## Chapter 8: Capillary Pressure

### 8.1 Introduction and Theory

Capillary pressure data are required for three main purposes:

- The prediction of reservoir initial fluid saturations.
- Cap-rock seal capacity (displacement pressures).
- As ancillary data for assessment of relative permeability data.

Capillary pressures are generated where interfaces between two immiscible fluids exist in the pores (capillaries) of the reservoir rock. It is usual to consider one phase as a wetting phase and the other as a non-wetting phase. However, intermediate cases occur which can greatly complicate the picture. The *drainage* case, i.e. a non-wetting phase displacing a wetting phase applies to hydrocarbon migrating into a previously brine saturated rock. *Imbibition* data is the opposite to drainage, i.e. the displacement of a non-wetting phase by a wetting phase. Thus, the drainage data can usually be used to predict non-wetting fluid saturation at various points in a reservoir, and the imbibition data can be useful in assessing the relative contributions of capillary and viscous forces in dynamic systems.

The basic relationship (Figure 8.1) between capillary pressure, interfacial tension, contact angle and pore radius is given by

$$C_p = \frac{2\,\pmb{g}\,\cos\,\pmb{q}}{a}\,.\,A \qquad\qquad (8.1)$$

where;

$C_p$      =      capillary pressure (psi)
$\pmb{g}$      =      interfacial tension (dynes/cm)
$\pmb{q}$      =      contact angle (degrees)
$a$      =      pore radius (microns)
$A$      =      145 x $10^{-3}$ (constant to convert to psi)

Applying this to a water wet rock having a broad spectrum of pore entrance radii, oil migrating into water filled pores under a given pressure differential will only enter pores larger than those indicated by 'a' in Equation (8.1). Thus for oil introduced at 2 psi into a system having $\pmb{g}$ = 40 dynes/cm and $\pmb{q}$ = 0 (water wet), oil will only enter pores larger than

$$2 = \frac{2 \text{ x } 40 \text{ x } 1}{a} \text{ x } 145 \text{ x } 10^{-3} \qquad\qquad (8.2)$$

giving a = 5.8 μm.

If capillary pressure data are available for a given system, it should be possible to convert to another system of known *q* and *g*. This is expanded in Section 8.2.

## Figure 8.1 Capillary Pressure Definition



$$P = (\rho_w - \rho_o)gh = \frac{2\gamma\cos\theta}{a}$$
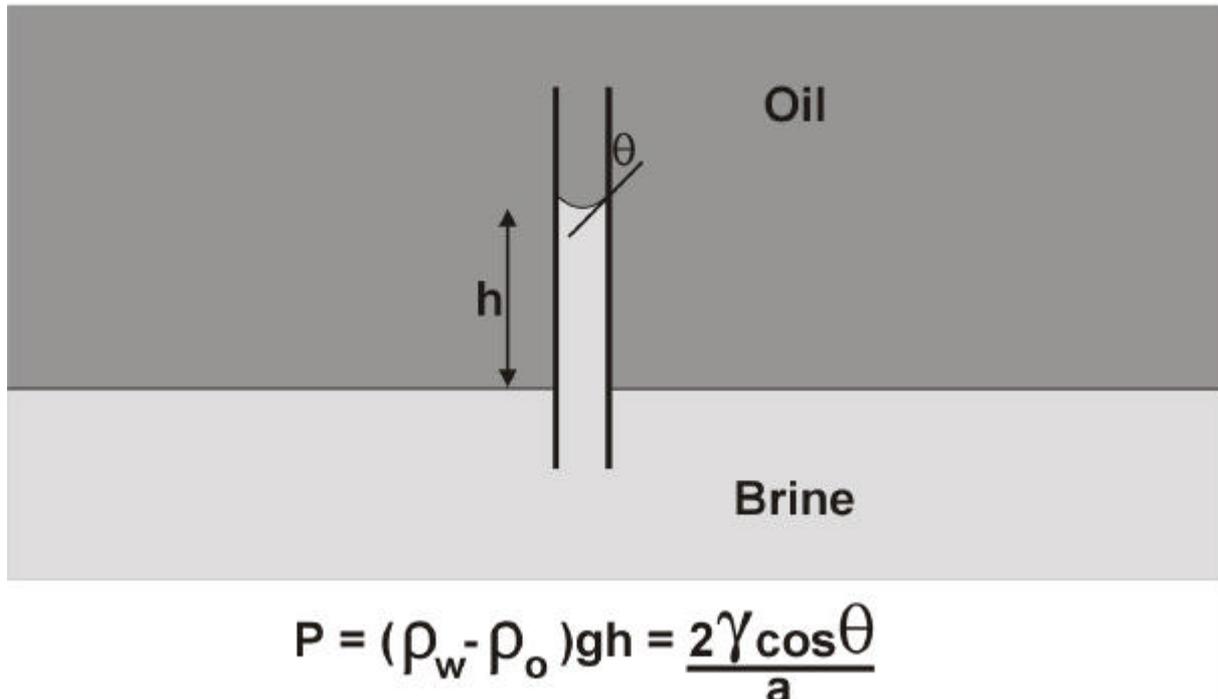
## 8.2 Mercury Injection

These tests can only be carried out on cleaned, dried test plugs. They are initially immersed in mercury at $<10^{-3}$ mm Hg vacuum within the apparatus sketched in Figure 8.2. The pressure in the system, effectively the differential across the mercury/vacuum interface, is raised in stages. The volume of mercury which has entered the pores at each pressure is determined from volumetric readings, and the proportion of the pore space filled can be calculated. This gives the curve shown in Figure 8.3. Further readings can be taken as the pressure is lowered to provide data for the imbibition case from $S_{wi}$ to $C_p = 0$ at point A in Figure 8.3.

The volume of mercury injected into the pores at a given pressure is usually expressed as a proportion of the total pore space, and is presented as a pore size distribution (Figure 8.4) or converted to oil or gas-brine data using appropriate contact angles and interfacial tensions. Typical conversions are given below:-

$$C_p \text{ (gas - brine)} = C_p \text{ (Air - Hg)} \ \frac{72 \cos 0^{\circ}}{480 \cos 130^{\circ}} \tag{8.3}$$

$$= 0.233 \, C_p \text{ (Air - Hg)}$$

$$C_p \text{ (oil - brine)} = C_p(\text{Air - Hg}) \frac{25 \cos 30^\circ}{480 \cos 130^\circ} \tag{8.4}$$

$$= 0.070 \, C_p \, (\text{Air - Hg})$$

## Figure 8.2 Mercury Injection
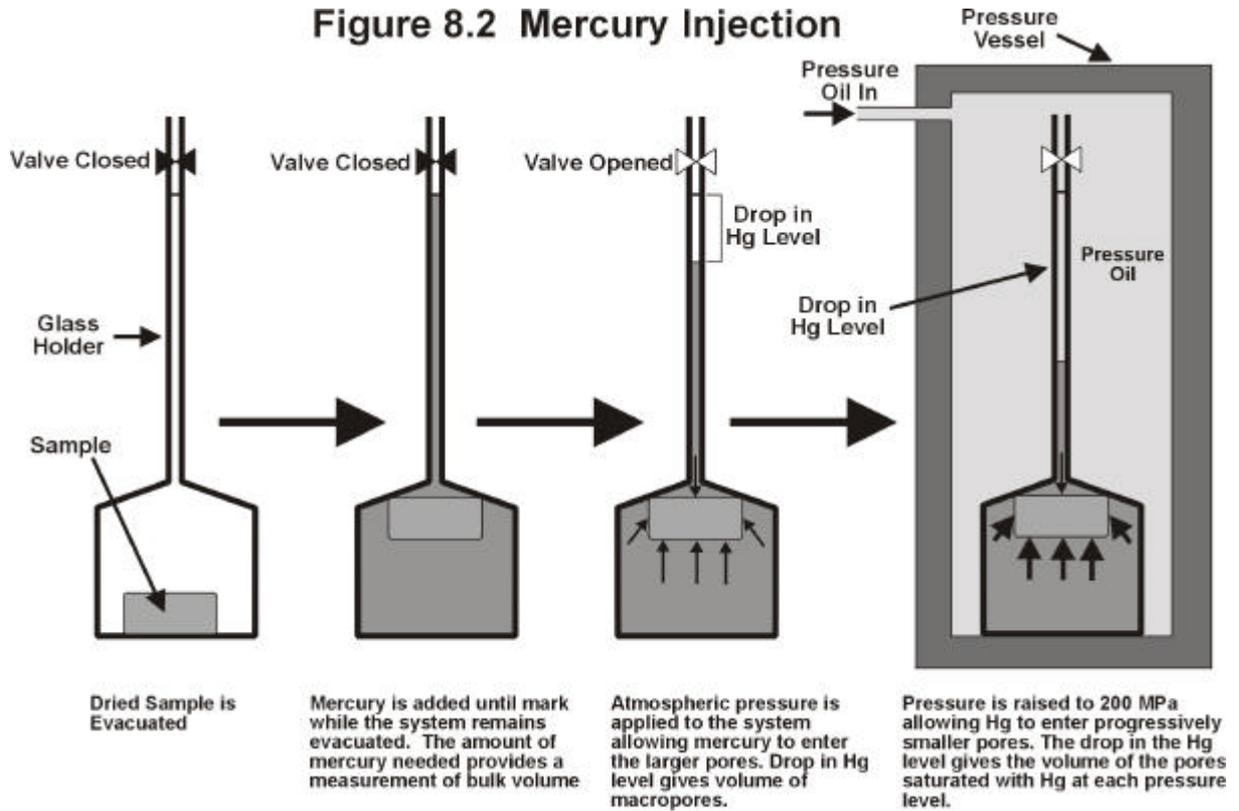


Further conversion to height above oil, or gas-water contact is possible from

$$C_p = hg \, (\boldsymbol{r}_w - \boldsymbol{r}_o) \tag{8.5}$$

Displacement pressures for the assessment of cap rock seal capacity can be assessed from the capillary pressure curves. Care has to be used and allowance made for the effect of surface irregularities. This is especially true of samples with small total pore volumes, i.e. less than 1 ml that are typically the case with cap rock samples.

Approximate permeabilities can also be calculated from pore size distribution data; but care has to be taken to exclude the contribution of surface irregularities, since a small number of large pores *disproportionately* increases the calculated permeability. The data presented in Figure 8.4 shows the effect of surface irregularities at pore throat diameters greater than 10 microns.

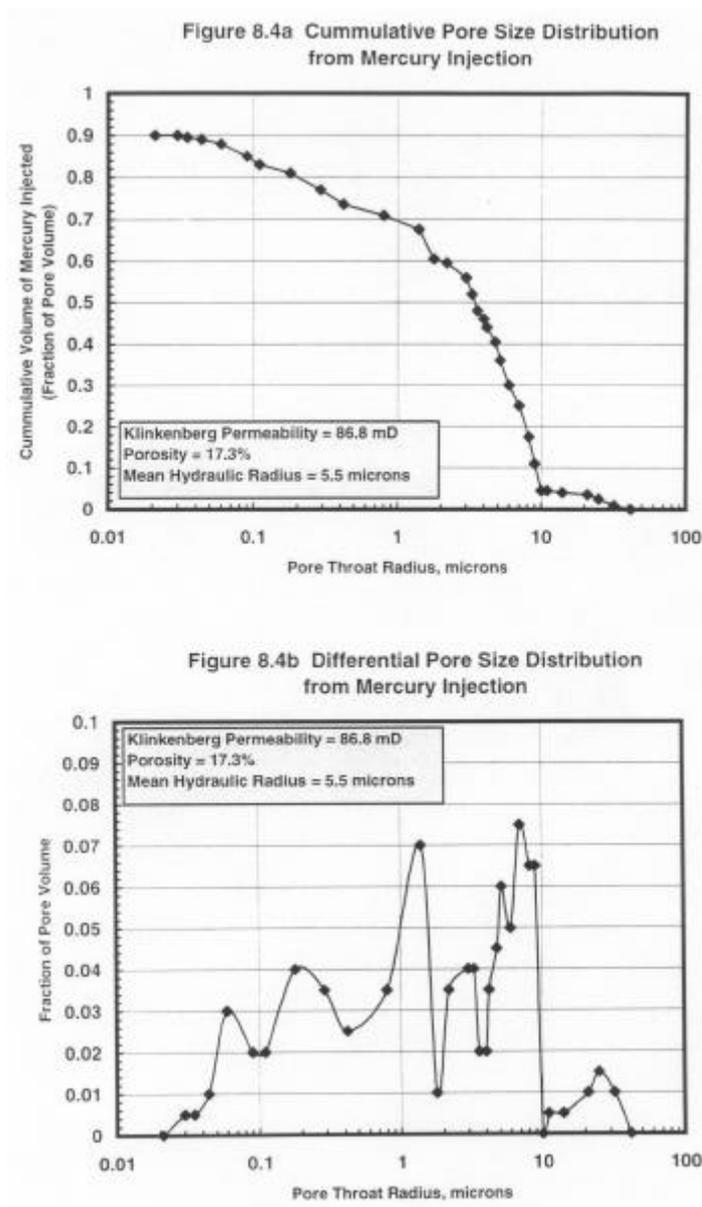## Figure 8.3 Mercury Injection Drainage and Imbibition Data
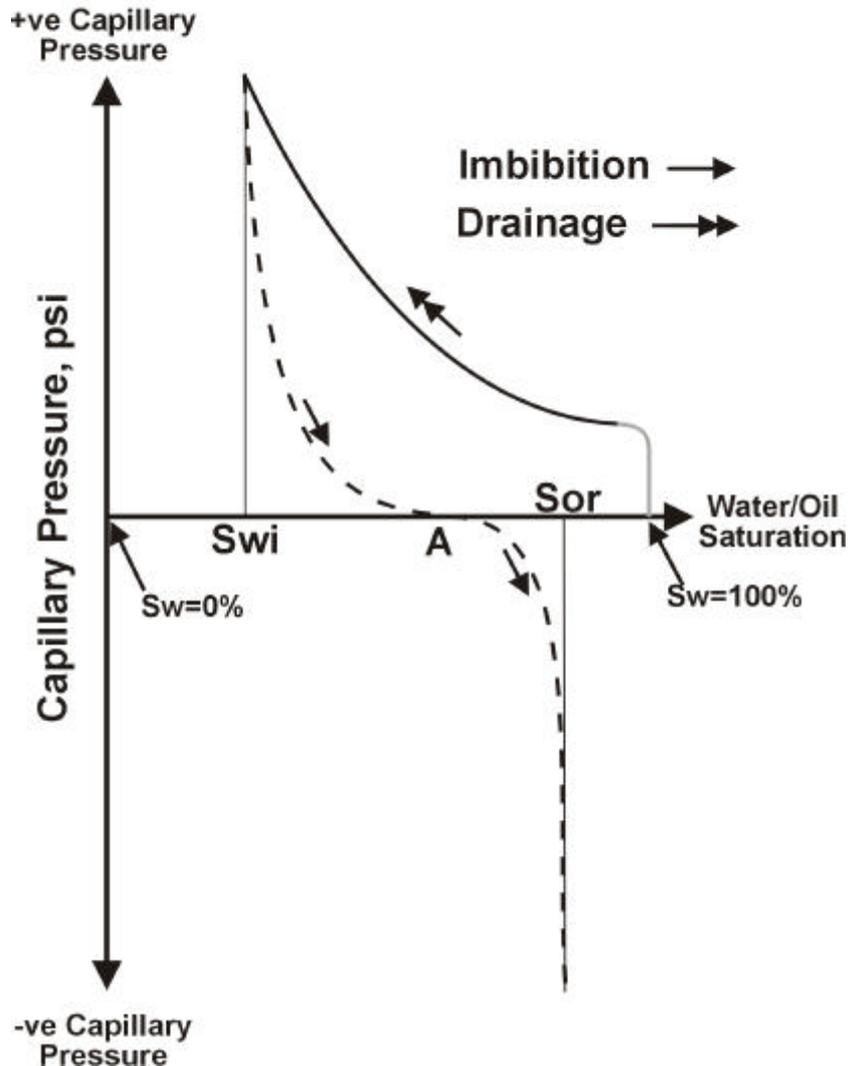


Mercury injection has the following disadvantages:

(i)    It is a destructive test.
(ii)   It is carried out on dried core which allows for no fluid-surface interactions.
(iii)  It can cause collapse of accumulations of grain surface coating minerals.

The latter two effects lead to low implied connate water saturations. The data obtained apply to a system containing a fully wetting phase and a fully non-wetting phase. The capillary pressure data obtained will not necessarily apply to pores containing fluids showing partial wetting preferences.

The advantages of the technique are that it is rapid (about three hours per sample) and irregular samples can be used. A drainage capillary pressure curve can be produced in a matter of hours and in certain circumstances drill cuttings can provide useful data.

Figure 8.4a  Cummulative Pore Size Distribution
from Mercury Injection

Klinkenberg Permeability = 86.8 mD
Porosity = 17.3%
Mean Hydraulic Radius = 5.5 microns

Pore Throat Radius, microns

Figure 8.4b  Differential Pore Size Distribution
from Mercury Injection

Klinkenberg Permeability = 86.8 mD
Porosity = 17.3%
Mean Hydraulic Radius = 5.5 microns

Pore Throat Radius, microns

## 8.3   Porous Plate Method

### 8.3.1    Gas-Brine Systems

This technique is generally applied in the drainage mode to air-brine systems starting with test plugs which are initially brine saturated.  The capillary pressure is applied across the test plug and a brine saturated porous plate.  The high displacement pressure of the porous plate allows brine from the plug to pass through, but prevents flow of the displacing fluid (normally air). The apparatus is shown in Figure 8.5.  Plugs are removed at intervals and weighed until weight (and therefore fluid) equilibrium is attained.  The pressure applied is then increased and the process repeated until a full curve of about six points is obtained.

In this method care has to be taken to maintain good capillary contact between the test plug and the porous plate.  This is assisted by using a paste of filter-aid and brine between the plate and a filter paper.  The test plug is positioned on the paper and a lead weight placed on the plug to keep it solidly in place. There is also the danger that the water in the sample will be

evaporated by the gas pressure. To avoid this the input gas can be saturated with water by bubbling it through a reservoir of water prior to use, and keeping a beaker of water inside the porous plate pressure vessel.
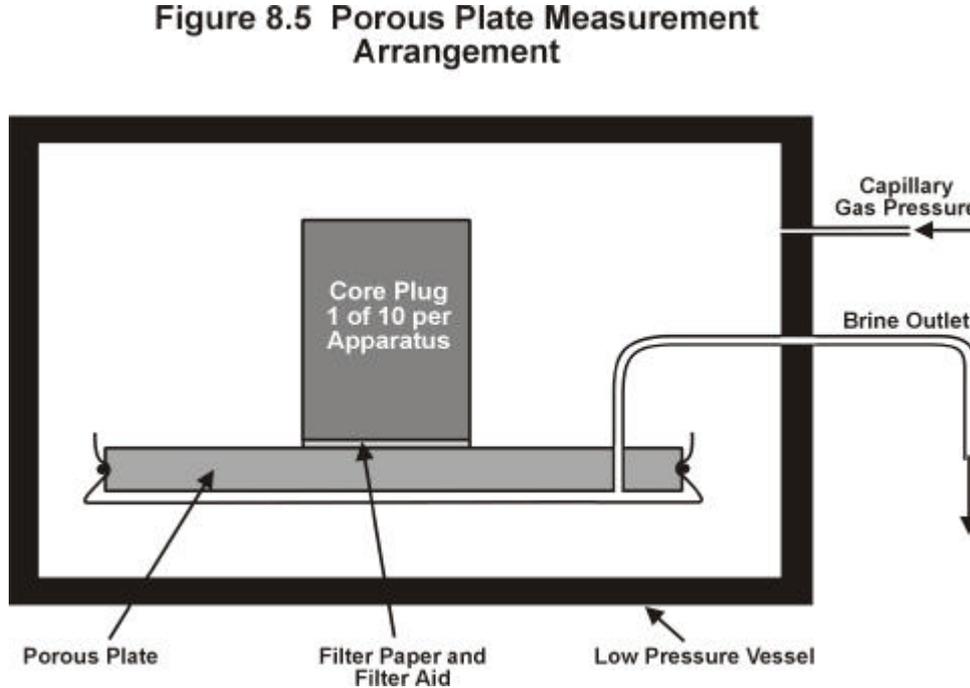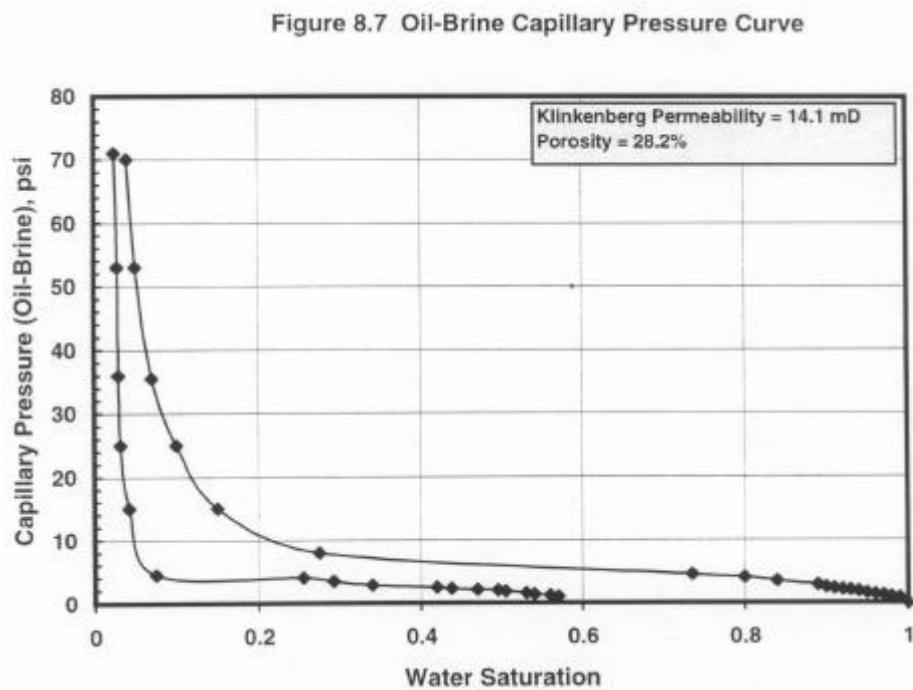


The resulting data is presented as (i) air-brine capillary pressure versus brine saturation (Figure 8.6), (ii) converted to oil-brine data (Figure 8.7), or (iii) as saturation versus height above oil (or gas) - water contact.

Figure 8.7 Oil-Brine Capillary Pressure Curve
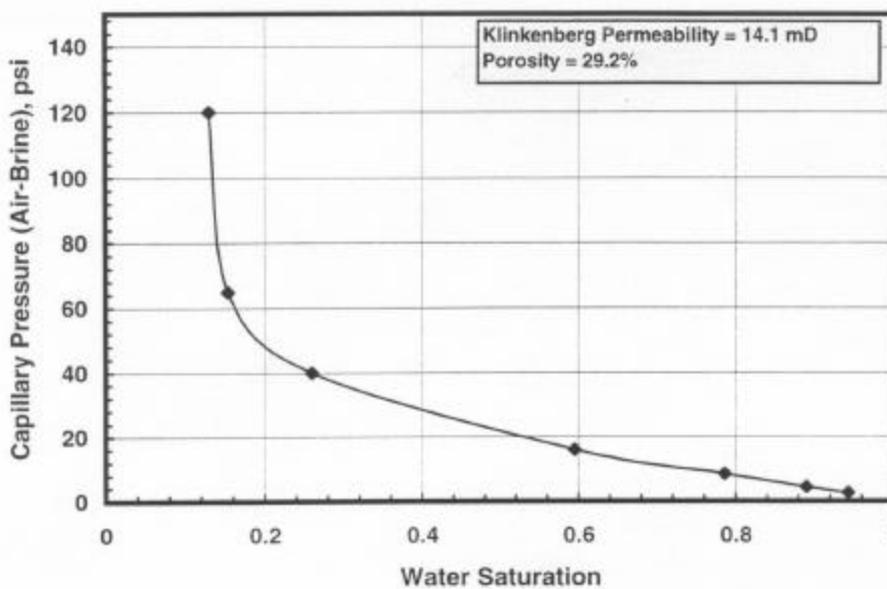
The disadvantages of the porous plate method are that it is time consuming, needing up to twenty days for equilibration at each pressure. Also, capillary contact with the porous plate may be lost at high pressures. This causes erroneously high connate water saturations to be implied. Imbibition measurements are not generally attempted.

The advantage of the method is that the test plug has at least one representative fluid in place, i.e. the brine. This ensures that brine mineral interactions e.g. clay swelling, which affect pore size and surface states, are taken account of. This is a large advantage over the mercury method, which cannot take account of clay-water interactions.

## 8.3.2 Oil Brine Systems

It is more difficult to make oil-brine measurements than air-brine. For a fully water-wet system, oil-brine drainage capillary pressure data can be inferred from air-brine data. Actual oil-brine drainage capillary pressure can be measured using a Hassler cell fitted with a brine saturated disc (see Figure 8.8). An initially brine saturated test plug is subjected to an oil pressure at the inlet face, and the volume of brine produced (oil taken up) observed at the outlet. Once equilibrium is achieved (this may take 1-3 weeks), the pressure is increased and the process repeated until a full curve is obtained. Care has to be taken that the displacement pressure of the disc is not exceeded, leading to brine displacement from the disc as well as the test plug. This can only be checked and allowed for by weighing the disc before and during the course of the experiments.

The disadvantages of the method are basically the same as for the gas-brine case, but with added complications if test plug wetting characteristics differ from those of the reservoir. The method is limited to approximately 50 to 100 psi depending upon disc characteristics. Imbibition measurements are extremely difficult and are limited to about 25 psi.

Figure 8.8 Hassler Cell Arranged for Capillary Pressure Measurement
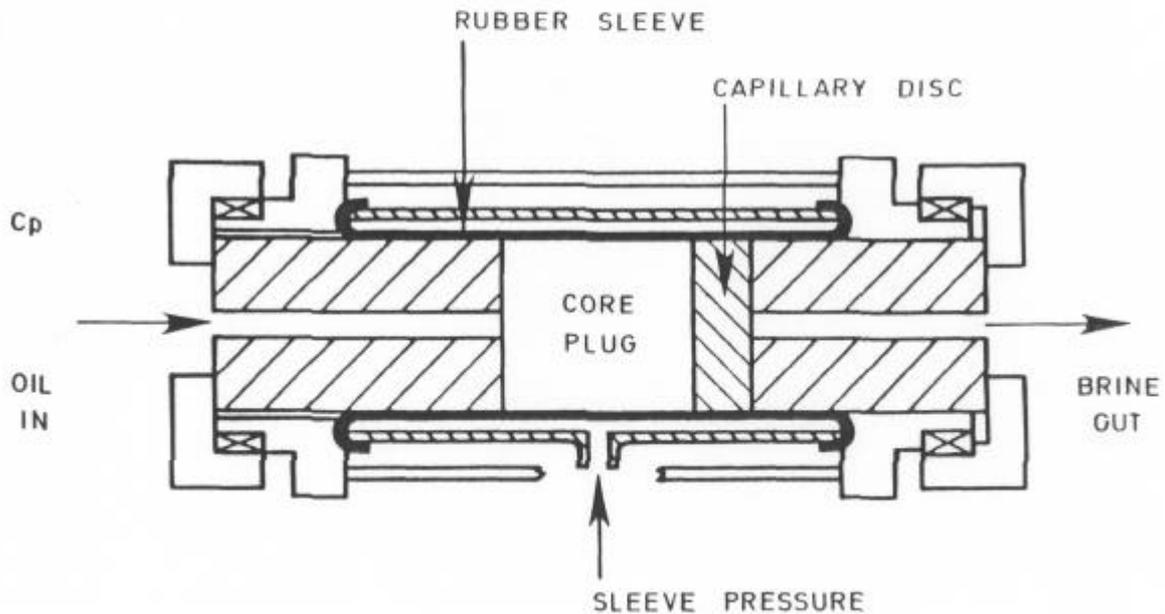
The advantages of the method are that, if the wetting characteristics are as in the reservoir, then representative data should be obtained for both mixed and oil wet systems.

### 8.3.3    Other Methods

There are several other more advanced methods of measuring capillary pressure that are currently being investigated by the hydrocarbon industry. All use a core in a Hassler or similar coreholder under confining pressure. The major ones are:

(i)    **The Dynamic Method**    This involves injecting the two fluids into a rock core simultaneously, and producing one behind a semi-permeable membrane.

(ii)    **The Semi-Dynamic Method**   This involves injecting a single fluid, while a membrane at the far end of the rock is washed with the other fluid. This method can be used to measure the complete drainage and imbibition parts of the capillary pressure curve.

(iii) **The Transient Method**    This method is technologically complex, and involves the measurement of saturation and pore fluid pressures simultaneously during fluid injection into the sample.

## 8.4 Centrifuge Method

The centrifuge method is widely advocated by US companies.  It relies upon increasing the g-term in the equation;

$$C_p \ = \ h \, g \, (r_w - r_o), \tag{8.6}$$

by spinning the core plug at a known radius and rpm.  The average capillary pressure is then given by:

$$C_p \, (psi) = 7.9 \text{x} 10^{-8} \, (r_1 - r_2) \, R^2 \, (r_b^2 - r_t^2) \tag{8.7}$$

where $r_1$ and $r_2$ are the densities of the two phases present and $r_b$ and $r_t$ are the radii of rotation of the bottom and top of the core respectively.

For the oil-brine drainage cycle, brine saturated test plugs are immersed in oil in specially designed holders.  Starting at a low rpm setting, the amount of brine expelled from the plug is noted for a given rate of rotation. The volumes are measured in the following manner. A calibrated glass vial is attached to the end of the sample. The volume of fluid being deposited in this vial can be read while the centrifuge is spinning fast using a stroboscope.  The rate is then increased in stages and produced brine volumes are recorded for each rotation speed to give the drainage curve. The imbibition curve can then be followed by stopping the centrifuge allowing spontaneous imbibition to occur to point A at $C_p = 0$ (Figure 8.3). The fluid in the imbibition cell is then changed from brine to oil, and the portion of the curve from A ($C_p$) = 0 to $S_{or}$ (Figure 8.3) can then be followed by recording the volume of oil produced at several increasing rates of rotation.

The main disadvantage of the centrifuge method is that a capillary pressure gradient is applied which must inevitably give rise to a saturation gradient.  This will be more exaggerated at low pressures.

The advantages of the centrifuge method are that it is rapid, a full drainage and imbibition cycle being complete in a matter of days, and that oil-brine data can be obtained, hopefully, under representative wetting conditions.  Centrifuges can also be operated at elevated temperatures (up to 150°).

Differences in wetting characteristics should be taken into account when applying laboratory data to the field.  Thus air-brine and mercury-air data obtained on cleaned core will represent a fully water wet system for the drainage case.  They may not adequately describe a mixed or oil wet system.  The closest one can get to this situation, on a routine basis, is with an actual oil-brine system when one would expect to find lower $S_{wi}$ values than a water wet system.

## 8.5  Applications of Methods

The applications of the various major methods described above are given in Table 8.1.

**Table 8.1** Parameters associated with various capillary pressure measurement methods.

| Range | Method | | | | |
|---|---|---|---|---|---|
| | **Mercury** | **Porous Plate** | | **Centrifuge** | |
| | **Hg - Air** | **Air - Brine** | **Oil - Brine** | **Air - Brine** | **Oil - Brine** |
| **Drainage** | $S_w = 1$ to $S_{wi}$ | | | | |
| **Imbibition** | $S_{wi}$ to $C_p=0$ | | $S_{wi}$ to $C_p=0$, $C_p=0$ to $S_{or}$ | $C_p=0$ to $S_{or}$ | $C_p=0$ to $S_{or}$ |
| **Sample wetting state** | Water wet | As sample | | | |
| **$S_w$ precision** | tends low | tends high | tends high | not known | not known |
| **Pressure limit, psi** | 1150 | 70-100 | 70-100 | 1000-2000 | |
| **Elapsed time** | 1-2 days | 3 months | 3 months | 1-3 days | 1-3 days |

## 8.6  Capillary Pressure Prediction (Leverett Method)

The Leverett 'J' function is an attempt to correlate capillary pressure with pore structure (defined in terms of porosity and permeability). The basic capillary model predicts that to displace a wetting phase with a non-wetting phase then:

$$C_p = \frac{2g \cos q}{a} .$$

(8.8)

For a simple capillary model, the mean hydraulic radius, a, is given by:

$$a = 2\sqrt{2}\, e \left(\frac{K}{q}\right)^{1/2}$$

(8.9)

Combining Eq. (8.8) and (8.9) we get;

$$\frac{C_p \left(\dfrac{K}{q}\right)^{1/2}}{g \cos q} = \frac{1}{\sqrt{2}\, e}$$

(8.10)

from which the Leverett 'J' function is defined:

$$ J = \frac{C_p \left( \dfrac{K}{q} \right)^{1/2}}{g \, \cos q} \tag{8.11} $$

or;

$$ J = 0.217 \, C_p \left( \frac{K}{q} \right)^{1/2} \tag{8.12} $$

where $C_p$ is in psi, $g$ is in dynes/cm, and K is in mD.

Given a typical J curve, the capillary pressure curve for a material of similar pore structure can be calculated for a given value of $q$ and K.