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RESERVOIR ROCK PROPERTIES **IS NOT** ROCKET SCIENCE

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What is this magazine?

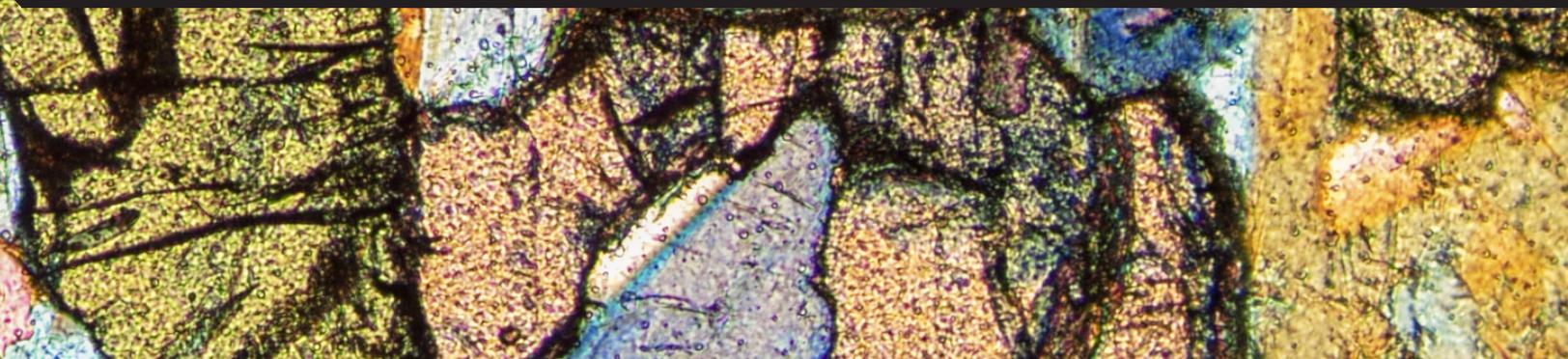
This magazine is a compiled effort of several students and the class instructor to summarize the different reservoir rock properties into a simple and easy-to-follow format with a one-page article covering each property. The magazine highlights each property with a basic knowledge that intends to convey a general understanding of the covered topics. The purpose of this magazine is to give a quick overview of the rock properties used in petroleum engineering and act as a quick refresher to those who studied them before. This magazine should not be used as a sole source of revising but more as complementary material to aid the understanding of the reservoir rock properties.

Why studying Reservoir Rock Properties is important?

Reservoir rock properties are part of petrophysics, which is the study of rock properties and rock-fluid properties. Reservoir rock properties are essential aspects of understanding hydrocarbon reservoirs. Those properties should help in estimating the amount of hydrocarbons in reservoirs as well as understanding the production behavior of hydrocarbons.

Who should read this magazine?

Geologists, petrophysicists, petroleum engineers, or any person interested in understanding reservoir rock properties.



CONVERSION OF UNITS

Length

1 ft = 0.3048 m = 12 in
1 m = 3.281 ft = 39.37 in = 100 cm

Mass

1 lbm = 0.45359 kg
1 kg = 2.2046 lbm = 1000 g

Interfacial Tension

1 N/m = 1000 mN/m = 1000 dyne/cm

Volume

1 ft³ = 0.02831 m³ = 28.3168 L = 0.178 bbl = 0.178 RB
1 m³ = 35.29 ft³ = 1000 L

Pressure

1 atm = 101.3 kPa = 1.013 bar = 14.696 lbf/in² (psia)
1 psia = 6.89 kPa = atm/14.696
1 Pa = 1 N/m² = 1 kg/m.s² = 10⁻⁵ bar = 1.450 x 10⁻⁴ lbf/in² = 10 dyne/cm²
psia = psig +14.7

Density

1 g/cc = 1000 kg/m³ = 62.427 lb/ft³ = 8.345 lb/gal = 0.03361 lb/in³

Viscosity

1 cP = 0.01 poise = 0.01 g/cm.s = 0.001 kg/m.s = 0.001 n.s/m² = 0.001 Pa.s
= 0.01 dyne.s/cm² = 6.72 x 10⁻⁴ lbm/ft.s = 2.09 x 10⁻⁵ lbf.s/ft²

Metric Prefixes

Prefix	Symbol	Multiplication Factor
giga	G	10 ⁹
mega	M	10 ⁶
kilo	k	10 ³
centi	c	10 ⁻²
milli	m	10 ⁻³
micro	μ	10 ⁻⁶
nano	n	10 ⁻⁹

Oilfield Prefixes

Prefix	Symbol	Multiplication Factor
Thousand	M	10 ³
Million	MM	10 ⁶
Billion	MMM or B	10 ⁹
Trillion	T	10 ¹²

Area

1 ft² = 0.092903 m² = 144 in²
1 m² = 10.7649 ft² = 10000 cm²

Force

1 lbf = 4.44822 N = 32.2 lbm.ft/s²
1 N = 0.2248 lbf = 1 kg.m/s²

Permeability

1 D = 1000 mD = 9.869233 x 10⁻¹³ m²

What is Porosity?

Porosity (ϕ) is the fraction or percentage of empty volume that exists in a rock over the total volume. This is where water, oil and gas reside in a rock. Think of the reservoir like a sponge, the way a sponge absorbs water in the empty spaces is the same way that the fluids occupy the pore spaces in a rock. The general formula for porosity is:

$$\phi = \frac{V_p}{V_b} = \frac{V_b - V_m}{V_b}$$

where:

ϕ = porosity [fraction or %]

V_p = pore volume [cm³ or ml]

V_b = bulk volume [cm³ or ml]

V_m = matrix volume [cm³ or ml]

Types of Porosity

There are two types of porosity:

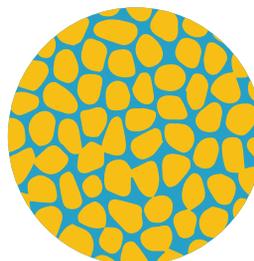
- Total porosity (ϕ_t)
- Effective porosity (ϕ_e)

The total porosity takes all the pore space in a rock into consideration. Whereas, effective porosity, is the fraction of the volume of interconnected space in a rock over the bulk volume. As petroleum engineers, we mostly care about the effective porosity. Imagine a school with an area of 100 m², 25 m² of those 100 m² are occupied by five hallways, and for simplicity let us say all the hallways have the same area. Now imagine that two of those hallways are closed. Students then can only walk through three of the hallways, or 15 m². In the same sense, fluids in the rock can only flow through pores that are not closed but are connected.

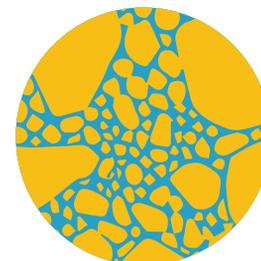
Factors Affecting Porosity

1. Primary porosity – developed during the burial of the rock:

Sorting



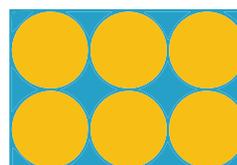
Well sorted



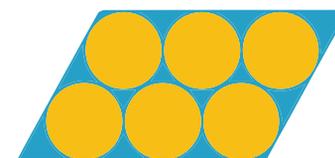
Poorly sorted

2. Secondary porosity (induced) – developed after deposition due to external factors:

a. Compaction due to stress (decreases porosity):

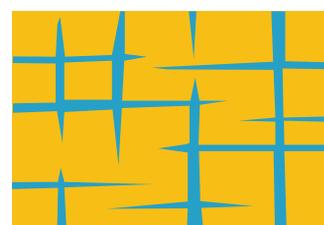


Unpacked



packed

b. Fractures (increase porosity):



c. Dissolutions (Vugs) (increase porosity):



Porosity is the fraction of a rock that consists of void space. A key aspect in studying porosity is studying rock compressibility.

Rock Compaction

Porosity is reduced by compaction, and the reduction is a function of the burial depth of the rock. Isothermal compressibility is defined as the change of volume per unit pressure change at constant temperature.

Effects of Compaction

- Changes in packing
- Deformation of rock fragments

Simplifying Assumptions

- Reservoirs are isothermal
- As pressure increases, material volume decreases
- As pressure decreases, material volume increases

These assumptions are used to derive the compressibility equation shown below

$$c = -\frac{1}{V} \frac{dV}{dP}$$

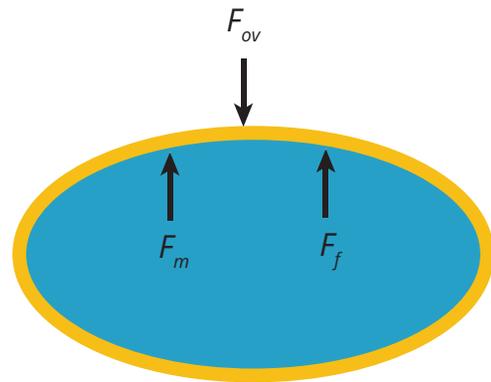
where:

- c = coefficient of isothermal compressibility [1/psia]
- V = volume [ft³]
- P = pressure [psia]

Types of Compressibility

Compressibility plays a major role on reservoir performance. It is divided into three types:

- Matrix Compressibility, c_m
- Pore or formation Compressibility, $c_{p/f}$
- Bulk Compressibility, c_b



For static conditions;
The summation of forces should equal zero

$$F_{ov} = F_m + F_f$$

Where F_{ov} is the overburden force, F_m is the matrix force resisting deformation, and F_f is the fluid force.

Similarly for pressures,

$$P_{ov} = P_m + P_f$$

As fluids are produced from a reservoir, the fluid pressure in the pores decreases; however, the overburden pressure remains constant causing the following effect:

1. Force on matrix increases
2. Bulk volume decreases
3. Pore volume decreases

This effect pushes some fluids out of the reservoir as the pore volume is decreasing with compaction. Also, this might cause subsidence, where formation thickness decreases to compensate for the produced fluids.

What is Liquid Permeability?

Pores usually contain water in them referred to as brine. Brine is water that contains more dissolved salt than typical seawater. In other words, brine is a solution of salt in water.

Permeability is a measure of the fluid conductivity of the rock, which means that permeability is the term used for fluid transport.

Understanding Permeability

It is important to understand permeability, as it influences the production of hydrocarbons. As previously discussed hydrocarbons are stored in the pores of the reservoir rocks.

Now you might be wondering what the relationship between porosity and permeability is. Permeability is the ability of fluids to be transported through porous rocks. If the pore spaces in rocks are not connected, then the rock is not permeable. The fluid then, will be trapped and unable to move. If the pore spaces in rocks are connected, then fluid can be transported so it is permeable. The figure below provides an illustration of how low and high permeability look like.



Low permeability
region

High permeability
region

Permeability can be calculated using Darcy's law for 1-D, single phase liquid (in Darcy's units):

$$q = \frac{kA}{\mu} \frac{dP}{dx}$$

Where

k = permeability [D]

$\frac{dP}{dx}$ = pressure gradient [atm/cm]

A = cross sectional area [cm²]

μ = viscosity of liquid [cP]

q = volumetric flow [cm³/s]

When finding the permeability using Darcy's law, there are certain conditions that must be assumed for Darcy's law to be valid:

- The pore spaces should be fully saturated with a single phase; water, oil, or gas.
- The flow must be laminar.
- The flow must be at steady-state condition.

Introduction

Often dry gas (He, N₂, air) is used in the laboratory for permeability determination since it is readily available and is relatively less reactive with the rock.

Gas Permeability

Since gasses are compressible, the average pressure P_m needs to be used, where:

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

Considering an ideal gas behavior of gas, we can assume:

$$P_1 q_1 = P_2 q_2 = P_m q_m$$

Thus, Darcy's law equation becomes:

$$P_{sc} q_{sc} = P_m q_m$$

$$q_{sc} = \frac{kA(P_1^2 - P_2^2)}{2\mu_g L P_{sc}}$$

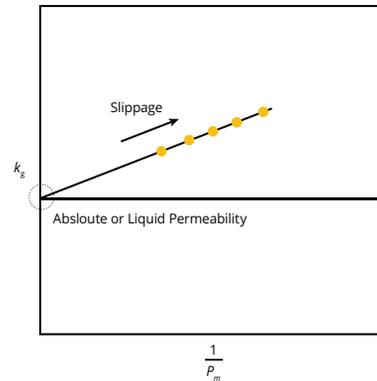
Where

- q_{sc} = gas flowrate at standard conditions [cm³/s]
- P_{sc} = pressure at atmospheric conditions [\approx 1 atm]
- k = absolute permeability [D]
- A = cross sectional area [cm²]
- P_1 = inlet pressure [atm]
- P_2 = outlet pressure [atm]
- μ_g = gas viscosity [cP]
- L = length of core [cm]

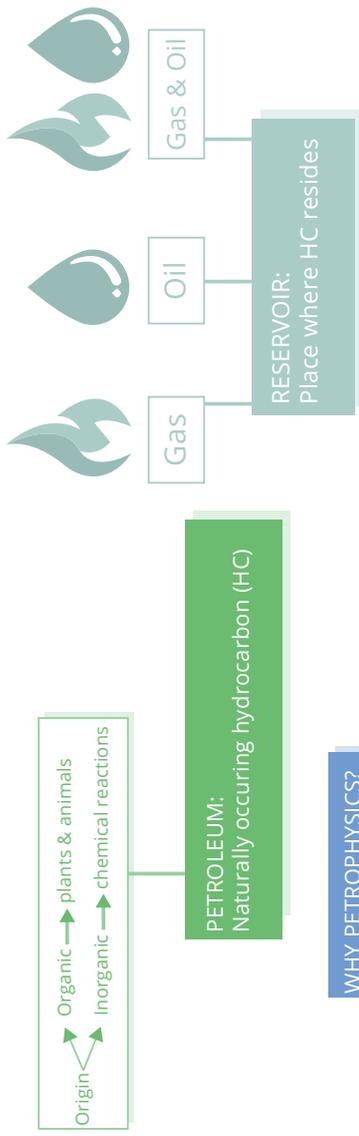
Klinkenberg Effect

Klinkenberg (1941) noticed that permeability measurements using liquids and gasses gave different results. Permeability with air gave a higher value than permeability measurement with water. This phenomenon was attributed to gas slippage at the pore walls. Liquids have zero velocity at the sand grain surface; however, gasses have some finite velocity at the sand grain surface. The slippage results in a higher flowrate for a given pressure differential for the gasses. Klinkenberg related the liquid permeability k_L to gas permeability k_g by the following equation:

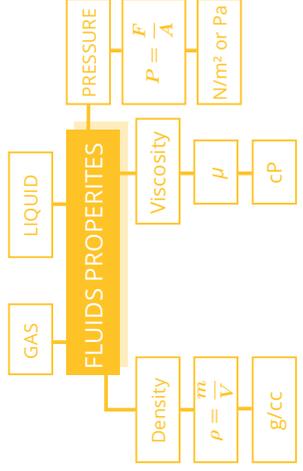
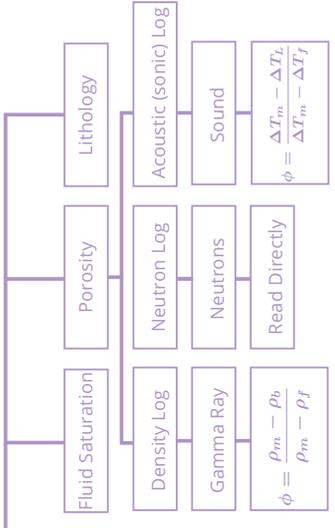
$$k_g = c \frac{1}{P_m} + k_L$$



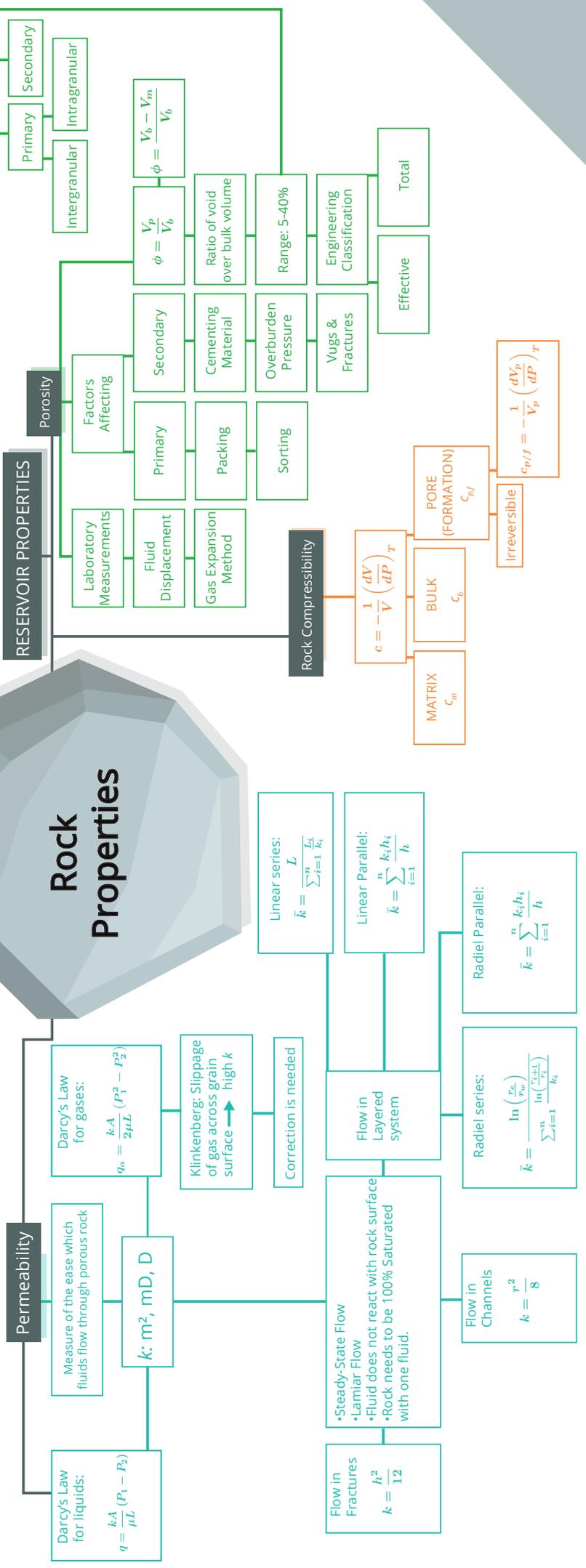
If we observe from the graph, the higher the value of P_m , the lower the value of $1/P_m$. At extremely high pressures (infinite pressure), gasses are believed to behave like liquids. Thus if we extrapolate our $1/P_m$ to zero, it would mean the permeability would be approximately equal to the liquid permeability. The slope c of the line is a function of absolute permeability, type of gas, and average radius of the rock capillaries.



WIRELINE LOGGING:
The acquisition & analysis of geographical data performed as a function of depth



Rock Properties



What is Saturation?

Pores usually contain more than one fluid in them. The fraction of pore space occupied by a specific fluid is called saturation. Saturation is the ratio of fluid volume to the pore volume.

$$S_w = \frac{V_w}{V_p}$$

$$S_o = \frac{V_o}{V_p}$$

$$S_g = \frac{V_g}{V_p}$$

where:

S_w = water saturation [fraction or %]

S_o = oil saturation [fraction or %]

S_g = gas saturation [fraction or %]

V_w = water volume [cm³ or ml]

V_o = oil volume [cm³ or ml]

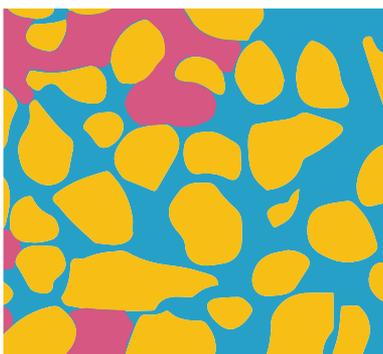
V_g = gas volume [cm³ or ml]

V_p = pore volume [cm³ or ml]

We could then notice that saturations are fractions, and collectively in pores the summation of all saturations should equal 1:

$$S_w + S_o + S_g = 1$$

Look at the figure below for an idea on how fluids look like in a pore



Rock
 water
 Oil or gas

Important Definitions

- **Connate water (S_{wc}):** it is the minimum water saturation which would remain adhered to the pores and not become mobile. During deposition, water saturation is 100% which declines by the migration of oil/gas to (20-30%) and that is the connate water saturation.
- **Irreducible water saturation (S_{wir}):** it is the minimum water saturation in a rock forming a layer of water stuck to the rock surface and that does not move. **Therefore, $S_{wc} = S_{wir}$**
- **Residual oil (S_{or}):** it is the oil left behind (could not be produced) after immiscible displacement. This oil is trapped in the pore spaces and cannot move.

Types of Measurements

There are two methods to determine or measure fluid saturation

- **Direct:** using core samples through:
 - Retort distillation
 - Solvent extraction (Dean-Stark method)
- **Indirect:** capillary pressure and well log analysis (resistivity logs)

Factors Affecting Saturation

There are many factors that affect saturation. For example, core samples from reservoir get affected by filtrate from drilling mud. The mud can usually be water or oil based and depending on the wettability of the rock could affect saturation differently.

Another factor that affects fluid saturation would be the differences in pressure and temperature that are caused by bringing the core sample from the reservoir to the surface. Those differences in pressure and temperature cause fluids such as gas trapped in oil to be released. This is especially important to know when conducting direct measurements to find the fluid saturation using core samples. The reason fluid saturation is very important is that it helps in estimating the amount of hydrocarbons stored in the reservoir.

The formation water (brine) contains dissolved salts which make up the electrolytes and help it conduct current within. These salts dissolve and break up into cations (Na⁺, Ca²⁺), and anions (Cl⁻ and SO₄²⁻). The higher the salt concentration, the better it is at conducting electricity.

Resistivity

Resistivity is a measure of the material's ability to resist the flow of electricity. The unit of resistivity is ohm.m [Ω.m]. The range for a poorly consolidated sand is 0.2 ohm.m to several ohm.m. For well consolidated sands the resistivity ranges from 1 ohm.m to 1000 ohm.m.

Notations for resistivity

R_w = formation water resistivity [Ω.m]

R_o = resistivity of rock with 100% water saturation [Ω.m]

R_t = true formation resistivity [Ω.m]

Factors that affect resistivity

- Water Resistivity
- Formation Porosity
- Formation Lithology
- Type and Amount of Clay

Formation Factor

Formation factor relates R_w to R_o based on an empirical formula/relation developed by Archie (1942). He found out that this correlation is related to three parameters: a , ϕ , and m as shown in the following equation:

$$F = \frac{R_o}{R_w} = a\phi^{-m}$$

where:

a = constant ≈ 1.0 for most formations

ϕ = porosity [fraction]

m = cementation factor ≈ 2 for most formations

Saturation Equation

Archie also found out the saturation equation (resistivity index) which relates R_t to R_o . He found out that this correlation is related to water saturation (S_w) and n is the saturation exponent.

$$I_r = \frac{R_t}{R_o} = S_w^{-n}$$

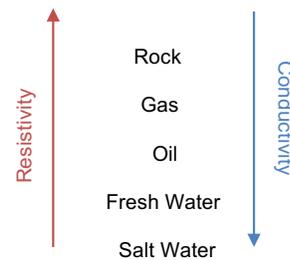
Archie's Equation

Archie's equation is the combination of the formation factor and the saturation equation since R_o is common in both equations. It is used to calculate the water saturation of un-invaded zones near the bore hole using wireline resistivity logs.

Archie's equation:

$$S_w = \sqrt[n]{\frac{aR_w}{\phi^m R_t}}$$

Resistivity of Earth Materials



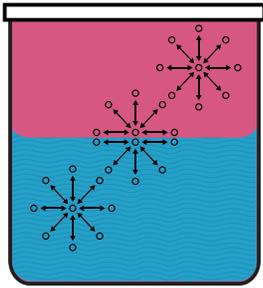
What is Wettability?

Wettability is a fluid's tendency to adhere on a solid surface, while co-existing with another immiscible fluid.

Immiscibility

Immiscible fluids are fluids that do not mix with one another. This is due to an imbalance in the molecular forces between two fluids in contact with one another. These molecular forces present at the interface of two fluids are known as the interfacial tension.

Interface between Immiscible Fluids

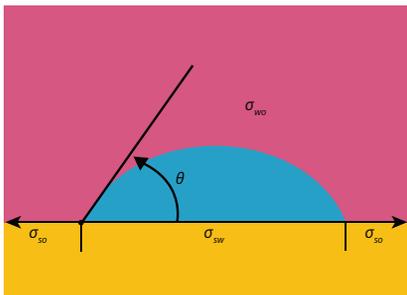


Adhesion Tension

A key factor in determining the wettability of a rock is adhesion, also known as the difference between two solid-fluid interfacial tensions, is expressed with the following equation:

$$A_T = \sigma_{sw} - \sigma_{so} = \sigma_{wo} \cos \theta$$

If the Adhesion tension is positive the denser fluid will wet the rock becoming the wetting phase fluid. For instance, water is the wetting phase in the figure below.



Wetting phase fluid	Non-wetting phase fluid
Occupy smallest pores	Occupy largest pores
Has low mobility	Usually of higher mobility

How to determine the wettability of a rock?

If a water droplet is surrounded by oil then;

Water-Wet	Oil-Wet
$\sigma_{os} > \sigma_{ws}$	$\sigma_{os} < \sigma_{ws}$
$A_T > 0$ (positive)	$A_T < 0$ (negative)
$0^\circ \leq \theta < 90^\circ$	$90^\circ < \theta \leq 180^\circ$

What affects wettability?

- Composition of pore-lining minerals
- Composition of the fluids
- Saturation history

What are the types of wettability?

- Oil- or water-wet
- Neutral- or intermediate-wet
- Fractional- or mixed-wet

Wettability Affects

- Capillary Pressure
- Residual oil saturation
- Relative permeability

What is Capillary Pressure?

Most of hydrocarbon reservoirs contain a minimum of two immiscible fluids. For water and oil, the interface at which the separation happens is called the oil-water contact. Capillary pressure is defined as the pressure difference between the two immiscible fluids at the interface.

To further define the capillary pressure, wettability needs to be recalled. In a heterogeneous system where one fluid wets the surface (wetting phase) in preference to the other fluid (non-wetting phase), the capillary pressure can be calculated as:

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

where:

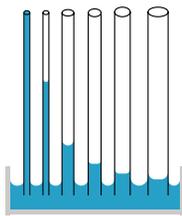
P_c = capillary pressure [Pa]

P_{nw} = pressure of the non-wetting phase [Pa]

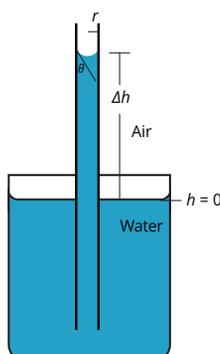
P_w = pressure of the wetting phase [Pa]

Understanding Capillary Pressure from Capillary Tubes

To simplify the study of capillary pressure, porous media in a reservoir can be modeled as a collection of capillary tubes as shown below.



For a water-gas system in a collection of capillary tubes, like in a reservoir, water (wetting phase) rises filling smaller pores and leaves the larger pores to be filled by air (non-wetting phase). The height of the water (shown below) in a capillary tube is a function of the adhesion tension between the air and water, the radius of the tube (shown below), and the density difference between air and water (the two immiscible fluids present).



The height of the water in the capillary tube can be calculated using the following formula:

$$\Delta h = \frac{2\sigma_{wa}\cos\theta}{\Delta\rho_{wa}gr}$$

where:

σ_{wa} = surface tension between air and water [N/m]

g = gravitational acceleration [9.8 m/s²]

$\Delta\rho_{wa}$ = density difference between air and water [kg/m³]

θ = contact angle between the surface and water [°]

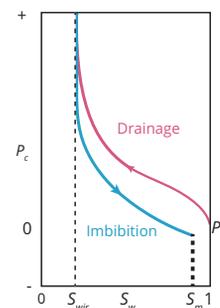
Combining the two previous equations, capillary pressure can also be computed using:

$$P_c = \frac{2\sigma_{wa}\cos\theta}{r}$$

Capillary Pressure Curves

As can be inferred, capillary pressure is very dependent on the wetting phase saturation. To graphically represent the capillary pressure, the capillary pressure curves can be drawn as a function of this saturation. To do that, two fluid flow processes need to be defined over which the capillary pressure varies. These are drainage and Imbibition.

Drainage: The process through which the saturation of the non-wetting phase increases.

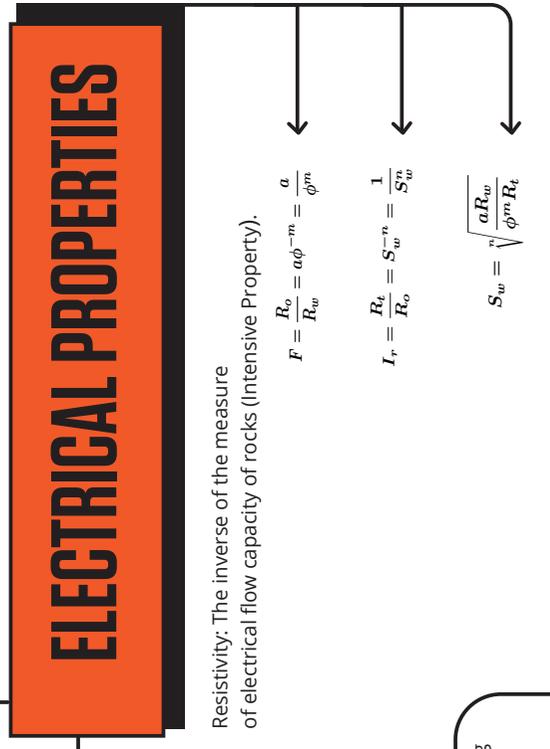
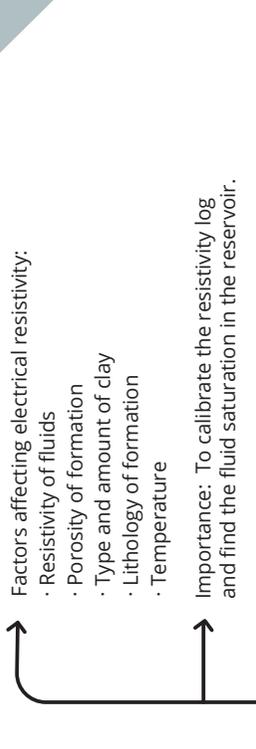
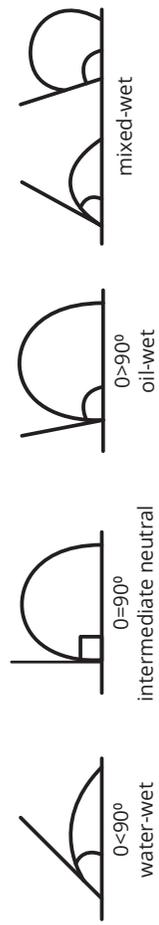
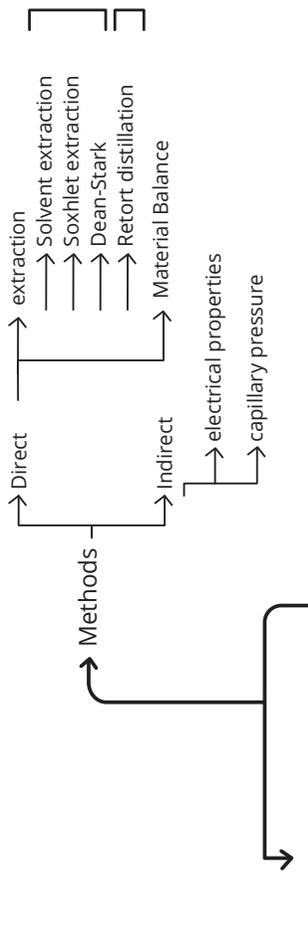


Imbibition: The process through which the saturation of the wetting phase increases.

Parameters used in the figure above are the following:

- S_{wir} = irreducible wetting phase saturation [fraction or %]
- $S_m = 1$ - residual non-wetting phase saturation [fraction or %]
- P_{ct} = threshold capillary pressure, the minimum pressure required to force non-wetting fluid into the largest pore [Pa]

The shapes of these curves are affected by reservoir quality. This includes the pore size distribution, grain sorting, and permeability.

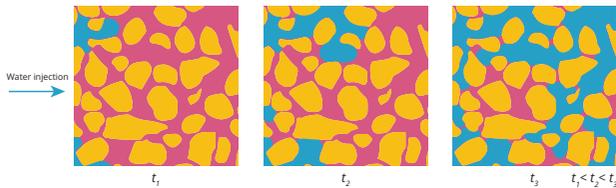


Methods

Method	Pros	Cons
Porous Plate	⊕ Most accurate	⊖ Uses reservoir fluids
Centrifuge	⊕ Fast	⊖ Uses reservoir fluid. Requires calculation of pressure and sat
Mercury Injection	⊕ Fastest	⊖ Does not use reservoir fluid. Least accurate. Requires interpretation

What is permeability?

Permeability is a rock's fluid conductivity, as its ability to allow fluid to flow through its pores. When a pore is completely saturated with only one fluid, the rock's ability to allow that fluid to pass through it is called absolute permeability. However, pores are usually being occupied with more than one fluid (oil, water, and/or gas), and fluids compete to flow through a rock. This is why when producing hydrocarbons by water injection for example; we are interested in the relative permeability of each fluid. The figure below provides a simplistic view of how water is injected in oil filled pores.



What is relative permeability?

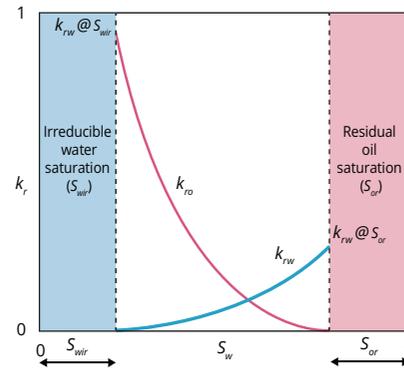
Because pores contain multiple fluids that are interacting with one another, they do not all move through the rock at the same rate. This is why we need to know the relative permeability for each fluid. The effectiveness of a medium to allow a certain fluid (oil, water or gas) to move in it is called effective permeability.

This all comes to play when trying to determine the relative permeability or the ratio of the effective permeability of a fluid at a specific saturation over the absolute permeability.

What affects relative permeability?

- Fluid saturation
- Geometry of the pore spaces
- Wettability

Using a relative permeability curve as the one shown below, we keep track of the relative permeability changes. The reason knowing relative permeability is very important is because it affects the flow characteristics of the reservoir fluids which in turn affect the recovery efficiency of the hydrocarbons when two or more fluids are flowing.



Looking at the figure provided above, we can tell that k_{ro} is reduced with the increase of k_{rw} . This is because they share the same area when they try to flow and when one fluid takes more space the other is forced to take less space. The irreducible water saturation is the minimum water saturation a rock could have, this water cannot be moved or reduced. On the other hand, residual oil saturation occurs during imbibition, where some of the oil we try to produce is trapped in the pore spaces of a rock.

	Permeability	Relative permeability
Equation	$k = \frac{q\mu L}{AdP}$ 1-D, linear flow for single phase liquid	$k_{r,f} = \left(\frac{k_f}{k}\right)$, where f is fluid and can be either water, oil, or gas.
Units	mD, D, or m ²	Dimensionless
Phase	1 phase flow	Multiphase flow

SUMMARY OF ROCK PROPERTIES

Parameter	Symbol	Definition	Importance
Porosity	ϕ	Is the ratio of pore volume to bulk volume	We use porosity to quantify the volume of oil and/or gas in the reservoirs.
Rock Compressibility	c	The relative change of volume per unit pressure	It is part of the recovery mechanisms under primary hydrocarbon production. Also, can cause subsidence which has an environmental impact.
Single Phase permeability	k	A measure of the ease with which fluid flows through a porous rock	We use permeability in determining the rate at which the gas and oil flow to the surface.
Fluid Saturation	S_i , (where i can be water, oil, or gas)	The fraction of pore volume occupied by the fluid	We use fluid saturation to quantify the volume of oil and/or gas in the reservoirs.
Electrical Properties	F and I_r	The rock properties to impede the follow of electric current through a rock. Electrical properties are a function of porosity and fluids in the pore space.	We use electrical properties to calibrate the resistivity log and find the fluid saturation in the reservoir.
Wettability	-	The tendency of a fluid to spread on a solid surface in the presence of another immiscible fluid	We use wettability to help us understand oil production when injecting water as wettability has a primary role in water injection performance.
Capillary Pressure	P_c	The pressure difference between the non-wetting phase and the wetting phase across the interface	We use capillary pressure to determine fluid distribution in the reservoir (initial condition) above the free water level.
Relative Permeability	k_r	Is the ratio of the effective permeability of that phase to the absolute permeability	We use relative permeability to study and understand the multi-phase flow in reservoirs. For instance, we use relative permeability to predict the recovery of oil by water injection.



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