost-effective and pragmatic measurement methodology for heterogeneous rock. The methodology is split into two parts: (i) How to ensure that a measurement on a single heterogeneous plug is representative for the part of the reservoir where the plug came from; (ii) How to ensure that measurements on a set of heterogeneous plugs are representative of a heterogeneous reservoir on the large scale. In Section 4 we present conclusions and recommendations.

2. BUSINESS IMPACT OF WRONG SCAL FLOW DATA

In order to address the business impact of wrong SCAL data in heterogeneous rock, we need first to address how heterogeneity can impact the results of flow experiments. We will assume that a core plug consists of two layers with a permeability contrast of a factor 10. We can estimate the capillary pressures to vary according to the well-known Leverett-J function [4]:

$$P_c(S_w) = J(S_w)s\sqrt{\frac{j}{K}} \qquad \text{Eq.1}$$

See for an explanation of symbols, the nomenclature at the end of this paper.

Consequently, the low-permeable layer is likely to have the strongest capillary pressure. Now, we will consider what will happen during measurements with the Steady-State technique. When brine and oil are injected simultaneously into a water-wet core plug, the brine will be pulled preferentially into the low-permeable layer. Then oil is left to flow preferentially through the high-permeable layer (provided that the capillary forces dominate the viscous forces as would be the case in the field). The result is that when standard Steady-State calculational procedures are followed, the water relative permeability will be pulled down, and the oil relative permeability is pushed up. It can be calculated that if the layers would be of equal thickness, the water effective permeability can be reduced by a factor of more than two when compared to a homogeneous plug with properties as averaged over the two layers. On the other hand, the oil effective permeability can be increased by a factor of two or more. In an oil-wet rock, brine and oil will change places.

Most rock is likely to be mixed-wet [7]. At low water saturations, mixed-wet rock behaves as water-wet, while at high water saturations mixed-wet rock behaves as oil-wet. Therefore, Steady-State imbibition measurements on the 2-layer plug under consideration are likely to generate significantly low water relative permeabilities early in the experiment, and significantly low oil relative permeabilities at high water fractional flow later.

A major problem arises in declaring the present plug and data to be representative for the reservoir, ignoring the fact that the data are dominated by the incidental layering. Another plug from the same heterogeneous rock could have more layers (or even have no layering at all), with completely different layer permeabilities. The impact on predicted field performance is immediate: injection pressures will be estimated wrongly, possibly by a factor of 2 or more. This has a direct impact on well distance and therefore on economics. The fact that ultimate recovery may be underestimated, due to too low oil mobility at low oil saturations, will further deteriorate the predicted economics.

2.1. UnSteady State (Welge) and Centrifuge technique

The above discussion focused on the use of the Steady-State technique. Implicitly, it was assumed that the measurement produces meaningful results for the plug so that we could focus on the issue of plug representativity. In the next Section, we will show that extracting data from Steady-State flow experiments on a heterogeneous plug is not trivial, but with some limitations it is technically feasible. More problems are likely to arise with the other measurement methods commonly used in the industry: the UnSteady-State or Welge method and the Centrifuge method. The centrifuge method to measure relative permeability is in essence a Welge-type measurement and we will limit this discussion therefore to the Welge method. The Welge method [3] analyses the production performance after water breakthrough. The saturation at the outflow face is calculated, and relative permeabilities are calculated at that saturation.

In a Steady-State experiment one can expect that with minor heterogeneities, eventually a true steady-state can be achieved and reasonable data can be produced, particularly if capillary pressure can be neglected. However, the Welge experiment analyses precisely the transient data and those data will be affected immediately by the presence of any heterogeneity. Dispersion created by the heterogeneities interferes with the production behaviour. Work has been published that proposes to use the information form the production profile to characterise plug heterogeneity [8]. We conclude that Welge, and therefore also centrifuge experiments are even more sensitive to the presence of heterogeneities than the Steady-State technique, and more prone to deliver data with a very large range of uncertainty. This conclusion is in line with many observations in the open literature [9].

3. MEASUREMENT METHODOLOGY FOR HETEROGENEOUS ROCK

Many research groups have been, or still are, addressing SCAL for heterogeneous reservoirs. Some focus on analytical work, others focus on simulation. The simulation work may be with flooding experiments in heterogeneously packed artificial sands [10], of which each body can be characterised independently. Another approach is by numerically simulating typical heterogeneous arrangements to arrive at flow-functions that should be used in a reservoir simulator on a larger scale [11]. Also, heterogeneous visual models are used to study the impact of (wettability) heterogeneities [12] with detailed information on saturation distribution.

With all methods progress is made, but none appears close to a cost-effective, industry-wide accepted measurement technique for heterogeneous reservoirs. In our view, there was scope for scouting a more direct route towards such measurements. The following guidelines for the development of a novel measurement technique for heterogeneous rock were decided:

- The new measurement technique should be manageable by third-party SCAL laboratories with limited investment and at an operational cost similar to current measurements. If not, we would run a serious risk to design a method that will not be useable in the near future (if at all) and impact on the business would be delayed.
- Focus has to be on usage of the data. The true issue is to provide a reservoir engineer with data that he needs to characterise the flow-dynamics of large-scale (say 100 x 100 x 10 m) grid blocks in a reservoir simulator. In the simulator all properties of a grid block, spanning many cubic meters, are collapsed onto a single point. Flow is calculated from one point to all neighbouring points, based on averaged properties. How to achieve statistically reliable averaging seems to be a key issue.

This last consideration gave us a starting point for the work.

3.1. Statistical approach

The essence of any measurement technique is representativity, both for the reservoir (unit) and for the field simulator. However, if a flooding experiment on a plug can be designed to be representative of the flow through the reservoir unit, it still can only be representative for that part of the unit for which the plug itself is representative. Therefore, it is essential that plugs be selected such that the selection is, in the statistical sense, a proper sample of the heterogeneous reservoir or unit. The core plugs in the sample-set will then show the same distribution of properties as is observed in the reservoir.

The first property to consider is layering: the distribution of layers across the plugs must be a reasonable reflection of the distribution of layers in the reservoir. Other properties that could be addressed, for example, are mineral composition (important for wettability), grain size distribution, porosity (distribution), and Hg-air capillary pressure curves measured on small cut-offs of the samples. A multi-disciplinary effort is required between geologist, petrophysicist and reservoir engineer, to define the attributes that will be used to define representativity. The core plug selection, to obtain a representative sample set, can then be screened and validated using standard statistical tools [13].

Now, if we would have a method that determines the flow parameters of a representative sample set of heterogeneous plugs, the distribution of the relative permeabilities will be representative of the reservoir. In other words, the average of the measured relative permeability for water and oil will be a good estimate of the average relative permeabilities in-situ; and the standard deviation of the distribution of the measured relative permeabilities will be a good estimate of the standard deviation in the heterogeneous reservoir. Therefore, the reservoir engineer should not use just averaged relative permeabilities as he would do for homogeneous rock, but he should use a distribution of relative permeabilities in his dynamic model. Different grid blocks need to have different relative permeabilities. In effect, this is an extension of the now common practice to assign a distribution of porosity and absolute permeabilities, based on the formulation of modern static geological models.

The distribution of flow parameters across grid blocks is to be carried-out at the appropriate length scale of the grid blocks. When it is necessary to reduce the number of grid blocks to reduce simulation time, upscaling is required. Upscaling will reduce the need for a high accuracy in relative permeabilities. Therefore, we recommend that before any major heterogeneous SCAL campaign is started, a sensitivity study be carried out to establish the true value of the detailed information. As in any SCAL measurement study, the value of the measurements should amply surpass the cost of the measurements.

3.2. Measurement technique

As we mentioned before, for the statistical approach to work, the measurements on a heterogeneous plug need to be representative of the flow in the reservoir. The data need to be fed into the dynamic model in which flow is calculated from one grid node to the next, using flow properties averaged on the scale of the grid block. These considerations translate into flow experiments in which the fluid distributions during the experiment mimic the distribution of the fluids in the reservoir, if the same pressure gradient would arise. In the reservoir, away from the wells, capillary forces dominate over viscous forces and the fluid distribution is fully determined by capillary forces that vary from one location to the next, in line with varying porosity and permeability (see Eq. 1). This is particularly important for the fluid distribution across layers: capillary forces will promote cross-flow between layers of different permeability and porosity.

So, in the experiments we need to allow capillary forces to dominate over the viscous forces. Note that this is contrary to normal measurement practice. Consequently, this presents immediately the problem of capillary end-effects that will interfere. We have run simulations of flow experiments in typical heterogeneous plugs and compared these simulations with flow experiments on field scale. In this way, we have established when the fluid distributions are reasonably close to the distribution in the field. More precisely, we have established how the measurement should be conducted in the presence of capillary end-effects so that the extracted relative permeabilities are representative for the field.

Given the first guideline, discussed early in Section 3, we decided not to search for a method that would require an X-ray tomograph or other detailed information on each individual heterogeneity: that would result in very costly and time consuming measurements. Moreover, we did not see how a reliable method could be devised to extract data on both porosity and absolute permeability of individual heterogeneities in a non-destructive manner. In the absence of such information, the UnSteady-State and Centrifuge methods did not seem promising, because interpretation-by-simulation seems to be the only option for those, in which case porosity and permeability per heterogeneity would then have to be established. Instead, we directed our efforts to modify the Steady-State method, aiming to avoid detailed interpretation-by-simulation, but use simulations to design the experiments and the interpretation technique.

We have tested our ideas and refined the measurement design by studying a variety of typical heterogeneous configurations with the Shell proprietary reservoir simulator MoReS. This is the same simulator that we employed for earlier SCAL work [14]. The following configurations have been investigated:

1) Two layers, of equal thickness, parallel to the main flow direction (Fig. 1a)
2) Ten layers, of equal thickness, parallel to the main flow direction, with a quasi random distribution of absolute permeability (Fig. 1b)
3) A single isolated heterogeneity centred within a core plug (Fig. 2a)
4) Two heterogeneities at opposite corners in a plug (Fig. 2b)
5) A pattern of 5x5 spots within a core plug (Fig. 3)

Permeability contrasts were set to different values (see figures), ranging from a factor of two, to ten, to a hundred. All simulations were performed in 2-D, in a vertical plane with a horizontal flow. Pressure taps were assumed to be at the top.

The general approach was to establish when relative permeabilities measured on a core plug would be representative of the field. For that reason we ran simulations in two different configurations:

(i) with the plug embedded in a long (say 500 to 1000m) reservoir, therefore in the absence of any end-effect; and with an injection rate typical for the field at 1ft/day. The plug itself was modelled with a grid of 100 x 100 blocks. The complete system was modelled with 150 blocks horizontally and 100 blocks vertically. The height across the reservoir was set constant to the height of the plug.

(ii) with the plug in isolation, representing a Steady-State set-up, using 1ft/day total injection rate. We studied sensitivity to the total injection rate up to 100 ft/d. Simulations were run with 100 x 100 blocks. Plug length was set to 5 cm.

In both configurations, the fractional flow was varied from 100% oil injection to 100% water: an imbibition experiment. All runs employed the same, dimensionless Leverett-J capillary pressure function $J(S_w)$, from which imbibition capillary pressure was calculated for each layer, based on the individual absolute permeability (see Eq.1). The dimensionless function is shown in Fig. 4. This function represents a typical mixed-wet situation, as should be representative for most core. We chose the slope of the function near the centre point to be minimal, but still realistic. This means that if capillary forces prevail over gravity and viscous forces already with this function, they will almost certainly do so in all other cases with larger capillary pressure gradients.

As input rock relative permeabilities, we used Corey type curves with $n_w = n_o = 4$, equal for all layers. Porosity was set to a fixed 25% for all blocks. The viscosity ratio was set to unity. Below, we will discuss some results in detail.

3.2.1. Layers parallel to the main flow direction

First, simulations were run on field scale and with field injection rate. This was to generate a fluid distribution over the layers representative of the field. During the simulation, we “measured” the relative permeability during a sequence of different fractional flows, following a standard Steady-State protocol: differential pressure was monitored across 5 cm of rock, and the value determined at stable pressure drop and stable average saturation. We averaged the saturation over the layers vertically, within the same 5 cm of rock, as would be read-off by a gamma- or X-ray in-situ saturation measuring tool presently available in modern SCAL laboratories.

Fig. 5 shows a comparison between the input Corey relative permeabilities and measured curves for the ten-layer system, depicted in Fig. 1b. The saturation scale has been normalised to mobile saturation:

$$S = \frac{(S_w - S_{cw})}{(1 - S_{cw} - S_{or})} \qquad \text{Eq. 2}$$

The first data point corresponds to a fractional flow of 0.01, while the last point was collected at a fractional flow of 0.99.

The relative permeability curves deviate up to 30% from each other. Clearly, the fluid distribution has affected the measurement and we should read the measured curves (solid lines) as the relative permeabilities effective for the present configuration on field scale. In other words: a correct measurement on a core plug in the laboratory should aim to reproduce the effective field curves.

Subsequently, Steady-State experiments were simulated using different injection rates. Due to capillary end-effects, the pressures can be significantly different between the two phases. To correct for that, we read-off the differential pressure within each phase. The pressure drop in the water phase was then used to calculate the water relative permeability, while the pressure drop in the oil phase was used for the calculation of the oil relative permeability. The resultant curves are plotted in Fig. 6, together with the “field” curves from Fig. 5. We observe that up to 30 times the field rate, a good agreement exists between the curves, with deviations of up to 15%. The higher injection rate reduced the capillary end-effects and extended significantly the saturation range that could be probed. The results proved to be insensitive to positioning the pressure taps either along the topside or along the bottom of the plug.

The results discussed above are typical for all the layered systems that we studied. Therefore our general observations are: representative relative permeabilities are extracted from Steady-State experiments on heterogeneous, layered, plugs when:

- The total flow rate is kept low, at or not more than one order of magnitude above the typical field rate (1 ft/day). This will limit the accessible saturation range: this is usually smaller than in ordinary Steady-State experiments where higher flow rates can be admitted.

- The pressure drop is measured in each phase separately
- Saturation is read as an average across the cross section of the plug between the pressure taps

3.2.2. Isolated heterogeneities in a core plug

Using the same protocol as for the layered systems, we have studied a variety of configurations with isolated heterogeneous spots. In Fig. 7, we present the results for the configuration as shown in Fig. 3, run for the field scale. The permeabilities of the patches were set to 1/100th of the permeability of the continuous facies. The deviation between input and output curves is much larger than for the layered systems that we studied: differences run up to 50% or more. Again, it is the objective of the Steady-State measurements on the plug scale to duplicate the effective field curves. Fig. 8 shows the results of those "measurements" for injection rates at 1ft/d, 10 ft/d and 100 ft/d. Although again the deviations are larger than for the layered models, an excellent agreement is found for injection rates up to 30 ft/d. These results are typical of the results for all the configurations with heterogeneous patches that we have studied. Generally, we have found that the "measurements" on the plug scale are in good agreement with the effective curves in the field when:

- The total flow rate is kept low, at or not more than one order of magnitude above the typical field rate (1 ft/day). As mentioned before, this will limit the accessible saturation range.
- The pressure drop is measured in each phase separately, between pressure taps away from the end-faces of the plug, e.g. one tap at one third and the second tap at two-third of the plug length.
- The pressure drop during the Steady-State experiments needs to be related to the effective absolute permeability "measured" at 100% saturation, across the <u>same</u> pressure taps.
- Saturation is read as an average across the cross section of the plug between the pressure taps

3.3. Experimental considerations

The proposed method requires one adaptation to a common Steady-State rig: differential pressure has to be measured in each phase separately. Presently, phase sensitive differential pressure measurements are being scouted at RTS as part of the "Pc-probe" project [15]. Water-wet filters are used to obtain the pressure drop in the water phase and oil-wet filters are mounted in the two other pressure taps to connect a pressure cell to the pressure in the oil-phase. The principle of this technique proved viable already, and efforts are directed to move these phase pressure measurements from the experimental stage towards a more operationally reliable measurement.

The differential pressures at low flow rates and measured from pressure taps relatively close to each other may be small. It may be necessary to replace the standard transducers by differential pressure transducers with an increased sensitivity. In any case, there will be an upper bound to the maximum absolute permeability of plugs that can be measured with a reasonable accuracy.

No other adaptations are required: current "standard" techniques for in-situ saturation monitoring, like gamma or X-ray absorption, prove to be sufficient.

4. CONCLUSIONS AND RECOMMENDATIONS

- A pragmatic approach has been developed and tested to measure a distribution of relative permeabilities, representative of the distribution in the field.
- Only one adaptation to existing Steady-State rigs is required: the measurement of the pressure gradient in the water and oil phase individually. RTS technology is already successfully under development.

- It is essential that a statistically representative sample set is defined to be used in the measurements. This requires a multi-disciplinary effort between geologist, petrophysicist and reservoir engineer.
- The estimated averaged curves and the standard deviation should be used in setting-up the dynamic model for field scale reservoir simulation.
- Upscaling may reduce the need for high accuracy in Steady-State data of heterogeneous plugs. Scouting simulations are required to assess the value of information, to be judged against the cost of the information.
- The proposed method is less suitable to determine tail-end behaviour: measurements at low oil saturations are not only time-consuming, but also low oil saturations may not be accessible due to capillary end-effects. No systematic research has been conducted into this issue, but a first recommendation is to use end-pieces to absorb the end-effects. However, capillary continuity between core plug and end-piece is a non-trivial experimental issue.
- The proposed method is designed for the situation where capillary forces dominate over viscous forces, as is expected to occur far from the well-bore. To obtain representative relative permeabilities for the near-well bore region, one should just set the injection rate in the experiments such that indeed capillary forces are dominated by the viscous forces. The same statistical approach can then be followed to arrive at the distribution of relative permeabilities representative for that region. For the intermediate distances where gradually capillary forces take over from the capillary forces, this method will be difficult to apply.
- The number of cases studied with isolated heterogeneities is too small to provide certainty that the adapted Steady-State technique is universally applicable for any type of heterogeneities. Further testing should be carried out, using the protocols outlined in this study to address heterogeneities of different classes or sizes.

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6. ACKNOWLEDGEMENT

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7. NOMENCLATURE

J	Leverett-J function (dimensionless)
K	absolute permeability (m^2)
k_r	relative permeability
P_c	capillary pressure
S	saturation (fraction)
Greek	
φ	porosity (fraction)
σ	interfacial tension between oil and water (N/m)
Subscript	
cw	connate water
or	residual oil
w	water

Layered parallel to flow direction

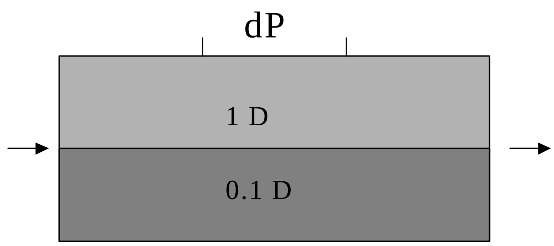
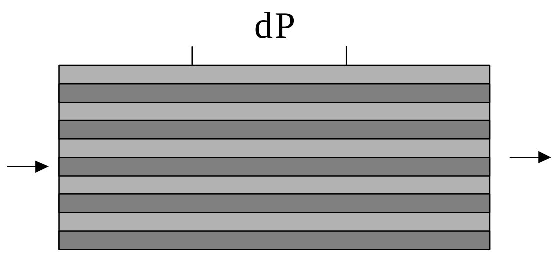


Figure 1a



Permeability for each layer from top to bottom:
.04, .4, .1, .01, .2, .7, .02, 1., .015, .07 Darcy

Figure 1b

Isolated heterogeneous spots

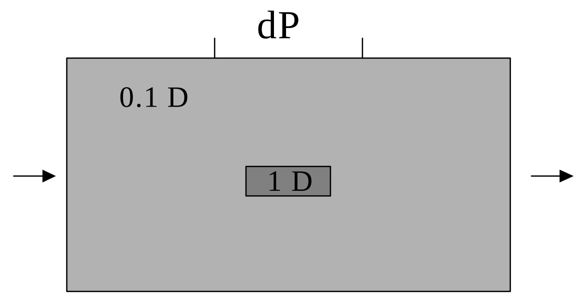


Figure 2a

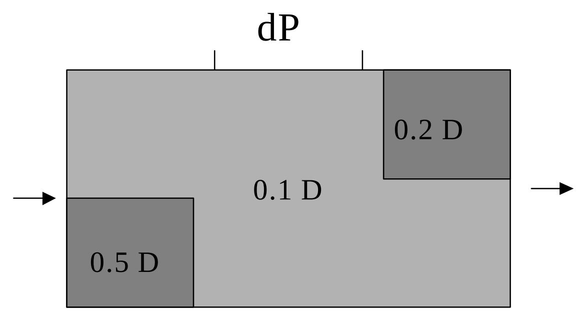
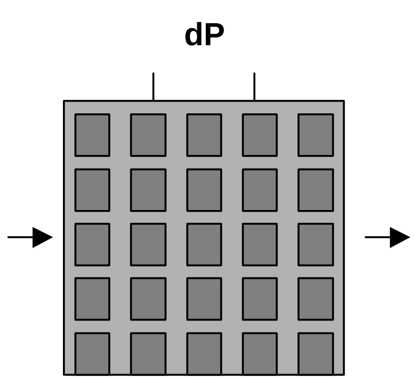


Figure 2b

Regular inhomogeneities



Permeability of patches is either .01 or 100 times the permeability of the continuous facies

Figure 3

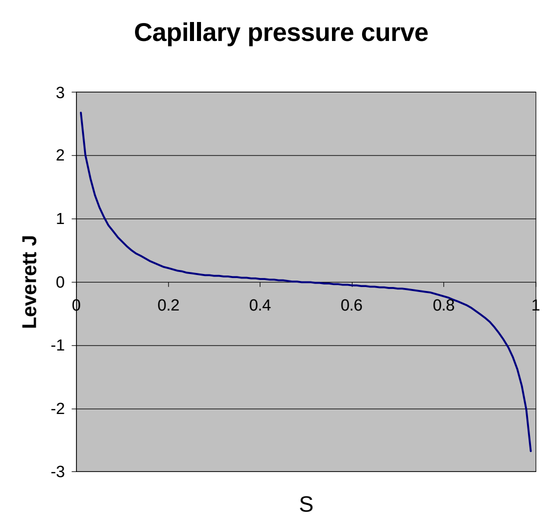


Figure 4

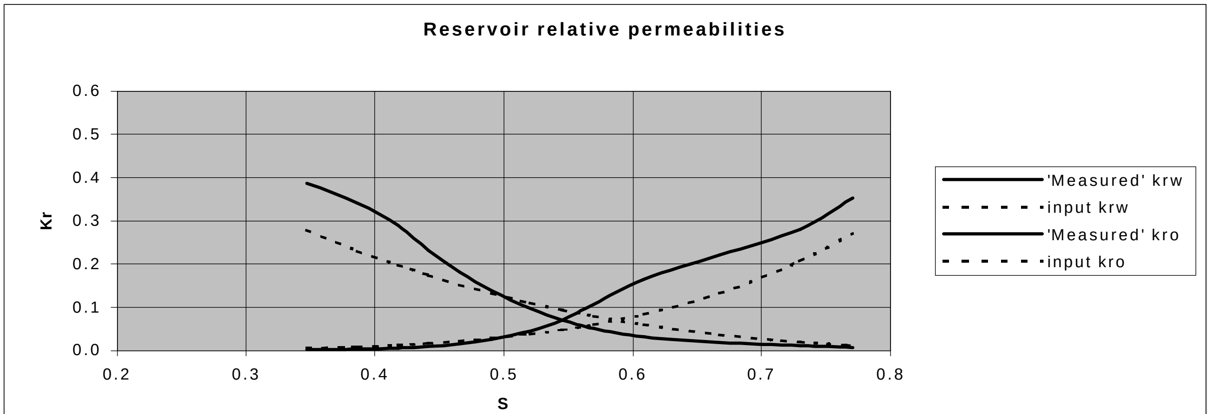


Figure 5

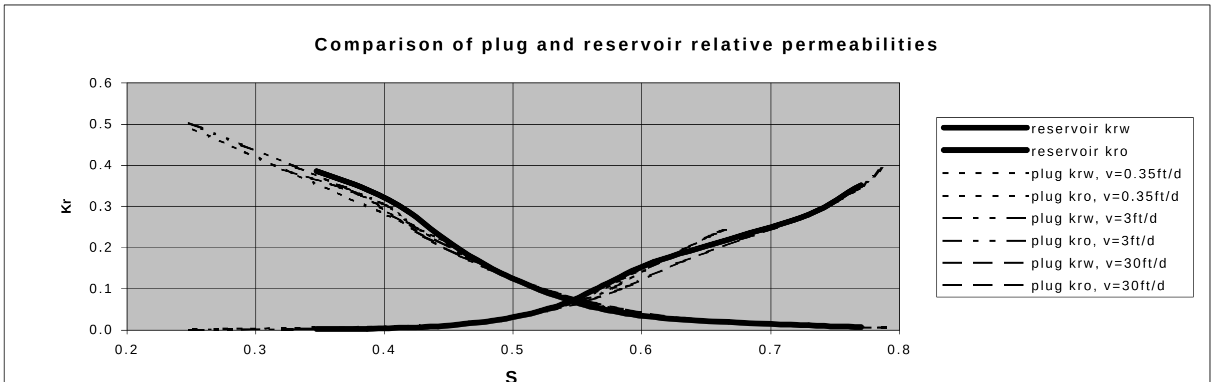


Figure 6

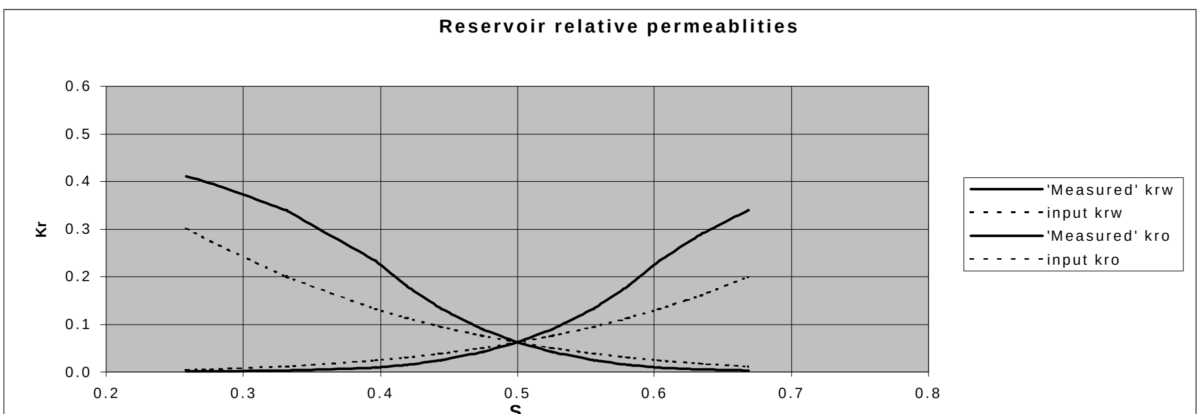


Figure 7

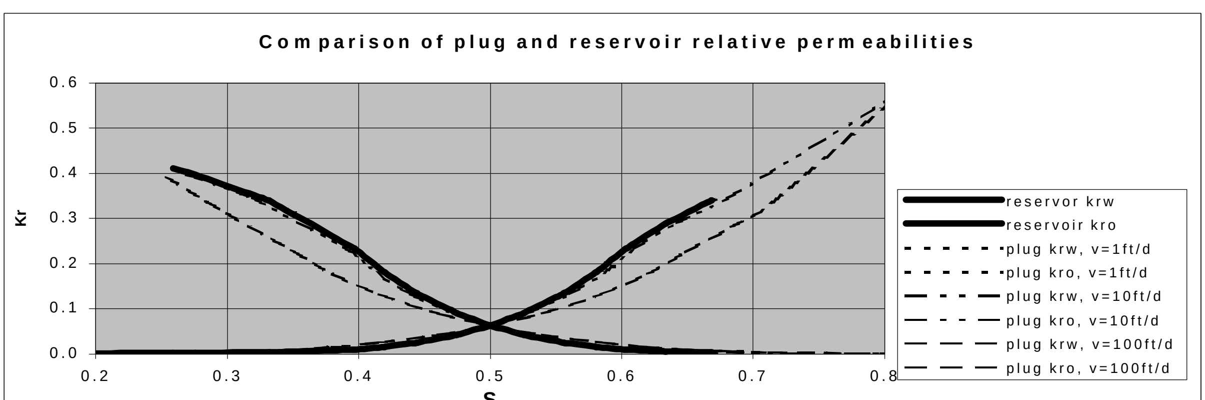


Figure 8