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1. **Introduction**

The response to measurements made by logging tools will depend on the formation properties being investigated. The first step in the interpretation of the logging data is to determine the type of rock which is being logged. The next step is the evaluation of reservoir rock properties which are basically three pieces of data: Porosity (the capacity of the rock to contain fluids); Saturation (the relative amounts of these fluids); Permeability (the ability of the fluids to low through the rock to the well bore). Separation of the hydrocarbons into either gas or oil is of lesser significance.

2. **Rock and Minerals**

Almost all oil and gas produced today comes from accumulations in the pore spaces of reservoir (sedimentary) rocks. Reservoir rock mainly composed of sandstone and carbonate rocks (Limestone and Dolomite). Rocks are classified according to the rock chemistry for the purposes of well log interpretation. This classification method is very useful since many of the measurements from well logging tools reflect physical and chemical properties of the rocks.

This classification system is based on the following categories of rocks:

*Figure (1)  Classification of Sedimentary rocks*
3. **Porosity**

The porosity of a rock is the fraction of the volume of space between the solid particles (grains or matrix) of the rock to the total rock volume (Figure 2). The space includes all pores, cracks, vugs, inter- and intra-crystalline spaces. The porosity is conventionally given the symbol (\(\emptyset\)) and is expressed either as a fraction varying between (0–1) or a percentage varying between (0–100%).

![Diagram of porosity](image)

**Figure (2)**  Diagram and equation of porosity

Porosity is calculated using the relationship:

\[
\emptyset = \frac{V_{\text{pore}}}{V_{\text{bulk}}} \times 100
\]

\[
= \frac{V_{\text{pore}}}{V_{\text{pore}} + V_{\text{matrix}}} \times 100
\]

\[
= \frac{V_{\text{bulk}} - V_{\text{matrix}}}{V_{\text{bulk}}} \times 100 \quad \text{........ (2.1)}
\]

\[
= \frac{V_{\text{bulk}} - (W_{\text{dry}} / \rho_{\text{matrix}})}{V_{\text{bulk}}} \times 100
\]

Where:

- \(\emptyset\) = Porosity
- \(V_{\text{pore}}\) = pore volume (Void Volume)
- \(V_{\text{bulk}}\) = bulk volume
- \(V_{\text{matrix}}\) = volume of solid particles composing the rock matrix (Grain Volume)
- \(W_{\text{dry}}\) = total dry weight of the rock
- \(\rho_{\text{matrix}}\) = mean (actual) density of the matrix minerals (Table 1)
### Table 1 Matrix density for common rocks or Minerals

<table>
<thead>
<tr>
<th>Rock (Mineral)</th>
<th>$\rho_{\text{matrix}}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sandstone (Quartz)</td>
<td>2.65</td>
</tr>
<tr>
<td>Limestone (Calcite)</td>
<td>2.71</td>
</tr>
<tr>
<td>Dolomite</td>
<td>2.87</td>
</tr>
<tr>
<td>Anhydrite</td>
<td>2.98</td>
</tr>
<tr>
<td>Gypsum</td>
<td>2.35</td>
</tr>
<tr>
<td>Salt</td>
<td>2.03</td>
</tr>
</tbody>
</table>

It should be noted that the porosity does not give any information concerning pore sizes, their distribution, and their degree of connectivity. Thus, rocks of the same porosity can have widely different physical properties. An example of this might be a carbonate rock and sandstone. Each could have a porosity of (0.2) but carbonate pores are often unconnected resulting in its permeability being much lower than that of the sandstone. In very clean sands, total porosity is equal to effective porosity.
3.1. Porosity Classification
Porosities are classified according to the physical arrangement of the matrix (grain) that surrounds the pores, the distribution and shape of the pores. Porosity can be subdivided into primary and secondary porosity. Primary porosity of the rock is formed at the time of its deposition as the spaces between the grains. Primary porosity decreases due to the compaction and packing of grains and produce inter-granular pores of clastics or carbonates. Secondary porosity develops after deposition process of the rock such as vugular spaces in carbonate rocks created by the chemical process. It is also including fracture spaces formed due to stress distortion in reservoirs rocks. A range porosities are of defined and recognized which used within the hydrocarbon industry for rocks:

Table (2) Some Porosity Definitions

<table>
<thead>
<tr>
<th>Porosity</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total porosity</td>
<td>The ratio of the entire pore space in a rock to its bulk volume</td>
</tr>
<tr>
<td>Connected porosity</td>
<td>The ratio of the connected pore volume to the total volume</td>
</tr>
<tr>
<td>Effective porosity</td>
<td>The same as the connected porosity, or it is total porosity less the fraction of the pore space occupied by shale or clay</td>
</tr>
<tr>
<td>Primary porosity</td>
<td>The porosity of the rock resulting from its original deposition</td>
</tr>
<tr>
<td>Secondary porosity</td>
<td>The porosity resulting from diagenesis</td>
</tr>
<tr>
<td>Micro-porosity</td>
<td>The porosity resident in small pores (&lt; 2 mm) commonly associated with clay minerals.</td>
</tr>
<tr>
<td>Inter-granular porosity</td>
<td>The porosity due to pore volume between the rock grains which are interconnected</td>
</tr>
<tr>
<td>Intra-granular porosity</td>
<td>The porosity due to voids within the rock grains</td>
</tr>
<tr>
<td>Dissolution porosity</td>
<td>The porosity resulting from dissolution of rock grains</td>
</tr>
<tr>
<td>Fracture porosity</td>
<td>The porosity resulting from fractures in the rock at all scales</td>
</tr>
<tr>
<td>Vug porosity</td>
<td>Porosity associated with vugs, commonly in carbonate rocks created by the dissolution of fragments, but unconnected</td>
</tr>
</tbody>
</table>

- Very clean sandstones: \( \phi_t = \phi_e \)
- Poorly to moderately well-cemented intergranular materials: \( \phi_t \approx \phi_e \)
- Highly cemented materials and most carbonates: \( \phi_e < \phi_t \)
3.2. **Range of porosity values for rocks**

Cement minerals can have a big impact on porosity value especially fracture porosity since fractures are an important part of storage capacity. Sometimes hydrocarbon is actually produced only from the fracture pore space itself. Fracture porosity can result in high production rates during initial testing of a well, followed by a rapid decline in production thereafter. When a rock has been fractured, the fractures do not necessarily remain open. They may be in filled by later cementation minerals by silica, calcite or dolomite after production (Figure.3).

![Fracture pores filled with cementation minerals](image)

**Figure (3)** Fracture pores filled with cementation minerals

High porosities can occur in carbonates when the porosity is due to dissolution (secondary porosity). Total porosity of carbonates may be very high, but their permeability can be very low as the pores are unconnected.

Shale or clay may contain over 40% water-filled porosity but the individual pores are so small the rock is impervious to the flow of fluids. Similarly, porosities can be very low in dense carbonates and evaporates may show practically zero porosity. Sandstones, generally, lie in the range 5% to 35%. (Table.3) gives approximate ranges of porosities for some common lithologies.
Table (3)  The range of porosity values for different lithology.

<table>
<thead>
<tr>
<th>Lithology</th>
<th>Porosity Range (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unconsolidated sands</td>
<td>35-45</td>
</tr>
<tr>
<td>‘Reservoir’ Sandstones</td>
<td>15-35</td>
</tr>
<tr>
<td>Compact Sandstones</td>
<td>5-15</td>
</tr>
<tr>
<td>Shale and Clays</td>
<td>0-45</td>
</tr>
<tr>
<td>Massive Limestone</td>
<td>5-10</td>
</tr>
<tr>
<td>Vuggy Limestone</td>
<td>10-40</td>
</tr>
<tr>
<td>Dolomite</td>
<td>10-30</td>
</tr>
<tr>
<td>Chalk</td>
<td>5-40</td>
</tr>
<tr>
<td>Granite</td>
<td>&lt;1</td>
</tr>
<tr>
<td>Basalt</td>
<td>&lt;0.5</td>
</tr>
<tr>
<td>Gneiss</td>
<td>&lt;2</td>
</tr>
<tr>
<td>Conglomerate</td>
<td>1-15</td>
</tr>
</tbody>
</table>

(Figure.4) shows the relation between porosity and reservoir frequency.

![Figure 4: Reservoir frequency versus porosity](image-url)
3.3. Controls on Porosity
The initial or primary (pre-digeneis) porosity is affected by three major micro-structural parameters. These are grain size, grain packing, particle shape, and the distribution of grain sizes or sorting. However, the initial porosity is rarely found in real rocks, as they have subsequently been affected by secondary controls on porosity such as compaction and geochemical digenetic processes.

3.3.1. Grain Packing
The theoretical porosity values for various grain packing arrangements decreases with increasing packing. The maximum porosity of other packing arrangements is shown in (Table.4) and (Figure.5).

**Figure (5)** Packing arrangements
In real depositional environments, ordered packings (Figure.5) are not formed because they are energetically unstable, and the grains become randomly distributed caused by frictional and cohesive forces operating between individual grains. These forces are proportional to the exposed surface area of the grains. The specific surface area ($S_v$) (exposed grain surface area per unit solid volume) is inversely proportional to grain size.

**Table (4)** Maximum porosity for different packing arrangements

<table>
<thead>
<tr>
<th>Packing</th>
<th>Maximum Porosity (fractional)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cubic</td>
<td>0.476</td>
</tr>
<tr>
<td>Hexagonal</td>
<td>0.395</td>
</tr>
<tr>
<td>Orthorhombic</td>
<td>0.395</td>
</tr>
<tr>
<td>Rhombohedral</td>
<td>0.260</td>
</tr>
<tr>
<td>Tetragonal</td>
<td>0.302</td>
</tr>
<tr>
<td>Triclinic</td>
<td>0.260</td>
</tr>
<tr>
<td>Random</td>
<td>$\geq$0.399 (dependent on grain size)</td>
</tr>
</tbody>
</table>
The theoretical calculation of the abovementioned ideal porosities is relatively simple. For example, the maximum porosity values for cubic, orthorhombic and rhombohedral-packing arrangement spheres (Figure.6) have been estimated as the following:

**Figure (6)**  Idealised porous medium for a) Cubic and b) Orthorhombic packed spheres

**a) Cubic-Packed Spheres**

\[ V_{\text{bulk}} = (2r)^3 = 8r^3 \]

\[ V_{\text{matrix}} = V_{\text{Sphere}} = \frac{4}{3}\pi r^3 \]

Where  \( r = \) sand grain (matrix) radius

\[ \phi = \frac{V_{\text{bulk}} - V_{\text{matrix}}}{V_{\text{bulk}}} = \frac{8r^3 - \frac{4}{3}\pi r^3}{8r^3} = 1 - \frac{\pi}{6} = 0.476 \text{ or } 47.6\% \]

Also, taking the cubic arrangement of identical uniform size spheres with radius \((r)\) occupying a cubic unit cell of length \((L)\). The maximum porosity value can also be calculated as the following:

The bulk volume of the cell:  \( V_{\text{bulk}} = L^3 \)

The number of spheres in the cell:  \( n=(L / 2r)^3 \)

Hence:

\[ V_{\text{matrix}} = n \cdot \left[ (\frac{4}{3}\pi r^3) \right] = \left( \frac{L}{2r} \right)^3 \cdot \left[ (\frac{4}{3}\pi r^3) \right] = (\pi \cdot L^3)/6 \]

The porosity can now be calculated from equation (2.1) as:

\[ \phi = \frac{L^3 - (\pi L^3/6)}{L^3} = \left( 1 - \frac{\pi}{6} \right) = 0.4764 \text{ or } 47.6\% \]
b) Orthorhombic-Packed Spheres

\[ V_{\text{bulk}} = 2r \cdot 2r \cdot h = 4r^2 \cdot 2r \sin(60^0) = 4\sqrt{3}r^3 \]

Where \( h = \) the height of the orthorhombic-packed spheres.

matrix volume is unchanged:

\[ V_{\text{matrix}} = V_{\text{Sphere}} = \frac{4}{3}\pi r^3 \]

and thus:

\[ \phi = \frac{V_{\text{bulk}} - V_{\text{matrix}}}{V_{\text{bulk}}} = \frac{4\sqrt{3}r^3 - \frac{4}{3}\pi r^3}{4\sqrt{3}r^3} = 1 - \frac{\pi}{3\sqrt{3}} = 0.395 \text{ or } 39.5\% \]

c) Rhombohedral-Packed Spheres

\[ h = \sqrt{4r^2 - 2r^2} = \sqrt{2}r \]

Where \( h = \) the height in the tetrahedron

\[ V_{\text{bulk}} = 2r \cdot 2r \cdot \sqrt{2}r = 4\sqrt{2}r^3 \]

Which gives:

\[ \phi = \frac{V_{\text{bulk}} - V_{\text{matrix}}}{V_{\text{bulk}}} = 1 - \frac{4\pi r^3}{12\sqrt{2}r^3} = 1 - \frac{\pi}{3\sqrt{2}} = 1 - 0.74 = 0.26 \text{ or } 26\% \]
3.3.2. Grain Size
Porosity is independent of the sphere (matrix) size for ideal grain packing models but this is not true for random packing model. Porosity is not affected by grain size but permeability increases with increasing grain size (Figure 7). In formations with large grains, the permeability is high and the flow rate larger and vice versa. The permeability in the horizontal direction is controlled by the large grains but in the vertical direction it is controlled by the small grains.

![Grain Size Increase](image)

*Figure (7)* Porosity, permeability and grain size.

<table>
<thead>
<tr>
<th>Rock (Mineral)</th>
<th>Grain Size</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gravel</td>
<td>&gt;256 – 2</td>
</tr>
<tr>
<td>Sand</td>
<td>2 – 0.062</td>
</tr>
<tr>
<td>Silt</td>
<td>0.062 – 0.004</td>
</tr>
<tr>
<td>Clay</td>
<td>&lt;0.004</td>
</tr>
</tbody>
</table>

3.3.3. Sorting (Grain Size Distribution)
Porosity and permeability are affected by sorting, both increases with better (increasing) sorting.

![Porosity and permeability and sorting](image)

*Figure (8)* Porosity and permeability and sorting
(Figure 9) below shows the relation between porosity and permeability depends on grain size and sorting.

3.3.4. Grain Shape
Grain shape is change over time after undergoes several weathering process (Figure 10). Matrix shape has an impact on porosity and permeability. The degree of roundness helps in knowing the distance of transportation in which angular clasts shows short distance of transportation and rounded clasts refers to long distance transportation. Porosity and permeability increases with increasing grain roundness.
4. Permeability

The flow rate of reservoir fluids through a formation in order to wellbore to be recovered depends on the pressure drop, viscosity of the fluid and permeability. Permeability measures the capacity and ability of the formation to transmit fluids. It controls the directional movement and the flow rate of the reservoir fluids in the formation. The unit of measurement is the (Darcy) and reservoir permeability is quoted in (md).

The permeability of any rock is governed primarily by the size of the pores. The larger the pore size, the higher the permeability. The fluid path also determines permeability. This is due to the fluid flowing around all the sand grains rather than in a straight line from one end of the core to the other.

In sandstones, controlling factors on permeability include the percentage of clay, grain size, packing, sorting, the presence cements, fractures and shale content. But in carbonate (Limestone and Dolomite) reservoirs is determined by deposition, post deposition events and fractures.

\[
Q = \frac{KA (P_2 - P_1)}{\mu L} \quad \text{or} \quad K = \frac{Q \mu L}{A (P_2 - P_1)}
\]

Where:
- \( K \) = permeability in (Darcy)
- \( L \) = length of the section of rock in (centimeter).
- \( Q \) = flow rate in (centimeter/sec)
- \( P_1, P_2 \) = pressures in (bar)
- \( A \) = surface area in (cm\(^2\))
- \( \mu \) = viscosity in (centipoises)

4.1. Types of Permeability

4.1.1. Absolute Permeability (k)

When the medium is completely saturated with one fluid, the permeability of the formation is referred to specific or absolute permeability

4.1.2. Effective Permeability (k\(_e\))

When the rock pore spaces contain more than one fluid, the permeability to a particular fluid is called the effective permeability. Or effective permeability is a measure of the fluid conductance capacity of a porous medium to a particular fluid when the medium is saturated with more than one fluid.

Effective permeability is less than absolute permeability because the presence of a second fluid reduces the effective pore diameter available for fluid flow.
4.1.3. **Relative Permeability** ($k_r$)

Relative permeability is defined as the ratio of the effective permeability of a specific fluid at a given saturation to absolute permeability. It is dimensionless.

- Oil:  
  \[ k_{ro} = \frac{k_{eo}}{k} \]

- Water:  
  \[ k_{rw} = \frac{k_{ew}}{k} \]

- Gas:  
  \[ k_{rg} = \frac{k_{eg}}{k} \]

Relative permeability curves reflect the capacity of the rock to produce given fluids by showing the permeability of those fluids as a function of saturation (Figure 11). It can be seen that at low water saturations only oil will flow. As the water saturation increases, the relative permeability of oil decreases until some critical level is reached at which point both oil and water flow. The oil flow continues to decrease and the water flow to increase as water saturation increases. At some level of water saturation, the oil no longer flows and only water flows. Beyond this point, as water saturation increases, the flow of water within the core continues to increase. In either case, the amount of fluid flowing is not a direct effect of the relative permeability since different fluids have different viscosities. For example, if gas and oil have an equal relative permeability, more gas than oil will flow within the rock because of the dramatic difference in viscosity.

![Diagram of Relative Permeability](image)

*Figure (11)  Diagram of Relative Permeability*
5. Saturation
Saturation is defined as the fraction (or percentage) of the pore volume occupied by a particular fluid (oil, gas and water). The symbol for saturation is \( S \) and expressed as the following:

\[
Fluid\ Saturation\ (S) = \frac{Total\ volume\ of\ occupied\ fluid}{Pore\ volume}
\]

Applying this equation for different reservoir fluids:

For oil:
\[
Oil\ Saturation\ \( S_o \) = \frac{Volume\ of\ oil}{Pore\ volume}
\]

For gas:
\[
Gas\ Saturation\ \( S_g \) = \frac{Volume\ of\ gas}{Pore\ volume}
\]

For water:
\[
Water\ Saturation\ \( S_w \) = \frac{Volume\ of\ water}{Pore\ volume}
\]

5.1. Types of Saturation
5.1.1. Connate (initial) water saturation \( (S_{wc}) \)
This is the water saturation that exists above the transition zone and remains in hydrocarbon zone. Because of capillary forces, some water clings to the grains of the rock and cannot be displaced.

5.1.2. Critical (irreducible) oil saturation \( (S_{oc}) \)
For the oil phase to flow, the saturation of the oil must exceed a certain value which is termed critical oil saturation. At this particular saturation, the oil remains in the pores and, for all practical purposes, will not flow.

5.1.3. Movable oil saturation \( (S_{om}) \)
It is defined as the fraction of pore volume occupied by movable oil as expressed by the following equation:

\[
S_{om} = 1 - S_{wc} - S_{oc}
\]

5.1.4. Critical gas saturation \( (S_{gc}) \)
As the reservoir pressure declines below the bubble-point pressure, gas evolves from the oil phase and consequently the saturation of the gas increases as the reservoir pressure declines. The gas phase remains immobile until its saturation exceeds a certain saturation called critical gas saturation, above which gas begins to move.

5.1.5. Critical water saturation \( (S_{wc}) \)
The critical water saturation, connate water saturation, and irreducible water saturation are extensively used interchangeably to define the maximum water saturation at which the water phase will remain immobile.
6. Capillary Pressure

Reservoir rocks are composed of many capillaries of varying sizes. Capillary pressure is the phenomenon by which water or any wetting liquid is drawn up into a capillary. The smaller the capillary (diameter), the higher the liquid rises.

In a reservoir that contains water (bottom) and oil (top) the demarcation between the two is not always sharp. There is a more or less gradual transition from water table to mostly oil named transition zone (interval). The transition zone is the zone which displays a change in the water saturation with height. If the oil-bearing interval is thick enough, water saturation at the top approaches a minimum value (connate or irreducible water saturation) above transition zone. All water with 100% water saturation which is below the transition zone also called water table or free water level (FWL) (Figure.12).

A formation at irreducible water saturation will produce water-free hydrocarbons. But within the transition interval some water will be produced with the oil and the amount increasing as ($S_w$) increases.

Most often it is considered the region in which both water and oil (or gas) flow. The smaller pore spaces, the lower permeability of the reservoir rock the more the small capillaries there are, the longer transition zone with the higher water saturation. Conversely, the larger the pore spaces, the higher permeability the fewer the small capillaries, the transition zone will be shorter with lower water saturation.

![Figure (12) Capillary Pressure and Saturation](image)
7. Reservoir Fluid Properties

Reservoir normally contains either water or hydrocarbon or a mixture (Figure.13). The hydrocarbon may be in the form of oil or gas. Initially, pore space filled 100% with water and the rock being water-wet. Hydrocarbons migrate up dip into traps and distributed by capillary forces and gravity.

![Figure (13)](Rock_matrix(Grain)_Water_Oil_and_or_Gas.png)

**Figure (13)** Pore structure filled with water and oil/gas

Oil and gas are not distinguishable in reservoir as separate entities but are a system. One way to define this system is with a pressure-temperature (P, T) diagram which describes the conditions of the material in the reservoir at any given pressure or temperature (Figure.14). The specific hydrocarbon produced depends on the reservoir pressure and temperature (phase diagrams). The formation water may be fresh or salty. The amount and type of fluid produced depends on the initial reservoir pressure, rock properties and the drive mechanism.

![Figure (14)](Pressure_Temperature_P_T_diagram.png)

**Figure (14)** Phase behaviour of reservoir fluid (Pressure-Temperature (P, T) diagram