Tikrit University

The College of Petroleum Processes Engineering

Petroleum and Gas Refining Engineering Department

An Introduction to Petroleum Technology

First Class

Lecture (6)

By

Assistant lecturer

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6-1 Classification of permeability:

1- Absolute permeability (Ka): permeability of a rock saturated 100% with flowing fluid.
2- Effective permeability (Ke) : permeability of a rock saturated less than 100% of flowing fluid.

Ke = function of saturation { Ke= f(S) }

When are Ke equal Ka ?

When the rock is saturated 100% with the flowing fluid.

When are Ke less than Ka ?

If saturation is less than %100

kg = effective gas permeability

ko = effective oil permeability

kw = effective water permeability

The effective permeability is used mathematically in Darcy's Law in place of the absolute permeability. For example, the expression for flow through the linear system under a partial saturation of oil is written:

$$q_o = K_o A (P_1 - P_2) / \mu_o L \qquad 6\text{-}1$$

where qo = oil flow rate, cc/sec

μ_o = oil viscosity, cm

ko = oil effective permeability, Darcys

Example : find effective permeability from the following data:

Volume of oil = 1000 cc , duration of test = 500 sec.

Up stream pressure = 1.45 atm.

Down stream pressure = 1 atm.

Cross suction area (A)= 2 cm^2 , L = 2 cm , μ=1 cp.

Solve:

Q= Volume/ time = 1000 cm^3 / 500 sec = 2 cm^3/sec

ΔP= (P1-P2)= 1.45-1= 0.45 atm

From equation (6-2)

K= (Q $\mu\Delta L$)/(A ΔP) = 2*1*2 / 2* 0.45 = 4.44 darcy

6-2 Relative permeability (Kr):

the ratio of Ke to Ka.

The absolute permeability is a property of the porous medium and is a measure of the capacity of the medium to transmit fluids. When two or more fluids flow at the same time, the relative permeability of each phase at a specific saturation is the ratio of the effective permeability of the phase to the absolute permeability, or:

$$Kr = Ke/Ka \qquad 6\text{-}2$$
$$Kro = Ko/Ka$$
$$Krw = Kw/Ka$$
$$Krg = Kg/Ka$$

Where :

Kro: oil Relative permeability.

Krw: water Relative permeability.

Krg: gas Relative permeability.

Ko: effective permeability of oil.

Kw: effective permeability of water.

Kg: effective permeability of gas.

For example, if the absolute permeability k of a rock is 200 md and the effective permeability ko of the rock at an oil saturation of 80 percent is 60 md, the relative permeability kro is 0.30 at So = 0.80.

Since the effective permeabilities may range from zero to k, the relative permeabilities may have any value between zero and one, or:

$0 =< krw, kro, krg =< 1.0$

6-3 Estimation permeability:

The best way to calculate permeability is by rock core. But when the core is not available, the permeability is calculated from:

1- Well test .
2- Well log.

There is no direct method for calculating the permeability from well logging, but the porosity & saturation is calculated, and then it has a special relationship with the permeability.

$$\mathbf{K}= \frac{a\ \Phi^{b}}{Sw^{c}} \qquad 6\text{-}3$$

Where:

K: permeability, md

a,b and c constant .

Sw : calculate from resistivity log.

Φ: calculate from Density log, Neutron log and Sonic log.

6-3 Averaging Absolute Permeabilities:

The most difficult reservoir properties to determine usually are the level and distribution of the absolute permeability throughout the reservoir.

They are more variable than porosity and more difficult to measure.

Yet an adequate knowledge of permeability distribution is critical to the prediction of reservoir depletion by any recovery process. It is rare to encounter a homogeneous reservoir in actual practice. In many cases, the reservoir contains distinct layers, blocks, or concentric rings of varying permeabilities. Also, because smaller-scale heterogeneities always exist, core permeabilities must be averaged to represent the flow characteristics of the entire reservoir or individual reservoir layers (units). The proper way of averaging the permeability data depends on how permeabilities were distributed as the rock was deposited.

There are three simple permeability-averaging techniques that are commonly used to determine an appropriate average permeability to represent an equivalent homogeneous system. These are:

- Weighted-average permeability
- Harmonic-average permeability.
- Geometric-average permeability

6-3-1 Weighted-Average Permeability:

This averaging method is used to determine the average permeability of layered-parallel beds with different permeabilities. Consider the case where the flow system is comprised of three parallel layers that are separated from one another by thin impermeable barriers, i.e., no cross flow, as shown in Figure 5-2.

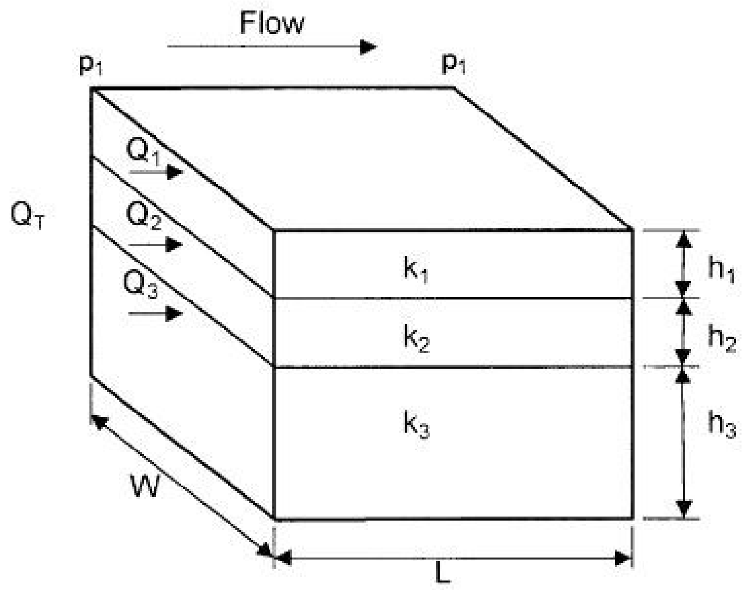


Figure 5-2

All the layers have the same width w with

a cross-sectional area of A.

The flow from each layer can be calculated by applying

Darcy's equation in a linear form as expressed by Equation 4-40, togive:

Layer 1

q1 = $\frac{K1\, wh1\, (p2-p1)}{\mu L}$

Layer 2

q2 = $\frac{K2\, wh2\, (p2-p1)}{\mu L}$

Layer 3

q3 = $\frac{K3\, wh3\, (p2-p1)}{\mu L}$

Layer 1

qt = $\frac{Kavg\, w.\ ht\, (p2-p1)}{\mu L}$

where qt = total flow rate.

kavg = average permeability for the entire model

w = width of the formation

ht = total thickness

The total flow rate qt is equal to the sum of the flow rates through each layer or:

qt = q1 + q2 + q3

Kavg = $\frac{\sum_{j=1}^{n} Ki\, hj}{\sum_{j=1}^{n} hj}$ 6-4

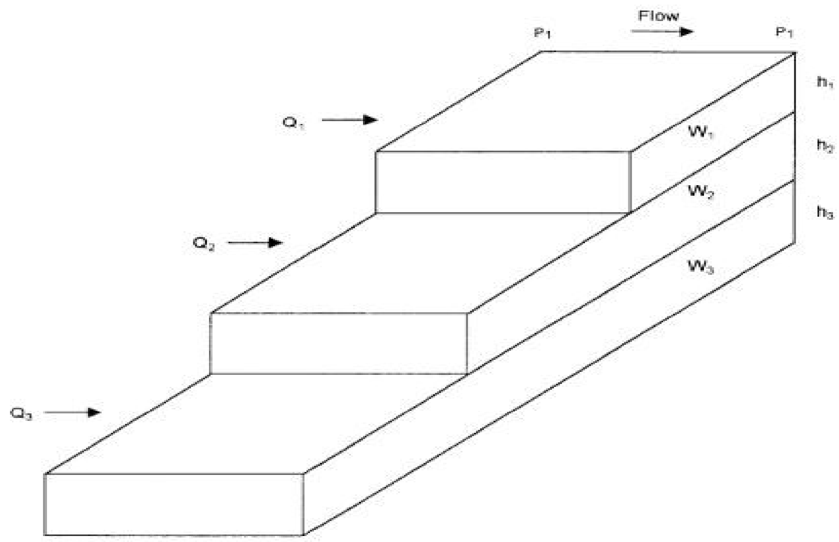


Figure 5-3

Kavg = $\frac{\sum_{j=1}^{n} Ki\ Aj}{\sum_{j=1}^{n} Aj}$

Example :Given the following permeability data from a core analysis report, calculate the average permeability of the reservoir.

Depth, ft	Permeability, md
3998-02	200
4002-04	130
4004-06	170
4006-08	180
4008-10	140

Solution

h_i, ft	k_i	h_ik_i
4	200	800
2	130	260
2	170	340
2	180	360
2	140	280
$h_t = 12$		• $h_ik_i = 2040$

$$k_{avg} = \frac{2040}{12} = 170 \text{ md}$$

Wettability

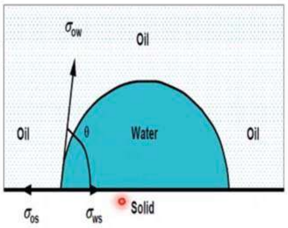
<u>Wettability:</u>

Tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids.

Wettability refers to interaction between fluid and solid phases.

<u>Interfacial tension</u> is the force per unit length required to create a new surface.

Interfacial tension is commonly expressed in Newtons/meter or dynes/cm (Newtons/meter = 1,000 dynes/cm).



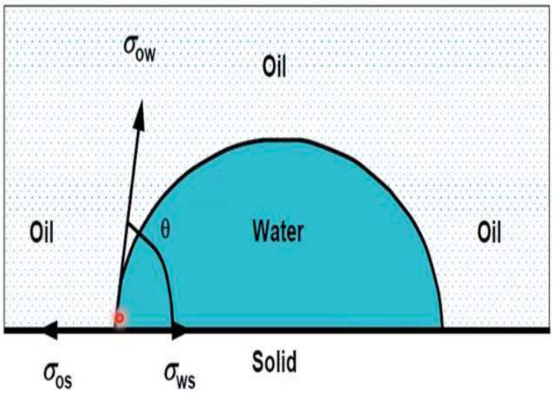
Wettability

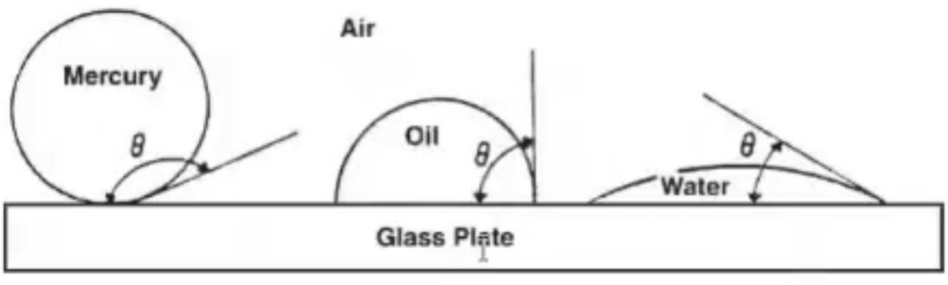
<u>Contact Angle:</u>

- The contact angle, θ, is measured through the denser liquid phase.
- Contact angle ranges from 0 to 180 degrees.
- Contact angle defines which fluid wets the solid surface.

In hydrocarbon reservoirs:

- Solid surface is reservoir rock (i.e., sandstone, limestone, dolomite or mixtures of each).
- Fluids are oil, water, and/or gas.





Wettability

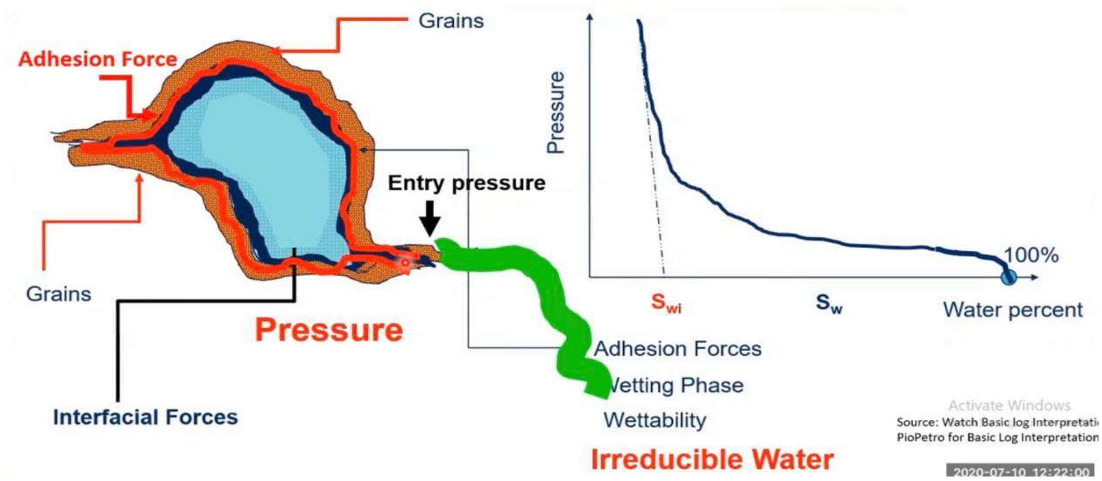
Adhesion tension

can be expressed as the difference between two solid-fluid interfacial tensions.

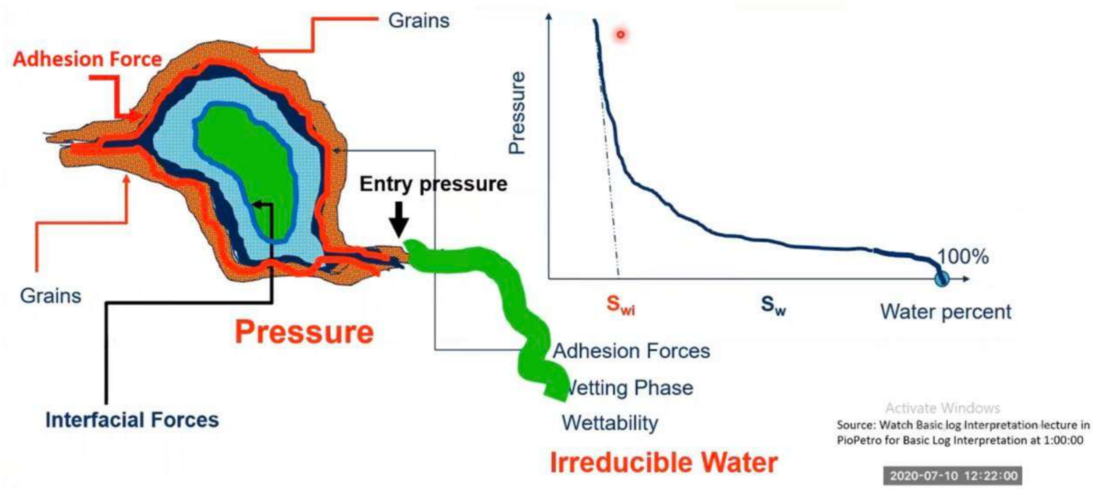
$$A_T = \sigma_{os} - \sigma_{ws} = \sigma_{ow} \cos\theta$$

A positive adhesion tension A_T indicates that water (the denser phase) preferentially wets the solid surface (**water wet**). An A_T of zero indicates that both phases have an equal affinity for the surface (**neutral system**). A negative A_T indicates the oil wets the solid surface (**oil wet**). The magnitude of the adhesion tension determines the ability of the wetting phase to adhere to the solid and to spread over the surface of the solid.

Wettability



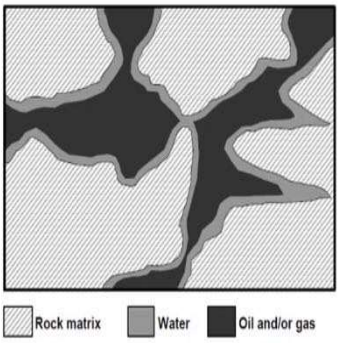
Wettability



Wettability

Wetting Phase Fluid:

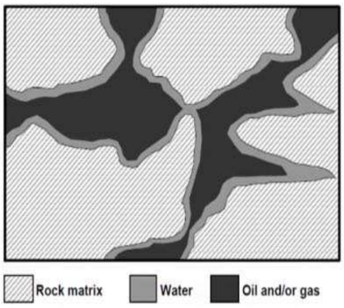
- Wetting phase preferentially wets the solid rock surface.
- Because of attractive forces between rock and fluid, the wetting phase is drawn into smaller pore spaces of porous media.
- Wetting phase fluid often is not very mobile.
- Attractive forces prohibit reduction in wetting phase saturation below some irreducible value (called irreducible wetting phase saturation).
- Many hydrocarbon reservoirs tend to be either totally or partially water wet.



Wettability

Nonwetting Phase Fluid:

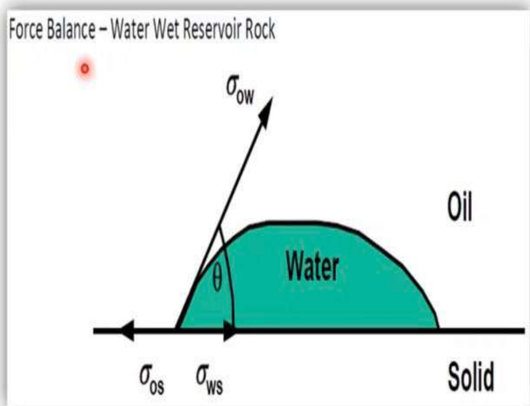
- Nonwetting phase does not preferentially wet the solid rock surface.
- Repulsive forces between rock and fluid cause nonwetting phase to occupy largest pore spaces of porous media.
- Nonwetting phase fluid is often the most mobile fluid, especially at large nonwetting phase saturations.
- Natural gas is never the wetting phase in hydrocarbon reservoirs.



Wettability

Water-wet Reservoir Rock:

- Reservoir rock is considered to be water-wet if water preferentially wets the rock surfaces.
- The rock is water-wet under the following conditions:
- $\sigma_{os} > \sigma_{ws}$
- $A_T > 0$ (i.e., the adhesion tension is positive).
- $0 < \theta < 90$
- If θ is close to 0°, the rock is considered to be "strongly water-wet".

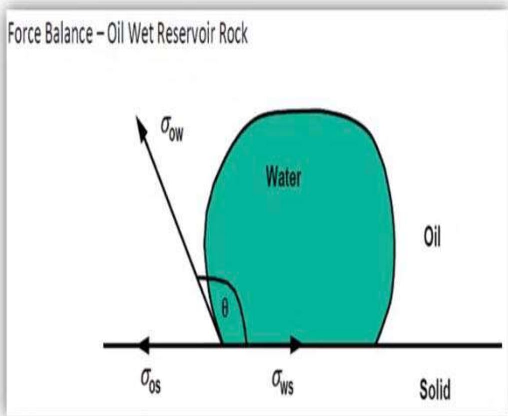


Activate Windows

Wettability

Oil-wet Reservoir Rock:

- Reservoir rock is considered to be oil-wet if oil preferentially wets the rock surfaces.
- The rock is oil-wet under the following conditions:
- $\sigma_{ws} > \sigma_{os}$
- $A_T < 0$ (i.e., the adhesion tension is negative).
- $90 < \theta < 180$
- If θ is close to 180°, the rock is considered to be "strongly oil-wet".



Imbibition and Drainage Processes:

Imbibition:

- Fluid flow process in **which the saturation of the wetting phase increases** and the nonwetting phase saturation decreases.
- Mobility of wetting phase increases as wetting phase saturation increases.

Example:

- Waterflooding an oil reservoir in which the reservoir rock is preferentially water-wet.

Drainage:

- Fluid flow process in which **the saturation of the nonwetting phase increases**.
- Mobility of nonwetting fluid phase increases as nonwetting phase saturation increases.

Example:

- Waterflooding an oil reservoir in which the reservoir rock is preferentially oil-wet.
- Gas injection in an oil- or water-wet oil reservoir.
- Pressure maintenance or gas cycling by gas injection in a retrograde condensate reservoir.