Petroleum geology-1

Petroleum geology is the study of origin, occurrence, movement, accumulation, and exploration of hydrocarbon fuels. It refers to the specific set of geological disciplines that are applied to the search for hydrocarbons (oil exploration).

Distribution of oil and gas fields based on geologic age:

The reservoir rocks of different ages frequently have different petroleum characteristics and productivity. The age of the rock does not necessarily coincide with the time of oil accumulation. Hydrocarbons accumulated sometime after the formations deposition.

Geologic Age	% of Fields
Neogene	18
Palaeogene	21
Cretaceous	27
Jurassic	21
Permo-Triassic	6
Carboniferous	5
Devonian	1
Cambrian-Silurian	1
	Total 100

Table 1: The distribution of discovered oil and gas fields based on geologic age.

Types of sedimentary rocks that are important in the production of hydrocarbons:

1-Sandstones

Sandstones are clastic sedimentary rocks composed of mainly sand size particles or grains set in a matrix of silt or clay and more or less firmly united by a cementing material (commonly silica, iron oxide, or calcium carbonate). The sand particles usually consist of quartz, and the term “sandstone”, when used without qualification, indicates a rock containing about 85-90% quartz.

2-Carbonates (limestones and dolomites)

Carbonates are sediments characterized by Calcite and aragonite minerals. Limestones are sedimentary rocks consisting chiefly of the mineral calcite. Limestones are the most important and widely distributed of the carbonate rocks. A sedimentary rock will be named dolomite if that rock is composed of more than 90% mineral dolomite and less than 10% mineral calcite.

3-Shales

Shale is a type of detrital sedimentary rock formed by the consolidation of fine-grained material including clay, mud, and silt and have a layered or stratified structure parallel to bedding. Shales are typically porous and contain hydrocarbons but generally exhibit no permeability. Therefore, they typically do not form reservoirs but do make excellent cap rocks. If a shale is fractured, it would have the potential to be a reservoir.

4-Evaporites

The term “*evaporite*” is used for all deposits, such as salt deposits, that are composed of minerals that precipitated from saline solutions concentrated by evaporation. *Evaporites* do not form reservoirs like limestone and sandstone, but are very important to petroleum exploration because they make excellent cap rocks and generate traps. They make excellent cap rocks because they are impermeable and, unlike lithified shales, they deform plastically, not by fracturing.

Source Rock and Hydrocarbon Generation

In petroleum geology, the term **source rock** refers to rocks in which hydrocarbons have been generated or are capable of hydrocarbon generation. They are organic-rich sediments that may have been deposited in a variety of environments: deep water, marine, lacustrine, and deltaic.

Hydrocarbons are generated when large volumes of microscopic plant and animal material are deposited in marine, deltaic, or lacustrine (lake) environments. The organic material may either originate within these environments and/or may be carried into the environment by rivers, streams or the sea. The microscopic plant and animal material generally is deposited with fine clastic (silt and/or clay) sediments. During burial the sediments protect the organic material by creating an anoxic (oxygen depleted) environment. This allows the organic material to accumulate rather than be destroyed by aerobic organisms such as bacteria. Over time, the organic remains are altered and transformed into gas and oil by the high temperatures and increased pressure of deep burial. The amount of petroleum generated is a function of the thickness of the accumulated sediments and organic material, the burial of these materials, and time.

Organically rich, black-colored shales deposited in a quiet marine, oxygen depleted environment are considered to be the best source rocks.

Petroleum Chemistry

Petroleum is a general term for all naturally occurring hydrocarbons, whether gaseous, liquid, or solid. It is both simple and complex and is composed almost entirely of carbon and hydrogen. Impurities like, nitrogen, sulfur, and oxygen play a somewhat important role in the formation of hydrocarbon molecules. The numerous varieties of petroleum are due to the way carbon and hydrogen can combine and form different sized molecules, thus creating different molecular weights. A thick black asphalt and yellow light crude are examples of two varieties of petroleum with different molecular weights.

Kerogen

Kerogen is solid, insoluble organic matter in sedimentary rocks. Consisting of an estimated 1016 tons of carbon, it is the most abundant source of organic compounds on earth. It is insoluble in normal organic solvents and it does not have a specific chemical formula. Upon heating, kerogen converts in part to liquid and gaseous hydrocarbons. Petroleum and natural gas form from kerogen. Kerogen may be classified by its origin: lacustrine (e.g., algal), marine (e.g., planktonic), and terrestrial (pollen and spores).

Thermal Maturation Processes

The conversion of kerogen to oil and gas is a process which requires both higher temperatures and a long period of geological time. The term " **Thermal Maturation** " refers here to the degree of thermal transformation of kerogen into hydrocarbons and ultimately into gas and graphite. The factors which influence the rate of this process are:

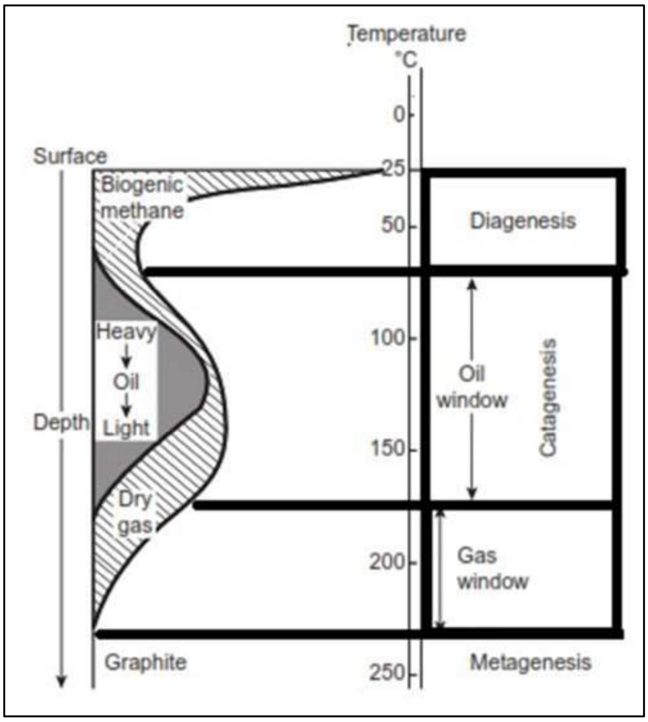
- Temperature
- Pressure
- Time

Thermal maturation processes are classified into:

1-Diagenesis: The initial stage maturation of kerogen that occurs at temperatures less than 50°C . The type of hydrocarbon generated depends on the type of organic matter in the kerogen, the amount of time that passes, and the temperature and pressure. During early diagenesis, microbial activity is a key contributor to the breakdown of organic matter and generally results in production of biogenic gas.

2-Catagenesis: The physical and chemical alteration of sediments and pore fluids at temperatures and pressures higher than those of diagenesis. Catagenesis involves heating in the range of 50° to 150°C. At these temperatures, chemical bonds break down in kerogen and clays within source rocks, generating liquid hydrocarbons. At the high end of this temperature range, secondary cracking of oil molecules can generate gas molecules.

3-Metagenesis: The last stage of maturation and conversion of organic matter to hydrocarbons. Metagenesis occurs at temperatures over 200°C. At the end of metagenesis, methane, or dry gas, is evolved along with nonhydrocarbon gases such as CO_2, N_2, and H_2S.



Correlation between hydrocarbon generation, temperature, and maturation processes.

Petroleum migration

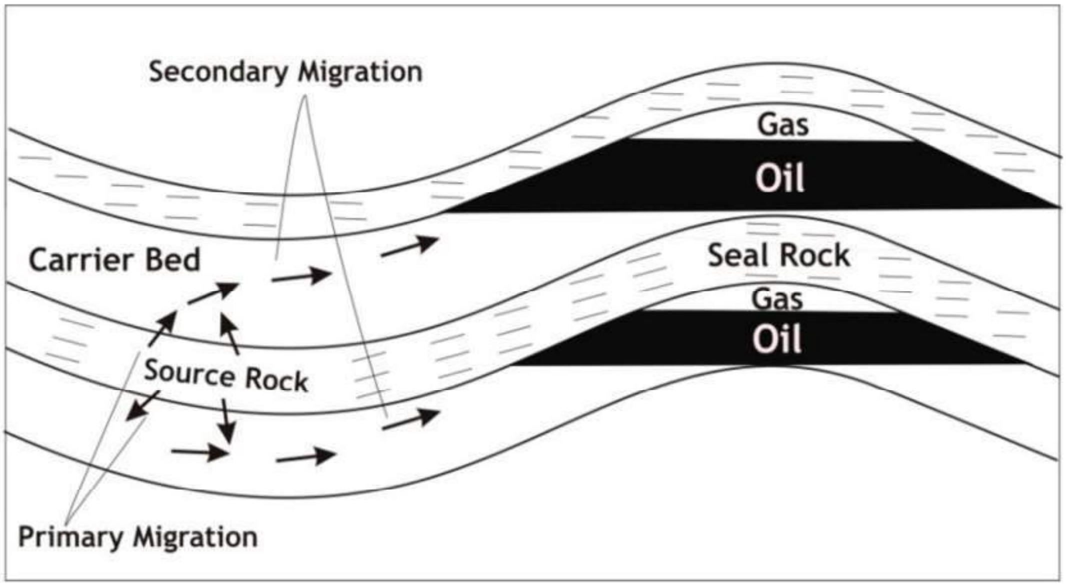
After fracturing of source rock due to pressure increase that happens due to the generation of oil and gas. Since gases and liquids are less dense than solids, they take up more volume causing pressure increase. So, it is important for a productive source rock to be easily fractured to let the fluids move through it.
Migration occurs in two stages:

Primary migration

During primary migration, gas and oil travel together as a single liquid phase because the high pressures in the source rock which usually become higher than the bubble point pressure at which gases start to be liberated from liquid. Expulsion from the source rock may occur in pulses and after some time from the first expulsion. With time, petroleum creates enough pressure to reopen fractures and pores causing a second expulsion, and the pulses continue to happen as long as the petroleum can rebuild enough pressure to reopen its path out of the source rock. After migration the pressure decreases and the fractures and pores close. Finally, petroleum migrates out of the source rock, pressures decline, especially if the petroleum migrates vertically.

Secondary migration

Secondary migration is the movement of petroleum outside of the source rock and into a reservoir bed. During secondary migration, the gas and oil separate with the gas traveling ahead of oil. In most cases, differences in permeability between adjacent stratigraphic layers inhibit migration.This causes petroleum to flow within geologic units. For petroleum to accumulate in a trap, it must encounter a cap rock or seal to become an oil or gas reservoir.



This figure shows the paths of primary and secondary migration.

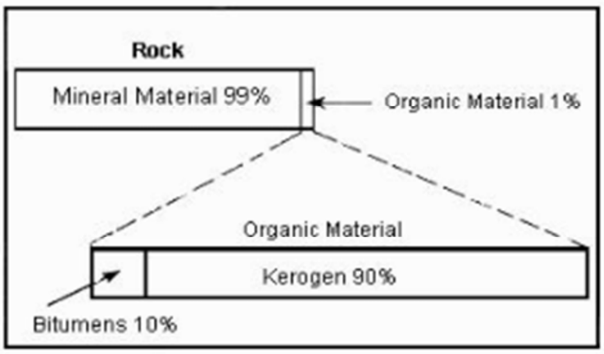
Petroleum geology-2

Five Major Types of Hydrocarbons of Interest to Petroleum Exploration:

1-Kerogen/Bitumens: Shale rock volume is composed of 99% clay minerals and 1% organic material. Most of this organic matter is in a form known as kerogen. Kerogen is that part of the organic matter in a rock that is insoluble in common organic solvents. It owes its insolubility to its large molecular size and heat is required to break it down. Maturation of kerogen is a function of increased burial and temperature and is accompanied by chemical changes. As kerogen thermally matures and increases in carbon content, it changes form an immature light greenish-yellow color to an over mature black, which is representative of a progressively higher coal rank. Different types of kerogen can be identified, each with different concentrations of the five primary elements, carbon, hydrogen, oxygen, nitrogen, and sulphur, and each with a different potential for generating petroleum.

The organic content of a rock that is extractable with organic solvents is known as bitumen. It normally forms a small proportion of the total organic carbon in a rock. Bitumen forms largely as a result of the breaking of chemical bonds in kerogen as temperature rises. Petroleum is the organic substance recovered from wells and found in natural seepages. Bitumen becomes petroleum at some point during migration. Important chemical differences often exist between source rock extracts (bitumen) and crude oils (petroleum).

Kerogen is of no commercial significance except where it is so abundant (greater than 10%) as to occur in oil shales. It is, however, of great geological importance because it is the substance that generates hydrocarbon oil and gas. A source rock must contain significant amounts of kerogen.



2-Crude Oil: Crude oil is a mixture of many hydrocarbons that are liquid at surface temperatures and pressures, and are soluble in normal petroleum solvents. It can vary in type and amount of hydrocarbons as well as which impurities it may contain. Crude oil may be classified chemically (e.g. paraffinic, naphthenic) or by its density. This is expressed as specific gravity or as API (American Petroleum Institute) gravity according to the formula:

$$API^{o} = \frac{141.5}{\text{sp. grav.} @ 60^{o}\text{F}} - 131.5$$

Specific gravity is the ratio of the density of a substance to the density of water. API gravity is a standard adopted by the American Petroleum Institute for expressing the specific weight of oils. The lower the specific gravity, the higher the API gravity, for example, a fluid with a specific gravity of 1.0 g cm^{-3} has an API value of 10 degrees. Heavy oils are those with API gravities of less than 20 (sp. gr. >0.93). These oils have frequently suffered chemical alteration as a result of microbial attack (biodegradation) and other effects. Not only are heavy oils less valuable commercially, but they are considerably more difficult to extract. API gravities of 20 to 40 degrees (sp. gr. 0.83 to 0.93) indicate normal oils. Oils of API gravity greater than 40 degrees (sp. gr. < 0.83) are light.

3-Asphalt: Asphalt is a dark colored solid to semi-solid form of petroleum (at surface temperatures and pressures) that consists of heavy hydrocarbons and bitumens. It can occur naturally or as a residue in the refining of some petroleums. It generally contains appreciable amounts of sulphur, oxygen, and nitrogen and unlike kerogen, asphalt is soluble in normal petroleum solvents. It is produced by the partial maturation of kerogen or by the degradation of mature crude oil. Asphalt is particularly suitable for making high-quality gasoline and roofing and paving materials.

4-Natural Gas: There are two basic types of natural gas, biogenic gas and thermogenic gas. The difference between the two is contingent upon conditions of origin. Biogenic gas is a natural gas formed solely as a result of bacterial activity in the early stages of diagenesis, meaning it forms at low temperatures, at overburden depths of less than 3000 feet, and under anaerobic conditions often associated with high rates of marine sediment accumulation. Because of these factors, biogenic gas occurs in a variety of environments, including contemporary deltas of the Nile, Mississippi and Amazon rivers. Currently it is estimated that approximately 20% of the world known natural gas is biogenic. Thermogenic gas is a natural gas resulting from the thermal alteration of kerogen due to an increase in overburden pressure and temperature.

The major hydocarbon gases are: methane (CH4), ethane (C2H6), propane (C3H8), and butane (C4H10).

The terms sweet and sour gas are used in the field to designate gases that are low or high, respectively, in hydrogen sulfide.

Natural gas, as it comes from the well, is also classified as dry gas or wet gas, according to the amount of natural gas liquid vapors it contains. A dry gas contains less than 0.1 gallon natural gas liquid vapors per 1,000 cubic feet, and a wet gas 0.3 or more liquid vapors per 1,000 cubic feet.

5-Condensates: Condensates are hydrocarbons transitional between gas and crude oil (gaseous in the subsurface but condensing to liquid at surface temperatures and pressures). Chemically, condensates consist largely of paraffins, such as pentane, octane, and hexane.

Reservoir

A **reservoir** is a subsurface volume of porous and permeable rock that has both storage capacity and the ability to allow fluids to flow through it. Hydrocarbons migrate upward through porous and permeable rock formations until they either reach the surface as seepage or become trapped below the surface by a non-permeable cap rock which allows them to accumulate in place in the reservoir. Porosity and permeability are influenced by the depositional pore-geometries of the reservoir sediments and the post-depositional diagenetic changes that take place.

Physical Characteristics of a Reservoir:

Physical characteristics of a reservoir include original deposition and subsequent changes, the 1-type of reservoir 2-depth 3-area and thickness 3- porosity and 4-permeability.

1-Type of reservoir: The major types of reservoirs are:

A-Sandstone reservoirs are generally created by the accumulation of large amounts of clastic sediments which is characteristic of depositional environments such as river channels, deltas, beaches, lakes and submarine fans. Sandstone reservoirs have a depositional porosity and permeability controlled by grain size, sorting, and packing of the particular sediments. Diagenetic changes may include precipitation of clay minerals in the pore space, occlusion of pores by mineral cements, or even creation of additional pores by dissolution of some sediments.

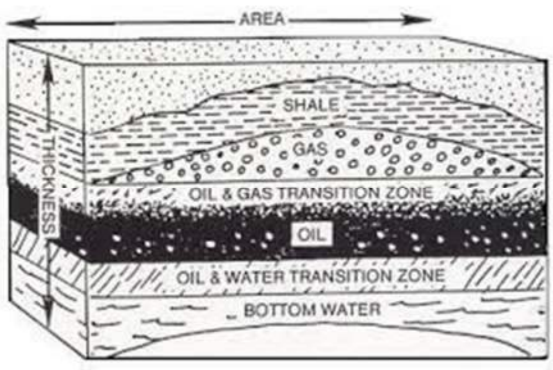
B-Carbonate reservoirs are created in marine sedimentary environments with little or no clastic material input and generally in a location between 30° north and south of the equator. Porosity types of carbonate reservoirs include vuggy (pores larger than grains), intergranular (between grains), intragranular or cellular (within grains), and chalky. Diagenetic changes such as dolomitization, fracturing, dissolution, and recrystalization (rare) are extremely important because they have the ability to create very effective secondary porosity. Cementation, another type of diagenesis, generally reduces porosity and permeability.

2-Depth: The physical characteristics of a reservoir are greatly affected by the depth at which they occur. According to depth, reservoirs are classified into:

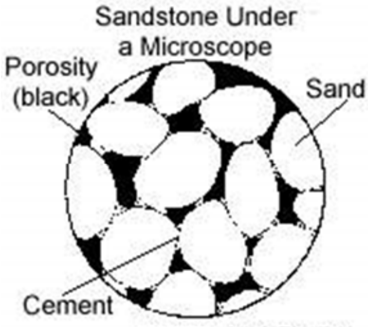
Shallow reservoir— Created by the folding of relatively thick, moderately compacted reservoir rock with accumulation under an anticline or some trap. The hydrocarbons would generally be better separated as a result of lower internal reservoir pressures, less gas in solution and oil of increased viscosity, resulting from lower temperatures.

Deep reservoir— Typically created by severe faulting. The hydrocarbons would be less separated with more gas in solution and oil of reduced viscosity because of higher temperatures. There is often a reduction in porosity and permeability due to increased compaction.

3-Area and Thickness: The total area of a reservoir and its thickness are of considerable importance in determining if a reservoir is a commercial one or not. The greater the area and thickness of the reservoir, the greater the potential for large accumulations of oil and gas. However, there are reservoirs that produce substantial amounts of hydrocarbons that are not of considerable size.



4-Porosity: Porosity is the ratio of void space in a rock to the total volume of rock, and reflects the fluid storage capacity of the reservoir.



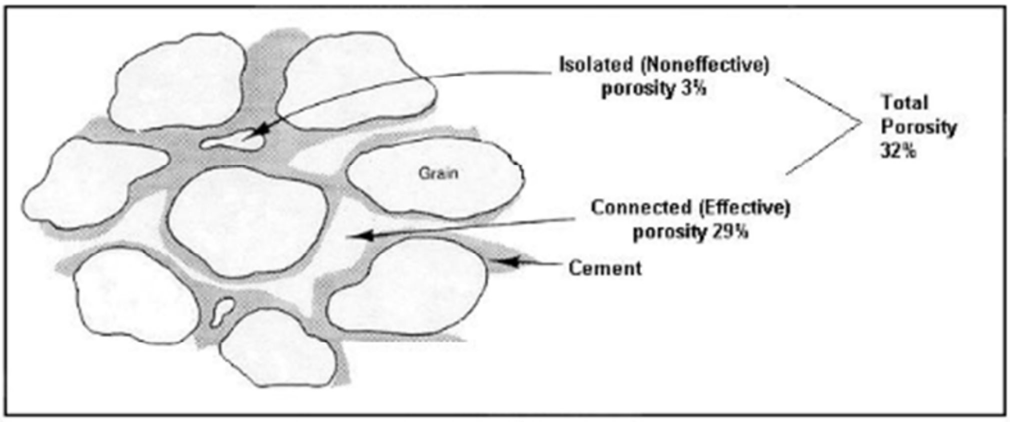
$$\text{Porosity } (\Phi) = \frac{\text{volume of void space}}{\text{total volume of rock}}$$

Porosity is expressed as a percentage on a log. When used in calculations, however, it is important that porosity be expressed in decimal form

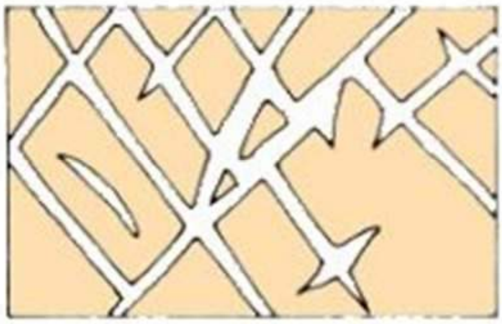
Primary Porosity— Amount of pore space present in the sediment at the time of deposition, or formed during sedimentation. It is usually a function of the amount of space between rock-forming grains.

Secondary Porosity— Post depositional porosity. Such porosity results from groundwater dissolution, recrystallization and fracturing.

Effective Porosity vs. Total Porosity— Effective porosity is the interconnected pore volume available to free fluids. Total porosity is all void space in a rock and matrix whether effective or noneffective.



Fracture Porosity— It results from the presence of openings produced by the breaking or shattering of a rock. All rock types are affected by fracturing and a rocks composition will determine how brittle the rock is and how much fracturing will occur. The two basic types of fractures include natural tectonically related fractures and hydraulically induced fractures. Hydraulic fracturing is a method of stimulating production by inducing fractures and fissures in the formation by injecting fluids into the reservoir rock at pressures which exceed the strength of the rock. Hydraulic fracturing can tremendously increase the effective porosity and permeability of a formation.



Vuggy Porosity— is a form of secondary porosity resulting from the dissolution of the more soluble portions of rock or solution enlargement of pores or fractures.

<u>Controls on Porosity</u>

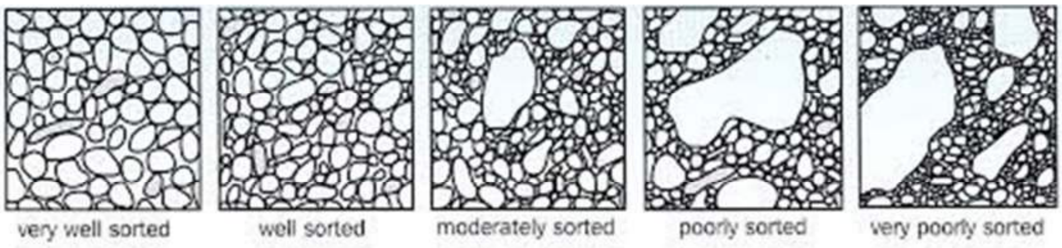
In sandstone, porosity is largely controlled by sorting. Sorting is a process by which the agents of transportation, especially running water, naturally separate sedimentary particles that have some particular characteristic (such as size, shape or specific gravity) from associated but dissimilar particles. Other important controlling factors include grain packing, compaction, and cementation.

1-Sorting

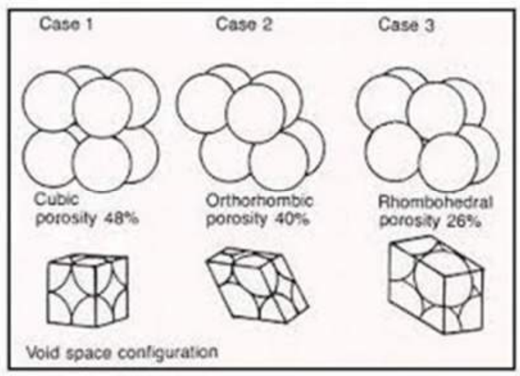
Well Sorted Rock— Grains are generally of the same size and shape. If the grains are well

rounded and of similar size, then they will not fit well together, thereby leaving a large amount of pore space between the grains. Porosity in a well sorted rock is generally high.

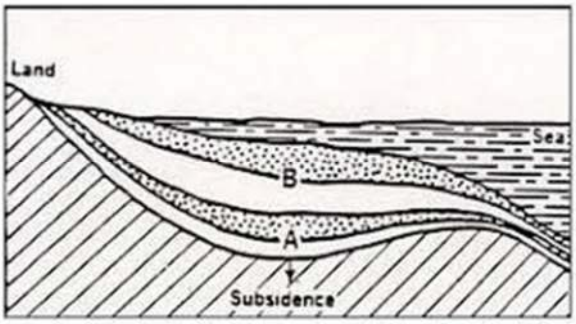
Poorly Sorted Rock— Rock that is composed of a wide variety of grain sizes and shapes. Porosity can be reduced considerably because smaller or irregularly shaped grains can be inserted in between the larger grains, thereby reducing the amount of pore space.



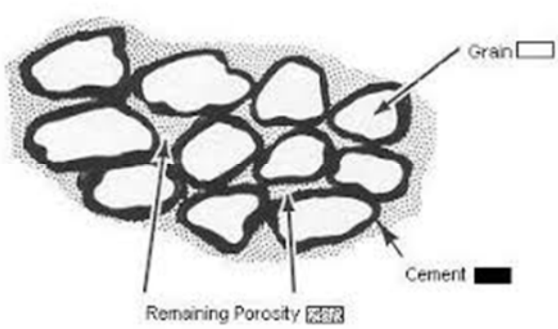
2-Grain Packing— Refers to the spacing or density patterns of grains in a sedimentary rock and is a function mainly of grain size, grain shape, and the degree of compaction of the sediment. Packing strongly affects the bulk density of the rocks as well as their porosity and permeability. The effects of packing on porosity can be illustrated by considering the change in porosity that takes place when even-size spheres are rearranged from open packing (cubic packing) to tightest or closed packing (rhombohedral packing). Cubic packing can yield a porosity of 47.6%. Rhombohedral packing yields approximately 26.0%.



3-Compaction— Over a long period of time sediments can accumulate and create formations that are thousands of feet thick. The weight of the overlying sediments squeezes the particles together into the tightest arrangement possible. The load pressure also squeezes out the water that occupies the pore spaces between the particles, thus reducing the bulk volume of the formation. Compaction is dependent not only on overburden pressure but also on the different types of clastic materials present in the formation. Compaction affects porosity and permeability by reducing the amount of interconnected pore space.



4-Cementation — Cementation is the Crystallization or precipitation of soluble minerals in the pore spaces between clastic particles. The process of lithification (the conversion of unconsolidated deposits into solid rock) is completed by cementation. Common cementing agents include calcite ($CaCO_3$), silica (SiO_2), and iron oxide (Fe_2O_3). Minerals in solution crystallize out of solution to coat grains and may eventually fill the pore spaces completely. Porosity and permeability can be reduced significantly due to cementation.



5-Permeability—

Recovery of hydrocarbons from the reservoir is an important process in petroleum engineering and estimating permeability can aid in determining how much hydrocarbons can be produced from a reservoir. Permeability is a measure of the ease with which a formation permits a fluid to flow through it. To be permeable, a formation must have interconnected porosity (intergranular or intercrystalline porosity, interconnected vugs, or fractures).

To determine the permeability of a formation, several factors must be known: the size and shape of the formation, its fluid properties, the pressure exerted on the fluids, and the amount of fluid flow. The more pressure exerted on a fluid, the higher the flow rate. The more viscous the fluid, the more difficult it is to push through the rock. Viscosity refers to a fluid's internal resistance to flow, or it's internal friction. For example, it is much more difficult to push honey through a rock than it is to push air through it. Permeability is measured in darcies. Few rocks have a permeability of 1 darcy, therefore permeability is usually expressed in millidarcies or 1/1000 of a darcy.

Permeability is usually measured parallel to the bedding planes of the reservoir rock and is commonly referred to as horizontal permeability. This is generally the main path of the flowing fluids into the borehole. Vertical permeability is measured across the bedding planes and is usually less than horizontal permeability. The reason why horizontal permeability is generally higher than vertical permeability lies largely in the arrangement and packing of the rock grains during deposition and subsequent compaction. For example, flat grains may align and overlap parallel to the depositional surface, thereby increasing the horizontal permeability, see Figure 25. High vertical permeabilities are generally the result of fractures and of solution along the fractures that cut across the bedding planes. They are commonly found in carbonate rocks or other rock types with a brittle fabric and also in clastic rocks with a high content of soluble material.

Examples of variations in permeability and porosity

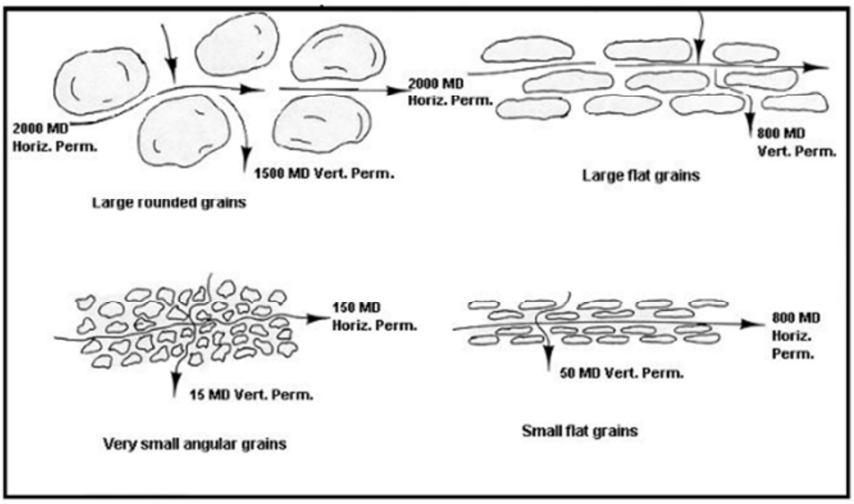
• Some fine-grained sandstones can have large amounts of interconnected porosity; however, the individual pores may be quite small. As a result, the pore throats connecting individual pores may be quite restricted and tortuous; therefore, the permeabilities of such fine-grained formations may be quite low.

• Shales and clays¾ which contain very fine-grained particles often exhibit very high porosities. However, because the pores and pore throats within these formations are so small, most shales and clays exhibit virtually no permeability.

• Some limestones may contain very little porosity, or isolated vuggy porosity that is not interconnected. These types of formations will exhibit very little permeability. However, if the formation is naturally fractured (or even hydraulically fractured), permeability will be higher because the isolated pores are interconnected by the fractures.

• POROSITY IS NOT DEPENDENT ON GRAIN SIZE

• PERMEABILITY IS DEPENDENT ON GRAIN SIZE



Petroleum geology-3

<u>Water saturation</u>

The pore space in a rock is occupied by fluids. In hydrocarbon reservoirs these fluids are hydrocarbon gasses, oil and an aqueous brine. We define the pore fraction of each of these as Sg, So and Sw, respectively.

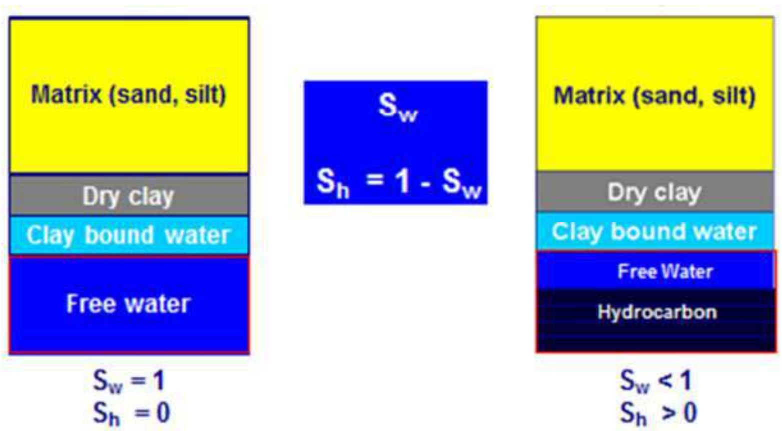
Saturation is defined as that fraction, or percent, of the pore volume occupied by a particular fluid (oil, gas, or water). This property is expressed mathematically by the following relationship:

$$\text{fluid saturation} = \frac{\text{total volume of the fluid}}{\text{pore volume}}$$

Applying the above mathematical concept of saturation to each reservoir fluid gives

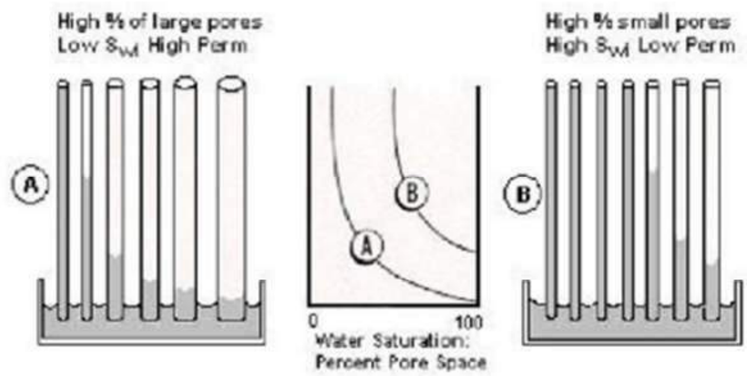
$$S_o = \frac{\text{volume of oil}}{\text{pore volume}} \qquad S_g = \frac{\text{volume of gas}}{\text{pore volume}}$$

$$S_w = \frac{\text{volume of water}}{\text{pore volume}}$$



Capillary Pressure

Reservoir rocks are composed of varying sizes of grains, pores, and capillaries (channels between grains which connect pores together, sometimes called pore throats). As the size of the pores and channels decrease, the surface tension of fluids in the rock increases. When there are several fluids in the rock, each fluid has a different surface tension and adhesion that causes a pressure variation between those fluids. This pressure is called capillary pressure and is often sufficient to prevent the flow of one fluid in the presence of another. For example, Figure 30 shows that the same adhesive forces that were mentioned previously will cause water, when in contact with air, to rise slightly against the walls of its container, against the pull of gravity, and form a concave meniscus. If several tubes of varying diameter are placed in a water-filled container, a meniscus forms on the inside walls of the tubes. In the very narrow tubes, the entire air-water interface will be concave upward. However, surface tension at the air-water interface will attempt to flatten this interface, thereby causing a slight rise in the level of water across the entire



diameter of the tube. As this occurs, the adhesion of the water to glass will continue to pull water molecules upward near the edge of the tubes. By this mechanism the water level in the tube will continue to rise until the upward force is balanced by the weight of the water column.

Large pore throat diameters

- Generally yield a lower capillary pressure because of the decrease in the amount of surface tension.
- Large pores that are often associated with large pore throat diameters will also contain lesser amounts of adsorbed (adhered) water because the surface-to-volume ratio of the pore is low.

Small pore throat diameters

- Generally yield higher capillary pressures because of the greater amount of surface tension.
- Small pores that are often associated with small pore throat diameters will have a high surface-to-volume ratio, and therefore may contain greater amounts of adsorbed (adhered) water.

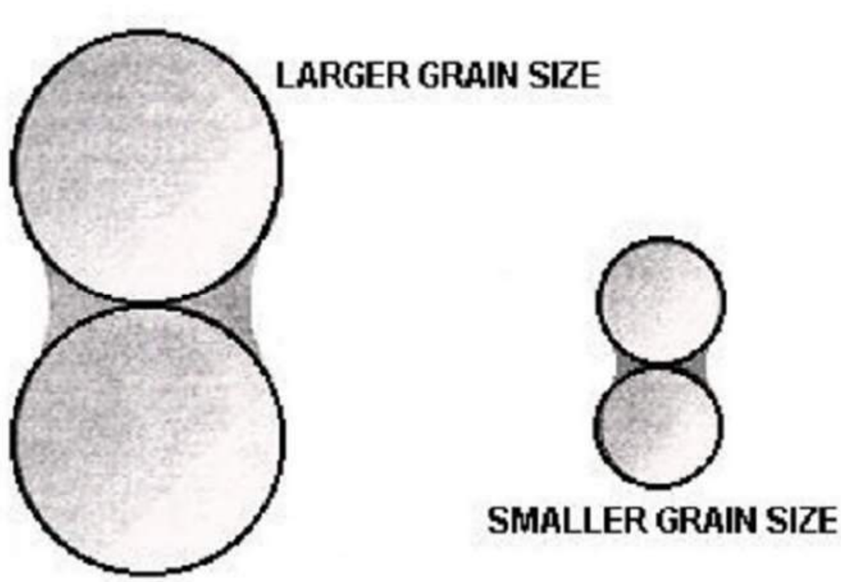


Figure 31 Grain size effects on capillary pressure and pore throat diameters.

Fluid Distribution within a Reservoir

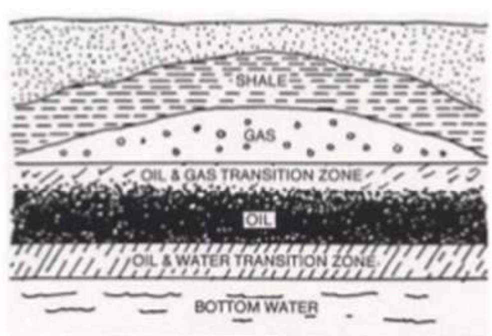
Petroleum reservoirs generally contain a combination of three fluids:

1) Natural Gas

2) Oil

3) Water

As hydrocarbons and water accumulate in a reservoir, vertical separation occurs as a result of the difference in the specific gravity of the various fluids. Typically, the lighter fluids, like gas, rise to the top of the reservoir. Below the lighter fluids is a gas to oil transition zone. This transition zone is a relatively thin zone above the oil accumulation. The oil accumulation may be of primary importance because it contains crude oil and possibly saturated gas. Below the oil accumulation in most reservoirs is an oil-water transition zone of varying thickness, which is partly filled with water and oil. Finally, beneath the oil-water transition zone is that part of the formation completely saturated with water. It is important to note that all reservoirs may not contain natural gas, oil, and water. Some formations may only contain water. However, any formation that contains hydrocarbons will also contain some amount of water. It is because of this water that we are able to measure the resistivity of a formation in logging.



6.4 RELATIONSHIP BETWEEN POROSITY, PERMEABILITY, AND TEXTURE

The texture of a sediment is closely correlated with its porosity and permeability. The texture of a reservoir rock is related to the original depositional fabric of the sediment, which is modified by subsequent diagenesis. This diagenesis may be negligible in many sandstones, but in carbonates it may be sufficient to obliterate all traces of original depositional features. Before considering the effects of diagenesis on porosity and permeability, the effects of the original depositional fabric on these two parameters must be discussed. The following account is based largely on studies by Krumbein and Monk (1942), Gaithor (1953), Rogers and Head (1961), Potter and Mast (1963), Chilingar (1964), Beard and Weyl (1973), Pryor (1973), and Atkins and McBride (1992). The textural parameters of an unconsolidated sediment that may affect porosity and permeability are as follows:

Grain shape (roundness, sphericity)
Grain size

Sorting
Fabric (packing, grain orientation)

These parameters are described and discussed in the following sections.

6.4.1 Relationship between Porosity, Permeability, and Grain Shape

The two aspects of grain shape to consider are roundness and sphericity (Powers, 1953). As Fig. 6.19 shows, these two properties are quite distinct. Roundness describes the degree of angularity of the particle. Sphericity describes the degree to which the particle approaches a spherical shape. Mathematical methods of analyzing these variables are available.

Data on the effect of roundness and sphericity on porosity and permeability are sparse. Fraser (1935) inferred that porosity might decrease with sphericity because spherical grains may be more tightly packed than subspherical ones.

6.4.2 Relationship between Porosity, Permeability, and Grain Size

Theoretically, porosity is independent of grain size for uniformly packed and graded sands (Rogers and Head, 1961). In practice, however, coarser sands sometimes have higher porosities than do finer sands or vice versa (e.g., Lee, 1919; Sneider et al., 1977). This disparity may be due to separate but correlative factors such as sorting and/or cementation.

Permeability declines with decreasing grain size because pore diameter decreases and hence capillary pressure increases (Krumbein and Monk, 1942). Thus a sand and a shale may both have porosities of 10%; whereas the former may be a permeable reservoir, the latter may be an impermeable cap rock.

6.4.3 Relationship between Porosity, Permeability, and Grain Sorting

Porosity increases with improved sorting. As sorting decreases, the pores between the larger, framework-forming grains are infilled by the smaller particles. Permeability decreases with sorting for the same reason (Fraser, 1935; Rogers and Head, 1961; Beard and Weyl, 1973). As mentioned earlier, sorting sometimes varies with the grain size of a particular

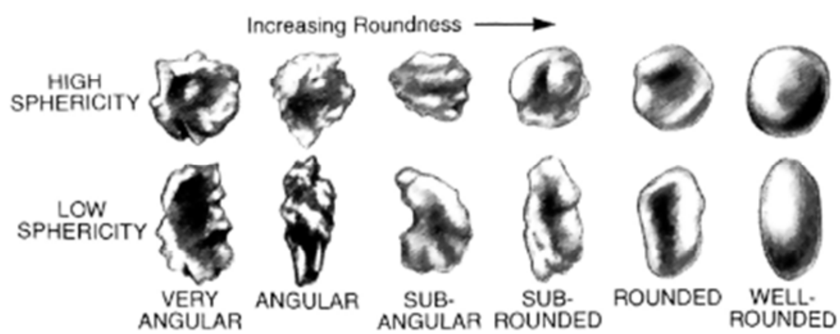


FIGURE 6.19 Sand grains showing the difference between shape and sphericity.

reservoir sand, thus indicating a possible correlation between porosity and grain size. Fig. 6.20 summarizes the effects of sorting and grain size on porosity and permeability in unconsolidated sand.

6.4.4 Relationship between Porosity, Permeability, and Grain Packing

The two important characteristics of the fabric of a sediment are how the grains are packed and how they are oriented. The classic studies of sediment packing were described by Fraser

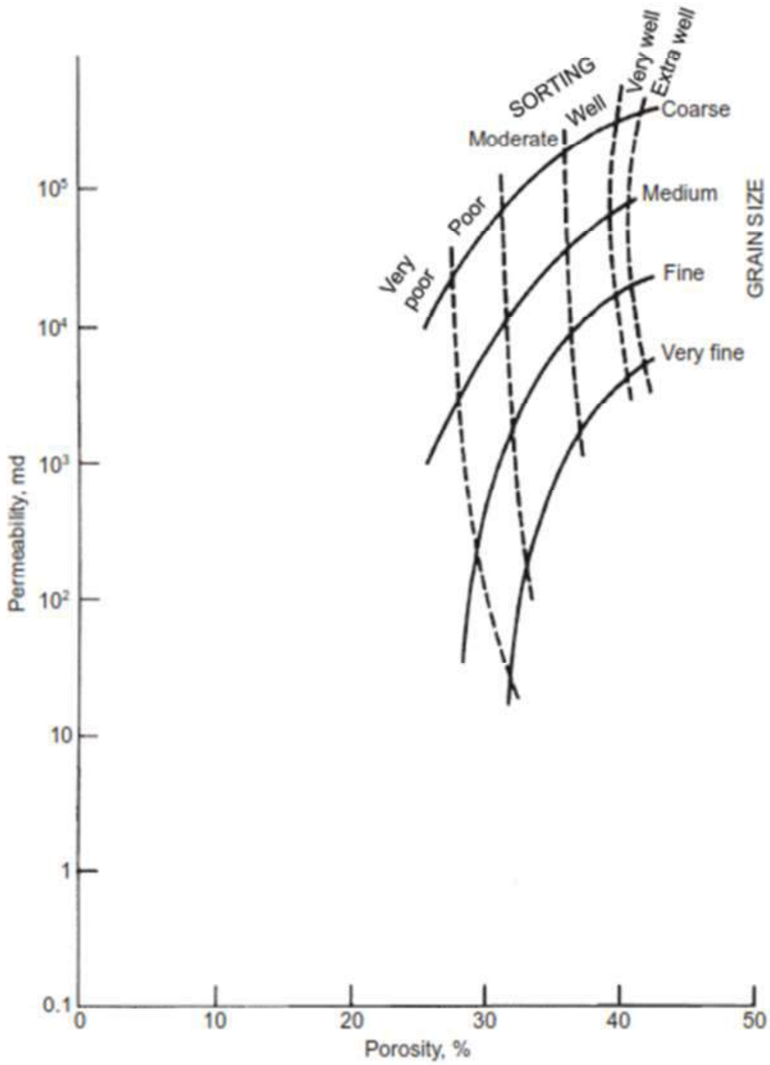


FIGURE 6.20 Graph of porosity against permeability showing their relationship with grain size and sorting for uncemented sands. *After* Beard and Weyl (1973), Nagtegaal (1978).

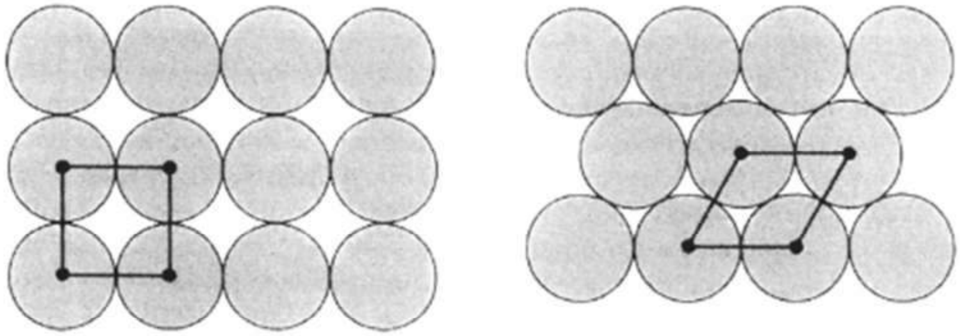


FIGURE 6.21 The loosest and tightest theoretical packings for spheres of uniform diameter.

(1935) and Graton and Fraser (1935). They showed that spheres of uniform size have six theoretical packing geometries. These geometries range from the loosest cubic style with a porosity of 48% down to the tightest rhombohedral style with a 26% porosity (Fig. 6.21).

The significance of packing to porosity can be observed when trying to pour the residue of a packet of sugar into a sugar bowl. The sugar poured into the bowl has settled under gravity into a loose packing. Tapping the container causes the level of sugar to drop as the grains fall into a tighter packing, causing porosity to decrease and bulk density to increase. Packing is obviously a major influence on the porosity of sediments; several geologists have tried to carry out empirical, as opposed to theoretical, studies (e.g., Kahn, 1956; Morrow, 1971). Particular attention has been paid to relating packing to the depositional process (e.g., Martini, 1972). Like grain sphericity and roundness, packing is not amenable to extensive statistical analysis. Intuitively, one might expect sediments deposited under the influence of gravity, such as fluidized flows and turbidites, to exhibit looser grain packing than those laid down by traction processes. However, postdepositional compaction probably causes rapid packing adjustment and porosity loss during early burial.

6.4.5 Relationship between Porosity, Permeability, and Depositional Process

Several studies have been made to try to establish the way in which the depositional process and environment of a sediment may effect its reservoir characteristics. This is not easy to resolve because grain size and sorting are related not only to the final depositional environment, but also reflect the characteristics of the rocks from which they were derived.

For what it is worth, Pryor (1973) recorded permeabilities averaging 93, 68, and 54 darcies, and porosities averaging 41%, 49%, and 49% for point bars, beaches, and dunes, respectively. Atkins and McBride (1992) reported comparable values for porosity, and noted that trapped air bubbles and packing effects accounted for several percent of the porosity. There is no doubt that porosity and permeability are rapidly reduced due to packing adjustments and compaction early on during burial.

6.4.6 Relationship between Porosity, Permeability, and Grain Orientation

The preceding analysis of packing was based on the assumption that grains are spherical, which is generally untrue of all sediments except oolites. Most quartz grains are actually prolate spheroids, slightly elongated with respect to their C crystallographic axis (Allen, 1970). Sands also contain flaky grains of mica, clay, shell fragments, and other constituents. Skeletal carbonates have still more eccentric grain shapes. Thus the second element of fabric, namely, orientation, is perhaps more significant to porosity and permeability than packing is. The orientation of grains may have little effect on porosity, but a major effect on permeability.

Most sediments are stratified, the layering being caused by flaky grains, such as mica, shells, and plant fragments, as well as by clay laminae. Because of this stratification the vertical permeability is generally considerably lower than the horizontal permeability. The ratio of vertical to horizontal permeability in a reservoir is important because of its effect on coning as the oil and gas are produced. Variation in permeability also occurs parallel to bedding. In most sands the grains generally show a preferential alignment within the horizontal plane. Grain orientation can be measured by various methods (Sippel, 1971). Studies of horizontally bedded sands have shown that grains are elongated parallel to current direction (e.g., Shelton and Mack, 1970; von Rad, 1971; Martini, 1971, 1972). For cross-bedded sands the situation is more complex because grains may be aligned parallel to the strike of foresets due to gravitational rolling. Figure 6.22 shows that permeability will be greatest parallel to grain orientation, since this orientation is the fabric alignment with least resistance to fluid movement (Scheiddegger, 1960).

Studies of the relationship between fabric and permeability variation have produced different results on both small and large scales. Potter and Pettijohn (1977) have reviewed the conflicting results of a number of case histories, some of which show a correlation with grain orientation and some of which do not. It is necessary to consider not only small-scale permeability variations caused by grain alignment but also the larger variations caused by sedimentary structures.

Grain-size differences cause permeability variations far greater than those caused by grain orientation. Thus in the cross-bedded eolian sands of the Leman field (North Sea), horizontal permeabilities measured parallel to strike varied from as much as 0.5 to 38.5 md between

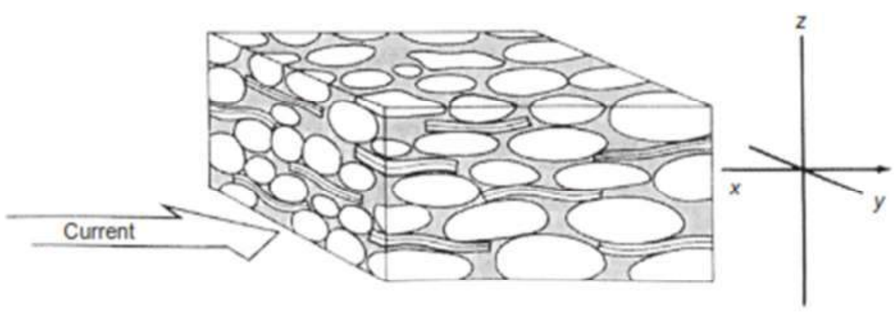


FIGURE 6.22 Block diagram of sand showing layered fabric with grains oriented parallel to current. Generally, $K_x > K_y > K_z$.

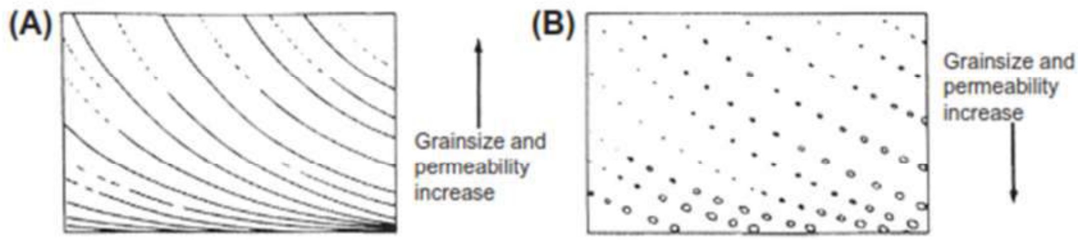


FIGURE 6.23 Permeability variations for (A) downward-fining and (B) downward-coarsening avalanche cross-beds.

adjacent foresets. This range in permeabilities is attributable to variations in grain size and sorting. Similarly, because eolian cross-beds generally show a decreasing grain size from foreset to toeset, permeability diminishes downward through each cross-bedded unit (Van Veen, 1975). Conversely, in many aqueously deposited cross-beds, avalanching causes grain size to increase downward. Thus permeability also increases down each foreset for the reason previously given (Fig. 6.23).

Detailed accounts of permeability variations within sedimentary structures, mainly cross-bedding, have been given by Weber (1982) and Hurst and Rosvoll (1991). The latter study reported 16,000 mini-permeameter readings. These showed that that there was greater variation of permeability found within sedimentary structures than between them.

On the still larger scale of whole sand bodies, grain-size-related permeabilities often have considerable variations (Richardson et al., 1987). When discussing the use of the SP log as a vertical profile of grain size it was pointed out that channels tend to have upward-fining grain-size profiles, and thus upward-decreasing permeability. By contrast barrier bar and delta mouth bar sands have upward-coarsening grain-size profiles, and thus upward-increasing permeability. These vertical changes in permeability are also often accompanied by commensurate variations in porosity. Thus there is a strong sedimentological control over the vertical and lateral variation of porosity and permeability within petroleum reservoirs on a hierarchy of scales, from variations within sedimentary structures, variations within sand bodies, and variations within formations, due to sand body trend (Fig. 6.24).

An example of the scale and significance of these variations is provided by a study of a Holocene sand-filled channel in Holland. Permeability increased from 25 md at the channel margin to 270 md in the center some 175 m away (Weber et al., 1972). Pumping tests showed that the drawdown was nearly concentric to the borehole, which suggests that the permeability had little preferred direction within the horizontal plane (Fig. 6.25).