Fundamentals Of Petroleum Engineering

ROCK AND FLUID PROPERTIES

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COURSE CONTENTS

- Reservoir Rock Characteristics
- Porosity
- Permeability
- Rock and Fluid Interaction
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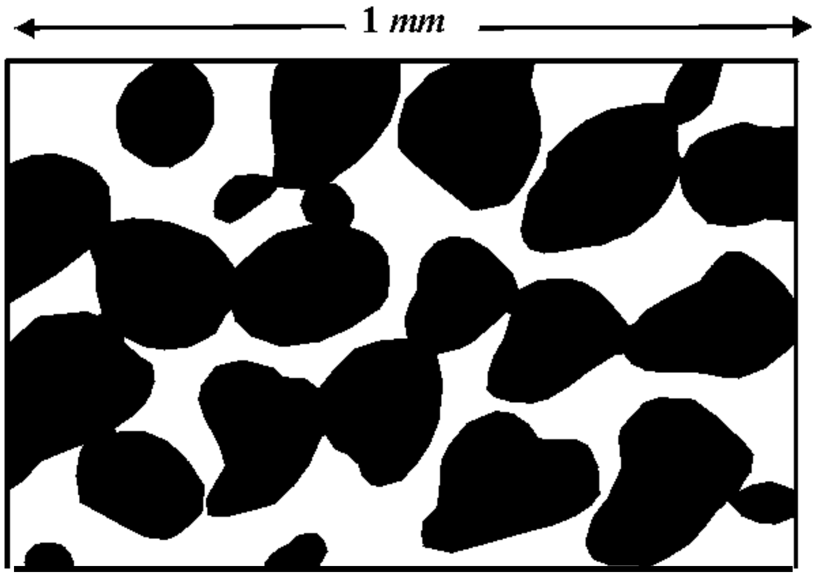
Reservoir Rock Characteristics

- To form a commercial reservoir of hydrocarbons, any geological formation must exhibit two essential characteristics.
- These are capacity for storage and a transmissibility to the fluids concerned.
- Storage capacity requires void spaces within the rock and the transmissibility requires that there should be continuity of those void spaces.

Porosity

- Petroleum is not found in underground rivers or caverns, but in pore spaces between the grains of *porous* sedimentary rocks.



A piece of porous sedimentary rock. The pore spaces are the white areas between the dark grains. It is within such pore spaces that fluids such as oil, natural gas, or water can be found in the subsurface.

- Porosity (ϕ) is defined as a percentage or fraction of void to the bulk volume of a material.
- Porosity of commercial reservoirs may range from about 5% to about 30% of bulk volume.

$$\phi = \frac{V_p}{V_b} x100\% = \frac{V_b - V_g}{V_b} x100\% = \frac{V_p}{V_p + V_g} x100\%$$

where:

V_p = pore or void volume

V_b = bulk volume of rock

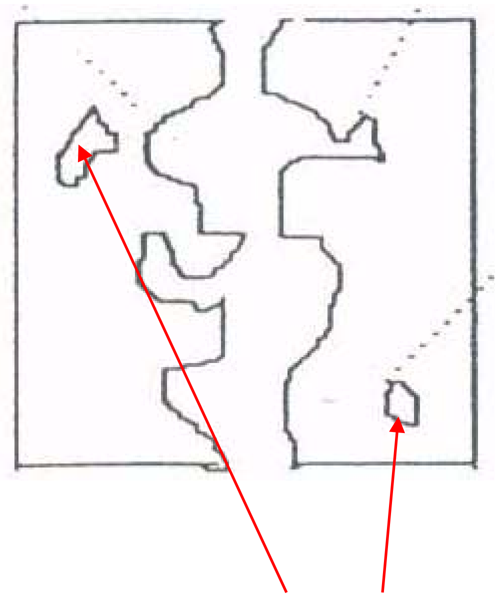
V_g = grain volume

Factors Affecting Porosity

- **Grain size**: grain size has no effect on porosity. Well rounded sediments that are packed into the same arrangement generally have porosities from 26% to 48% depending on the packing.
- **Sorting**: Well sorted sediments generally have higher porosities than poorly sorted sediments for the simple reason that if a sediment is a range of particle sizes then the smaller particles may fill in the voids between the larger particles.
- **Grain shape**: Irregularly shaped particles tend not to pack as neatly as rounded particles, resulting in higher proportions of voidspace.

Total and Effective Porosity

- Total porosity is defined as the ratio of the volume of all pores to the bulk volume of a material, regardless of whether or not all of the pores are interconnected.
- Effective porosity is defined as the ratio of the interconnected pore volume to the bulk volume.



Isolated pores

Primary and Secondary Porosity

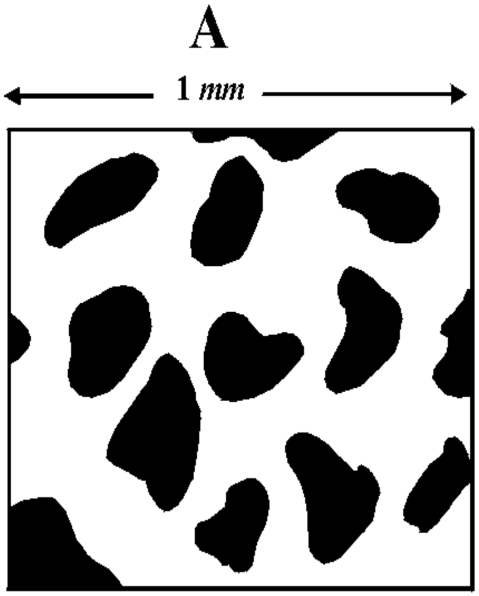
- Primary porosity is defined as a porosity in a rock due to sedimentation process.
- Secondary porosity is defined as a porosity in a rock which happen after sedimentation process, for example fracturing and re-crystallization.

Porosity Measurement

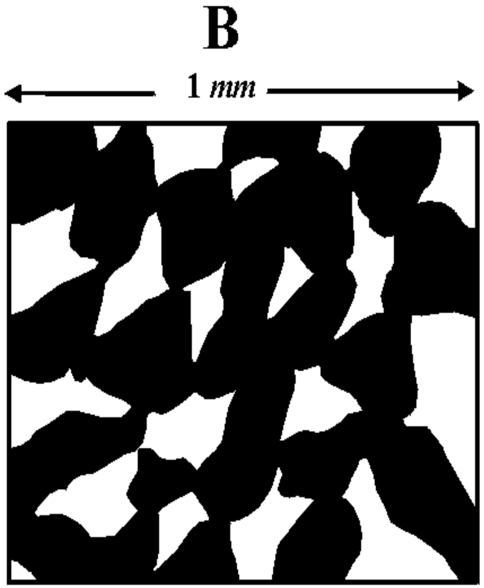
- Boyle’s Law porosimeter.
- Wet and dry weight method.
- Summation of fluids.

Permeability

- The permeability of a rock is a measure of the ease with which fluids can flow through a rock. This depends on how well the pore spaces within that rock are interconnected.



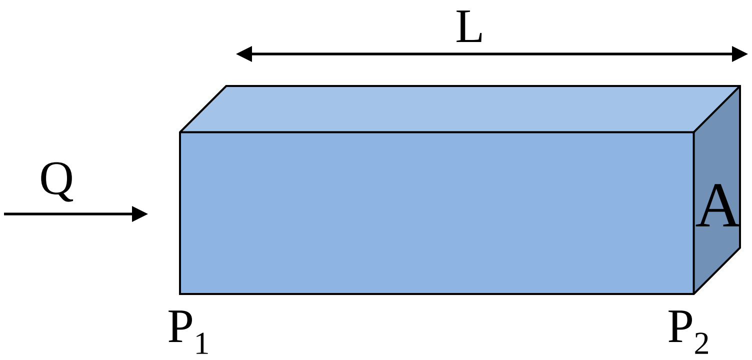
Good Permeability



Poor Permeability

- Permeability is a measure of the ability of a porous material to transmit fluid under a potential gradient.
- The unit for permeability (k) is darcy named after a French scientist, Henry Philibert Gaspard Darcy who investigated flow of water through filter beds in 1856.
- 1 Darcy = 0.987×10^{-12} m^2.

- The general darcy's equation is:



$$\frac{Q}{A} = -\frac{k}{\mu}\left(\frac{dP}{dL}\right)$$

where:

Q = flowrate (cm^3/sec)

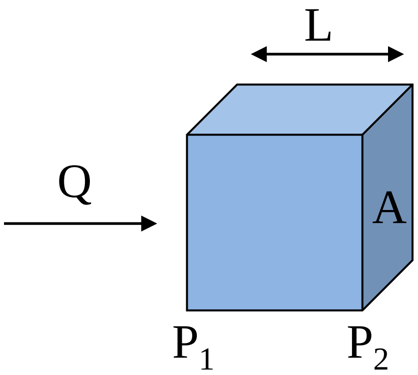
K = permeability (darcy)

A = cross section area (cm^2)

μ = fluid viscosity (cp)

P = pressure (atm)

L = length (cm)



$Q = 1 cm^3/sec$

$A = 1 cm^2$

$\mu = 1$ cp

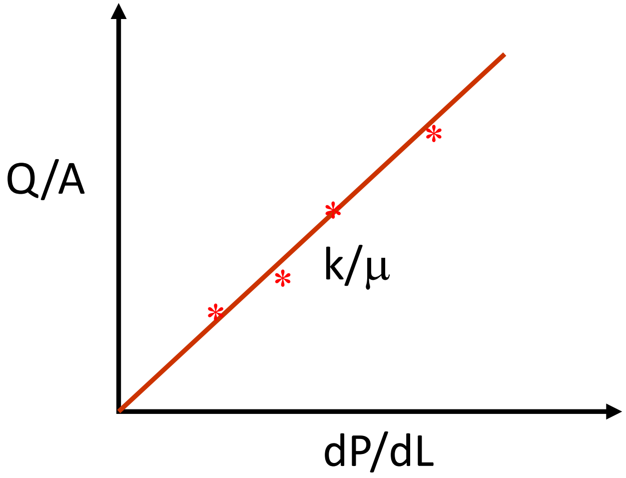
P = 1atm

L = 1cm

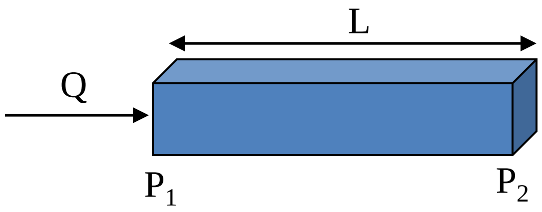
Find k ?

- 1 darcy is defined as the permeability that will permit a fluid of 1 centipoise viscosity to flow at a rate of 1 cubic centimeter per second through a cross sectional area of 1 square centimeter when the pressure gradient is 1 atmosphere per centimeter.

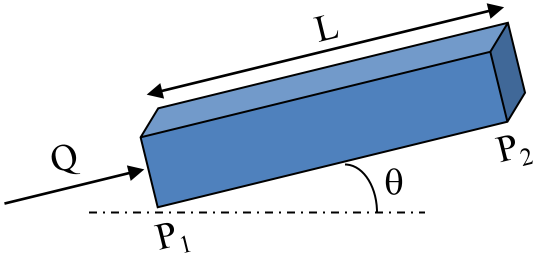
- There are four conditions that are required for this equation to be valid:
  - Laminar flow.
  - No accumulation.
  - Single-phase liquid flow.
  - The porous media is not reactive with the flowing fluid.
- Plot of Q/A against dP/dL should yield a single straight line as shown below where the slope = k/μ = fluid mobility



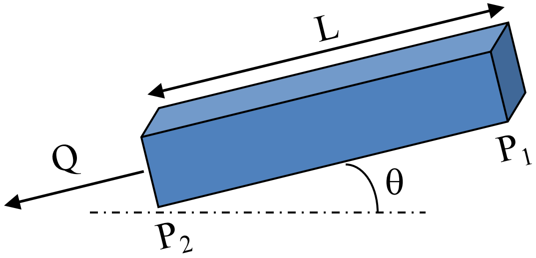
Linear Flow



$$Q = \frac{kA}{\mu}\left(\frac{P_1 - P_2}{L}\right)$$

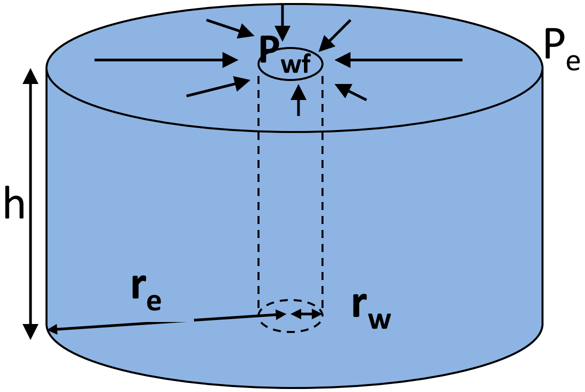


$$Q = \frac{kA}{\mu}\left(\frac{P_1 - P_2}{L} - \rho g \sin\theta\right)$$



$$Q = \frac{kA}{\mu}\left(\frac{P_1 - P_2}{L} + \rho g \sin\theta\right)$$

Radial Flow



$$Q = -\frac{kA}{\mu}\left(\frac{dP}{dR}\right)$$

$$Q = \frac{-k2\pi H}{\mu}R\left(\frac{dP}{dR}\right)$$

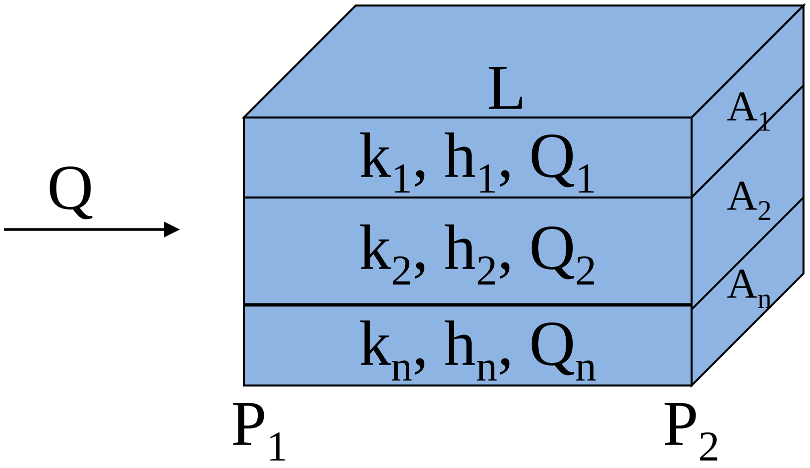
$$\frac{dR}{R} = \frac{-2\pi kH}{\mu Q}dP$$

$$\int_{r_e}^{r_w}\frac{dR}{R} = -\int_{p_e}^{p_{wf}}\frac{2\pi kH}{\mu Q}dP$$

$$\ln\frac{r_w}{r_e} = \frac{-2\pi kH}{\mu Q}\left(P_{wf} - P_e\right)$$

$$Q = \frac{2\pi kH\left(P_e - P_{wf}\right)}{\mu\ln\left(r_e/r_w\right)}$$

Averaging Permeability (Parallel Sand)



$$Q = \sum_{i=1}^{i=n} Q_i = Q_1 + Q_2 + Q_n$$

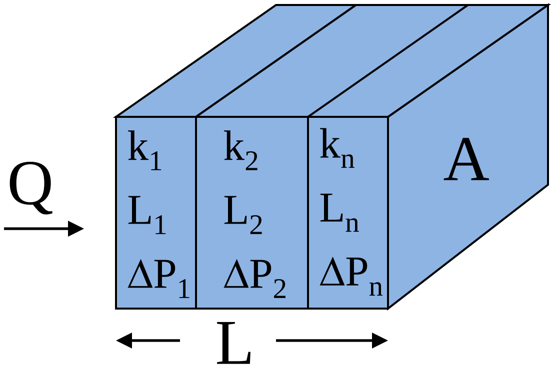
$$k\sum_{i=1}^{i=n} A_i \frac{\Delta P}{\mu L} = k_1 A_1 \frac{\Delta P}{\mu L} + k_2 A_2 \frac{\Delta P}{\mu L} + k_n A_n \frac{\Delta P}{\mu L}$$

$$k\sum A_i = \sum k_i A_i$$

$$k = \frac{\sum k_i A_i}{\sum A_i} \text{ or } \frac{\sum k_i h_i}{\sum h_i}$$

Arithmetic averages

Averaging Permeability (Series Sand)



$$\Delta P = \sum_{i=1}^{i=n} \Delta P_i = \Delta P_1 + \Delta P_2 + \Delta P_n$$

Harmonic averages

$$k = \frac{\sum_{i=1}^{i=n} L_i}{\sum_{i=1}^{i=n} \frac{L_i}{k_i}}$$

Prove it ?

Exercise 1

Given:

Porosity = 0.19

Effective horizontal permeability, md = 8.2

Pay zone thickness, ft = 53

Reservoir pressure (P_{avg}), psi = 5,651

Flowing Bottomhole pressure (P_{wf}), psi = 1,000

Bubble point pressure, psi = 5,651

Oil formation volume factor, bbl/STB = 1.1

Oil viscosity, cp = 1.7

Drainage area, acres = 640

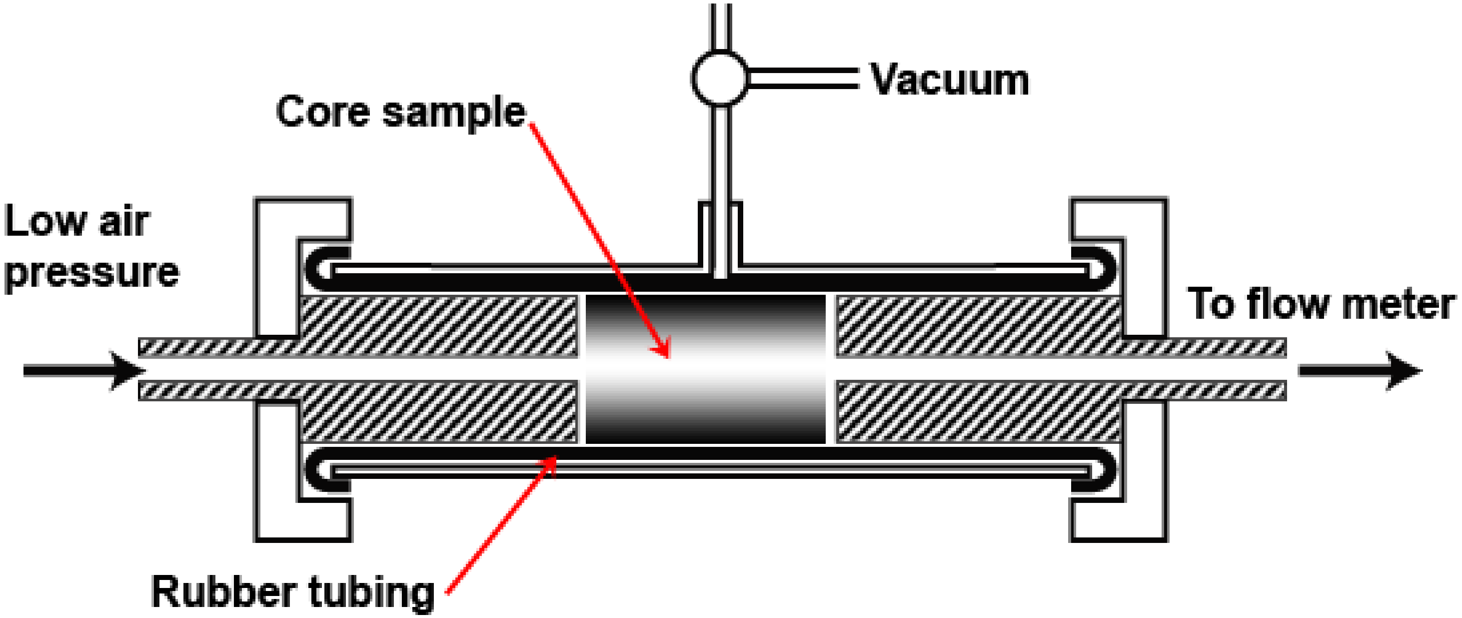
Wellbore radius, ft = 0.328

Calculate the flow rate.

Permeability Measurement

- Permeability of core sample can be measured by liquid permeameter and gas permeameter.
- Liquid permeameter:
    - Non reactive liquid (paraffin oil) is forced to flow through a core sample in a core holder.
    - A flow rate is measured, and permeability is calculated using general Darcy equation.
- Gas permeameter:
    - Non reactive gas (typically helium) is used in the measurement of permeability.
    - The gas is flow through the sample, and the flow rate of gas is measured.

- Figure below illustrates the schematic diagram of the Hassler-type permeability measurement under steady state flow conditions.



- The permeability is calculated using following modified form of darcy equation which takes into account the gas compressibility during flow.

$$\frac{Q}{A} = \frac{k_g}{\pi}\frac{\left(P_1^2 - P_2^2\right)}{2P_a\Delta L} \Longrightarrow k_g = \frac{2Q\pi P_a\Delta L}{A\left(P_1^2 - P_2^2\right)}$$

where:

Q = gas flowrate (cm^3/sec)

k_g = gas permeability (darcy)

A = cross section area (cm^2)

μ = fluid viscosity (cp)

P_1 = inlet pressure (atm)

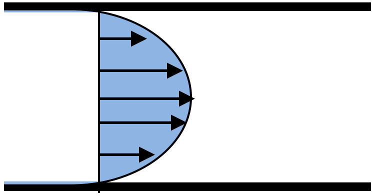
P_2 = outlet pressure (atm)

P_a = atmospheric pressure (atm)

L = length (cm)

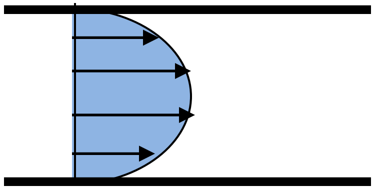
Slippage Phenomenon during Gas Permeability Measurements

liquid



v (wall) = 0

gas



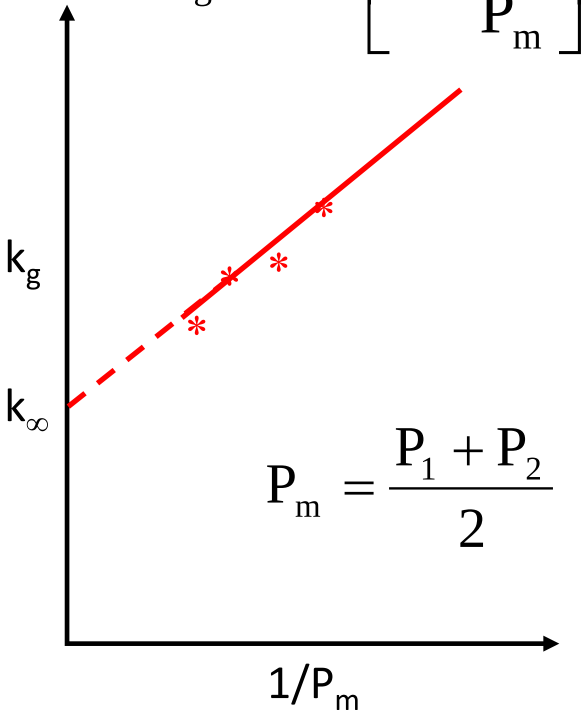
finite velocity at wall

- Gas permeability dependent on the mean pressure of the gas existing at the time of measurement.
- At low mean gas pressure, gas permeability exceeds liquid permeability.
- At high mean gas pressure, gas permeability approaches liquid permeability.
- Slippage effect is a laboratory phenomenon due to low flowing gas pressure, but negligible for gas flow at reservoir conditions.

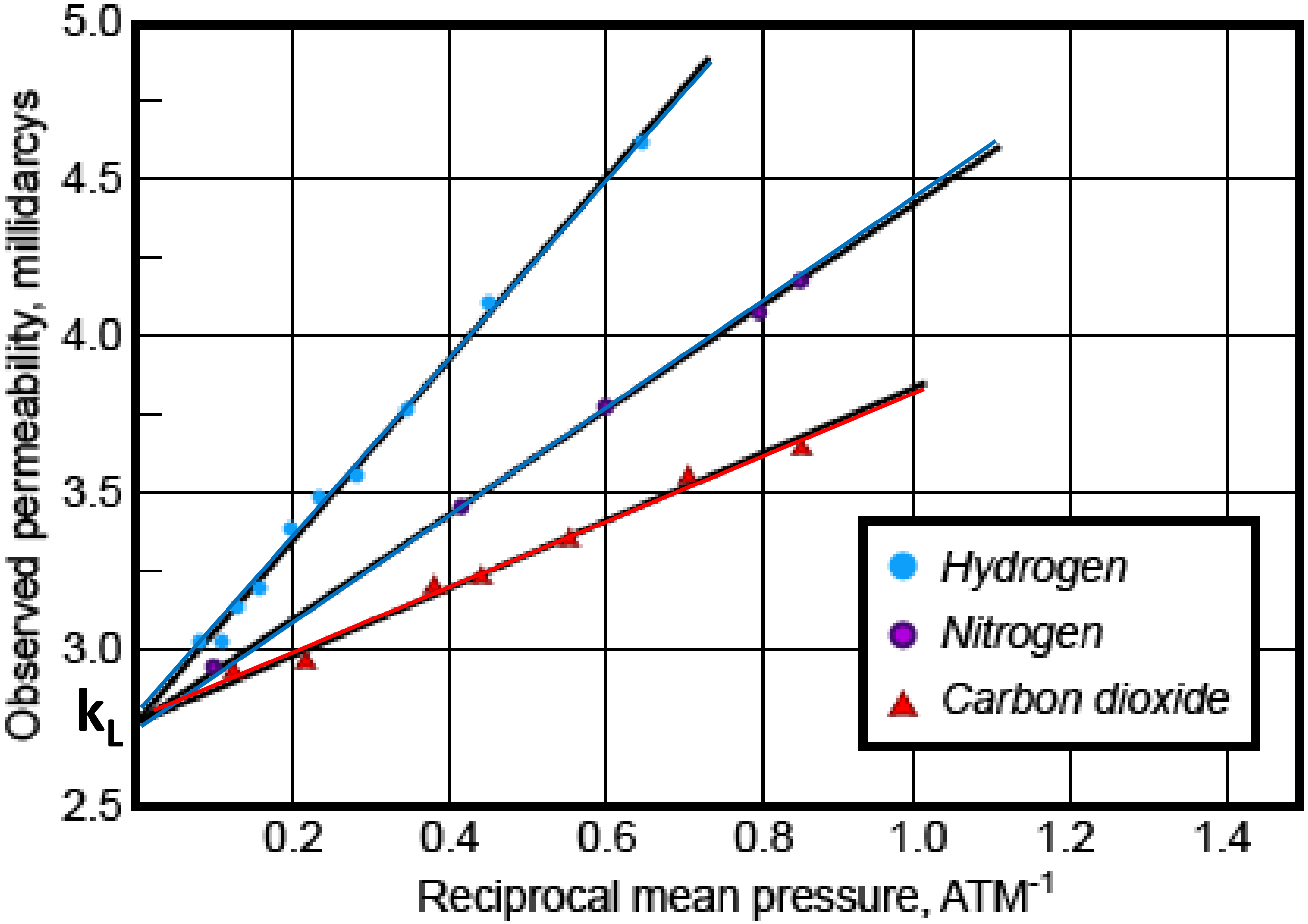
Klinkenberg correction

- Plot of k_g versus the inverse of mean flow pressure ($1/P_m$) yields a straight line with slope $k_\infty b$ and an intercept of k_∞. “b” is klinkenberg slippage function.
- Slope is a function of molecular weight and molecular size.

$$k_g = k_\infty \left[1 + \frac{b}{P_m} \right]$$



$$P_m = \frac{P_1 + P_2}{2}$$



The klinkenberg effect plot

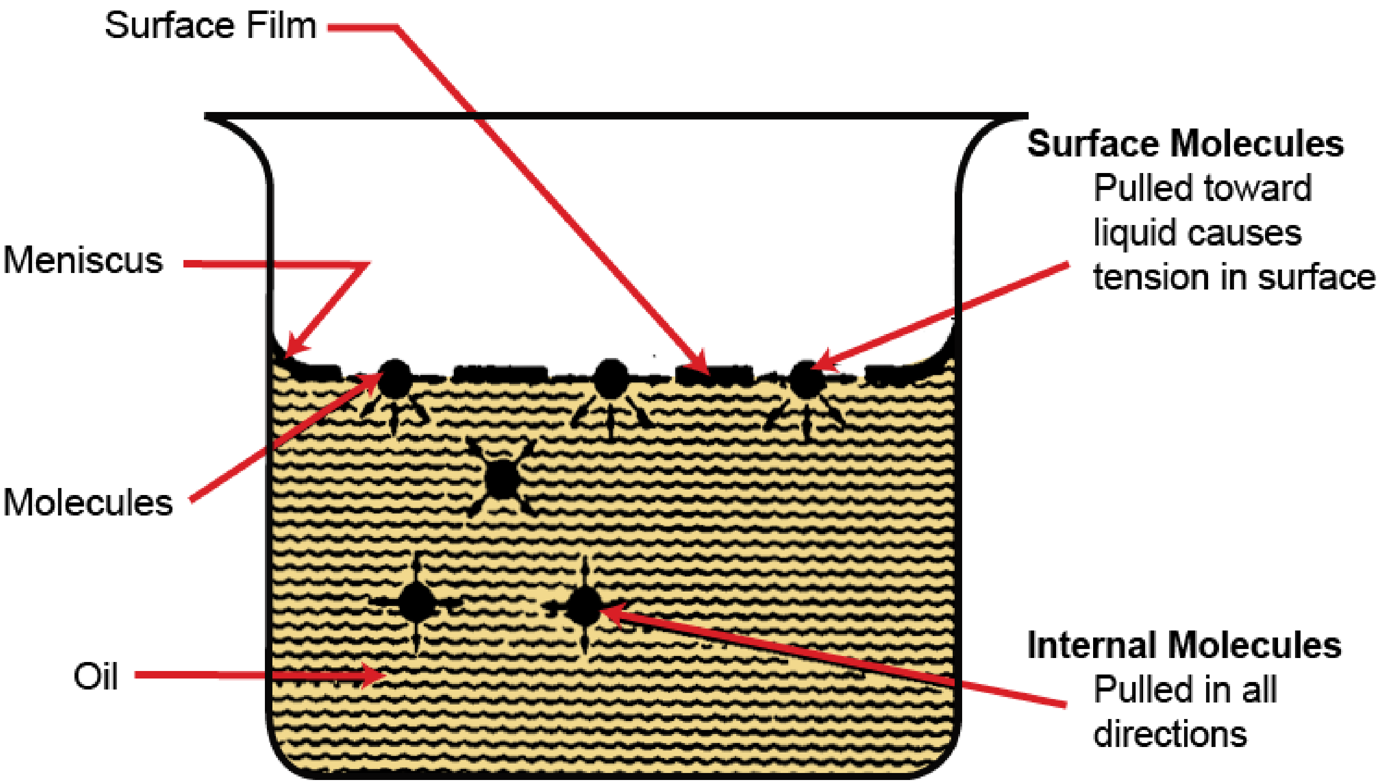
Rock and Fluid Interaction

- Interfacial tension.
- Capillary pressure.
- Wettability.
- Relative permeability.
- Stock tank oil initially in place (STOIIP).

Interfacial Tension

- Interfacial tension is a force at the interface that acts to decrease the area of the interface.
- A drop of water can hang down from the edge of a glass tube using the force at the interface.
- However, when the interfacial tension is weaker, only a smaller (lighter) drop can hang down from the edge of the glass.
- The interfacial tension can be measured using this phenomenon.

- The reason why surface tension is decreased when something is adsorbed on the surface.
  - The attractive force between water molecules is greater than that between other molecules because of the hydrogen bonding.
  - At the surface, the attractive force works only from inside since there is no water on the outside (air side), so a water molecule on the surface is strongly attracted toward the inside.
  - This force is called “surface tension”. However, when something is adsorbed on the water surface, interactions between the adsorbed molecules themselves and also the adsorbed molecules and the water occur at the surface, so that the surface tension decreases.

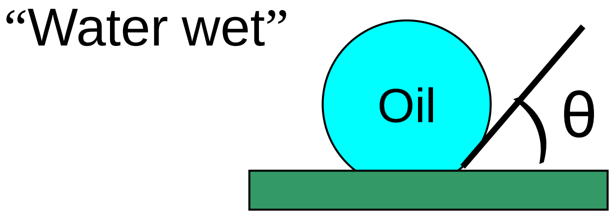


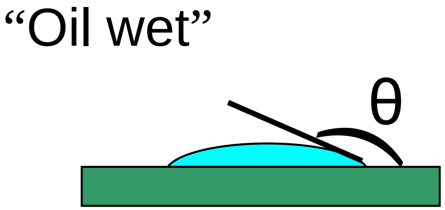
Surface Molecules
Pulled toward liquid causes tension in surface

Internal Molecules
Pulled in all directions

Wettability

- The wettability of a liquid is defined as the contact angle between a droplet of the liquid in thermal equilibrium on a horizontal surface.





- The wetting angle θ is given by the angle between the interface of the droplet and the horizontal surface.
- The liquid is seemed wetting when 90<θ<180 and non-wetting when 0<θ<90.

- The wetting phase will tend to spread on the solid surface and a porous solid will tend to imbibe the wetting phase.
- Rocks can be water wet, oil wet or intermediate wet.
- The intermediate state between water wet and oil wet can be caused by a mixed-wet system, in which the surfaces are not strongly wet by either water or oil.

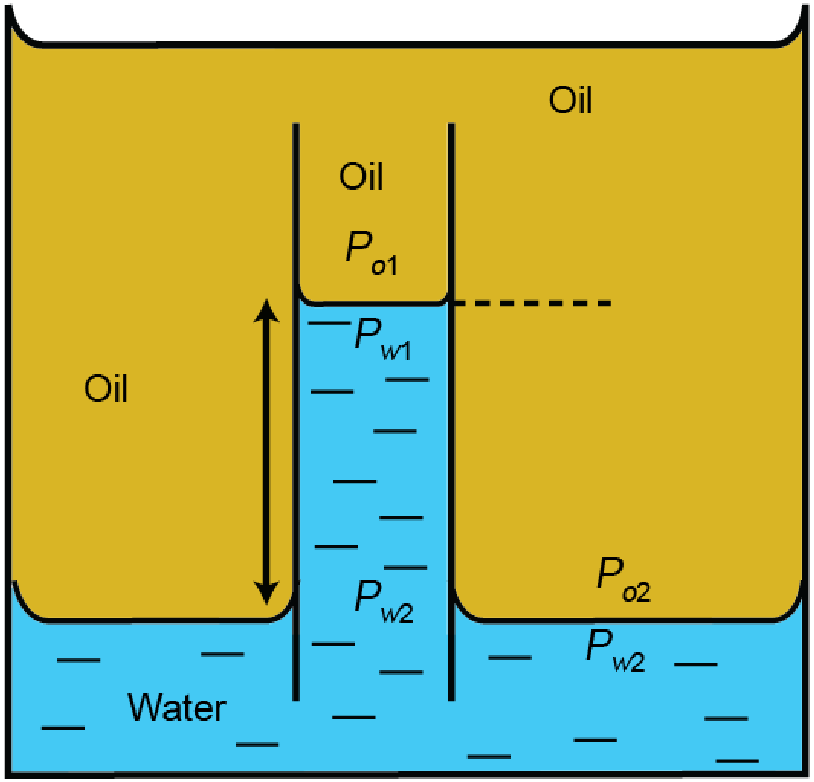
Capillary Pressure

- Capillary pressure is the pressure difference existing across the interface separating two immiscible fluids.
- It is defined as the difference between the pressures in the non-wetting and wetting phases. That is:

$$P_c = P_{nw} - P_w$$

- For an oil-water system (water wet): $P_c = P_o - P_w$
- For a gas-oil system (oil-wet): $P_c = P_g - P_w$

- Oil-water system.



$$P_{a2} = P_{w2}$$

$$P_{w2} = P_{w1} + h\rho_w g$$

$$P_{o2} = P_{o1} + h\rho_o g$$

$$\text{Since, } P_{w2} = P_{o2}$$

$$\text{Then, } P_{w1} + h\rho_w g = P_{o1} + h\rho_o g$$

$$\text{Therefore, } P_{o1} - P_{w1} = (\rho_w - \rho_0) hg$$

$$\text{That is, } P_c = (\rho_w - \rho_o) hg$$

Relative Permeability

- Relative permeability measurements are made routinely on core samples, to define the relative amounts of fluids that will flow through the rocks when more than one fluid phase is flowing.
- Definitions are:

$$k_{ro} = \frac{k_o}{k_a} \qquad k_{rw} = \frac{k_w}{k_a} \qquad k_{rg} = \frac{k_g}{k_a}$$

where:

o, w, g = oil, water, gas

k_r = relative permeability

k = permeability to a specific fluid, o, w, or g

k_a = theoretical "air" permeability

STOIIP

- In place volumes of oil is always quoted at surface conditions.

$$\text{STOIIP} = 7758 \text{ x BV x } \phi \text{ x } S_o \text{ x } \frac{1}{B_o}$$

where:

STOIIP = Stock tank oil initially in place, barrels

BV = Bulk volume of rock, acre-ft

ϕ = Porosity

S_o = Oil saturation

B_o = Oil formation volume factor, reservoir bbl/STB

Exercise 2

An oil well has been drilled and completed. The production zone has been encountered at depth 5,220 – 5,354 ft. The log analysis showed that:

Average porosity = 21%
Water saturation = 24%
Formation volume factor = 1.476 bbl/STB
Area = 93 acres

Calculate the STOIIP.

Type of Reservoir

- Oil Reservoir.
  - Contain mainly oil with or without free gas (gas cap).
  - Can be divided into two:
    - Undersaturated Oil Reservoir ($P_{res} > P_b$) - no free gas exists until the reservoir pressure falls below the bubblepoint pressure.
    - Saturated Oil Reservoir ($P_{res} < P_b$) – free gas (gas cap) exists in the reservoir.
- Gas Reservoir

Recovery

Recovery of hydrocarbons from an oil reservoir is commonly recognised to occur in several recovery stages. These are:

- Primary Recovery.
  - the recovery of hydrocarbons from the reservoir using the natural energy of the reservoir as a drive.
- Secondary Recovery.
  - the recovery aided or driven by the injection of water or gas from the surface.

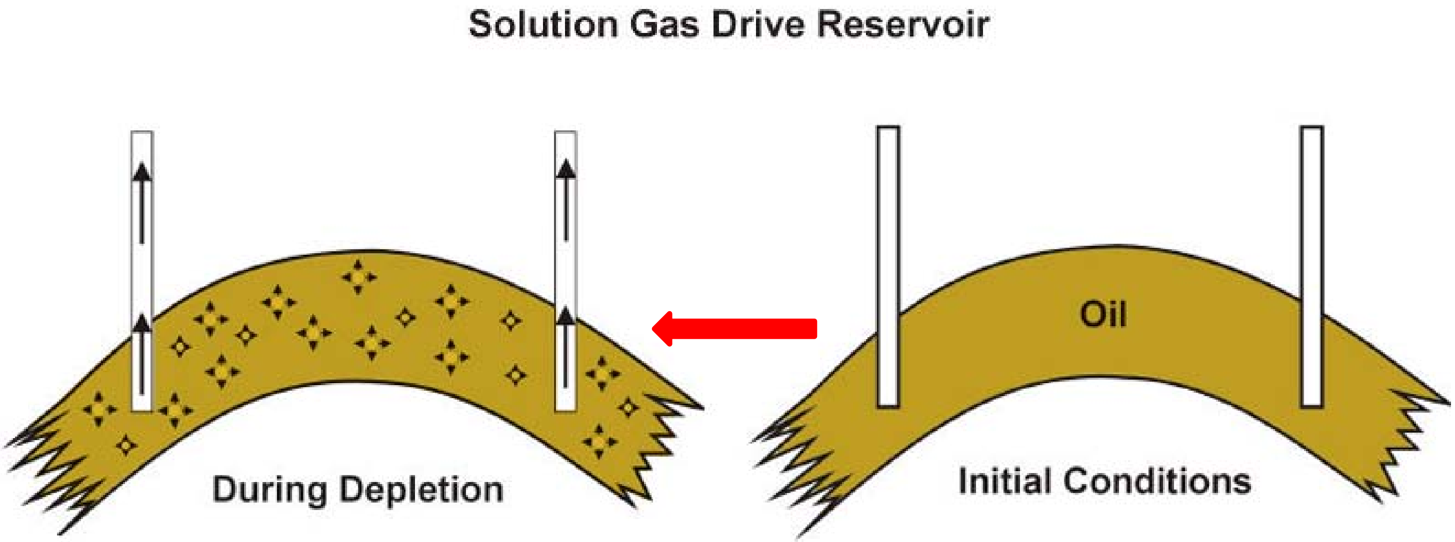
- Tertiary Recovery (Enhance Oil Recovery – EOR).
  - A range of techniques broadly labelled ‘Enhanced Oil Recovery’ that are applied to reservoirs in order to improve flagging production.
- Infill Recovery.
  - Carried out when recovery from the previous three phases have been completed. It involves drilling cheap production holes between existing boreholes to ensure that the whole reservoir has been fully depleted of its oil.

Drive Mechanism

- The natural energy of the reservoir used to transport hydrocarbons towards and out of the production wells.
- There are five important drive mechanisms (or combinations).
  - Solution Gas Drive.
  - Gas Cap Drive.
  - Water Drive.
  - Gravity Drainage.
  - Combination or Mixed Drive
- A combination or mixed drive occurs when any of the first three drives operate together or when any of the first three drives operate with the aid of gravity drainage.

Solution Gas Drive

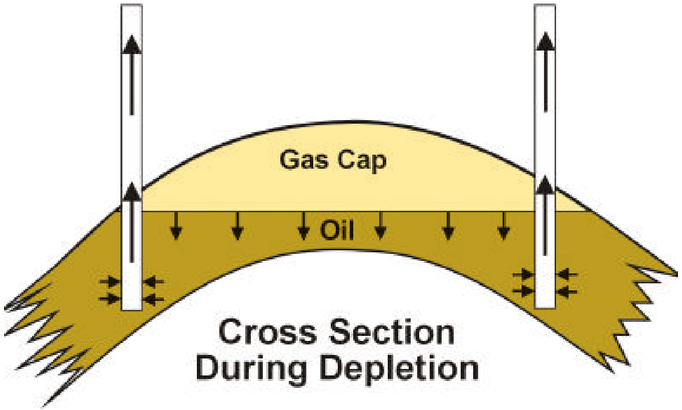
- This mechanism (also known as depletion drive) depends on the associated gas of the oil.
- The virgin reservoir may be entirely liquid, but will be expected to have gaseous hydrocarbons in solution due to the pressure.
- As the reservoir depletes (due to production), the pressure falls below the bubble point, and the gas comes out of solution to form a gas cap at the top. This gas cap pushes down on the liquid helping to maintain pressure.
- The exsolution and expansion of the dissolved gases in the oil and water provide most of the reservoirs drive energy.


Solution Gas Drive Reservoir
Oil
During Depletion
Initial Conditions

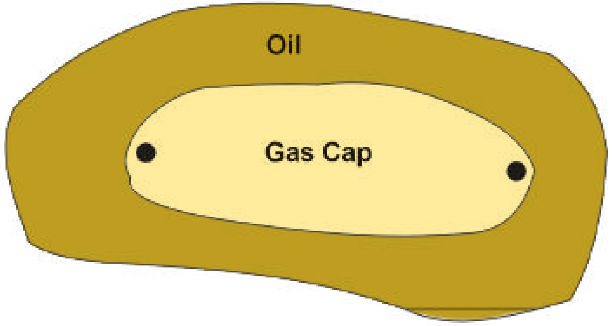
Gas Cap Drive

- In reservoirs already having a gas cap (the virgin pressure is already below bubble point), the gas cap expands with the depletion of the reservoir, pushing down on the liquid sections applying extra pressure.
- The presence of the expanding gas cap limits the pressure decrease experienced by the reservoir during production.

Gas Cap Drive Reservoir



Cross Section
During Depletion



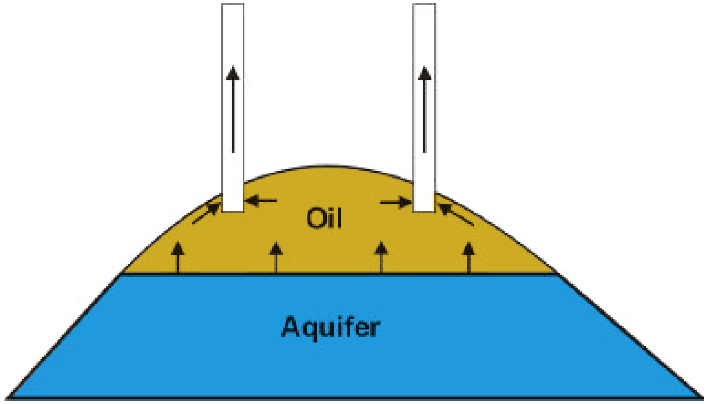
Map View
During Depletion

Water Drive

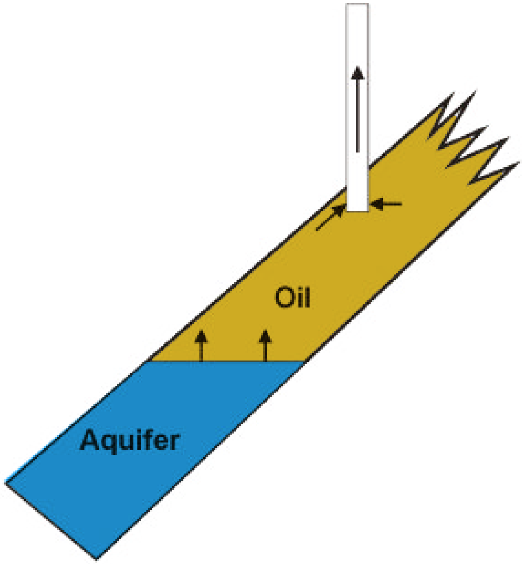
- The drive energy is provided by an aquifer that interfaces with the oil in the reservoir at the oil-water contact (OWC).
- As the hydrocarbons depleted (production continues), and oil is extracted from the reservoir, the aquifer expands slightly. If the aquifer is large enough, this will translate into a large increase in volume, which will push up on the hydrocarbons, and thus maintaining the reservoir pressure.
- Two types of water drive are commonly recognised: Bottom water drive and Edge water drive.

Type of Water Drive

Water Drive



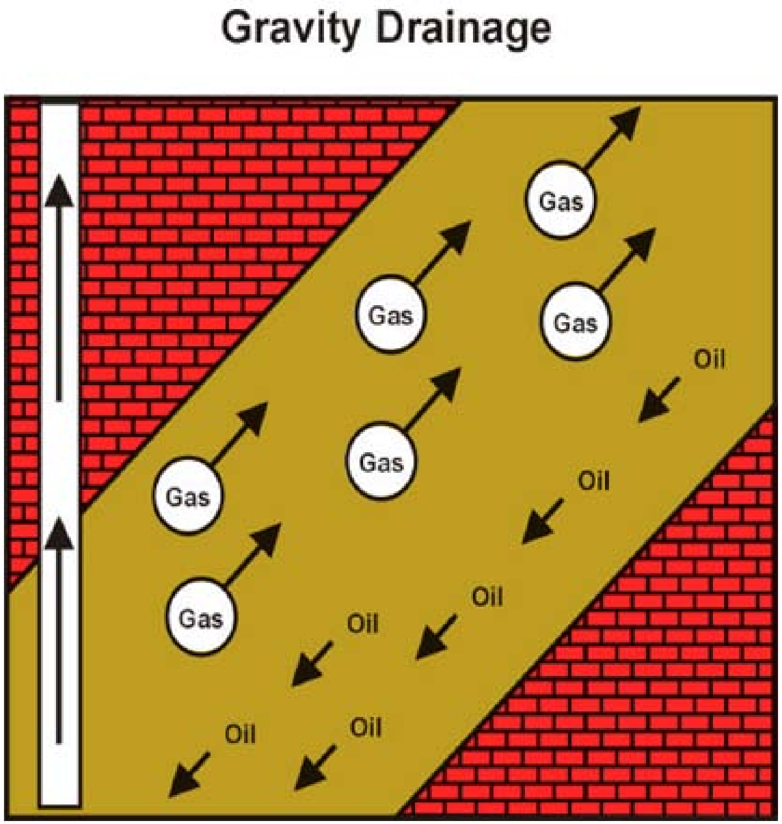
Bottom Water Drive



Edge Water Drive

Gravity Drainage

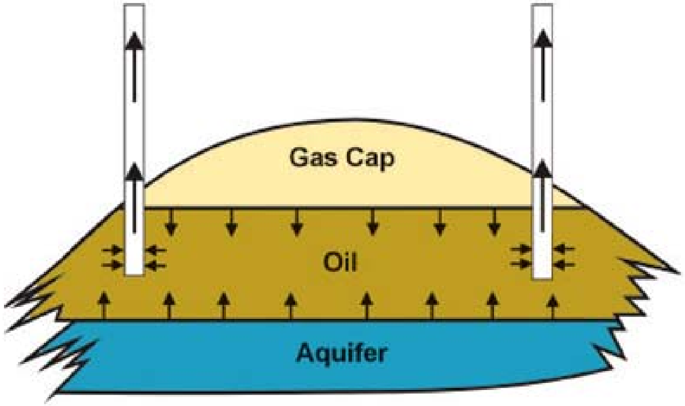
- The density differences between oil and gas and water result in their natural segregation in the reservoir. This process can be used as a drive mechanism, but is relatively weak, and in practice is only used in combination with other drive mechanisms.

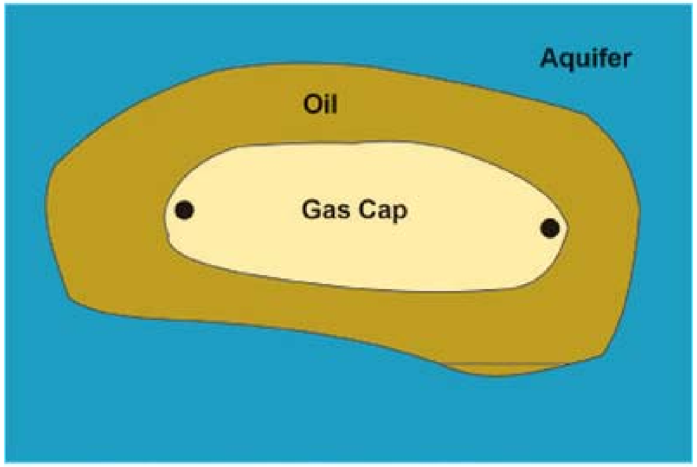


Combination

- In practice a reservoir usually incorporates at least two main drive mechanisms.

Mixed Drive Reservoir





Map View During Depletion

Secondary Recovery

- Secondary recovery is the result of human intervention in the reservoir to improve recovery when the natural drives have diminished to unreasonably low efficiencies.
- Two techniques are commonly used:
  - Waterflooding – involve injection of water at the base of a reservoir to:
    - Maintain the reservoir pressure, and
    - Displace oil towards production wells.
  - Gas Injection - This method is similar to waterflooding in principal, and is used to maintain gas cap pressure even if oil displacement is not required

Tertiary Recovery (EOR)

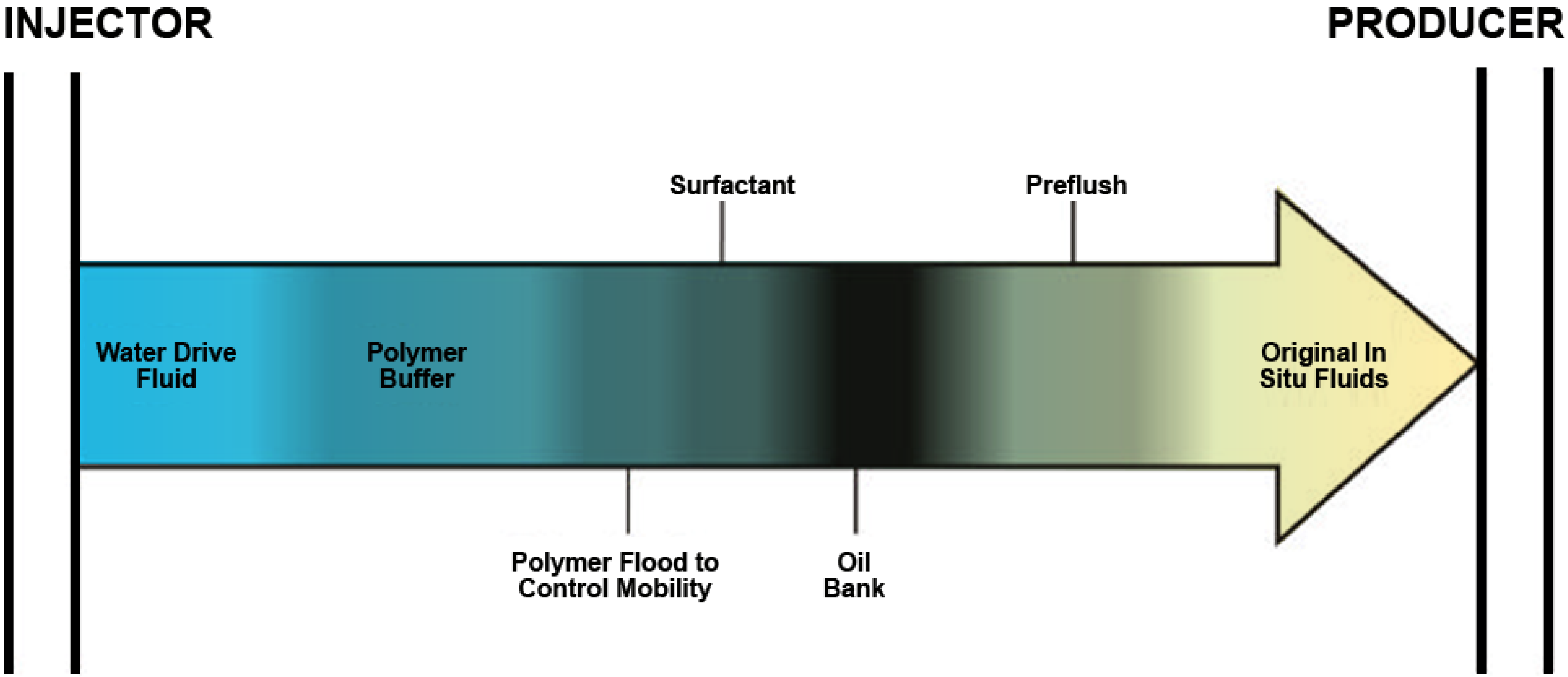
- Primary and secondary recovery methods usually only extract about 35% of the original oil in place. Clearly it is extremely important to increase this figure.
- Many enhanced oil recovery methods have been designed to do this, and a few will be reviewed here. They fall into three broad categories:
    - Thermal EOR
    - Chemical EOR
    - Miscible Gas
- All are extremely expensive, are only used when economical.

Thermal EOR

- These processes use heat to improve oil recovery by reducing the viscosity of heavy oils and vaporising lighter oils, and hence improving their mobility.
- The techniques include:
  - Steam Injection.
  - In-situ combustion (injection of a hot gas that combusts with the oil in place.
  - Increasing the relative permeability to oil (micellar and alkaline floods).
- Thermal EOR is probably the most efficient EOR approach.

Chemical EOR

- These processes use chemicals added to water in the injected fluid of a waterflood to alter the flood efficiency in such a way as to improve oil recovery.
- This can be done in many ways, examples are listed below:
  - Increasing water viscosity (polymer floods).
  - Decreasing the relative permeability to water (cross-linked polymer floods).
  - Microwave heating downhole.
  - Hot water injection.



INJECTOR

PRODUCER

Surfactant

Preflush

Water Drive Fluid

Polymer Buffer

Original In Situ Fluids

Polymer Flood to Control Mobility

Oil Bank

The Chemical EOR Process

Miscible Gas Flooding

- This method uses a fluid that is miscible with the oil. Such a fluid has a zero interfacial tension with the oil and can in principal flush out all of the oil remaining in place.
- In practice a gas is used since gases have high mobilities and can easily enter all the pores in the rock providing the gas is miscible in the oil.
- Three types of gas are commonly used:
    - CO_2
    - N_2
    - Hydrocarbon gases.