# Rock/Fluid System for EOR

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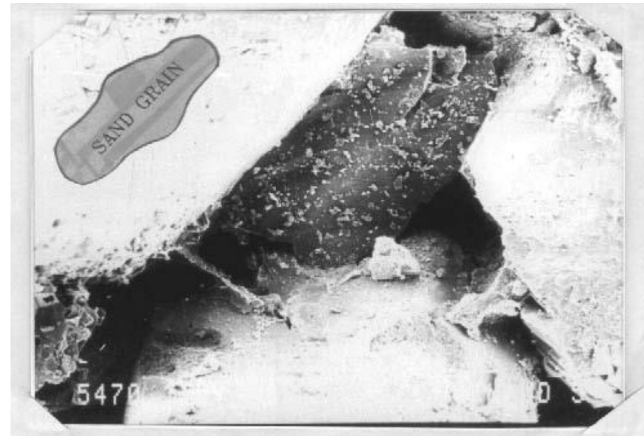
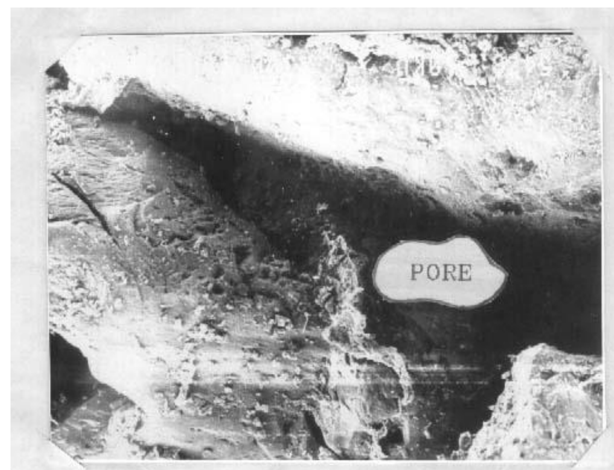
# Porosity

- **Porosity** is the ratio of void or pore volume to macroscopic or bulk volume.




- The porosity is a strong function of grain size distribution and a weak function of the pore size itself.

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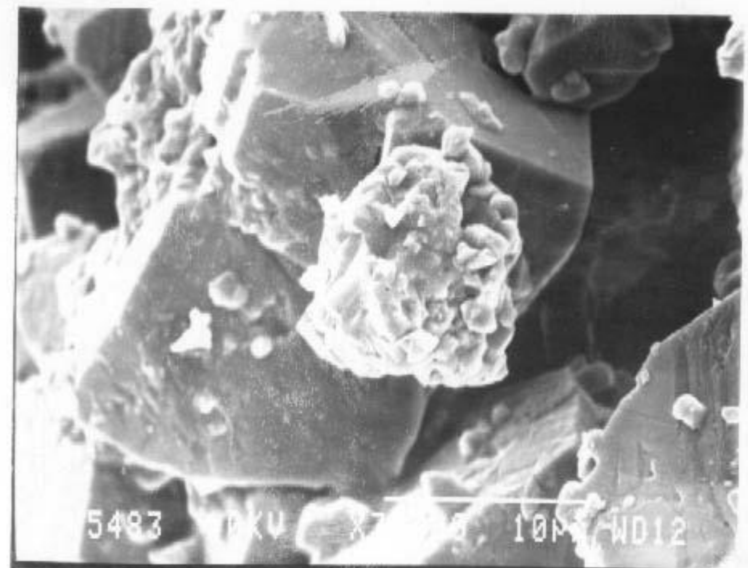
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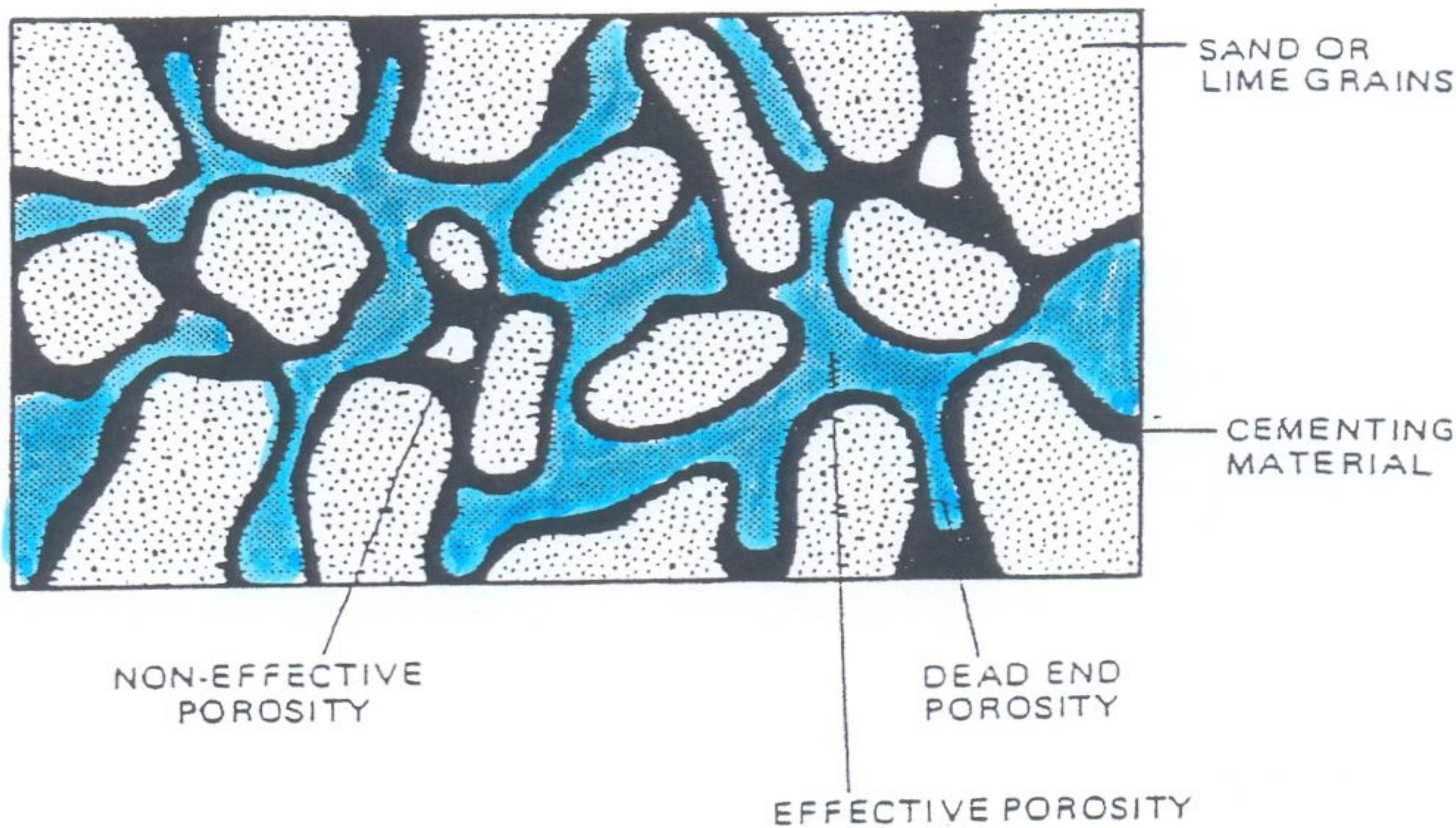
**EFFECTIVE**: which accounts for only that void space which is interconnected and which participates in the fluid movement in the reservoir. All reservoir-engineering calculations are based on this value as it pertains to pore space of economic interest.



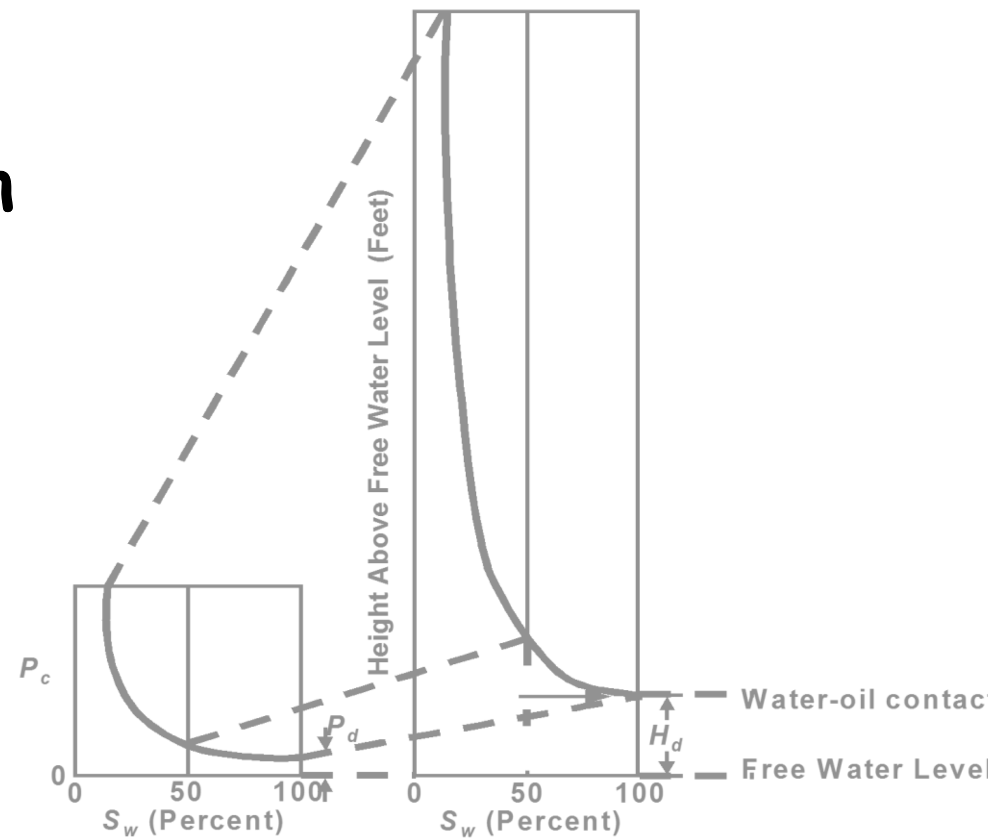
# PERMEABILITY

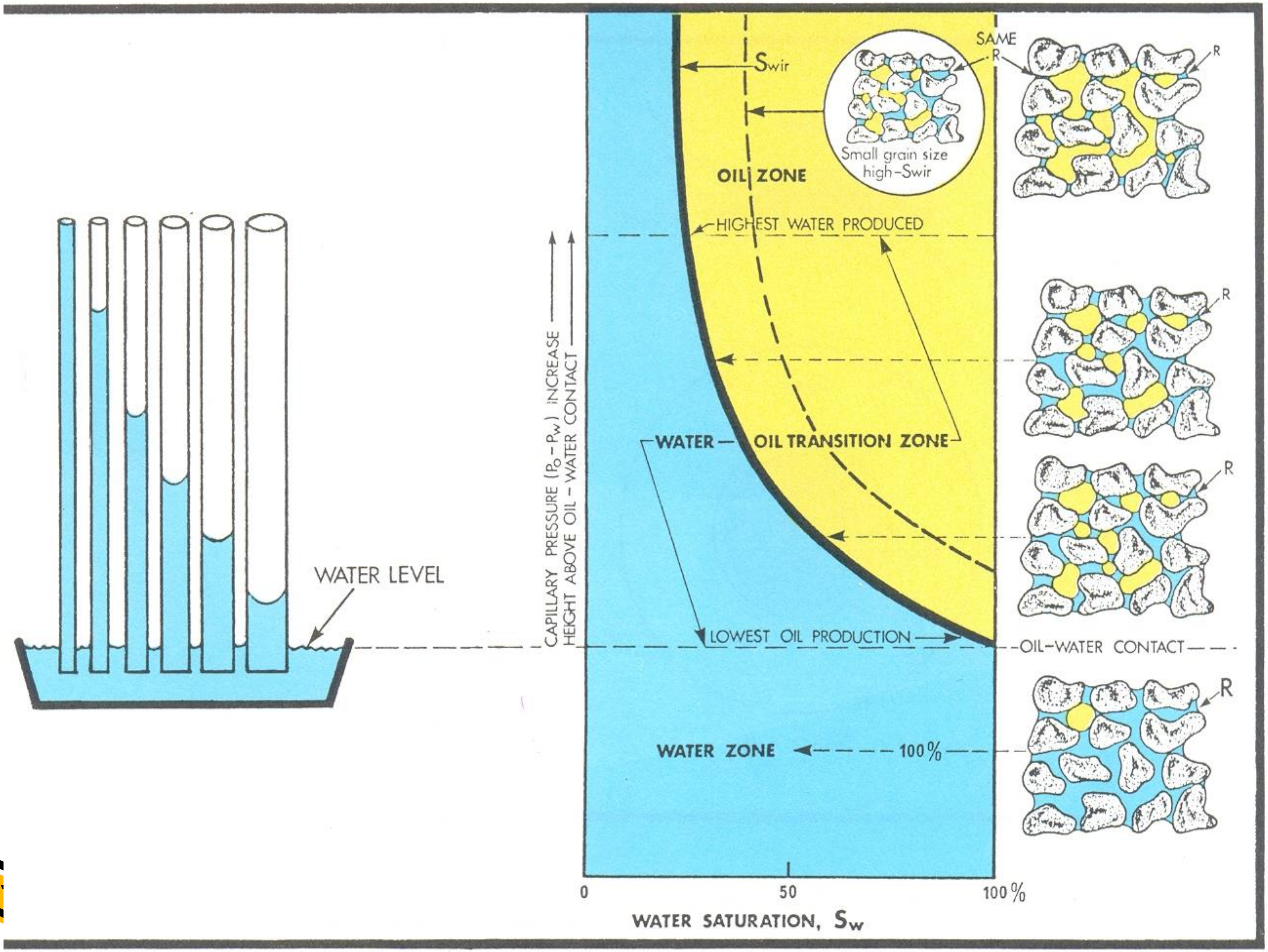
- Permeability is the measure of the ease of flow of fluids through the interconnected pore space.
- It is the single most important property, since it governs the rate of fluid flow. Hence, the economics of a project.

- **The permeability of a medium is a strong function of the local pore size and a weak function of the grain size distribution.**

# Capillary Pressure

**Capillary pressure** is the most basic rock-fluid characteristic in **multiphase flow.**

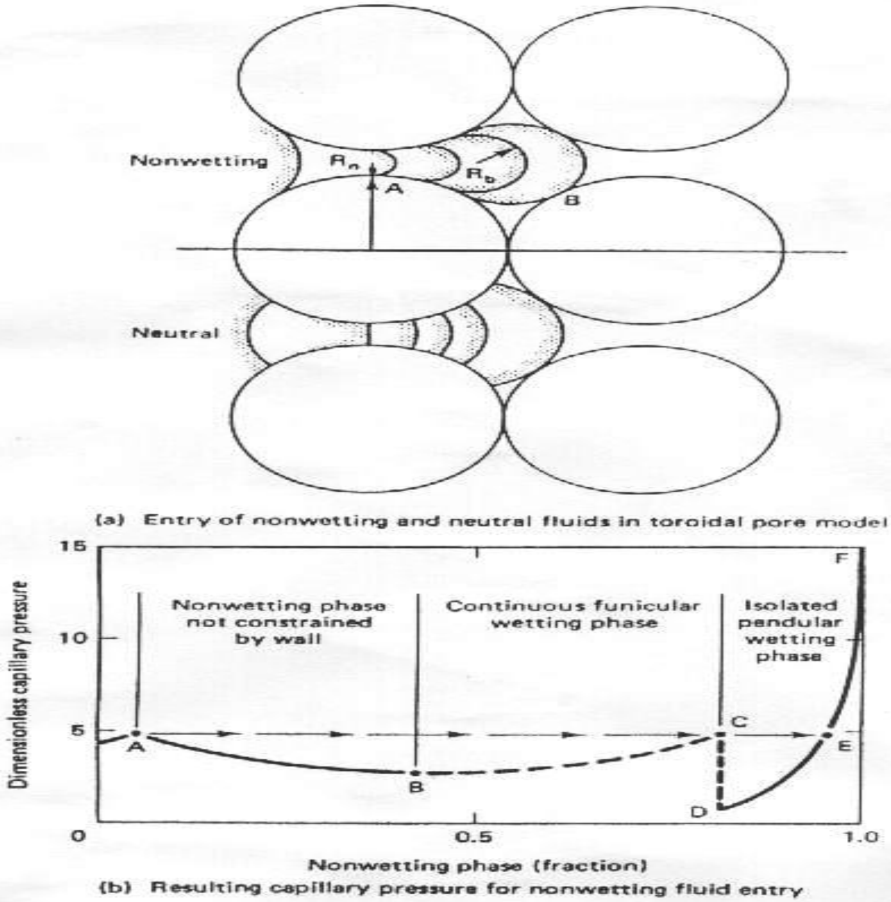



WATER LEVEL
CAPILLARY PRESSURE ($P_o - P_w$) INCREASE
HEIGHT ABOVE OIL - WATER CONTACT
$S_{wir}$
Small grain size
high-Swir
SAME R
R
OIL ZONE
HIGHEST WATER PRODUCED
WATER — OIL TRANSITION ZONE
LOWEST OIL PRODUCTION
OIL-WATER CONTACT
WATER ZONE
100%
0
50
100%
WATER SATURATION, $S_w$

- A static force balance across the interface yields:

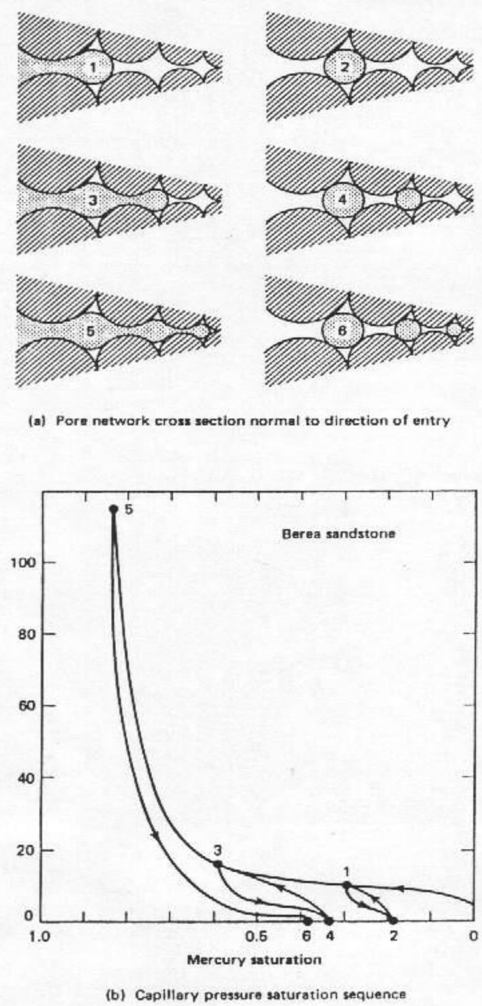
$$P_c = P_2 - P_1 = 2\,\delta \cos\theta / R$$

- If either the interfacial tension is zero or the interface is perpendicular to the tube wall, the **capillary pressure is zero.**

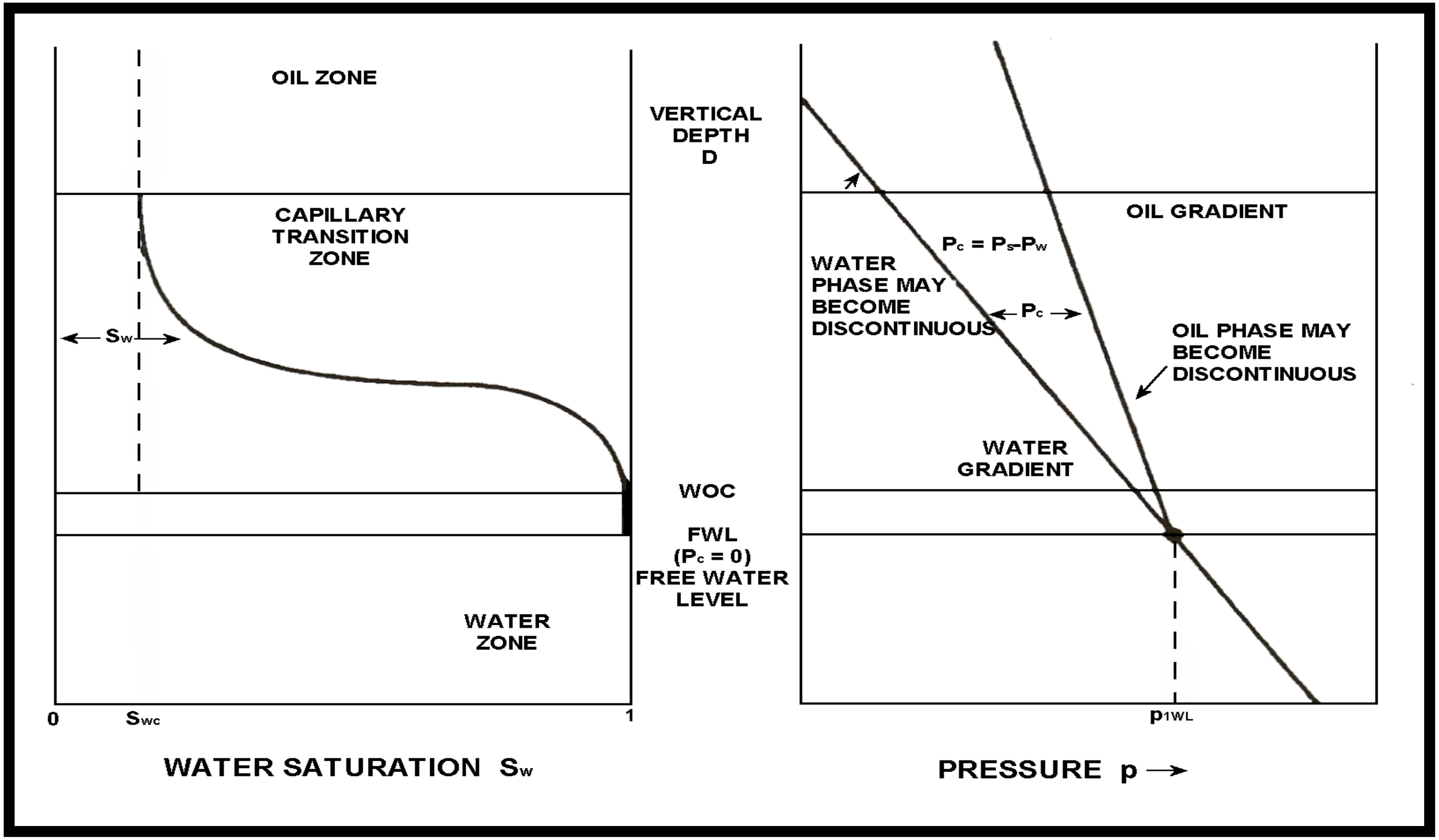


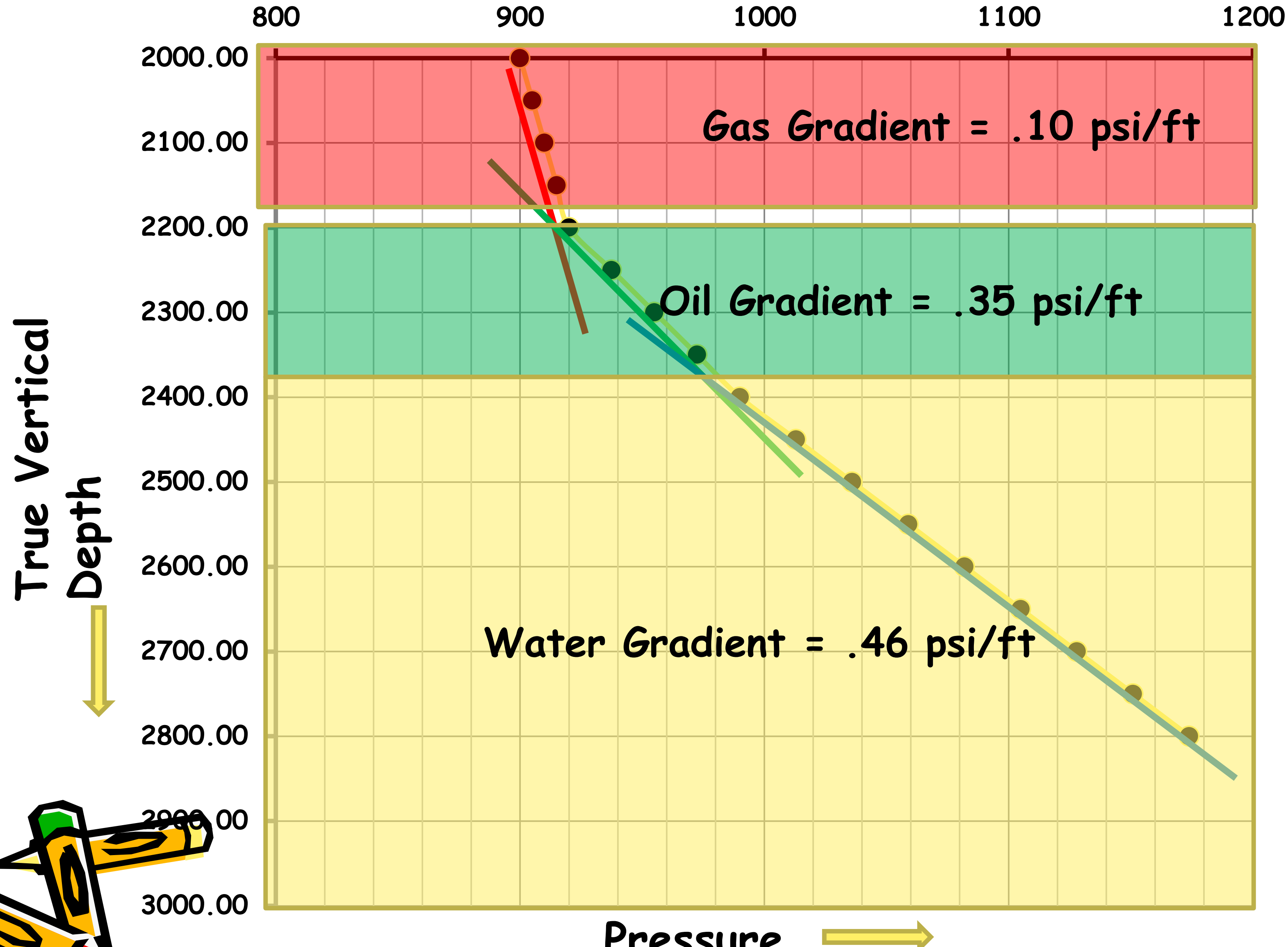

Schematic of interface entrance into a toroidal pore (adapted from Stegemeier, 1976)

- **Actual capillary pressure curves exhibit a sense of hystersis, which can tell us much about the permeable medium.**




The distribution of a non-wetting phase at various saturations (adapted from Stegemeier, 1976)


OIL ZONE
CAPILLARY TRANSITION ZONE
Sw
WATER ZONE
0
Swc
1
WATER SATURATION Sw
VERTICAL DEPTH D
WOC
FWL (Pc = 0) FREE WATER LEVEL
OIL GRADIENT
Pc = Ps-Pw
WATER PHASE MAY BECOME DISCONTINUOUS
Pc
OIL PHASE MAY BECOME DISCONTINUOUS
WATER GRADIENT
p1WL
PRESSURE p


800
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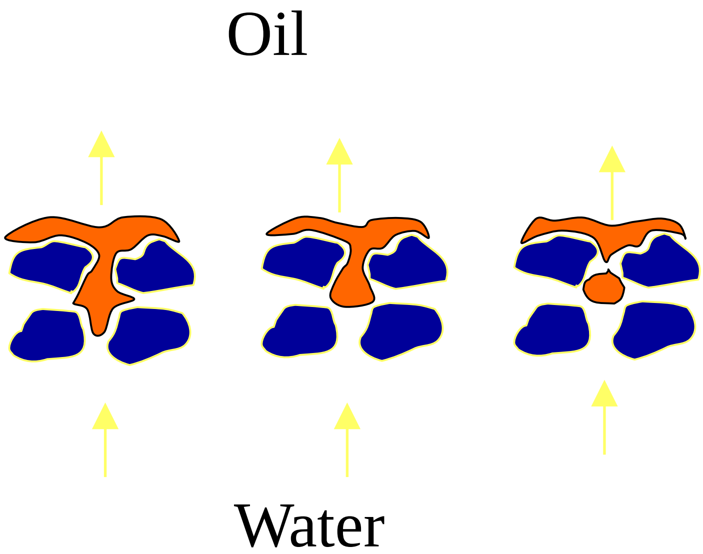
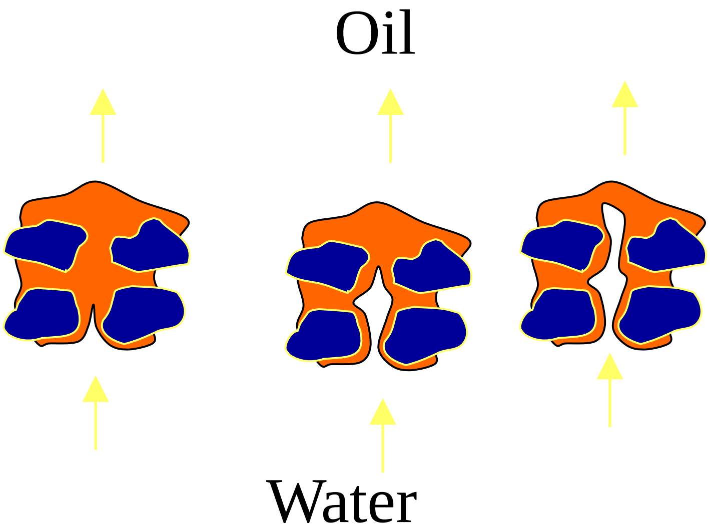
2300.00
2400.00
2500.00
2600.00
2700.00
2800.00
2900.00
3000.00
Gas Gradient = .10 psi/ft
Oil Gradient = .35 psi/ft
Water Gradient = .46 psi/ft
True Vertical Depth
Pressure

# ROCK WETTABILITY

- Wettability is the tendency of one liquid (oil or water) to preferentially spread over the surfaces of a rock, when two or more fluids (oil, gas, and water) are present together

# Wettability




Strongly Water Wet

Strongly Oil Wet

- Many reservoirs exhibit a large range of wetting tendency (from strong water-wet to neutral-wet to strongly oil-wet).
- The change must have occurred some time after oil accumulation.

- A number of possible reasons for the alteration have been suggested:

(1) some crude oils contain surface-active ingredients and polar compounds.

(2) some are rich in asphaltenes and wax-like material.

# Amott test

- wettability is determined by the amount of oil or water imbibed in a core sample compared to the same values when flooded.

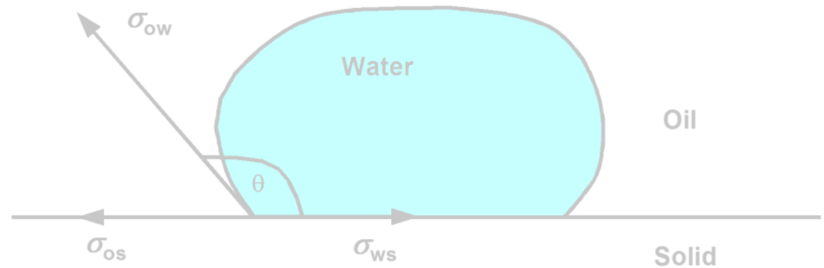
- Amott wettability values range from +1 for complete water wetting to -1 for complete oil wetting.

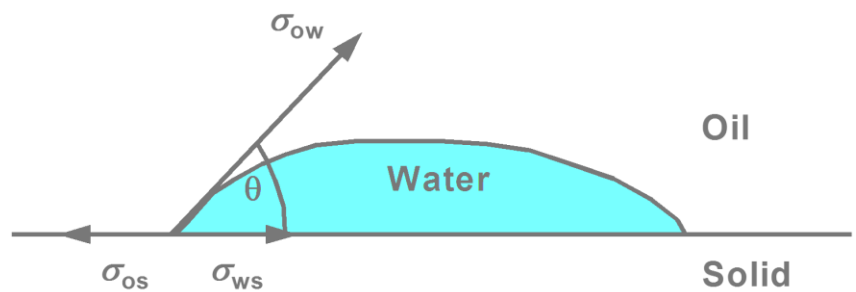
# U.S.Bureau of Mines test

- wettability index W is the logarithm of the ratio of the areas under Pc curves in both imbibitions and drainage processes.
- This index can range between -1.5 and +1

# Contact angle test

- Ranges are from 0 to 75° for water wet, from 105 to 180° for oil wet, and from 75 to 105° for intermediate wettability.



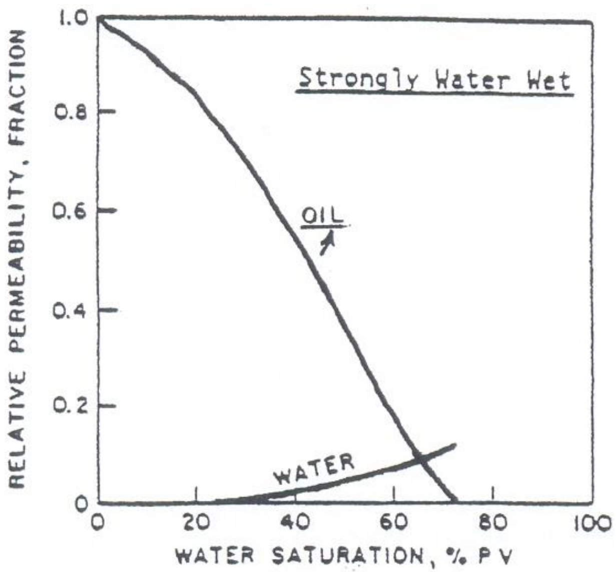
The Amott index and the W index can be taken in actual permeable medium, but their correspondence to capillary pressure is not direct.

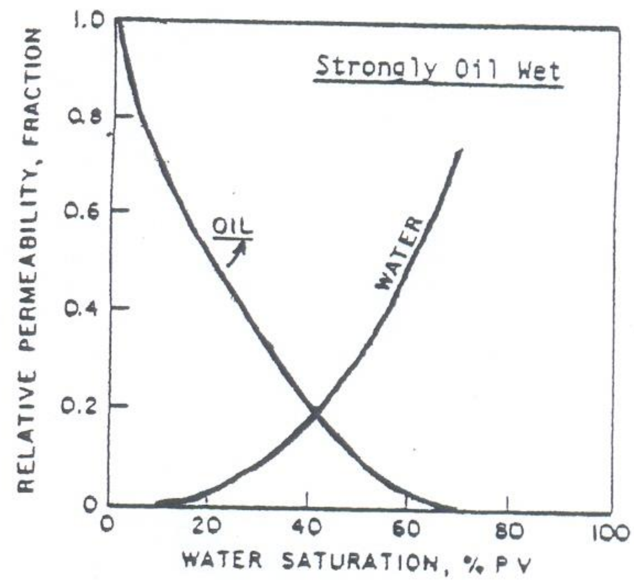
- But both of these methods are measures of aggregate rather than local wettability.

- The contact angle method is direct but it is not clear to what extent a polished surface represents the internal surface of the permeable medium.

Most sandstone reservoirs tend to be water wet or intermediate wet, where as most carbonate reservoirs tend to be intermediate wet or oil wet.

## 4. Shape of the Relative Permeability Curves




| | |
|---|---|
| $S_{WC} = 25\text{-}40\%$ | $S_{WC} < 15\%$ |
| $K_{rw}\vert_{SORW} = 0.1\text{--}0.2$ | $K_{rw}\vert_{SORW} \geqslant 0.3$ |
| $K_{ro}\vert_{SWC} \geqslant 0.85$ | $K_{ro}\vert_{SWC} \leqslant 0.7$ |
| $S_W \geqslant 50\%$ at $K_{rw} = K_{ro}$ | $S_W \leqslant 50\%$ at $K_{rw} = K_{ro}$ |

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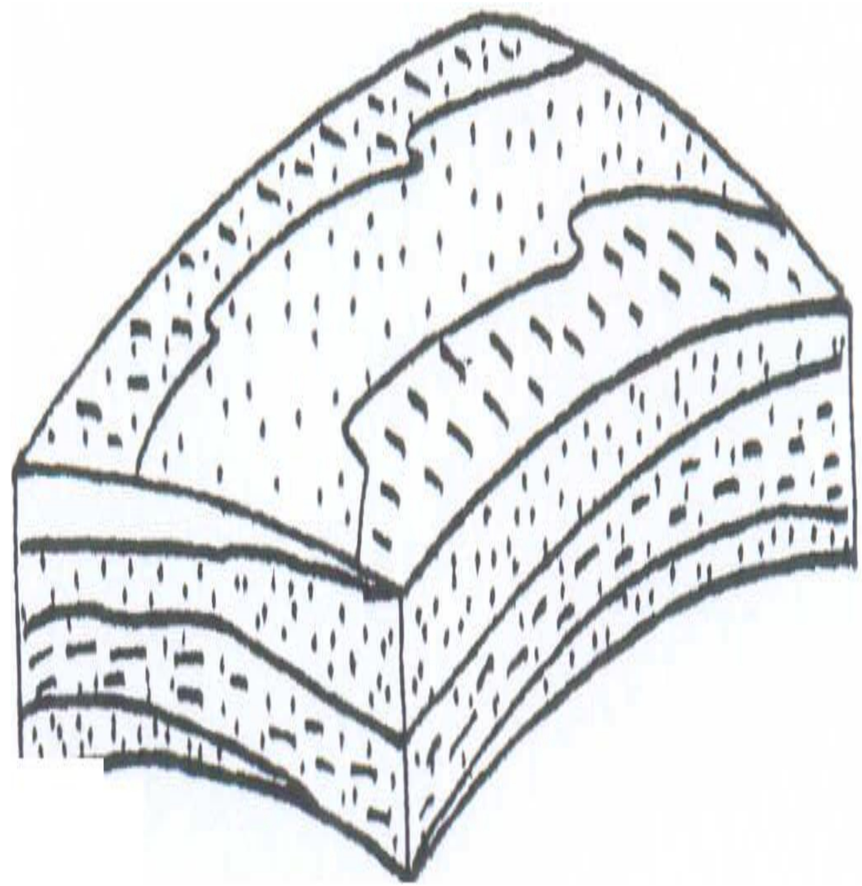
# Reservoir Heterogeneity

- Heterogeneity is the spatial variation of the reservoir properties.
- It is the most difficult attribute to define but has the highest influence on the recovery efficiency of the primary as well as all the displacement processes



# RESERVOIR FACTORS

- Location of field
- Choice of reservoirs,
- Reservoir characterization (depth, rock, oil, homogeneity, aquifer)
- Internal drive mechanisms
- Potential technical risks

# COMMERCIAL FACTORS

- Sources of capital
- Economic selection criteria
- Market availability
- Price of oil
- Risk

# POLITICAL FACTORS

- Economic climatic
- Issues of safety/security/stability
- Manpower and technology availability

# MOBILITY RATIO CONSIDERATIONS

- Mobility of the fluid is defined as the effective permeability of the rock to a fluid divided by the viscosity of that fluid.

- ***Mobility can be decomposed into***

- a rock property, the absolute permeability,
- a fluid property, the viscosity, and
- the rock-fluid property, the relative permeability

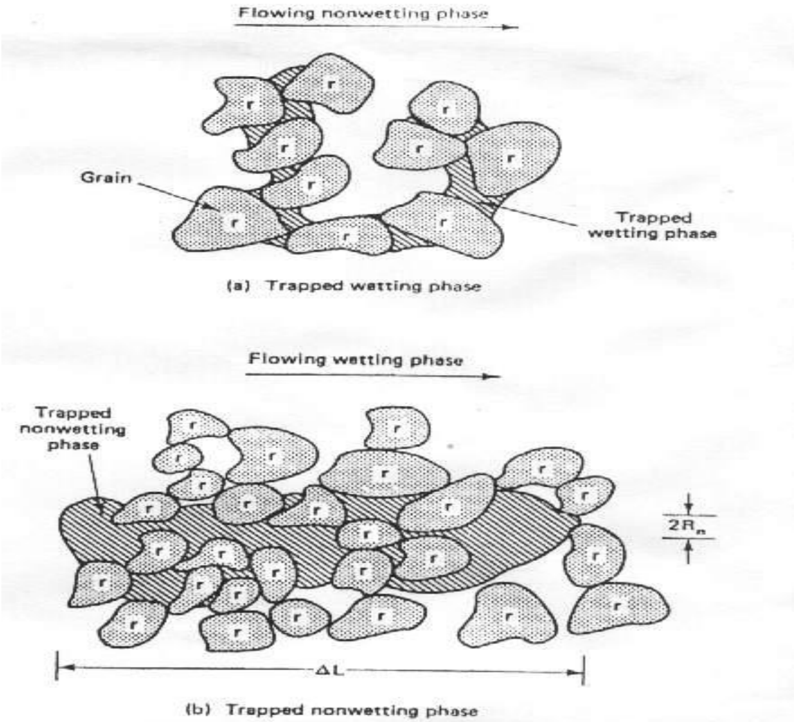
$$\lambda_j = K\,(K_{rj}/\mu_j)$$

- The relative permeability is a strong function of the fluid saturation of phase Sj.
- Relative mobility can be defined as
- $\lambda_{rj} = K_{rj}/\mu_j$
- and the phase permeability
- $K_j = K\,K_{rj}$
- Kj is a *tensorial property* in three dimensions.

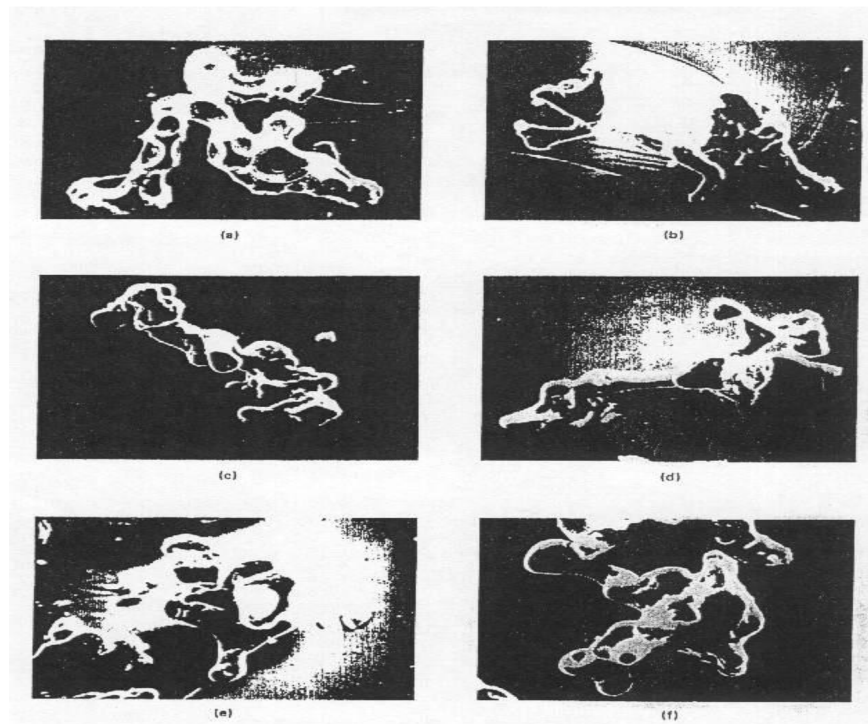
**Mobility ratio at water breakthrough is the term that is of significance in describing relative mobility ratio.**

- $M < 1$ - Favorable displacement as oil moves faster than water.
- $M = 1$ - Favorable displacement as both oil and water move at equal speed.
- $M > 1$ - Unfavorable displacement as water moves faster than oil

# Residual Oil Saturation




Schematic illustration of trapped wetting and nonwetting phases.



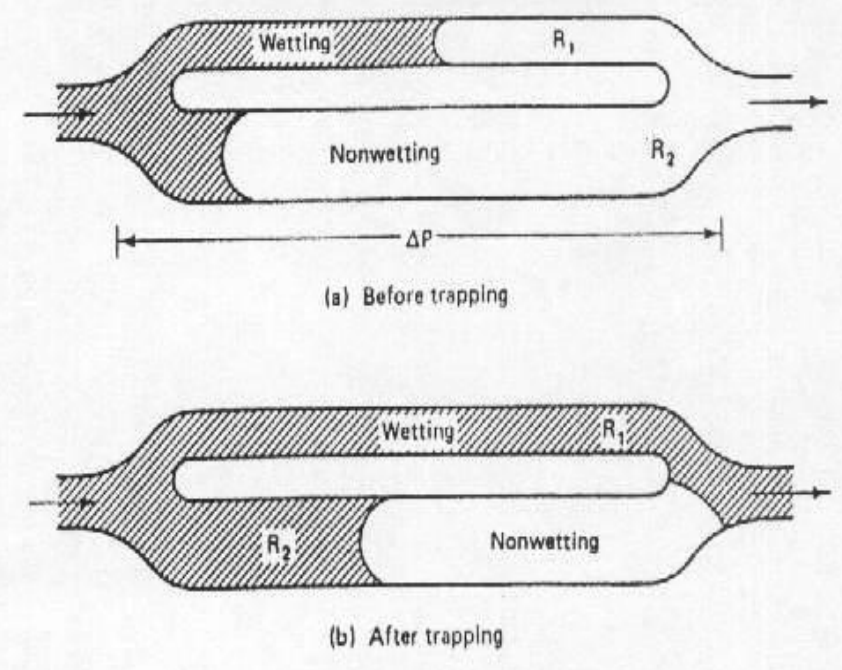

Typical large oil blobs in (a) bead packs and (b) to (f) Berea sandstone (from Chatzis et al., 1983)

- Oil recovery is dependent upon the reduction in oil saturation (original minus the remaining) in the reservoir pore space at any point in time.

- The mechanism for residual phase saturation may be illustrated through two simplified models:

# The pore doublet model

- This model assumes well-developed Poiseuille flow occurs in each path of the doublet and the presence of the interface does not affect flow.
- When the wetting-nonwetting interface reaches the outflow end of the doublet in either path, it traps the residual fluid.




Schematic of pore doublet model

- The interface of the small-radius path will reach the outflow end before the large-radius path, and the nonwetting phase will be trapped in the large-radius path.

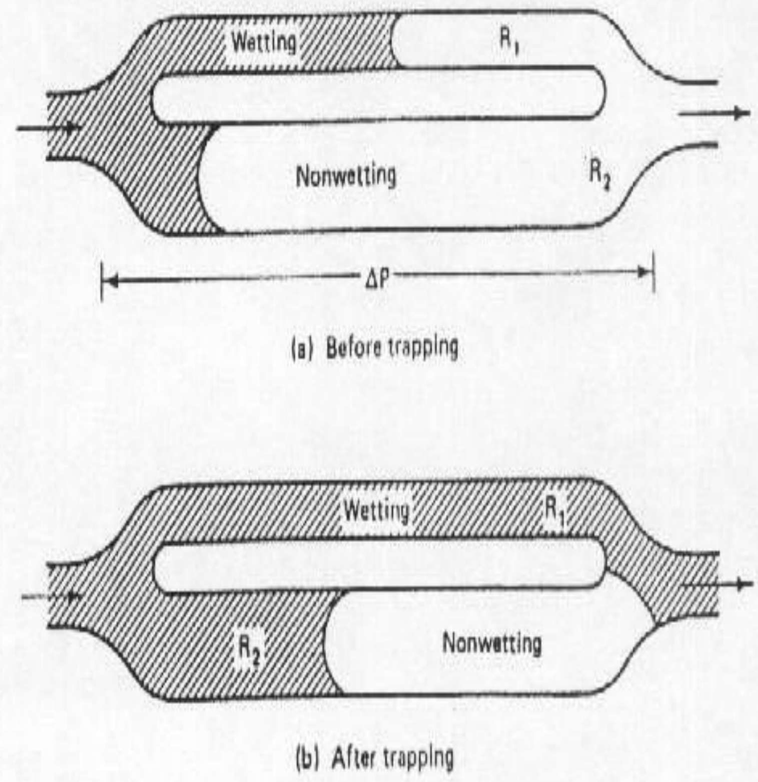
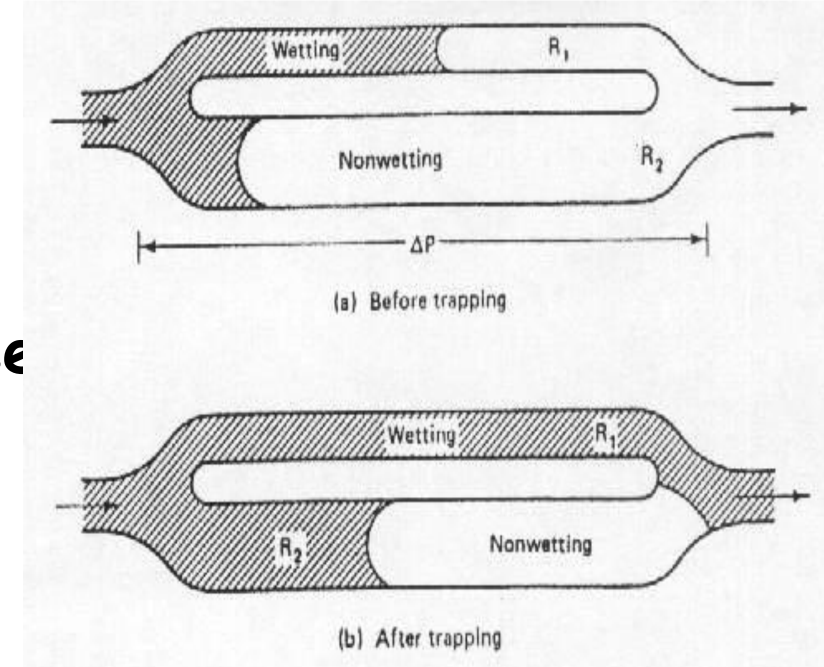


Figure 3-14 Schematic of pore doublet model

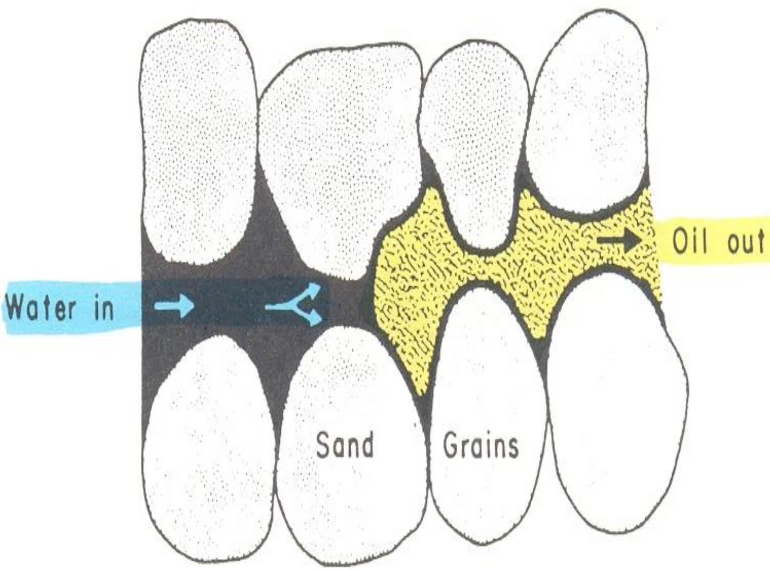
- This model illustrates several qualitative observations about phase trapping.

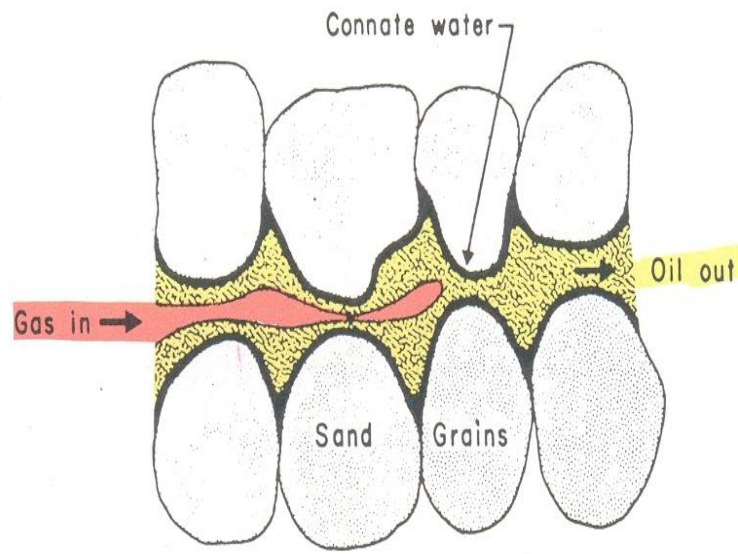
- The nonwetting phase is trapped in large pores; the wetting phase, in small cracks and crevices.




Schematic of pore doublet model

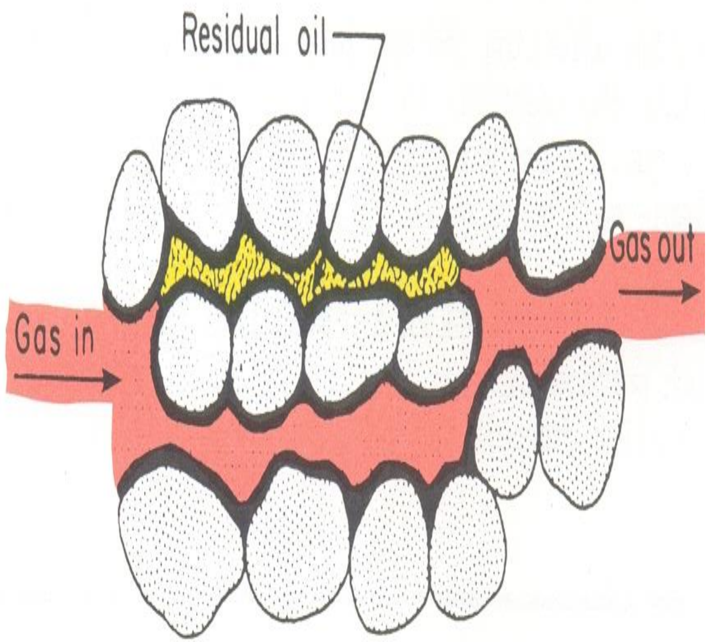
# Displacement of oil by water

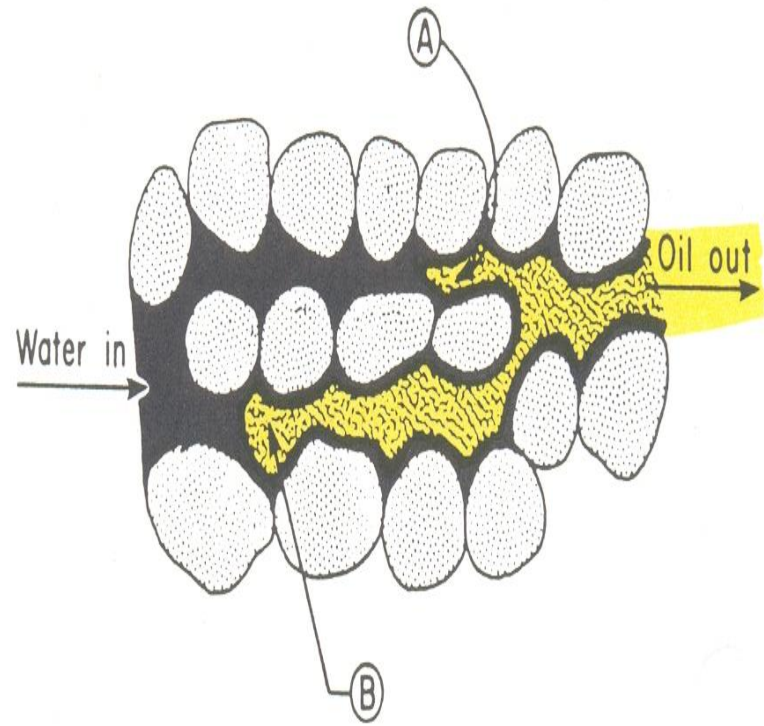



# Displacement of oil by gas

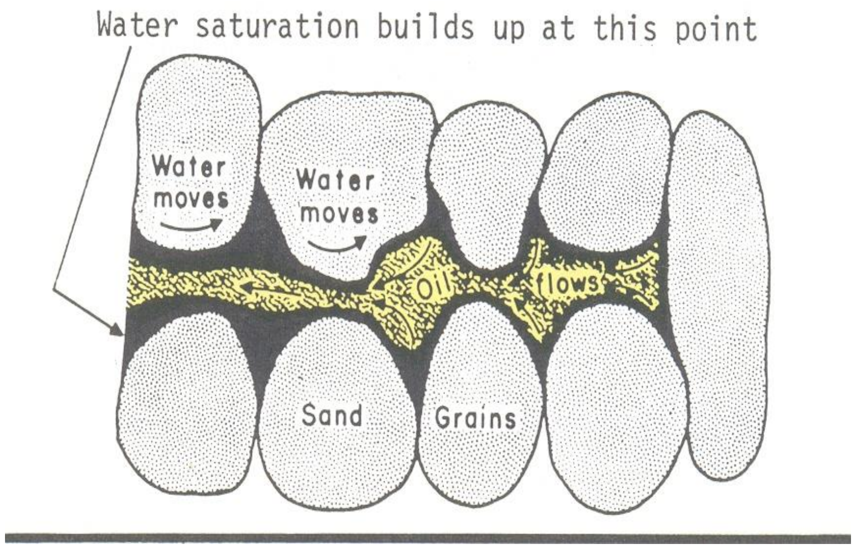
Gas displaces oil first from high permeability pore channels. Residual oil occurs in lower Permeability pore channels.

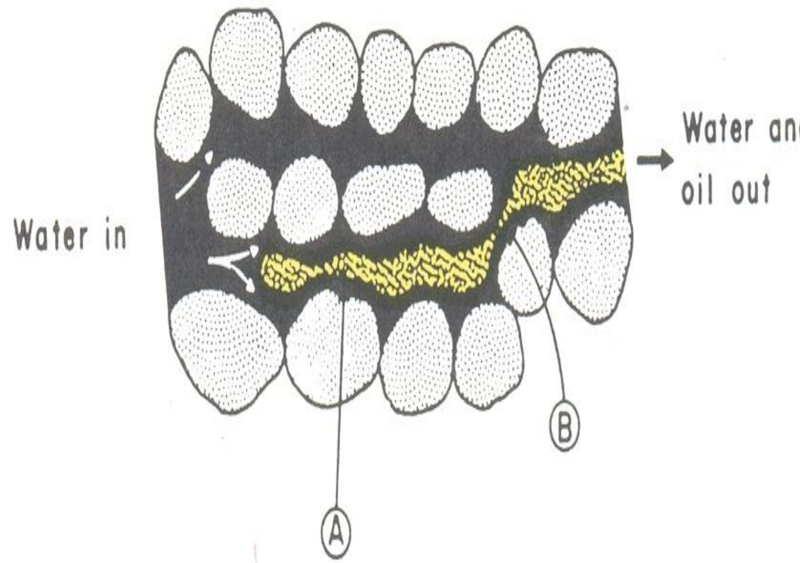



Capillary forces cause water to move ahead faster in low perm. pore channel (A) when water is moved slow through high perm. Pore (B).

Capillary pressure gradient causes oil to move out and water to move into a Dead-end pore when sand is water-wet.

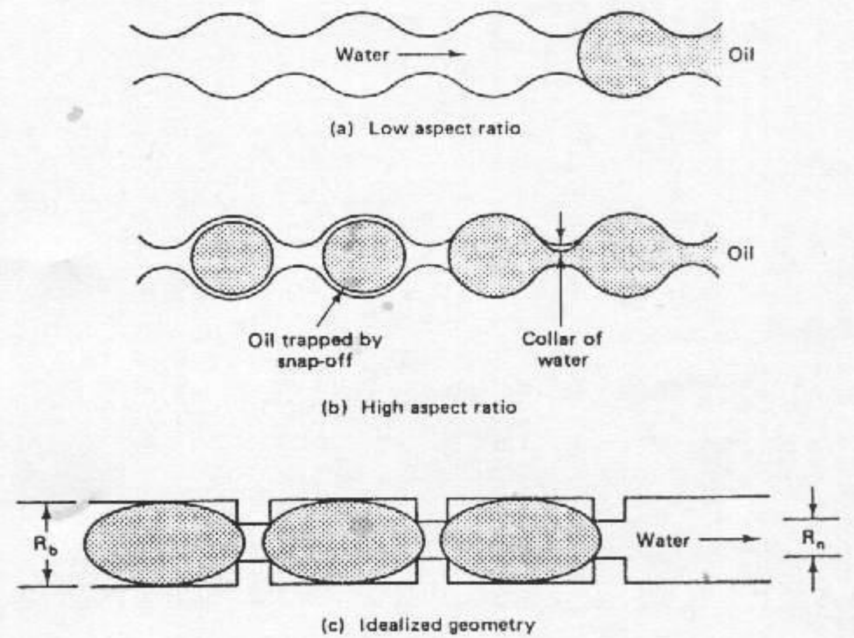



As thread of oil gets smaller, interfacial tension increased in the film at restricted points A and B, where film subsequently breaks.

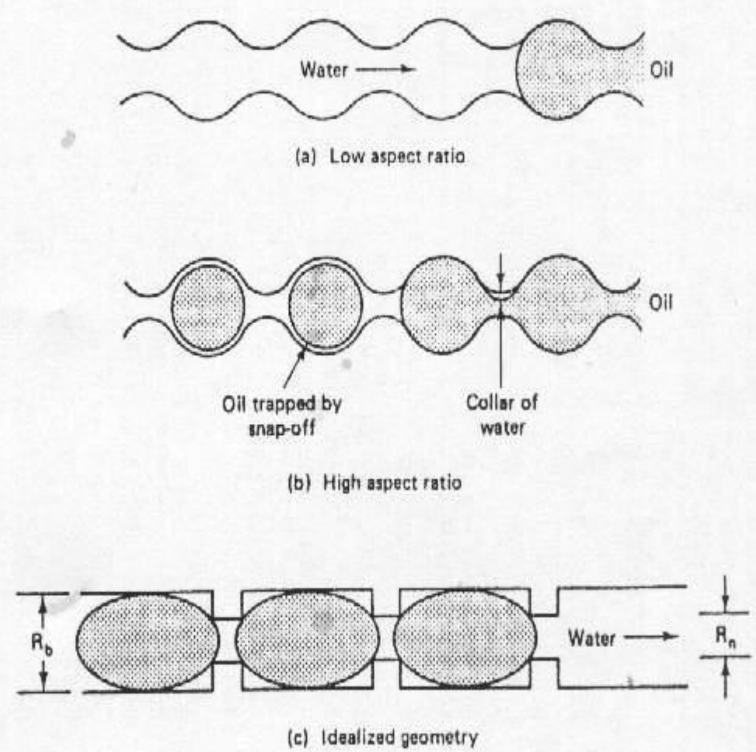
# Snap-off Model

- The snap-off model **assumes** a single-flow path of variable cross-sectional area through which is flowing a nonwetting phase.




Various geometries of the pore snap-off model

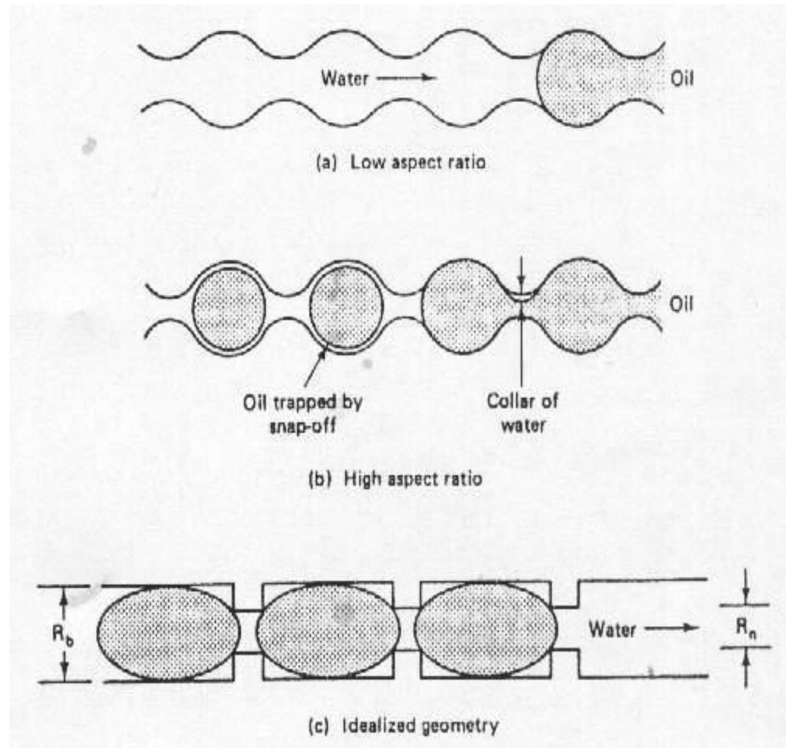
- For certain values of the potential gradient and pore geometry, the potential gradient in wetting phase across the path segment can be less than the capillary pressure gradient across the same segment.




Various geometries of the pore snap-off model

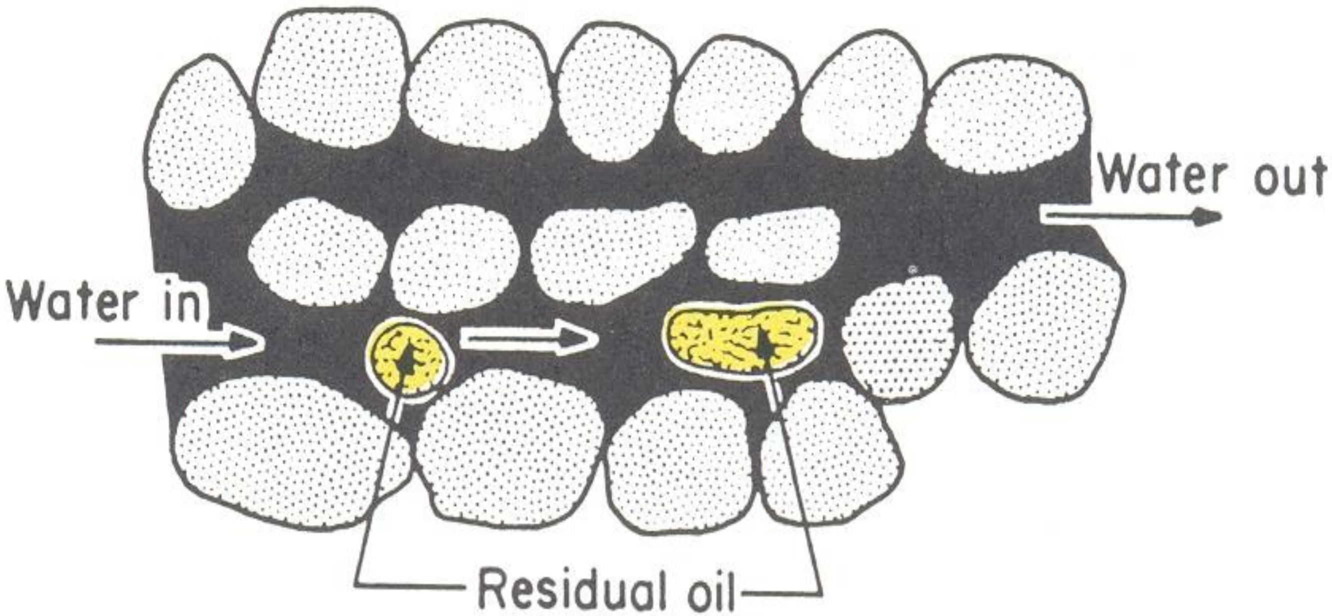
- The external force is now insufficient to compel the nonwetting to enter the next pore constriction.

- The nonwetting phase then snaps off into globules that are localized in the pore bodies of the flow path.




Various geometries of the pore snap-off model

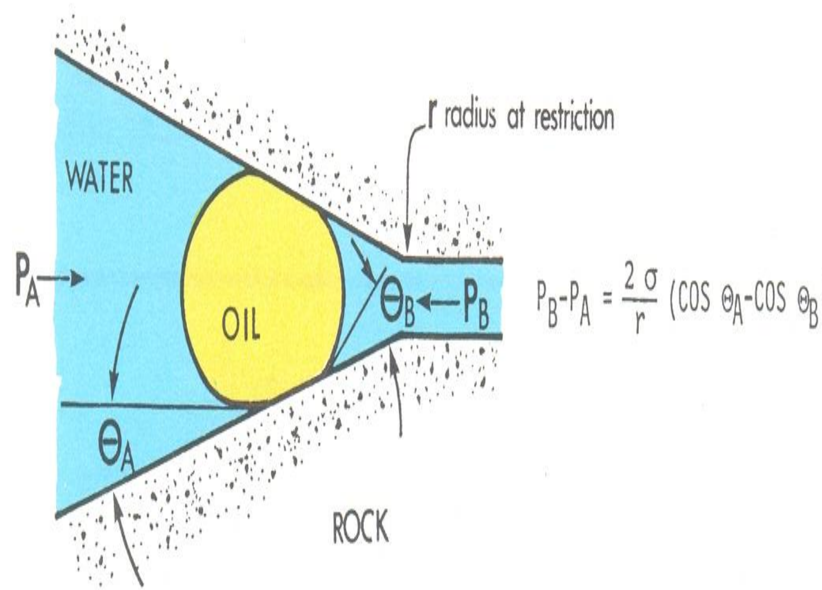
**Water drive leaves residual oil in sand because surface films break at restrictions in sand pore channels.**



- ***The condition for reinitializing the flow of any trapped globule is***

- $\Delta\Phi w + \Delta\rho g \Delta L \sin \acute{a}$ >= $\Delta Pc$

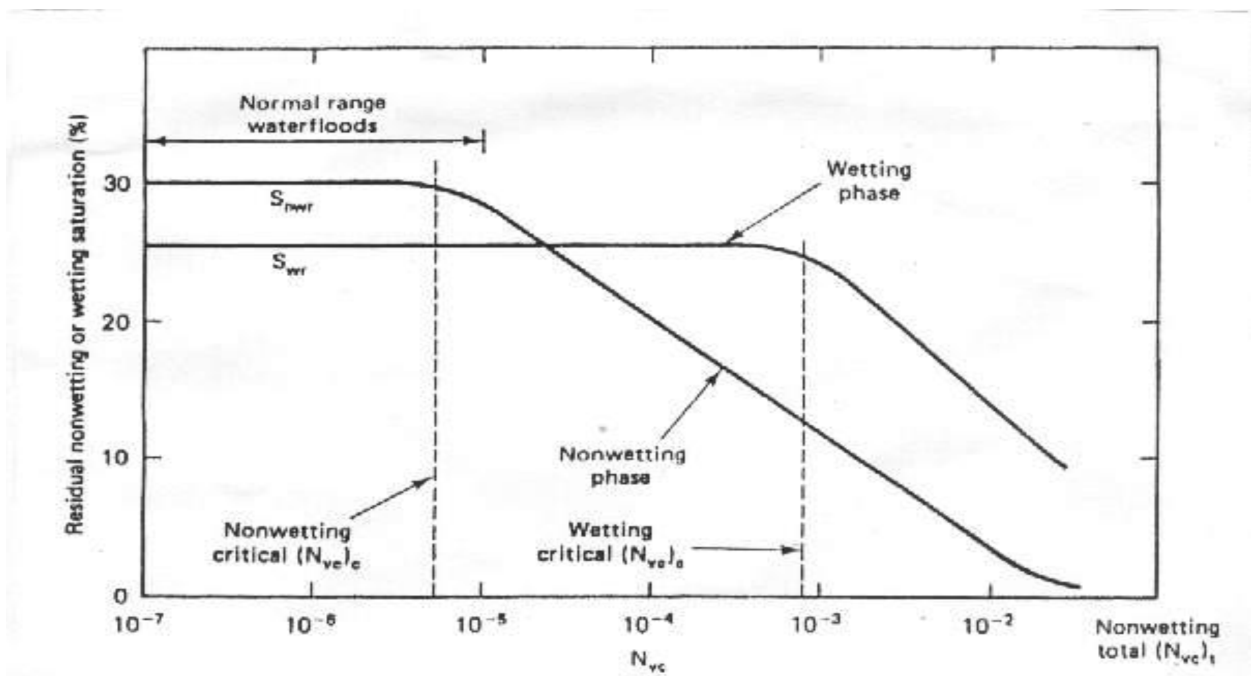
- **Where:**
- $\Delta L$ is the globule size and á is the angle between the globule's major axis and the horizontal axis.



- **Capillary Number**, an approximate measure of the ratio of Viscous to Capiltary forces, shows the effect of reservoir forces on the residual oil saturation.

- The capillary number Nc is a dimensionless ratio of viscous to capillary forces and can be written as:

- $Nc = V\mu/\delta\cos\theta$ or
- $= k\Delta P/\delta\cos\theta$




Schematic capillary desaturation curve (from Lake, 1984)

- **Areal sweep efficiency**
- improvement is achieved by drilling additional wells in un-swept areas and by controlling injection production balancing.
- Other opportunities are:
- (1) pattern rotation,
- (2) infill drilling,
- (3) high angle, horizontal, and multi-lateral wells.

# Oil recovery is dependent on many factors

1. Accuracy of original oil and gas volume estimates.
2. Drive Mechanisms Drive mechanisms are often some combination of rock & fluid expansion, pressure depletion, gas cap expansion, water influx, Gas Injection, water injection.

3. Depositional Heterogeneity Facies variation Permeability stratification Fractures, faults, partitioning
4. Completion Practice Well placements pattern, spacing Completion practice, open hole, cased hole, completion interval, reservoir connectivity, damage , stimulation, wellbore integrity
5. Production Practice Rate control- coning, cusping , fingering, gravity override, natural flow, artificial lift

# Conclusions

1. Some reservoir properties are more dominant than the others in influencing the success of a development project or an optimization scheme or a recovery enhancement program.

2. Initial development strategy sets up the stage for reservoir performance and hence for the subsequent optimization and recovery enhancement efforts.

3. All recovery processes have limitations - while some are caused by the nature of the reservoir and its fluids, others are the results of the development, production, and operating practices.

4. Choice of the injection fluid is not an easy one as it controls the production performance and the recovery behaviour of the reservoir.

5. Mobility ratio between the injection fluid and the crude oil has a pronounced effect on the efficiency of all displacement processes.

6. Residual oil saturation in the reservoir pore space is mainly dependent upon the balance between capillary and viscous forces.

7. The areal and vertical sweep of the reservoir by an injection fluid is essentially dependent upon reservoir characterization.

8. There are many reasons for oil recovery of a project falling below the expectation level.

9. Technical success is good, but economic success is a must.