Chapter 2
Porosity

Porosity is a measure of void spaces in the rock. This void fraction can be either between particles or inside cavities or cracks of the soil or rock. Porosity defined as a unit fraction between 0 and 1 or as a percentage between 0 and 100%. For most rocks, porosity is normally varying from less than 1 to 40%.

Permeable rock is the key element of oil and gas reservoirs. Porous rocks are able to hold fluids. Normally, both oil and gas is generated from source rocks (kitchen), migrate upwards and trapped under sealing layers (impermeable) that will not permit oil and gas to escape to the surface. Reservoir rock was classified into clastics and carbonates hydrocarbon reservoirs. Clastics reservoirs for example sandstone are comprised of small particles usually buried and compacted in riverbeds for a long time. Carbonates reservoirs are normally generated by biological processes then buried and compacted for a long time. Approximately 60% of hydrocarbons are exists in clastics reservoir rocks and 40% in carbonates reservoir rocks refer to Fig. 2.1. Porosity is a key parameter as it is measuring the storage capacity for hydrocarbons. Typically, carbonate porosity varying from 1 to 35%, average porosity in dolomite formations is 10% and in limestone formations is 12% (Schmoker et al. 1985). Porosity is known simply as pore volume over by bulk volume.

It is difficult to visualize the pore space and pore-throat without using scanning electron microscopy (SEM) as seen in Fig. 2.2. In general, there might be fine paths termed as pore throats detached by wide passages known as pore bodies.

The critical concentration is the point where small grains completely fill the pore space of the large grain pack while the large grains are still in contact with each other (as shown in middle figure). This point indicates the separation between two structural domains. The domain on the left is where an external load is supported by the large grain framework, hence it is shaly sand. In the domain on the right the large grains are suspended in the small particle framework which is load bearing; e.g. sandy shale.

T. A. O. Ganat, *Fundamentals of Reservoir Rock Properties*,
https://doi.org/10.1007/978-3-030-28140-3_2

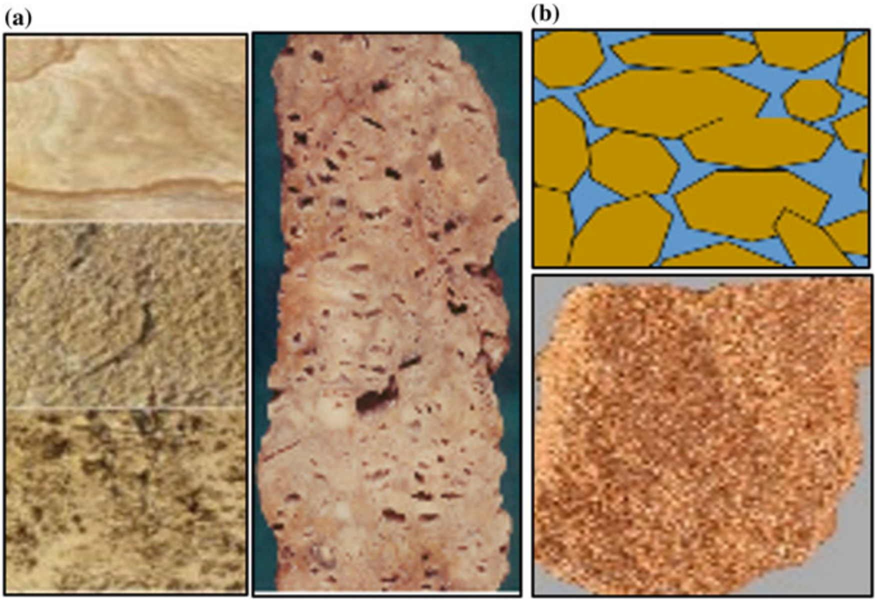


Fig. 2.1 Pores and throat model. **a** Carbonate rock. **b** Clastic rock

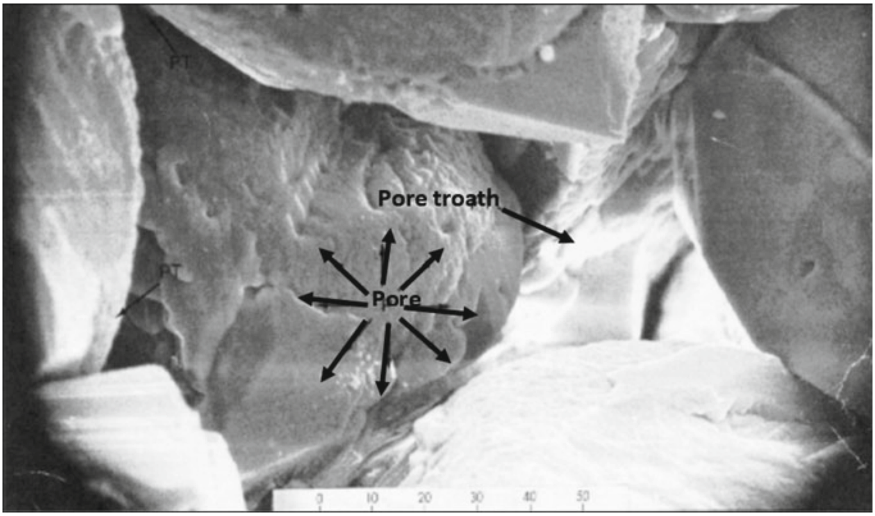


Fig. 2.2 Microphotograph of bore and pore throat (*Source* Jorden and Campbell 1984)

2.1 Types of Geologic Properties

1. **Primary porosity**

It's the main porosity accompanying with the initial depositional structure of the sediment. The primary porosity is the aperture space between the particles. This form of porosity is identified as primary intergranular porosity. While the void space in mineral particles that was occurred former to deposition is known as a primary intragranular porosity. Figure 2.3 illustrates the primary porosity of the rock causing after its original depositional environment.

2. **Secondary porosity**

It's porosity that often enhancing overall voidage of a rock in the sedimentary basin. This porosity results from dissolving of particles, depositional environment, or cement which originally bounded the particles together at the initial place. Secondary intragranular porosity is so easily identifiable porosity. Secondary intergranular porosity is in some environments hard to recognize and measure.

Tectonic movement and degradation diagenetic processes may cause fracture and vug porosities. This type of porosity, which created after a long time of rock deposition, is known as secondary porosity as depicted in Fig. 2.4.

3. **Fracture porosity**

This porosity accompanying a tectonic fracturing system that can generate secondary porosity in rocks see Fig. 2.5.

In extremely unusual cases, non-reservoir rocks as granite can turn into reservoir rocks if adequate fracturing occurs. The orientation of the fracture can be everyplace from vertical to horizontal.

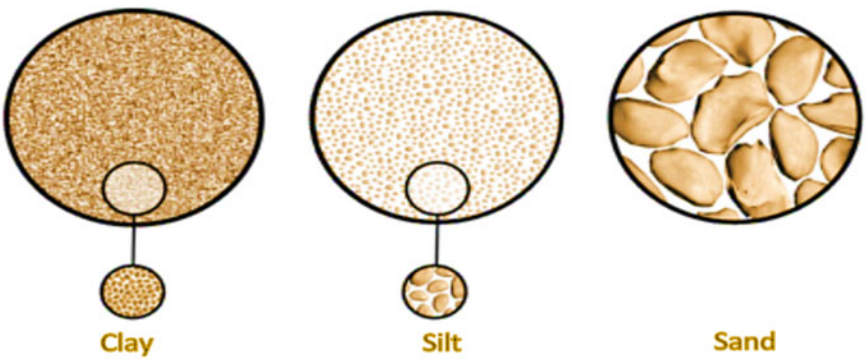


Fig. 2.3 Diagram display primary porosity at different particle sizes

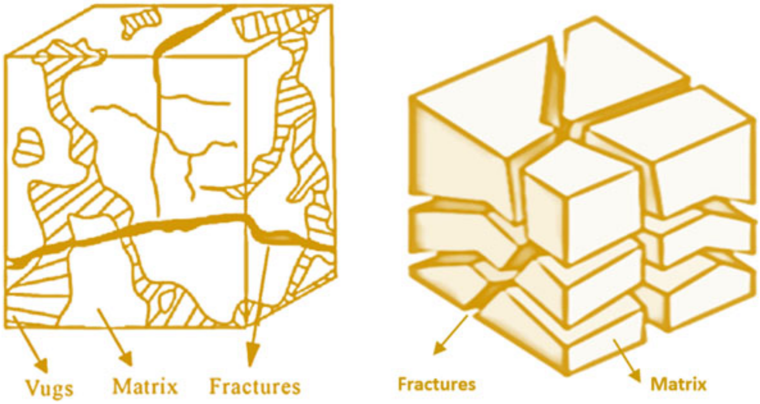


Fig. 2.4 Diagram shows type of secondary porosity existing in reservoir rock

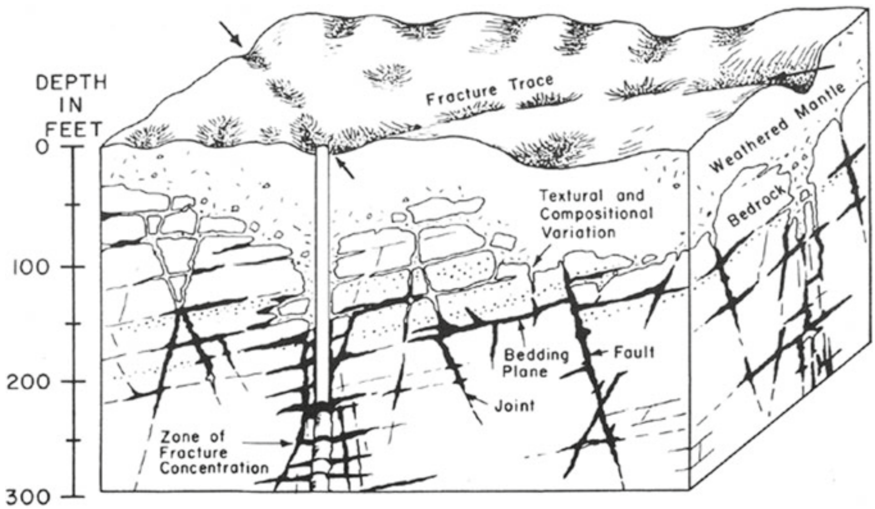


Fig. 2.5 Schematic showing cross-sections of fractures in carbonate rock (*Source* Parizek et al. 1971)

4. **Vuggy porosity**

It's a form of secondary porosity in which the pore spaces are formed by solution vugs, leaving large holes, caves, or vugs in a rock that are normally lined with mineral precipitates. Vugs generally exist as dissolved grains shown in Fig. 2.6.

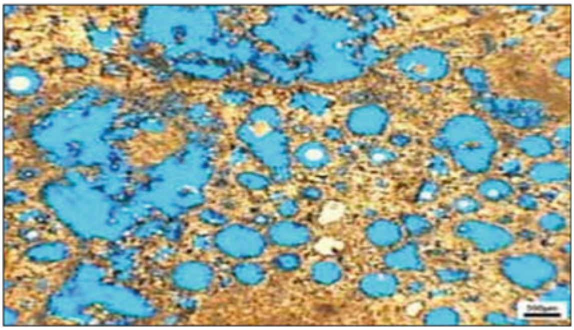


Fig. 2.6 Showing carbonate vuggy porosity (*Source* Etminan and Abbas 2008)

5. **Effective porosity**

It's known also as open porosity, and can be determined by subtracting the total porosity from the part of the void space filled by clay or shale. Typically, the total reservoir porosity in clean reservoir sands is identical to effective porosity.

Another description of effective porosity, it's known as interconnected pore space. Refer to Fig. 2.7 shows the clean pore space and the effective porosity.

Figure 2.8 shows the several types of clay distributions existing in reservoir rocks and their effect on reservoir porosity.

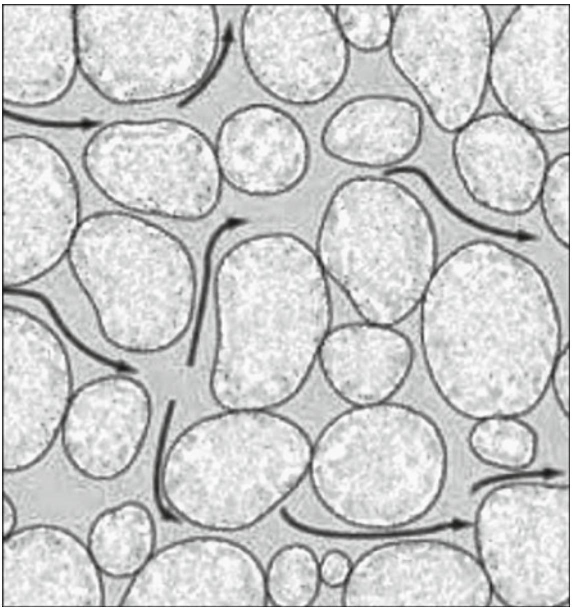


Fig. 2.7 Illustrates the interconnected porosity

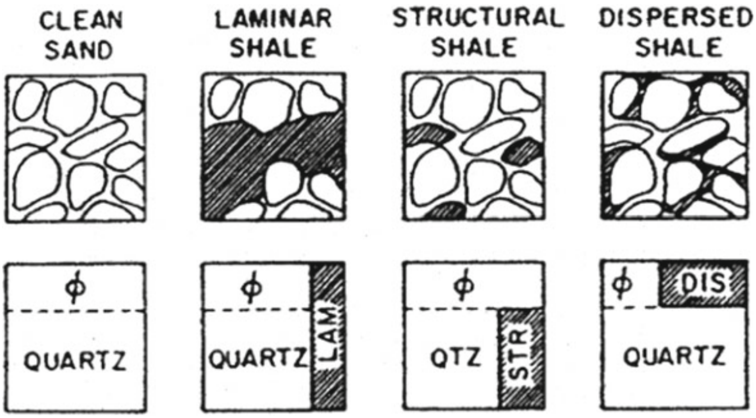


Fig. 2.8 Show the effective porosity at different shale distributions (*Source* Dewan 1983)

6. **Ineffective porosity (also called closed porosity)**

This porosity also called closed porosity, where the pores are isolated and not interconnected. Also, it's known as the part of the total volume where liquids or gases are exists but in which fluid flow can't efficiently occur includes the closed apertures see Fig. 2.9.

7. **Dual porosity**

Known as dual porosity reservoirs because the fractured reservoirs have two dissimilar porosities, call matrix porosity, and fractures porosity. However, naturally fractured reservoirs comprise of asymmetrical fractures, they might be characterized by same homogeneous dual porosity systems. Dual porosity is defined also as a combination of primary, fracture and or vuggy mix where fluid flows are not simple shown Fig. 2.10.

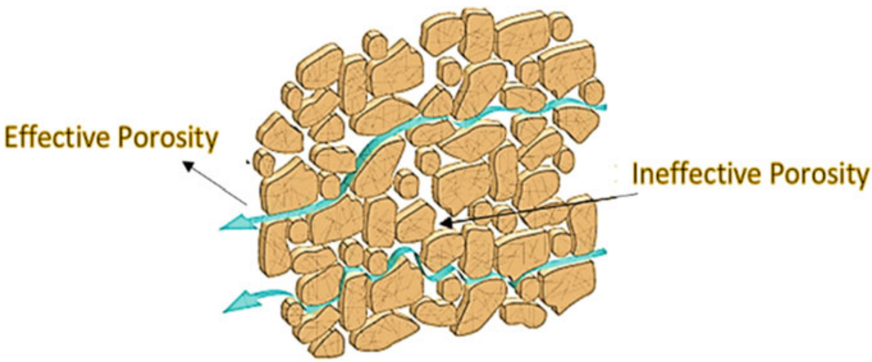


Fig. 2.9 Diagram showing effective and ineffective porosity inside reservoir rock

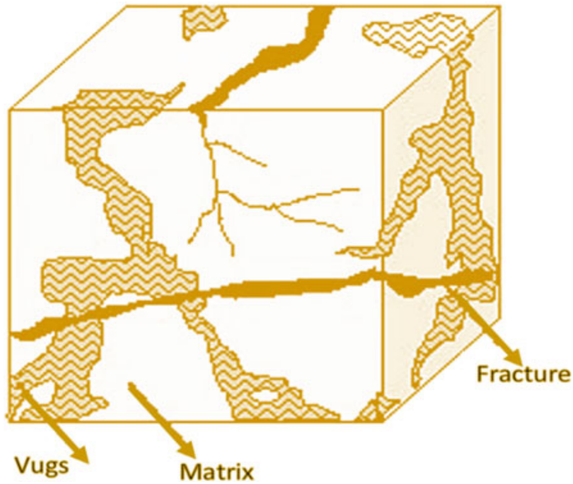


Fig. 2.10 Diagram represent dual porosity model

8. **Macroporosity**

The term 'macroporosity' point out to apertures bigger than 50 nm in diameter. Macroporosity is commonly used in the estimation of soil compaction. If the macroporosity decreased this may be lead to small drainage, and soil degradation. Figure 2.11 shows the interconnected porosity in the reservoir rock.

9. **Mesoporosity**

The term 'mesoporosity' point out to apertures bigger than 2 nm and less than 50 nm in diameter. It's defined as the rock which has its pore size in between microporous and macroporous. This porosity may contain a great amount of hydrocarbons in the pores above the free water level.

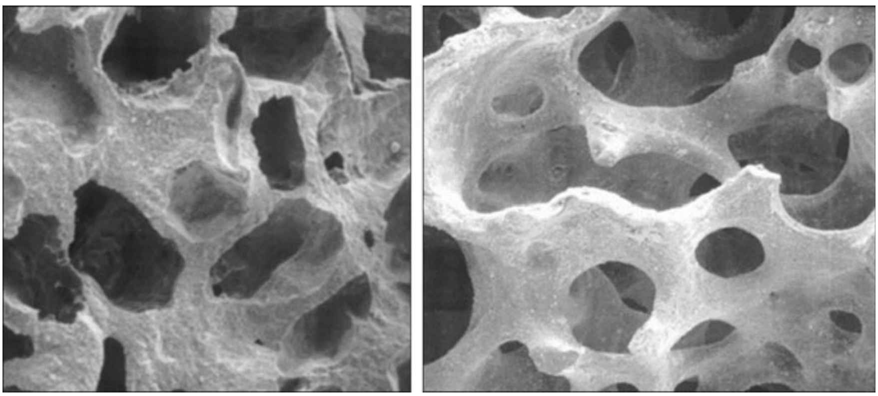


Fig. 2.11 Showing interconnected macroporosity in the formations (*Source* Le Geros et al. 2003)

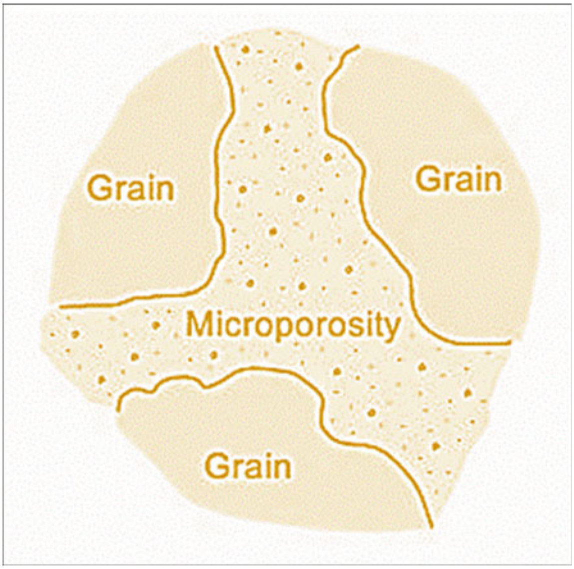


Fig. 2.12 Microporosity matrix

10. **Microporosity**

The term 'microporosity' point out to apertures lesser than 2 nm in diameter. Microporosity exists in siliciclastic rock and in carbonate rock shown in Fig. 2.12. Hence it's directly affect the existing fluid flow properties (i.e. output) and as well as the log response. Normally, it's existing in very fine grain mixture formed at rapid solidification.

Mostly dominant in carbonate rock, the presence of micropores raises the capillary pull to the wetting phase caused in rich bound water in the micropores. Consequently, the conventional logs reading may interpret high water saturation which resulting wrong hydrocarbon determination (Pittman 1983). Therefore, microporosity must be taken into account in any formation evaluation, to avoid erroneous calculation of hydrocarbon in place.

2.2 Porosity of Packing

The porosity of identical rock particle size is independent of the particles size. Figure 2.3a shows the maximum theoretical porosity of 47.6% is attained with cubic packing of spherical particles. While Fig. 2.3b shows 39.5% porosity of Hexagonal packing. Figure 2.3c shows Tetragonal packing. Figure 2.3d shows rhombohedral packing, which is more representative of reservoir environments. Figure 2.3e shows the second lesser size of spherical particles is hosted into cubic packing. This will reduce the porosity from 47.6 to 13%. Therefore, porosity is dependent on the amount

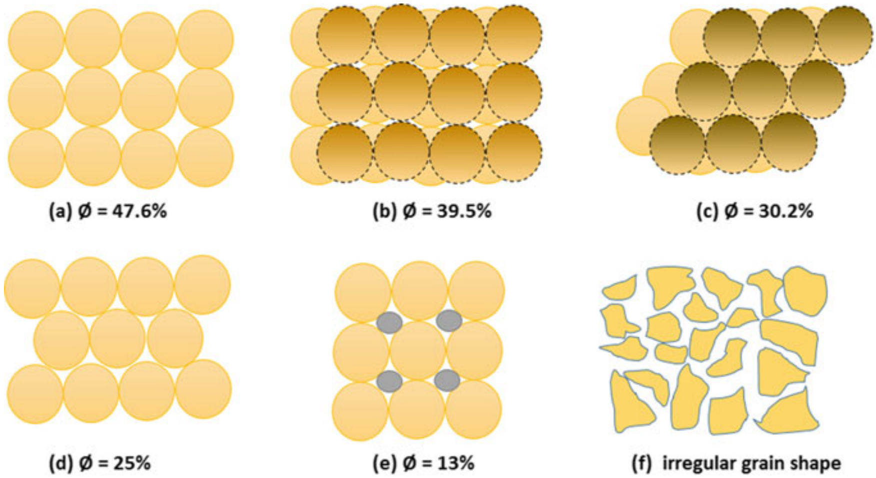


Fig. 2.13 Cubic packing (**a**), hexagonal (**b**), tetragonal (**c**), rhombohedral (**d**), cubic packing with two particle sizes (**e**), and sand with irregular particle shape (**f**)

of cementing materials, the arrangement of the particles, and particle size distribution. A classic reservoir sand shape is illustrated in Fig. 2.13f.

2.3 Particle Shape

Particle shape provides a remarkable amount of evidence about the geologic history environment of the sediment. Whether particles in the sediment are angular or rounded is determined by the amount of erosion the particles have undergone. This erosion somewhat wears down the edges of the sediment. Consequently, as a material transported from the origin place, further erosion takes place results in more rounded material. Generally, the primary porosity of the formations depends on the shape, sorting, and packing form of sediment grains. Where the sharpness of sediment may decrease or increase porosity of the rocks, subject if the grains connection openings or are packed together.

2.4 Factors Affecting Porosity

The best manifestation is in the rock type. Metamorphic and crystalline igneous rocks have no significant porosity. Table 2.1 shows the main factors affecting the porosity value of the deposited rocks.

Limestone porosity can be developed as secondary porosity through the presence of joints and faults. The outer stress of the rock formation can make compaction

Table 2.1 Factors affecting the porosity value of the sedimentary rocks

Factor	Description
Particle size	Particle size is not a factor in porosity. If all particles are the same size, there is more porosity than if the particles are of mixed sizes
Sorting	Good sorted sediments mostly have greater porosities than poorly sorted sediments
Particle shape	The more well-rounded the particles within a rock sample are, the more porosity the sample has
Packing	If the packing of the particles turns into tighter the porosity becomes small

of the pores space which is being influenced by on the depth. Krumbein and Sloss (1951) presented that porosity decrease as a result of compaction increase by depth see Fig. 2.14. While the packing and rearrangement after compaction leading to porosity reduction.

The graphic shown in Fig. 2.15 denotes to the compaction process. Compaction is the irreversible volume reduction because of effective pressure caused by overburden sediments, drainage of pore fluids, and grain packing.

Rowan et al. (2003) used log data from 19 offshore wells, and derived a relationship between porosity versus depth for sand, silt, and shale sediments. They used the shale content (V_{sh}) from a Gamma log as a parameter for classification. The following are the three derived equations (Eqs. 2.1–2.3):

$$\text{For}\quad \text{sand}\ (V_{sh} < 0.01)\quad \emptyset = 0.5 \cdot (-0.29 \cdot z) \tag{2.1}$$

$$\text{For}\quad \text{silt}\ (0.495 < V_{sh} < 0.01)\quad \emptyset = 0.44 \cdot (-0.38 \cdot z) \tag{2.2}$$

$$\text{For}\quad \text{shale}\ (V_{sh} > 0.9)\quad \emptyset = 0.4 \cdot (-0.42 \cdot z) \tag{2.3}$$

2.5 The Range of Porosity Values in Environment

Table 2.2 shows the total porosity ranges in nature for many geologic materials. In general, the total porosity in rocks is not a fixed magnitude since the rock mainly clayey soil, alternately swells, compacts, cracks, and shrinks. In recent deposited sediments, for example, those may exist on the surface of a lagoon; porosity may be very excessive (more than 80%). For instance, the porosity of the loose sands can reach 45%. These sands can be very stabilized or unbalanced by cement. In the formation rocks, the secondary porosity can be created due to dissolution typically in carbonate rocks. Normally, in carbonate rocks, the porosity can be either too small or too high depending on the depositional environment.

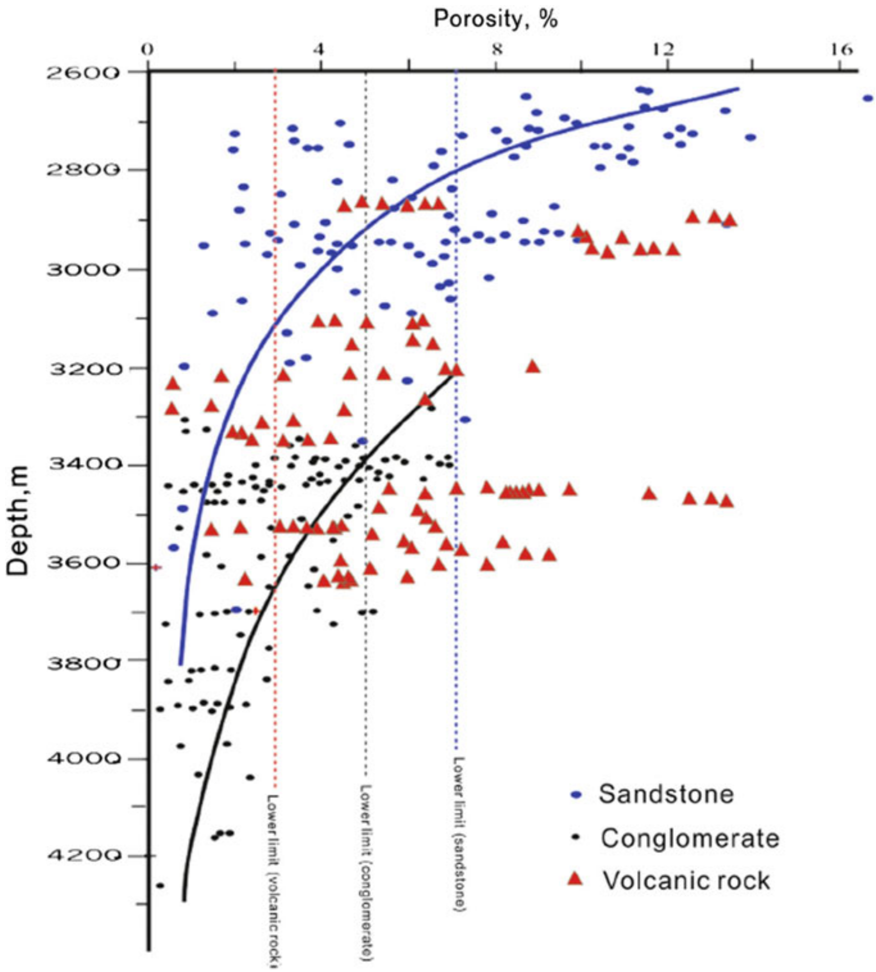


Fig. 2.14 Porosity versus depth diagram of different lithologic reservoirs

The grouping and assessment of hydrocarbon reservoirs are depending on the rock parameter. Table 2.3 shows the gradations of rocks porosity giving by the industry standard of China. However, carbonate and clastic rocks have different gradation because of different classifications, size, and the measure of apertures in both rocks types.

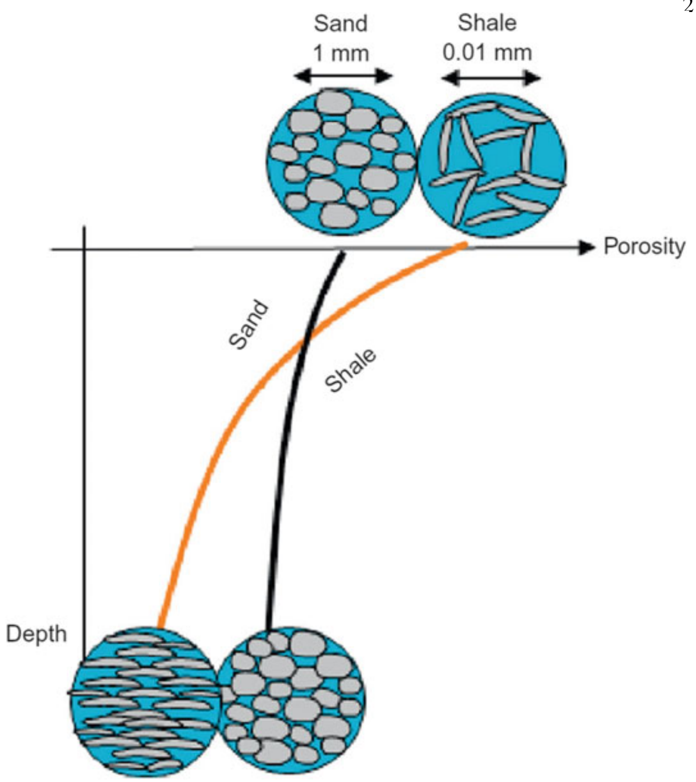


Fig. 2.15 Compaction process for sand and shale

Table 2.2 Rocks porosity range (after Paul 2001)

Lithology	Porosity range (%)
Unconsolidated sands	35–45
Reservoir sandstones	15–35
Compact sandstones	1–15
Compact carbonate rocks	<1–5
Shales	0–45
Clays	0–45
Massive limestones	5–10
Vuggy limestones	10–40
Dolomite	10–30
Chalk	5–40
Granite	<1
Basalt	<0.5
Gneiss	<2
Conglomerate	1–15

Table 2.3 Reservoir porosity gradation [SY/T 6285-2011 (2011)]

Clastic rock		Carbonate rock	
Type of porosity	Porosity (%)	Type of porosity	Porosity (%)
Very high porosity	$Ø \geq 30$		
High porosity	$25 \leq Ø < 30$	High porosity	$Ø \geq 20$
Moderate porosity	$15 \leq Ø < 25$	Moderate porosity	$12 \leq Ø < 20$
Low porosity	$10 \leq Ø < 15$	Low porosity	$4 \leq Ø < 12$
Extremely low porosity	$5 \leq Ø < 10$	Extremely low porosity	$Ø < 4$
Ultra-low porosity	$Ø < 5$		

2.6 Measurement of Porosity

Porosity measurement on core sample in a laboratory normally needs to measure pore volume and bulk volume of the core sample. The total porosity (Absolute Porosity) can be obtained either from core samples or from well logs refer to Fig. 2.16, that could involve effective porosities. Generally, the obtained porosity values using direct methods are more accurate. Therefore, it's used to rectify and calibrate with indirect methods such as log-derived porosity data.

The following Porosity, given the symbol Ø can be calculated using Eq. 2.4

$$Porosity = \frac{Pore\ Volume}{Bulk\ Volume} = \frac{Bulk\ Volume - Matrix\ Volume}{(\text{Grain} + \text{Pore volume})}$$

$$Ø = \frac{V_p}{V_b} = (V_b - V_m)/V_b \tag{2.4}$$

where:

V_p pore space volume,
V_m matrix (solid rock) volume, and
V_b bulk volume ($V_p + V_m$).

Bulk volume (V_b) can be calculated using Eq. 2.5, cylindrical core, or by fluid displacement methods, or directly by volume displacement.

$$V_b = \pi r^2 l \tag{2.5}$$

Porosity will rely on the average form of the particles and the packed method. This sequentially will reliant on deposition method for a long time period such as solid particles of sand dumped progressively on riverbeds (clastics), or evolution and degeneration of biological materials (carbonates). Reservoir engineers are usually concerned in connected porosity (Effective Porosity), which is defined as the total volume of connected pores to total bulk rock volume. Where the hydrocarbon pore volume is defined as the total rock volume that occupied with hydrocarbon. It is

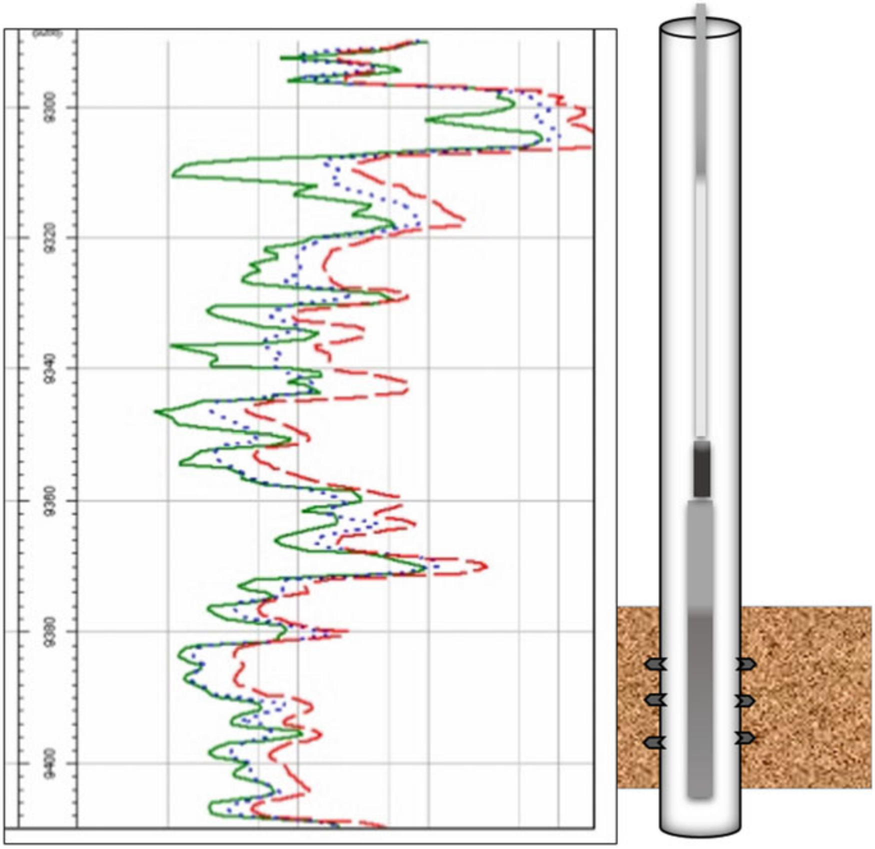


Fig. 2.16 Schematic of wireline well logging

known by the equation (Eq. 2.6):

$$HCPV = V_b \cdot \emptyset \cdot (1 - S_{WC}) \tag{2.6}$$

where:

S_{wc} is the connate water saturation.

The following are the general conventional range and view of Porosity: 0–5% Negligible, 5–10% Poor, 10–15% Fair, 15–20% Good and 20–25% Very Good. Once more, the effective porosity can be defined as the total porosity minus the fraction of the aperture filled by shale or clay. In pure clean sands, total porosity is equivalent to effective porosity (Interconnected Pores) shown in Fig. 2.17. As seen in Fig. 2.18, effective porosity can be defined also as the aperture that contains hydrocarbon and non-clay water (Al-Ruwaili and Al-Waheed 2004). Therefore, the description of effective porosity is the total porosity less volume of clay-bound water.

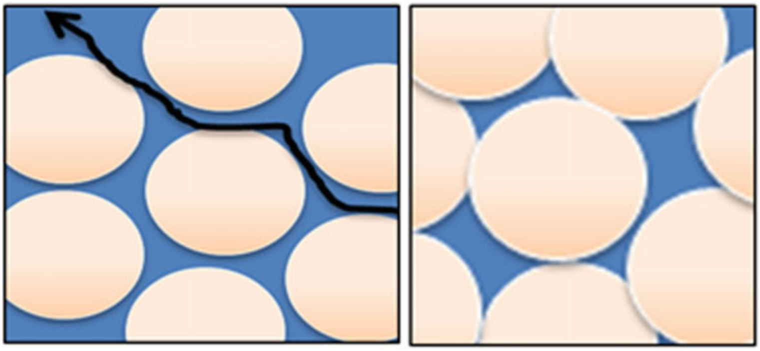


Fig. 2.17 Effective porosity

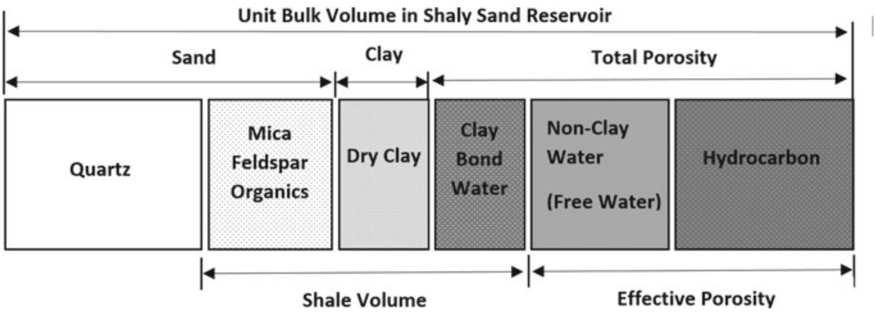


Fig. 2.18 Porosity model for a shaly sand reservoir

The following Eq. 2.7 shows the total porosity as a function of effective porosity for a shaly sand model:

$$\emptyset_t = \emptyset_e + V_{sh} x \emptyset_{sh} \tag{2.7}$$

In Eq. (2.7), $\emptyset_t$ = total porosity, fraction; $\emptyset_e$ = effective porosity, fraction; V_{sh} = volume of shale, fraction; and $\emptyset_{sh}$ = shale porosity, fraction. It's difficult to determine the shale porosity from well logs because the selection of the 100% shale unit can be incorrect (Al-Ruwaili and Al-Waheed 2004). Hence, the estimated form of Eq. (2.8) is attained by changing shale porosity $\emptyset_{sh}$ with total porosity $\emptyset_t$:

$$\emptyset_t = \emptyset_e + V_{sh} x \emptyset_t \tag{2.8}$$

Example 2.1
10.10 cm Core sample long with 3.80 cm was carefully cleaned and dried. The core was saturated with 100% brine that has a specific gravity of 1.03. The saturated core

weight is 385 g and tried sample weight is 355 g. Determine the porosity of the core sample.

Solution
The bulk volume Eq. (2.2):

$$V_b = \pi r^2 l$$

$$V_b = \pi \left(\frac{3.80}{2}\right)^2 \times 10.10 = 114.591 \text{ cm}^3$$

The pore volume is known as:

$$V_p = \frac{wt. of\ saturated\ core - wt. of\ dried\ core}{specific\ gravity\ of\ brine}$$

$$V_p = \frac{385.0 - 355.0}{1.03} = 29.126 \text{ cm}^3$$

Using Eq. (2.1), porosity of the core sample is:

$$\emptyset = \frac{V_p}{V_b}$$

$$\emptyset = \frac{29.126}{114.591} = 0.2542 \quad \text{or} \quad 25.42\%$$

Example 2.2
An oil reservoir has initial pressure is the same to its bubble point pressure of 1000 psia, and the gas oil ratio is 500 SCF/STB at reservoir temperature of 150 °F and the gravity is 35° API with gas specific gravity is 0.63. The following are additional reservoir data available:

- Effective porosity = 18%
- Reservoir area = 550 acres
- Connate water saturation = 20%
- Average thickness = 15 ft
- Formation volume factor = 1.49 bbl/STB

Determine the initial oil in place in STB.

Solution
First, estimate the specific gravity of the oil (γ_o) using the API gravity.

$$API = \frac{141.5}{\gamma_0} - 131.5$$

Therefore,

$$\gamma_0 = \frac{141.5}{35 + 131.5} = 0.849$$

Determine the pore volume from Equation:

$$PV = 7758\ Ah\emptyset \text{ bbl}$$

$$PV = 7758 * 550 * 15 * 0.18 = 11{,}520{,}630 \text{ bbl}$$

$$OIIP = 7758\ Ah\emptyset(1 - S_w)/B_0$$

$$OIIP = 11{,}520{,}630\frac{(1 - 0.20)}{1.49} = 6{,}185{,}573 \text{ STB}$$

The reservoir rock could display enormous variants in porosity. The following are the mathematical techniques used for calculating the averaging porosity:

(1) If there are vertically variants in porosity but does not show big deviations in porosity parallel to the bedding planes;

$$Arithmetic\,average\,\emptyset = \Sigma\emptyset_i/\text{n}$$

Or

$$Thickness\ weighted\,average\ \emptyset = \Sigma\emptyset_i h_i/\Sigma h_i$$

(2) If there is any alteration in the depositional environment, that can create significantly different porosities over the reservoir area;

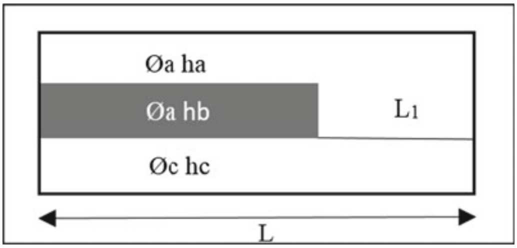
$$Areal\ weighted\,average\ \emptyset = \Sigma\emptyset_i A_i/\Sigma A_i$$

Or

$$Volumetric\,weighted\,average\ \emptyset = \Sigma\emptyset_i A_i\text{h}/\Sigma A_i h_i$$

Where, n is total number of core samples, A is reservoir area, Ø is porosity, and h is thickness of core sample.

Example 2.3
Calculate the Areal weighted average for the below reservoir data measurements:
$\emptyset_a = 20\%, \emptyset_b = 11\%, \emptyset_c = 29\%,$
$L_1 = 0.35\ L + 0.24,$
$h_a = h_b = 0.5\ h_c$



Solution

$$Areal\ weighted\ average\ \emptyset = \Sigma\emptyset_i A_i / \Sigma A_i$$

$$\Sigma\emptyset_i A_i = \emptyset a(ha * L) + \emptyset a(hb * 0.35\ L) + \emptyset b(hb * 0.65 * L) + \emptyset c(hc * L)$$

$$\Sigma\emptyset_i A_i = \emptyset a(0.5 * hc * L) + \emptyset a(0.5 * hc * 0.35\ L) + \emptyset b(0.5 * hc * 0.65 * L) + \emptyset c(hc * L)$$

$$\Sigma\emptyset_i A_i = hc * L(0.675\emptyset a + 0.325\emptyset b + \emptyset c)$$

$$\Sigma\emptyset_i A_i = 0.46075\ hc * L$$

$$\Sigma A_i = (1.35 * ha) + (0.65 * hb) + (hc * L)$$

If:
ha = hb = 0.5hc

$$\Sigma A_i = (1.35 * 0.5hc * L) + (0.65 * 0.5hc * L) + (hc * L)$$

$$\Sigma A_i = hc * L[(1.35 * 0.5) + (0.65 * 0.5) + 1]$$

$$\Sigma A_i = hc * L[(0.675) + (0.325) + 1]$$

$$\Sigma A_i = hc * L[(0.675) + (0.325) + 1]$$

$$\Sigma A_i = 2hc * L$$

$$\emptyset = \frac{0.46075hc * L}{2hc * L}$$

$$\emptyset = 23\%$$

Example 2.4

The reservoir has porosity variation along the three reservoir sections. The average reservoir porosity and the area for each section as follows.

Calculate the Areal weighted average porosity?

Section	Avg. Porosity (%)	Area (ft^2)
1	13	160,422,211
2	20	302,140,285
3	27	10,550,111
Total		473,112,607

$$\emptyset = \frac{\Sigma \emptyset_i A_i}{\Sigma A_i} = ((0.13 * 160{,}422{,}211) + (0.20 * 302{,}140{,}285) + (0.27 * 10{,}550{,}111))/473{,}112{,}607$$

$$\emptyset = 18\%$$

Example 2.5

Determine the arithmetic average porosity and thickness weighted average porosity for the below reservoir data measurements?

Core No.	Porosity (%)	Thickness (ft)
1	8	1.3
2	10	1
3	15	1.1
4	9	2

(continued)

(continued)

Core No.	Porosity (%)	Thickness (ft)
5	11	2.1
6	13	1.5

$$Arithmetic\, average\ \emptyset = \Sigma\emptyset_i/\mathrm{n}$$

$$Arithmetic\, average\ \emptyset = \Sigma(8 + 10 + 15 + 9 + 11 + 13)/6$$
$$\emptyset = 11\%$$

$$Thickness\ weighted\, average\, \emptyset = \Sigma\emptyset_i h_i/\Sigma h_i$$

$$Thickness\ weighted\, average\ \emptyset = \Sigma(8 * 1.3) + (10 * 1) + 15 * 1.1)$$
$$+ (9 * 2) + 11 * 2.1) + (13 * 1.5)/\Sigma(1.3 + 1 + 1.1 + 2 + 2.1 + 1.5)$$
$$\emptyset = 11.5\%$$

References

Al-Ruwaili S, Al-Waheed H (2004) Improved petrophysical methods and techniques for shaly sands evaluation. Paper presented at the 2004 SPE International Petroleum Conference in Puebla, Mexico, November 8–9, 2004

Dewan J (1983) Modern open hole log interpretation. Pennwell Publ. Co., Tulsa Oklahoma, p 361

Etminan A, Abbas S (2008) An improved model for geostatistical simulation of fracture parameters and their effect on static and dynamic models. https://doi.org/10.2174/1874834100801010047

Jorden J, Campbell F (1984) Well logging I—rock properties, borehole environment, mud and temperature logging. Henry L. Doherty Memorial Fund of AIME, SPE: New York, Dallas

Krumbein WC, Sloss LL (1951) Stratigraphy and sedimentation, 2nd edn. W. H. Freeman, San Francisco and London, p 497 (1963, p 660)

LeGeros R, Lin S, Ramin R, Dindo M, John P (2003) Biphasic calcium phosphate bioceramics: preparation, properties and applications. https://doi.org/10.1023/a:1022872421333

Parizek R, White W, Langmuir D (1971) Hydrogeology and geochemistry of folded and faulted carbonate rocks of the Central Appalachian type and related land use problems, p 29. Prepared for the Annual Meeting of The Geological Society of America and Associated Societies

Paul G (2001) Petrophysics M.Sc. Course Notes.http://www2.ggl.ulaval.ca/personnel/paglover/CD%20Contents/GGL-66565%20Petrophysics%20English/Chapter%202.PDF; http://www2.ggl.ulaval.ca/personnel/paglover/CD%20Contents/GGL-66565%20Petrophysics%20English/Chapter%203.PDF

Pittman R (1983) Multilateral productivity comparisons with undesirable outputs. Econ J 93:883–891

Rowan E, Hayba D, Nelson P, Burns W, Houseknecht D (2003) Sandstone and Shale compaction curves derived from sonic and gamma ray logs in offshore wells, North Slope, Alaska—parameters for basin modeling. U.S. Geological Survey, Open-File Report 03–329

Schmoker JW, Krystinic KB, Halley RB (1985) Selected characteristics of limestone and dolomite reservoirs in the United States. AAPG Bull 69(5):733–741

SY/T 6285-2011 (2011) Evaluating methods of oil and gas reservoirs (China)