CORE ANALYSIS

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CONTENTS

1. ROCK PROPERTIES

1.1 Introduction

A porous medium is extremely complex. Pore structure affects all rock properties; however, we cannot hope to describe rock properties on a microscopic scale. A macroscopic approach allows engineers and earth scientists to quantify material properties, although it must be recognized that important information may be lost. Two important rock properties are porosity and permeability. Permeability is handled differently depending on the number of fluid phases present in the porous material. Capillary pressure caused by interfacial tension plays an important role in the recovery of hydrocarbons. Rock compressibility affects reserves calculations and recovery efficiency. It is also important to understand how rock properties are measured to appreciate the limitations and inherent inaccuracies of the data under consideration.

1.2 Porosity

Porosity is a measure of the pore space in reservoir rock and hence determines the fluid capacity of the medium. Porosity ϕ is defined as follows:

$$\phi = \frac{\text{volume of pores}}{\text{total rock volume}} \cdot$$

The limiting values of porosity can be determined by considering a porous medium consisting of systematically packed spheres of uniform size. Figure 1.1 shows the "loosest" and "tightest" sphere packing arrangements for cubic packing and rhombohedral packing, respectively. The porosities of these packing arrangements are:

Packing	Porosity
Cubic	47.64%
Rhombohedral	25.95%

Porous media will never be organized systematically. The porosity of nonuniformly packed spheres of identical size will vary between the above

2. Sensitivity of Recoveries Predicted for Waterfloods to Relative Permeability

Depending on the importance of gravity drainage, recoveries predicted for waterfloods depend primarily on the water-oil relative permeability ratio vs saturations or on the relative permeability to oil at lower saturations. In reservoirs with low viscosity oils and high vertical permeabilities, gravity segregation may be important and hence accurate relative permeabilities to oil at low saturations are needed.

As a general rule, it may be said that the k_{rw}/k_{ro} ratio curves control displacement efficiency when gravity segregation is not important. The oil relative permeability-saturation relations at low oil saturations control displacement efficiencies when gravity segregation is important.

3. Sensitivity of Gas Drive Recovery Predictions to Errors in Rock Properties

Recoveries predicted for gas drive reservoirs are much more sensitive to errors in core data than are those for water drive. Gas drive recoveries can be very high, >80% OOIP, if vertical permeabilities are high. On the other hand, recoveries by gas drive may be only 30 or 40% OOIP if flow is confined to that along bedding planes. As discussed above for water drive, errors in gas drive recovery caused by errors in the gas-oil relative permeability saturation can be determined by one-dimensional displacement efficiency calculations.

Similar one-dimensional calculations can demonstrate that the oil relative permeability saturation-relation and the vertical permeability determine the recovery by gravity segregation.

B. Use of Core Data in Reservoir Simulators

When the reservoir is sufficiently large to justify the cost, computer models are usually built to simulate the reservoir. Simulators require that the permeability and porosity of each block be specified. Hence, core data must be extended to the regions between wells to construct the models. Increasing use is being made of geologic computer models such as SACM and others in generating data for blocks between wells.

limiting values, but will tend to be closer to rhombohedral packing as the spheres attempt to arrange themselves in the most stable fashion.

Naturally occurring particles are seldom spherical in shape and are present in a range of sizes. A nonuniform size distribution is typified by smaller particles occupying the interstitial spaces formed by larger particles. This reduces the porosity. Porosity is also affected by particle shape and by crushing of the material as overburden pressure is applied. This means that porosity is not a simple function of grain size distribution. Table 1.1 shows porosity measurements and grain size distributions of several sandstones. Note the slight differences in particle size distributions of samples 7 and 8 and the measured porosity values of 19.7% and 15.9%, respectively.

1.3 Absolute Permeability

Permeability is a measure of the ability of a fluid to flow in a porous medium. Permeability is a macroscopic property that quantifies the continuity of interconnected pore spaces. In 1856 the French engineer Darcy developed a relationship to describe fluid flow in porous rocks. He found that the volumetric flow rate was proportional to the pressure gradient and inversely proportional to the viscosity of the fluid. By introducing a property with units of area, the darcy, determined only by the structure of the medium in question and entirely independent of the nature of the fluid, Darcy's Law became (in oilfield units):

$$q = 1.127 \times 10^{-3} \frac{kA(p_1 - p_2)}{B\mu L} , \qquad (1.1)$$

where:

q = flow rate, stb/day;
k = permeability, md;
A = flow area, ft^2;
μ = fluid viscosity, cp;
L = flow length, ft;
p_1, p_2 = inlet and outlet pressures, psi; and
B = formation volume factor, res. bbl/stb.

above example errors in porosity and water saturation, the error in oil in place would be $\frac{(1.1)(1.071)(1.1) - 1.0}{1.0}$ X 100 or 29.6% too high. Obviously, careful, objective analysis of all data is necessary to yield proper oil in place values.

III. OIL RESERVES

The oil reserves are defined as the amount of oil which will actually be recovered. Reserves are the oil in place times the recovery efficient and depend on the type of drive and on operating decisions. Use of core data in predicting recovery efficiencies is discussed below.

A. Use of Core Data in Calculating Displacement Efficiency

Recovery efficient is defined as the displacement efficient times the volumetric sweep efficiency. Displacement efficiency is defined as the fraction of the oil originally in place displaced from the region actually invaded. Displacement efficiencies are usually calculated from relative permeability - saturation relations using one dimensional procedures as outlined below.

Displacement of oil by water in a one-dimensional system is usually calculated by the Welge procedure. The equations of interest are as follows:

$$Fw = \frac{1 - c_1 k_{ro}}{1 + \frac{k_{ro}\mu_w}{k_{rw}\mu_o}}$$

and $C1 = \frac{0.00784\ kA\ \Delta p \sin a}{q_t \mu_o}$

in which,

Fw = Fraction of the flowing stream that is water

k = Permeability, darcy's

k_{ro} = Relative permeability to oil fraction,

k_{rw} = Relative permeability to water, fraction

$$\frac{L}{K_{avg}} = \frac{l_1}{k_1} + \frac{l_2}{k_2} + \frac{l_3}{k_3} \quad . \qquad (1.3)$$

where:

L = total length;
l_1, l_2, l_3 = individual zone lengths;
K_{avg} = average permeability; and
k_1, k_2, k_3 = individual zone permeabilities.

Note the similarity between these equations and the equations for parallel and series resistors in electric circuits.

1.4 Relative Permeability

Darcy's Law was developed to describe single phase flow of an incompressible fluid in a porous medium. In hydrocarbon reservoirs water is almost always present and may be mobile or immobile. The absolute permeability, measured in a single phase system, is independent of fluid properties. With more than one phase present, the movement of each fluid is governed by a separate effective permeability. The effective permeabilities are a function of fluid saturation and are always less than the absolute permeability. This occurs because of fluid-fluid and rock-fluid interfacial tension. In fact, the sum of effective pemeabilities cannot exceed the absolute permeability, for any saturation condition.

Several rock properties are important in the discussion of relative permeability. The irreducible water saturation, s_{wir}, is the lowest water saturation that can occur in the rock. This should not be confused with the connate water saturation, s_{wc} , which is the water saturation at native state. At the irreducible water saturation, water will not flow and the effective permeability to water, k_w , is zero. As the water saturation increases from s_{wc} in an oil-water system, water and oil can flow simultaneously until the residual oil saturation s_{or} is reached, at which point there is no oil flow and k_o=0. In between the two limiting values of saturation, k_w monotonically increases and k_o monotonically decreases. The shapes of the oil and water effective permeability curves is dominated by

Maps of porosity-thickness of each zone can then be prepared and used with structure maps to develop curves of pore volume versus depth.

B. Saturation Distribution

The oil saturation in a reservoir is usually determined from height vs water saturation curves calculated from capillary pressure tests of small cores. The first step in this procedure is to measure capillary pressure saturation relations as discussed in previous lectures on several cores from each geologic zone. A capillary pressure correlation is then obtained fro each zone. Several methods of correlation are usually tried to find the technique which best fits the data. Correlation methods are,

(1) The Leverett J - Function $J_{(s)} = \frac{Pc}{\sigma \cos \phi}\sqrt{k / \phi}$

in which $J_{(s)}$ is the dimensionless J function

P_c = Capillary pressure, dynes/cm^2

σ = Interfacial tension, dynes/cm

$\cos\phi$ = Cos of the contact angle

k = Permeability, cm^2

ϕ = Porosity, fraction

The J - Function is effective in correlating data where the permeability varies because of change in grain size.

(2) Water Saturation at a Given Capillary Pressure Level vs Permeability

This method works in shaley sands when permeability is reduced as the amount of clay present increases.

(3) Water Saturation at a Given Pressure vs Porosity

Sometimes porosity is the best correlating parameter in rocks with complex pore structure.

Correlations of the laboratory data are used to construct height vs water saturations using the relation, same degree of accuracy for the end point values of irreducible water saturation and residual oil saturation. There is always uncertainty about the shape of the relative permeability curves and these curves are commonly adjusted to give a history match in reservoir simulation studies. Whether one condones such activities or recognizes this as a pragmatic approach to achieving a solution, the amount of money and time spent on relative permeability measurements is brought into question.

1.6 Wettability

Wettability is defined as the tendency of one phase to adhere to the rock surface, in the presence of other immiscible phases. Wettability effects are not well quantified even though they play an important role in determining recovery and flow properties. Interfacial tension or energy is the underlying feature of wettability. Figure 1.6 illustrates an idealized oil-water system consisting of a drop of water contacting a clean, flat rock sample in the presence of oil. A force balance yields:

$$\sigma_{os} = \sigma_{ws} + \sigma_{ow} \cos \theta_c \, , \qquad (1.4)$$

where:

σ_{os} = interfacial tension between the oil and the solid;
σ_{ws} = interfacial tension between the water and the solid;
σ_{ow} = interfacial tension between the oil and the water; and
θ_c = angle at the oil-water interface, measured through the water phase.

The contact angle is a recognized measure of wettability. The contact angle can vary from 0° to 180°. A contact angle near zero indicates a preferentially water-wet system. A contact angle near 180° indicates a strongly oil-wet system. Mixed or intermediate wettability is indicated by contact angles near 90°. Contact angles are difficult to measure in the laboratory. Uncontaminated oil and water samples are critical. Minute quantities of polar compounds in reservoir crude affect the wettability. Surfactants introduced into the crude

$$PI = \frac{.00708\,H}{\mu o\,Bo\left(\frac{In\frac{re}{r_D}}{k} + \frac{In\frac{r_D}{rw}}{k_D}\right)}$$

in which,

r_D is the radius damaged, ft

k_D is the permeability of the damaged zone, md

It can be readily shown that PI's can be reduced several fold by well bore damage.

(2) *Perforation Density*

Depending on the number of perforations per foot, the size of the perforated holes and depth of penetration, the PI of a well may be reduced.

(3) *Partial Penetration Effects*

If a well is completed in only part of an interval, flow is three-dimensional rather than radial near the well bore. Thus permeabilities calculated from the steady-state radial flow equation will be too low.

In summary, if productivity data are used to estimate formation permeability, corrections for well bore damage, perforations and partial penetration effects may be necessary.

b. PERMEABILITY CALCULATED FROM PRESSURE BUILDUP TEST DATA

Pressure buildup data measured following shutting in of a producing well can yield accurate permeability data. Permeabilities are calculated by

$$k = 162.3\frac{q\,\mu_o\,B_o}{M}$$

in which,

pressure values decrease up the vertical scale because of the change in wettability.

Capillary pressure data can be correlated with the *J*-function, defined as

$$J(S_w) = \frac{p_c \left(\frac{k}{\phi}\right)^{0.5}}{T \cos\theta} \tag{1.7}$$

An example of the *J*-function is shown in Figure 1.10. The *J*-function is justified in theory by assuming a porous medium comprised of a bundle of capillary tubes, but in practice is limited to specific lithology types within the same formation.

Saturation history causes capillary pressure hysteresis and also creates relative permeability hysteresis. For a given capillary pressure, there are two values of s_w corresponding to drainage and imbibition processes. Figure 1.11 shows relative permeability hysteresis for the non-wetting phase. The relative permeability is always lower during imbibition, for a given wetting phase saturation. The wetting phase relative permeability is a function of saturation only and does not depend on saturation history.

1.7 Initial Saturation, Bedding Effects And Pseudo Relative Permeability

Initial saturation in a reservoir is characterized by the oil-water and gas-oil contacts, if present. These contacts can be determined by logs, cores, drill-stem tests, side wall fluid samplers and capillary pressure data. With finite capillary pressure, there will be a gradual transisition rather than an abrupt interface between zones. The simplified areal and cross-sectional maps reservoir engineers are accustomed to, do not portray the actual fluid distribution in the reservoir.

Capillary pressure was presented earlier in terms of interfacial tension and contact angle (Equation 1.4) and the pressure difference between the oil and

3. Correlation with Log Data

Usually only a small fraction of the wells in the field are cored. Also, core recoveries are often less than complete. On the other hand, logs are usually available on every well throughout the interval of interest. A common procedure is to correlate core porosities with porosities, correlate permeabilities and porosities from core data and then to use porosities from logs and the k vs. ϕ plot to estimate permeabilities for each foot.

a. CORRELATION OF POROSITIES FROM LOGS AND CORES

The first step in the procedure of estimating permeabilities from log data is to make sure that porosities calculated from logs are consistent with those measured on cores from the same interval. Usually parameters used in logging calculations can be calibrated to yield a good match of porosity data.

b. POROSITY - PERMEABILITY CORRELATION

The second step in the procedure is to correlate porosity and permeability data from cores. The k - $\phi\phi$ correlation was used with porosities calculated from logs to estimate permeabilities for intervals where no cores were recovered. Similar calculations were made using logs from three other wells which were not cored to obtain the average reservoir properties for the sand the for the shale. The large coefficients of permeability variations indicate the sands are highly stratified.

$$V = \frac{\bar{k} - k\sigma}{\bar{k}}$$

in which,

V is the coefficient of permeability variation

k is the median permeability

kσ is the permeability where 84.1% of the interval has greater values.

and having calculated the saturation distribution, reading the relative permeability value from the relative permeability curves. The thickness averaged relative permeability is:

$$k_{rw1,avg}\,(s_{w,avg}) = \frac{1}{h}\int_{0}^{h} k_{rw}[S_w(z)]dz \quad . \qquad (1.11)$$

The equation to calculate the average oil relative permeability is equivalent to Equation 1.10.

The average relative permeabilities should be calculated for a range of average water saturations. This is done by assuming a different free water level and repeating the relative permeability evaluation. This information is useful for waterflood evaluation and is required during primary recovery if the water level is rising to an active water drive.

The average saturation and thickness averaged relative permeabilities are more difficult to calculate if the reservoir consists of stratified layers. The general method can be extended to handle defined variations in reservoir parameters with reservoir thickness. The average water saturation in a layered reservoir is calculated as follows:

$$S_{w,avg} = \frac{\sum_{i=1}^{I} h_i \phi_i S_{wi,avg}}{\sum_{i=1}^{I} h_i \phi_i} \quad , \qquad (1.12)$$

where:

$s_{wi,avg}$ is defined in Equation 1.10

Similarly, the thickness averaged relative permeability is calculated as follows:

USE OF LABORATORY DATA IN RESERVOIR STUDIES

I. Reservoir Rock Description

The most important step in a reservoir study is that of developing an accurate description of the reservoir and its aquifer. This requires knowledge of how the permeability and porosity of the pay zone vary and knowledge of the size and extent of the shale or dense zones within the reservoir. The best approach is to develop a consistent description by integrating core data with geologic, log and well test data.

A. Permeability Distribution

1. <u>Methods of Averaging</u>

Permeabilities measured on each foot of core must be averages to represent the flow characteristics of a reservoir formation. The proper method of averaging depends on how permeabilities were distributed as the rock was deposited.

a. ARITHMETIC AVERAGE

If the sands were laid down as blanket sands extending hundreds of feet around the well, arithmetic averaging should yield correct values for horizontal flow. The arithmetic average is K_{average} $(Arithmetic) = \dfrac{K_1 + K_2 \cdots K_n}{n}$.

b. HARMONIC AVERAGE

For blanket sands where arithmetic averaging is correct for horizontal flow, harmonic averaging should be used for vertical flow. The harmonic (or series) average is K_{average} $(Harmonic) = \dfrac{L}{\dfrac{L_1}{K_1} + \dfrac{L_2}{K_2} + \cdots \dfrac{L_n}{K_n}}$.

Samples of oil water and gas oil relative permeability curves are shown in Figure 1.12.

The oil three phase relative is a function of both the water and gas saturations. This function is not easily measured in the laboratory. Stone (1973) predicted three phase oil relative permeability from channel flow considerations to take the following form:

$$k_{ro} = k_{rocw} \left[\left(\frac{k_{row}}{k_{rocw}} + k_{rw} \right) \left(\frac{k_{rog}}{k_{rocw}} + k_{rg} \right) \right] - (k_{rw} + k_{rg}) \quad . \qquad (1.14)$$

An example of an application of the Stone three phase relative permeability model is shown in Figure 1.13. The three phase curves oil relative permeability curves are shown on a ternary diagram. The water and gas relative permeabilities are taken from the oil water and gas oil curves.

1.9 Rock Compressibility

Reservoir rocks will expand as the confining pressure is removed. Rock compressibility is defined as:

$$c_r = - \frac{1}{V_p} \frac{\partial V_p}{\partial p_g} \quad . \qquad (1.15)$$

The negative sign is required to ensure that the compressibility is a positive number, because an increase of the grain pressure p_g will always decrease the pore volume V_p. In reservoir engineering the fluid pressure is of primary importance; the fluid pressure p is related to the grain pressure p_g by $dp = - dp_g$. If the compressibility is assumed to be small and independent of pressure, the porosity variation is:

$$\phi = \phi_0 \left[1 + c_r (p - p_0) \right] \quad , \qquad (1.16)$$

where:

USE OF LABORATORY DATA IN RESERVOIR STUDIES

I. Reservoir Rock Description

A. Permeability distribution

1. Methods of Averaging
    - a. Arithmetic Average
    - b. Harmonic Average
    - c. Geometric Average
2. Geologic Framework
    - a. Average by Geologic Zones
    - b. Significance of Shales
3. Correlation with Log Data
    - a. Correlation of Porosities from Cores and Logs
    - b. Porosity - Permeability Correlation
4. Correlation with Well Test Data
    - a. Permeability Calculated from Productivity Index Data
        - (1) Well Bore Damage
        - (2) Perforation Density
        - (3) Partial Penetration Effects
    - b. Permeability Calculated from Buildup Test Data

B. Porosity distribution

1. Method of Averaging
2. Average by Geologic Zones

II. Oil in Place

A. Reservoir Pore Volume

B. Saturation Distribution

C. Oil in Place

D. Effect of Errors in Core Data on Oil in Place

Table 1.1 Rock Properties versus Grain Size Distribution

	SAND NUMBER									
Mesh	1	2	3	4	5	6	7	8	9	10
10									3.41	
20									17.35	
30									24.34	
40			0.24		0.59			0.17	30.14	
50			0.62		12.84		0.29	2.44	14.59	0.07
70		0.15	1.39		46.67		18.43	23.23	4.92	6.90
100	3.81	6.57	11.74		14.61		42.09	49.28	2.03	48.21
140	57.3	56.04	71.54		8.77		31.93	22.45	1.75	25.83
200	17.42	17.99	6.90	1.14	2.94	1.14	4.79	1.77	0.69	4.73
270	12.59	10.13	6.95	20.32	2.60	20.32	1.30	0.44	0.78	3.31
> 270	8.88	9.12	0.62	78.54	10.98	78.54	1.16	0.22		10.95
Por %	12.5	12.3	16.9	37.0	20.3	37.8	19.7	15.9	11.9	19.5
k md	2.6	2.8	44.4	5.1	29.5	8.8	182	350	1130	63.8

Data from: Fancher, G.H., J.A. Lewis and K.B. Barnes, *Bull. 12, Mineral Industries Exp. Sta.*, Penn State College, 1933.

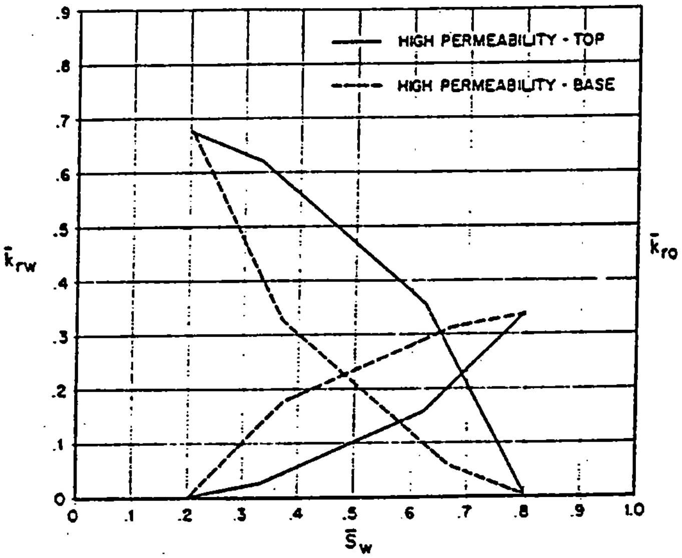
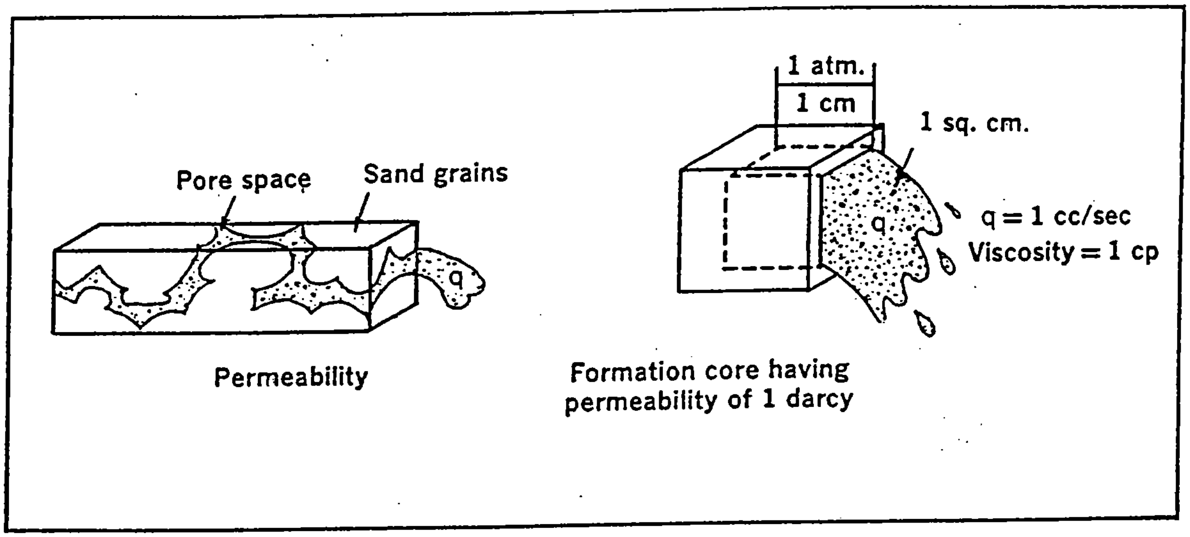


Figure P1.7 – Averaged relative permeability curves for three layer case, segregated flow.



Permeability

Formation core having permeability of 1 darcy

Figure 1.2 - Fluid Flow in Permeable Sand.

PROBLEM 1.7 AVERAGED RELATIVE PERMEABILITY FOR SEGREGATED FLOW

Repeat Problem 1.6 assuming no capillary transition zone. This situation is referred to as segregated flow.

Solution

With connate water saturation in each layer, the average water saturation is 0.2 and the average water and oil relative permeabilities are 0.0 and 0.678, respectively, as shown in the solution of Problem 1.6.

If the water level rises to the interface between layers 1 and 2, the following average parameters can be calculated:

$$s_{w,avg} = \frac{(0.15 \times 0.8 \times 10) + (0.17 \times 0.2 \times 20) + (0.20 \times 0.2 \times 10)}{(0.15 \times 10) + (0.17 \times 20) + (0.20 \times 10)} = 0.330$$

$$k_{rw,avg} = \frac{(50 \times 0.24 \times 10)}{(50 \times 10) + (100 \times 20) + (200 \times 10)} = 0.027$$

$$k_{ro,avg} = \frac{(100 \times 0.6 \times 20) + (200 \times 0.8 \times 10)}{(50 \times 10) + (100 \times 20) + (200 \times 10)} = 0.622$$

If the water level rises to the interface between layers 2 and 3, the following average parameters can be calculated:

$$s_{w,avg} = \frac{(0.15 \times 0.8 \times 10) + (0.17 \times 0.8 \times 20) + (0.20 \times 0.2 \times 10)}{(0.15 \times 10) + (0.17 \times 20) + (0.20 \times 10)} = 0.626$$

$$k_{rw,avg} = \frac{(50 \times 0.24 \times 10) + (100 \times 0.30 \times 20)}{(50 \times 10) + (100 \times 20) + (200 \times 10)} = 0.160$$

$$k_{ro,avg} = \frac{(200 \times 0.8 \times 10)}{(50 \times 10) + (100 \times 20) + (200 \times 10)} = 0.356$$

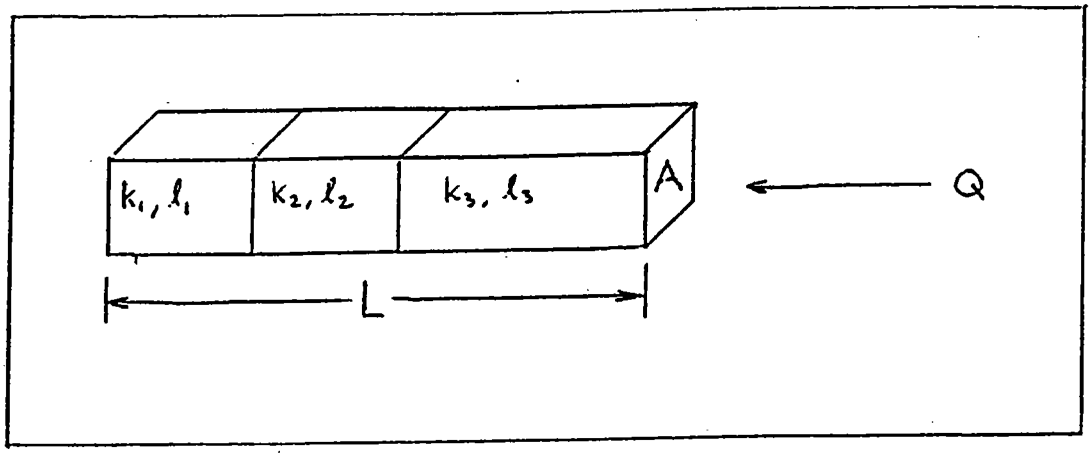


Figure 1.4 – Series Flow

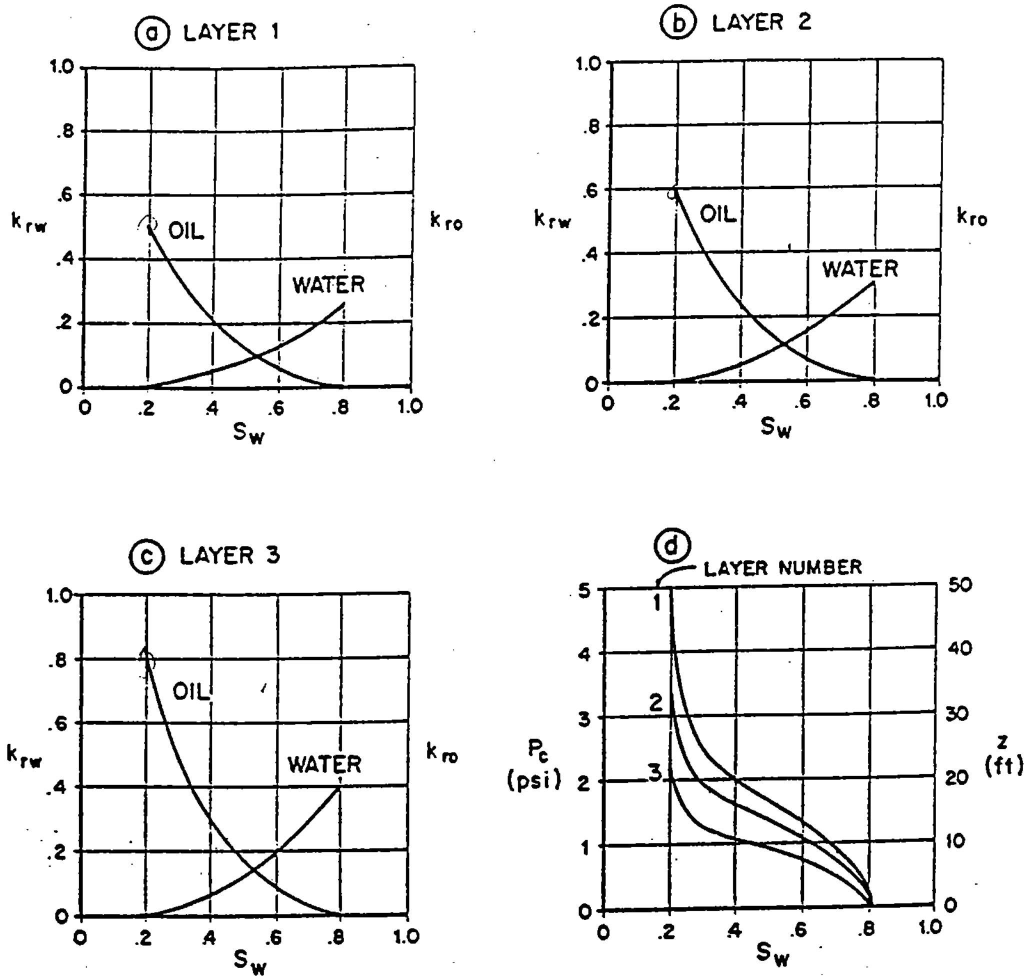


Figure P1.6a– Rock relative permeabilities and capillary pressure for a layered reservoir.

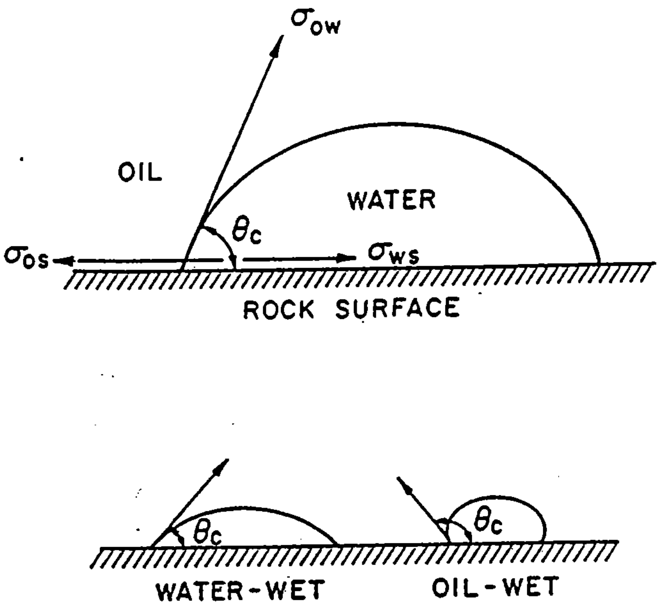


Figure 1.6 – Wettability of an oil-water system.

Layer	Height (ft)	p_c,psi	s_w	k_{rw}	k_{ro}	
1	0	0.0	0.80	0.24	0	$s_{w1,avg} = 0.763$
1	5	0.5	0.78	0.23	0.002	$k_{rw1,avg} = 0.220$
1	10	1.0	0.69	0.18	0.02	$k_{ro1,avg} = 0.006$
2	10	1.0	0.63	0.17	0.05	
2	15	1.5	0.45	0.07	0.18	$s_{w2,avg} = 0.351$
2	20	2.0	0.29	0.02	0.40	$krw2,avg = 0.045$
2	25	2.5	0.24	0.003	0.50	$k_{ro2,avg} = 0.345$
2	30	3.0	0.22	0.001	0.55	
3	30	3.0	0.20	0.0	0.80	$s_{w3,avg} = 0.200$
3	35	3.5	0.20	0.0	0.80	$k_{rw3,avg} = 0.000$
3	40	4.0	0.20	0.0	0.80	$k_{ro3,avg} = 0.800$

$$s_{w1,avg} = \frac{(2.5 \times 0.80) + (5 \times 0.78) + (2.5 \times 0.69)}{10} = 0.763$$

$$k_{rw1,avg} = \frac{(2.5 \times 0.24) + (5 \times 0.23) + (2.5 \times 0.18)}{10} = 0.220$$

$$k_{row1,avg} = \frac{(2.5 \times 0.0) + (5 \times 0.002) + (2.5 \times 0.02)}{10} = 0.006$$

$$s_{w2,avg} = \frac{(2.5 \times 0.63)+(5 \times 0.45)+(5 \times 0.29)+(5 \times 0.24)+(2.5 \times 0.22)}{20} = 0.351$$

$$k_{rw2,avg} = \frac{(2.5 \times 0.17)+(5 \times 0.07)+(5 \times 0.02)+(5 \times 0.003)+(2.5 \times 0.001)}{20} = 0.045$$

$$k_{ro2,avg} = \frac{(2.5 \times 0.05)+(5 \times 0.18)+(5 \times 0.40)+(5 \times 0.50)+(2,5 \times 0.55)}{20} = 0.345$$

$s_{w3,avg}$ = 0.20 (no variation)
$k_{rw3,avg}$ = 0.00 (no variation
$k_{ro3,avg}$ = 0.80 (no variation)

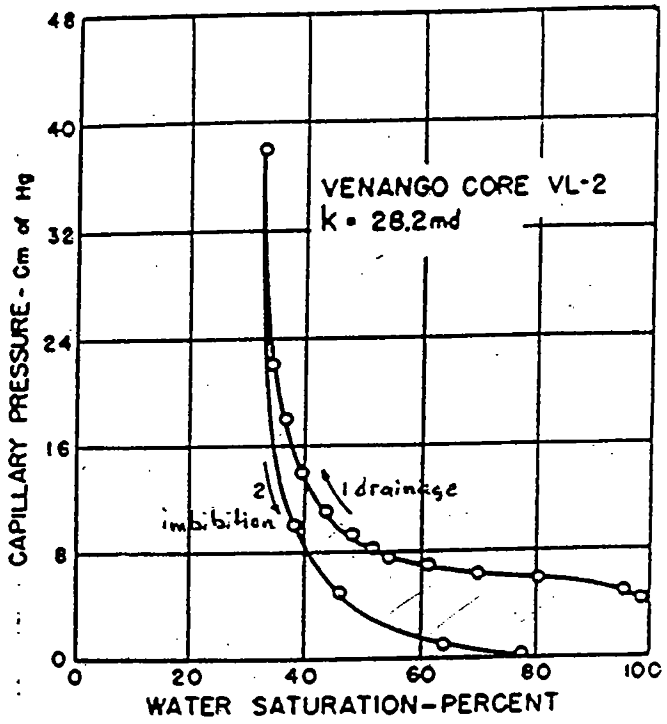


Figure 1.8 – Capillary pressure of a strongly water-wet rock.

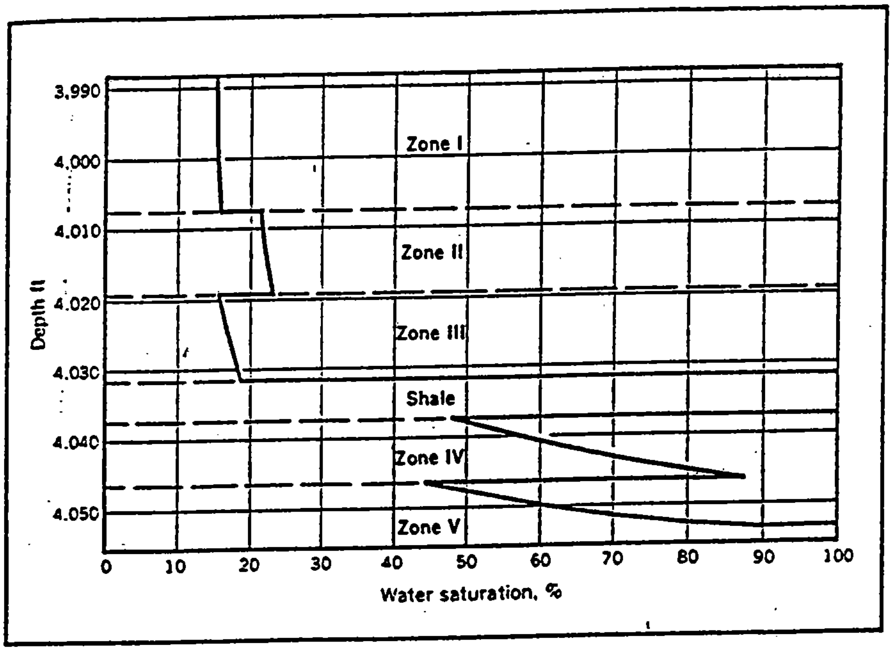


Figure P1.5b – Saturation distribution for reservoir with stratified reservoir of figure P1.5b

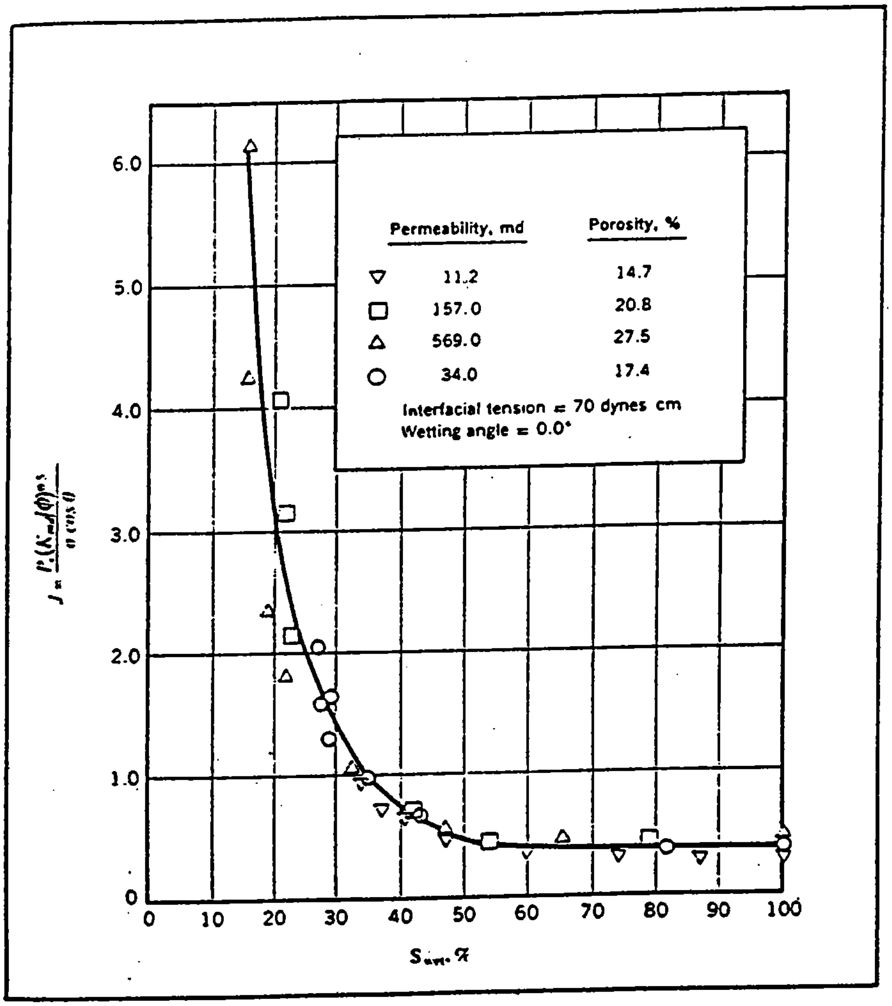


Figure 1.10 – J-Function Curve

Depth (ft)	Height above free water (ft)	p_c, psi	Zone	s_w, %
4053	7	0.45	V	100
4049	11	0.69	V	55
4047	13	0.82	V	47
4045	15	0.94	IV	80
4042	18	1.07	IV	67
4039	21	1.33	IV	53
4036	24		Shale	100
4033	27		Shale	100
4030	30	1.89	III	18
4021	39	2.46	III	16
4018	42	2.65	II	23
4009	51	3.21	II	22
4006	54	3.40	I	16
4000	60	3.78	I	16

The saturation distribution is plotted in Figure P1.5b.

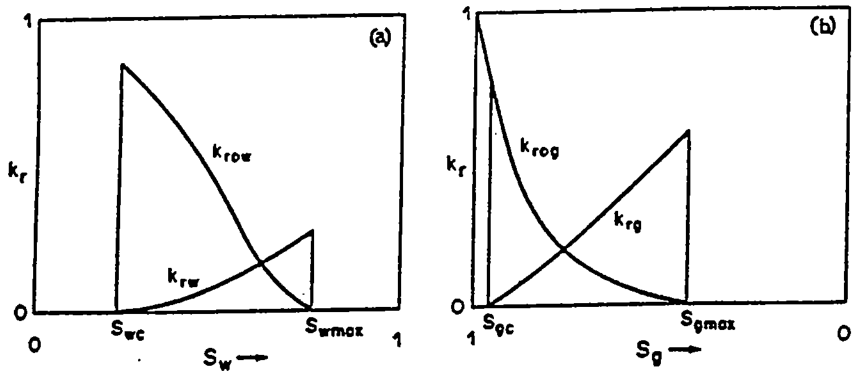
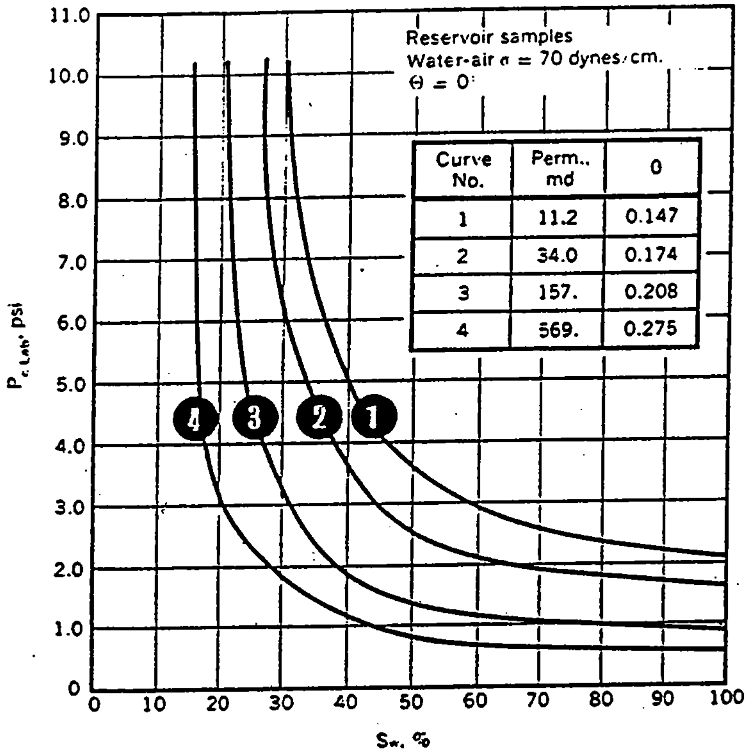


Figure 1.12 - Oil-water and gas-oil relative permeabilities.



Reservoir samples
Water-air σ = 70 dynes/cm.
$\theta = 0°$

Curve No.	Perm., md	0
1	11.2	0.147
2	34.0	0.174
3	157.	0.208
4	569.	0.275

Figure P1.4 – J–Function

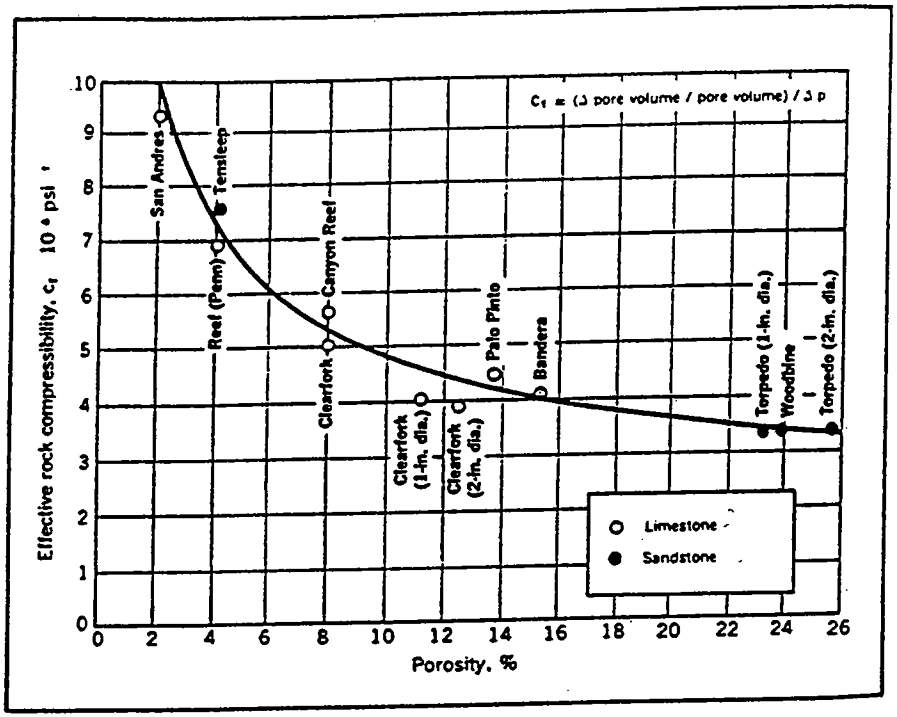


Figure 1.14 Formation compressibility.

$$k = \frac{0.63 \times 1 \times 3}{5 \times 2} = 189 \text{ darcies or } 189 \text{ md}$$

The relative permeabilities are calculated in the same manner.

s_w	k_w	k_o	$k_{ro} = \frac{k_o}{k}$	$k_{rw} = \frac{k_w}{k}$
1.00	189	0	0.00	1.00
0.90	114	0	0.00	0.60
0.80	57	7.2	0.03	0.30
0.60	12	72	0.26	0.06
0.40	3	180	0.66	0.02
0.30	0	273	1.00	0.00

PROBLEM 1.2 ABSOLUTE PERMEABILITY

Using Equation 1.1, provide expressions (Equations 1.2 and 1.3) for the average permeability of layered and laterally heterogeneous systems. Assume single phase flow of an incompressible fluid.

Solution

a) Layered System

Referring to Figure 1.3, the pressure drop across each layer is constant. The total flow rate Q is the sum of the flow rates in the individual layers.

$$Q = q_1 + q_2 + q_3$$

$$1.127 \times 10^{-3} \frac{hwk_{avg}\Delta p}{\mu L} = 1.127 \times 10^{-3} \frac{h_1wk_1\Delta p}{\mu L_1} + 1.127 \times 10^{-3} \frac{h_2wk_2\Delta p}{\mu L_2} + 1.127 \times 10^{-3} \frac{h_3wk_3\Delta p}{\mu L_3}$$

$$k_{avg} = \frac{k_1h_1 + k_2h_2 + k_3h_3}{h}$$

b) Lateral Permeability Variation

Referring to Figure 1.4, the flow rate in each member is constant and the total pressure drop is a sum of the pressure drops in the individual members.

$$\Delta p = \Delta p_1 + \Delta p_2 + \Delta p_3$$

$$\frac{Q\mu L}{1.127 \times 10^{-3}\, Ak_{avg}} = \frac{Q\mu l_1}{1.127\ 10^{-3}\, Ak_1} + \frac{Q\mu l_2}{1.127\ 10^{-3}\, Ak_2} + \frac{Q\mu l_3}{1.127\ 10^{-3}\, Ak_3}$$

$$\frac{L}{k_{avg}} = \frac{l_1}{k_1} + \frac{l_2}{k_2} + \frac{l_3}{k_3}$$

II. CORE ANALYSIS

Core analysis is a very important part of an overall reservoir evaluation program. Core analysis provides direct evaluation of reservoir properties and also furnishes a basis for calibrating other evaluation tools such as logs. All wells drilled cannot be cored because coring is an expensive operation. However, early plans for reservoir development should provide for coring a reasonable number of wells. These well location should be selected to provide representative coverage of the reservoir.

In addition to selecting wells for coring, the type of core analysis data required should also be decided ahead of time. Special coring and core-handling procedures are necessary to provide a suitable cores for certain types cores analysis tests. Thus, wells to be cored should be selected far enough in advance so plans can be made to handle these special procedures. As we will see later, some reservoir conditions tests require that cores be cut under controlled condition and be preserved to maintain true formation wettability.

A. CONVENTIONAL CORE ANALYSIS

Conventional core analysis include measurements of porosity, permeability, and fluid saturation.

(1) MEASUREMENTS OF RESERVOIR POROSITY

Direct methods for measuring porosity differ depending upon the nature of the sample and its size:

(a) Fresh or preserved samples (fluid summation method).

(b) Exposed or extracted samples.

from flooding or from centrifuge experiments. The centrifuge provides data at low oil saturations, while flood data is somewhat limited in its applicable saturation range. In either case the effect of capillary pressure must be minimized by taking necessary precautions.

(a) Soxhlet type washer extractors
(b) Dean - Stark type extractors.
(c) Vacuum retorting.
(d) Centrifuging and washing.

The method combining a Soxhlet and a centrifuge is very rapid and effective in conventional rock analysis. Vacuum retorting is no doubt the best solution for large cores except for clayey samples.

Amongst the most generally used solvents should be mentioned toluene, xylene, chloroform, carbon tetrachloride, acetone, Chlorothene hexane, etc.

Drying is very important following extraction, especially if minerals which can be dehydrated are present. In some cases vacuum drying at low temperatures possible.

In the laboratory it is indispensable to standardize the various operation for extracting, washing, drying and storing the samples before the various measurement are made.

(a) Measurement of total volume (V_T)

This is determined by measuring if the sample has simple geometrical shape (cube or cylinder) and is not chipped or notched. A sliding caliper is used.

Determination by means of a *mercury volume pump* (Fig. 2.1). Before inserting the sample, the mercury is brought to a fixed mark above the sample chamber. The pump is brought to zero by means of a calibrated disk. The piston is removed and the sample is placed in a chamber, and the mercury is than brought back to the previously mentioned mark. The total volume is given by a reading of the pump gage.

Measurement accuracy: $\Delta V = \pm 0.01$ cm. Measurement is performed rapidly. The method is valid only if the mercury does not enter the pores of the sample.

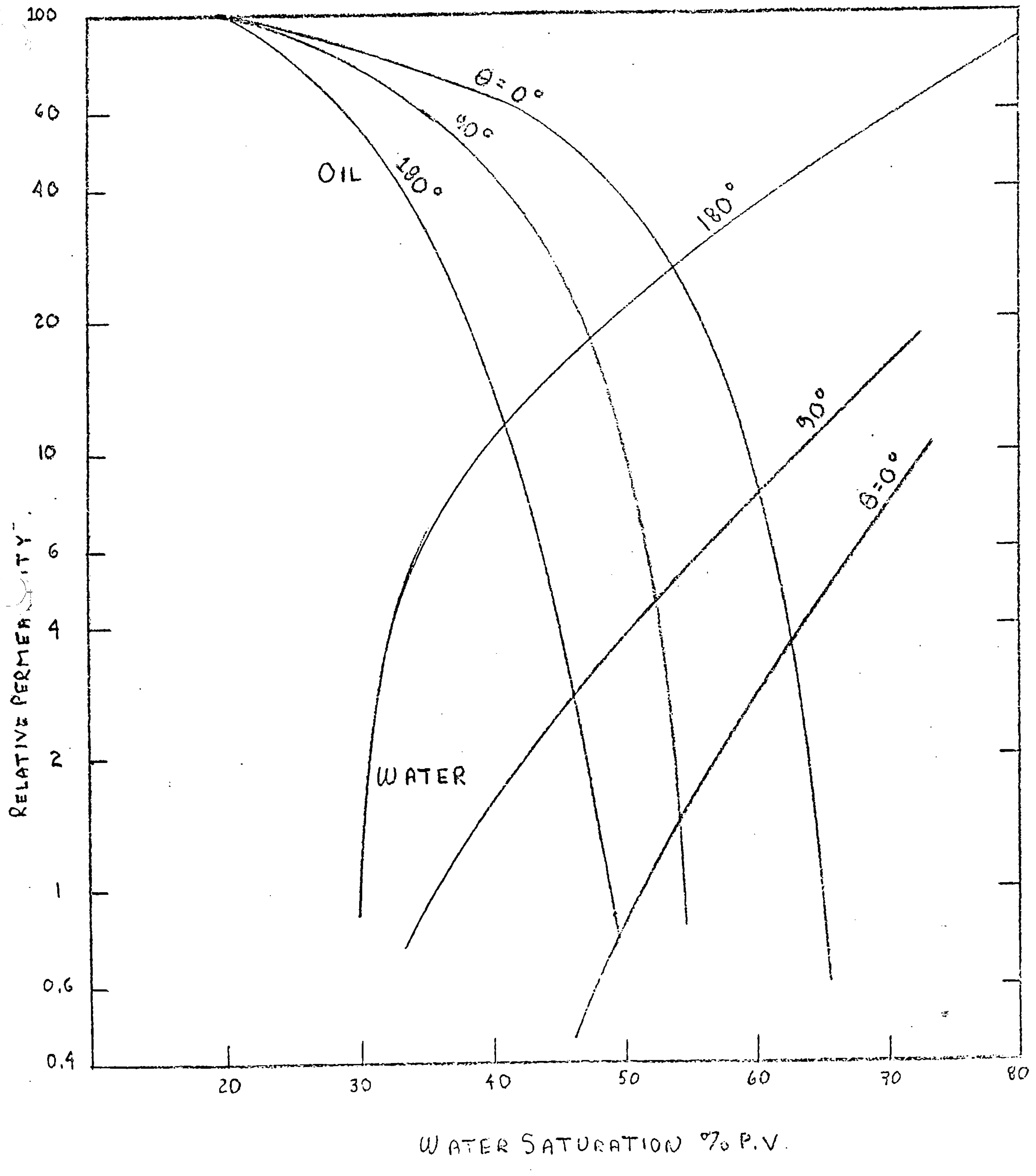


Fig. 2.63 Effect of wettability on relative permeability.

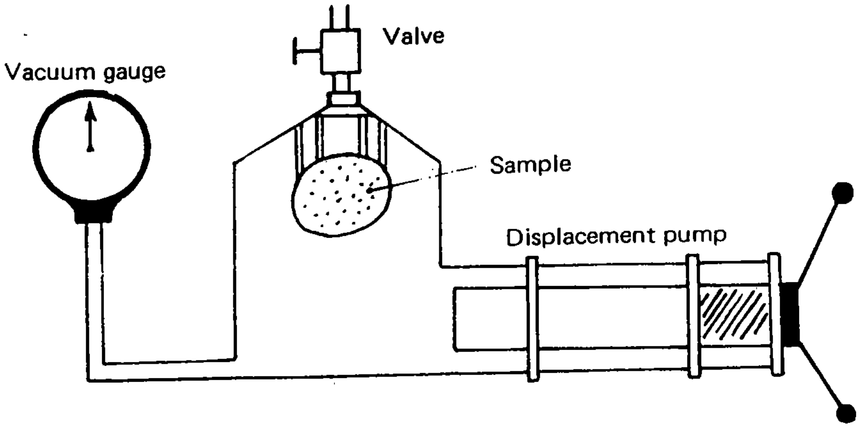


Fig. 2.1 Pore volume determination.

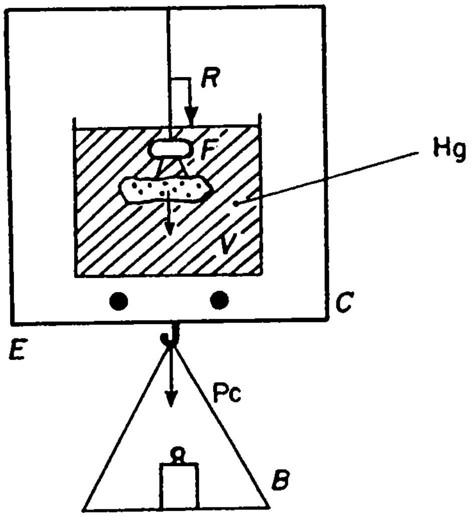


Fig. 2.2 IFP "voltomètre".

One difficulty with the centrifuge method is associated with capillary end effects. As very low oil saturations are achieved the capillary pressure effects cause oil flow to cease before a true residual is reached. Even with this problem, lower oil saturation data can be obtained in the centrifuge than is possible in waterfloods.

These tests can also be run at pseudo reservoir conditions.

FACTORS AFFECTING RELATIVE PERMEABILITY MEASUREMENTS

There is some controversy concerning what factors do or not do affect relative permeability measurements. One factor which definitely does have an effect is the wettability of the rock. In general as a system goes from water-wet to oil-wet the relative permeability to oil at a given saturation will decrease and that to water will increase (see Figure 2.63). Systems containing gas do not show this behavior since gas is always non-wetting.

Other factors which could have an effect are the flow rate, viscosity ratio, and interfacial tension. It is generally felt that flow rate does not affect the measurements except in connection with the capillary end effect. For some systems exhibiting complex flow patterns there may be a flow rate effect. For water-wet systems the viscosity effect, if present at all, is negligible; however, for systems of mixed wettability, the jury is still out. There is no concrete evidence which shows any viscosity effect, however feelings are mixed on the issue. Interfacial tension does not appear to have any effect, except perhaps at abnormally low values (< .1 dyne/cm).

At times it is desirable to use composite cores in gas and water floods. These longer cores help reduce capillary effects. They are assembled from several shorter core samples. Good capillary contact must be established between the pieces. The ordering of these cores can affect the relative permeability curves obtained from the floods. J. D. Huppler has proposed a procedure for the ordering of cores in a composite sample. His procedure is to:

1. Start the ordering at the end of the composite where the pressure gradient will be the most important.

It should be noted that this method is valid only if the mercury does not enter the pores. The immersion conditions for the sample are the same as in the mercury volume pump method.

(b) Measurement of solid volume (V_s)

V_s can be determined by the following three methods:

(a) By means of picnomeeter.
(b) Immersion method: measurement of buoyancy for the solid phase in a wetting fluid.
(c) Utilization of pressure chamber.

The first two procedures suppose that the sample is saturated . The third is based upon Mariotte - Boyle law.

The following sequence of operation is necessary for saturation a porous sample (or many simultaneously) by means of wetting fluid (Figs. 2.3 and 2.4):

(a) High vacuum with dry samples.
(b) Vacuum eliminated by gas which is soluble in the solvent utilized.
(c) High vacuum.
(d) Saturation of samples under vacuum with a degasified solvent.
(e) Establishment of atmospheric and placing of saturated samples under pressure of the order of 150 - 200 bars. The time necessary for placing the saturated samples under pressure depends upon their permeability, and this period becomes longer as permeability falls. The laboratory saturation operations should be standardized.

Use of picnometer

Supposing that

P_0 = the weight of the empty picnometer,

P_1 = the weight of the picnometer full of solvent with destiny p,

V = the volume of the picnometer.

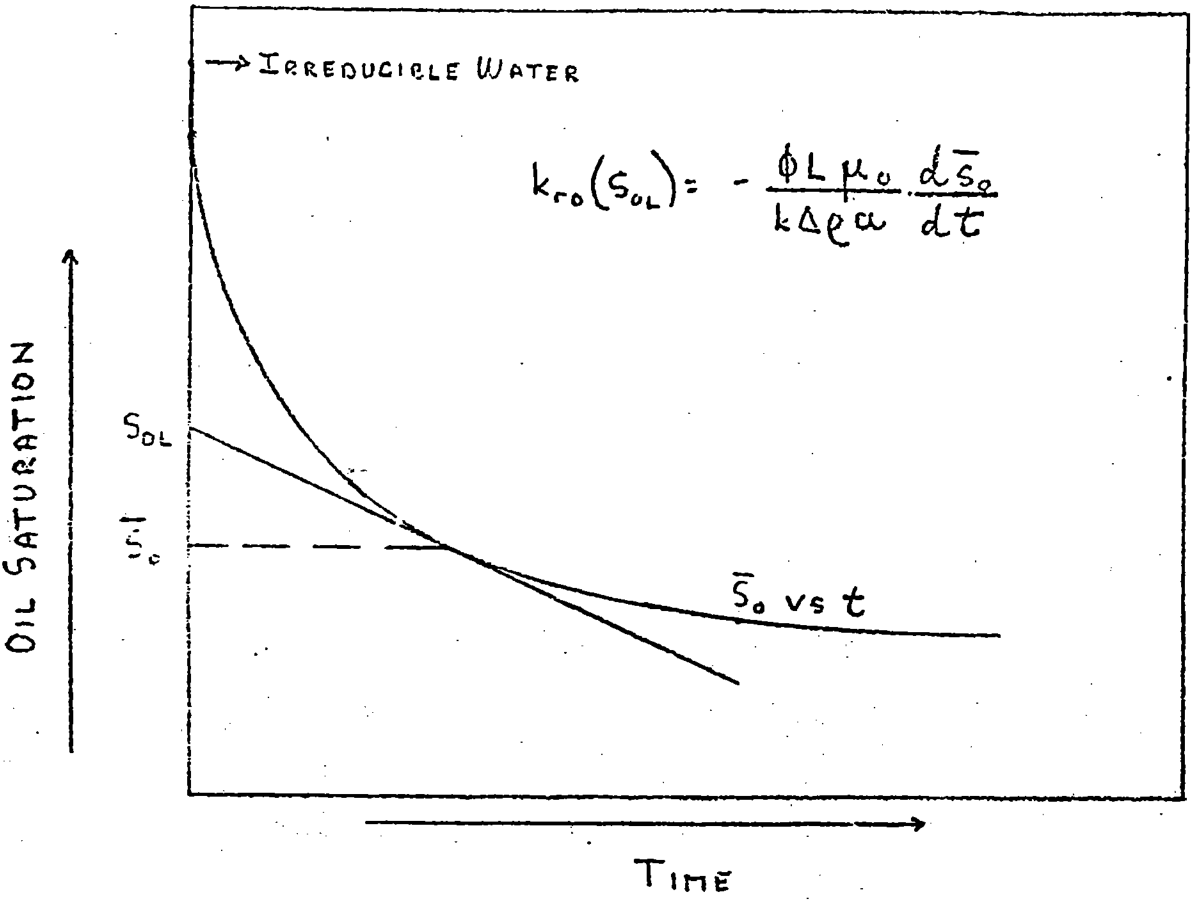


Fig. 2.62 Calculation of relative permeability from centrifuge data.

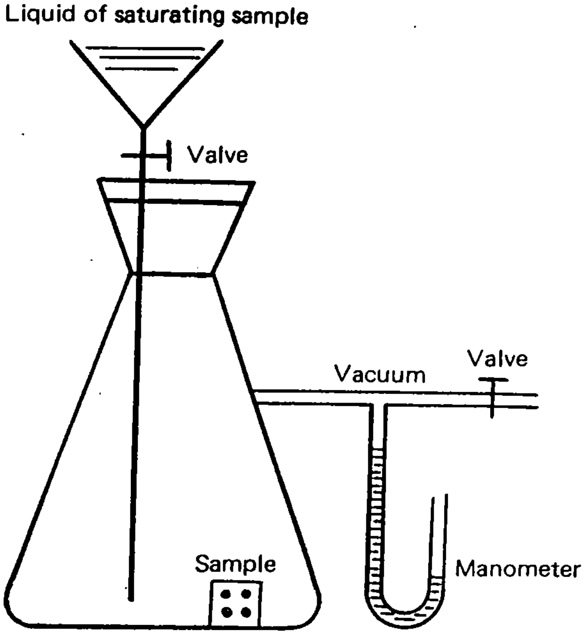


Fig. 2.3 Vacuum saturation of samples.

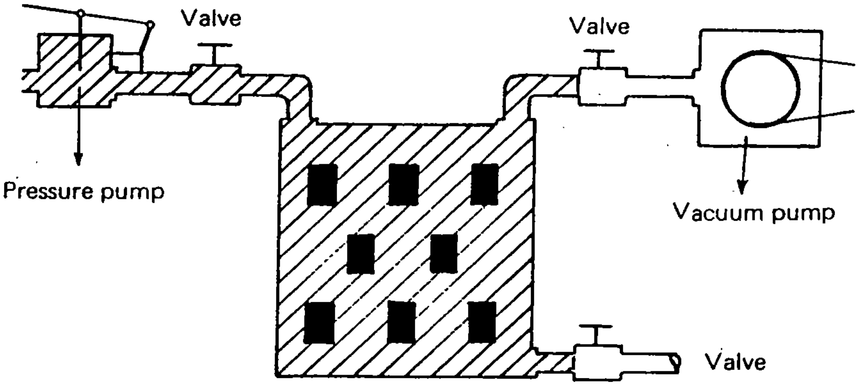


Fig. 2.4 Sample saturation in vacuum under pressure.

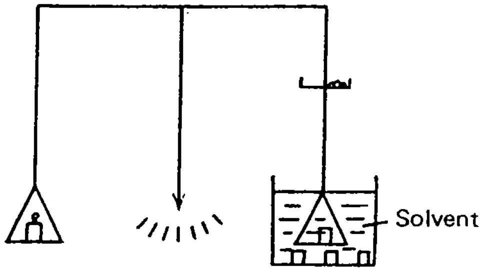


Fig. 2.5 Grain volume determination.

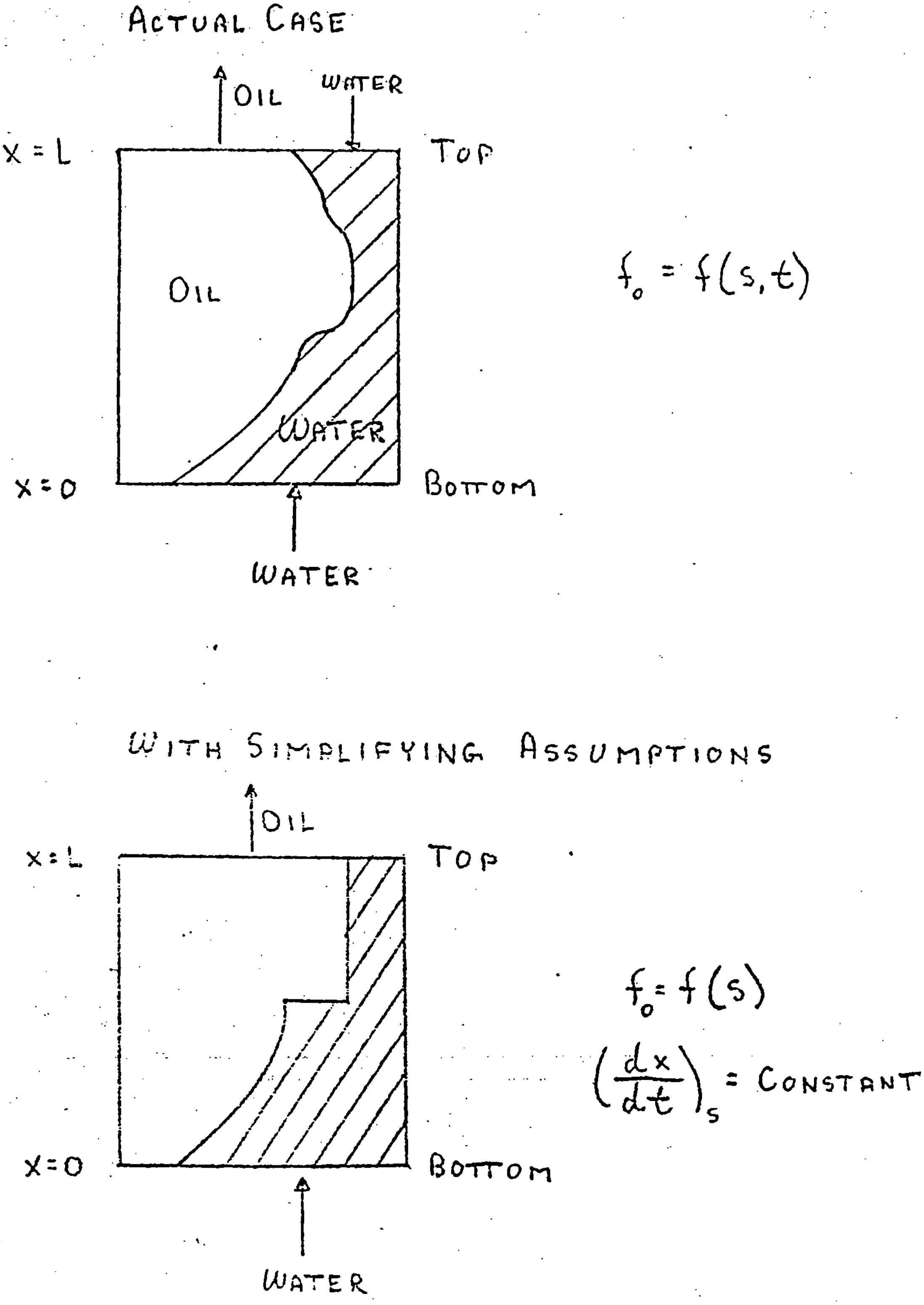


Fig. 2.61 Centrifuge fluid saturations.

Immersion method

V_S is determined by the buoyancy thrust on the solid phase of the sample immersed in a solvent (Fig. 2.5).

The dry weight P_S is determined after washing and drying.

As we indicated above, the samples are saturated in a solvent with a density p at measurement temperature.

The immersed weight P_i is determined .

The calculation is made. Solid volume:

$$V_S = \frac{P_S - P_i}{p} \qquad \text{(Eq. 2.8)}$$

It can be seen that:

$$\Delta V_S = \frac{2\Delta P}{p}$$

For $\Delta V_s < 0.01$ cm^3, it is necessary that $\Delta P < 0.008$ g with $p \approx 1.6$.

The solvents used have high densities so s to make the phenomenon more apparent. Generally, carbon tetrachloride (CCl_4: $p_{20\,°C} = 1.6$)or Clorothene NU (1) ($p_{20\,°C} \approx 1.32$) are used. The latter has a lower specific gravity and is much less toxic than former.

Toxicity of carbon tetrachloride:

(a) Maximum admissible concentration: 25 ppm.

(b) Minimum concentration detectable by smell: 80 ppm.

Precautions: ventilated are, frequent washing of hands after contact, removal of contaminated objects

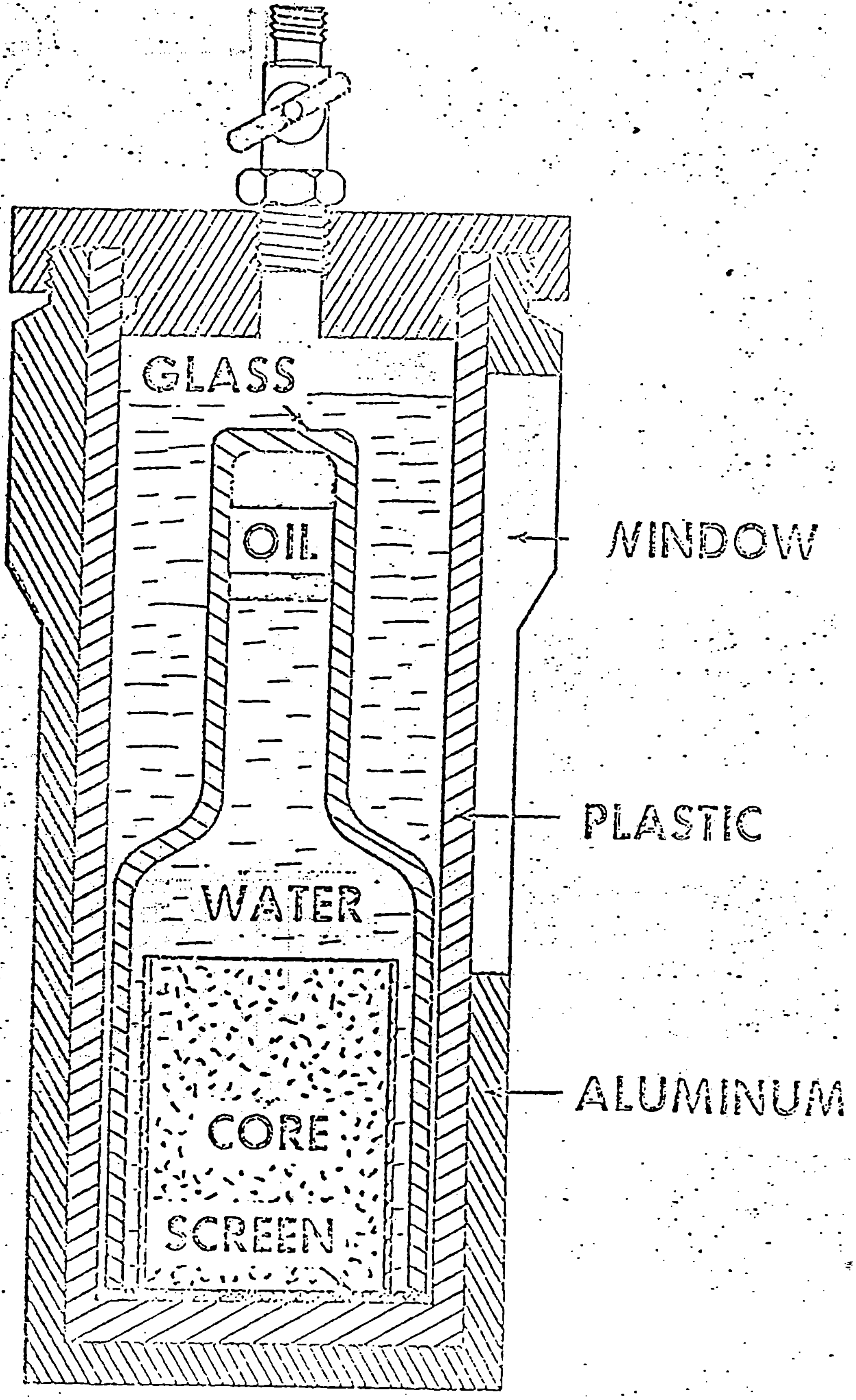


Fig. 2.60 Centrifuge relative permeability test cell.

Utilization of a compression chamber

Many apparatuses have been built in the United States and in Europe. They are based upon the Marriote - Boyle law and exist for a large or small cores. All (Fig. 2.6) include a chamber in which the sample is placed at the pressure which is changed with the variations in volume. The degree to which solid matter fills the chamber is than deduced.

There is a core holder with the volume V. When it contains a core of the volume V_S, it does not contain more than $V - V_S$ of gas. If this gas is brought isothermally from P_1 to P_2, we have:

$$(V - V_S) P_1 = (V - V_S + \Delta V) P_2 \qquad \text{(Eq. 2.9)}$$

or

$$(V - V_s)(P_1 - P_2) = P_2 \Delta V \qquad \text{(Eq. 2.10)}$$

so that

$$V_S = V - \frac{P_2}{P_1 - P_2} x \Delta V \qquad \text{(Eq. 2.11)}$$

Figures 2.6 and 2.7 show an apparatus for large cores, while the apparatus in Fig. 2.8 is for small sample.

These sample devices are subject to various errors which should not be overlooked:

(a) Readings are linked to atmospheric pressure.

(b) Adsorption of water vapor or of the gas utilized by clays can falsify the measurement of the high degree.

(c) Measurement of pore volume (V_P)

Pore volume can be measured directly:

By measuring the air volume contained in the pores.

saturations which can be covered. For a high ratio (μ_o/μ_w) water breakthrough occurs early, but reduction to residual oil is very slow. For a low ratio the reverse is true.

As in the case of the porous diaphragm capillary pressure method, these displacement tests can be run at reservoir conditions. Thus the laboratory system can approximate as closely as possible the reservoir environment.

For strongly water-wet systems the displacement method is quite satisfactory in that low oil saturation can be obtained by using a moderate number of pore volumes of water. For gas-oil and mixed wettability floods, several thousand pore volumes may be needed to reduce the system to residual oil. For these systems a centrifuge method has been developed.

Centrifuge Relative Permeability

The setup for these tests, which is shown in Figure 2.60, is similar to the capillary pressure tests described earlier. In the relative permeability tests, however, the centrifuge is run at a constant high rate; and the oil produced is measured as a function of time. Capillary end effects can be important in this technique as well, and high centrifuge speeds should be used to minimize these effects. A major advantage of this method is that low residual oil saturations are easily obtained. The test is rapid and several samples may be run simultaneously in one centrifuge. A difficulty is that only the relative permeability to the displaced phase can be calculated. The permeability to the displacing phase must be obtained by other methods. Results from flood tests extrapolated to low oil saturation are probably adequate.

The actual movement of water in a water-oil test is from both ends in a sample. The introduction of some simplifying assumptions reduces the flow to a single frontal advance as described in Figure 2.61. These assumptions are:

1. A homogeneous core.

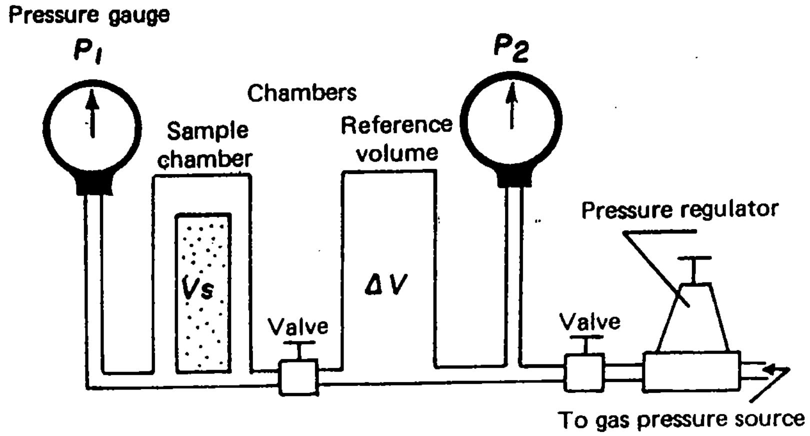


Fig. 2.6 Boyle's law porosimeter: grain volume determination.

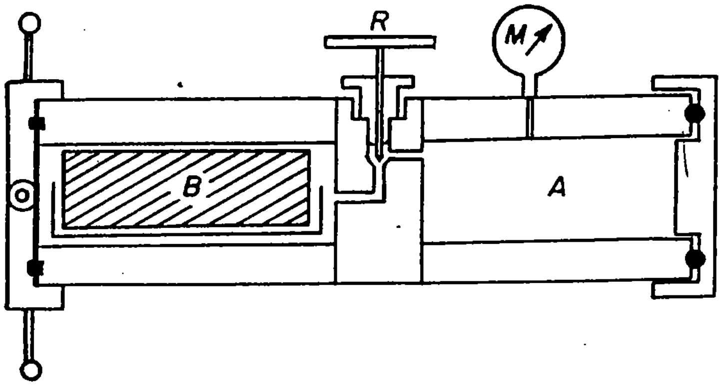


Fig. 2.7 Boyle's law grain volume determination (porosimeter).

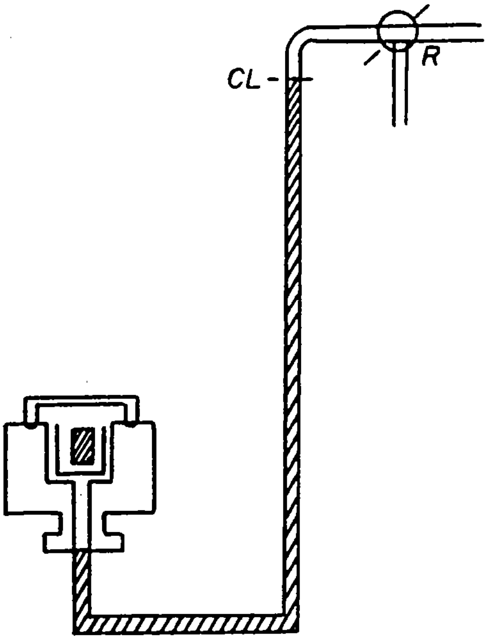


Fig. 2.8 Boyle's law porosimeter: pore volume determination.

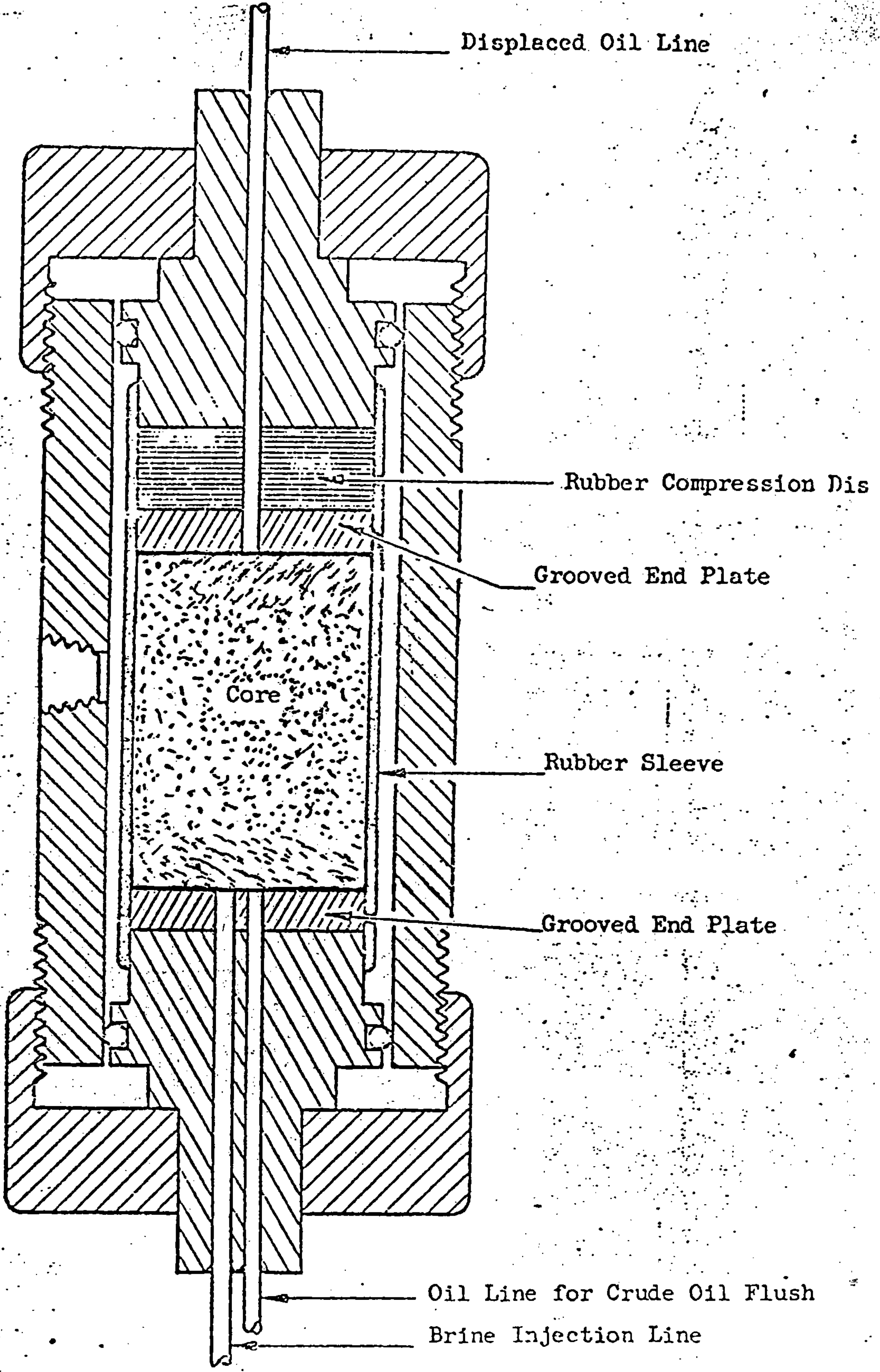


Fig. 2.59 Triaxial Compression Coreholder used in waterflood relative permeability tests.

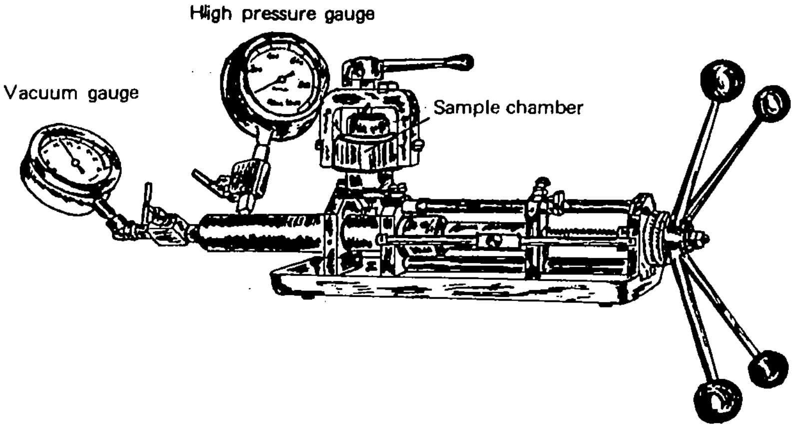


Fig. 2.9 Vellinger, Washburn Bunting type porosimeter.

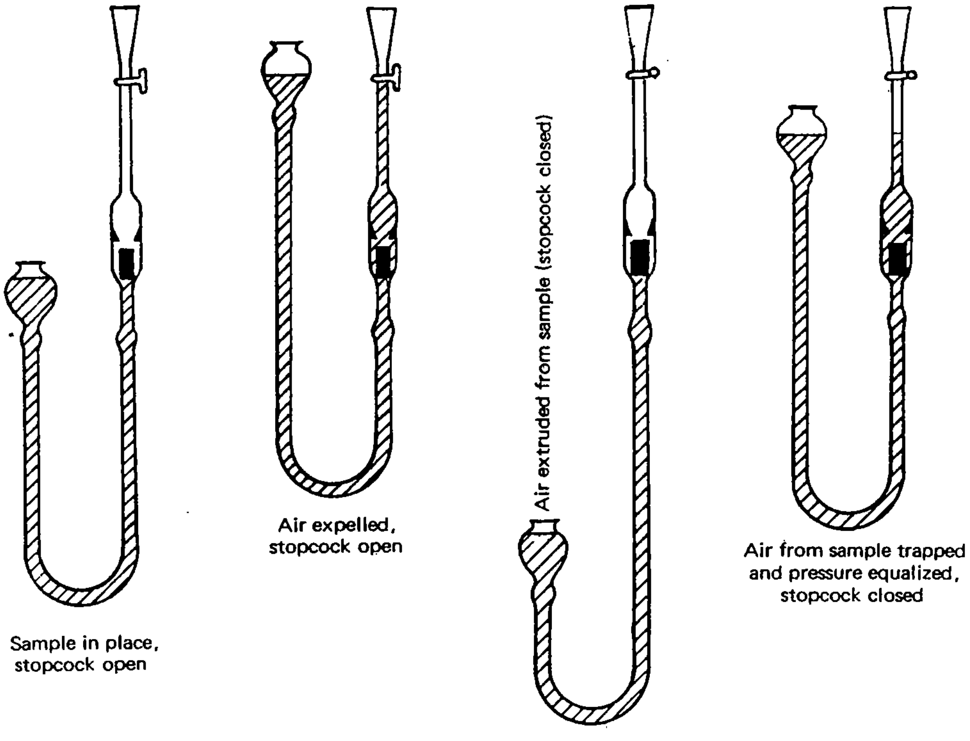


Fig. 2.10 Boyle's law porosimeter (mercury pump).

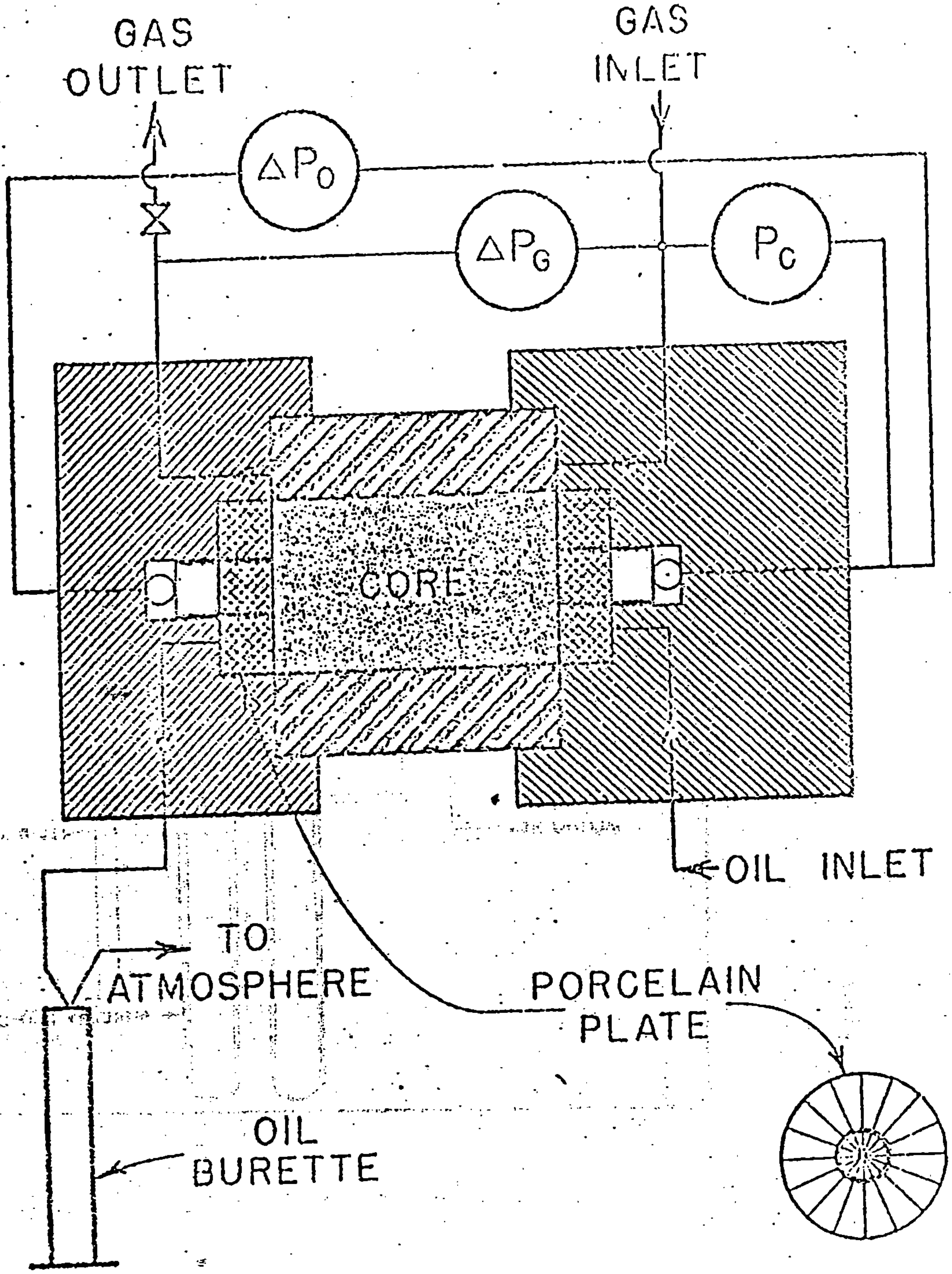


Fig. 2.58 Hassler Apparatus.

it follows that:

$$V = V_P$$

and

$$\phi = \frac{V_P}{V_T} * 100 \qquad \text{(Eq. 2.13)}$$

Pore volume is equal to the volume of mercury withdrawn in order to make the pressure drop by one half atmosphere.

In reality atmospheric pressure is not always 76 cm of mercury, and corrections of the pump are necessary because of trapped air, etc.

In practice, the operation take place at:

$$\frac{H_o}{\Delta H_o} = Const.$$

and

$$\frac{\Delta V_P}{V_P} = \frac{\Delta H_o}{H_o} = \frac{1}{f}, f = \frac{pore\ volume}{pump\ reading} = \frac{V_P}{\Delta V}$$

The coefficient *f* depends upon the volume of the air contained in the pores and on the ΔP adopted which is close to one half atmospheres. It is sufficient to expand known volumes of air (0.5 - 1 - 2 - 3- 4... *N* cm ^{3}) at ΔP = Const. without a sample and to calculate f (close to 1 for $\Delta P = \frac{H_o}{2}$).

from one section to the next. Also the conditions must still be such at the final segment is long enough to absorb the end effect.

Another method proposed to damp out the end effect is the Hassler method. In this method (see Figure 2.58), a semi-permeable disk (permeable only to the wetting phase) is placed on each end of the sample. The non-wetting phase passes through grooves cut into this end plate. The pressure drops in each phase can be controlled and are set equal to each other to minimize the boundary effect.

The most common way in which end effects are minimized is to use high flow rates. This compresses the end effect into a very small region of the core. The flowing pressure gradient is high compared with the capillary difference between the flowing phases. This type of displacement is called a stabilized displacement.

The main advantage of steady-state methods is the amount of time required to make a test. For this reason the displacement methods are commonly used.

Waterfloods and Gasfloods

These methods are dynamic methods in which there exists an intentional saturation gradient in the core. The average saturation in the sample is continually changing. The basic theory used to calculate the relative permeability functions is an extension of Buckley-Leverett, Welge theory. The samples are mounted in a core holder (see Figure 2.59) similar to the one used in the porous diaphragm capillary pressure test, however the end plates are no longer preferentially wet. Initial saturation are established in the core and the sample is mounted.

These tests are run by flowing gas or water through the sample at a measured rate and pressure drop. The end effects are minimized by the use of high flow rates. The amount of oil produced is continuously collected and measured at various times throughout the test. The relative permeabilities are calculated using the equations below. These equations were reported by Johnson, Bossler, and Naumann.

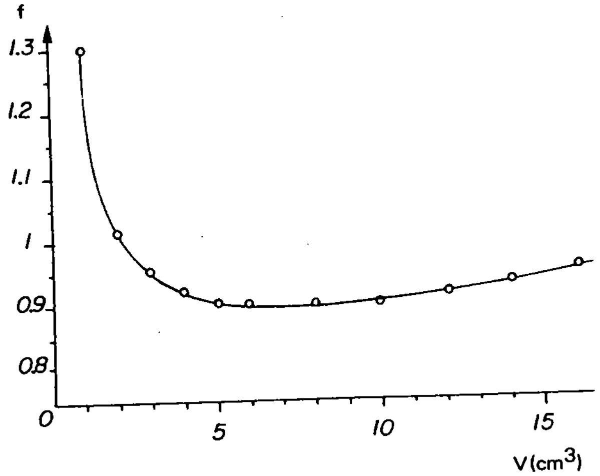


Fig. 2.11 Value of *f* versus air volume.

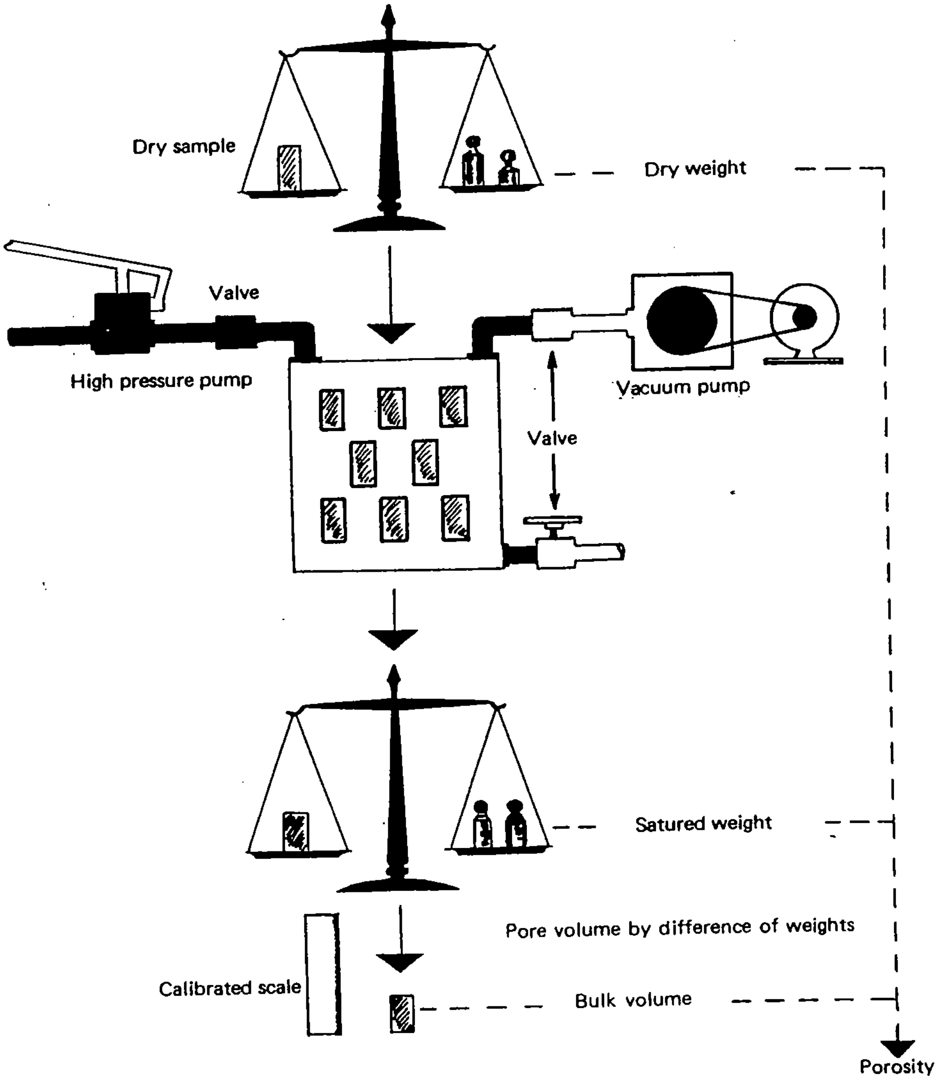


Fig. 2.12 Resaturation porosity procedure.

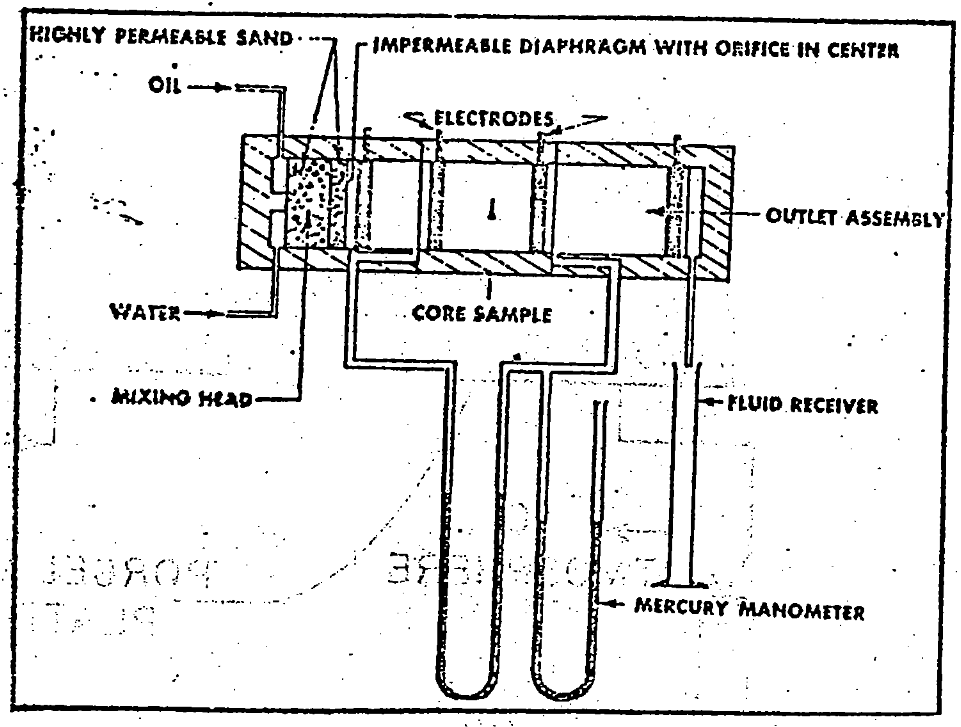


Fig. 2.57 Penn State Method.

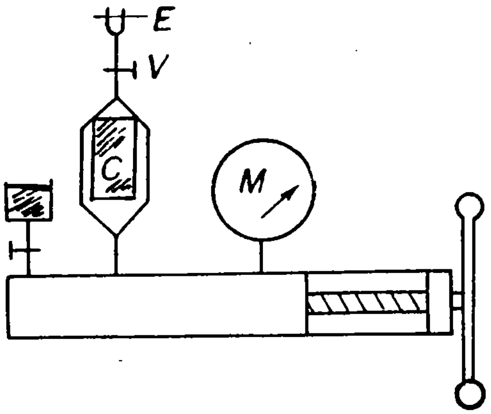


Fig. 2.13 Volume pump for mercury injection.

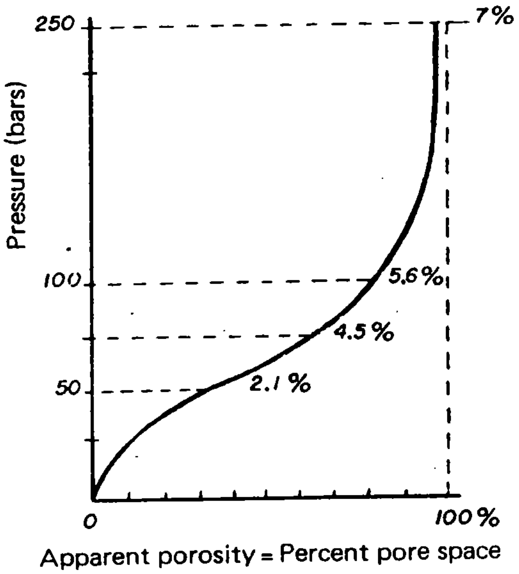


Fig. 2.14 Porosity through mercury injection.

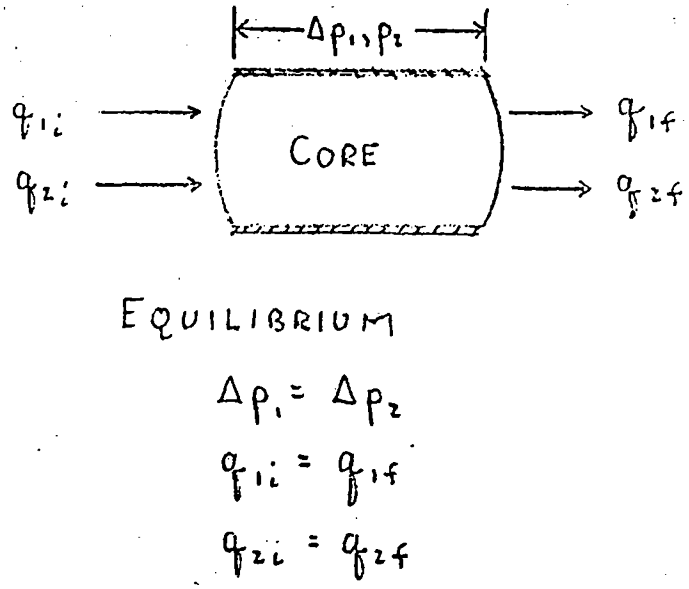


Fig. 2.55 Steady State Relative Permeability Tests.

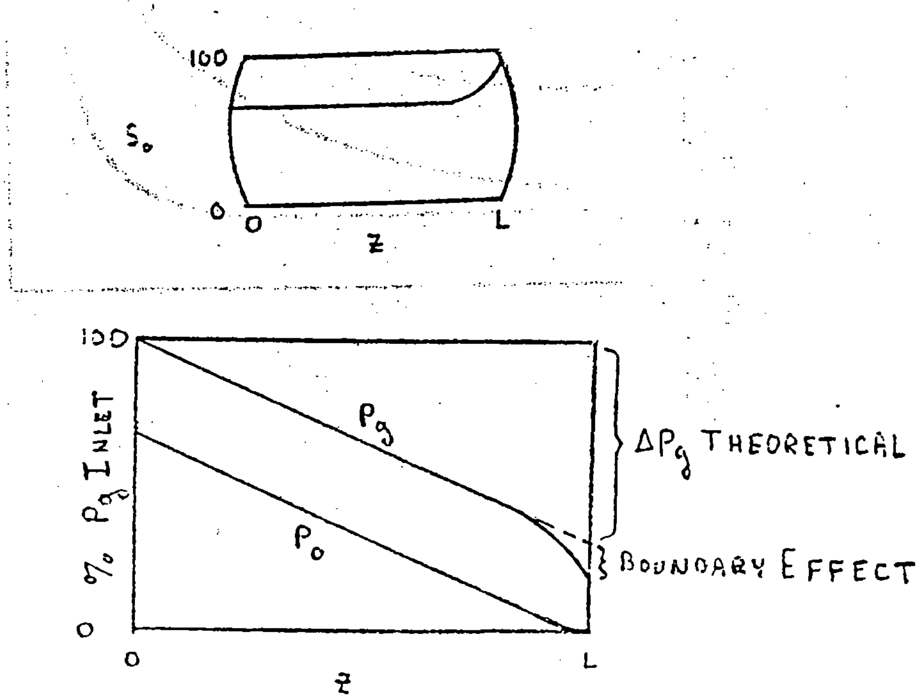


Fig. 2.56 Boundary Effect.

If the dry weight is known the real and apparent densities can be calculated. The method is long and difficult but it gives a total porosity.

(2) MEASUREMENTS OF RESERVOIR ROCK PERMEABILITY

The technique for laboratory measurement of rock sample permeability veries depending upon:

(a) The state of consolidation of the sample.
(b) Sample dimensions.
(c) The fluid used (gas - water- oil).
(d) The range of pressure on the sample.

For consolidated soils, samples are generally collected in geometric shapes:

(a) Either full cylinder with the following approximate dimensions :
Diameter = 2.3 cm to 4.0 cm and height = 2.5 to 5.0 cm.
(b) Or cubes with 2 cm sides.
(c) Or hollow cylinders for radial circular flow measurements.

In certain case when the state of consolidation is insufficient, it is necessary to make a small assembly or to coat:

(a) For example to coat a fragment with wax in order to measure permeability in side wall core analysis or for unconsolidated sand.
(b) Coating with bakelite or plastic ("plasticore" by means of a thermosetting plastic).

A special technique is necessary for measuring the permeability of cores from fissured limestone deposits. These measurements are made on whole cores.

<u>Measurement of air permeability k_a for geometric samples (parallel flow)</u>

The instruments which are currently utilized make possible measurement of 1.10^{-4} to 20 darcys.

droplets trapped within the pores of the rock. These residual oil droplets severely restrict the flow of water through the rock pores.

Typical relative permeability curves for a system where gas and oil are flowing are shown in Figure 2.54. Water is present at its irreducible saturation so water has no permeability in this system. Gas-oil relative permeability data are plotted against total liquid saturation, S_L. Gas saturation equals 1.0 minus SL. Relative permeability curves are shown for the liquid saturation range from 1.0 to the residual liquid saturation, S_{lr}, which is the sum of S_{iw} and the residual oil saturation. As gas saturation increases, the relative permeability to oil falls from 1.0 to 100 percent liquid saturation to zero at S_{lr}. Relative permeability to gas becomes finite at the critical gas saturation, S_c, which often is in the 2 to 5% PV range. For gas saturation less than S_{gc}, gas exists as discontinuous bubbles in the larger pores and restricts the flow of oil. As gas saturation increases from S_{gc}, relative permeability to gas increases to a value slightly less than 1.0 at S_{lr}.

MEASUREMENT OF RELATIVE PERMEABILITY

The techniques for the measurement of relative permeability-saturation relations in the laboratory can be broken down into roughly two categories, 1) steady-state techniques and 2) displacement techniques. Displacement methods can be further subdivided into 2a) gasfloods, 2b) waterfloods, and 2c) centrifuge experiments. The discussion which follows will proceed in the above order. Interestingly, the order is indicative of the historical development of tests and of the amount of time required for a test (ranging from slowest to most rapid).

Steady-State Methods

There are several experimental setups which have been proposed for use in steady state methods. There are several features and problems which are common to all of these methods.

The basic concept behind these methods is to flow two phases through the core simultaneously until equilibrium is established. Equilibrium is indicated when the outlet

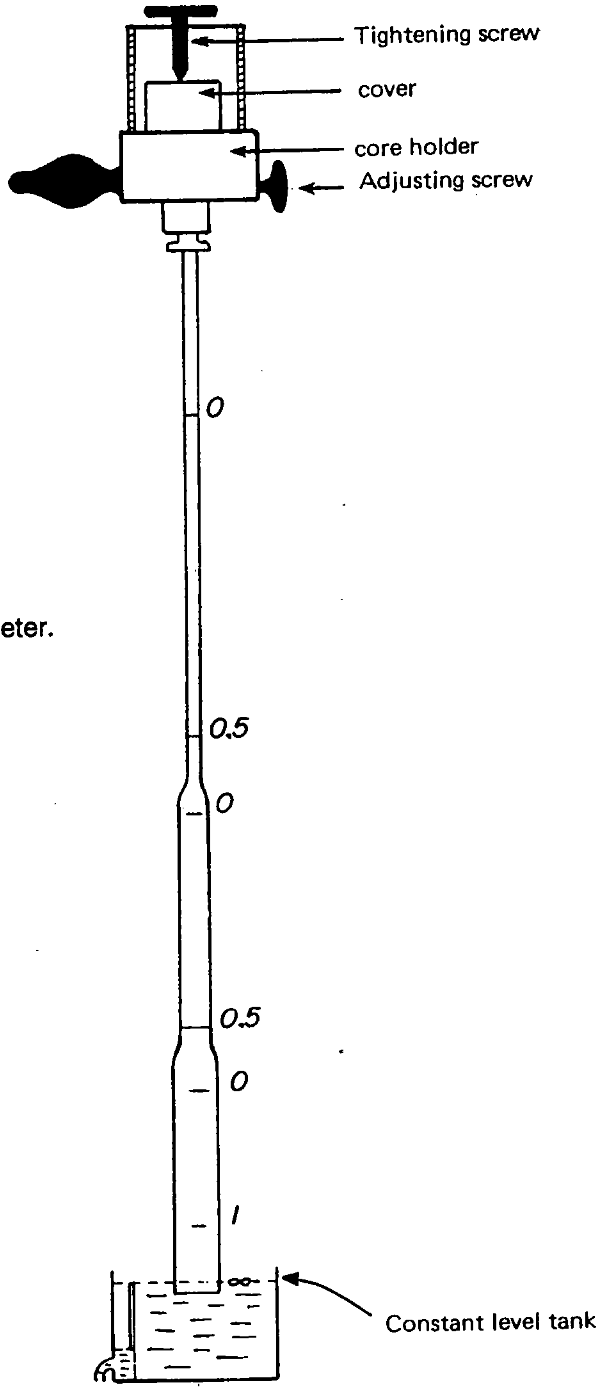


Fig. 2.15 Variable head permeameter. IFP type.

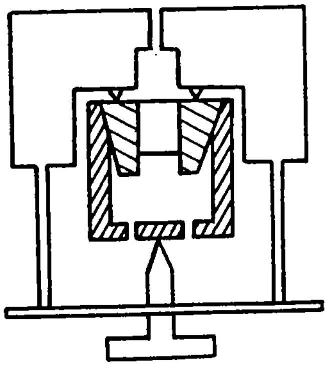
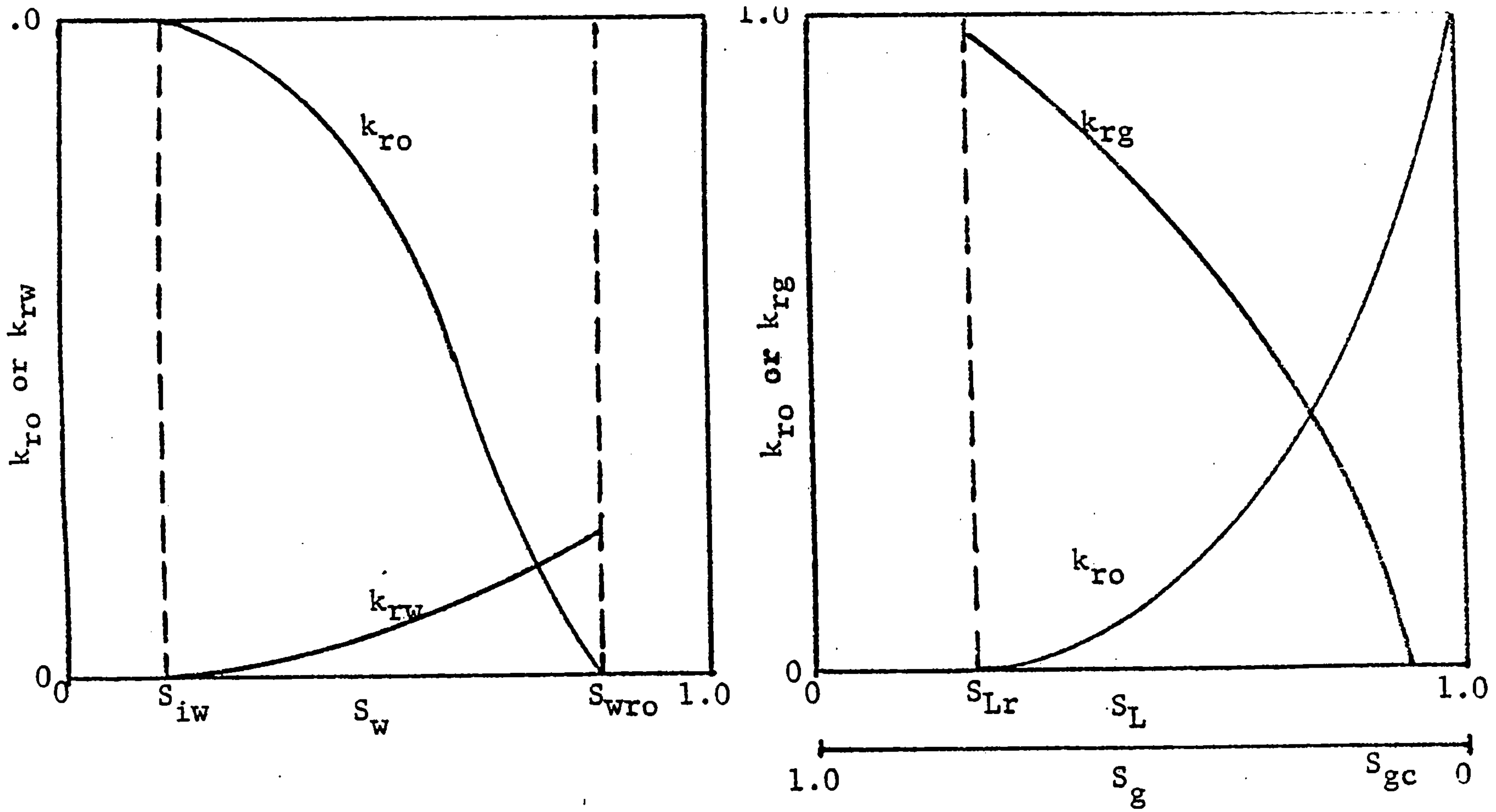


Fig. 2.16 Core holder of changeable load air permeameter.



A. Water-Oil System

B. Gas-Oil System

Fig. 2.54 Typical Relative Permeability Curves.

Air permeability, k_a, is given by:

$$k_a = \frac{2\mu * \theta_a * L}{S} \frac{P_a}{(P_1^2 - P_2^2)} \qquad \text{(Eq. 2.14)}$$

θ_a = rate of air flow measured at pressure Pa (atmospheric),

L = sample lenght,

S = sample section,

P_1 = pressure upstream,

P_2 = pressure downstream,

μ = air viscosity.

Remark:

Practical units:

$$k_a\,(\mathrm{mD}) = \frac{2\mu(cP)\,.Q_a\,(cm^3/s.L\,(cm)\,P_a\,(abs.atm.).1000}{(P_1^2 - P_2^2)\,(abs.atm)^2.S(cm^2)} \qquad \text{(Eq.2.15)}$$

Measurement of gas permeability for hollow cylindrical samples: dry gas

Figure 2.18 gives a diagram of the apparatus utilized.

Measurements are made for circular radial flow. According to Darcy's law we have:

$$k = \frac{\mu\theta_a}{\pi h} \ln\frac{R}{a} * \frac{P_o}{P_1^2 - P_0^2} \qquad \text{(Eq.2.16)}$$

k = permeability,

μ = gas viscosity,

θ_a = gas flow rate measured at pressure P_o,

R = outside radious of sample,

a = inside radious of sample,

h = height of sample,

Relative permeability is the permeability to a fluid (when more than one fluid is present) expressed as a fraction of either the absolute permeability (permeability at 100 percent saturation of single fluid), or the permeability to oil at the irreducible water saturation.

Relative permeability ratio is the ratio of the relative permeability of the fluids in a two fluid system at a specific saturation of one of the fluids.

A *waterflood test* provides data on the relative permeability to oil and to water as a function of water saturation. At the start of the test, the core sample is filled with oil at the irreducible water saturation. Water is flowed through the core at a constant rate and the volumes of oil and water production are recorded. This provides data on the cumulative oil recovery and the water-oil ratio as a function of cumulative water injection. The pressure drop across the core is also recorded throughout the flood, to provide a basis for determining the relative permeabilities to oil and to water as a function of water saturation.

If the flood test is run at the proper oil to water viscosity ratio, the oil recovery data can be used directly to predict waterflood recovery for a reservoir. If a high oil to water viscosity ratio is used, relative permeability data can be calculated. A waterflood recovery curve for any lower viscosity ratio can be calculated using this relative permeability data.

Waterflood tests are sometimes run at room temperature using refined oil and a synthetic brine, but best results are obtained using reservoir fluids in preserved cores. The oil to water viscosity ratio used is often equal to that for the reservoir being studies. If water-oil relative permeability data are desired, it is best to use a high oil to water viscosity ratio.

Waterflood test can be run under reservoir conditions using reservoir fluids. Reservoir temperature is maintained in an oven, and reservoir pressures are maintained throughout the test. The cores used for this type of flood must be cut under controlled conditions to maintain true reservoir wettability. The cores must be preserved for

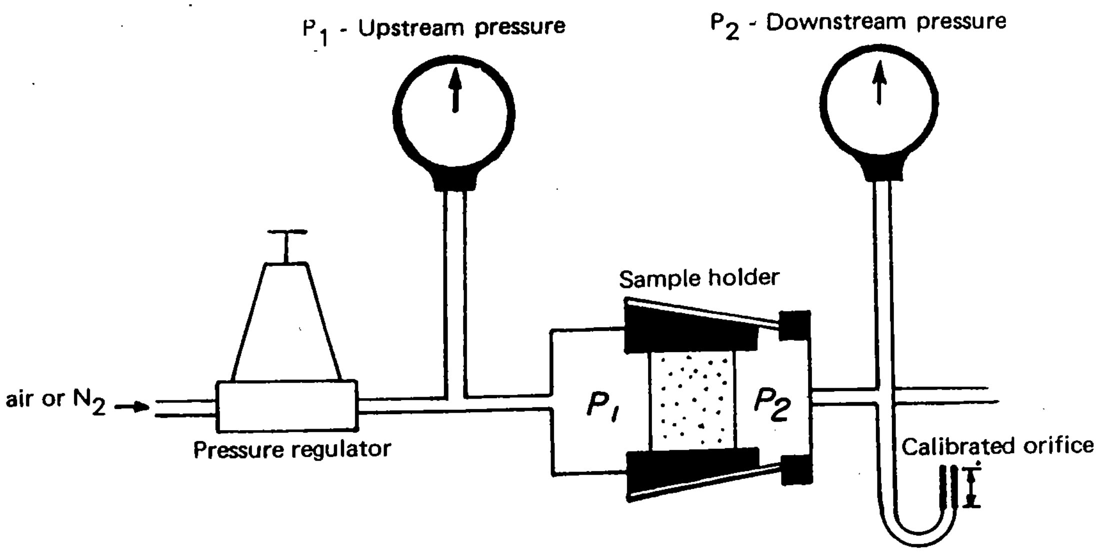


Fig. 2.17 Permeameter: schematic flow diagram.

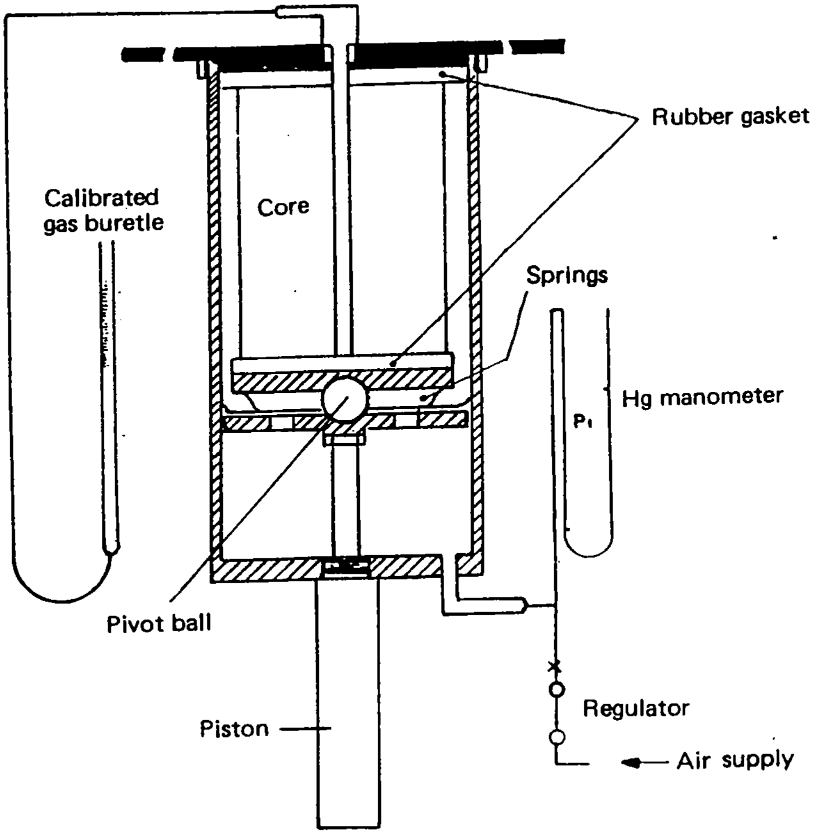
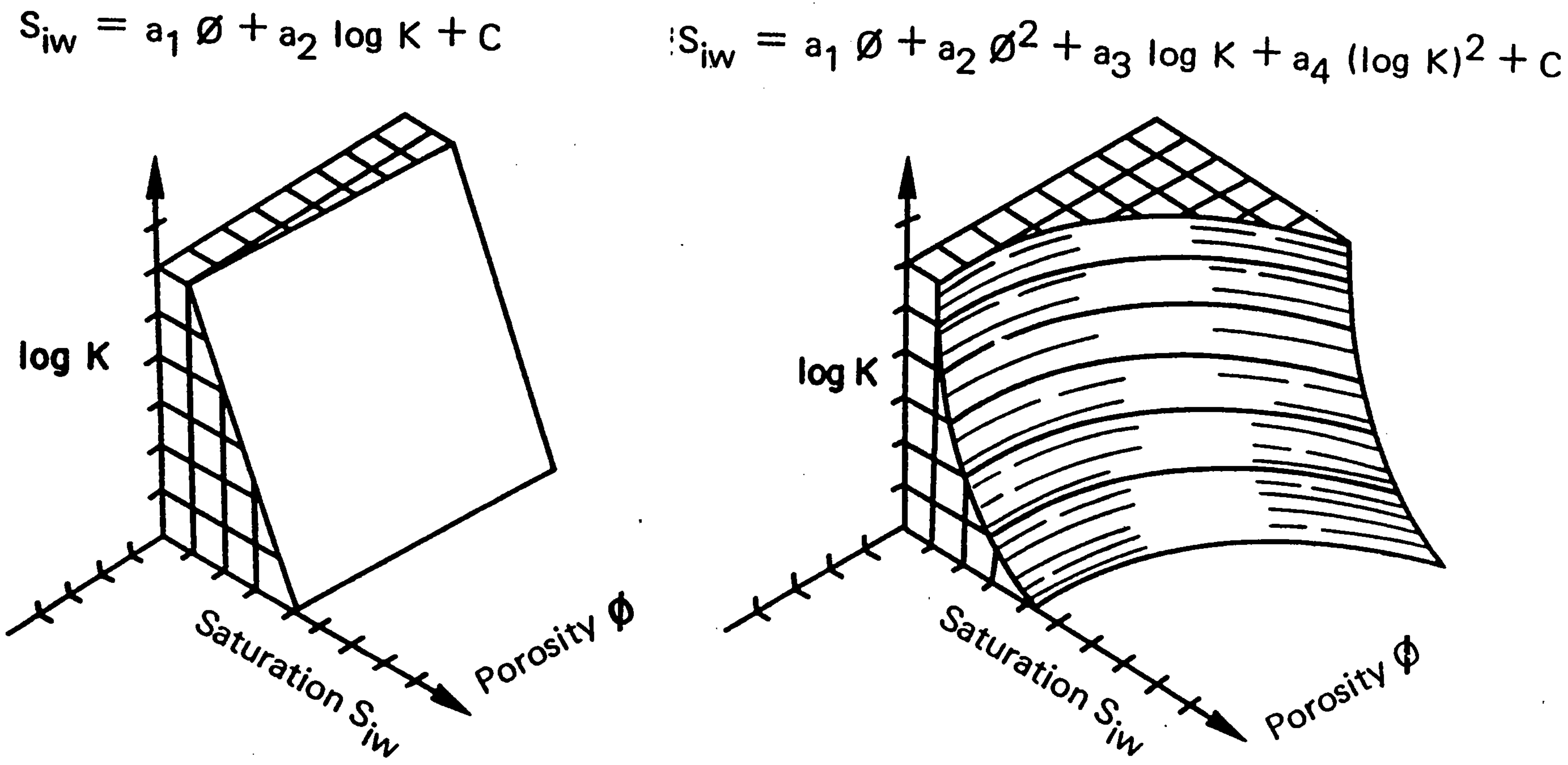


Fig. 2.18 Full diameter radial permeameter.



$$S_{iw} = a_1 \emptyset + a_2 \log K + C$$

$$S_{iw} = a_1 \emptyset + a_2 \emptyset^2 + a_3 \log K + a_4 (\log K)^2 + C$$

Fig. 2.53 Correlation of S_{iw} and ϕ, K.

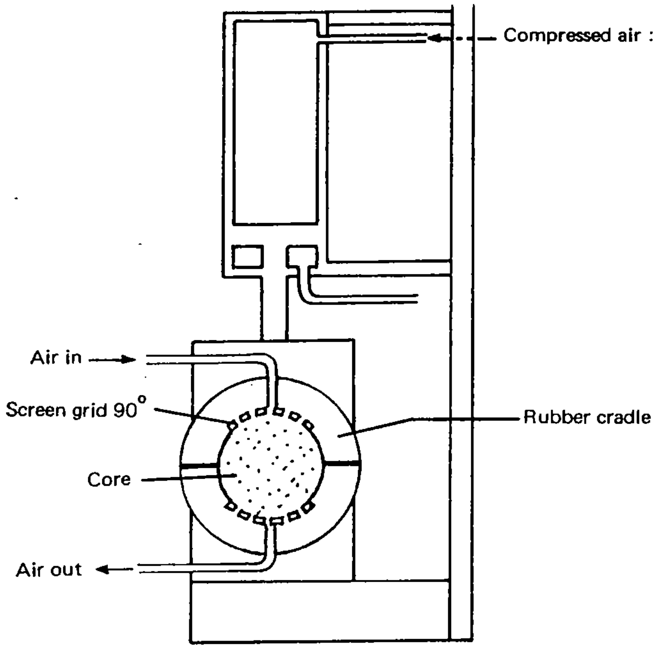


Fig. 2.19 Whole core permeameter. (from *Core Laboratories, Inc.*).

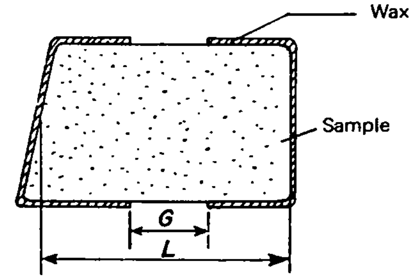


Fig. 2.20 Preparation of whole core for k_a measurements.

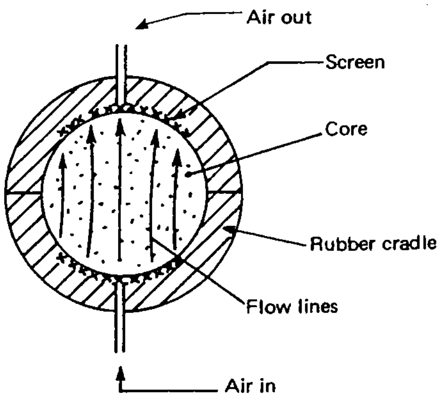
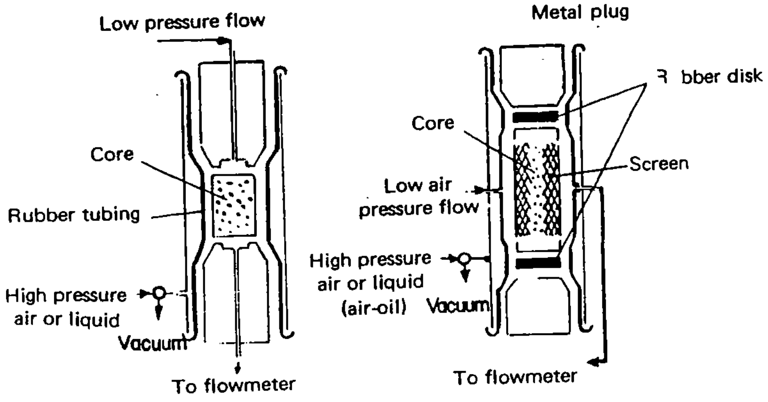


Fig. 2.21 Passage of air in sample during measurement.



A. VERTICAL FLOW

B. HORIZONTAL FLOW

Fig. 2.22 Hassler type permeameter.

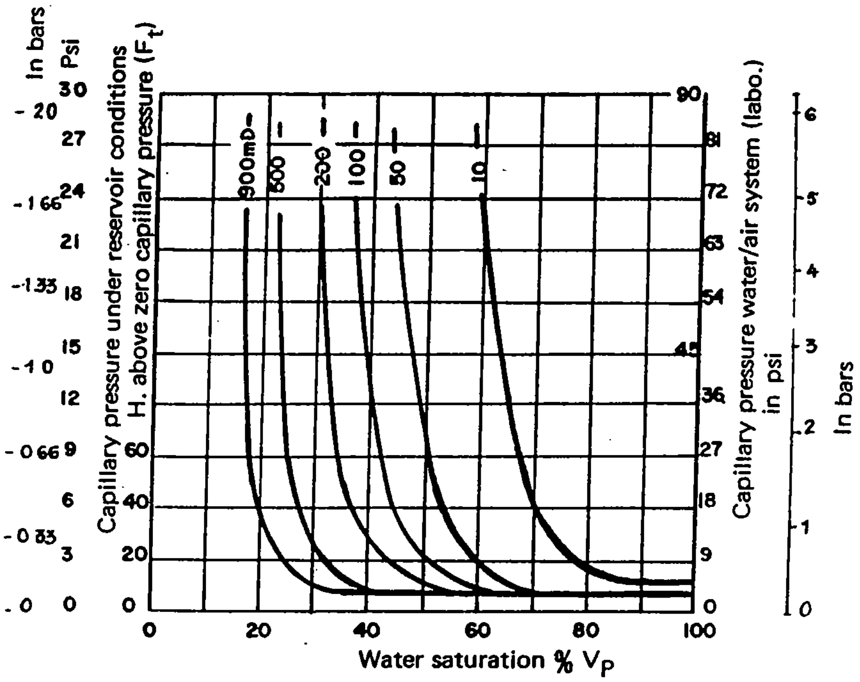


Fig. 2.51 Reservoir fluid distribution curves.
(from Wright and Wooddy).

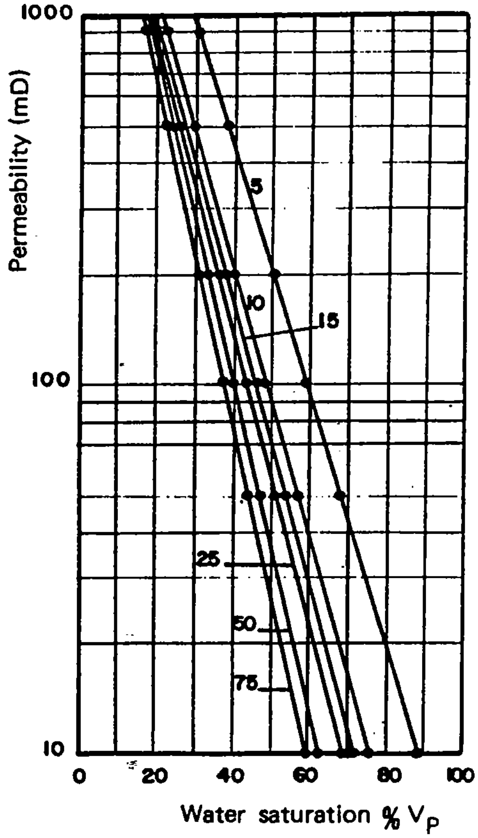


Fig. 2.52 Correlations of water saturations and permeabilities for different capillary pressure.
(From Wright and Wooddy).

Utilization of the Hassler assembly

This assembly is an improvement on the use of rubber plugs whose tightness is limited at certain pressures. The core is placed in the flexible rubber tube (Fig. 2.22). At each end of the core there are steel fittings which make it possible to inject or collect fluids or to measure the pressure. Tightness is assured by inflation either with air or with the liquid.

This method, which may be less rapid than the plug, has undeniable advantages:

(a) Excellent tightness.

(b) Can be used for samples of very different sizes.

(c) Much higher pressure or ΔP can be used: it is possible to reproduce geostatic pressures

(d) Permeability measurements in two directions *H* and *V* (Fig. 2.22).

(e) Measurement of air, oil or water permeability.

(f) Hassler assemblies can be used foe various measurement such as relative water / oil, gas / oil permeabilities.

Permeability unconsolidated media

It is possible to measure the permeability of sands:

(a) A sample is collected and is consolidated in some ways I. e. by means of paraffin, wax, plasticore etc.

(b) A permeameter with relatively unconsolidated sand is used. The sand is placed in the tube in a special way and the packing is very important (packing in waterpacking in air) as well as the compaction and the materials acting as cement. The permeability values very during the measurement and becomes stabilized at the end of the certain period of time. (Fig. 2.23).

(c) In the case of the so - called side wall core analysis, a piece of sample is placed in the center of the copper cylinder with the unit being placed on fine sand (Fig. 2.24). Wax is poured between the sample and the cylinder. After the base has been removed, the unit is placed in an air permeameter either at variable or constant head.

(a) The function of capillary pressure

Some authors have attempted to link the permeability of rocks to their morphology. Within a more limited field , Leverett believes that different samples from the same sediment have linked properties so that there exists an invariant specific to the sediment. He has introduced the function J (S_w) known as the capillary pressure which is a dimensionless grouping of the physical properties of the rock and the fluids saturating it:

$$J\,(S_w) = \frac{P_c}{T} * \left(\frac{k}{\phi}\right)^{1/2} \qquad \text{(Eq. 2.41)}$$

Some authors write it:

$$J(S_w) = \frac{P_c}{T\cos\theta} * \left(\frac{k}{\phi}\right)^{1/2} \qquad \text{(Eq.2.42)}$$

It should be noted that this function J (S_w) is proportional to a quantity which is in relatively direct relation to the pore radius. Function J was at first proposed as a means of conversion for all the capillary pressure results to a general curve. There are considerable differences in the correlation between function J and water saturation from one formation to another, which makes it impossible to plot a general curve, but for the same formation a very good curve can be plotted.

The example shown in Figure 2.50 (according to W. Rose and W. A. Bruce) is the function J (S_w) plotted on the basis of capillary pressure curves for various samples in the case of the water/air pair.

(b) Second correlation method for calculating connate water saturation

Capillary pressure measurements are made for a selection of representative samples. The selection is made in terms of permeability (Figure 2.51) according to Wright and Wooddy. As a first approximation, for the establishment of capillary pressure correlation, the water saturation curves as a function of log k_a are plotted for constant

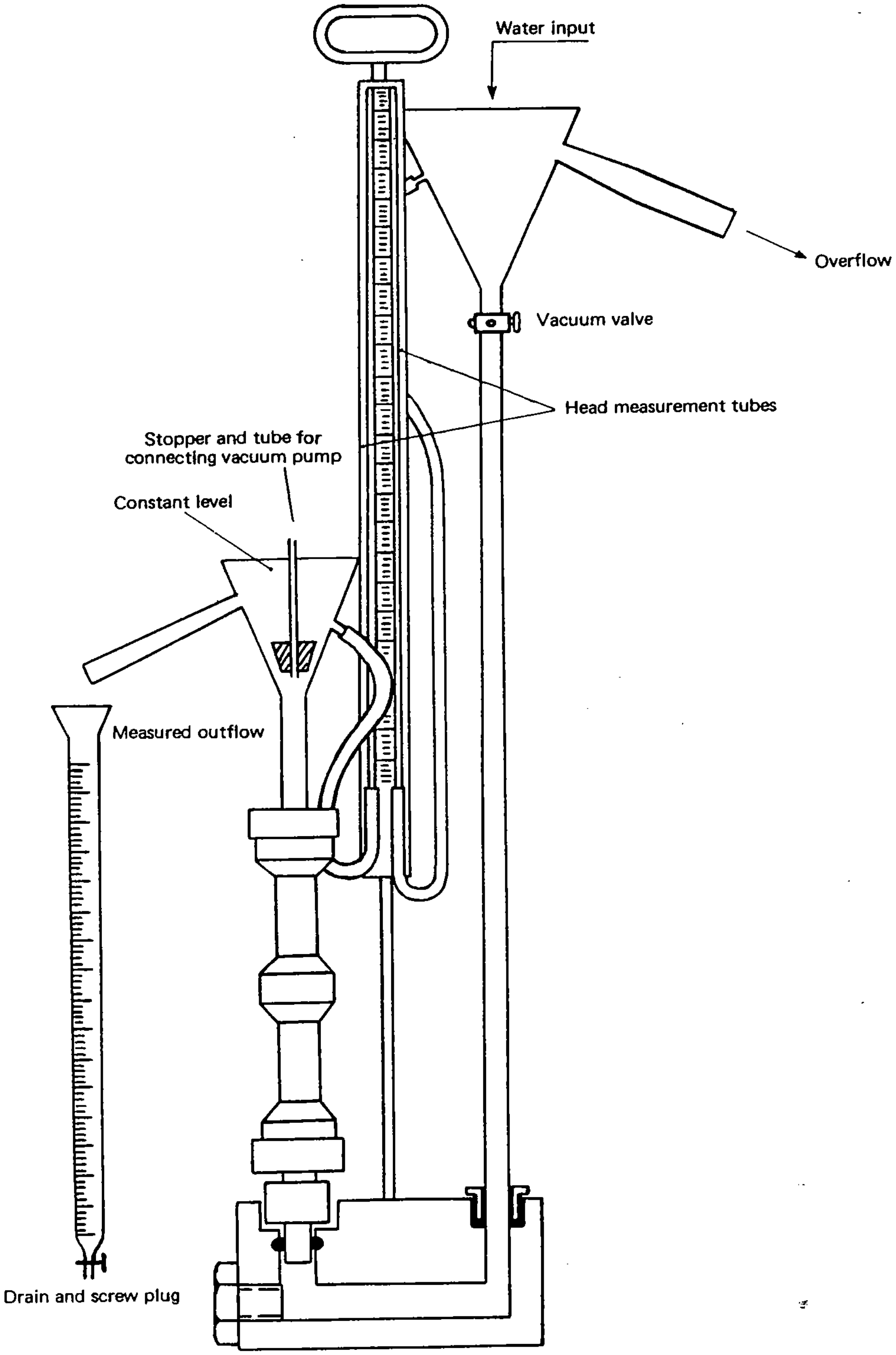


Fig. 2.23 Sand permeameter. Overall view. IFP model.

$$\frac{P_c H_g / air}{P_c water / air} = \frac{480}{70} = 6.57 \qquad \text{(Eq.2.37)}$$

Experience has shown that we have :

(a) For limestone: a ratio of the order of 5.8.

(b) For sandstone: a ratio of the order of 7.5.

There is no common factor for all rocks.

In order to use the laboratory results for capillary presser, it is necessary to convert them to a reservoir conditions. The laboratory results are obtained with gas / water, oil / water system which should have the same physical properties as the water, oil or gas of the reservoir. Two techniques differing only by their initial hypothesis are used for converting the laboratory capillary pressure results for reservoir conditions:

$$(P_c)_{reservoir} = \frac{T_{water/oil} \cos\theta_{water/oil}}{T_{water/gas} \cos\theta_{water/gas}} * (P_c')_{laboratory} \qquad \text{(Eq.2.38)}$$

or

$$(P_c)_{reservoir} = \frac{T_{res.}}{T_{lab.}'} (p_c')_{laboratory} \qquad \text{(Eq.2.39)}$$

Examples

1. Conversion of water / air pair (laboratory) to water / oil couple (reservoir).

We have:

In the laboratory	In the reservoir
Capillary pressure = P'_c	$T_{water/oil} \approx 28$ *dyn / cm*
$T'_{water/air} \approx 70$ *dyn / cm*	$\theta_{water/oil} \cong 33$ to $55°$
$\theta'_{water/air} \approx 0°$	
	$\cos\theta = 0.869$ to 0.643

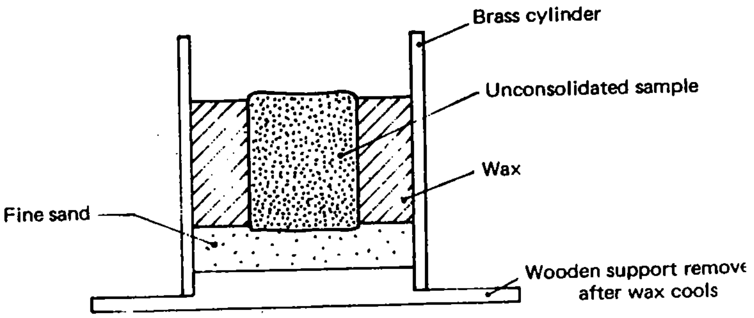


Fig. 2.24 Preparation of unconsolidated sample for k_a measurements.

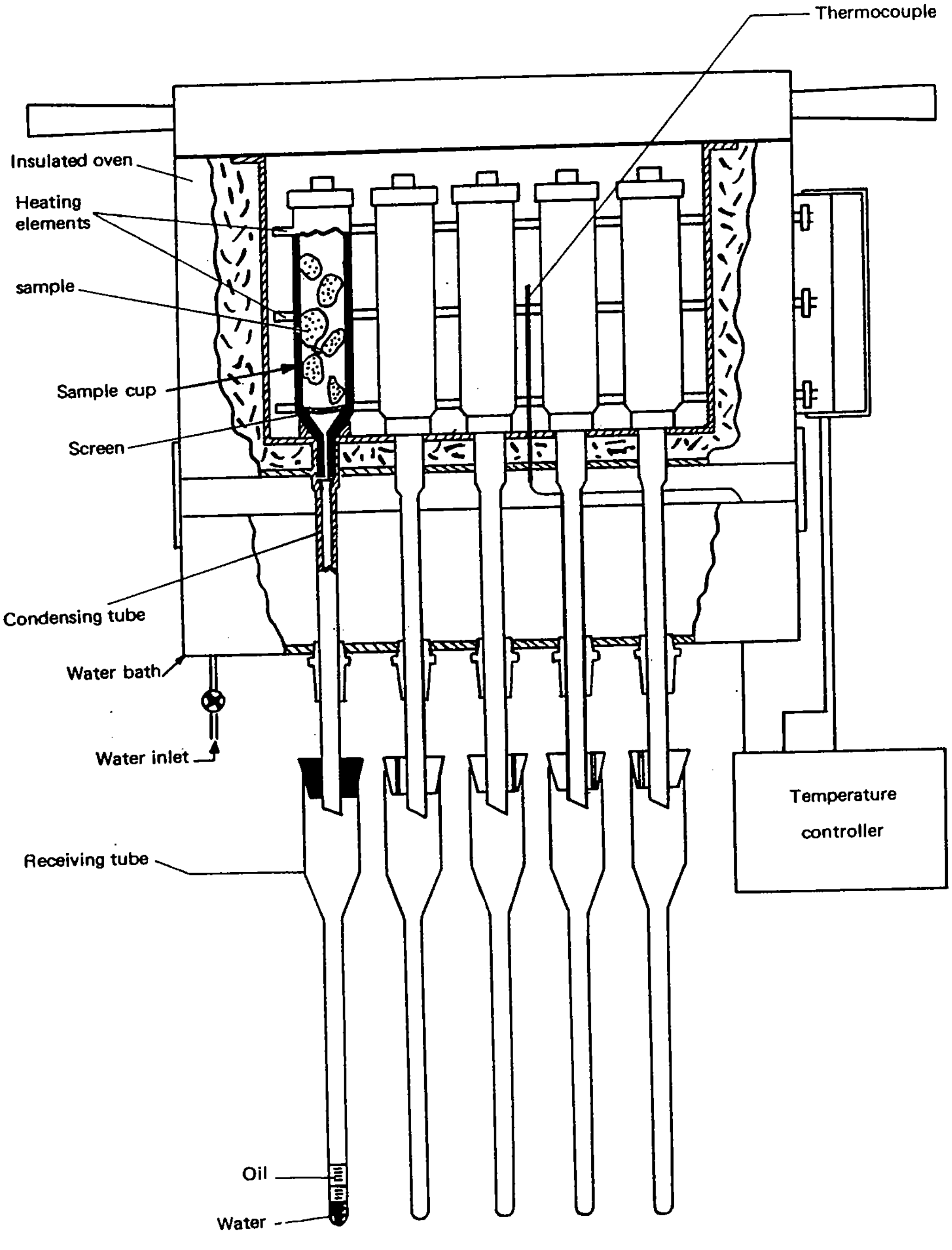


Fig. 2.25 Oven retort atmospheric pressure.
(*Core Laboratories Inc.* type retorts.)

At the beginning, surface evaporation is fed by the interstitial water and there is a given slope. When the irreducible water is reached there is evaporation only by diffusion so that the slope is much flatter (method used by Continental Oil Co., Bureau of Mines, Elf. etc.).

Measurement of capillary pressure by centrifuging

The brine saturated sample with density p_1 is placed in a centrifuge rotating at n RPM. The sample is located within the medium with the specific gravity p_2 (air or oil). The maximum pressure difference on the end face of the core is given by the equation:

$$\Delta P = A * (p_1 - p_2)\, n^2 h * \gamma \qquad \text{(Eq.2.36)}$$

where

ΔP = the pressure difference on the end of the face and

$$P_m = \frac{\Delta P}{2},$$

h = centrifuge plate redious,

γ = constant depending upon instrument ,

A = constant depending upon units.

In the case of small samples with n = 16000 RPM and $p_1 - p_2 = 1.064 - 0.754 = 0.310$, we have found for a given centrifuge that ΔP = 11.95 bars and $P_m = \frac{\Delta P}{2} \approx$ 6 bars.

Case of Application

Certain samples have swelling marls and very low k_a. In order to have a point well above the maximum possible pressure with semi - permeable walls (4 to 5 bars), the centrifuging method is used which makes it possible to show one or two points as high as 21 bars.

Saturation	Oil	Gas	Water
At surface	↑40 %	↑30 %	30
	shrink		
	and expulse		
In core barrel	70 %	0	30
	invade		
in reservoir	↑70 %	0	30

It is clear that the measurement of fluid saturation can be carried out only on fresh or very protected samples. In no case should the samples be washed when removed from the core holder or exposed for long.

The fluids contained in the core whose saturation is to measured are therefore:
Gas
Oil
Water

Determination of gas saturation

The determination is done by injecting mercury into a fresh core of known volume. The procedure will be described below under the so - called fluid summation method. The equipment used is a mercury volume pump.

Determination of water and oil saturation by distillation at atmospheric pressure (Retort method of fluid summation, Core Laboratories process, Patent Nos. 2282 and 2361844)

A known weight and volume of fresh samples from the core center is coarsely ground and placed in the hot oven (Fig. 2.25) whose temperature is controlled.

- Oil and water are collected in test tubes by distillation.
- If the rock volume and the collected water and oil volumes are known, it is possible to determinate the values of the fluids as a percentage of rock volume.
- Saturation is calculated by means of porosity.

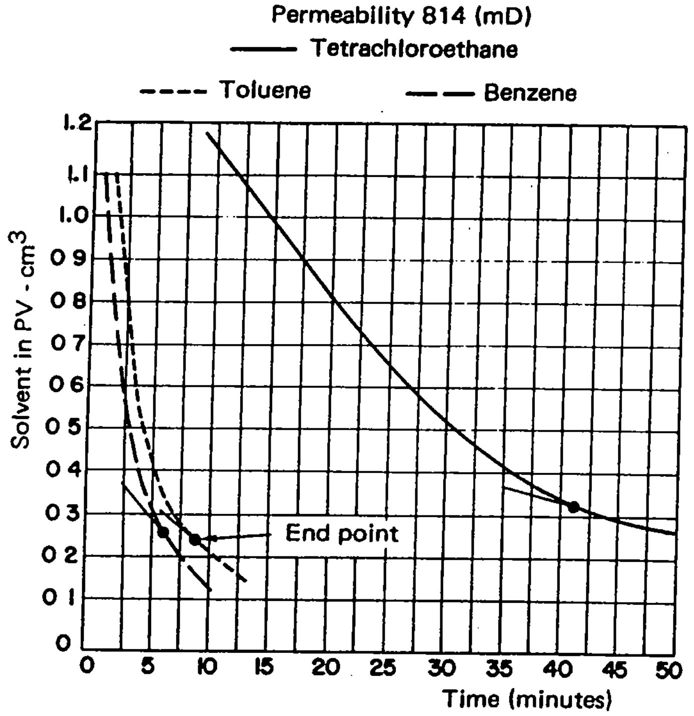


Fig. 2.49 Evaporation curve. (from P. Albert).

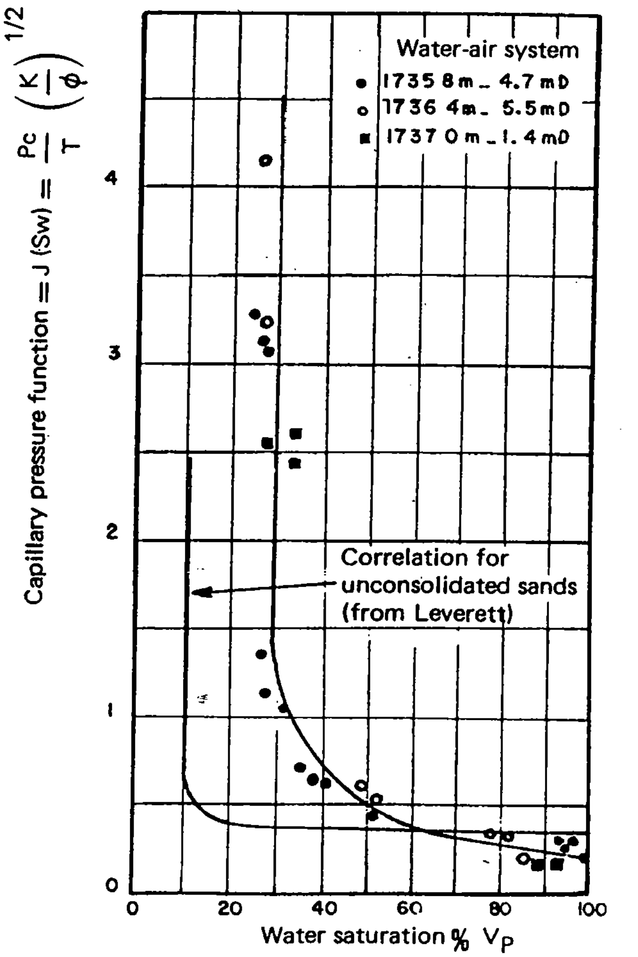


Fig. 2.50 Capillary pressure function in Weber consolidated sandstone (from W. Rose and W.A. Bruce).

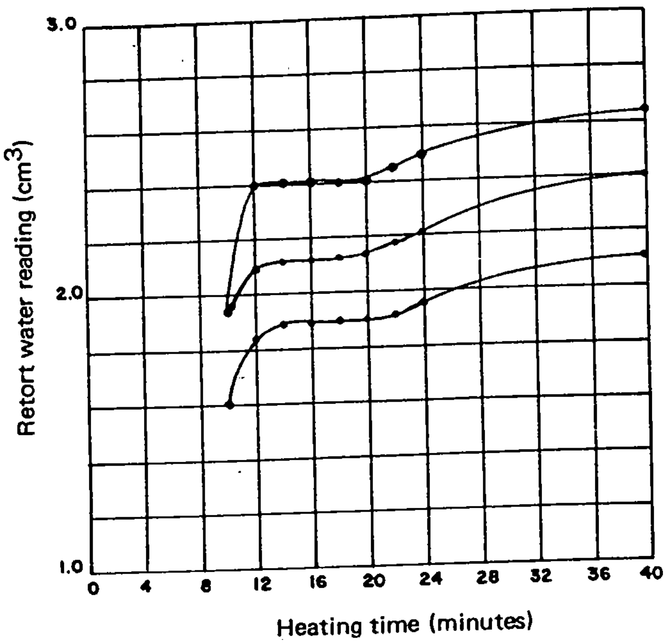


Fig. 2.26 Water calibration curves.

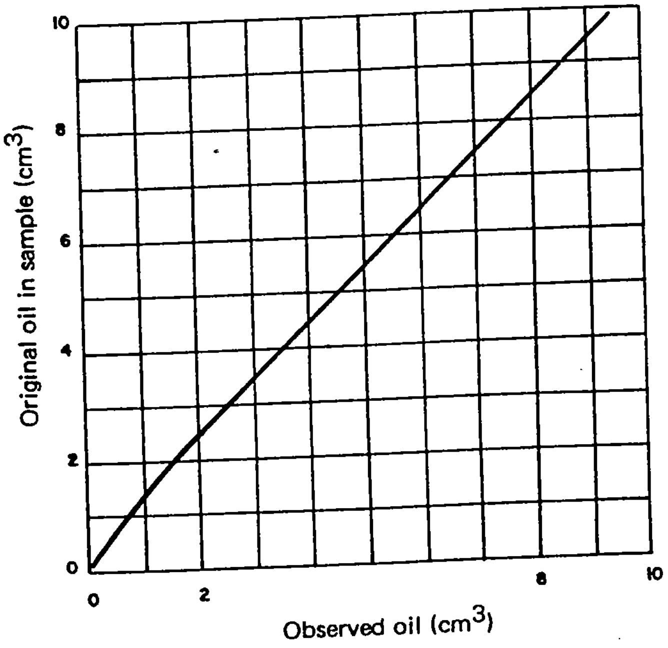


Fig. 2.27 Oil calibration curve.

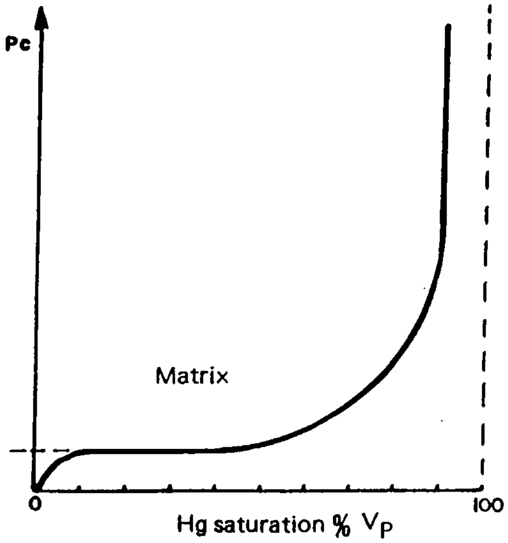


Fig. 2.46 Capillary pressure by mercury injection: homogeneous matrix medium.

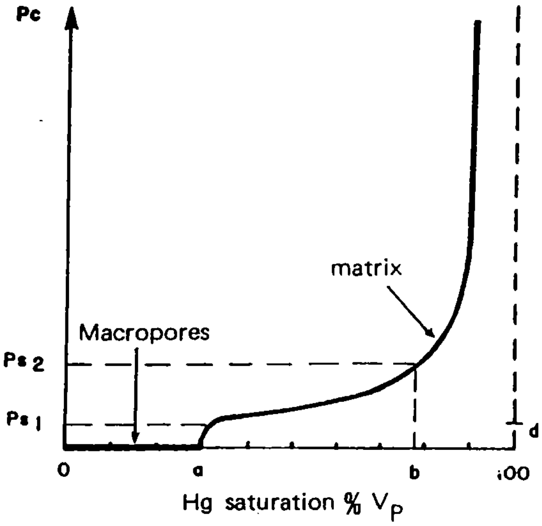


Fig. 2.47 Capillary pressure by mercury injection: medium with macropores and matrix.

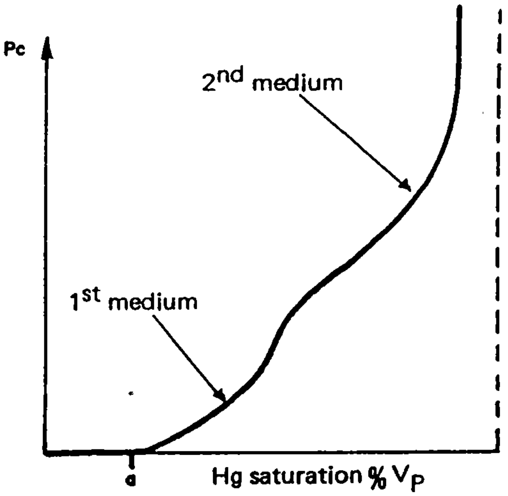


Fig. 2.48 Capillary pressure by mercury injection in the case of 2 matrix.

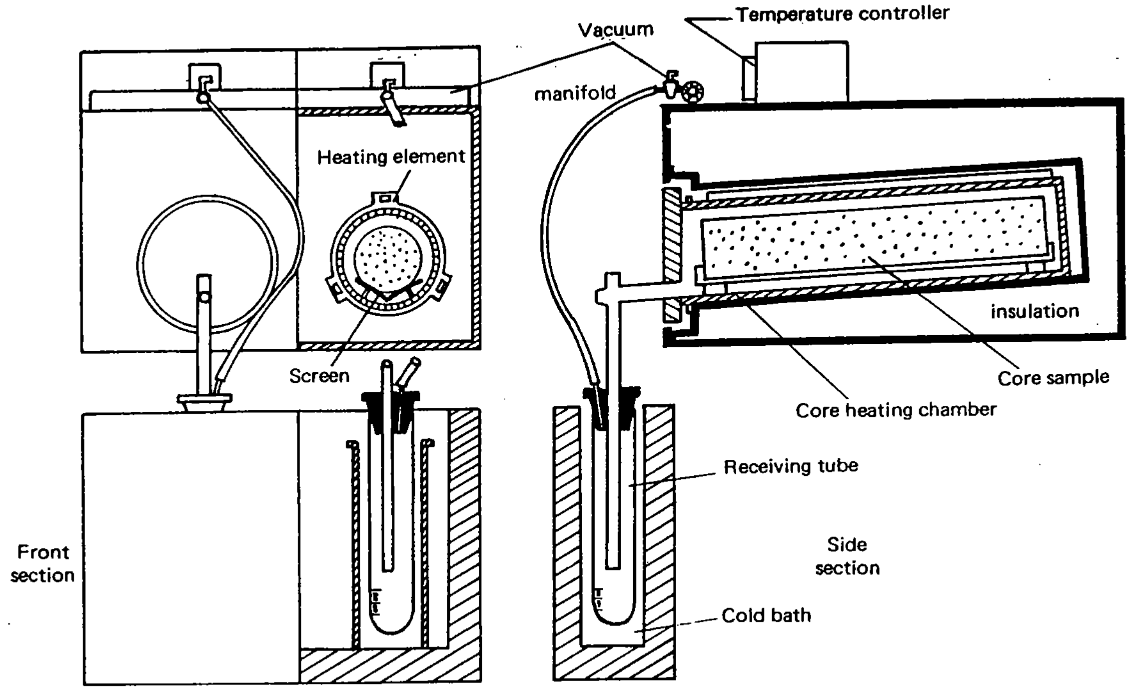


Fig. 2.28 Vacuum retort.

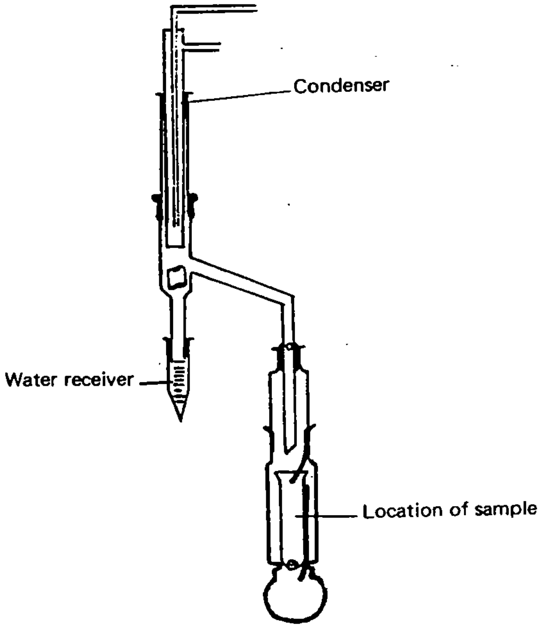


Fig. 2.29 ASTM. Distillation extraction apparatus (modified by RAP).

Mercury saturation is calculated as a percentage of pore volume in terms of pressure in order to establish capillary pressure curves by mercury injection (Purcell method).

Remarks:

(a) At the beginning, at the time of the zero setting when the plug is immersed in the mercury although to a very slight degree (approximately 2 to 3 cm of a mercury), the mercury may already have penetrated into a very large or macropores. This penetration can be very considerable in certain cases, amounting to as much as 30 to 40 % and it must be measured.

(b) In practice, the last stage corresponds to 250 bars. At that moment most of the samples are practically 100 % saturated. This pressure corresponds to pore radii of the order of 0.04 microns.

(c) The state of equilibrium can be very long in cases of low permeabilities.

In the case of water / air pair where the wetting phase is displaced, there it allows a path through which circulation is possible leading to the creation of irreducible saturation in the pores which do not participate in the circulation.

In the cease of the mercury/air pair, this condition does not exist and the curves obtained do not show the characteristic asymptote for irriducible saturation. The latter can perhaps be defined by the saturation corresponding to the beginning to the rectilinear part of the curve (if this point is marked, or if not, to the saturation corresponding to the pressure of, for example, 10 to 15 or 20 bars depending upon samples.

The shape of the curves obtained by the plotting the equation for capillary pressure as a function of mercury saturation expressed as a percentage of the pore volume is very variable from one sample to another (pore volume is carefully determinate by an appropriate method such as immersion on a solvent).

(b) An ASTM trap in which the water is collected which is poured off after condensations of the distilled azeotropic mixture.

The problem consists in the collection in the trap of water which should be the only substance to be found there. There are many sources of error and the method is not always very effective, while extraction time us very long (several days to several weeks). The quantity of water is read directly.

Determination of water content by reaction with calcium hydride

This method was developed and used principally by S. N .Repal and SNPA. The sample is placed in the test tube with an inert material. 3 g of calcium hydride in powder form are placed in the tube and the tube is connected to an assembly for measuring the volume of gas discharged. The tube is immersed an oil bath which brings the sample temperature from 40 ° to 135 ° C in approximately one half hour.

If the sample is clayey, the final temperature will be < 110 ° C.

Heating times is 2 to 3 hours for average permeabilities, 8 hours for very low permeabilities.

The following very exothermic chemical reaction occurs:

$$CaH_2 + 2\,H_2O \rightarrow Ca(OH)_2 + 2\,H_2$$

If the temperature is high we then have:

$$CaH_2 + H_2O \rightarrow CaO + 2\,H_2$$

The measured volume of H_2 (corrected for temperature and atmospheric pressure) is much higher in the second case for the same quantity of water.

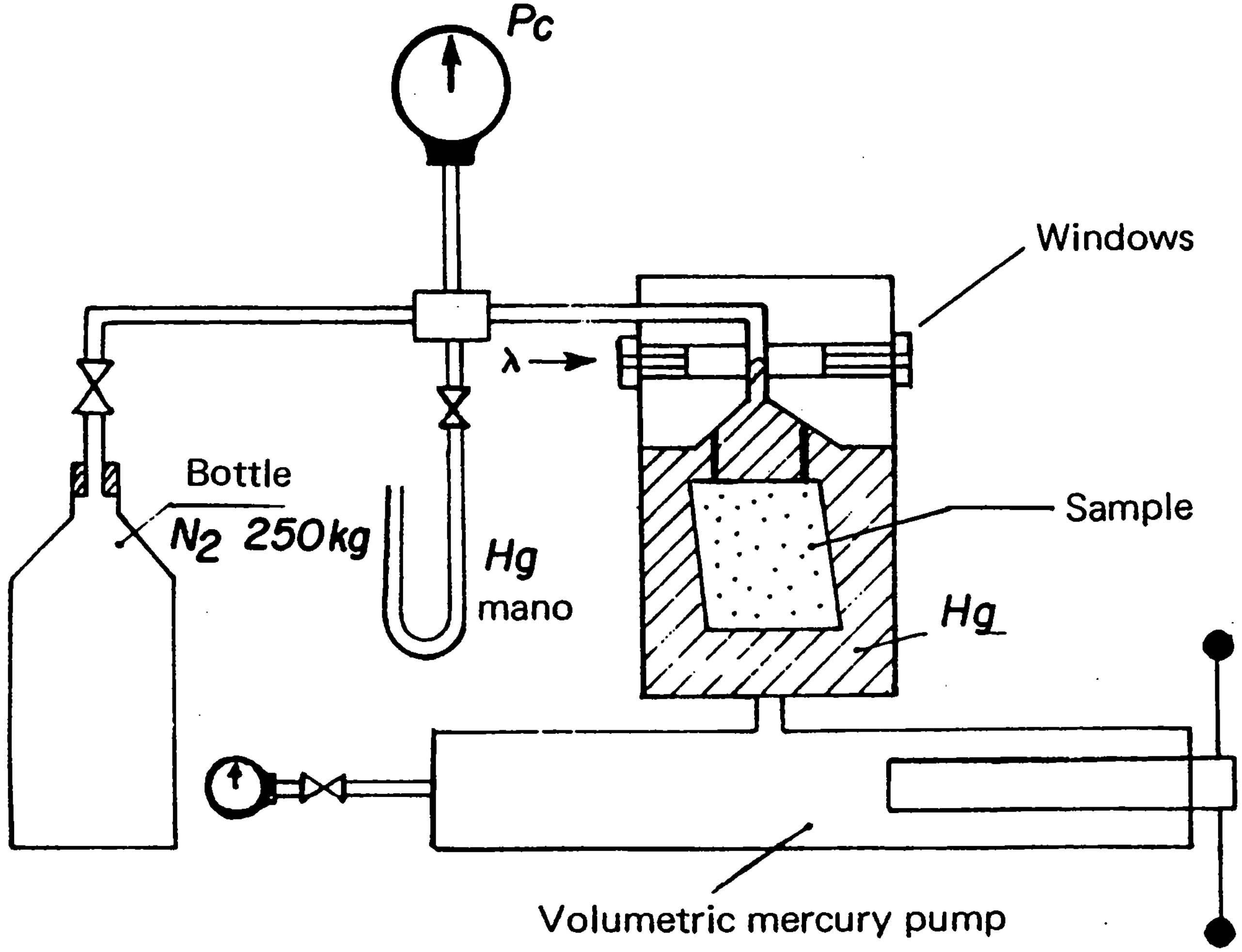


Fig. 2.45 Assembly with mercury pump for capillary pressures by H_g injection.

(a) Air permeability either with a variable head permeameter or with constant ha head permeameter.

A cube sample gives horizontal and vertical permeabilities or, if not, two cylindrical sample must be collected.

The air permeability values are corrected for the Klinkenberg effect by means of laboratory tables so as to obtain k_1 and liquid permeability.

(b) Porosity either by immersion (see course on porosity) which immediately gives the true mass densities or by gas expansion or by some other method, but the first probably gives the best results.

Complete core analysis by summation of fluids (Method, Core Laboratories Inc., US Patents 2282654, 2345535 and 2361844

The analysis is carried out on a fresh core sample, wiped with a clean rag (never washed with water), 8 to 10 cm thick and with good representativity. The fresh sample is divided into the three parts (Fig. 2.30 and 2.31).

(a) A cube (for horizontal and vertical permeability) or a cylinder (horizontal permeability) is collected from one part.

(b) One part of approximately 30 to 40 g is sed for determination of gas saturation.

(c) One part selected as far as possible from the core center is coarsely ground: approximately 125 g. It is used for determination of oil and water saturation through the atmospheric pressure distillation method.

Air permeability: A cube (k_H and k_v) or a cylinder (k_H)is collected in water, washed with combination of a Soxhlet apparatus and centrifuge and then dried in appropriate manner. Air permeability is measured by means of a variable or constant head permeameter. This sample is used for measuring permeability and it is preserved.

Measurement of porosity and saturation: The second part, which is lightly rounded off with a hammer (sharp angles should be avoided), is first weighed (approximately 30 g). Let w be its fresh weight.

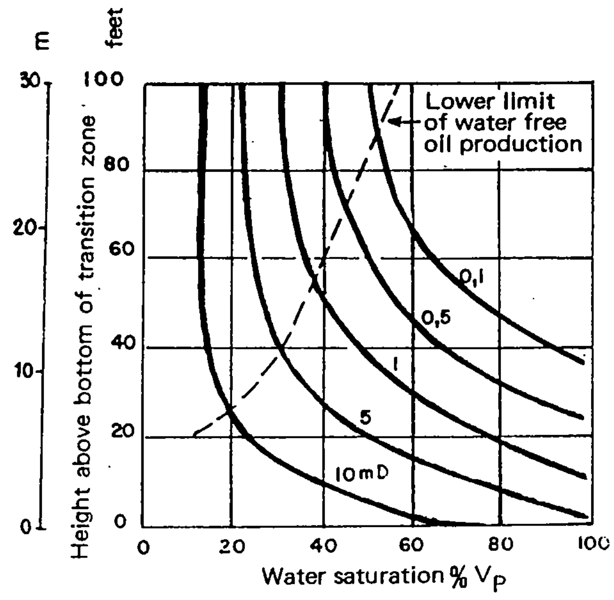


Fig. 2.41 Capillary pressure versus k_a.

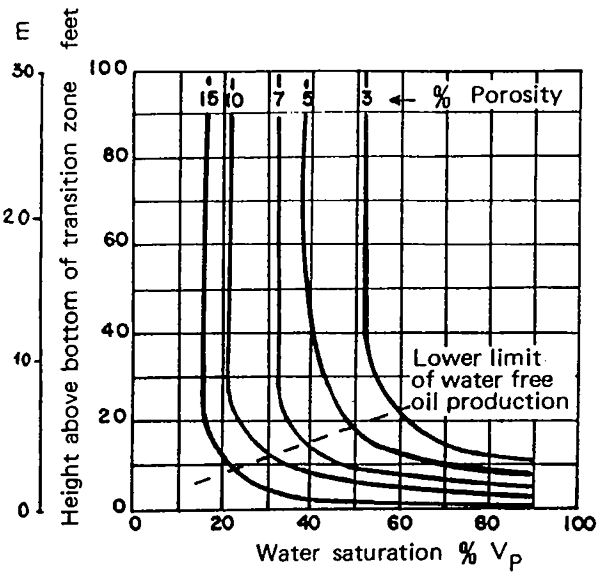


Fig. 2.42 Water distribution curves.

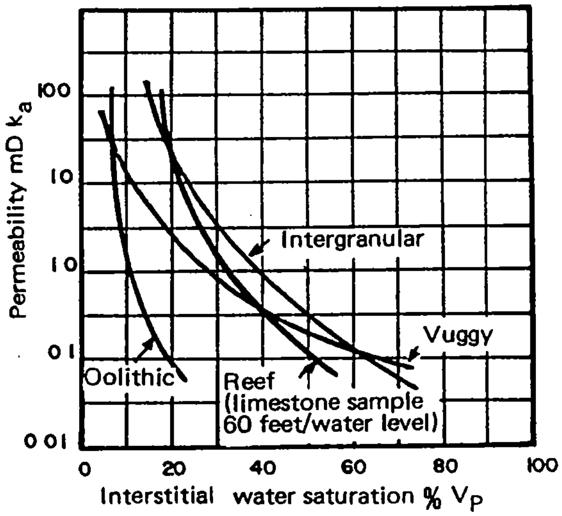


Fig. 2.43 Typical water distribution.

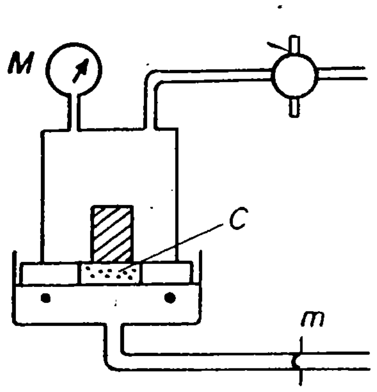


Fig. 2.44 Assembly with porous plate for restored states.

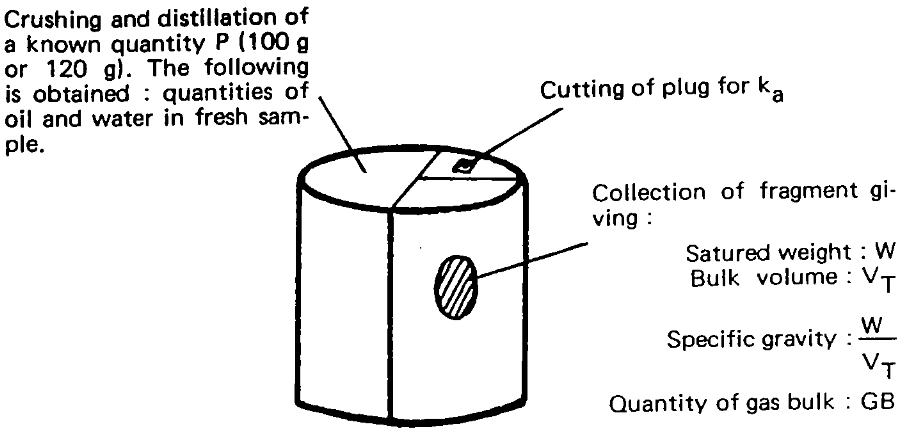


Fig. 2.30 Division of fresh sample for summation of fluids.

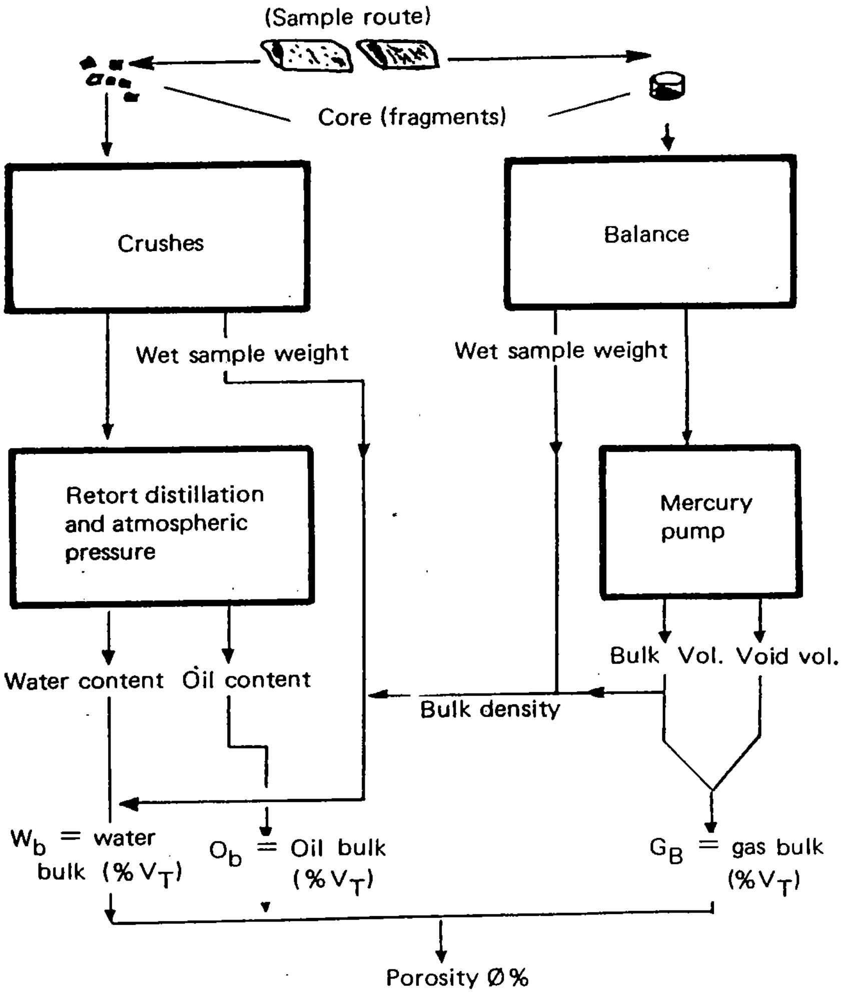


Fig. 2.31 Conventional core analysis by summation of fluids procedures.

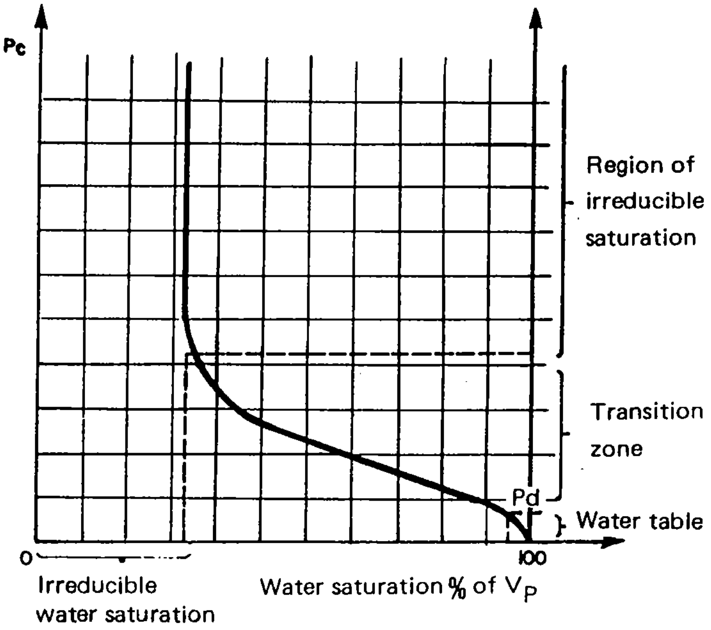


Fig. 2.38 Typical capillary pressure curve.

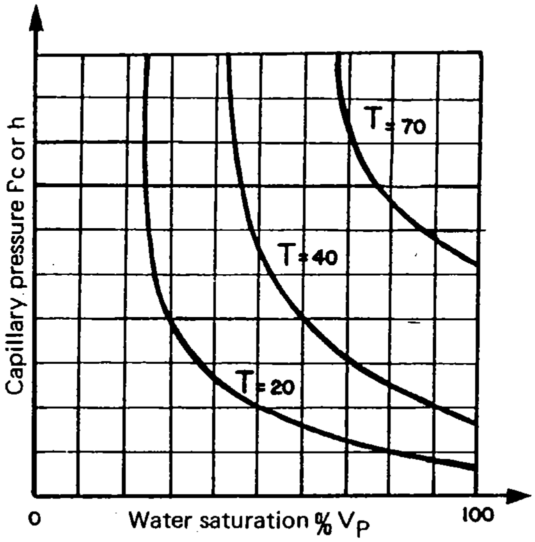


Fig. 2.39 P_c versus T.

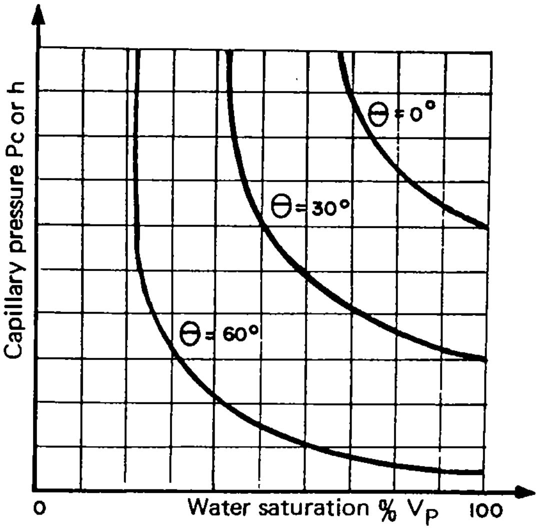


Fig. 2.40 P_c versus θ.

At the end of twenty - five minutes (when the oven temperature is of the order of 650°C) it is possible to read the total collected oil volume, "OBS_o". This observed oil volume should be corrected after cracking. These correction is made after sampling: observed (or measured oil in terms of real oil volume. From this the true value for the quantity of oil "$CORR_o$" contained in the sample follows. Consequently, volume V of ground sample weighing 125 g contains:

$$\text{Water} = W_B = \frac{"Init._w"}{V} * 1000$$

$$\text{Oil} = O_b = \frac{"CORR_o"}{V} * 100$$

Porosity, ϕ, is therefore the sum of fluids contained in the sample expressed as a percentage of the volume:

$$\phi\ \% = G_b\ \% + W_b\ \% + O_b\%$$

For calculating saturation we have:

$$\text{Oil saturation} = S_o = \frac{O_b}{\phi} * 100$$

$$\text{Water saturation} = S_{TW} = \frac{W_b}{\phi} * 100$$

It should be noted here that total water saturation is connate water plus water of invasion. A factor (*SF)* was established empirically depending upon the values of ϕ and G_b which makes it possible to determinate connate water saturation S_{cw}:

$$S_{cw} = S_{TW} * (SF)$$

(d) Rock porosity = ϕ.

The curves in Figs. 2.39, 2.40, 2.41, 2.42 represent variation of P_c with T, θ k ϕ.

The curves in Fig.2.43 show interstitial water distributions in terms of permeability for various porous media.

The assembly utilized for the restored state method in order to displace the wetting stage shown in Fig. 2.44

We have:

(a) A steel cell for imposing pressure.

(b) A semi - permeable wall C (principal part of the assambly which is fine porcelain wall whose large pores are small enough so that they are permeable only at pressures above 5 bars.

(c) Manometer and source of gas saturated with water vapor.

The brine saturated wall is in contact with a chamber containing brine. The water phase is entirely at atmospheric pressure. The sample which are 100 % saturated in this brine are placed on the wall with the sample - wall contact being as complete as possible (very fine diatom powder). Above the wall, the cell is filled with the air at constant pressure. At each pressure plateau (of the order of 48 h)the following are noted:

(a) The brine volume produced (capillary tube).

(b) Or the variation in weight.

It is possible to determine the relation P_c in terms of brine saturation (S_w expressed as percentage of pore volume). The pressure plateaus which are frequently used are: 0 - 0.03 - 0.07 - 0.14 - 0.28 - 0.56- 1- 2 -3 - 4 bars rel. (in the case of the water / air pair capillary pressure of 3 bars corresponding to a high above the zero capillary level of the order of 30.5 m for the water \ oil pair).

(b) The second part is treated as above but with an appropriate material:

Porosity is determinate by fluid summations.
Gas saturation is determined by mercury injection.
Oil and water saturation are determined by distillation in small retort (Fig. 2.32)
Mercury, oil and water are collected.

This very quick method gives good results with samples which are representative to varying degrees of the formation and are weathered.

Extraction with pentane (pentane cut method)

The fresh sample is again divided into two parts:

(a) The first part is treated as above for permeability measurement.
(b) On the second part of the side wall sample:

The weight is determined by weighing.
The quantity of gas is determined by mercury injection.
The volume is determined with a mercury pump.
The sample is ground and placed in 100 cm ^{3} of pentane.
The pentane is evaporated (heating in a bath of T° = Const. (Fig.2.33).
The residual oil volume is noted and the latter figure is subjected to an experimental correction (Fig. 2.34)

We then have:

(a) The gas measured above
(b) Total oil
(c) The water is calculated with material balance.
(d) porosity is determined by fluid summation.

This method is no doubt more complicated than distillation method but its often quicker. The results are presented as in the preceding method and the measurements are completed by a lithological description and observation of fluorescence.

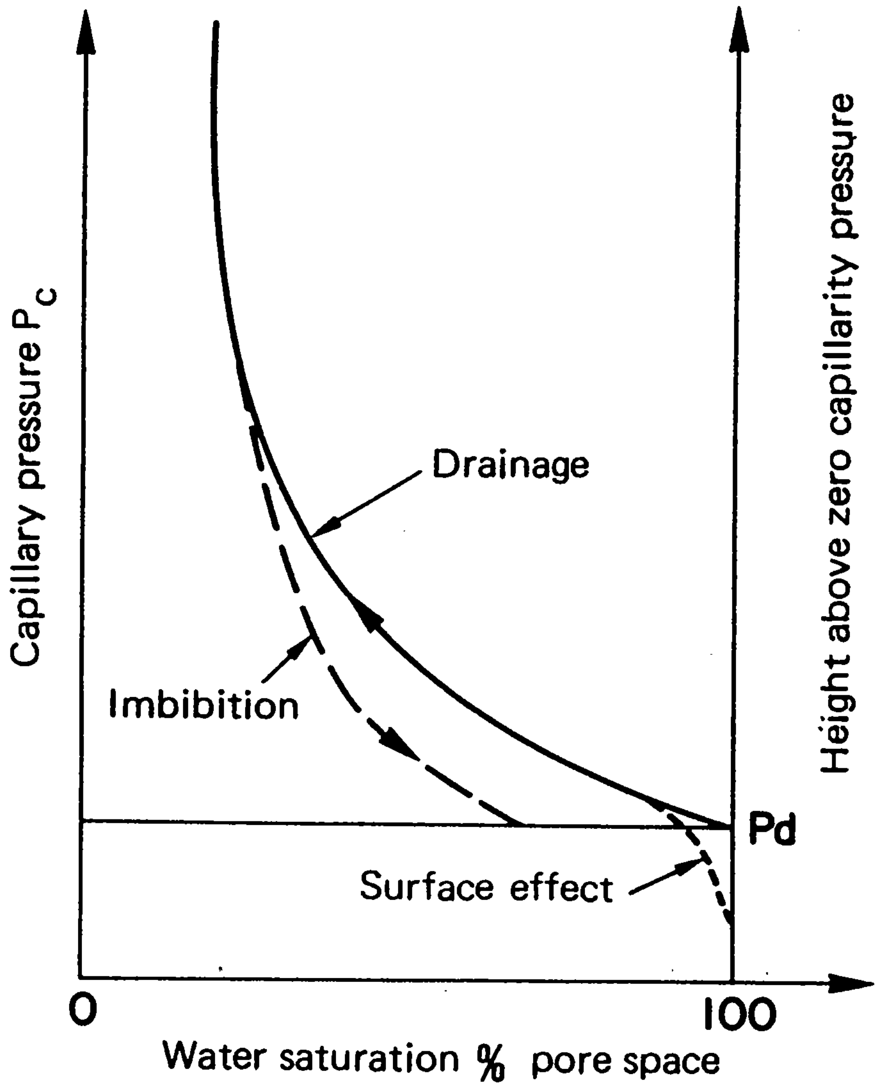


Fig. 2.37 Capillary pressure curve. (restored states method).

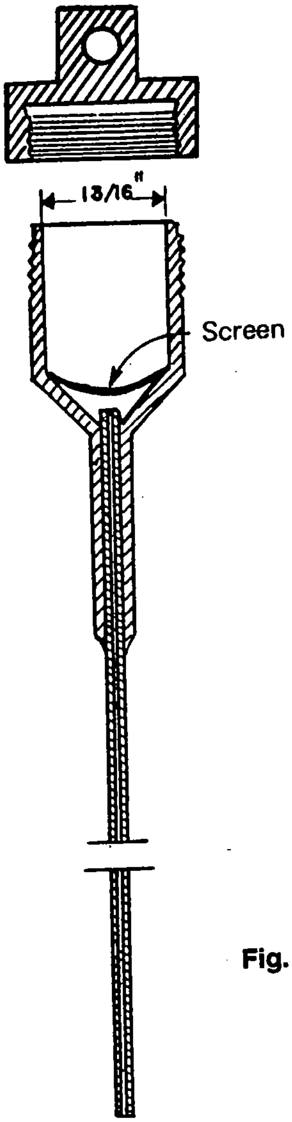


Fig. 2.32 Retort cup. Side wall sample.

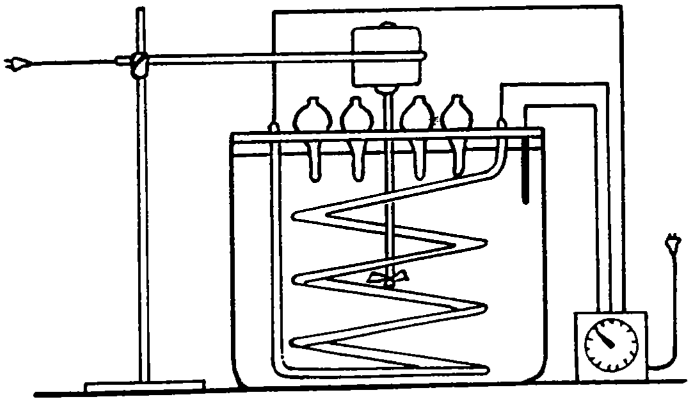


Fig. 2.33 Pentane evaporation apparatus.

$$P_c = \frac{2T\cos\theta}{r} = \frac{T}{r} * g(S_{w)}$$

The relation between r and water saturation S_w is not rigorously constant if we go from one pair to another, but it will be supposed that there is an invariable relation between S_w and r. Hence the relation which is experimentally obtained in the laboratory between P_c and S_w can therefore be validly transformed for the real pair by the equation:

$$P_c = \frac{T\cos\theta}{T\cos\theta} * P_c' = h(p_w - p_o)g + {}^{Cons't}. \quad \text{(Eq.2.34)}$$

If P_c', T'' and θ' are known for one pair, T, θ for the other pair and also p_w, p_a, the following curves can be plotted:

(a) Capillary pressure in terms of water saturation (Fig.2.37).
(b) Or water saturation in terms of the distance h above the zero capillary level.

The height h is given by the equation:

$$h = \frac{P_c - P_c(z_o)}{(p_w - p_o)g} \qquad \text{(Eq.2.35)}$$

(a) If h is counted from the zero capillary level = $P_c(z_o) = 0$
(b) And if h is counted from the water / oil interface ("water level") previously defined as $P_c(z_o) \neq 0$

Remark:

Units: According to the Eq. 32.11 we have:

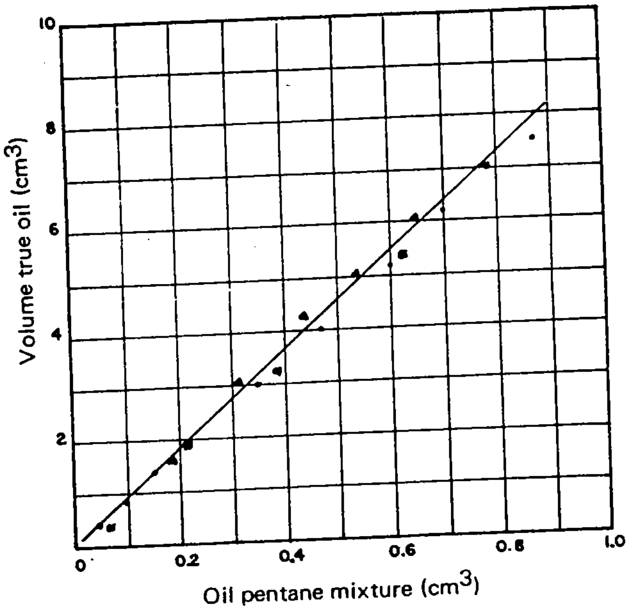


Fig. 2.34 Pentane evaporation data. Water bath temperature: 160°F.

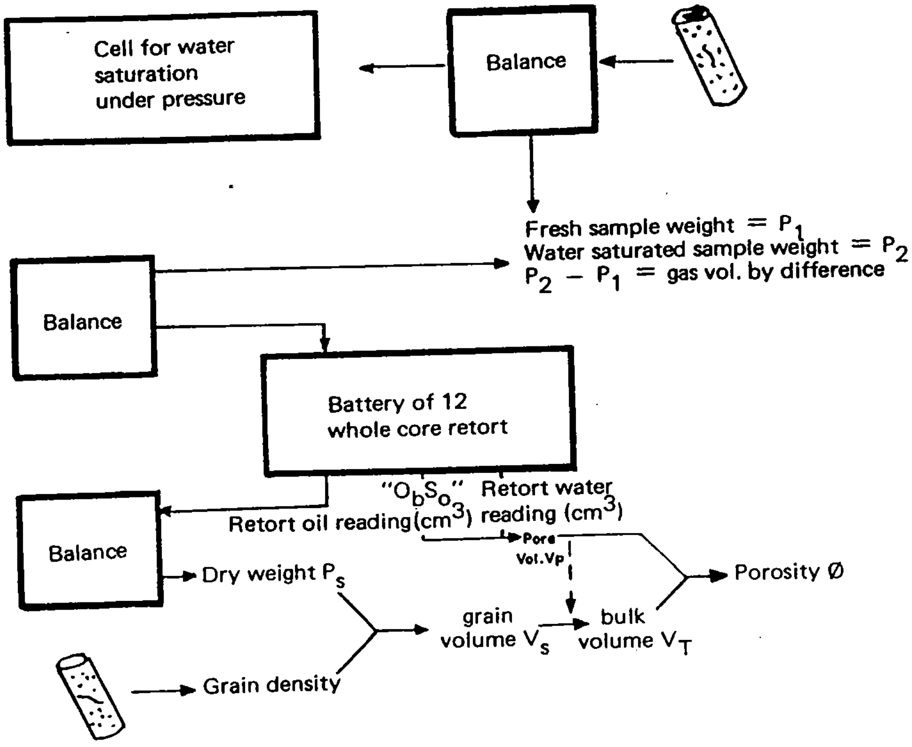


Fig. 2.35 Whole core analysis procedure.

At the start of an imbibition capillary pressure test, the core sample contains water at the irreducible saturation with the remaining pore volume filled with oil. These saturation conditions could exist at the end of a drainage imbibtion test if water has been displaced by oil. The imbibition test duplicates the displacement of oil by water in a bottom - water drive reservoir. The end point of the test is the residual oil saturation, as shown in Fig. 2.36. Most imbibitions capillary pressure tests are run on the centrifuge. Before the centrifuge test is started the sample must be allowed to imbibe water until equilibrium is reached. This gives the saturation conditions at the capillary pressure of zero. The sample, surrounded by water, is then put into the centrifuge and the imbibition test is run. The test is terminated when an increase in centrifuge speed does not further reduce the oil saturation.

A recently developed procedure allows imbibition capillary pressure tests to run at pseudo- reservoir conditions in the centrifuge. The core must be cut and preserved under conditions that retain true wettability. Reservoir temperature is maintained in the centrifuge and the core is saturated with water and gas free crude oil from the reservoir. Gas must be removed from the crude because the centrifuge environment is at atmospheric pressure. Refined oil should not be used unless it can be shown that they do not change the wettability of the core sample.

The area between the drainage and imbibition capillary pressure curve (Fig. 2.36), the hysteresis loop, results because oil forced into rock pores cannot be so easily forced out. In fact part of the oil, the irreducible oil saturation, cannot be forced out even at extremely high negative capillary pressure. As pointed out earlier, a negative capillary pressures occurs when the wetting phase (water)pressure is greater than non- wetting phase pressure. In the centrifuge imbibition test, only the negative capillary pressure are possible. However, this test defines the low oil saturation region of the curve which is an important part for determining water drive recovery efficiency.

(2) Capillary Pressure and Interstitial Water Determination

In order to determine water saturation in the reservoir by means of cores, the following methods can be used:

(a) Collections of water :water in pores plus water corresponding to gas. Since the samples are limestone or Dolomite there is no reason to fear the clay dehydration phenomenon.

(b) Collections of oil: a corrective factor should be applied because of cracking.

The sample is weighed after removal from the oven = $P =_{dry}$

Loss of weight = $P_2 - P_{dry} \approx$ pore volume.

The total volume of the fragment is calculated as follows:

Total volume $V_T = \dfrac{\text{Dry weight}}{\text{True density}}$ + (Weight loss).

The average grain density values are:
2.82 for dolomites,
2.72 for limestone.

Calculation of percentage of gas, oil and water contained in the fragment:

$$\%\,\text{gas} = G_b = \frac{P_2 - P_1}{V_T} * 100 \qquad \text{(Eq.2.28)}$$

$$\%\,\text{oil} = O_b = \frac{\text{corrected quantity of oil collected}}{V_T} * 100 \qquad \text{(Eq.2.29)}$$

$$\%\,\text{water} = W_b = \frac{\text{quantity of water in sample}}{V_T} * 100 \qquad \text{(Eq. 2.30)}$$

Hence

$$\text{Porosity}: \phi = G_b + O_b + W_b \qquad \text{(Eq.2.31)}$$

residual oil saturation:

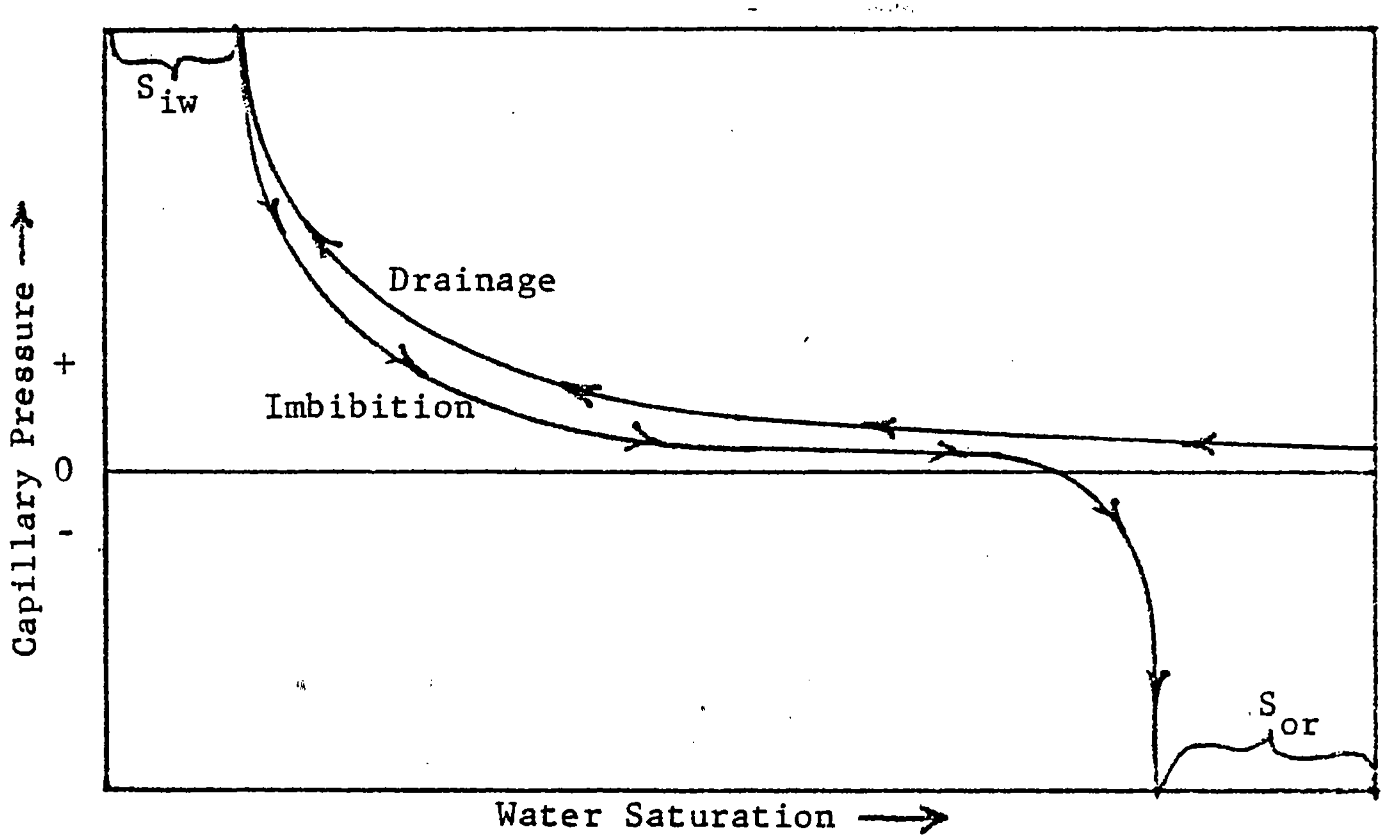


Fig. 2.36 Capillary Pressure Curves

B. SPECIAL CORE ANALYSIS

Although the data on porosity, permeability, and fluid content are important, special core analysis test are required for accurate calculation of the initial oil in place and to permit the calculation of oil recovery efficiencies by various drive mechanism. These special core analysis tests and their general uses are described in the following text.

The properties of capillary pressure and relative permeability are two of the most important pieces of information which are used in determining reservoir behavior, help determine how the reservoir fluids will flow and how they will distribute themselves .in the reservoir. In order to have a meaningful reservoir model, it is necessary to have reasonable estimates of these saturation dependent functions.

The most common special core analysis tests are capillary pressure tests, waterflood tests, and gas flood tests. best results are obtained on cores that have been cut under conditions designed to retain true formation wettability. Furthermore, the cores must be handled by procedures that will retain true wettabillity during shipping, storage, and testing.

(1) Capillary pressure Tests

Two types of capillary pressure tests can be run, drainage and imbibition. Drainage capillary pressure tests attempt to duplicate the original accumulation of oil in the reservoir. The use of drainage capillary pressure data to estimate initial water saturation in the reservoir is described in the section on Fluid Distribution. Residual oil saturation for some bottom - water drive reservoirs can be estimated from imbibition capillary pressure tests data as described in the section on Water Drive Reservoirs. Figure 2.36 shows the drainage and imbibition capillary pressure curves on the same core sample. Positive values of capillary pressure denote that the oil phase pressure is higher than the water phase pressure. For negative capillary pressure, the water phase

III. CORING

A. OPERATIONS

Diamond coring methods retrieve longer cores than possible with conventional core bits because they can stay on bottom longer. Core barrels up to 60 ft and more in length are used.

Every method of coring stresses the necessity for a clean hole but it is especially true in diamond coring operations because of the expense of the bit. Each diamond on the bit is continually on bottom, continually doing work. The bit must be kept clean and cool for efficiency, prevention of balling up, and to keep new formation continually exposed to cutting action to prevent loss of diamonds.

Any junk lost in the hole - like bearings and cones - must be fished out rather than forced to the wall of the hole. A junk basket should be run during two or three roller-bit runs prior to coring. A wiper should be around the drill-pipe at all items to guard against tools being accidentally dropped in the hole (an old wiper is best for running in the hole).

Most operators require a substantial circulation period and the running of a magnetic tool to bottom before coring.

The drill pipe is held in tension, as normal, by carrying sufficient drill collars in the string. All core barrels are equipped with a stabilizer positioned directly above the bit. The stabilizers are machined to be from zero to 0.03 inches smaller than core-bit diameter. When they wear so that they are 1/16 inches under-sized they should be rebuilt or replaced.

Most diamond coring is now done in the full diameter of the borehole. Whether coring is done this way or in a rat hole depends on the full gauge-keeping ability of the rock bits used prior to initiating the coring operation.

least ½" of paraffin surround it. Another problem is the prevention of repair of air holes to the paraffin surface caused by evolution of gas from the core as it warms up. Paraffin is slow to cool and the core may be heated appreciably in the casting operation.

The methods works and can be used successfully but is not generally recommended. It probably requires less lead time to assemble the necessary equipment than the other procedures. Another way to say it, if you must preserve cores tomorrow, you can probably find the things required to do it in any grocery store. The second set of cores you preserve will probably be preserved by one of the other procedures if the necessary equipment can be made available.

Summary

The purpose of this operation is to select and preserve cores so that the true reservoir water-oil displacement characteristics can be measured in the laboratory at a later time.

It is of prime importance that cores be cut using a non-contaminating drilling mud. If the formation cannot be cored with an acceptable mud, it is not possible to cut the cores that are needed.

Limit the time of core exposure to air. Keep cores under water until they can be preserved. Any exposure detracts from the preservation and over 30 minutes of exposure might seriously alter wettability. Thus, subsequent tests will be subject to serious question.

Cores can be preserved by any of three procedures:

1. A molten plastic dip of cores wrapped with Saran and aluminum foil is quite successful and widely used. It requires considerable core for personal safety because the 300° syrup is a likely source of painful, if not serious, burns. This is a procedure best done by someone with experience. The service is almost universally provided by Core Laboratories and other service groups.

Table 3.1 - TYPES OF CORE BARRELS (Courtesy of International Association of Drilling Contractors)

Core barrel size & type	Outer tube OD, in.	Outer tube X-sectional Area, sq in.	Core dia., in.	Annulus area sq in.	Fluid capacity, cpm
AMERICAN COLDSET CORPORATION					
Standard core barrels					
3 5/8" x 2" x 40'	3 5/8	3.83	2 or 1 7/8	1.08	85
4 1/8" x 2 1/4" x 60'	4 1/8	5.07	2 1/4	1.80	140
4 1/2" x 2 1/2" x 60'	4 1/2	5.58	2 1/2 or 2 3/8	2.65	205
5" x 3" x 60'	5	7.07	3 or 2 7/8	2.25	175
5 3/4" x 2 1/2" x 60'	5 3/4	8.25	3 1/2 or 3 3/8	3.54	275
6 7/8" x 4 3/8" x 60'	6 7/8	10.01	4 3/8 or 4 1/4	4.42	345
Maritime core barrels					
6 1/4" x 4" x 60'	6 1/4	16.49	3	3.14	245
4 1/2" x 2 1/8" x 60'	4 1/2	7.61	2 1/8	1.80	140
CHRISTENSEN DIAMOND PRODUCTS COMPANY					
3 1/2 x 1 3/4 Slim Hole	3 1/2	3.7	1 3/4	1.5	118
4 1/8 x 2 1/8 250 P Series	4 1/8	5.1	2 1/8	1.8	141
4 1/2 x 2 1/8 Marine Series	4 1/2	7.6	2 1/8	1.8	141
4 3/4 x 2 5/8 250 P Series	4 3/4	6.7	2 5/8	2.1	164
5 3/4 x 3 1/2 250 P Series	5 3/4	9.2	3 1/2	2.6	204
6 1/4 x 4 250 P Series	6 1/4	10.1	4	2.9	227
6 1/4 x 3 Marine Series	6 1/4	16.5	3	3.1	245
6 3/4 x 4 250 P Series	6 3/4	13.1	4	5.0	387
8 x 5 1/4 250 P Series	8	15.8	5 1/4	3.8	295

A less desirable but probably satisfactory procedure was used while collecting cores at Prudhoe Bay. Troughs filled with water were out of the question because of the cold so the cores were put in wooden transfer boxes where they were marked and sample by the geologist. Here cooperation between engineers and geologists was of prime importance in keeping the exposure time at a minimum. In this case it was necessary to preserve all of the core material that was cut. The work of preservation was started within about 10 minutes after the core came from the barrel. A preliminary seal with plastic wrap was placed on all samples within abut 30 minutes and the final preservation was completed in 2-3 hours. This amount of exposure is certainly enough to cause concern but it represented the minimum under the circumstances.

Core Preservation

Three methods for preserving cores have been widely used in the past few years. They all work and each has its advantages as will be discussed.

Seal Peel

The most widely used procedure for core preservation over the past five years employs a plastic that can be melted in a pot to a syrupy consistency at about 300 °F. Various types of plastic have been used with success. This type of casting is sometimes used to protect the cutting edges of chisels and other tools on the shelf in a hardware store.

Core samples are first wrapped in a plastic film such as Saran Wrap, then wrapped and sealed in aluminum foil. The plastic wrap protects the aluminum foil from contact with formation brine which could cause corrosion. The aluminum foil prevents contact of the core by the molten plastic.

Depth and orientation data for the core sample are written on the aluminum foil, and can be seen through the plastic coat. As a practical matter, one or more wire loops are wrapped around the core over the aluminum foil to facilitate the handling of the core as it is dipped into the vat of molten plastic. When the core is completely coated it is hung on a line by means of the wire loops to dry. Occasionally the hot plastic causes gas expansion or the generation of steam and blowouts in the plastic coat will result. These

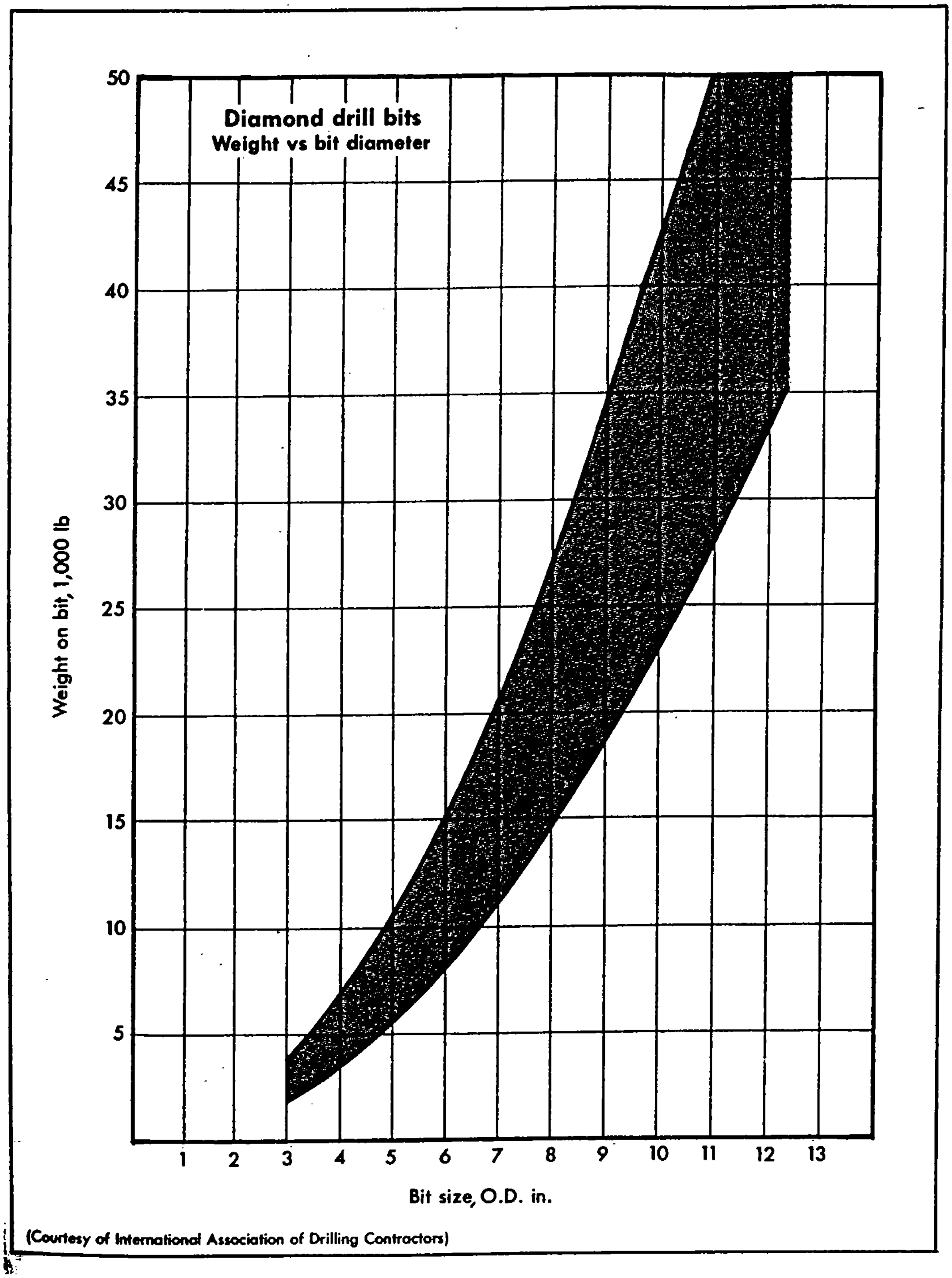


Fig. 3.1 Recommended operational range for diamond drill bits. Courtesy of International Assoc. of Drilling Contractors.

Sampling Guidelines - Special Core Analysis Tests

The job of the well-site engineer assigned to collect preserved core samples is two-fold:

1. To select samples representative of the formation of interest in sufficient number to provide material for a special core analysis program.
2. To retain the selected core samples in a preserved condition as near to that which exists in the reservoir as possible.

It is probably best to again define the terms "routine core analysis" and "special core analysis".

Routine core analysis covers the testing of cores that can be done quickly either at the wellsite or in a nearby laboratory to measure characteristics of the formation such as permeability, porosity, and fluid saturation. Electrical properties and rock compressibility are also generally considered routine tests. These results may be used to plan additional coring, drillstem tests, or other drilling operations. Routine core analysis data can also provide permeability and porosity profiles and calibration for porosity logs. Cores used for routine tests are thoroughly extracted and no preservation of the core material is required at the wellhead.

Special core analysis tests are performed on a suite of preserved cores to provide information about the producing characteristics of the reservoir. These tests include water-oil relative permeability, water-oil inhibition capillary pressure, gas-oil relative permeability, and drainage capillary pressure as well as other more specialized measurements. Special core analysis tests are done in a specially-equipped laboratory and may require months for completion. The data are used in simulator programs and other engineering studies to plan production operations for the reservoir.

Role of Core Preservation

The procedures for core preservation and the rules to be followed even now represent more art than science. It is known that the wettability of the reservoir rock is the result of a long period of contact with the contained fluids at the existing temperature and

The pressure drop across the face of a diamond bit has a tendency to lift the face off the bottom. This "hydraulic pumpoff force" should be compensated for through the addition of bit weight.

Hydraulic pumpoff for (lb) = 0.785 x bit pressure (psi) x (1.2 x bit diameter (in) - 1.2)

With the bit drilling (coring), the pump strokes should be the same as before coring was started, but the pump pressure should now be 200 - 275 psi greater. This represents the pressure drop across the face of the bit. (The pressure drop may be 100 to 1000 psi).

Hydraulic horsepower across the face of the bit can be varied according to the type of formation being drilled. In shales and soft formations the optimum is 2-3 hp/sq inch of hole area. In harder drilling, 1.5 to 2.5 hp/sp inch is desirable.

$$Hydraulic\ horsepower(hhp) = \frac{V\,x\,P}{1{,}714}$$

where: V = volume in gpm

P = pressure loss, psi

$$hhp\,/\,sq\,in. = \frac{hhp}{A}$$

where: hhp = Hydraulic horsepower (above)

A = Area of the bit (sq in.)

Pressure drop should be watched closely. Any deviation from it during a coring operation means that something abnormal has happened and core recovery is in jeopardy. If the pump pressure and torque fluctuate for no understandable reason, the bit should be raised off bottom and restarted. Core blockage or formation fracturing are the probable causes. If the problem persists, attempts to drill at an increased weight for a couple of inches should be made. If neither method solves the problem, the bit must be pulled.

SAMPLING GUIDELINES - CONVENTIONAL CORE ANALYSIS

Removal of Cores

A core should be considered as a piece of costly evidence which should be investigated according to a carefully thought out general plan. After being removed from the core barrel, a file card is filled out with the following data:

(a) Footage intervals of the core.

(b) Length collected and inventory of fragments (the lost pieces are arbitrarily placed at the foot of the core).

(c) Detailed geological description and drawing.

(d) Description of shows in impregnated zones (gas, oil, fluorescence).

In the case of saturation measurements, **the core should never be washed** but wiped off with **clean** rags.

The fragments reserved for immediate analysis are collected and sent to the laboratory of the work site or preserved for later shipment and analysis in a central laboratory which is often far from the work site.

Fragments intended for analyses for determining only physical properties of the reservoir are placed in boxes, well identified and sent to the geological laboratory.

A core analysis laboratory at the work site, or the central laboratory if the distance is not too great, should supply rapid results for the guidance of the rest of the drilling program, i.e. zones with probable oil or water production, drill stem tests to be carried out immediately, transition zones, continued drilling, completion, etc.

Sampling. Collection of Samples and Preservation

Sampling varies with the prospecting companies. In general the best frequency of collection for conventional analysis with small plugs is:

If the core will not break, circulate with drilling pump pressure and hold the strain on the core. When the core has broken, raise the bit 10 ft and slowly lower back to where bottom should be, as marked on the kelly to make certain the core has been picked up.

After making the connection, put the bit back on bottom without rotating and add about 50% more weight than used when coring . . . this will allow the new core to enter the barrel. Raise the drill string until the recommended drilling weight is on the weight indicator and start the pump and rotary to continue coring.

Where it is known that the formations are fractured, it is good practice when making a connection to lock the rotary table so the fractures will mesh and not crumble the core. This can cause jamming and an unnecessary trip.

The mud-logging geologist will be primarily concerned with the drill rate and gas recorded while the core is being cut but perhaps more important, he must continue to collect cuttings samples at the shaker for the case where there is incomplete or negligible core recovery.

The drilling rate during coring will vary with the type of bit, the pump pressure, weight, rotary rpm, and formation drilled. The gas curves recorded by the mud-logging instruments will be severely damped since there are fewer cuttings and drilling is slow. Basically, until the core is brought to the surface, the logging geologist cannot help but feel that he has been "logging blind" since what little sample that does show up as cuttings on the shaker may come from the wall of the hole, scraped away by the stabilizers.

Sample Receiving

As the barrel with the core is brought out of the hole, arrange the core boxes on the drilling rig floor, out of the way, but in the order in which they will be filled when the core is received. The drilling crew has several steps to complete before they are ready to help with removal of the core from the inner barrel. Explain to the driller how far off the floor to lift the barrel (2 or 3 ft) so as to get the maximum whole section which will fit into

Core Preservation

Before taking the plugs and samples needed to make the core analysis, it may be required to preserve parts of the core for further laboratory study by the restored state method. How much, and which parts of the core must be preserved will depend on oil-company policy and instructions. The material used to preserve the core will depend on what experience indicates is the most satisfactory for the rock in question. Some material used are:

Air-tight cans. No absorbent packing material should be in the cans. The core piece should very nearly fill the inside of the can. Wrap core piece in foil for traveling before inserting in can.

Sealed aluminum, steel or plastic tubes. Drain pipes with suitable "O" ring-sealed end connectors slightly larger than the core diameter are ideal. Again the core piece must be wrapped in foil for transport to avoid shattering or wear.

Plastic bags. The minimum of air is allowed in the bag. Proper sealing is not easy and there is a sharp edge breaking the plastic. Where plastic is used, the wrapped pieces should be placed in a container.

Freezing. This method used dry ice which consolidates the core very quickly. It is useful where the laboratory receiving the cores is nearby. Care must be taken in thawing the cores to avoid atmospheric condensation on the core. Thawing which is done slowly will cause fluid redistribution in the core.

A method not widely used has been developed by Core Laboratories to examine the gamma radiation of a core which, when compared with the gamma ray logs run in the open hole, makes it possible to pinpoint the exact cored zones which have been lost for one reason or another. See Figure 3.2.

Scrape the mud or, if still wet, wipe it off the face of the cores when in the boxes. Make an inspection of the core suitably detailed to satisfy the objectives of the operator. Select pieces at appropriate intervals for core analysis. The remainder of the core may be washed to simplify the descriptive part of the core report, but only if there will be no further sampling required at the rig or in a laboratory.

techniques using special sample-holding devices with fluid and air-permeable mediums will allow measurements of such rocks and even the, it is difficult to guarantee that the grain orientation will remain constant. In such sands the grains are usually well rounded and porosities of 35-40% can be conservatively assumed.

With the air-injection porosity-measurement method the sample which is cut for permeability is the same sample used for porosity measurement.

Immediately after the sample is shaped or the plug is cut, weigh the sample and prepare it for fluid extraction in the extractor. Fasten a metal tag to the sample.

Permeability Sample. Where a core is not fractured, whole cores, full diameter cores, and plugs from cores will yield almost exactly the same results. Very often it takes a bit of judgment in deciding just how to cut the permeability plug sample, so a discussion on this point is well worthwhile.

Normally in grossly bedded formations there is no problem and the side of the core is penetrated by the diamond drill. The use of air or water as a lubricating agent is common practice, but water is not recommended since it can alter the pore structure. The us of CO_2 as a lubricating agent is becoming more common now since it prevents overheating of the plug and eliminates closing of pore spaces and loss of fluids in the action.

When the plug is cut to a convenient length, about ¾-in long, make certain that both ends of the plug are freshly broken and do not contain the face of the outer core wall. It is helpful if the ends are relatively perpendicular to the sides of the plug in the interest of making accurate length measurements. This measurement is very important for an accurate analysis. If not perpendicular it is necessary to take several measurements with the caliper and use the average length for calculations.

If the plug is to be used also for porosity measurement as with the air-injection method, it must be weighed immediately. Fasten a metal tag to the plug.

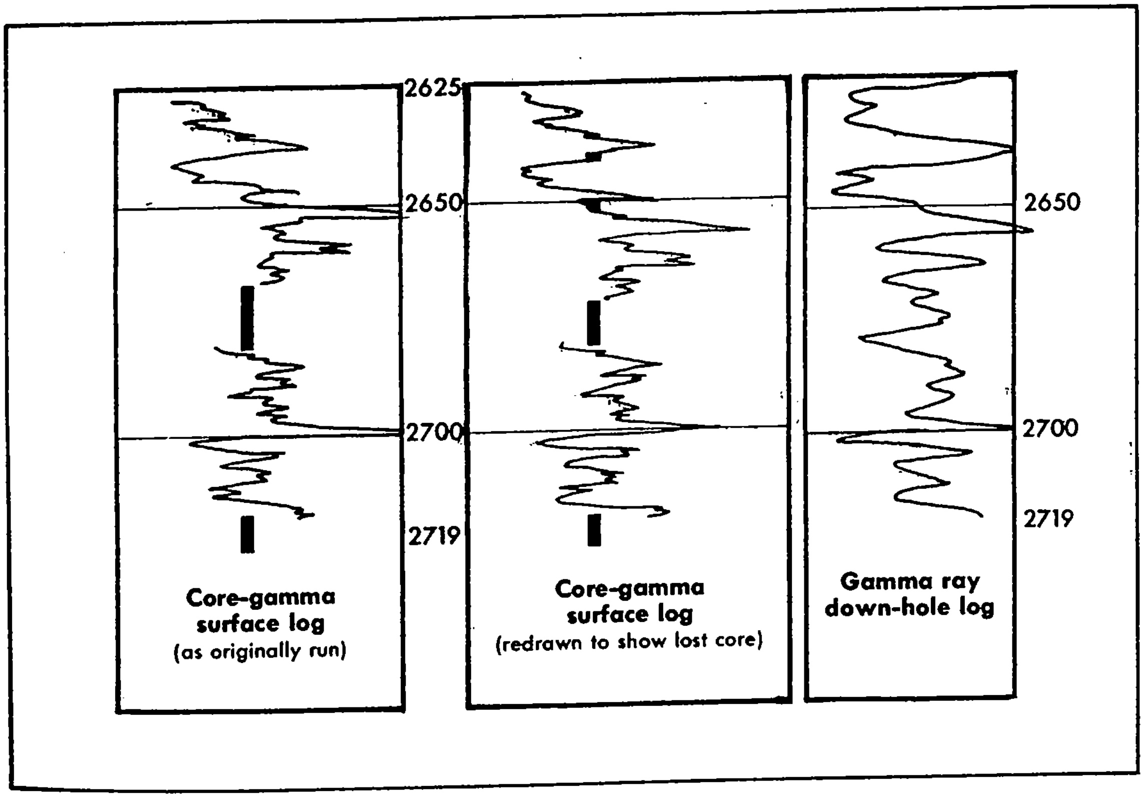


Fig. 3.2 Comparison of gamma ray logs makes it possible to locate points where core material was lost. From The Fundamentals of Core Analysis, Core Laboratories,

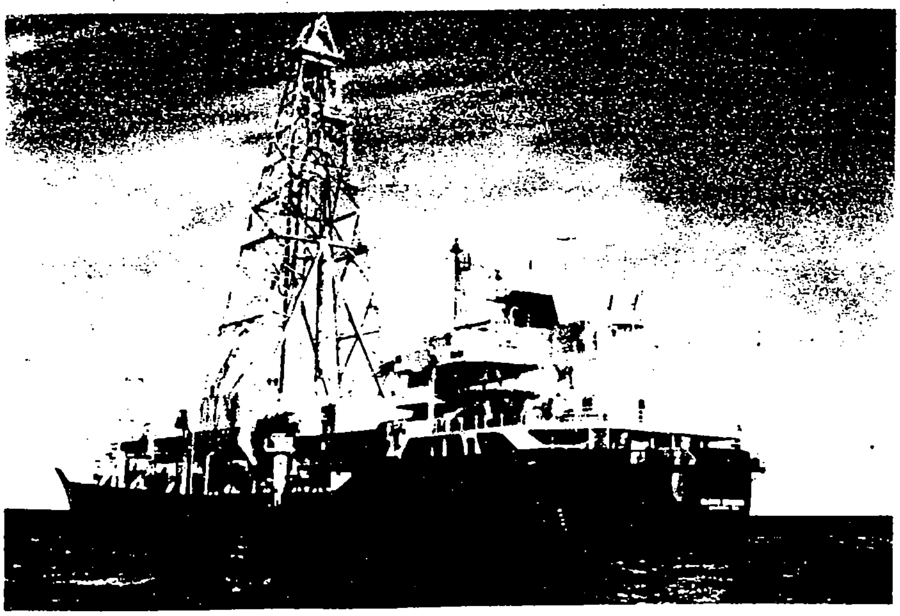


Fig. 3.3
Drilling Vessel Glomar Challenger

Sampling Guidelines - General

If the oil company has not specified at what interval to take the samples from the core, or if they have left it to the logging geologist's discretion, samples should be taken which best describe the whole cored section of interest.

For example, do not cut a plug through a single vug to show porosity unless vugs are a firm characteristic of the section. Another case might be where the core was started when drilled cuttings were limestone and when the core is recovered it is learned that the formation had again become anhydrite. Rather than do an analysis on anhydrite, it is advisable to call the operating company for further instructions. It is wasted time and money to analyze the evaporate in the field.

In fairly thick formations of sand, sampling may be done every 2 feet for an accurate analysis. In carbonate formations, dipping formations, and cross-bedded formations, it is advisable to sample every foot or less since the constituency of the formation can change radically throughout the section.

In formation horizons where there are alternately thin sand and shale members, it is necessary to sample every sand member which is over 2 inches thick to obtain reasonable results.

A thin reservoir member with variable lithologic properties should be sampled to ascertain the properties of the top, middle, and bottom of the particular member.

Saturation Sample. Preparation of each sample for saturation measurements must be done quickly since the fluids are continuously evaporating from the sample. The sample should be taken from the center portion of the core where the drilling fluids have affected the saturation the least. Break it up with a mortar and pestle or in the case of harder rocks, pound the sample until there are enough particles which will pass through a ¼ inch sieve.

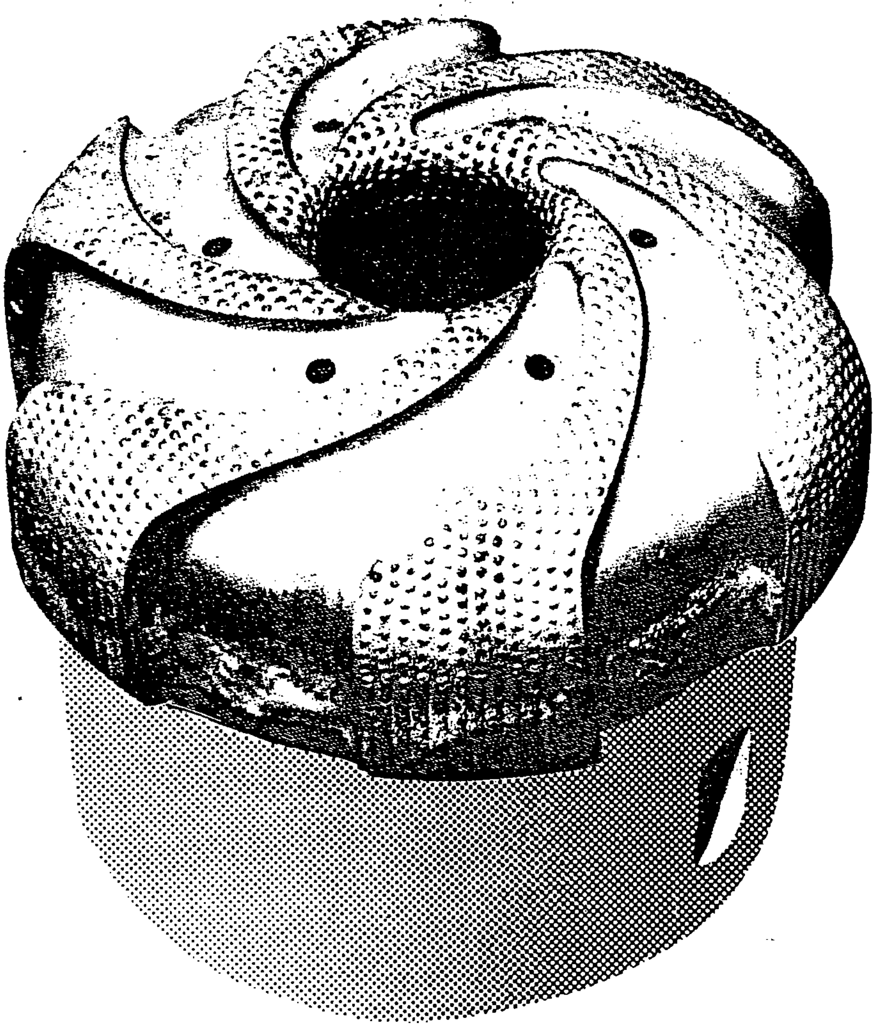


Fig. 3.4
Diamond Core Bit

Marking Tags and Trays. Careful marking helps maintain organization through the many steps of the analysis. Small metal tags stamped with numbers from 1 to 100 should be enough. Each stage is tied to a sample with a thin pliable wire.

The trays are small boxes into which the samples can be placed while waiting to process them through the analysis.

Ultraviolet Light. The "UV box" should be a portable type with a long extension cord. The core is examined under UV light as soon as possible for mineral and oil fluorescence.

The mud on the core surface should be wiped away, not washed away.

Binocular Microscope. The microscope is as useful as the ability of the geologist to use it. One which can magnify through four or five lenses up to 50 power is ideal.

A rotating stage is helpful in observing the character of the pore spaces in the sample.

In most field analyses there is too little emphasis placed on microscope evaluation of cores. The logging geologist should look at a freshly broken piece of core, make a written description, clean the sample with solvent in the extractor and re-examine the sample for any changes.

Equipment Checklist

Good core analysis at the wellsite is impossible without the proper equipment.

Table 3.6 provides a convenient checklist for the wellsite geologist. This list should be checked before each trip to the field.

logging tools with nuclear, electrical, sonic, and magnetic probes can be tripped in and out of the hole to provide a graphic record of the variation in these properties through and across the formations of interest.

Even with all these sophisticated and indirect methods, the only way to obtain an assay or a direct measurement of the materials, flow properties, and fluids in a prospective formation, is through the extraction of cores.

The assay of a core taken from an ore body, or results of core analysis on a sample from an oil or gas reservoir, provide the data for making decisions on questions of efficiency, recovery, profitability, investment, and production techniques. In practice, such decisions are made on a combination of direct and indirect evidence, sound judgment, and practical experience. In hydrocarbon reservoir studies, the evaluation of the core sample makes it possible to estimate the volume of oil and gas in place, its boundaries, and the probable percentage recovery, and to provide a data base for planning of an efficient pressure maintenance and secondary or tertiary recovery operation.

Techniques for measuring the properties of rocks are also continuously being perfected. Included are tests for capillary pressure, relative permeability, porosity, and water (or other fluid) flood susceptibilities. In conducting these tests, several procedures are used, (A) conventional core analysis, in which a small plug about ½" (12.7 mm) in diameter representing the formation interval is taken from a core, (B) whole core analysis in which the larges practical specimen is used in its entirety, and (C) side-wall core analysis in which small samples, usually taken by percussion methods from the wall of a borehole, are used.

State of the Art

Conditions encountered in coring and sampling are as varied as the structure of the Earth itself. Formations may be consolidated, well cemented and massive, or may be unconsolidated, sandy with round or jagged boulders and fluids mixed together. Recent sediments may have properties resembling those of a sandy mud, when examine under atmospheric pressure conditions, even though cored with difficulty at

The system for marking the boxes varies from company to company and operation to operation, but generally the boxes should be marked on the end starting with the core number and the box number written underneath starting with number one. Number one is the bottom of the core and therefore the first out of the barrel.

On the side of the box an arrow is used to show the orientation of the core in the box and sometimes a "T" for top on one end and a "B" for bottom on the other end.

After the core has been received and examined, the top and bottom depth of the core in the box may be marked on each end of the lid before it is nailed to the box.

API Oil Gravity Hydrometers. There are two hydrometers necessary for making specific gravity measurements. One measures from 10 to 45° API and the other from 45 to 90° API.

Weighing Scales. These, which measure the weight of a sample to 0.01-g accuracy are necessary to insure optimum results in the analysis.

Scales with finer measurement capabilities cannot be used on offshore rigs because the rig movement upsets the balance too greatly.

It is desirable but not essential that the scales can weigh as much as 600 g, in which case the retort sample can be weighed in the retort cylinder. This shortens the procedure and provides more accuracy through less handling of the sample.

Sieves. Sieves are used to sort the sample particles from undesirable ground-up rock particles. Unless the core is a hard carbonate or evaporate, it is possible to make rock particles which will fall through a ¼-in.-mesh screen. If this is too small, a ½-in.-mesh screen should be used. Uniformly sized particles mean a more consistent set of figures through the analysis.

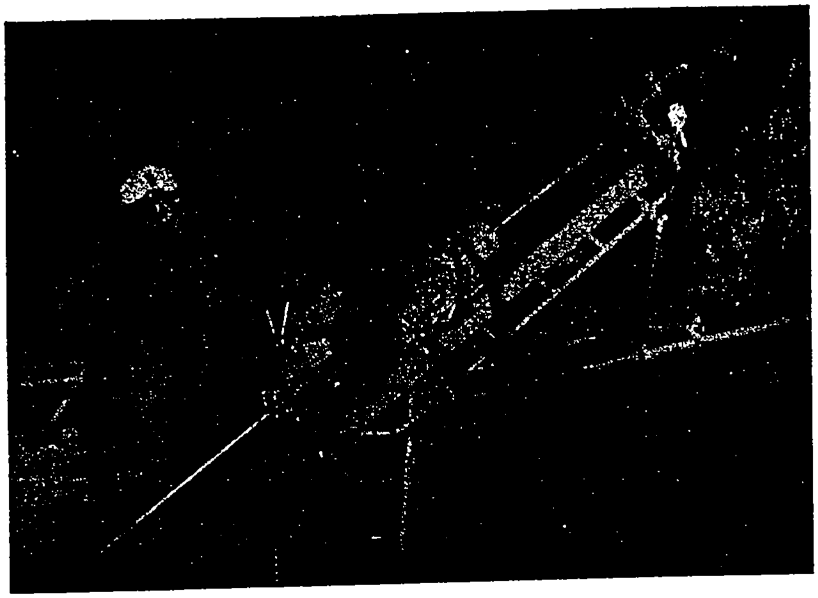


Fig. 3.6

Underground Drill

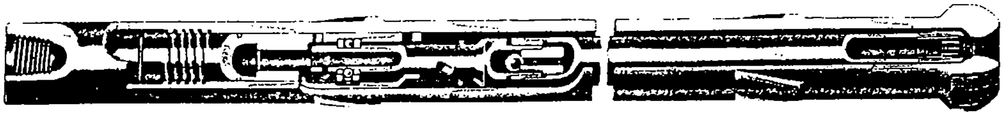


Fig. 3.7

Conventional Rotary Double Tube Barrel

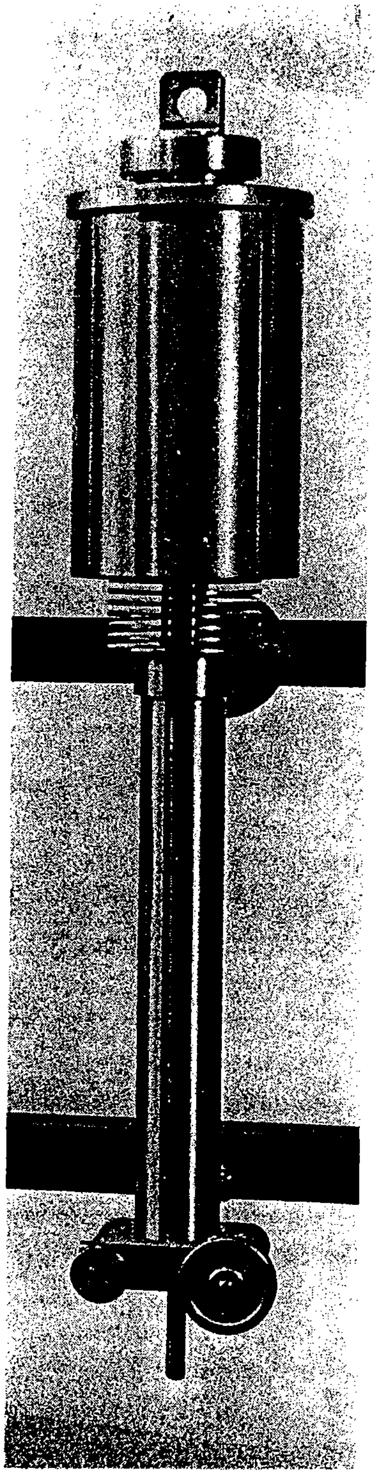


Fig. 3.28 Fluid-content still.

development of small diameter downhole motors with higher thrust and torque capabilities.

Among the most difficult problems encountered in smaller diameter coring and sampling applications are those associated with non-massive formations, particularly those which are highly fractured, vuggy, or contain caverns. Loss of circulating fluids makes the coring operation difficult, costly, and in some cases technically non-feasible.

In mineral exploration field operations, it is important to be able to quickly stabilize the wall of the borehole to prevent caving and lost circulation. Current methods available are considered expensive in terms of time lost, cost of drilling water, purchase of drilling mud components, and transportation costs, as well as the environmental impacts involved with pipeline transportation of water. Problems of caving and lost circulation are encountered in all kinds of drilling, not just mineral exploration. In oil and gas exploration, more expensive but routine methods involving casing and sophisticated mud programs are used to minimize problems of lost circulation and caving.

Setting casing into cavernous lost circulation zones in small diameter mineral exploration work is not generally a practical solution, because a few feet below the casing point more lost circulation zones may be encountered with no diameter left for more casing.

Drilling or coring with air is not a feasible solution to the cavernous lost circulation problem, either. This is because cuttings suspended in the vicinity of the lost circulation point fall back into the hole as soon as circulation is stopped to make a connection. The pipe then gets stuck and a string of rods could be lost or drilling progress interrupted to fish out the rod string.

Attempts at using rigid foams capable of being mixed and expanded under the water hydrostatic head in the vicinity of the bottom of the hole have not been very successful yet, but his approach does offer an opportunity for development. Such a foam should be capable of being redrilled and of holding the hydrostatic water pressure, sealing off a cavernous lost circulation zone.

The instrument is normally mounted in banks of two, six or eight, depending on the amount of work to be down and the speed with which it must accomplished. The retorts, referred to as "stills", extract the fluids from the rock samples which have been placed in the retort sample cylinders. Approximately 125 g of sample is an ideal amount for the retort. In a suite of analyses, accuracy is increased in the resulting values of saturation if the samples retorted are approximately the same size. See Figure 3.28.

Since the retorts heat up to a temperature of 1,200 °F., it is impossible to take the retorted water or oil to ascertain salinity and gravity values. Distilled water and fractioned oil are received from the retorting process to which table values are applied to correct the amounts to "approximate actual" amounts contained in the rock during original surface conditions. There is much debate on the validity of the values obtained with current retort methods, but suffice it to say that the results will coincide reasonably well with porosity measurements and electrical log data.

The water-cooled stills have closed condensers with flow controls for the water so that the operator can adjust the cooling rate in order to assure fairly complete recovery of the distillate. The light hydrocarbons and water which are evaporated first are condensed at a low temperature while the heavier, more viscous distillate, which may cling to the walls of the condenser tube at low temperature can flow through the condenser at progressively higher temperatures.

The temperature is controlled by first circulating water through the condenser jacket, then stopping ;the circulation and finally draining the condenser jacket of water. The times for the three phases of operation are:

1. Up to 15 min. with water circulation.
2. From minute 15 to minute 25, stop water circulating.
3. From minute 25 to minute 40, retort with drained condenser.

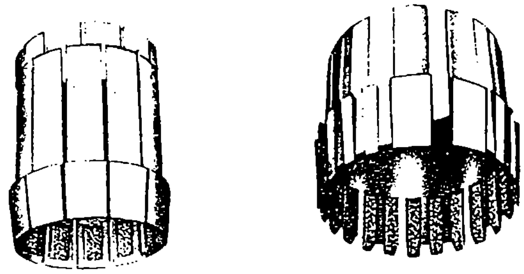


Fig. 3.8
Typical Core Catchers

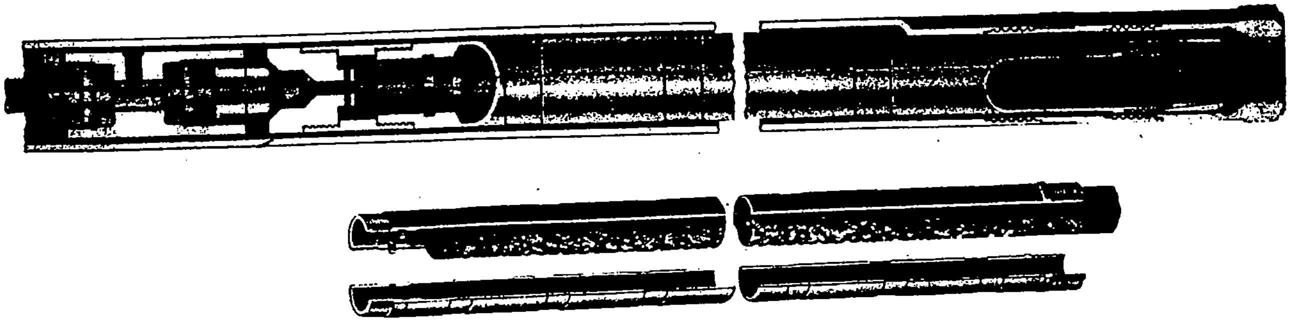


Fig. 3.9
Split Tube Core Barrel

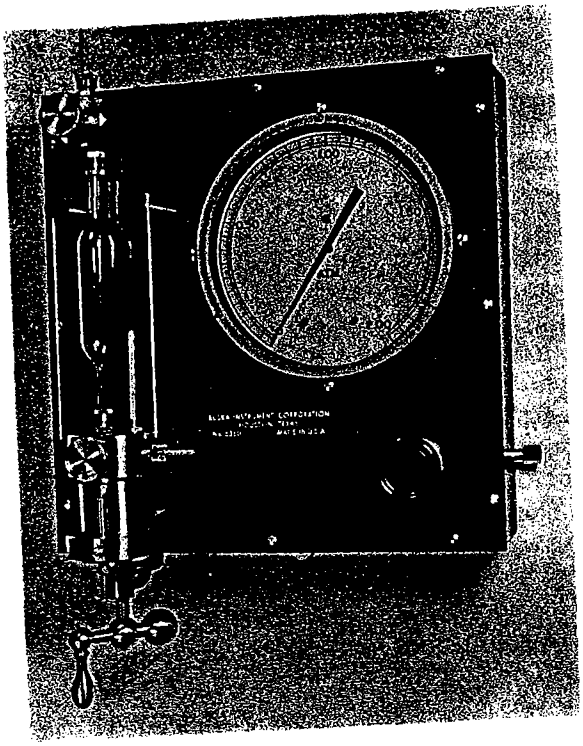
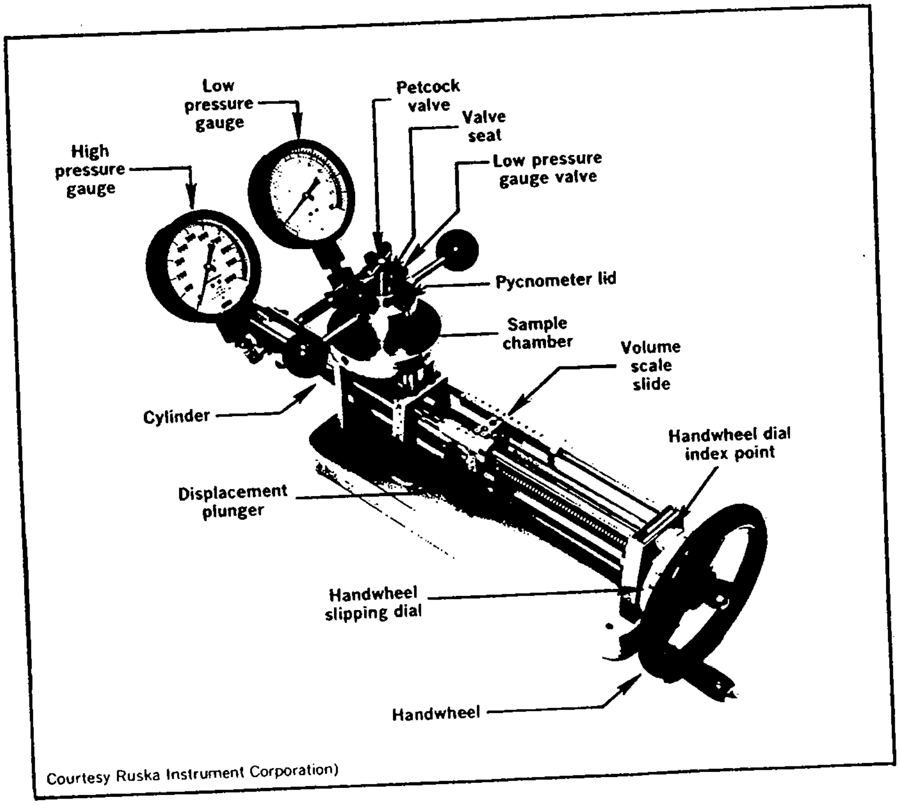


Fig. 3.24 The liquid permeameter.



Courtesy Ruska Instrument Corporation)

Fig. 3.25 Universal porometer.

tube, shown in Figure 3.9, opens readily and does not require the usual hammering or pumping on the core to get it out of the inner tube.

The problems with conventional coring are mainly (A) core jamming or (B) incomplete recovery or (C) a combination of jamming and incomplete recovery. Fractured core is sometimes lost during the trip out of the hole. Incomplete recovery may be due to bridging of the core in the barrel. Bridging results in the new core being destroyed by grinding as it tires to enter the inner barrel. Incomplete recovery can be reduced by decreasing friction between the core and the inner barrel, by developing full clearance-full closure core catchers, and by effecting better control of the fluid in the vicinity of the core.

Wireline Core Barrels

Wireline coring has been used in the petroleum industry since 1929 and has been adapted for use in the minerals exploration industry. Minerals applications include badly broken or unconsolidated formations that result in blocked cores and excessive pipe trip costs. There are also applications in deep holes, as in deep ocean coring, where again the relatively short wireline trip time is an important cost savings.

The wireline core barrel, as illustrated in Figure 3.10, is similar to the conventional double tube barrel. The difference is in the inner barrel assembly, which can be brought to the surface by lowering an overshot on a wireline, releasing the lock mechanism, and after breaking the core with the rod string, retrieving the inner barrel containing the core. An empty inner barrel can then be dropped or lowered through the drill string and locked into position for further coring.

In wireline coring, the drill pipe or rods are pulled only when the bit has to be changed. In mineral applications this results in an increase in on-bottom drilling time, and more recovered core per shift.

Oilfield wireline barrels have been developed and are capable, as in minerals exploration, of being dropped through the drill string and held on-bottom in the outer barrel by latches. Disadvantages of the wireline system for oilfield operations are (A)

Analysis Equipment

The most widely used equipment for both field and laboratory core analysis is designed by Ruska of Houston Texas. Discussions and explanations conducted in this handbook will be concerned primarily with Ruska equipment.

The basic instruments are the porometer for porosity measurements, the permeameter for permeability measurements, and the saturation retorts for saturation measurements.

The liquid permeameter and mercury-injection capillary pressure apparatus, as shown in Figures 3.23 and 3.24 are not discussed in detail since this equipment, unfortunately, is not ordinarily found at the wellsite. Where it is used, the individual who has learned to operate the porometer and permeameter will have no difficulty in adapting to the necessary techniques required for operating the additional equipment. Other equipment used to process the core will be discussed.

Porometer. The universal porometer as shown in Figure 3.25 consists of a 100-cc volumetric mercury pump to which a pycnometer vessel is attached. The pycnometer will take core plugs 1¼-in long and 1½-in in diameter. The pycnometer has a breech-locked lid which utilizes an "O" ring for pressure sealing. A needle (petcock) valve in the pycnometer lid allows opening and closing the sample chamber to the atmosphere when the lid is breech-locked to the top of the chamber.

Volumetric readings to an accuracy of 0.01 cc can be measured and read directly with the porometer. The universal porometer may be used for either the mercury-injection porosity method or the Boyle's Law air method.

The 0.01 cc accuracy already mentioned can be improved on with the Boyle's Law-type air-injection method. Correction factors are applied in both the mercury-injection and air-injection methods to limit the errors inherent in the porometer, and the changes in temperature and atmospheric conditions.

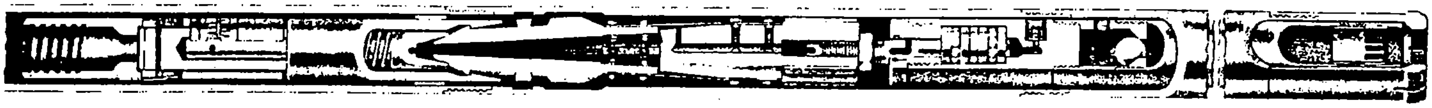


Fig. 3.10
Wireline Core Barrel

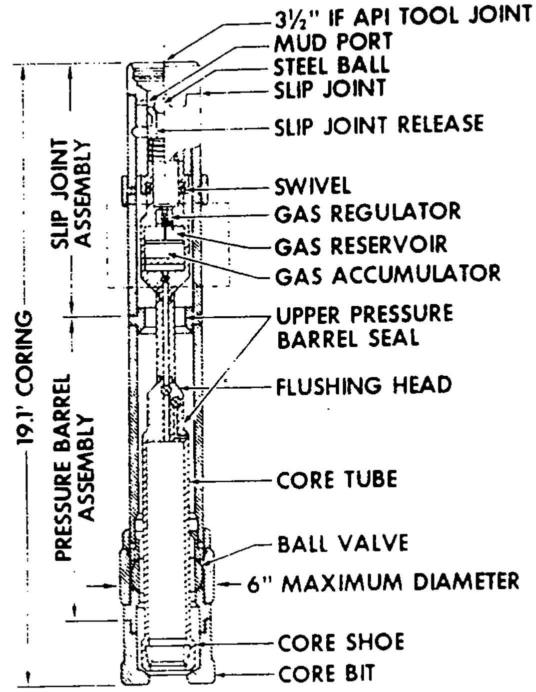


Fig. 3.11
Schematic Exxon Pressure
Core Barrel

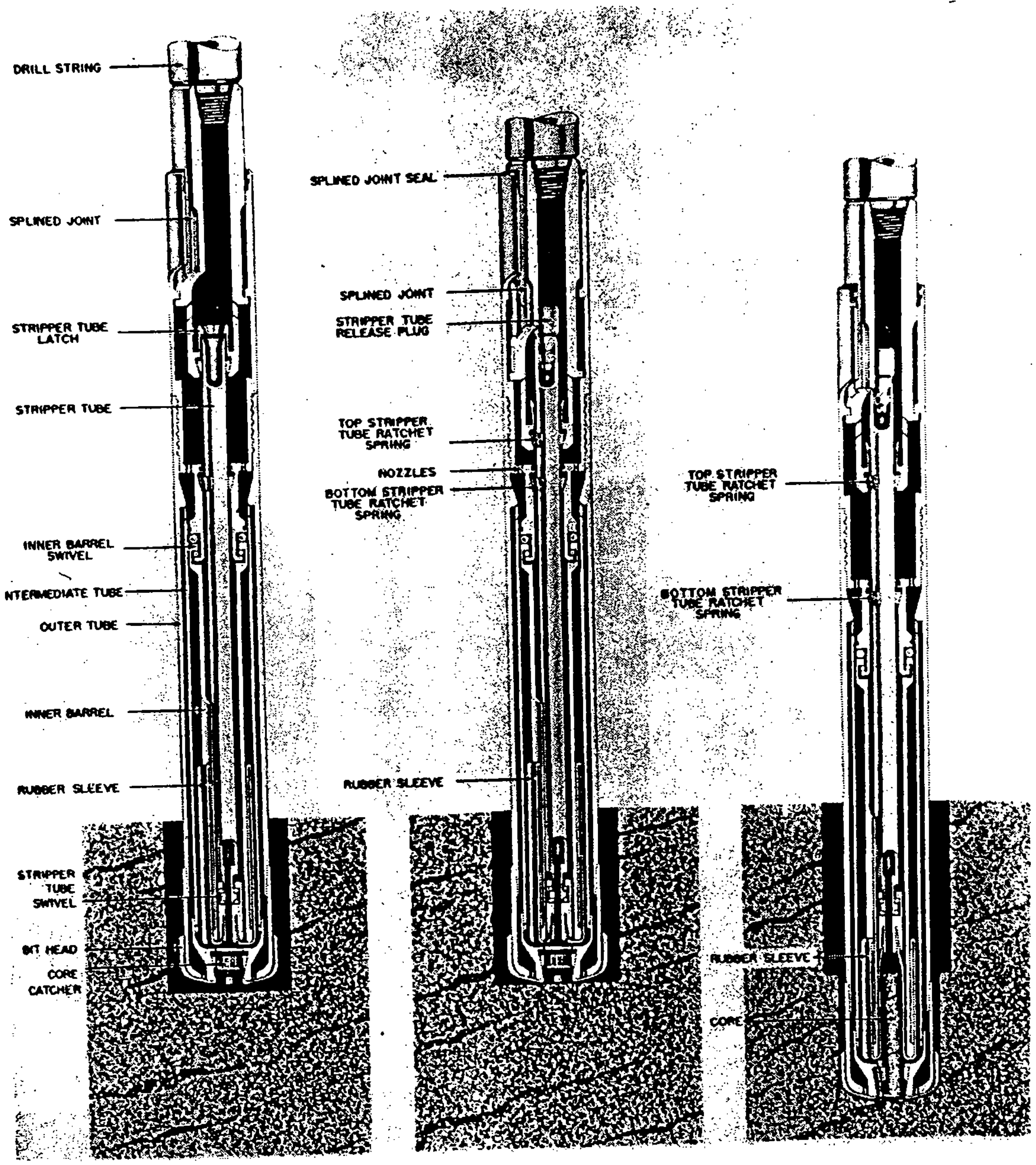


Fig. 3.21 Rubber-sleeve core barrel. (1) Lowered to bottom of hole; (2) ready to cut core; (3) after cutting 2 ft of core. This tool is especially useful in soft or fractured formations. (Courtesy Christensen Diamond Products.)

Several types of pressure core barrels have been designed to help prevent decompression of oilfield cores. Carter Oil Company reported the development of one of the first in 1939. Since then, the recovery ratio has improved with newer pressure core barrels having larger core diameters and core lengths. A new regulating section, shown in Figure 3.11, has been added to compensate for volume changes in the barrel due to pressure and temperature changes. The pressure barrel illustrated in Figure 3.41 has a design capacity for 5,000 psi (352 kp/cm^2) differential and has been applied at 7,000 feet (2134 m).

Coring with a pressure barrel is similar to conventional coring except that the inner barrel must be closed and sealed after the core is cut, before starting the trip out of the hole. This is done with a ball seal on the bottom of the inner barrel, controlled by the relative movement of a slip joint actuated rack and pinion drive.

The handling of pressure at the surface is understandably much more complicated than for conventional cores. Additional steps include displacing the coring fluid with gelled kerosene, freezing the core in dry ice to immobilize the core liquids, and cutting and transporting the frozen core to the laboratory for vacuum distillation procedures. Some of the surface equipment that is needed to displace the coring fluid, to freeze and de-pressure the core barrel is shown in Figure 3.12.

Pressure coring has had limited application partly because of the difficulty of handling the pressure elements and the associated fluids. But also, pressure core barrels do not offer a solution to the second difficulty of making accurate measurements of hydrocarbon saturation and distribution because of contamination due to coring fluid invasions. Hydrocarbons may be flushed or dissolved away from the core during the coring process, or they may be displaced by invasion of the mud filtrate under both static and dynamic filtration conditions. Since experiments have shown that zero mud circulation is not feasible, the contamination and loss of original fluids in the core are significant economic and technical problems that tend to inhibit the successful exploitation of additional energy resources.

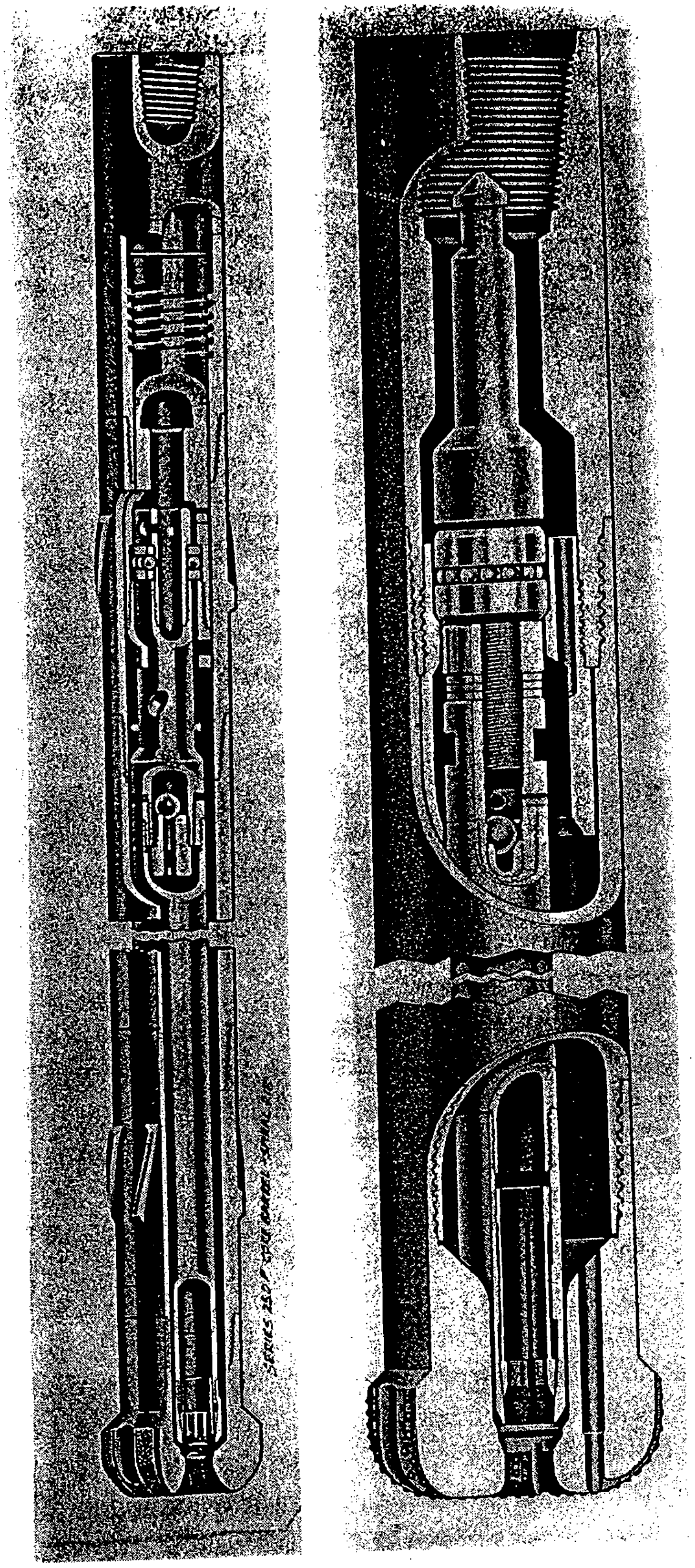


Fig. 3.20 Commonly used core barrels. At left (a) is the 250 P Model which can be made up in 30-ft sections. It features a safety joint to allow pulling the inner barrel with the cores in case the outer barrel becomes stuck. At right is a wireline core barrel that permits continuous coring without pulling the pipe. The core-holding tube is held in place by mud pressure. (Courtesy Christensen Diamond Products.)

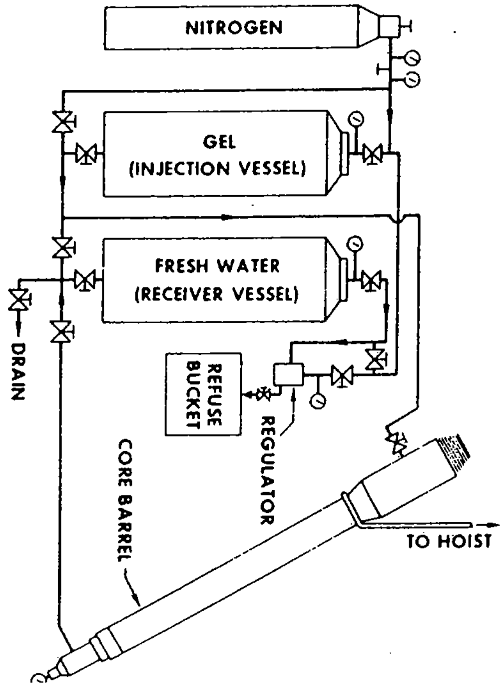


Fig. 3.12
Pressure Coring Surface Equipment

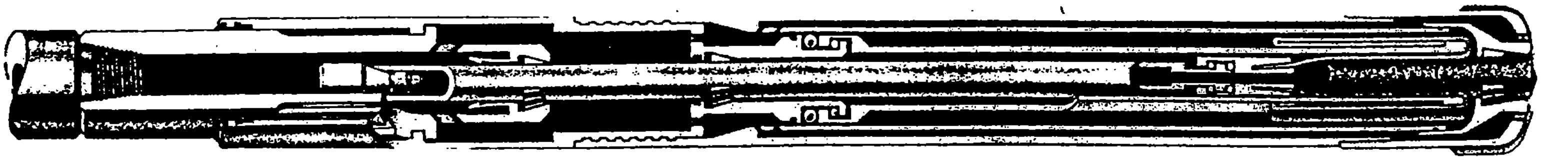


Fig. 3.13
Rubber Sleeve Core Barrel

III. CORING

B. REQUIREMENTS:

The first coring tool appeared in 1908 in Holland. The first one used in the United States appeared some years later (1915) and was a piece of modified drill-pipe with a saw-toothed edge for cutting - much like a milling shoe.

Core-analysis equipment has been developed primarily during the last 25 years. The instruments are very functional, accurate, and robust for field work.

The checklist kept by the geologist making an analysis is very important so that time is not wasted and steps forgotten in handling and processing the core. On wells which are far from ready supply stores, the list provided will prove an effective means by which to take stock of the required items to complete a suite of analyses.

Coring Tools

With the modified drill pipe and saw-toothed cutter mentioned above, the required amount of rack was cored and held by the rotating drilling string. When enough core had been cut, weight was added to the string to press the jagged cutting teeth inwards. This effectively cut the core held it in place for the trip to the surface. Since there was no proper fluid flow, the cores were usually badly burned and not of much use except as curiosity pieces.

J.E. Elliott in 1921 was the first individual to use the inner barrel and toothed bit successfully. In 1925 the facility had been added to allow exchange of core bits; the inner barrel had been designed to remain stationary; a core catcher had been added.

Since coring was first attempted, many variation of the same principle of operation have been developed. Presently three types of coring tools do over 90% of the coring work. They are the conventional 3-cone roller, wireline (roller and diamond), and full-core diamond cutting tools. The diamond tools are now recognized as the best tools

Continuous Coring and Sampling

At least two methods for continuous coring and sampling have been developed. In the U.S.A. these procedures have been called the Con Core or Stratodrill. Two concentric pipes provide for circulation down to the bit in the annular pipe space and pumping the broken core pieces back up the center tube to the surface. The annulus is stabilized with a static fluid, sealed at the bit end. Core jamming in the riser is a disadvantage of the coring version. In the air circulation version, a drill bit may be used. Cuttings pumped back to the surface are accumulated as an averaging-type sample, similar to the conventional oilfield method of collecting drill cuttings off the shale shaker screen.

Oriented Coring

Petrographic studies of sediments and the determination of directional properties of formations, such as directional permeability, can be made using oriented cores. Core orientation combines the process of scribing the core, so it can be continuously oriented to itself as a function of depth, and the process of orienting the scribe marks to North using magnetic or pyroscopic multi-shot borehole survey instruments. By way of example, Figure 3.16 shows a 3½ inch (89 mm) core cut at 16, 890 feet (5148 m) and scribed with the knives of a 3-knife orienting shoe. Core orientation helps geologists, reservoir engineers, and mineralogists to improve their understanding and evaluation of directional factors associated with complex stratigraphic subsurface conditions.

The process of cutting an oriented core does not differ greatly from conventional rotary double tube coring, expect for the need to record data on hole depth versus elapsed time. This coordinates the clock and photo record in the multi-shot instrument with the depth interval cored for each "picture".

Orienting instrumentation using gyro or ;magnetic multi-shots is available with about 400 exposures. Gyro units are available as small as 2 inched (51 mm) in diameter, capable of hydrostatic working pressures of 17,500 psi (1230 kp/cm^2).

The potential value of oriented cores in the oil, gas, geothermal and minerals industries has probably not been fully exploited. Core orientation studies are not only valuable as

The data provide convincing evidence that an attapulgite-starch-Tar Springs brine coring fluid should perform well at loudon. Excellent rheological and filter loss control should be obtainable with concentrations of about 5 lb/bbl (ppb) of attapulgite and 7.5 ppb of starch. No other additives should be necessary. For this reason and because of the barriers to vertical permeability in the Loudon sand, filtrate invasion should be low and very little disturbance of the internal pore surfaces should occur.

To summarize, the design of a coring fluid starts with a recognition of the priorities of the purposes for which cores are desired and with a recognition of the specific wellbore and formation characteristics that will affect the performance of the coring fluid. Since fluid invasion of the core can be limited but not eliminated, every reasonable attempt should generally be made to formulate the coring fluid with ingredients which will not alter the natural wettability of the core and which will not swell or disperse any clay minerals which the core may contain. Combinations of ingredients should be sought that economically meet the rheological and fluid loss control guidelines presented.

Finally, it should be emphasized that the recommendations presented here are limited by our current knowledge. Better recommendations will evolve from future laboratory research and continued intelligent, innovative experience.

Fig. 3.16

Scribe Mark on Oriented Core

Table 3.3

PROPERTIES OF STARCH-ATTAPULGITE SUSPENSIONS IN TAR SPRINGS BRINE

Starch Concentration (lbs/bbl)	PV (cp)	YP (lbs/100 ft^2)	10"/10" Gels (lbs/100 ft^2)	API FLUID LOSS (ml)		pH
				7½ min	30 min	
NO ATTAPULGITE:						
5.0	3	1	0/0	105 ml in 35 sec		7.9
7.5	5	1.5	0/1	--	104	7.8
5 PPB ATTAPULGITE:						
7.5	8	8	3/5	2.7	5.9	7.5 @ 35°C
10.0	9.5	8	1/3	1.2	3.8	7.9
12.5	14	9	1/3	1.1	3.4	7.9
7.5 PPB ATTAPULGITE:						
7.5	8	14	5/9	2.7	5.9	7.7
10.0	11	18	7/12	2.0	4.6	7.6
12.5	15	22	8/14	2.2	4.7	7.6

limitation of this type of drill is the inability of the drill steel to transmit the impact energy for very great distances.

Greater depth can be reached using a downhole air hammer, located at the bit. In the downhole hammer, energy in the compressed air (or potentially in the mud) is converted into a reciprocating percussion, impacting the hammer against the anvil of the bit. Mud hammers have been field tested but are still under development.

Mineral exploration contractors feel than in many instances when water influx requires termination of air drilling, conversion from a downhole air hammer to a downhole mud hammer would greatly reduce their costs of continued drilling to the core point. Improved mud driven hammer drills are needed, especially in mineral exploration contracting.

Sidewall Coring and Sampling

Conventional sidewall cores are obtained from hollow bullets which imbed themselves into the formation after firing and the samples are retrieved on the wireline. The application is considered to be limited to soft, consolidated rocks. Limitations are that the impact of the bullet may modify the physical characteristics of the rock, which has already sustained lengthy exposure to filtration fluids from the borehole mud.

Several special sidewall coring or sampling devices have been investigated, including an electrical diesel slicing device and a hydraulically-powered sidewall coring tool. In the case of the slicer, electric motors power a pair of diamond saw blades and an opposing hose forces the assembly into the wall to cut triangular specimen as the tool is raised by wireline. The sliced specimens are caught in a basket below the tool. This tool has the disadvantage of yielding irregularly shaped core specimens which have been exposed to the borehole fluid for considerable time prior to being cut; it has the advantage of providing a sidewall core sample after the hole has been logged.

The hydraulically-powered sidewall coring device is intended to drill through a window in a specially equipped drill collar. Mud would actuate a vane type rotary mud motor, to turn a small diamond core bit attached to the end of a hollow, flexible cable. After the adversely affected by salt water. When bentonite can be prehydrated in fresh water and then added to salt water, it retains much of its desirable fluid loss control quality.

A large number of carbohydrates such as starch, carboxymethylcellulose (CMC) and various natural gums build viscosity and control fluid loss to varying degrees and should be considered in formulating a coring fluid. All carbohydrates are susceptible to biological attack. For example, fluids containing starch, unless protected by a pH of at least 11.5 or saturated with salt, may undergo bacterial fermentation. A bactericide may have to be used if the coring cannot be completed within a few days after adding starch to the fluid.

Starch is stable only to about 180 °F and none of the other carbohydrates should be expected to perform at temperatures above 200-250 °F. For coring at higher temperatures, it may be necessary to use causticize lignite for filtration control in spite of its surface-altering effects or to use a bentonite-fresh water system in spite of the adverse effects of fresh water on the swelling and dispersion of formation clay minerals.

Surface altering chemicals such as deflocculents should be avoided if at all possible. These materials strongly affect the wettability of the pore surfaces. This is also true for many bactericides and even caustic soda and other chemicals used for pH adjustment.

Although clays are chemically stable at all temperatures normally encountered in coring operations, flocculation at high temperatures might be a problem in deep, hot holes. Pilot testing any proposed system at the temperature expected at coring depth is recommended both before using it for the first time in the field and also during the coring operation to be sure unavoidable contamination is not adversely affecting its performance to a significant degree.

The following example will illustrate the application of these principles to the design of a coring fluid for Loudon, a shallow oil field now in an advanced state of depletion by waterflooding. Cores are desired to confirm the presence of sufficient residual oil to justify a field test of a surfactant tertiary recovery process.

The change in direction from vertical to horizontal radically alters the effect gravity has on the drill string and on the force distribution at the bit. The drill rod tends to lie on the bottom side of the hole and, as the thrust is increased, forces the bit to drill uphill. By balancing the normal force applied along the rods with the up thrust due to the rod deflection against the unsupported gravity force at the bit end, the right bit can produce a relatively straight, horizontal hole. If the hole tends to deflect upward, the bit weight can be reduced and if the bit tends to drill down, the upward component of the force from the drill rods can be increased by increasing thrust.

Performance improvements in horizontal coring might be obtained by adapting from some of the stabilizer placement analytical techniques used in the petroleum industry. It has been found that the bit drill in a direction resulting from the combination of effects of the direction it is pushed (resultant force angle) and the direction it is aimed (tilt angle), as shown in Figure 3.17. Studies of the location of drill collar stabilizers and the elastic properties of the drill string, combined with drilling variables such as clearance between the collar and the hole wall, clearance (wear) of the stabilizer and the hole wall, the amount of torque input in the drill collar section, the amount of torque transmitted through the drill collar section, and the axial bit weight related force applied at the top of the collar section, can yield a predictable directional behavior. It is probable that additional analytical methods and active control mechanisms at the bit end can be combined so the bit can be pushed (resultant force vector) and aimed (bit tilt angle) in a desired direction.

If the thrust controls at the machine end or the bit end are not adequate to control the hole direction, an alternative method is the use of common, retrievable mechanical wedges, which can be set to make the bit to drill away from present course, left, right, uphill or downhill. Due to the weight of a wedge, it tends to turn to the bottom of the hole. For this reason it is more difficult to practice to deflect the hole down tan up.

A third method available is the so-called "bent sub" technique, using a hydraulic downhole motor, adapting from oilfield directional drilling practices. A piece of drill pipe with a quarter of half-degree bend can be attached to the up end of the motor. The bent sub is then oriented mechanically, or with survey tools, so that the motor axis and

Suggested Range of Plastic Viscosity

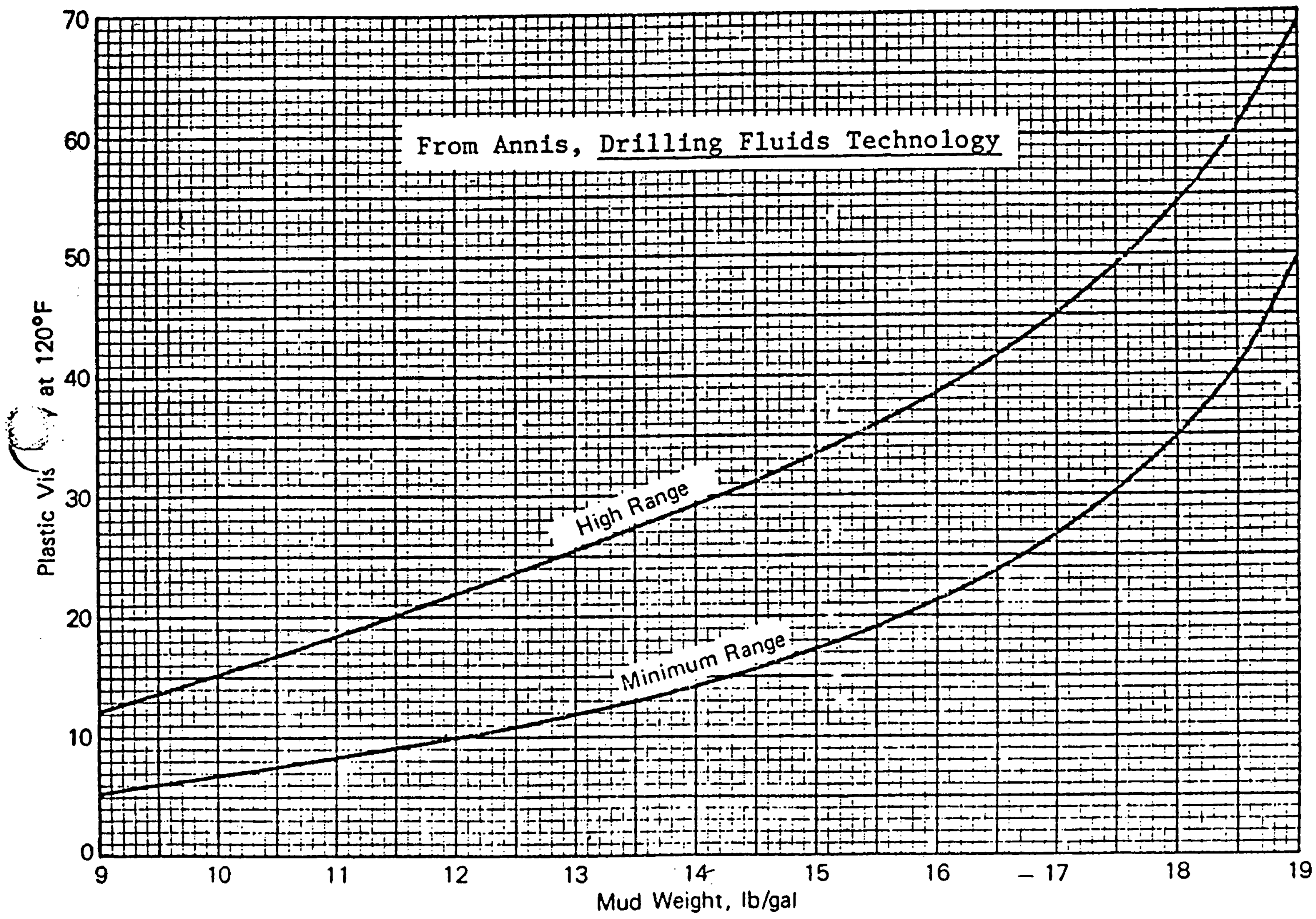


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Fig. 3.18

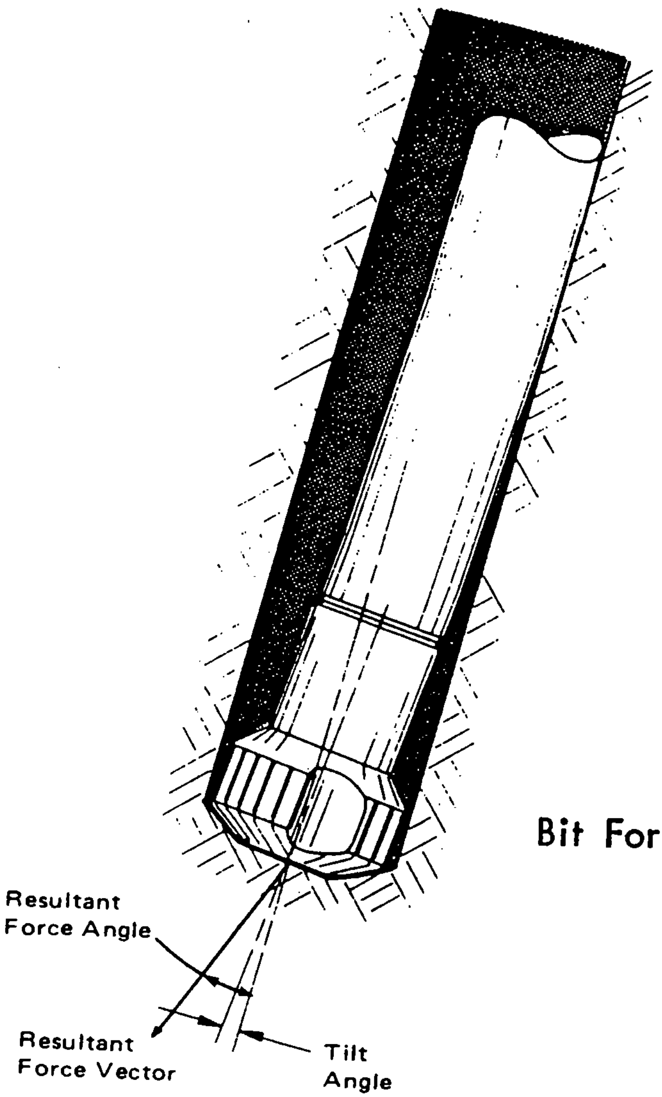

Fig. 3.17
Bit Force and Angle Relationships

Table 3.2

DESIGNING A WATER-BASE CORING FLUID

I. MAKE A TENTATIVE CHOICE FOR THE WATER TO BE USED
   - A. FORMATION WATER
   - B. SEA WATER
   - C. SYNTHETIC BRINE (90% NaCl - 10% $CaCl_2$)
   - D. FRESH WATER

II. SPECIFY THE DENSITY REQUIRED; BUILD DENSITY WITH BARITE

III. SPECIFY RANGE OF ACCEPTABLE RHEOLOGICAL PARAMETERS
   - A. PLASTIC VISCOSITY
   - B. YIELD POINT
   - C. GEL STRENGTH

IV. SELECT SPECIFIC MATERIALS FOR DESIRED RHEOLOGICAL PROPERTIES AND FILTRATION CONTROL
   - A. CLAY MINERALS - ATTAPLUGITE, BENTONITE, ETC.
   - B. CARBOHYDRATES - STARCH, CMC, XANTHAM GUM, ETC.

V. AVOID SURFACE ALTERING MATERIALS IF POSSIBLE
   - A. DEFLOCCULENTS - PHOSPHATES, LIGNOSULFONATES, LIGNITE
   - B. BACTERICIDES
   - C. CAUSTIC SODA

of the variables of bit and pipe stabilization, the elastic deflection of the rods in the vicinity of the bit, the effect of design on longitudinal and lateral drilling capacity of bits, the control of passive and active forces at the bit, rotary speed, torque, penetration rate, and circulating fluid effects.

Microbit coring studies have shown that in the absence of barriers to vertical permeability, permeable rock being cored is flushed by mud filtrate well ahead of the advancing core bit. This occurs because the advancing bit scrapes away the filter cake beneath the bit almost as fast as it forms, permitting mud filtrate to enter the formation at a high rate characteristic of dynamic filtration and the very early stages of static filtration.

Field coring experience indicates invasion can be limited to a modest level of 10% pore volume (P.V.) or so if excessive pressure overbalances are avoided, if the formation being cored has barriers to vertical permeability spaced no more than 2-3 inches apart, and if the coring fluid has an API fluid loss no higher than 5-6 ml/30 min and an initial spurt loss no higher than 1 ml. Since the holdup volume in the outlet from a typical API filtration cell is about 1 ml, the initial spurt loss probably will not be excessive if the fluid loss at 30 min is at least twice the fluid loss at 7½ min.

It would be preferable to use the API high-temperature filtration test if the coring temperature is 150 °F or more. Measurements should be made at the coring temperature, and since the filtration pressure in the high temperature test is 500 psi, the suggested fluid loss guideline is no more than 25-30 ml/30 min. Here, too, the fluid loss after 30 minutes should be at least twice the fluid loss after 7½ minutes to insure qa low initial spurt loss.

The actual amount of fluid invasion in a field coring operation can be determined quantitatively by incorporating a suitable tracer into the coring fluid. Tritiated water is an excellent tracer for water-base muds and tritiated hexadecane is equally satisfactory for oil-base fluids. Isopropyl alcohol is another good tracer for water-base muds.

Drilling muds and coring fluids are suspensions of solids in a liquid and are termed water base or oil base depending on the liquid used. Water-base fluids sometimes contain from 2 to 10 volume precedent emulsified oil, and oil-bas fluids nearly always contain emulsified water, sometimes as much as 50 volume percent.