Review of Rock Properties and The Wellbore Environment

By

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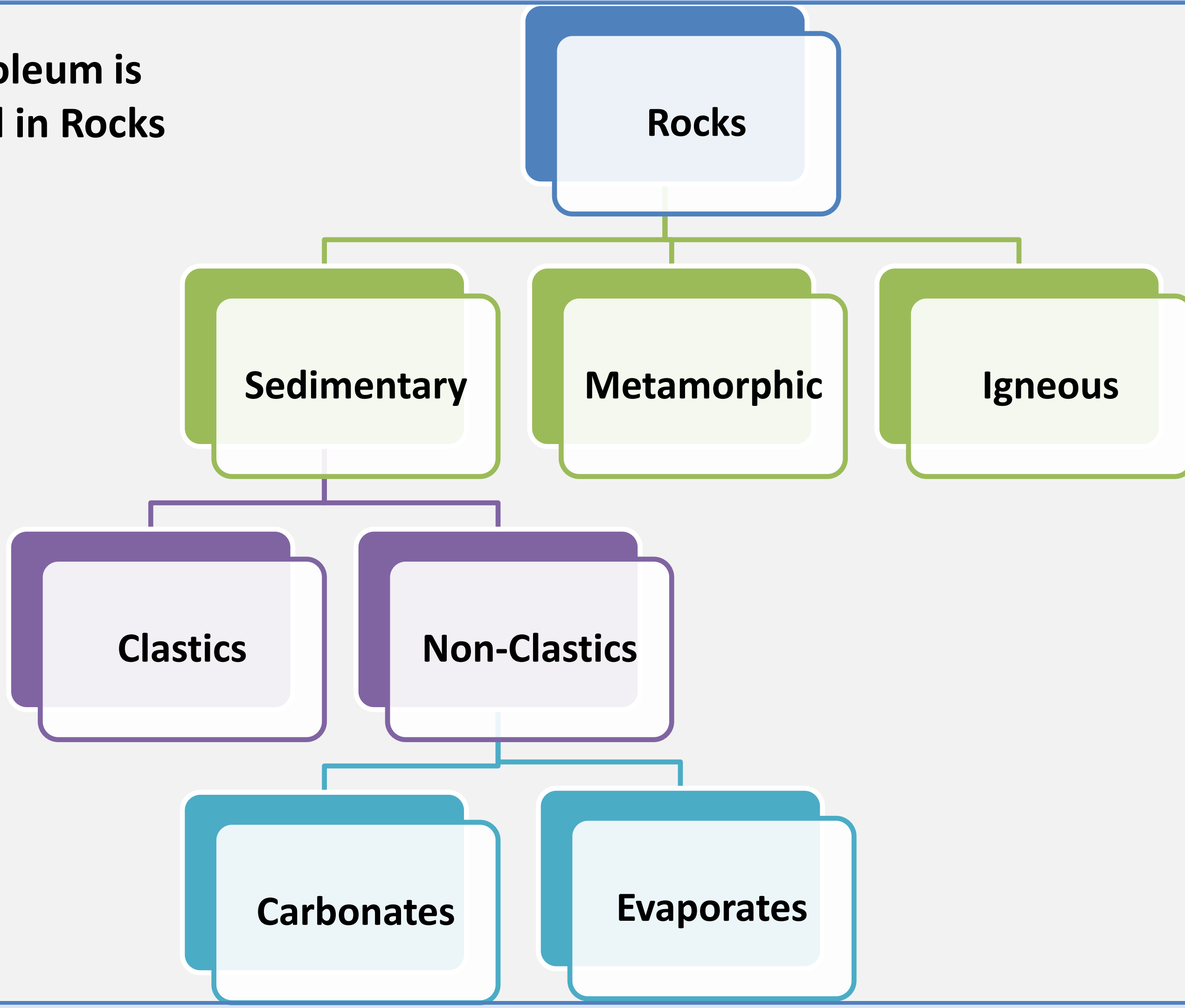
Lecture Outline

- Rock Type and Sedimentary Rocks
- Review of Rock Properties (Petrophysics)
  - Porosity
  - Saturation
  - Permeability
  - Relative Permeability
  - Capillary Pressure
  - Water Salinity
- Formation Temperature
- Formation Pressure Gradient
- Wellbore Drilling
- The Invasion Process and Profile
- Logging Considerations and Corrections

Petroleum Geology

Petroleum is stored in Rocks



Sedimentary Rocks

- Rocks of most interest to petroleum engineers
- Formed at the earth's surface due to deposition of sediments from;
  - Weathered rocks fragments (Clastic or Detrital)
  - Biochemical Activities (formed by organisms)
  - Chemical (precipitation from Solution)
- Rocks are usually deposited in layers

- Clastics (from rock fragments): Siltstone, Sandstone, Mudstone or Shale (Clay), Conglomerates

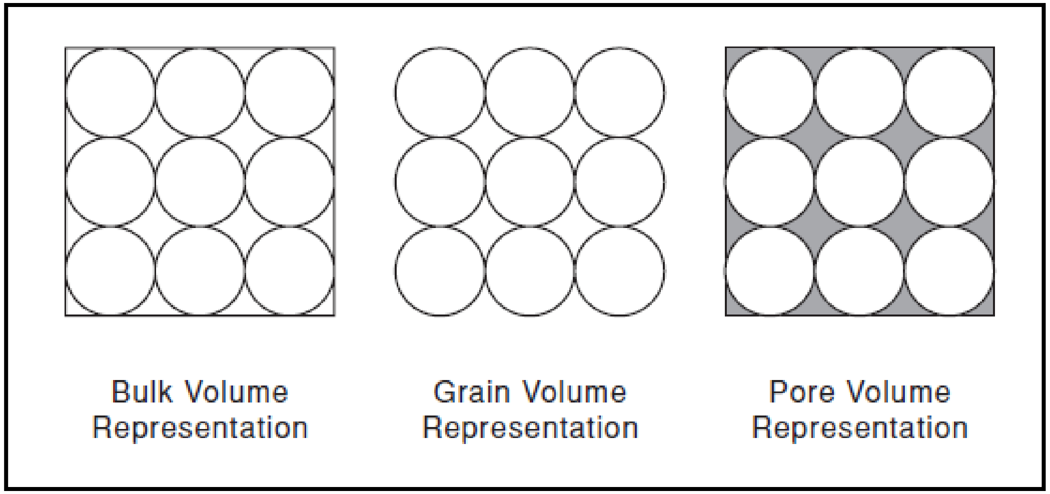
- Non-Clastics (Not from rock fragments)
  - Biochemical
    - Carbonate: Limestone, Dolomite, Coal
  - Evaporates: Anhydrite, Halite (rock Salt), Gypsum

Mineralogy of Some Sedimentary Rocks

Rock Type	Mineral	Chemical Formula
Sandstone	Quartz	SiO2
	Feldspar;	
	Albite	NaAlSi3O8
	Orthoclase (K-Feldspar)	KAlSi3O8
	Anorthite	CaAl2Si2O8
	Plagioclase	NaAlSi3O8 – CaAl2Si2O8
Shale (Clay)	Kaolinite	Al2S12O5(OH)4
	Montmorillonite (Smectite or Bentonite)	(CaNa)(Al,Fe,Mg)4(Si,Al)8(OH)8
	Illite (Muscovite)	KAl2(AlSi3O10)(OH)2
	Chlorite	(Al,Fe,Mg)6(Al,Si)4O10(OH)8
Carbonates	Calcite	CaCO3
	Dolomite	CaMgCO3
Evaporates	Anhydrite	CaSO4
	Halite	NaCl

Porosity

- Measure of the void space in a rock or formation
- $\emptyset = \frac{V_b - V_{gr}}{V_b} = \frac{V_p}{V_b}$
  - $\emptyset$= Porosity, fraction
  - V_b=Bulk volume
  - V_{gr}=grain volume
  - V_p=*pore* volume

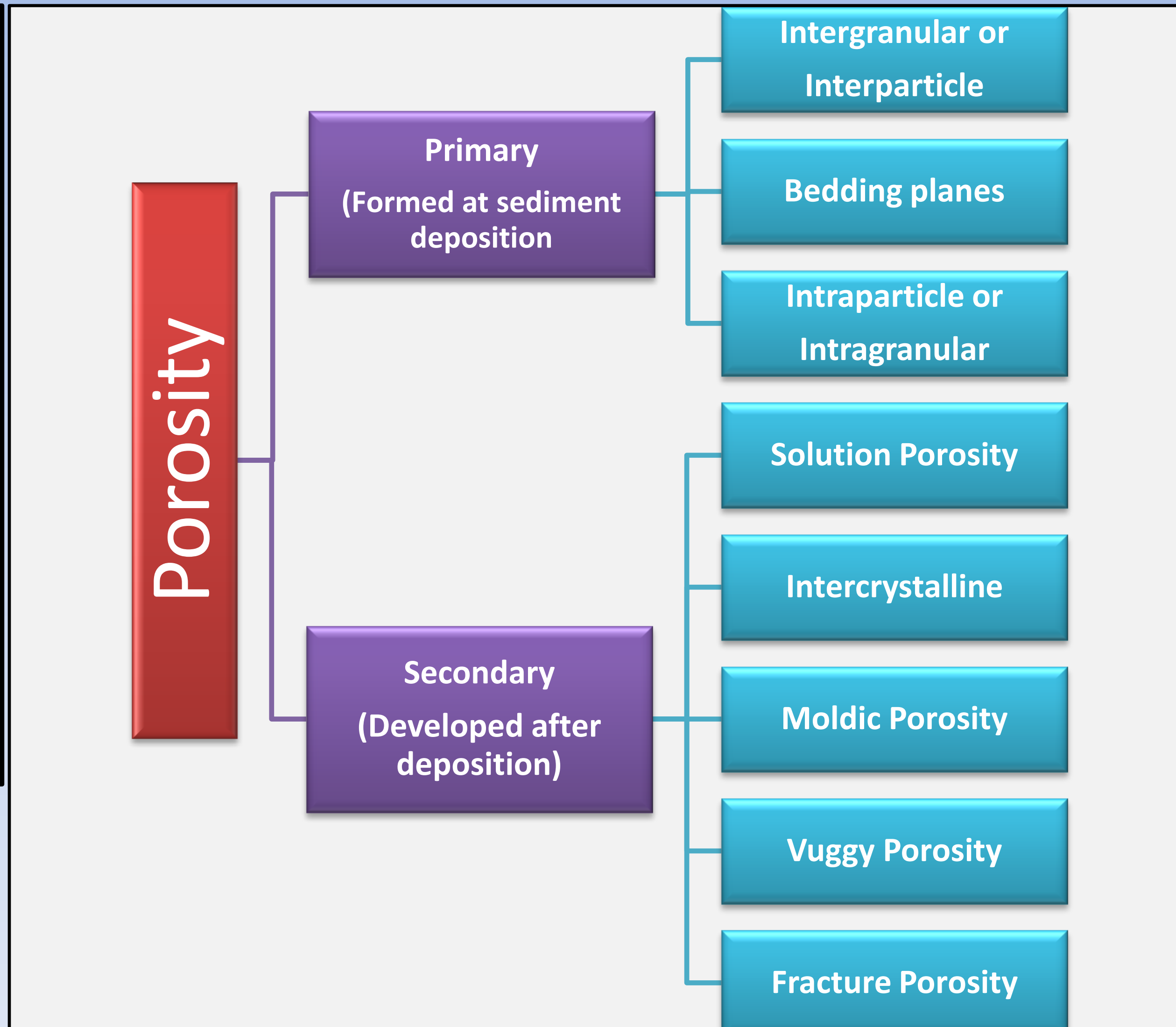


- Types of Porosity
  - **Primary Porosity-** formed at the initial deposition of sediments
  - **Secondary Porosity**-result of geological processes after initial deposition
  - **Effective or Interconnected Porosity-** connected pore spaces
  - **Non-effective, Unconnected, Isolated porosity-** unconnected spaces
  - **Absolute or Total Porosity**=Sum of Effective and Unconnected porosity

Geological Classification of Porosity

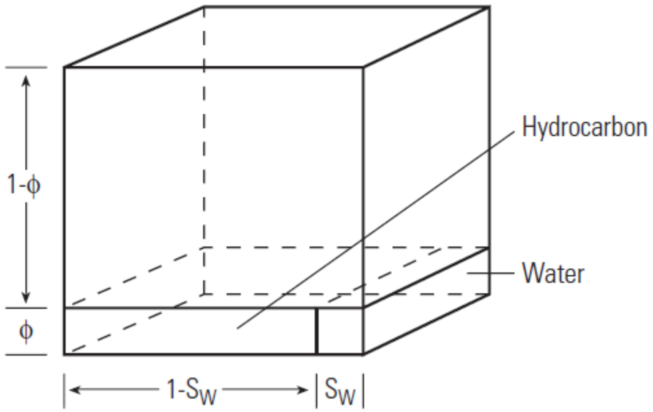
Factors that Control the <u>Magnitude of Porosity</u>

- Grain size distribution, the uniformity or sorting.
- Degree of cementation or consolidation.
- Amount of compaction during and after deposition
- Method of packing; random or close packing.



Fluid Saturation

- Ratio of the volume of a fluid in the pore space to total pore volume, it is denoted by S and a subscript representing the fluid type.



- $S_x = \frac{V_x}{V_p}$
  - S= Saturation
  - Where $x = o, g, or\ w\ representing\ oil, gas\ and\ water\ respectively$
  - V_x= Volume of reservoir fluid *x*
  - *Vp= Reservoir pore volume*

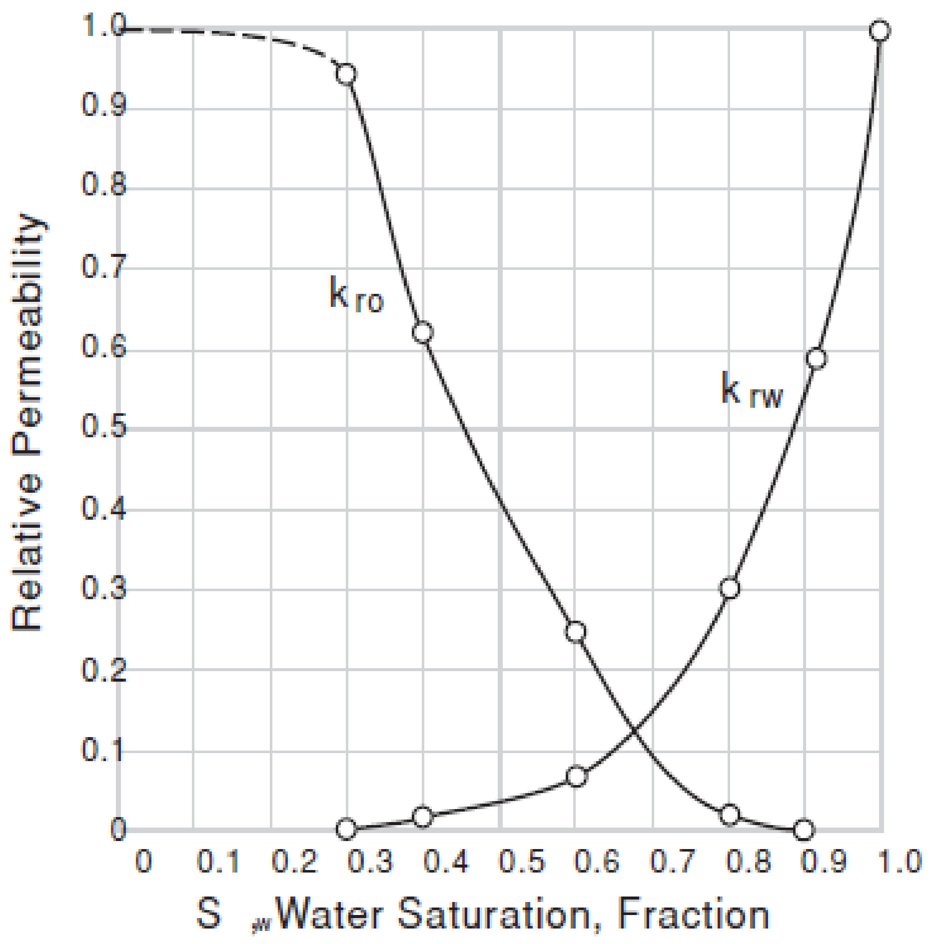
Permeability

- Permeability is a measure of the ability of a porous medium to transmit fluid. Reservoir rocks must not only be porous, they must be permeable.
- Permeability is dependent on;
  - Fluid viscosity
  - Pressure gradient
  - Grain size, sorting and distribution
  - Pore size and pore throat size
  - Tortuosity
  - Clay content and distribution
  - Cementation
  - Presence or absence of fractures

Relative Permeability

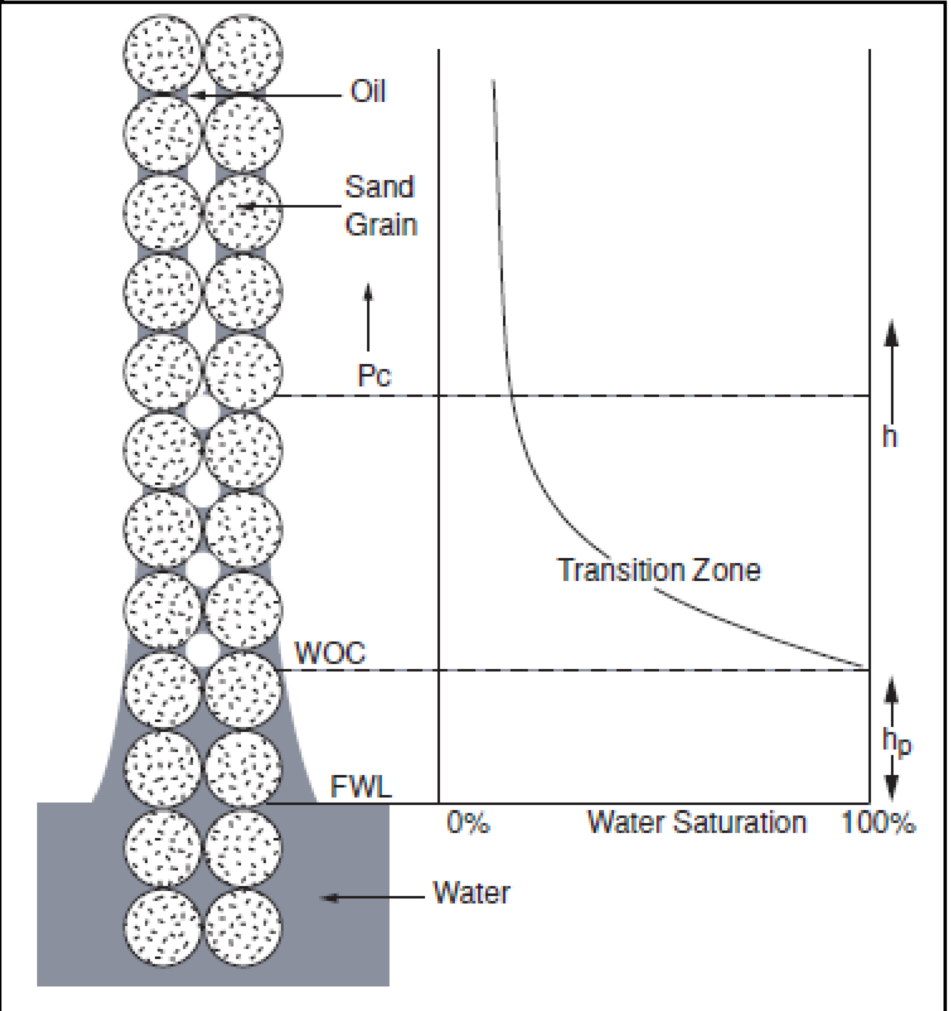
- Absolute permeability- Permeability of the formation when only one fluid is present in the pore spaces.
- Effective Permeability- Permeability to one fluid in the presence of another fluid.
- Relative Permeability-Ratio of the effective permeability to the absolute permeability
- $k_{rx}=\frac{k_x}{k}$
- Where;
- k =*Absolute permeability*
- k_x =*Effective permeability to fluid x (x=o,g,w;* $\sum_x^n k_x < K$ *)*
- k_{rx}=*Relative permeability to fluid x (*k_{rx}*<=1)*

Relative Permeability Curve



Relative permeability can me measured using representative reservoir core samples in the laboratory. It is a SCAL (Special Core Analysis) measurement.

Capillary Pressure

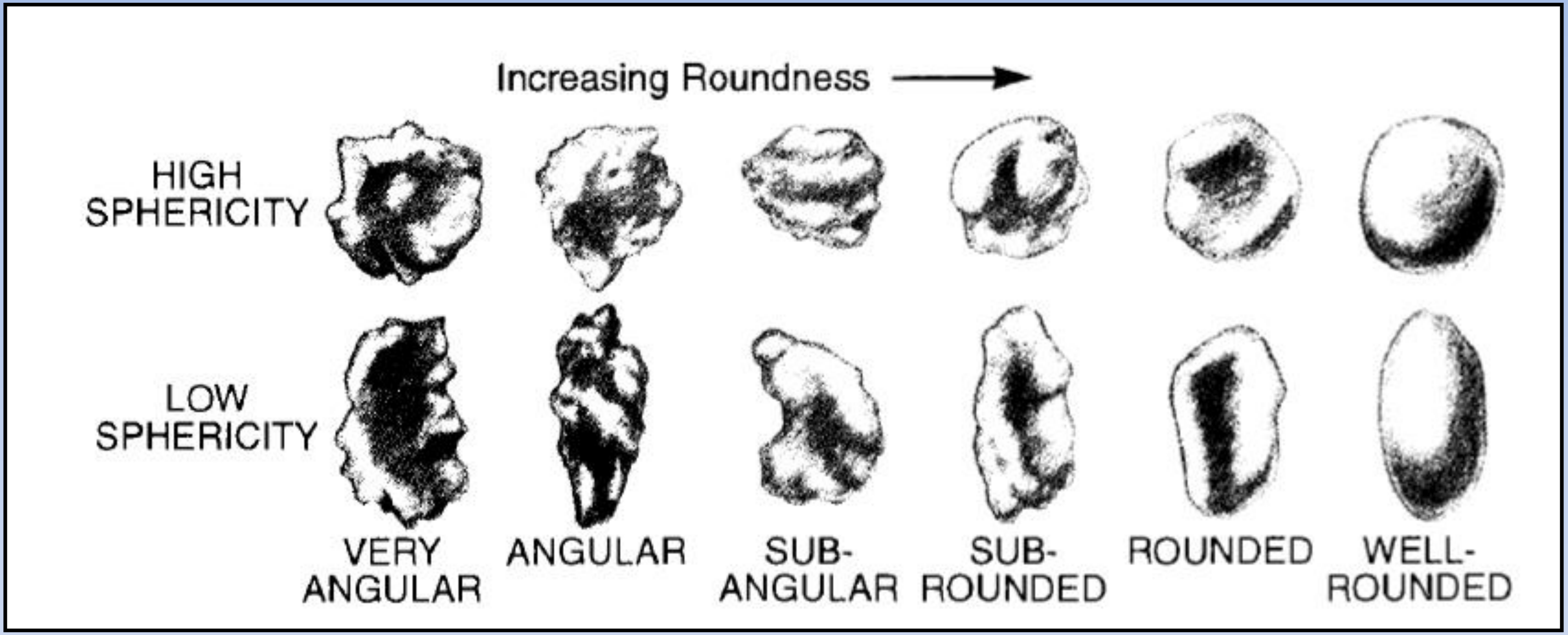


Capillary pressure is the force that exists between two immiscible fluid in thin capillaries. It is defined as the pressure difference between the wetting phase and the non-wetting phase. It is the force by which any wetting fluid is drawn up into a capillary. The smaller the capillary, the higher the liquid rises. The higher the porosity, the lower the height of the transition zone.

The size of the capillaries in a rock determines;

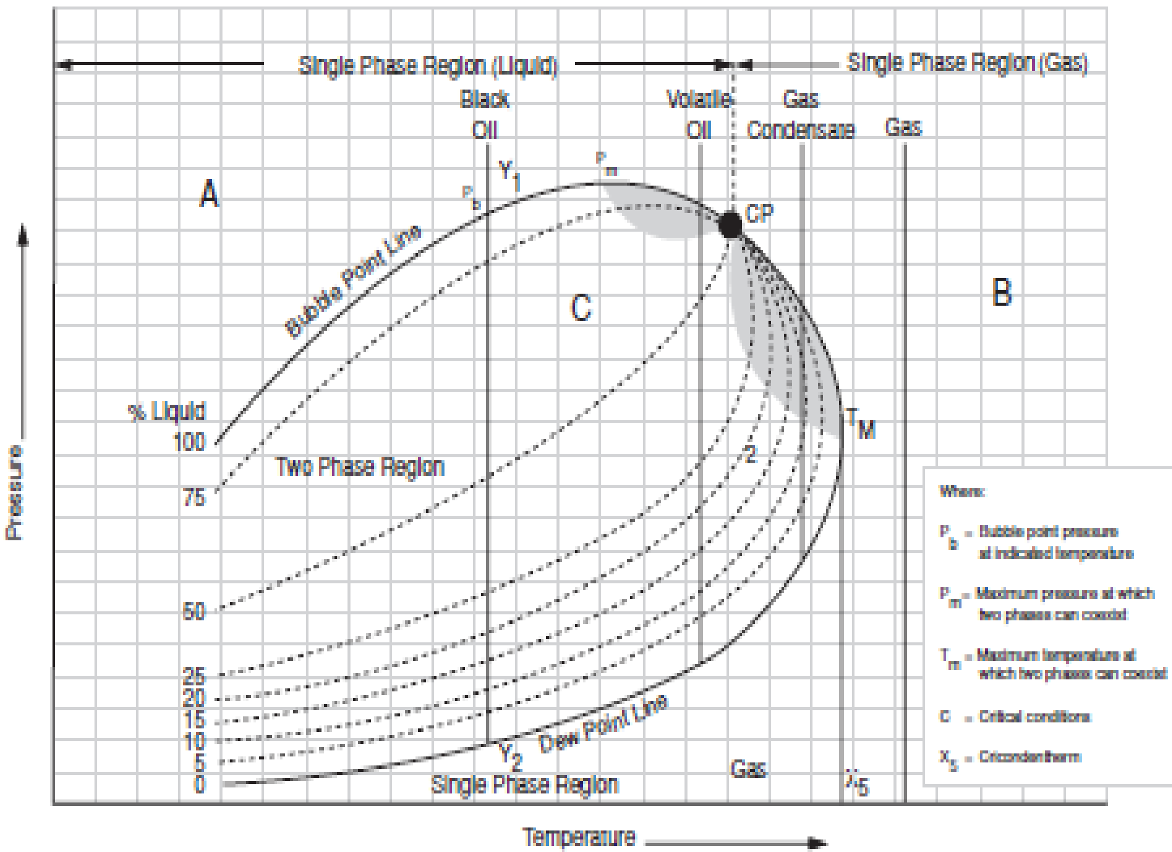
- **The permeability**
- **Irreducible water saturation**
- **The height of the transition zone**

Grain Shapes and Sphericity



Differences between a rounded and a spherical grain. This and the resultant packing would affect the rock properties.

Phase Envelope



- **The state of the hydrocarbon reservoir will depend on its position on the phase envelope at discovery.**
- **This is based on its composition, pressure and temperature at discovery.**

Water Salinity

- This is a very important parameter in log analysis, because it is used in calculating the water saturation (S_w), and ultimately the hydrocarbon saturation if any.
- Water varies from fresh water to salt saturated water (also called **brine**), such salt water are composed of various salt minerals dissolved in solution.
- Salinity is recorded in ppm (parts per million), and it's a function of depth, temperature, depositional environment, and mineralogical composition of rocks.
- S_w has direct effect on the magnitude of resistivity data and its interpretation.
- The S_w value has been known to vary with depth even in the same reservoir.

Formation Temperature

- Knowing the temperature at the depth of interest is very important in log analysis.
- Electrical based measurements (**resistivities**) in aqueous environments are very sensitive to salinity, and ionic activity which is a direct function of temperature.
- A linear **geothermal gradient** is assumed in log analysis, hence surface temperature and temperature @ TD (total depth) suffices to calculate the temperature at any depth in a wellbore.
- Formation temperature is recorded as a passive record by most logging tools.

Formation Pressure Gradient Definitions

Pressure Gradient: This is when any pressure is measured or stated relative to formation depth. This is relative to a surface datum and a particular pressure at that depth, usually expressed in **psi/ft**.

Formation Pore Pressure (Formation Pressure): This is the pressure of the fluid in the pore space of the formation or rock.

Overburden Pressure (Geostatic Pressure): This is the vertical pressure at any point in the earth crust. The overburden pressure is a function of the mass of rock and fluid above the point of interest. A value of **1 psi/ft** is usually used as the overburden pressure gradient.

Normal Pressure: This is the pressure gradient due to formation water, though the value varies regionally, a value of **0.465 psi/ft** for **80,000 pppm** salinity is usually used.

Hydrostatic pressure: This is pressure gradient due to freshwater , fresh water gradient is **0.433 psi/ft** also **8.32 ppg**.

Mud Column Pressure: This is the pressure exerted by the mud column during drilling, usually while drilling, the mud column pressure is designed to be greater than the pore pressure.

Depth Datum and Depth Terms Used in Logging

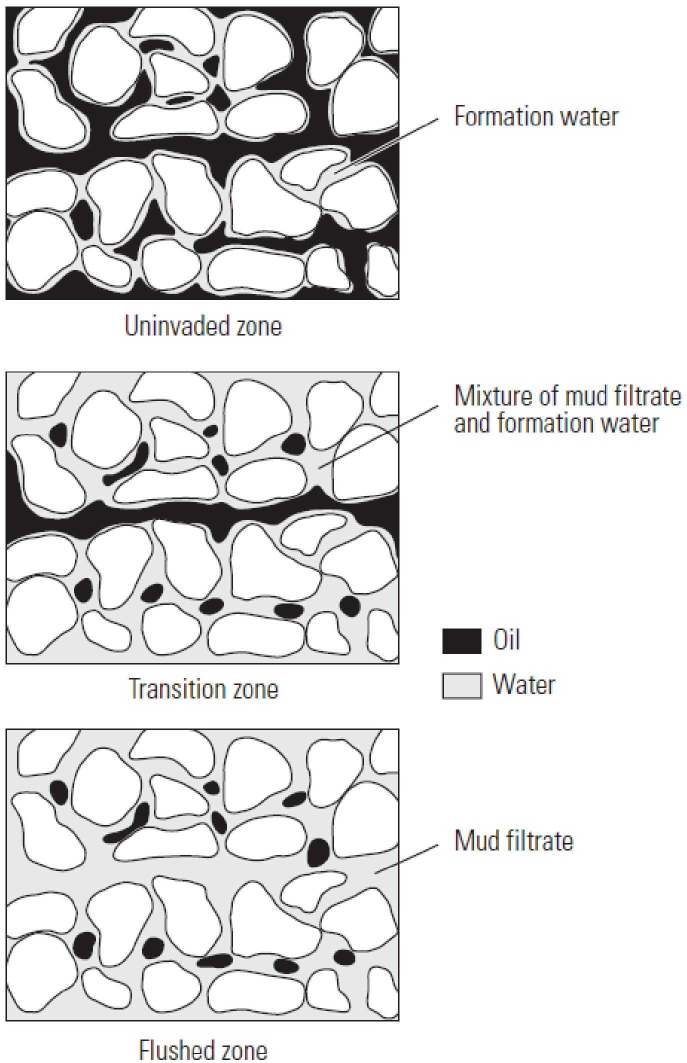
- Depth Datum
  - Drill Floor (DF)
  - Kelly Bushing (KB)
  - Mean Sea Level (MSL)
  - Permanent Datum (PD)
  - Drill Floor Elevation
  - Kelly Bushing Elevation

- Depth Terminologies
  - Depth Driller; Casing Driller
  - Depth Logger; Casing Logger
  - Top Logged Interval
  - Bottom Logged Interval
  - TVD
  - Measured depth, Along hole depth

Drilling and the Wellbore Environment

- Hole diameter
- Mud type, mud density and hydrostatic pressure
  - WBM, OBM, Polymer etc.
  - Pressure maintenance, overbalanced drilling
  - Mud pressure at Depth
- Mud cake
- Mud filtrate Invasion
  - Porous zone
  - Non-porous zone
  - Depth of invasion (compare porosity magnitude)
  - Consequences of invasion on a resistivity log or any tool with multiple depths of investigation (DOI)

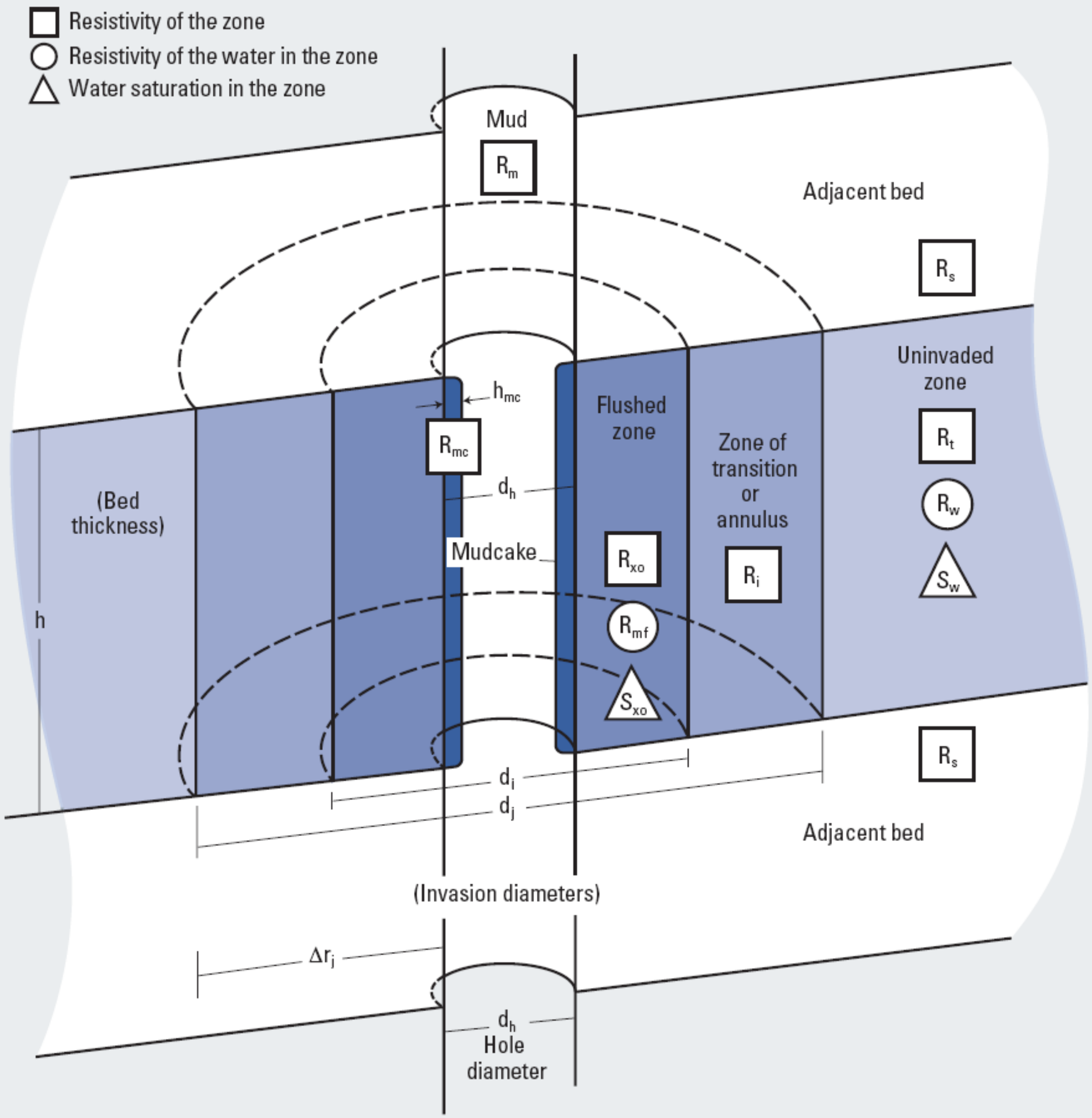
The Invasion Process



The depth of mud filtrate invasion is dependent on the following parameters:

- Drilling mud type and design
- Differential between hydrostatic pressure and pore pressure (reservoir pressure)
- Formation Depth
- Porosity
- Permeability
- Time since well was drilled

The Invasion Profile



Definition of the Parameters

Zone	Parameter	Description
Wellbore	R_m	Mud Resistivity
	R_{mc}	Mud Cake Resistivity
	d_h	Wellbore diameter
	h_{mc}	Mud cake thickness
Flushed Zone	R_{xo}	Flushed zone resistivity
	R_{mf}	Mud filtrate resistivity
	S_{xo}	Flushed zone saturation
	d_i	Depth of flushed zone
Transition Zone	R_i	Transition zone resistivity
	d_j	Depth of Transition zone
Uninvaded Zone	R_t	True Formation Resistivity
	R_w	Formation water resistivity
	S_w	Formation water saturation
Other	h	Bed thickness
	R_s	Adjacent bed resistivity

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