

Chapter 10: Relative Permeability

10.1 Introduction and Definition

Routine permeability measurements are made with a single fluid filling the pore space. This is seldom the case in the reservoir situation except in water zones. Generally, two and sometimes three phases are present, i.e. oil, water, and occasionally gas as well.

Here one would expect the permeability to either fluid to be lower than that for the single fluid since it occupies only part of the pore space and may also be affected by interaction with other phases. The concept used to address this situation is called *relative permeability*. The relative permeability to oil, K_{ro} , is defined as:

$$K_{ro} = \frac{K_{eo}}{K} = \frac{\text{effective oil permeability}}{\text{base permeability}} \quad (10.1)$$

Similarly we can define:

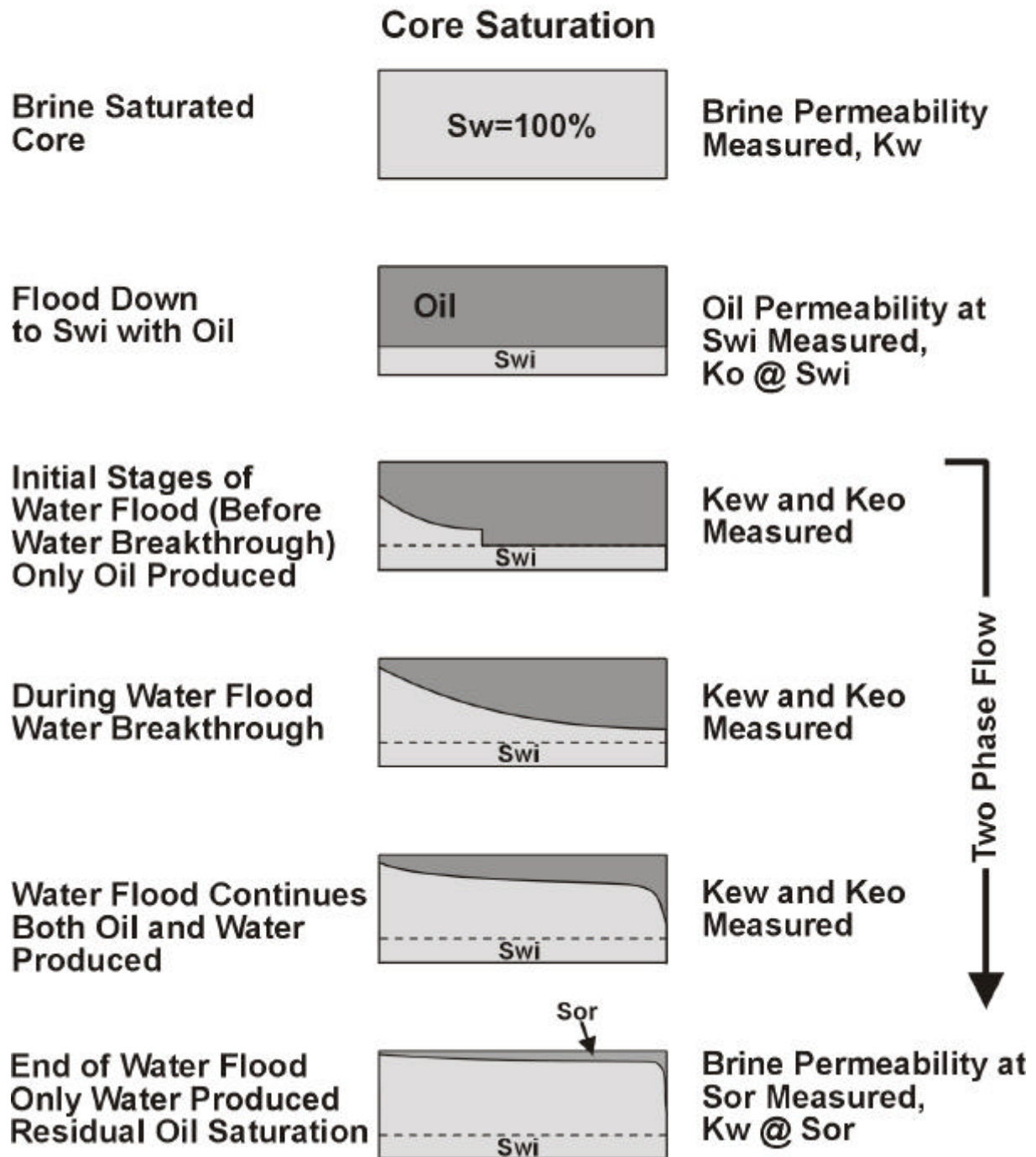
$$K_{rw} = \frac{K_{ew}}{K} = \frac{\text{effective water permeability}}{\text{base permeability}} \quad (10.2)$$

$$K_{rg} = \frac{K_{eg}}{K} = \frac{\text{effective gas permeability}}{\text{base permeability}} \quad (10.3)$$

The choice of base permeability is not, in itself, critical provided it is consistently applied. Conversion from one base to another is a matter of simple arithmetic. However, experimentally, the base permeability is usually chosen as that measured at the beginning of an experiment. For example, an experiment may start by measuring the permeability to oil in the presence of an irreducible water saturation in the core. Water is then injected into the core, and the oil permeability and water permeabilities measured as water replaces oil within the core. The base permeability chosen here, would most commonly be the initial permeability to oil at S_{wi} .

Laboratory measurements are made by displacing one phase with another (unsteady state tests see Figure 10.1) or simultaneous flow of two phases (steady state tests Figure 10.2). The effective permeabilities thus measured over a range of fluid saturations enable relative permeability curves to be constructed. Figure 10.3 shows an example of such a curve from an unsteady state waterflood experiment. At the beginning of the experiment, the core is saturated with 80% oil, and there is an irreducible water saturation of 20% due to the water wet nature of this particular example. Point A represents the permeability of oil under these conditions. Note that it is equal to unity, because this measurement has been taken as the base permeability. Point B represents the beginning water permeability. Note that it is equal to zero because irreducible water is, by definition, immobile. Water is then injected into the core at one end at a constant rate. The volume of the emerging fluids (oil and water) are measured at

Figure 10.1 Unsteady State Waterflood Procedure



the other end of the core, and the differential pressure across the core is also measured. During this process the permeability to oil reduces to zero along the curve ACD, and the permeability to water increases along the curve BCE. Note that there is no further production of oil from the sample after $K_{ro}=0$ at point D, and so point D occurs at the irreducible oil saturation, S_{or} . Note also that $K_{ro} + K_{rw} \leq 1$ always.

Figure 10.2 Steady State Waterflood Procedure

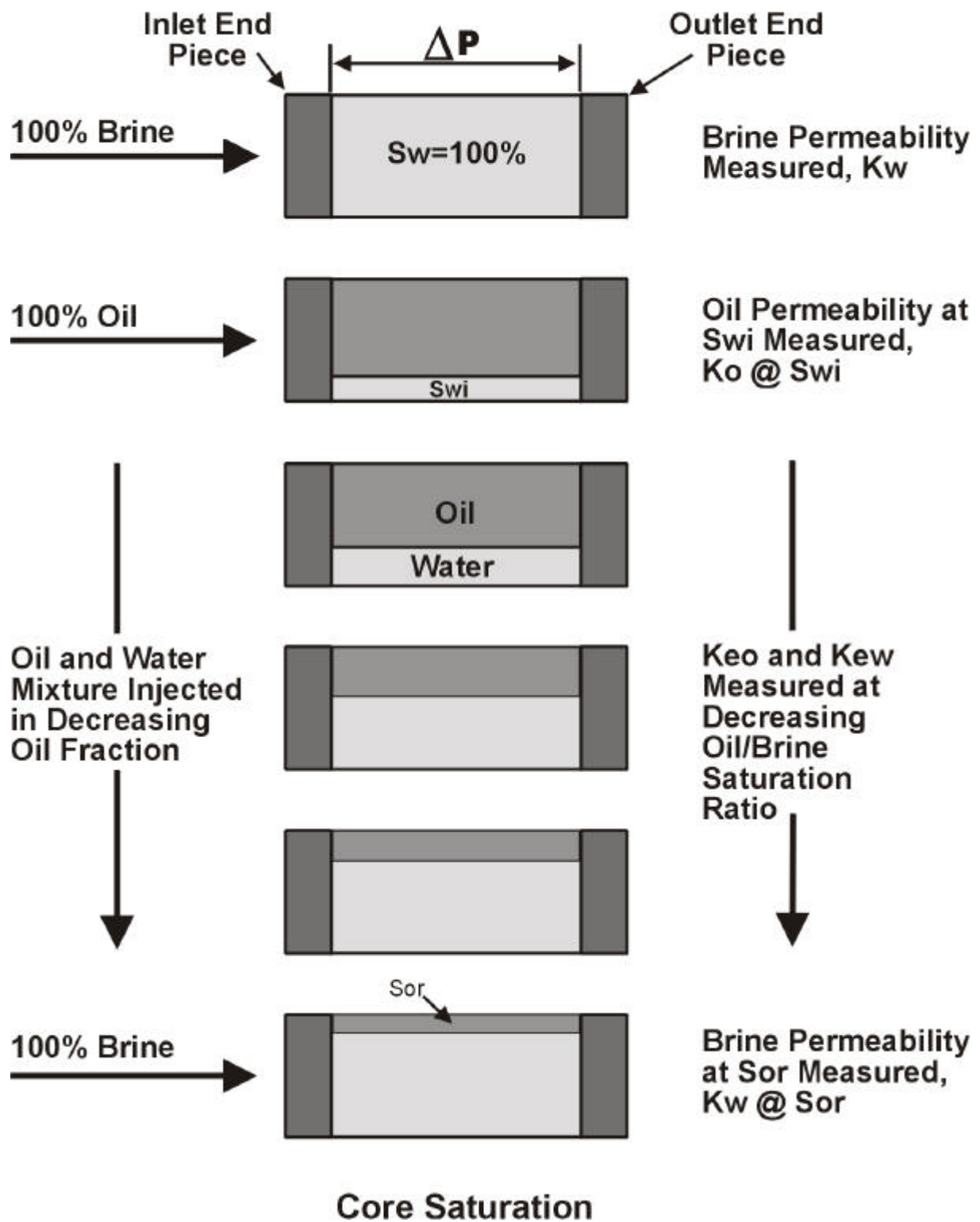
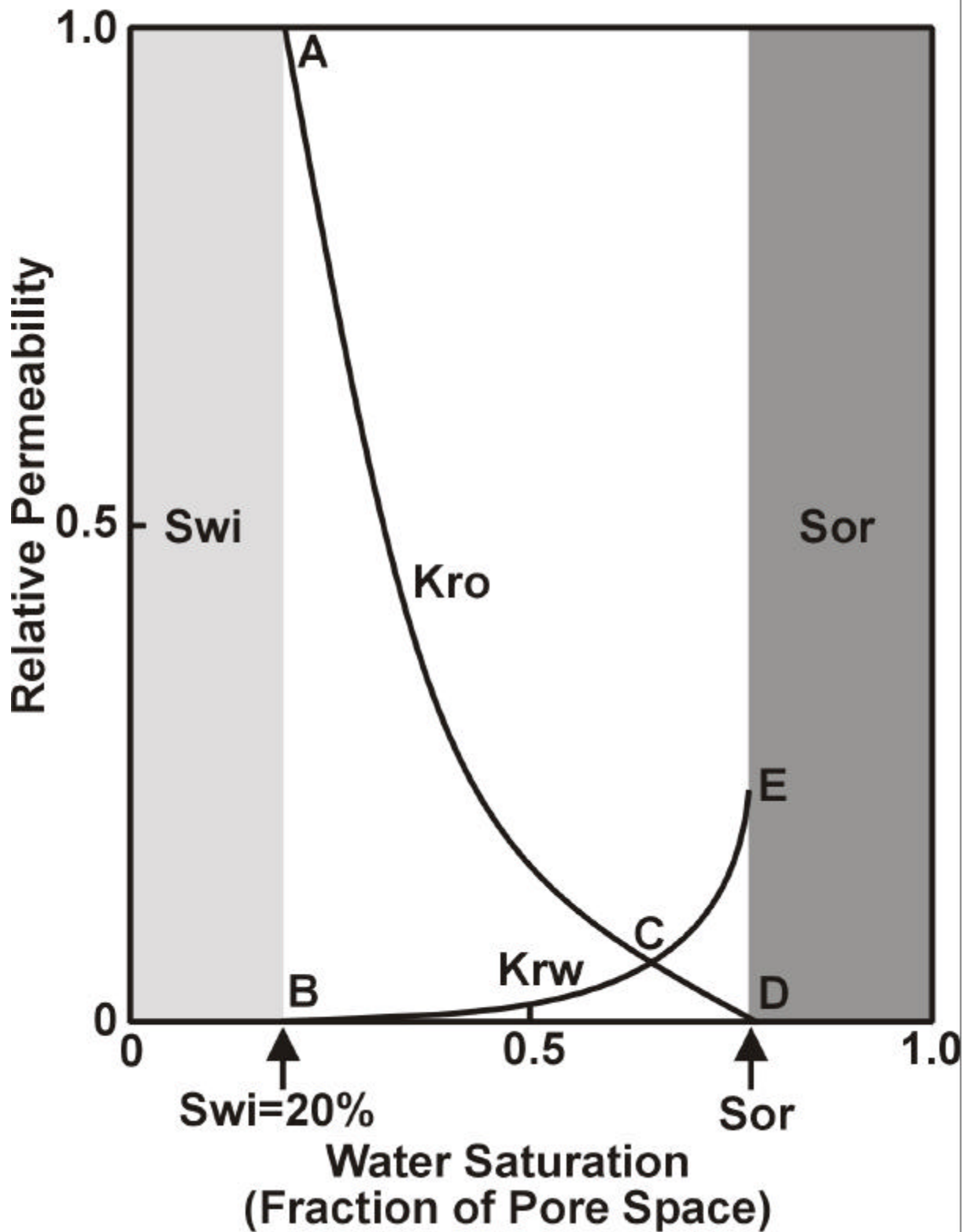
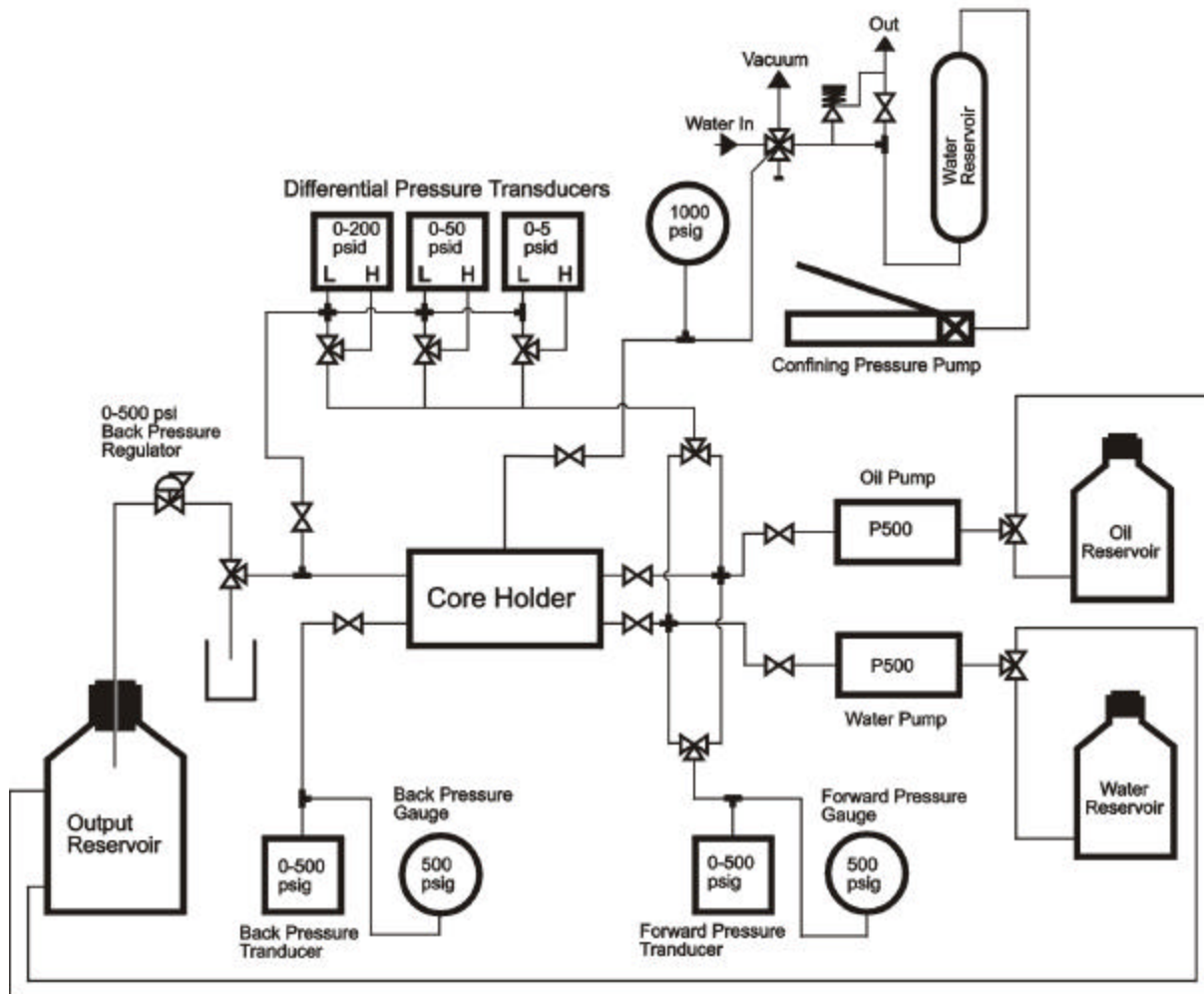


Figure 10.3 A Typical Relperm Curve from a Water Flood



It must be stressed, however, that these curves are not a unique function of saturation, but are also dependent upon fluid distribution. Thus the data obtained can be influenced by saturation history and flow rate. The choice of test method should be made with due regard for reservoir saturation history, rock and fluid properties. The wetting characteristics are particularly important. Test plugs should either, be of similar wetting characteristics to the reservoir state, or their wetting characteristics be known so that data can be assessed properly.

Figure 10.4 Relative Permeability Rig



Rigs for relperm measurement are often varied in design depending upon the exact circumstances. Figure 10.4 shows an example of a typical rig piping diagram. The fluid flow lines would be nylon or PTFE tube for ambient condition measurements (fluid pressures up to a few hundred psi, and confining pressures up to 1500 psi), and stainless steel for reservoir condition measurements (fluid pressures of thousands of psi, confining pressures up to 10,000 psi, and temperatures up to 200°C). These latter experiments are extremely complex, time-consuming, and expensive especially if live fluids are to be used. The mean saturation in the core is measured by collecting and measuring the volume of time-spaced aliquots of the evolving fluids. However, there are various successful methods of monitoring the saturation of the various fluids inside the core during the experiments. These are:

- (i) **GASM** (Gamma Attenuation Saturation Monitoring). Commonly used by BP, this uses doped oil or water phases to attenuate the energy of gamma rays that travel through the core perpendicular to the flood front. Each gamma source/detector pair measures the instantaneous water and oil, or gas and oil saturation averaged over a thin cross section of the core. Up to 8 pairs are used to track the fluid saturations in the core during an experiment, giving a limited resolution. Modern techniques use a single automated motorised source/detector pair.
- (ii) **X-Radiometry**. Commonly used by US companies. It is similar to GASM, but uses x-rays instead of gamma rays.
- (iii) **CT Scanning**. Uses x-rays and tomographic techniques to give a full 3D image of the fluid saturations in the core during an experiment. The spatial resolution is about 0.5 mm, but is extremely expensive, and measurements can be made only every 5 minutes or so.
- (iv) **NMR Scanning**. A very new application that is similar to the CT scanning. It has an increased resolution, but is even more expensive.

The first two methods are commonly used, whereas the last two are rarely used due to their cost.

10.2 Oil-brine relative Permeability Theory

Three cases will be considered:

- (i) Water-wet systems
- (ii) Oil-wet systems, and
- (iii) The intermediate wettability case.

It should be remembered that in water-wet systems capillary forces assist water to enter pores, whereas in the oil wet case they tend to prevent water entering pores.

Many reservoir systems fall between the two extremes, which does nothing to make laboratory water-flood data easier to interpret. However, a knowledge of the two extreme cases allows misinterpretation of intermediate data to be minimised.

Consideration must be given to flow rates. Close to the well bore, advance rates will be high, further away, rates can be very low. This can be modelled in laboratory tests; but in the case of oil wet systems, there is a tendency for low recoveries to be predicted due to end effects, i.e. retention of wetting phase at test plug outlet face.

10.2.1 Water Wet Systems

Consider a water-wet pore system at S_{wi} (generally 15 to 30%) some distance from well bore such that flow rates are low, typically advancing at 1 ft/day. This is equivalent to about 4 cc/hr in a typical laboratory waterflood. The following sequence occurs as water migrates into the rock:

Figure 10.5 Microsaturation and Water Flood Relperm Curve for a Water Wet System at S_{wi}

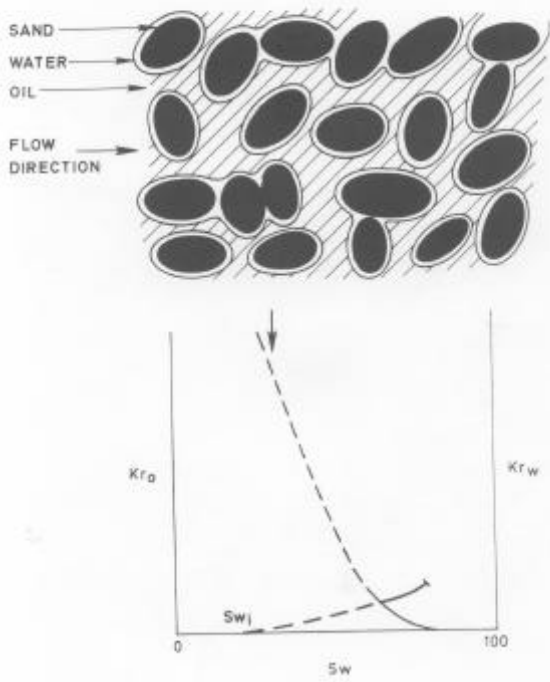


Figure 10.6 Microsaturation and Water Flood Relperm Curve for a Water Wet System during Flood

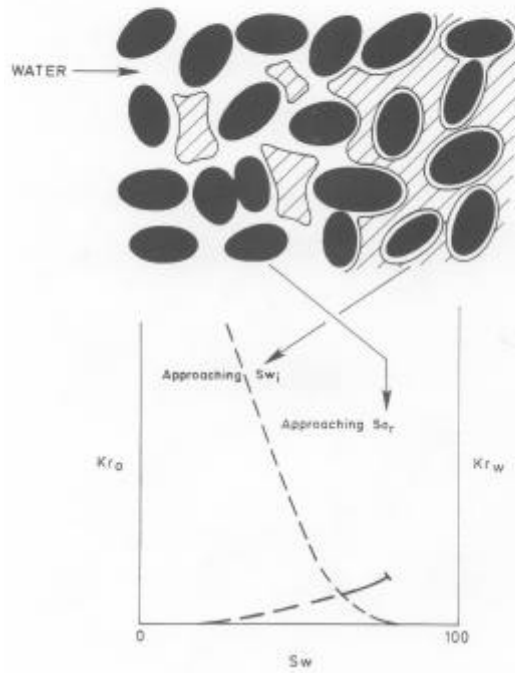


Figure 10.7 Microsaturation and Water Flood Relperm Curve for a Water Wet System at S_{or}

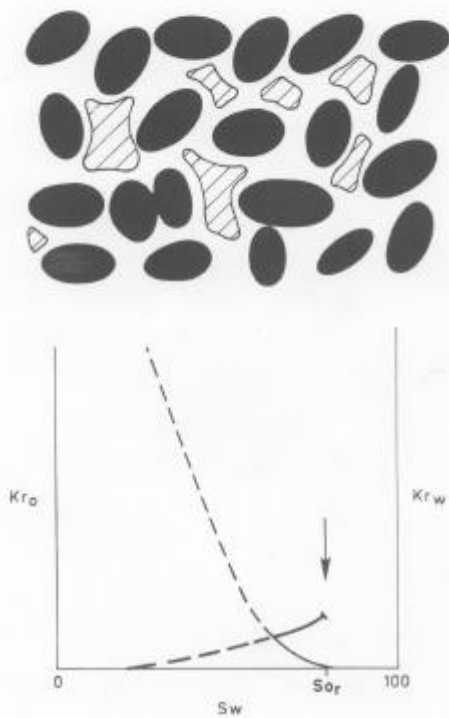
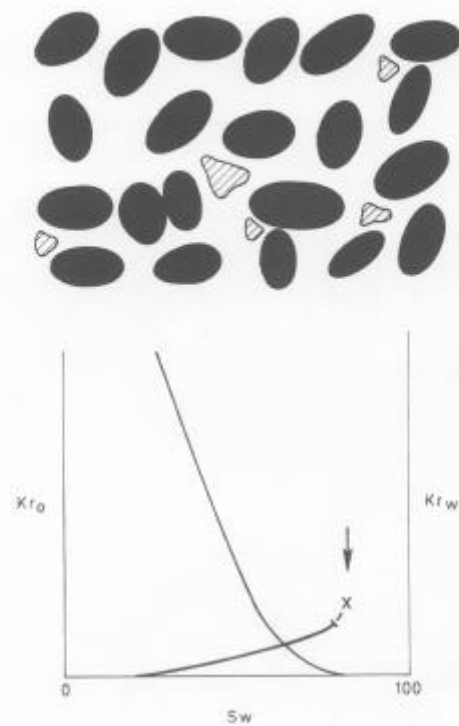


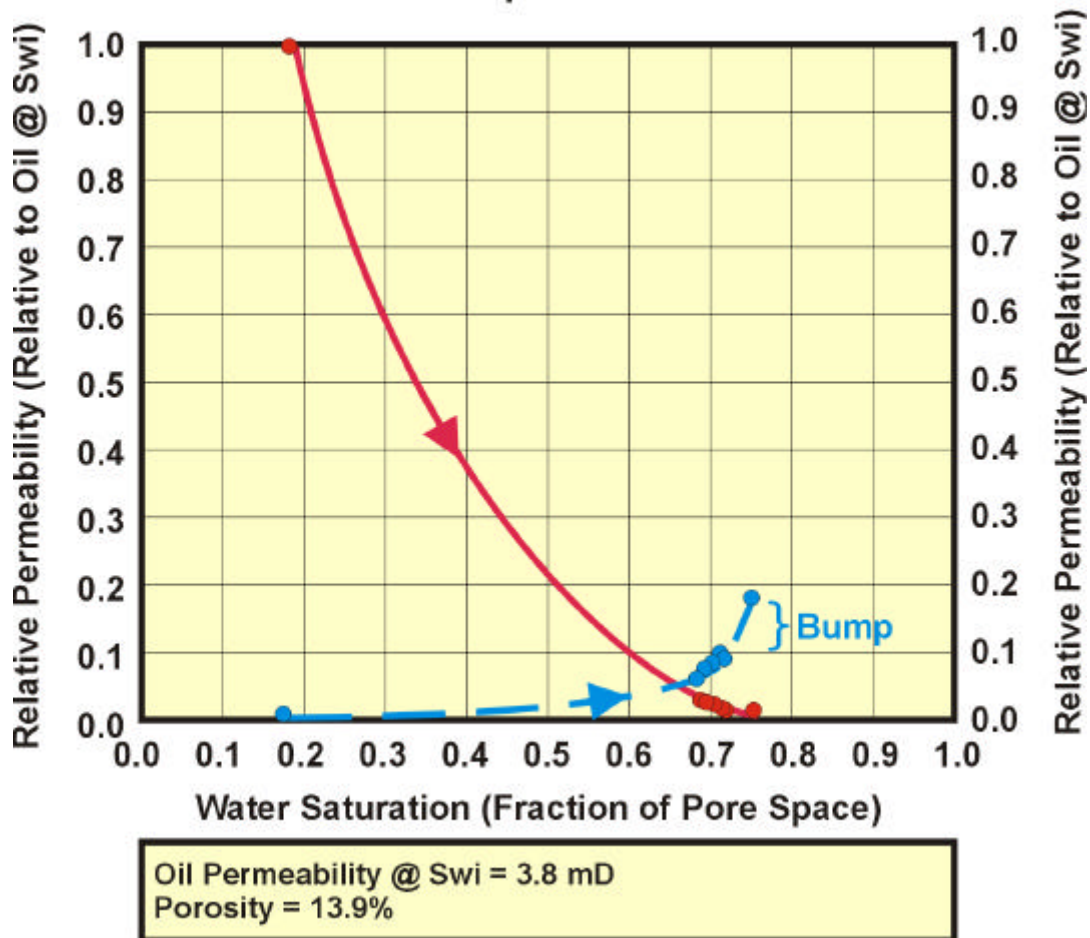
Figure 10.8 Microsaturation and Water Flood Relperm Curve for a Water Wet System after High Rate Bump

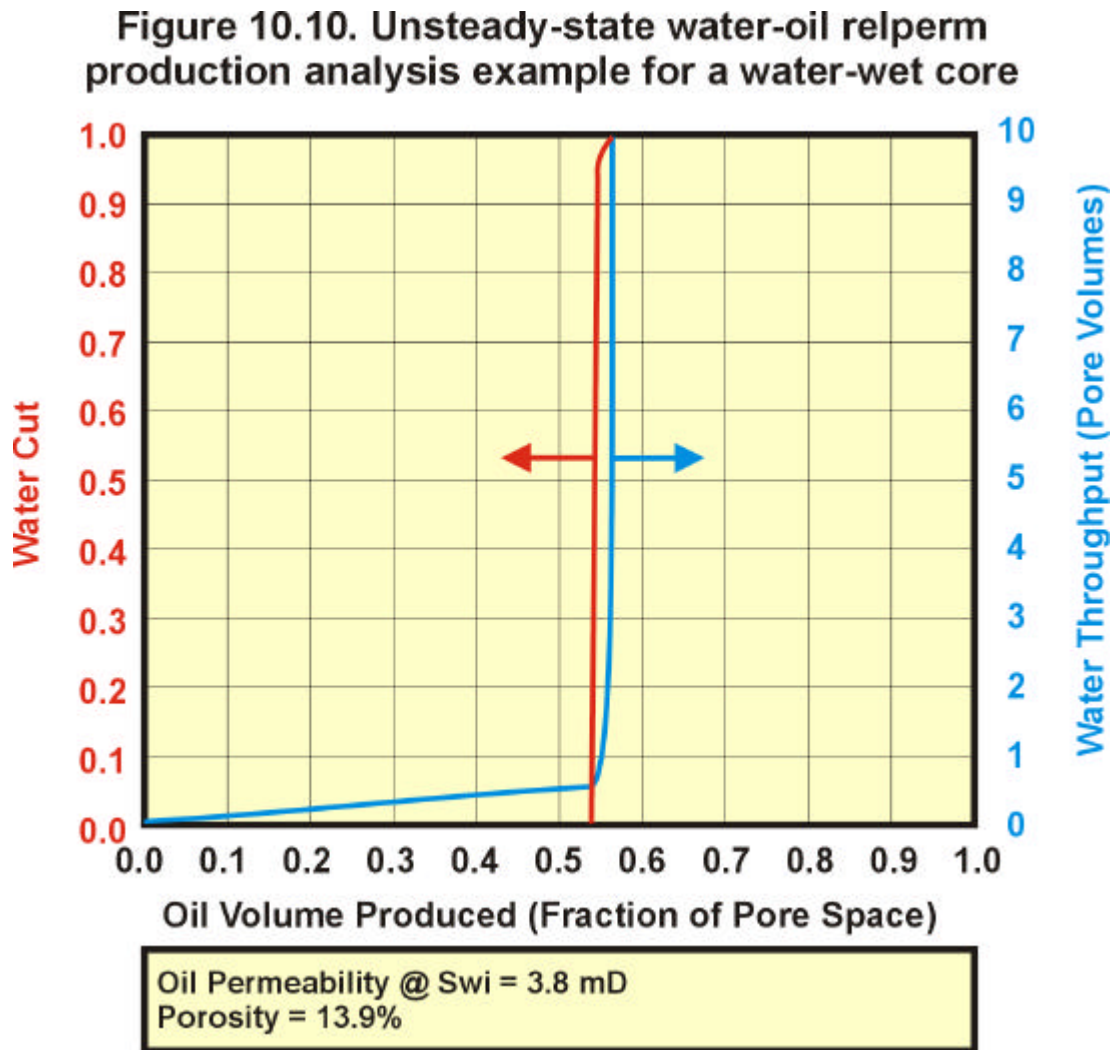


- (i) **Figure 10.5.** Initially at S_{wi} , water is the wetting phase and will not flow. $K_{ro} = 1$ and $K_{rw} = 0$.
- (ii) **Figure 10.6.** Water migrates in a piston like fashion, tending to displace most of the oil ahead of it.
- (iii) **Figure 10.7.** As water saturation increases oil flow tends to cease abruptly, and S_{or} is reached.
- (iv) **Figure 10.8.** Dramatically increasing the water flow rate (bump) has very little effect on oil production or K_{rw} . This is because capillary forces provide most of the energy required for displacement of the oil.

If floods are carried out at too high a flow rate on water-wet cores the trapping mechanisms present in the reservoir are not allowed to occur. Instead of entering small pores preferentially by capillary forces, the water flows at a relatively higher velocity through larger pores, thus tending to bypass 'groups' of smaller pores containing oil. The S_{or} value obtained may then differ from the true reservoir situation.

Figure 10.9. Unsteady-state water-oil relperm low rate flood example for a water-wet core





Water wet systems are usually adequately described by low rate floods, and do not exhibit end effects to any significant extent. Water wet data are characterised by:

- (i) Limited oil production after water breakthrough.
- (ii) Generally good recoveries.
- (iii) Low K_{rw} values at S_{or} .

Some typical data are presented in Figures 10.9 and 10.10. Points to take note of are the limited amount of incremental data obtained (although this may be extended by using viscous oils). This is caused by the rapid rise in water cut and the very short period of two phase flow typical of water wet systems.

10.2.2 Oil Wet Systems

Consider water entering an oil-wet pore system containing (typically) very low water saturations. The sequence of events from S_{wi} is illustrated by Figures 10.11 to 10.14 as follows:

Figure 10.11 Microsaturation and Water Flood Relperm Curve for an Oil Wet System at S_{wi}

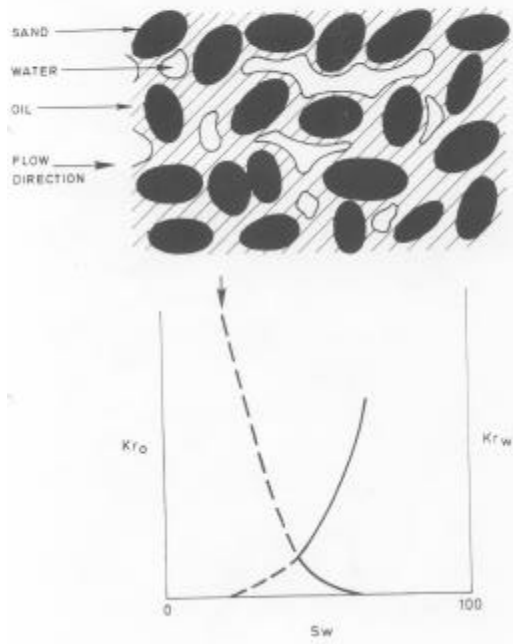


Figure 10.12 Microsaturation and Water Flood Relperm Curve for an Oil Wet System at Water Breakthrough

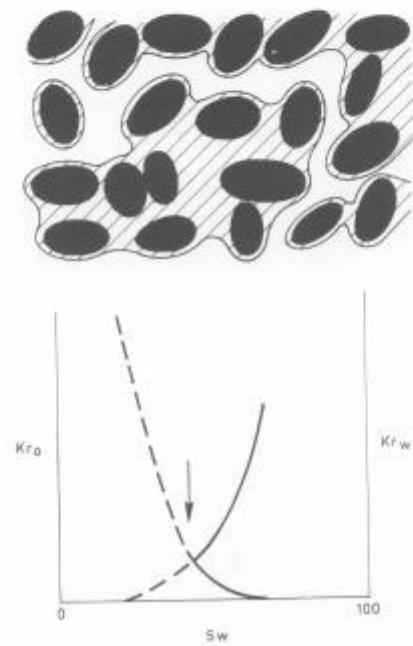
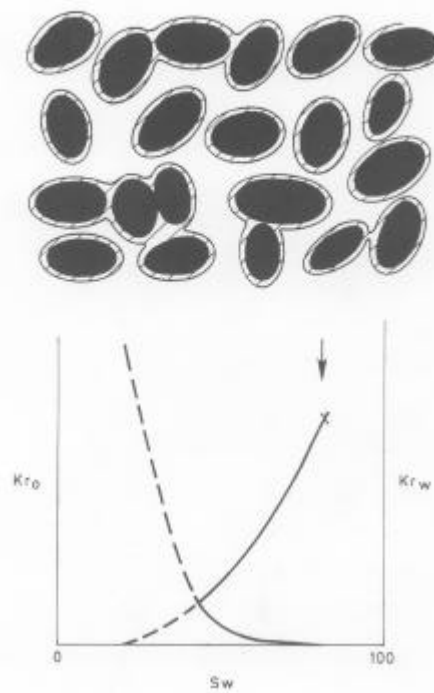


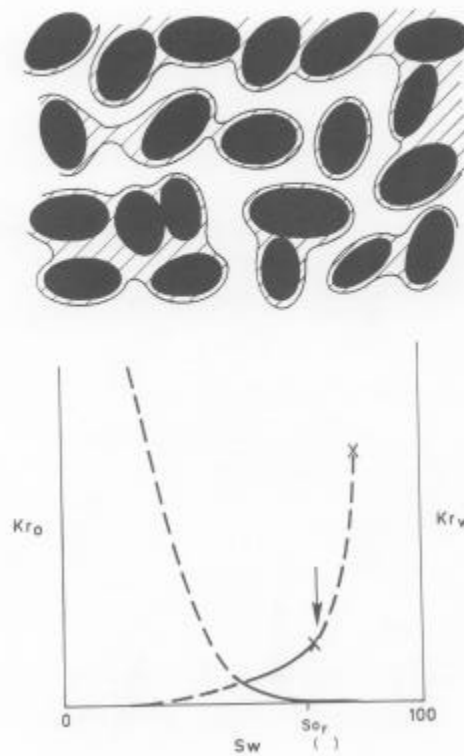
Figure 10.13 Microsaturation and Water Flood Relperm Curve for an Oil Wet System at S_{or}



- (i) **Figure 10.11.** Capillary pressure considerations indicate that an applied pressure differential will be required before water will enter the largest pore. The actual pressure differential required is dictated by Eq. (8.1).
- (ii) **Figure 10.12.** Water flows through the largest flow channels first, K_{ro} falls and K_{rw} rises rapidly.
- (iii) **Figure 10.13.** After large volumes of water have flowed through the system, S_{or} is reached. This equilibrium is attained slowly giving the characteristic prolonged slow production of oil after early water breakthrough.

If waterfloods on oil wet core are carried out at too low a flow rate there may be inappropriate retention of oil at the outlet face of the test plug. This is illustrated in Figure 10.14. At the end of a low rate flood, K_{rw} and the amount of oil produced are relatively low. If the flow rate (and hence the pressure differential) are increased at this stage, substantial further oil production occurs and K_{rw} increases significantly. This situation does not model processes occurring in the reservoir and should be avoided by appropriate choice of waterflood rate at the beginning of the experiment.

Figure 10.14 Microsaturation and Water Flood Relative Permeability Curve for a Low Rate Oil Wet System at S_{or} where a Bump is Inappropriate



Typical high rate valid oil wet data are shown in Figure 10.15 and 10.16.

Figure 10.15. Unsteady-state water-oil relperm low rate flood example for an oil-wet core

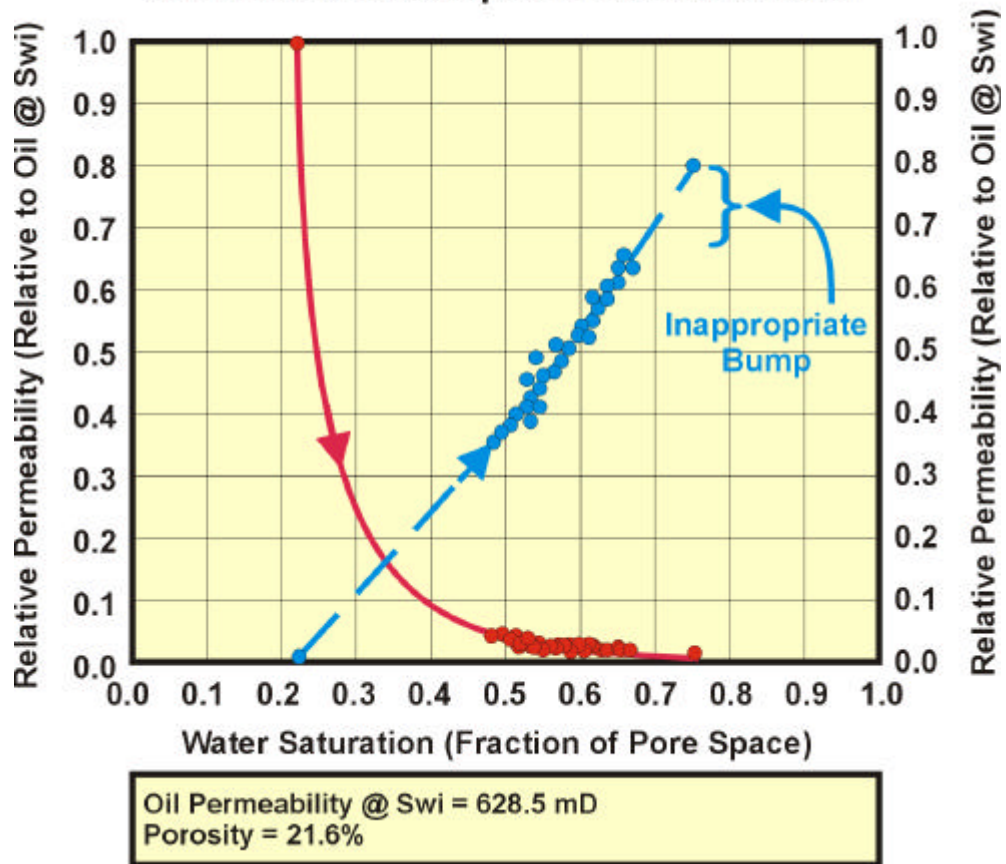
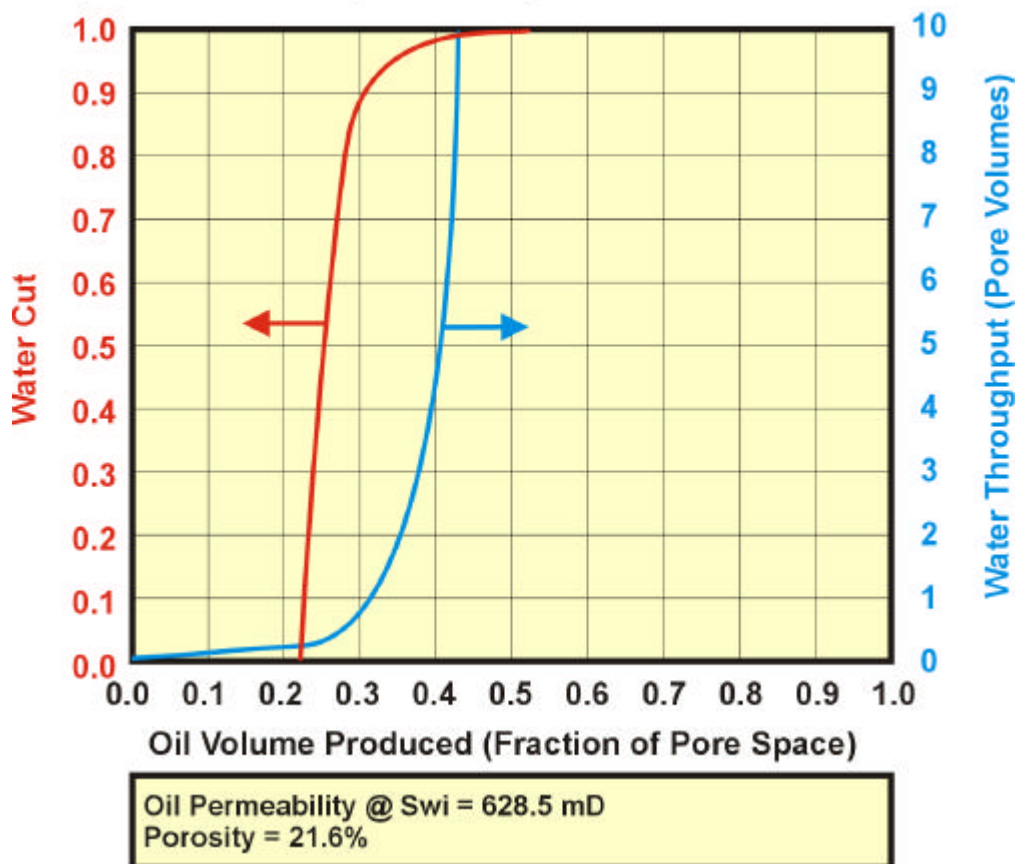


Figure 10.16. Unsteady-state water-oil relperm production analysis example for a water-wet core



10.2.3 Intermediate Systems

Data from intermediate wetting rock-fluid systems can be difficult to assess, especially if a single test mode has been used to obtain data. It is usually necessary to carry out a variety of flood modes to fully assess end effects and rate dependence. A low rate flood followed by a high rate bump flood will usually give an indication of the extent of end effects. Flow reversal may indicate whether low recoveries are due to pore scale end effects evenly distributed within the test plug. Steady state tests may be necessary to fully define the shape of the relperm curves.

Typical intermediate wettability relperm data are shown in Figures 10.17 and 10.18. The shape of the relperm curves is significantly different for the high and low rate floods. However, the volume of oil produced is similar.

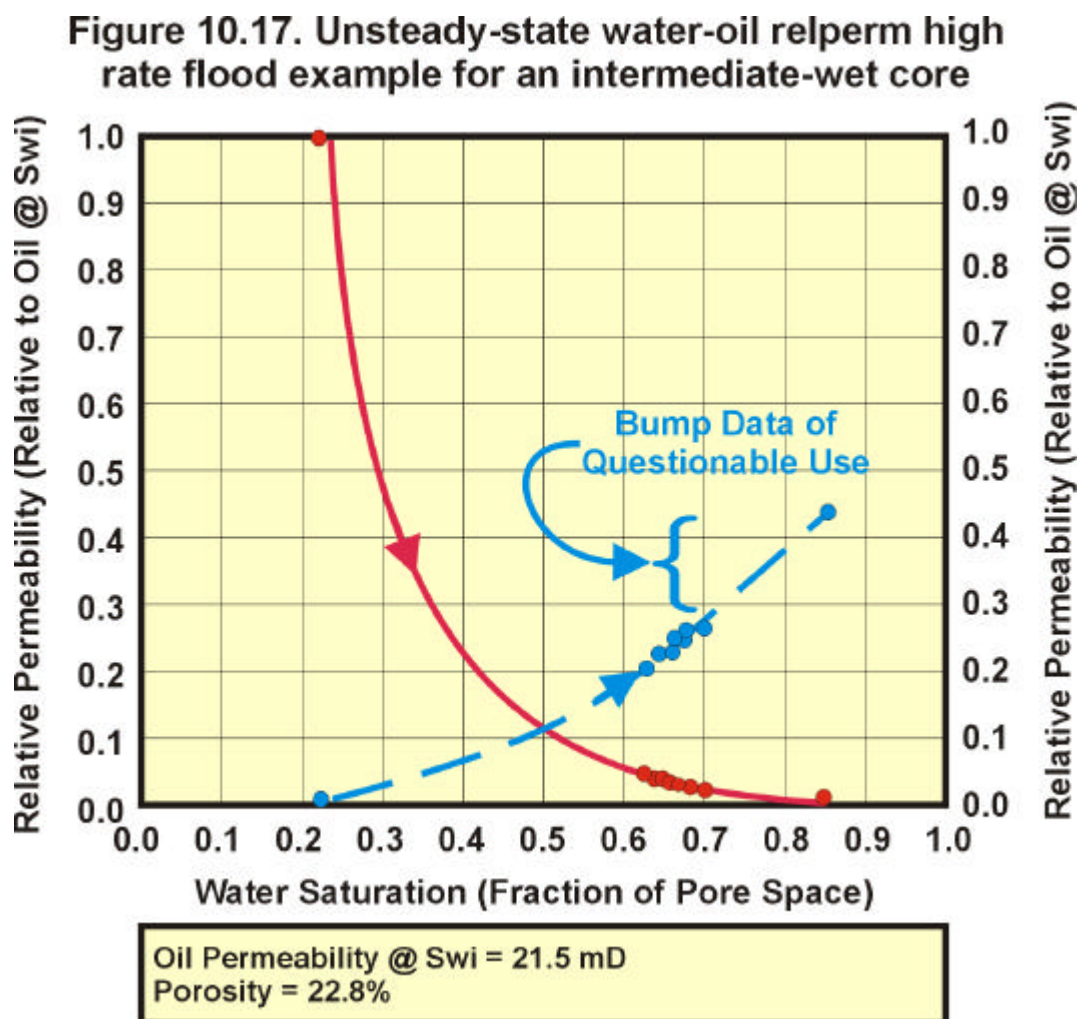


Figure 10.19 shows steady state data obtained from a core containing mobile kaolinite fines. These were mobilised during the prolonged simultaneous flow of oil and brine during the steady state test sequence. They have caused the water relative permeability to be suppressed. Figures 10.17, 10.18 and 10.19 contain data obtained on the same test plug and illustrate the need for more than one test made in obtaining valid relative permeability data. Note also that

the data points are more reasonably spaced and are less scattered for the steady state test, but there are fewer of them. The steady state test is more controlled because it takes much longer to carry out, but the length of time required to come to equilibrium at each flow rate ratio (at least a few days compared to less than one day for a whole unsteady state test) results in fewer data points being taken.

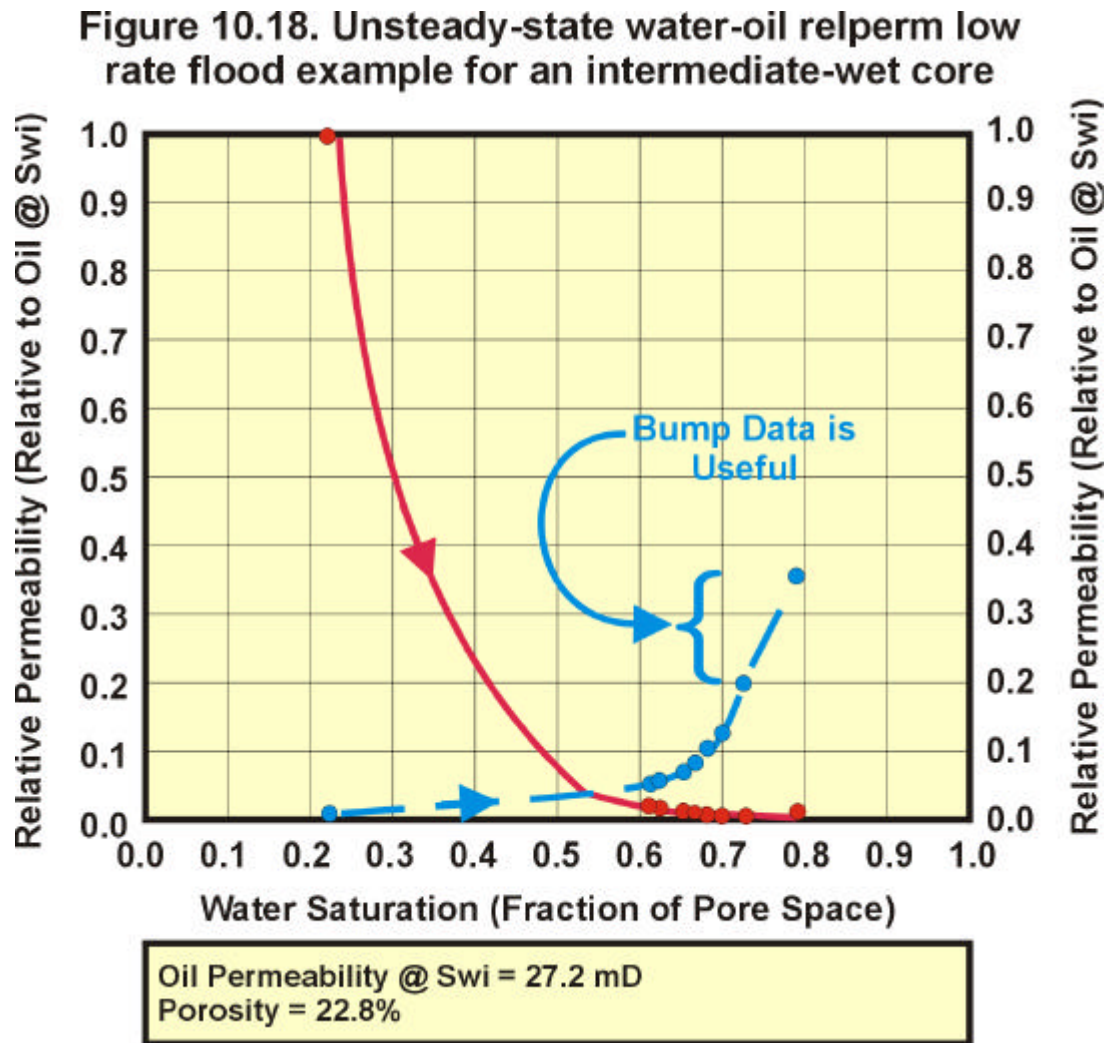
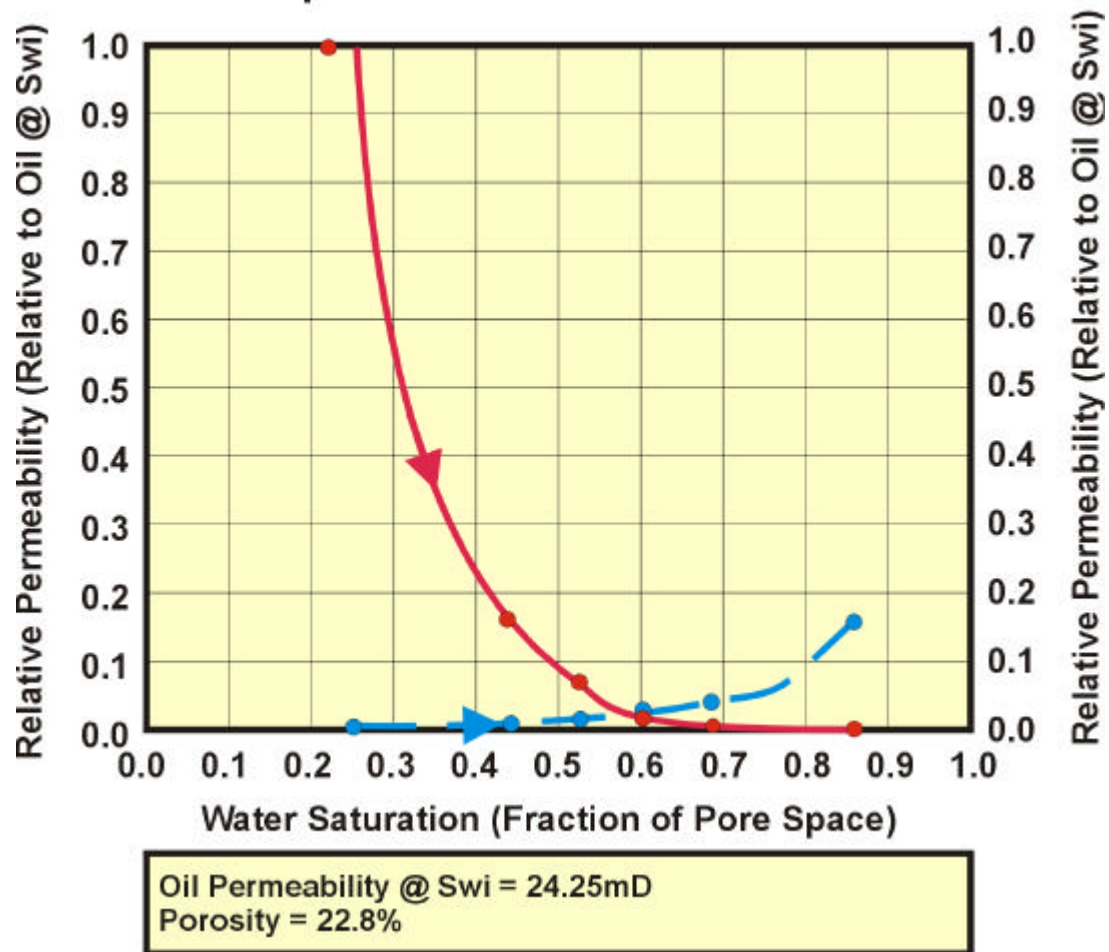


Figure 10.19. Steady-state water-oil relperm example for an intermediate-wet core



10.2.4 Relative Permeability Calculations

This section includes:

- (i) Calculation of relative permeability from laboratory waterflood data and the basic equations from Johnson Bossler & Nauman (JBN).
- (ii) Prediction of fractional flow from relperm curves and capillary pressure data.
- (iii) Fractional flow from transition zones.
- (iv) Variation of fractional flow with viscosity ratio.

I. Calculation of Relative Permeability from Waterflood Experiments: JBN Analysis.

The experimental data generally recorded includes:

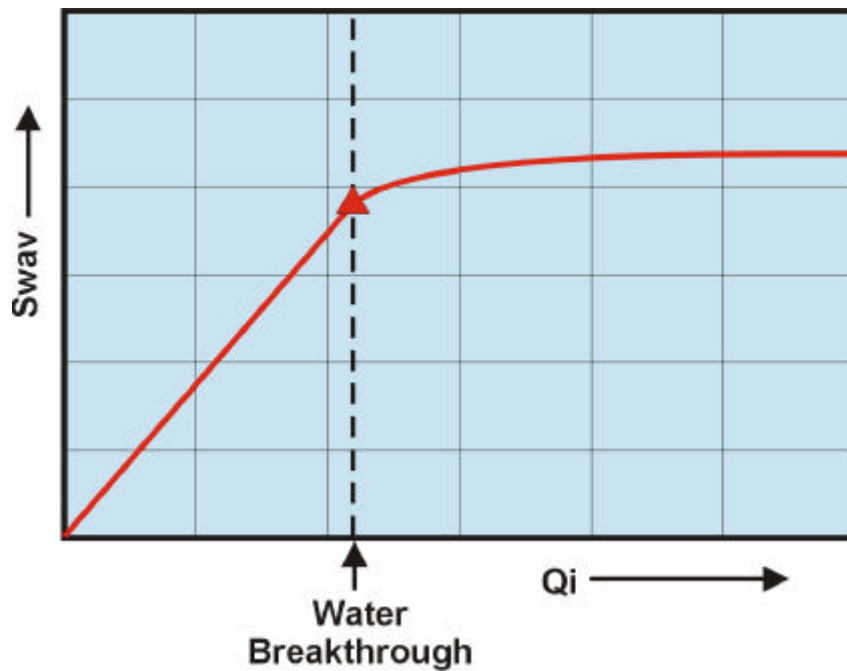
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|--------------|---|---|
| Q_i | = | Quantity of displacing phase injected |
| Δp | = | Pressure differential |
| Δp_i | = | Pressure differential at initial conditions |
| Q_o | = | Volume of oil produced |
| Q_w | = | Volume of water produced |

These data are analysed by the technique described by Johnson, Bossler and Nauman (see reference list [4]), which is summarised below. Three calculation stages are involved:

- (a) The ratio K_{ro}/K_{rw} .
- (b) The values of K_{ro} and hence K_{rw} .
- (c) The value of S_w .

The method is aimed at giving the required values at the outlet face of the core which is essentially where volumetric flow observations are made.

- (a) **K_{ro}/K_{rw}** The average water saturation (S_{wav}) is plotted against Q_i :



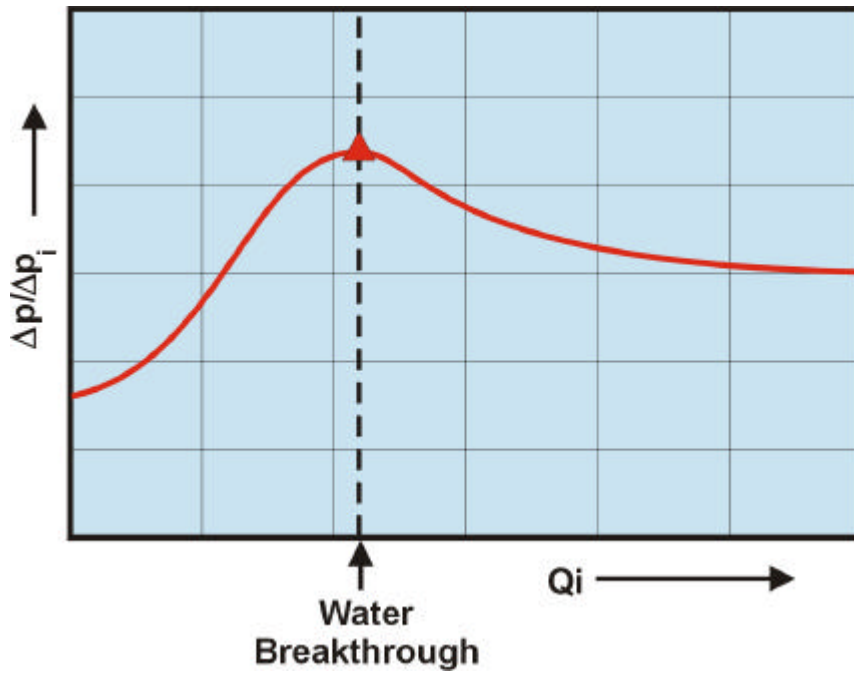
It can be shown that the fractional flow of oil, at the core outlet is given by:

$$f_{out} = \frac{d S_{wav}}{d Q_i} \tag{10.4}$$

Together with:

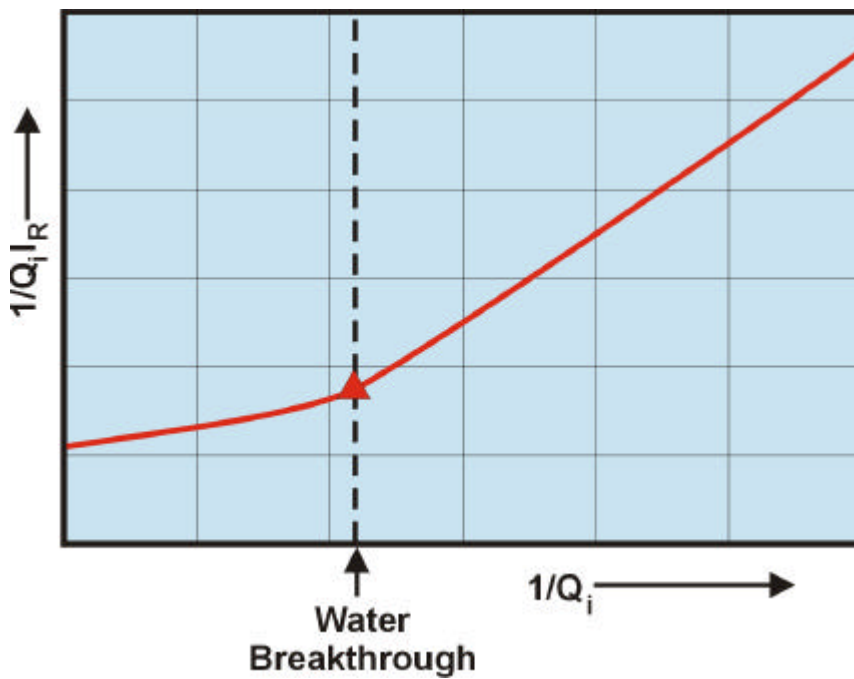
$$f_{out} = \frac{1}{1 + \left(\frac{K_{rw} m_o}{K_{ro} m_w} \right)} \tag{10.5}$$

- (b) **K_{ro}** A plot of $\Delta p/\Delta p_i$ against Q_i is used to obtain the injectivity ratio I_R :



$$I_R = \frac{\Delta p_i}{\Delta p} \frac{1}{Q_i} \tag{10.6}$$

K_{ro} is obtained by plotting $1/Q_i I_R$ versus $1/Q_i$;



and using the relationship;

$$K_{ro} = f_{out} \frac{1}{\frac{d(1/Q_i I_R)}{d(1/Q_i)}} \quad (10.7)$$

Knowing K_{ro}/K_{rw} from (a) above, then K_{rw} can be calculated.

(c) **Using Welges correction** to convert average saturations to outlet face saturations (S_{wout});

$$S_{wout} = S_{wav} - f_{out} Q_i \quad (10.8)$$

Thus K_{ro} and K_{rw} can be plotted against S_{wout} to give the normal relative permeability curves.

II. Prediction of Fractional Flow

Fractional flow can be predicted from capillary pressure data and relperm curves. Capillary pressure data gives the saturations expected, and the relperm curves provide the values for K_{rw} and K_{ro} at that saturation. Water cut can then be calculated.

Water and oil cuts are defined as follows:

$$\text{Water Cut \%} = \frac{\text{Water production}}{\text{Total production}} \times 100\% \quad (10.9)$$

and

$$\text{Oil Cut \%} = \frac{\text{Oil production}}{\text{Total production}} \times 100\% \quad (10.10)$$

Using the radial flow equations;

$$Q_o = \frac{2p K_{eo} H_t P_d}{m_o \ln\left(\frac{R_e}{R_w}\right)} \quad (10.11)$$

and;

$$Q_w = \frac{2p K_{ew} H_t P_d}{m_w \ln \left(\frac{R_e}{R_w} \right)} \quad (10.12)$$

where; H_t = Thickness of the producing zone being considered.
 P_d = Drawdown pressure.

But from equations 10.1 and 10.2;

$$K_{eo} = K_{ro} K \quad (10.13)$$

and

$$K_{ew} = K_{rw} K \quad (10.14)$$

Thus, since the fractional water cut, f_w , is defined as;

$$f_w = \frac{Q_w}{Q_o + Q_w} \quad (10.15)$$

we can say:

$$f_w = \frac{1}{1 + \frac{m_w K_{ro}}{m_o K_{rw}}} \quad (10.16)$$

III. Fractional Flow from Transition Zones

Transition zones or zones with S_w at some value greater than S_{wi} may present problems with unsteady state tests. It may not be possible to perform an unsteady state waterflood starting at S_w values greater than S_{wi} , i.e. where the initial oil saturation is lower than the irreducible saturation attained at 'infinite' capillary pressure. The steady state test may be more applicable in such cases. This situation frequently exists in transition zones before production is started. When production commences the oil/water flow ratio should correlate with steady state water drainage test data, i.e. carried out with S_w increasing. This is the most probable direction in which saturation last changed to place the reservoir in its discovery state.

IV. Variation of Fractional Flow with Viscosity Ratio

For cases where capillary forces are negligible, it can be shown that the fractional flow of water increases as the viscosity of water decreases relative to the oil viscosity. Using the term mobility, defined as:

$$M_{ro} \text{ for oil phase} = K_{ro} / m_o \quad (10.17)$$

$$M_{rw} \text{ for water phase} = K_{rw} / m_w \quad (10.18)$$

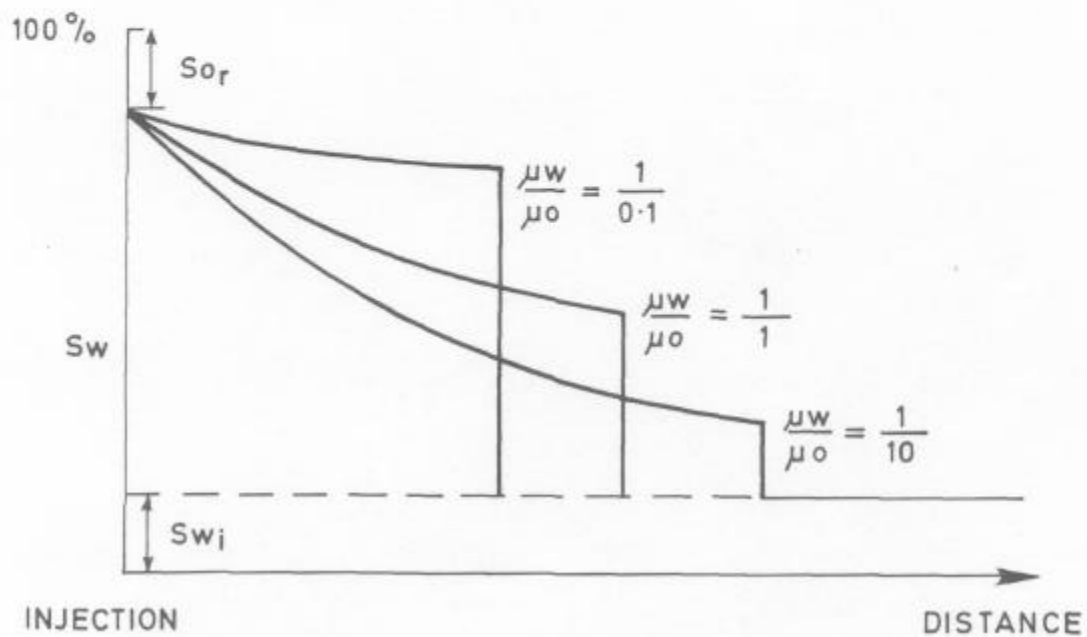
$$\text{the Mobility Ratio } I = M_{ro} / M_{rw} \quad (10.19)$$

Eq. (10.16) is then expressed as:

$$f_w = \frac{1}{1 + I} \quad (10.20)$$

Thus f_w decreases as μ_w is increased or as μ_o is decreased. The effect is shown in Figure 10.20.

Figure 10.20 Saturation Profiles for a Given Flow Rate and Various Viscosity Ratios



10.3 Laboratory Tests Available

There are at least ten usual variations of room condition tests, and each can also be done at full reservoir conditions of confining pressure, fluid pressure, and temperature with live fluids (Table 10.1).

Table 10.1 Common Laboratory Relperm Tests

Type	Mode	S_w	S_o	S_g
Oil/brine imbibition	Steady state	Increasing	Decreasing	$S_g=0$
Oil/brine drainage	Steady state	Decreasing	Increasing	$S_g=0$
Oil/brine imbibition	Unsteady state	Increasing	Decreasing	$S_g=0$
Oil/brine drainage	Unsteady state	Decreasing	Increasing	$S_g=0$
Gas/brine drainage	Unsteady state	Decreasing	$S_o=0$	Increasing
Gas/brine imbibition	Unsteady state	Increasing	$S_o=0$	Decreasing
Gas/oil drainage	Unsteady state	$S_w=0$	Decreasing	Increasing
Gas/oil imbibition	Unsteady state	$S_w=0$	Increasing	Decreasing
Gas/oil drainage	Unsteady state	$S_w=S_{wi}$	Decreasing	Increasing
Gas/oil imbibition	Unsteady state	$S_w=S_{wi}$	Increasing	Decreasing

The most representative and costly test is the reservoir condition waterflood. This is carried out on core which has been restored to full reservoir conditions of temperature, overburden loading, fluid contents (live crude) and wettability. Limited numbers of these tests are performed to assess more economical room condition waterflood data.

In view of the large number of possibilities, detailed discussion here will be limited to those most frequently studied, i.e. water-floods, steady and unsteady state, gas/brine drainage and imbibition, and gas/oil drainage and imbibition.

10.3.1 Oil-Brine Relative Permeability

This is the most frequently requested relative permeability test. It attempts to simulate the displacement of oil by a rising oil-water contact or a waterflood. The choices of test mode available are unsteady state or steady state, and each has its limitations and advantages. In general terms unsteady state tests are less time consuming than steady state tests, but can suffer from uneven saturation distributions (end effects). Displacement rates can be modified to accommodate wettability characteristics to some extent, and to model reservoir flow rates. Steady state tests can be set up to avoid end effects but are more time consuming, requiring time to reach equilibrium at each chosen oil/brine flow ratio.

10.3.2 Oil-Brine Unsteady State Test Procedure

Cleaned cores at S_{wi} are confined in a Hassler or other type of core holder fitted with a breakthrough detector and subjected to a *constant* brine flow. Data recorded are incremental oil and brine production (in calibrated vials), the pressure differential across the core, and the brine breakthrough point. The data are used to calculate the relative permeability characteristics by using the Johnson, Bossler and Naumans technique.

The normal full test sequence is as follows:

- (i) Miscibly clean core by flushing alternately with toluene and methanol; measure weight saturated with methanol.
- (ii) Saturate with formation brine without drying; measure weight saturated with brine.
- (iii) Measure K_{ew} at $S_w=1$.
- (iv) Flood down to S_{wi} at a suitable differential pressure.
- (v) Measure K_{eo} at S_{wi} .
- (vi) Carry out waterflood, recording pressure differential, incremental oil and water production, etc. (data required for JBN analysis).
- (vii) Use JBN analysis to calculate K_{eo} , K_{ew} , K_{ro} , and K_{rw} for various S_{wout} and S_{wav} .
- (viii) Measure K_{ew} , and calculate K_{rw} at S_{or} before and after bump.
- (ix) Clean, dry, measure K_L and ϕ .

Flooding down to S_{wi} is carried out in a Hassler or other type of core holder fitted with a capillary pressure disc. This process may take several weeks, but has the advantage over centrifuge techniques that even saturation distributions are obtained. Oil wet and intermediate systems tend to flood to typically low values of S_{wi} more rapidly, and at lower pressure differentials than water wet systems. Figures 10.9, 10.15 and 10.17 show example data for water-, oil- and intermediate wet cores.

10.3.3 Oil-Brine Steady State Test Procedure

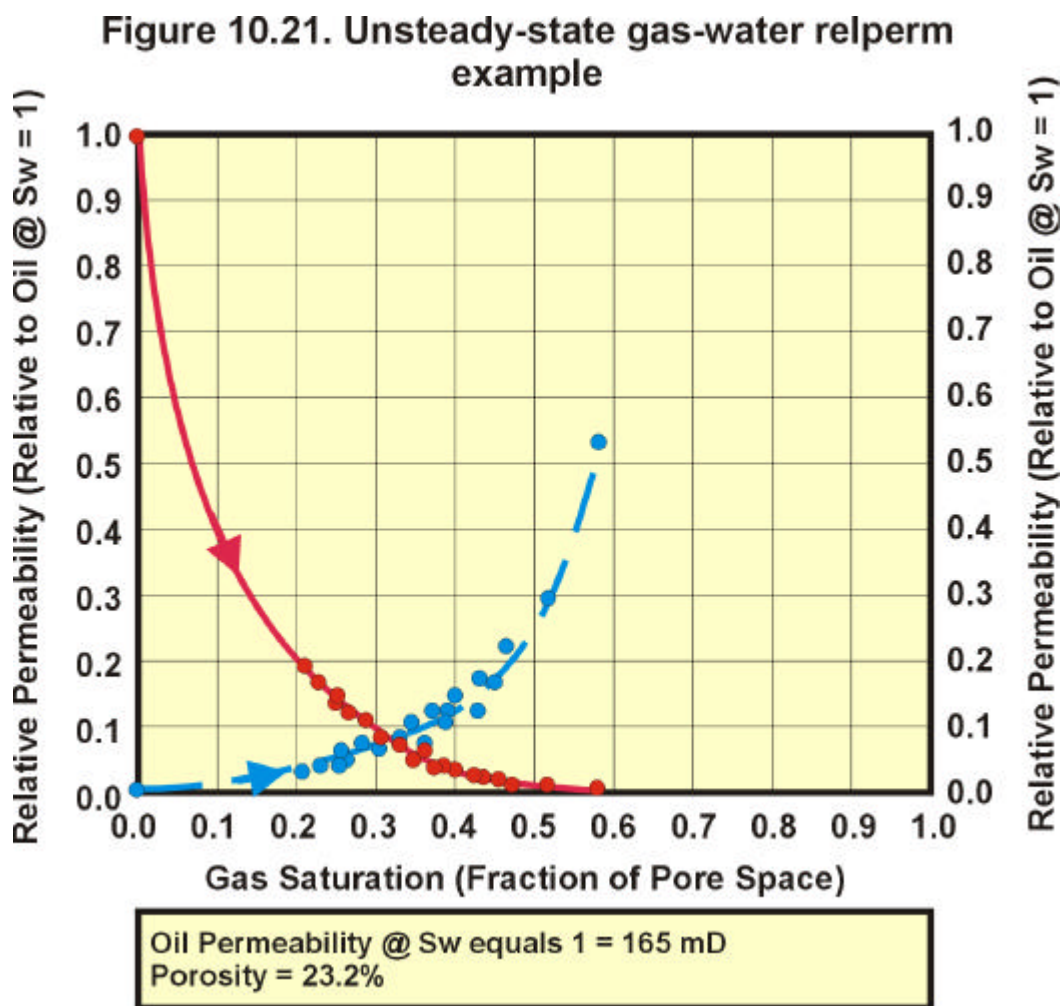
These differ from the unsteady state tests in that oil and brine are flowed simultaneously through the test plug at a fixed ratio until equilibrium is attained, Figure 10.2 (constant pressure differential). The saturations were traditionally determined by demounting the plug and weighing, but are now done using one of the methods discussed at the end of section 10.1. The process is repeated with various oil/brine ratios, changing to suit the expected reservoir history, to build up complete relative permeability curves (e.g., Figure 10.19). The effective permeabilities are simply calculated using Darcy's Law.

The disadvantages of steady state tests are that they are more time consuming both in man-hours and elapsed time than unsteady state floods. It usually takes at least 24 hours for each flow ratio to equilibrate, but this can extend to 72 hours for low permeability samples or samples made from several core plugs abutted to each other to form a long test sample. Estimation of saturation can be difficult for friable samples if grain loss occurs each time the plug is removed for weighing. The methods of measuring fluid saturations *in situ* overcome this problem.

Steady state tests have the advantage that end effects (which can affect certain unsteady state tests) are eliminated. The test core is mounted between mixer heads made from adjacent core material. These have similar wetting characteristics to the test plug and allow the correct flow regime to fully establish itself before the test plug is entered. End effects then occur in the outlet end piece instead of the test plug.

10.3.4 Gas-Brine Relative Permeability Tests

Unsteady state tests are most common due to difficulties handling injection of gas over long periods in steady state tests. Consequently, this section will only deal with unsteady state gas-brine relperm tests. The drainage cycle, i.e. gas displacing brine, models gas injection into a brine saturated zone. Full relative permeability curves are generated and more importantly, gas permeability at irreducible brine saturation. The imbibition cycle models movement of a gas/water contact into the gas zone. Imbibition tests cannot be set up to give the full relative permeability curves, but do give brine permeability at trapped gas saturation and the actual trapped gas saturation itself. Typical gas-brine drainage and imbibition data are shown in Figures 10.21 and 10.22.



The drainage test is performed by flowing gas (saturated with water vapour to ensure that the gas does not evaporate the brine) into a brine saturated plug. Incremental gas and brine production and pressure differential are recorded. Relative permeability curves can then be calculated using JBN analysis.

Figure 10.22 Gas/Brine Relative Permeability Data

Plug Code	K_L , mD	Drainage					Imbibition			
		K_{ew} at $S_w=100\%$ mD	K_{eo} at S_{wi} , mD	K_{ro} at S_{wi} , mD	S_w at End of Test	S_g at end of Test	K_{ew} at S_{gi} , mD	K_{rw} at S_{gi} , mD	S_g at end of test	S_w at end of test
3	12.8	4.3	5.2	1.21	0.38	0.62	0.21	0.05	0.53	0.47
5	411	165	87	0.53	0.42	0.58	1.48	0.01	0.19	0.81
12	103	50	44	0.88	0.21	0.79	1.05	0.02	0.48	0.52

Imbibition data are obtained by recording the pressure differential across the core as brine is flowed into the test plug initially at $S=S_{wi}+S_g$. As the initially dominant gas phase is replaced by more viscous water, the pressure differential rapidly increases to a maximum. It then falls slowly as gas dissolves in the flowing brine. This dissolution is unavoidable to some extent, but can be reduced by equilibrating the injected brine with the gas at pressure prior to injection. It should be noted that the injected brine will not completely displace the gas, and a trapped gas saturation will always remain. The maximum pressure differential is recorded and used to calculate K_{rw} at residual (trapped) gas saturation. K_{rw} at trapped gas saturation can be surprisingly low, values of 0.02 to 0.1 being frequently recorded.

It is interesting to consider the reservoir situation which is slightly, but significantly, different from the laboratory technique. In the reservoir water migrates into the gas zone as pressure declines, but unlike the core test, the gas saturation does not necessarily decline. It tends to remain high or increase slightly, since the trapped gas expands as pressure falls. This maintenance or even increase in S_g tends to keep K_{rw} low or reduce it even further. This scenario operates in many reservoirs even if some of the gas migrates onwards and upwards.

10.3.5 Gas-Oil Relative Permeability Tests

Unsteady state tests can be performed in both drainage and imbibition modes. The drainage mode (gas displacing oil) models gas advance into an oil zone, and usually yields full relative permeability curves. The imbibition cycle provides data for an oil zone advancing into a gas cap but only end point permeability and trapped gas saturation are obtained. It is worth considering the mechanism occurring as an oil reservoir is depleted to a pressure below its bubble point. The process which occurs is represented in Figures 10.23, 10.24 & 10.25.

- (i) Referring to Figure 10.23. Initially gas forms in discrete, immobile bubbles, which reduces K_{ro} very significantly.
- (ii) Figure 10.24. As pressure falls further, the gas saturation increases. The bubbles eventually become connected and give rise to a significant gas permeability. The saturation at which gas becomes mobile is termed the critical gas saturation. K_{rg} rapidly increases and K_{ro} further declines. The relative flow rate of oil is further reduced by the lower viscosity and higher mobility of the gas.
- (iii) Figure 10.25. Eventually the oil droplets become discontinuous and only gas is produced.

Figure 10.23 Microsaturation and Gas Flood Relperm Curve for a Water Wet System: Initial Stage

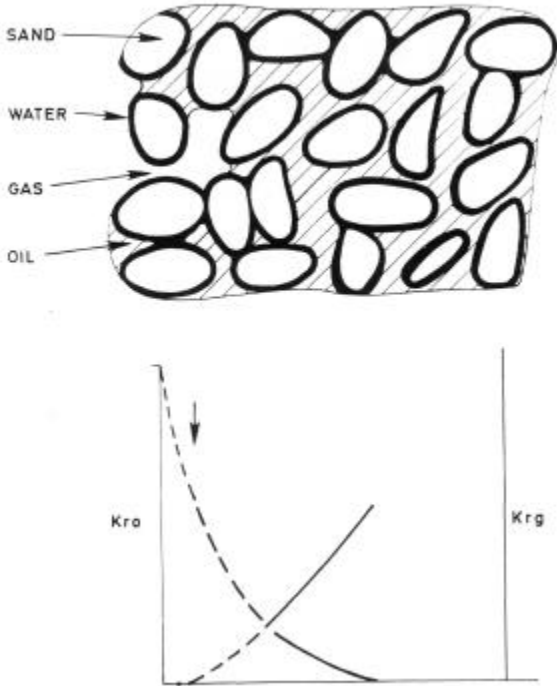


Figure 10.24 Microsaturation and Gas Flood Relperm Curve for a Water Wet System: At Gas Breakthrough

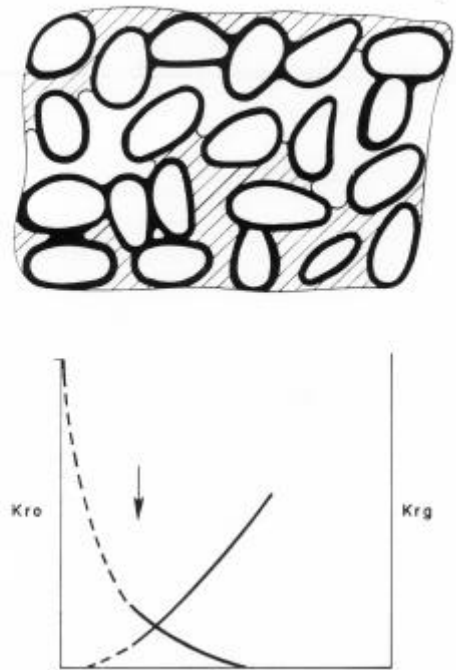


Figure 10.25 Microsaturation and Gas Flood Relperm Curve for a Water Wet System: At Sor

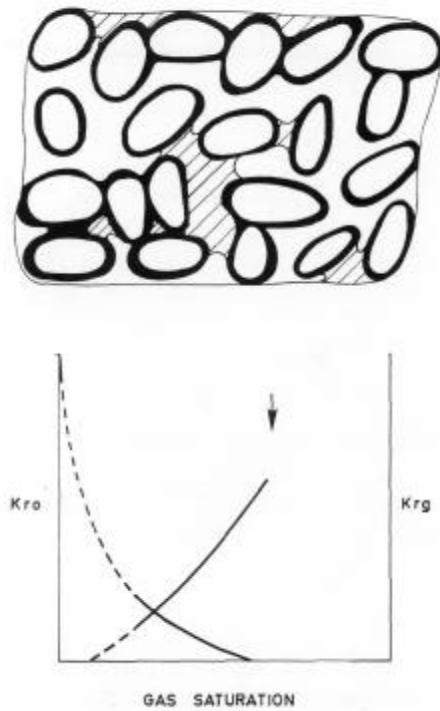


Figure 10.26. Unsteady-state gas-water relperm example for Plug A with $S_w=0\%$

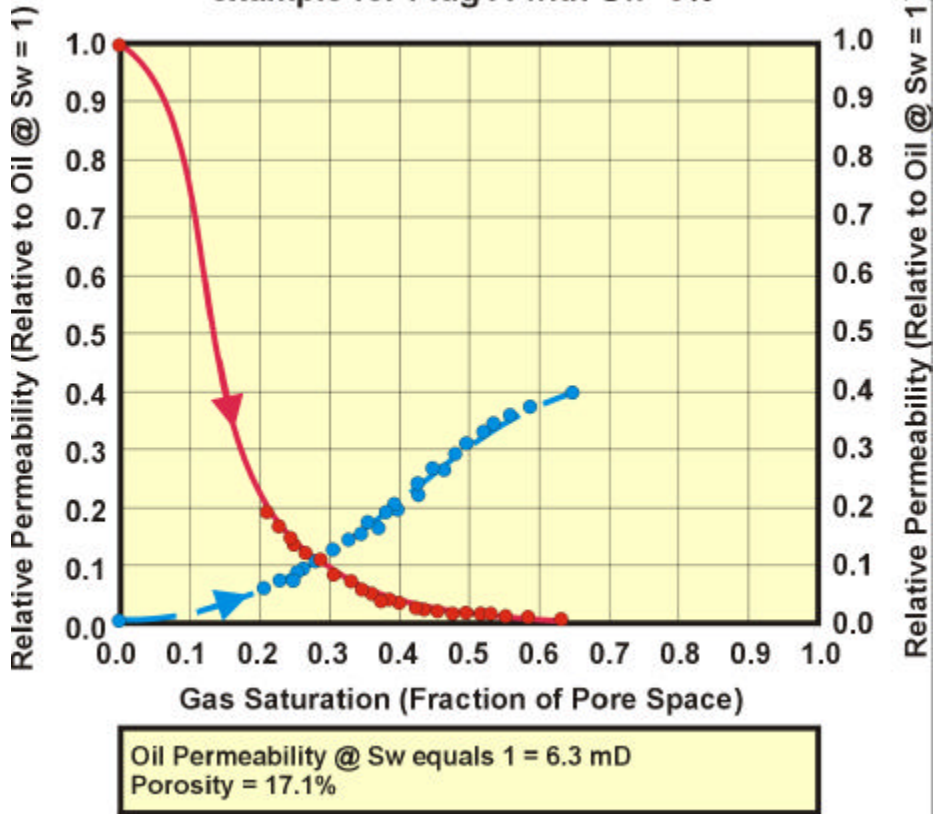
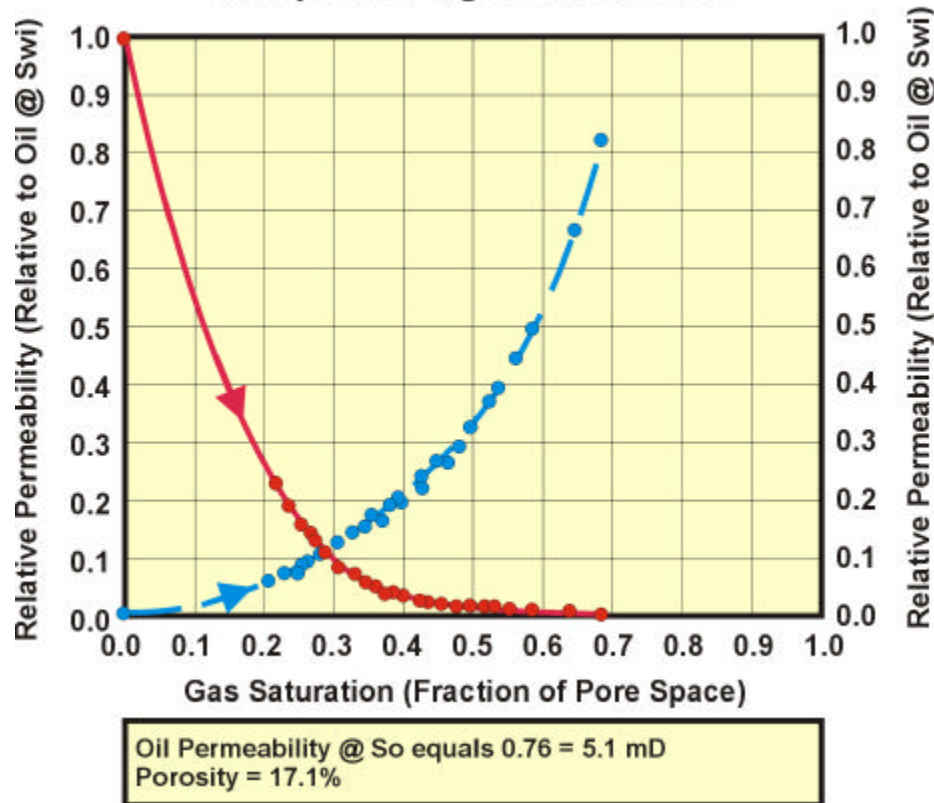


Figure 10.27. Unsteady-state gas-water relperm example for Plug A with $S_w=S_{wi}$



Laboratory gas-oil relative permeability tests are performed in a similar manner to the gas-brine tests. If required, the tests can be performed with connate water present, but this requires that brine saturated cores be flooded to S_{wi} with oil prior to gas flooding. The relative merits of tests with and without connate water have not yet been fully investigated. It can be argued that the connate water will be immobile and this has been found to be true in some experiments. However, where connate water is present we have noticed that K_{rg} tends to show a more concave upwards curve than when it is absent. The situation is very complex, but could possibly be affected by the wetting characteristics of the rock. The effect is shown in Figures 10.26 & 10.27.

10.3.6 Relative Permeability Data Treatment

Interpretation and use of relative permeability data to predict individual well or reservoir performance can be complicated by lateral variations in rock properties. Thus, although the laboratory tests can adequately describe the behaviour of a particular test plug, modelling of a well or reservoir performance may require modified relative permeability data. Correlations of overall curve shape, cross-over points, recovery at a given produced volume, brine permeability at residual oil saturation etc., must all be made with reference to lithology, permeability, and initial fluid saturations.

Choice of test method will be governed by application of data, i.e. high flow rate for near the well bore, and low flow rates away from the well bore. As stressed previously, no one test method can fully describe a system and choice of data will be influenced by laboratory scale limitations; in particular, end effects in oil wet cores and problems sometimes caused by wettability alterations and mobile fines.

Good petroleum engineering reports should highlight any experimental difficulties encountered and indicate the most reliable data. However, it is often impossible to assess service company data since flow rates are seldom constant and $\Delta p/\Delta p_i$ versus Q_i curves are not reported. If you are ever in a position to commission this type of work, ensure that provision of this information is part of the contract.