Engineering Encyclopedia

Saudi Aramco DeskTop Standards

PETROLEUM GEOLOGY AND RESERVOIRS

Section **Page**

List of Figures

List of Tables

INFORMATION

INTRODUCTION

Geology is of major importance to the petroleum industry for the following reasons:

- It is necessary to drill through the rock structure of the earth in order to gain access to the hydrocarbon reservoir.
- Hydrocarbon is generated in the *source rock*.
- Hydrocarbon is stored within the rock structure of the earth.
- Hydrocarbons must be produced from the rocks of the earth.

ROCK STRUCTURES

The geology of interest to the petroleum industry lies in the earth's crust.

Earth Structure

The earth is essentially a sphere approximately 8,000 miles in diameter, with a circumference of approximately 25,000 miles. The earth consists of:

- A solid inner *core* (approximately 758 miles in diameter) (1,220 km)
- A liquid outer core (approximately 1,398 miles thick) (2,250 km)
- A solid, yet plastic, mantle (approximately 1,802 miles thick) (2,900 km)
- A surface crust varying in thickness from approximately 5,000 meters (3 miles or 16,000 ft) to approximately 70,000 meters (44 miles or 230,000 ft)

Figure 1 represents a highly simplified model of the earth's structure. Each region within the structure is complex in composition, with mass and energy transferring from one region to adjacent regions as geologic time passes.

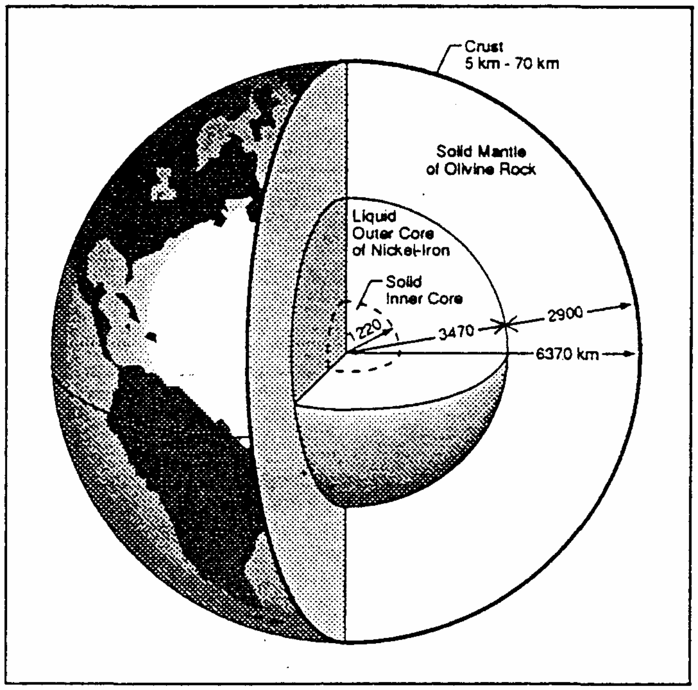

Figure 1. Structure of the Earth

The crust of the earth is of primary importance to the petroleum industry because this is where hydrocarbons are generated and from which hydrocarbons are produced. The average thickness of the crust is approximately 17,000 meters (10.5 miles or 55,000 feet). This crust consists of continental plates and oceanic plates moving in geologic time relative to one another. Properties and studies of relative motion of the plates are referred to as *plate tectonics*.

Sea level is the basic reference used in comparing relative elevations of the solid surface of the earth. Figure 2 indicates distribution of elevations of the solid surface of the earth relative to sea level. Over 70% of the earth's surface is covered by water. There would therefore appear to be essentially 2 1/2 times the potential for offshore hydrocarbon reservoirs as onshore hydrocarbon reservoirs, because of the significantly greater portion of the earth's surface covered by water. This Module will show, however, surface regions with primary hydrocarbon potential: the continents, their continental shelves, continental slopes, and continental rises. The abyssal plains of the major ocean depths do not have proper geologic characteristics to provide significant potential for hydrocarbon presence. These abyssal plains make up a significant percentage of the earth's surface.

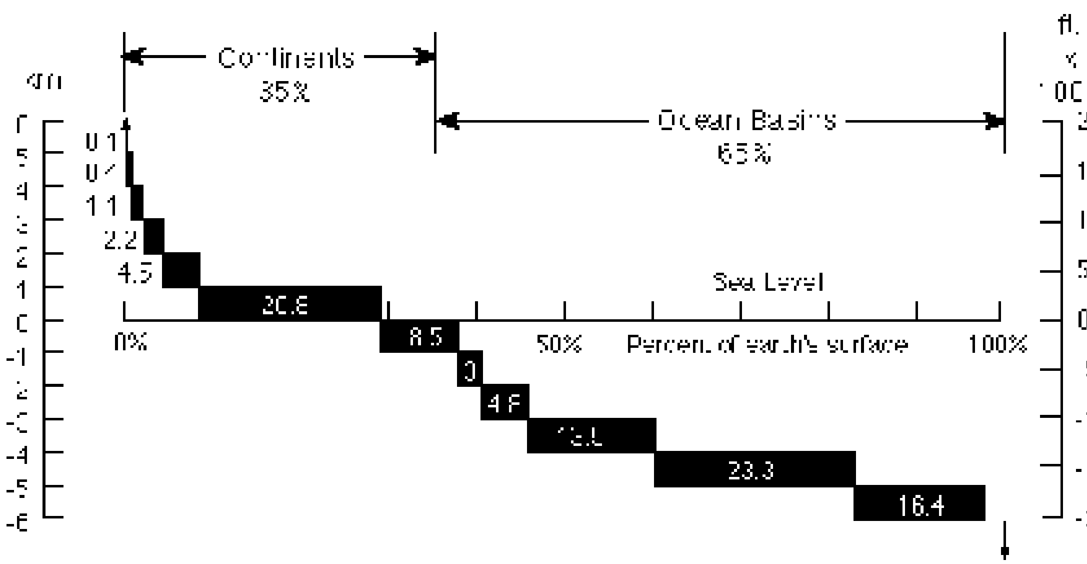

Figure 2. Graphic Representation of Earth Surface Elevation Relative to Sea Level

Figure 3 shows a typical major ocean cross-section. Assume that this graphic represents a *geologic cross-section* from west to east, across the southern Atlantic Ocean. A geologic cross-section is a vertical cut into the earth, with the horizontal axis representing surface position and the vertical axis representing depth. From west to east will be the continent of South America; its continental shelf; continental slope; continental rise to the western abyssal plain of the Atlantic Ocean; across the Atlantic Ocean's mid-oceanic ridge to the eastern abyssal plain; the continental rise; continental slope; continental shelf; and the continent of Africa on the east of the Atlantic Ocean.

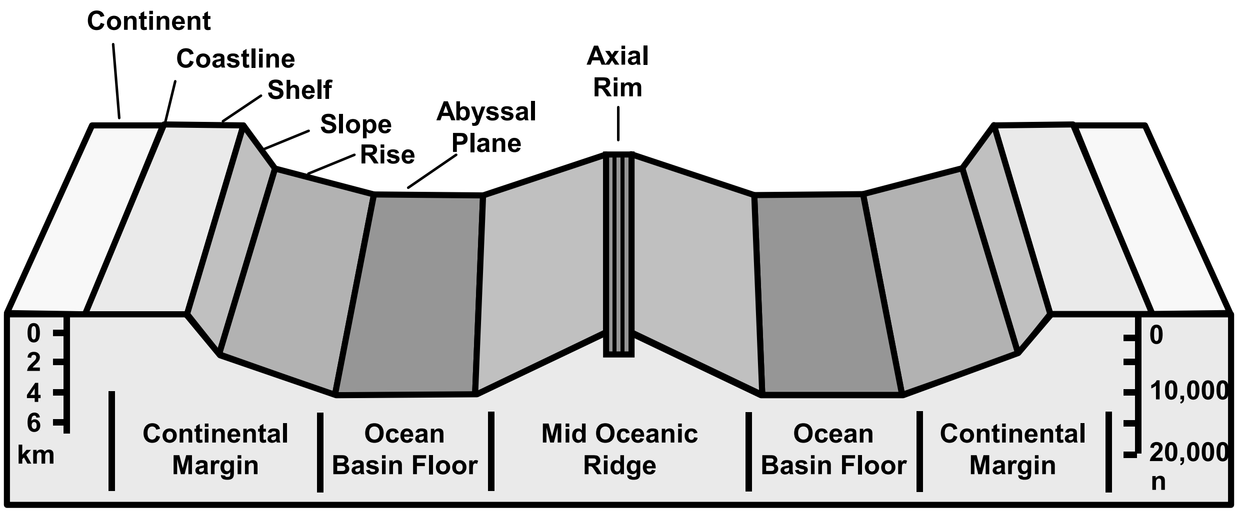

Figure 3. Typical Major Ocean Cross-Section

The crust of the earth is a dynamic system because the continental plates and oceanic plates are moving relative to one another. The Atlantic Ocean's width, for example, is increasing at a rate of about one inch per year. In terms of geologic time, its width is increasing by five feet every 60 years along the ocean's axial rift. Iceland is an above-sea-level exposure of the mid-oceanic ridge of the Atlantic Ocean and is therefore a geologically unstable land mass.

The theory of plate tectonics refers to the motions of continental and oceanic plates. According to this theory, the major land masses of the earth began colliding approximately 500 million years ago. The collision process continued for approximately 235 million years and resulted in the formation of the supercontinent of *Pangaea*. Pangaea existed as a single supercontinent until 200 million years ago, when it began to break apart to form the Atlantic and Indian Oceans and separate into the continents of North America, South America, Africa, Eurasia, Australia, and Antarctica. At this time, the land mass of Saudi Arabia separated from the continent of Africa, beginning the formation of the Red Sea. The subcontinent of India broke away from the southeastern part of Africa and began to move to the northeast. It collided with the land mass that is now China, forming the Himalayan Mountains. These crustal plate motions occur as the plates move on the plastic mantle of the earth. This breakup of Pangaea and the relative motions of the plates continue, as indicated by the widening of the Atlantic Ocean and the increasing width of the Red Sea.

According to one theory, this formation and breakup of a supercontinent, in geologic time, is a cyclic process caused by the earth acting as a heat engine as heat is dissipated from the earth’s interior. The separation of the land masses of the supercontinent of Pangaea is nearing completion. At a later time, these masses will come back together, forming a new supercontinent as the cyclic process continues.

Most major earthquakes result from relative motion between crustal plates of the earth. As these plates collide or slide relative to one another, the frictional forces between the plates prevent relative motion until the maximum force of static friction is exceeded. When this occurs, the abrupt movement of the plates results in major earthquakes. It is estimated that the earthquake that caused major damage and loss of life in Mexico City in 1985 resulted from approximately nine inches of slippage between crustal plates. The crust of the earth is a dynamic system, and the petroleum industry operates within that system.

The earth was formed approximately 5 billion (5,000 million) years ago. As will be shown, the petroleum industry is primarily interested in the most recent 500 million to 600 million years.

Classes of Rock

The earth is made up of three rock classes:

- Igneous
- Sedimentary
- Metamorphic

Igneous Rock

Igneous rock is rock formed from cooling *magma*, or molten rock. Igneous rock at the earth's surface usually implies volcanic activity where magma has been extruded to the surface in the form of *lava*. Upon exposure to the atmosphere, cooling and solidifying occurs, resulting in the formation of *extrusive igneous rock*. The greatest presence of igneous rock in the crust of the earth, however, is intrusive or *plutonic igneous rock*. This is rock that was formed within the crust of the earth when magma was intruded into overlying rock structures during volcanic activity, then cooled and solidified, without being exposed to the atmosphere.

The most common *intrusive igneous rock* is *granite*. Figure 4 graphically represents a microscopic view of a granite sample. The microscopic view indicates randomness in arrangement of its crystalline structure, with no particular order apparent. The greatest significance to the petroleum industry is that most igneous rock has very little void space (open space within the rock) so there is no potential storage of hydrocarbons. Although there are exceptions, in general, hydrocarbon reservoirs will not be found in igneous rock.

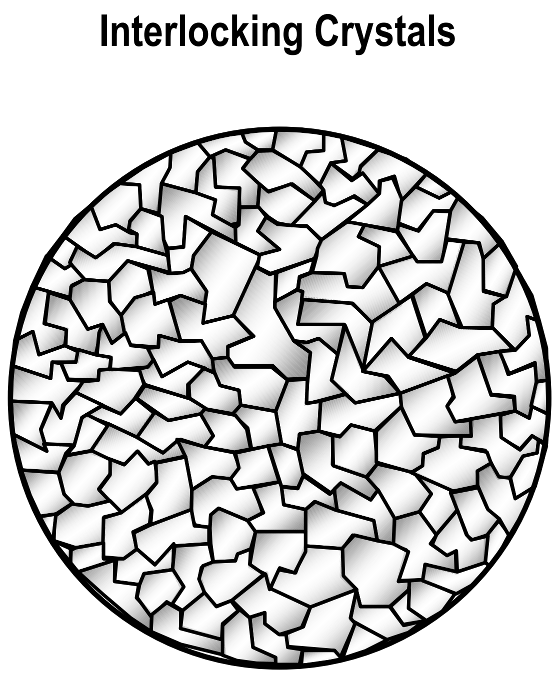

Figure 4. Graphical Representation of Microscopic View of Sample of Granite

According to one theory, earth formation first consisted of gases converging to form a molten sphere. As this molten sphere cooled, its surface solidified to form an igneous crust. After formation, the earth had an atmosphere with the presence of air and water. This atmosphere provided an environment for weathering or erosion, breaking down this original igneous crust by mechanical and chemical processes, resulting in additional classes of rock in the crust.

Igneous rock beneath the surface rock of the earth's crust is referred to as *basement rock*. This basement rock is usually granite. When drillers drill into basement rock, they will normally cease drilling. Unless evidence to the contrary is available, drillers normally assume that when granite is drilled into, it is basement rock. Since it is not expected that hydrocarbons will be found in igneous rock, there is no justification to continue drilling.

However, when granite is drilled into, it may not necessarily be the basement rock. Granite may result from an intrusion of magma into overlying rocks during volcanic activity. Massive igneous intrusions into overlying rock structures are referred to as *batholiths*. Essentially vertical veins of igneous intrusions are called *dike*s, and essentially horizontal veins of igneous intrusions are called *sills*.

Sedimentary Rock

A second class of rocks making up the earth is sedimentary rock. Figure 5 graphically represents a microscopic view of a sandstone sample as a representative sedimentary rock. Note in this graphic that the solid particles of the sandstone have a random orientation. As was the case of granite as the representative igneous rock, there is no particular order in the particle arrangement. However, unlike most igneous rock, many sedimentary rocks have void space, as indicated in the figure. These open spaces provide for potential storage of hydrocarbons, which may be found in sedimentary rocks.

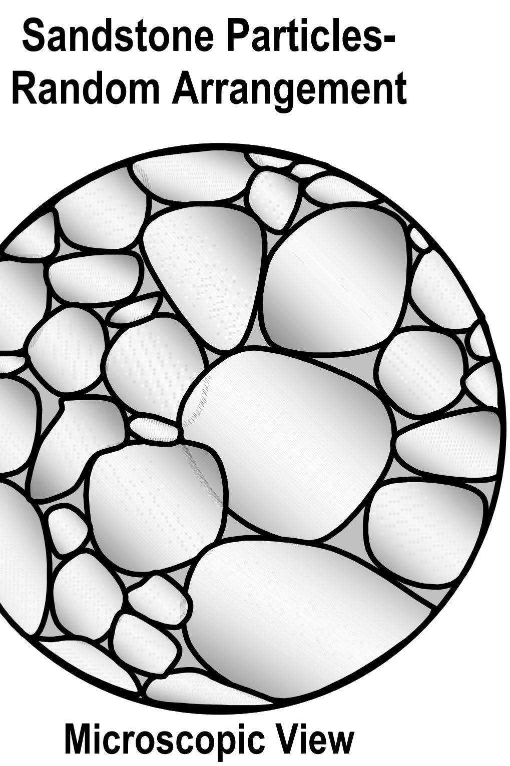

Figure 5. Graphical Representation of Microscopic View of Sample of Sandstone

Sedimentary rocks have several different origins or sources. Three of these sources dominate:

Fragmental Source (Clastics) – These rocks result from the consolidation of fragments of previously existing rocks into more recently formed rocks. The original crust of the earth was probably igneous, but the earth had an atmosphere, resulting in weathering or erosion of that original crust. Weathering occurs in the forms of freeze-melt cycles during winter, wind erosion and abrasion, water action, solution breakdown in the presence of water, and chemical action. As time passes, previously existing rocks break down to form fragments or particles that eventually will combine to form sedimentary rocks.

Regions such as the Rocky Mountains, Alps, Pyrenees, Andes, and Himalayas may experience many freeze-melt cycles in a single winter season. Water fills fractures within the rock structure, and as that water freezes, it expands and opens the fractures. It later melts and upon refreezing, expansion again occurs, further opening the fractures. In a region experiencing many such cycles during a season, significant breakdown of rock structures can occur.

When the mechanical action of water runoff due to snow and ice melt and rains in combined solution and chemical effects in the presence of water, the weathering and erosional process will result in the formation of small rock fragments.

Mountains with major snow accumulations in the winter season and significant snow melt in the springtime combining with spring rains result in major water volumes flowing from the mountains to lower elevations onto plains, into rivers and lakes, and finally into seas and oceans. Depending on the rate of snow melt and rainfall, the velocity of the streams will transport rock particles of various sizes. The greater the water velocity, the larger the rock particles that can be transported downstream. Many of these particles may be several inches in diameter. These larger rocks may be trapped between other rocks on the stream-bed and not break loose for thousands of years, but this is a brief time geologically. Their net resultant motion is downstream. If, due to the velocity of this water runoff, these large particles are being transported, then particles of all smaller sizes will also be transported until they reach an environment of deposition.

As a stream empties into a large lake, the water velocity reduces drastically with distance from the mouth of the stream into the lake. As that velocity decreases, the first solid particles to fall out will be the larger rocks. The smaller particles will be dropped, according to size, farther out into the lake. When, due to decreasing velocity, running water deposits its solid load, it will grade those particles according to size, from largest to smallest: gravel, pebbles, sand, silt, and mud. With proper conditions existing in future geologic time, these particles will form into *clastics*:

- Gravel and pebbles form *conglomerates* and breccias
- Sand and larger silt particles form sandstones
- Smaller particles, from smaller silts to mud size, form *shale's*.

The implication is that the difference between sandstone and shale is the particle size, determined by the difference in the environment of deposition.

Environments of deposition may vary extensively. Typical examples are:

- Desert sand and sand dunes
- Beaches
- River deltas
- River channels
- Flat plains at the base of major mountain chains
- Offshore adjacent to the continents
  - Continental slope environments
  - Continental shelf environments
  - Continental rise environments

These particles may then be converted from simple fragments into solid rock during geologic time, if proper conditions exist for that conversion. *Lithification* is the process by which this conversion occurs, through action of pressure, temperature, and geologic time with chemical action involved as time passes. A beach sand deposit may therefore be converted into beach sandstone over millions of years of geologic time, as a result of pressure, temperature, and chemical action. Several different clastics formed through lithification are listed in Table 1.

TEXTURE	SEDIMENT	CLASTICS
Coarse	Rounded Pebbles Angular Pieces	Conglomerate Breccia
Medium	Sand	Sandstone
Fine	Mud	Shale

Table 1. Some Clastics

Because of their source, all sedimentary rocks of the earth are in its crust. If types of sedimentary rocks within the earth's crust are compared, about 20% by volume may be classified as sandstones and about 70% by volume may be classified as shale's. Therefore, at least 90% by volume of the sedimentary rocks of the earth are clastics. Even though there are three dominant sources of sedimentary rocks, the first of these listed, fragmental, is the primary source.

Approximately 10% by volume of the sedimentary rocks of the earth are *limestone*. By chemical composition, limestone is calcium carbonate ($CaCO_3$). Some limestone's may be considered clastics. However, this is a minor source. Limestone is primarily formed by one of the other two dominant sources of sedimentary rocks: biogenic and chemical.

Biogenic Source – The second dominant source of sedimentary rock is biogenic, implying that the rock is organic in origin, resulting from deposition of plant and/or animal residue. This type of rock is generated in geologic time through geologic processes as those organic materials evolve into *biogenic source sedimentary rock*.

Consider an earth surface environment today that, in geologic time, will likely lead to generation of biogenic source limestone and is now in the process of that generation. The Great Barrier Reef off the Australian coast is a coral reef. Coral is living organism, and coral populations such as those that make up the Great Barrier Reef generate calcium carbonate as a residue of their life cycle. In geologic time under proper conditions, lithification will occur and the original organic debris from the coral will convert, through lithification, into biogenic limestone.

One of the most common biogenic source sedimentary rocks is *coal*. The common earth surface environment which leads to the formation of coal is a swamp environment. In this swamp or stagnant water environment, trees and plants grow and complete their life cycle. Upon dying, their organic debris falls into the swamp and begins to deteriorate as new plants grow. This process continues for millions of years as the organic materials accumulate. Lithification begins as the deposited organic debris first becomes peat moss, then lignite, and finally bituminous or soft coal (sedimentary coal). It has now become a biogenic source sedimentary rock. While biogenic limestone originates primarily from animal residue, coal originates primarily from plant residue.

Chemical Source – The third dominant source of sedimentary rock is chemical, a major source of limestone. Over 70% of the earth's surface is water surface, with the majority of that surface being salt water seas and oceans containing calcium salts. Under proper conditions, these salts react with carbon dioxide (CO_2) in the atmosphere, resulting in the chemical formation of calcium carbonate ($CaCO_3$). Calcium carbonate is a solid precipitate that settles to the sea floor in this ocean environment and, upon lithification, forms limestone. If this is truly a chemical process, then no organic presence is necessary. However, in most water environments, both plant and animal life exist. As those plants and animals go through their life cycle and die, their organic residue is deposited on the sea floor along with the calcium carbonate precipitate. During lithification, there will have been an organic presence. Most limestone has been formed as a by-product of, or in the presence of, organic materials. Limestone can be biogenic in origin or chemical in origin. *Chalk* is a form of biogenic limestone. If chalk exists as sedimentary rock, it is biogenic in origin.

Essentially all shale and limestone result from deposition in a water environment. In summary, comparing percent by volume, sedimentary rock is approximately 20% sandstone, 70% shale, and 10% limestone (calcium carbonate). These are approximate percentages, because other types of sedimentary rock do exist. Some of these are coal, sedimentary salt or rock salt (one form being anhydrite), and conglomerates. When compared with sandstone, shale, and limestone, these others are present in minor quantities. In particular instances relative to hydrocarbon presence and production, however, minor sedimentary rocks may be of major significance.

The reservoir engineer or petroleum geologist might refer to the reservoir as a carbonate reservoir, even though the reservoir may be limestone. While all limestone's are carbonates, not all carbonates are limestone's. For example, *dolomite* is a carbonate, but it is magnesium calcium carbonate, indicating the presence of magnesium atoms within the carbonate molecular structure. Many hydrocarbon reservoirs exist in dolomite.

The above percentages are important to the world petroleum industry. Hydrocarbons are not expected to be found in igneous rock nor in *metamorphic rock*. Only sedimentary rock remains. Hydrocarbons are not expected to be produced from shale, so 70% of the sedimentary rocks may also be eliminated as possible hydrocarbon *reservoir rocks*.

Metamorphic Rock

Metamorphic rock is rock formed from previously existing rocks by extremes of pressure, temperature, time, and chemical action. When conditions leading to lithification are carried to the extreme, metamorphism occurs. As an example, sand originally deposited as desert sand may undergo lithification to form sandstone in geologic time. During further passage of geologic time, conditions may then exist leading to the metamorphosis of that desert sandstone, resulting in its conversion to *quartzite*, a form of metamorphic rock. The resulting quartzite will have very different properties from those of the desert sandstone from which it was formed, and may have significant implications for petroleum operations in the region. For example, sandstone is relatively easily to drill. However, quartzite may cause problems in the drilling operation. Most drilling occurs by exceeding the compressive strength of the rock. Some quartzite's have compressive strengths greater than that of structural steel. This metamorphic rock, therefore, affects drilling operations and requires a change in drill bit type.

Another example of the effect of metamorphism on petroleum activities involves extreme temperatures. In order for organic depositions to be converted into hydrocarbons, they must be exposed to a minimum temperature. If, however, a particular maximum temperature is exceeded, any organic materials or hydrocarbons present within the sediment or rock will be destroyed. This temperature range is referred to as the "temperature window." In many metamorphic processes occurring in geologic history, this maximum temperature will be exceeded. If a hydrocarbon reservoir was present prior to this high temperature condition, that hydrocarbon will have been destroyed and will therefore not be available for production in today's industry. How could such extreme conditions of temperature and pressure exist in a natural setting? Two examples will follow.

Consider the offshore depositional environment adjacent to a continental shoreline, as illustrated in Figure 6. Particles eroded from onshore rocks will, in geologic time, be carried by water runoff and deposited offshore adjacent to the shoreline. Overburden is the sedimentation overlying a particular sedimentary bed. The overburden pressure is the pressure at depth due to the weight of those overlying sediments. The overburden pressure is dependent upon depth of overlying sediments, the various densities of those sediments, and the fluids present within them. As time passes, the weight of these sediments will increase as they accumulate, resulting in an increasing overburden pressure on the underlying basement rock. Even though this igneous basement is solid rock, it is plastic and will deform with increasing pressure and temperature. Its deformation may not seem significant in normal time considerations, but in geologic time, resulting deformations are very important.

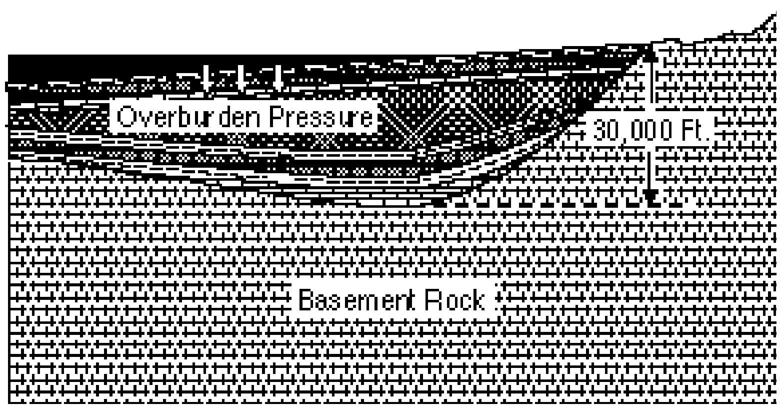

Figure 6. Offshore Depositional Environment

Assume, for example, that the underlying basement rock subsides with geologic activity as time passes, so that those sedimentary deposits subside an average of one inch per 100 years as a result of basement deformation. In 1,000 years as deposition and subsidence continue, there are 10 inches of subsidence, and in 1 million years 10,000 inches, or 833 ft. Passage of 100 million years is significant but not excessive in geologic time. In only 100 million years, as a result of only one inch of subsidence and deposition per 100 years, these sediments would be over 83,000 ft, or 15.7 miles, in depth.

In a sedimentary environment, upon lithification, any void space remaining in the resultant rock will be 100% filled. There is no such condition as a perfect vacuum within the earth. The most probable materials within the void space will be a combination of fluids. The pressure within these void spaces is known as the formation fluid pressure or reservoir fluid pressure, in the case of a hydrocarbon reservoir. This pressure is dependent upon, but not equal to, the overburden pressure within the rock itself. From experience, a normal formation fluid pressure gradient is accepted as 0.465 psi/ft of depth. This compares to an average overburden pressure gradient of 1 psi/ft of depth. For example, if a rock structure containing fluids is drilled into at a depth of 5,230 ft, the rock overburden pressure at this depth should be 5,230 psig and the formation fluid pressure should be 2,432 psig, if it is a normal pressured reservoir. If the formation fluid pressure is greater than 2,432 psig, it is considered an abnormally high pressured reservoir. If the formation fluid pressure is less than 2,432 psig, the reservoir is considered to be an abnormally low pressured reservoir.

Consider a sedimentary bed at a time in geologic history, at a depth of 20,000 ft, with an average overburden pressure gradient of 1 psi/ft of depth. This sedimentary bed should exist with an overburden pressure of 20,000 psig. In addition to the pressure consideration, earth temperature increases with depth. The deeper the sedimentary bed, the longer the passage of geologic time since its deposition, with chemical action occurring as that time passes. Consequently, with depth, all necessary conditions exist for metamorphism to occur.

Extreme pressures, high temperatures, long periods of geologic time, and chemical action occurring as that time passes result in conversion of the previously existing rocks into metamorphic rocks. In the drilling operation, the deeper the well is drilled, the more likely it is that the driller will encounter metamorphic rocks.

It is not necessary that rocks exist at great depths in order for metamorphism to occur. The Appalachian Mountain region of eastern North America is an excellent example of how conditions leading to metamorphism can exist relatively near the surface.

Figure 7 is a typical geologic cross-section, from west to east, of the Appalachian Mountain region. Because of the presence of coal deposits, this is an excellent example of range of geologic activity in a region. Approximately 500 million years ago, due to motion of continental plates of the crust of the earth (plate tectonics), the land mass of the Continent of Africa began colliding with the land mass of the Continent of North America. This collision activity continued for 235 million years, until 265 million years ago. As a result of the colliding crustal plates, forces were great enough to cause rock beds relatively near the surface to be folded. To the west of the Appalachian Mountain region, the forces of collision did not affect the rocks, so that in this region, bituminous or sedimentary coal (soft coal) exists. To the east, into the western Appalachian Mountain region, forces created by the colliding continents were sufficient to cause folding of sediments and metamorphism of the coal. These original sedimentary beds were metamorphosed into anthracite or metamorphic coal (hard coal). Further to the east, the forces of the colliding continents were so great and metamorphism was carried to such an extreme that, instead of simple folding, there is distortion, fracturing, and *fault*ing of the rocks. In this region, the original coal has been so affected that it no longer exists in the form of coal, but has been converted into pure carbon in the form of graphite. The Appalachian Mountain region thus illustrates the full potential range of metamorphic activity.

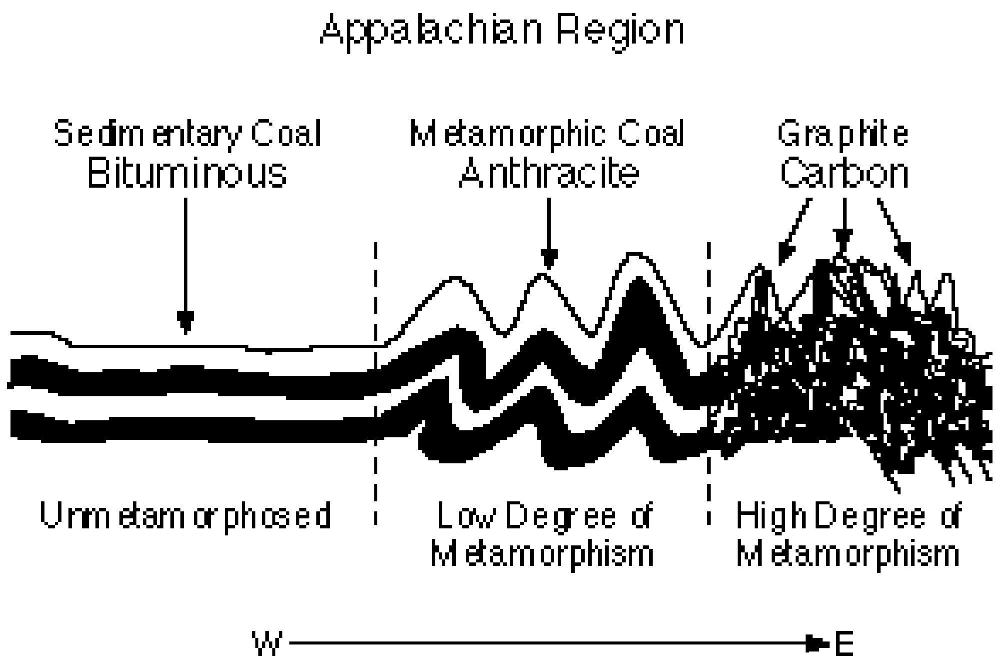

Figure 7. Geologic Cross-section of Appalachian Mountain Region of North America

Since this metamorphic activity occurred at more shallow depths, the temperatures of metamorphism were not so great. It was necessary, therefore, that higher pressures exist in order for metamorphism to have occurred.

The previous existing rocks, which have been changed through metamorphism, may have been igneous, sedimentary, or even other metamorphic rocks. As illustrated in Table 2, desert sandstone becomes quartzite, limestone becomes *marble*, and shale becomes *slate*. If that slate should undergo further metamorphism, it may become schist. If that schist should undergo further extremes of conditions, it may become gneiss.

STRUCTURE	ROCK	ORIGIN
Foliated	Slate	Shale
	Phyllite	Shale
	Mica Schist	Shale or Phyllite
	Gneiss	Shale, Granite or Sandstone
Non-foliated	Marble	Limestone
	Hornfels	Shale or Phyllite
	Quartzite	Sandstone or Conglomerate
	Anthracite Coal	Bituminous Coal

Table 2. Some Metamorphic Rocks

Figure 8 graphically represents a microscopic view of representative metamorphic rock. There is an alignment or order of the rock particles unlike the randomness that exists in typical igneous and sedimentary rock. However, like igneous rock, there is no void space or open space for potential storage of hydrocarbon. It is not expected that hydrocarbon will be found in metamorphic rock.

Figure 8. Graphical Representation of Microscopic View of Sample of Gneiss

In summary, as illustrated in Figure 9, igneous rock and sedimentary rock have particles in a random orientation, while metamorphic rock particles will normally have a more orderly arrangement. However, only in sedimentary rock is there the likelihood for organic materials to have been deposited that may lead to the generation of hydrocarbon, and only in sedimentary rock is there the likelihood for the existence of void space or open space for the potential storage of hydrocarbon. Therefore, only in sedimentary rock is it expected that hydrocarbon will have been generated and only from sedimentary rock is it expected that hydrocarbon will be produced.

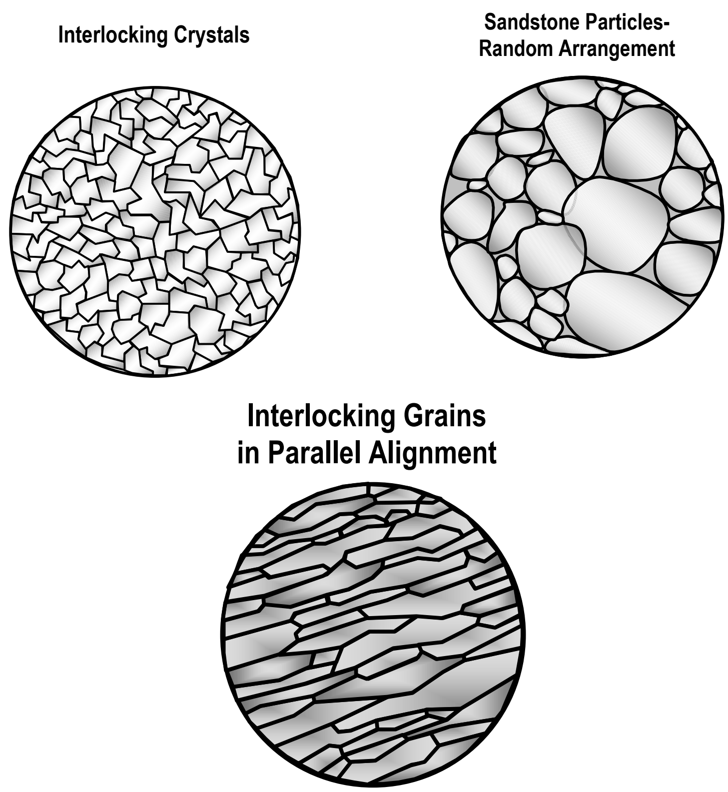

Figure 9. Summary of Relative Characteristics of Igneous, Sedimentary, and Metamorphic Rocks

Historical Geology

The petroleum geologist seeks to determine

- The time order of geologic events (the geologic chronology of events)
- The conditions under which those events occurred

For example, if there is a sandstone existing today,

- At what time in geologic history were the original sand grains deposited?
- Under what conditions did that deposition occur? (Did the sandstone result from a delta sand deposit, beach sand, desert sand, river channel sand, or some other environment of deposition?)
- What has been the sequence of events in geologic history since that original deposition until the present time?

The Rock Record

The petroleum geologist uses many tools in gathering evidence leading to these determinations. Some of these tools include:

- Principle of superpositon
- Analysis of radioactive residue
- Index or marker *fossils*
- Analysis of fossils for geologic events

Principle of Superposition – Sedimentation generally occurs in layers or in beds, usually in a water or water-related environment (a major exception is desert sand). These layers of sedimentation may occur over large regions. A given sediment may have been deposited in a horizontal plane of essentially uniform thickness over that region of deposition. As other deposits occur, resulting from changing surface environment or water depth at that location, different types of sediments with different depths of deposition are deposited and, upon lithification, result in different types and thicknesses of sedimentary rock formed, as illustrated in Figure 10. The principle of superposition simply uses this principle of deposition, assuming that the deeper the sediment, the older it is.

A geologic cross-section is a vertical cut into the earth where the horizontal axis represents surface position and the vertical axis represents depth. For the geologic cross-section of Figure 10, sedimentary bed #2 should be younger than #1; #3 should be younger than #2, etc. This permits the geologist to classify the sediments according to relative age. The geologist must be extremely cautious, however, in that what might seem to be a simple sequence of events in geologic time may involve an exception to the process. For example, it is possible that sedimentary bed #4 is older than sedimentary bed #3, even though bed #3 is younger than #2. This possibility exists in regions of overthrust activity. An example is the Rocky Mountain Overthrust or Thrust Belt.

If sediments should be deposited in horizontal parallel planes, followed by lithification into solid rock, and then if fracturing with faulting should occur, older rocks might overthrust younger rocks. Sedimentary bed #4 might have overthrust sedimentary bed #3. Consequently, there is a discontinuity in chronological order of geologic events in this geologic cross-section. Sedimentary bed #4 is actually older than sedimentary bed #3 and yet, by the principle of superposition, bed #3 is younger than bed #2. The petroleum geologist must be aware of this possibility and must seek to confirm true superposition.

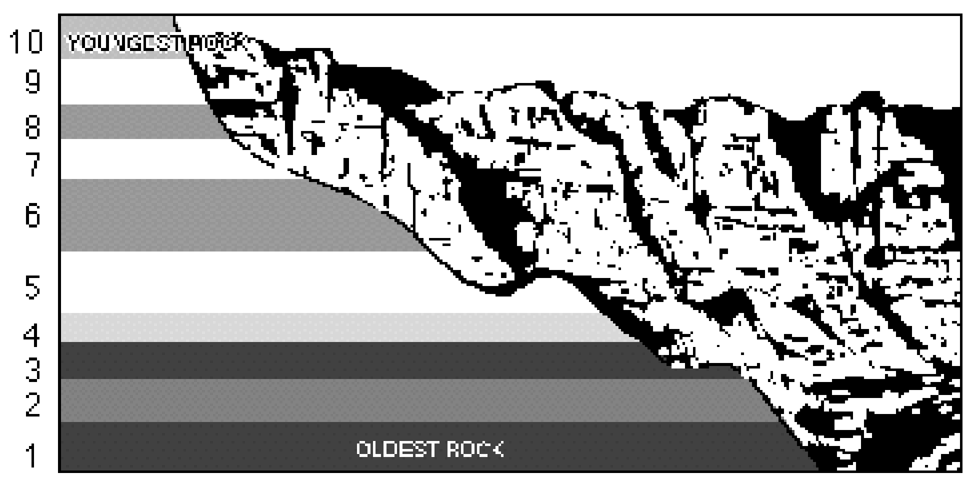

Figure 10. Principle of Superposition Applied to a Sedimentary Basin

Analysis of Radioactive Residue – Geologic age of rocks may be determined by analysis of radioactive residue present in the sediments. The elapsed time since sedimentation can be estimated with considerable accuracy by

- Determining the environment of sedimentation that, in geologic time, has led to the sedimentary rocks as they exist today
- Knowing the chemistry of the original sediments and their natural radioactivity
- Applying the concept of radioactive half-life and analyzing the residues of radiation present

This dating of the sedimentation is obviously a major tool in determining the time order of geologic events.

Index or Marker Fossils – Another tool of the geologist is the fossil remains of plants and animals within the sediments. If plant and animal life remains, or significant evidence of those remains, are found in a sedimentary bed of a determined geologic age, then those particular plants and animals lived on the earth at that time in geologic history. If those plants and animals were of a species that changed considerably in geologic time, through evolutionary processes, then the fossils become index or *marker fossils*. If these same fossils should be found in other sedimentation, that sedimentation took place at the same time in geologic history as the original sedimentation. This sedimentation should be of the same age as the sedimentation in which the *index fossils* were originally found. In this way, index fossils may be used as a geologic clock to determine the time of geologic events.

Analysis of Fossils for Geologic Events – Fossil remains of plant and animal life may also be used to determine the conditions under which geologic events occurred. The North Sea surface environment, for example, has not changed much over the past 190 million years, but water depths have. How was this determined? In a region, the water depth at a particular time in geologic history can be estimated by identifying fossils within sediments deposited in the water environment at that particular time. In a water environment near a continental shoreline or a land mass shoreline, the primary deposition should have resulted in the formation, through lithification, of shale’s, limestone’s, and in some instances, sandstones. By taking a core sample vertically through the sediments and returning this large rock cylinder to the surface, laboratory analysis will indicate the time of deposition of the sediments present. By analyzing the fossil remains of plant and animal life in those sediments, at those particular times in geologic history, the water depth at the time of sedimentation can be estimated. This is possible because shallow water plant and animal life varies considerably from deep water plant and animal life. The types of plant and animal life in 50 ft of water will be considerably different from the types of plant and animal life in 200 ft of water. In many instances using this method, the water depth at a particular time in geologic history can be estimated within a few feet.

Once the geology of a region has been determined by accumulation of geologic data, a geologic time sequence of events can be projected. The geologic cross-section is of primary importance to the petroleum geologist in identifying geologic environments where hydrocarbon reservoirs may exist.

Geologic Time Scale

The earth's age, estimated at approximately 5 billion (5,000 million) years, is divided into geologic eras, as shown in Figure 11. The Precambrian Era lasted from the formation of the earth, for 4.5 billion years. It was followed by the Paleozoic, Mesozoic and Cenozoic Eras, up to the present day. The Precambrian Era ended with the beginning of the Paleozoic Era, approximately 550 million years ago $\pm$ 50 million years (between 500 and 600 million years ago). Scientists can only measure this time event with confidence within a 100 million year range.

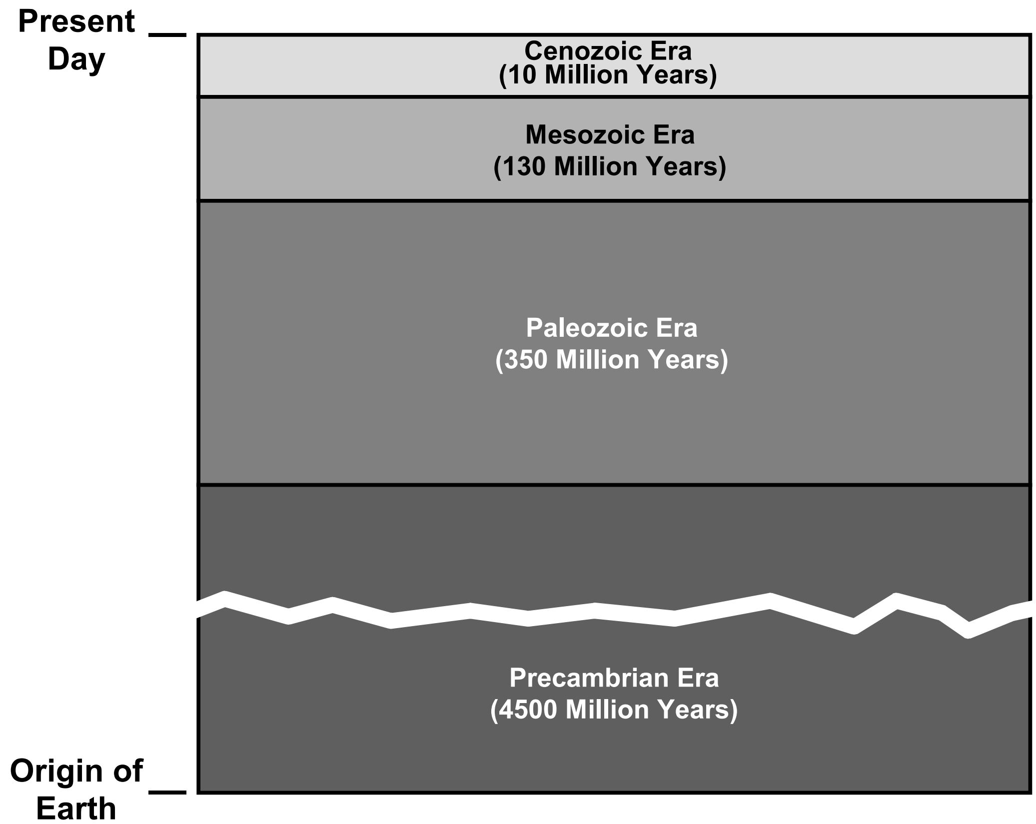

Figure 11. Geologic Eras of the Age of the Earth

The time period since the beginning of the Paleozoic Era has been approximately 1/10 the age of the earth (500 million to 600 million years). This is the portion of the earth's age that is of primary importance to the oil industry.

What determined the end of one era and the beginning of another era, for example, the end of the Precambrian and the beginning of the Paleozoic? Precambrian-age rock have a minor presence of plant and animal fossils. During this dominant era of the age of the earth, there was insufficient plant and animal life to result in sufficient organic deposition for the formation of hydrocarbons to occur. Therefore, it is not expected that hydrocarbon reservoirs should be found in Precambrian-age rock. From the beginning of the Paleozoic Era, however, there has been sufficient plant and animal life on earth, as indicated by their fossil presence, for hydrocarbons to have been generated from that organic deposition. There are exceptions to this consideration. Some hydrocarbon reservoirs have been found in Precambrian-age rock, but this does not necessarily disprove the theory. A reasonable explanation is that the hydrocarbons were generated from organic debris deposited in younger rocks and, after a generation, migrated into the older Precambrian-age rock.

In studying the history of plant and animal life on earth, at several distinct times during the history of the earth, major changes in types or species of plants and animals occurred over brief time intervals. Some became extinct and others became prolific. For example, approximately 60 to 70 million years ago, the dinosaur became extinct. There are many speculations as to what happened to the dinosaur, but it was a catastrophic event and took place over a brief time interval. One theory speculates that a major volcanic activity occurred, filling the earth's atmosphere with ash, blocking out the sun, and reducing the earth's temperature sufficiently to kill the dinosaurs. Whatever the event, it marked the end of the Mesozoic Era and the beginning of the Cenozoic Era.

Eras are divided into periods, and periods are divided into epoches. Such divisions vary, dependent upon the region of the earth under consideration.

The more prominent periods and epoches are given in Table 3. The degree of accuracy in selecting times for the end of one period or epoch and the beginning of another is shown in the right-hand margin of this geologic time scale. All of these eras, periods, or epoches are significant somewhere for the world petroleum industry, dependent upon geographic location and geologic history of that location.

Era	Period	Epoch	Duration (millions of years	Dates (millions of years)
Cenozoic	Quarternary	Recent	0.01	0.01
		Pleistocene	1	1
	Tertiary	Pliocene	10	11
		Miocene	14	25
		Oligocene	15	40
		Eocene	20	60
		Paleocene	10	70
Mesozoic	Cretaceous		65	135 ± 5
	Jurassic		30	165 ± 10
	Triassic		35	200 ± 20
Paleozoic	Permian		35	235 ±30
	Pennsylvanian		30	265 ± 35
	Mississippian		35	300 ± 40
	Devonian		50	350 ±40
	Silurian		40	380 ± 40
	Ordovician		70	460 ± 40
	Cambrian		90	550 ± 50
Precambrian			4500	5000

Table 3. Earth Geologic Time Scale

Most regions do not have rocks of all ages shown. To illustrate, consider that most sedimentation results from water deposition, and most erosion occurs in an atmospheric environment (above sea level). Assume that, in the drilling of a well, rocks are drilled through near the surface of ages Paleocene and younger. Directly beneath the Paleocene-age rock, Triassic-age rock is drilled into. This was determined by geologic analysis of data collected from the well drilled, indicating a geologic time discontinuity of approximately 95 million years between the Triassic-age sediments and the Paleocene-age sediments above. What happened? More information is required before this question can be answered. However, some theories can account for this situation. For example, this entire region may have been below sea level through the Jurassic Period of geologic time. There were therefore Triassic-age sediments deposited on top of Permian-age sediments, and Jurassic-age sediments deposited on top of Triassic-age sediments. At the end of the Jurassic Period, a geologic event uplifted this region above sea level, so that during the Cretaceous Period, not only did no sedimentation occur, but the Jurassic-age sediments eroded away in this atmospheric environment.

By the end of the Cretaceous Period, all Jurassic-age sediments had been removed by erosion. At the end of the Cretaceous Period, there was a geologic event resulting in the region’s sinking again below sea level, followed by further sedimentation during the Paleocene Epoch and continuing to the present. Upon lithification, Paleocene-age rocks were directly on top of Triassic-age rocks, resulting in the 95-million year time discontinuity.

This is the type of information the petroleum geologist seeks, with all related geologic events described as specifically as possible. The regions of the Arabian Gulf, the North Sea, and the Permian Basin of West Texas are excellent illustrations of how significantly surface environments of the earth might change during the passage of geologic time.

In each geographic region, particular rock formations of various classes (igneous, sedimentary, metamorphic) are named, such as the Rotliegend Sandstone of the Groningen Gas Field of the Netherlands, the Bartlesville Sandstone of Oklahoma, the Dunlin Shale of the North Sea, and the Austin Chalk of Texas.

GENERATION OF HYDROCARBONS

There are three requirements to meet before a petroleum reservoir can exist.

- Hydrocarbon source rock
- Reservoir rock
- *Hydrocarbon trap*

If any one of these does not exist, the presence of a hydrocarbon reservoir is not possible.

Source Rock

The primary theory accepted for the generation of hydrocarbons is that it is formed by organic evolution. Plants and animals complete their life cycles and die, with their organic debris being deposited on the earth's surface. The primary source of these organic depositions is microscopic plant and animal life and the smaller plants and animals within a water environment. Significant organic sedimentation occurs primarily in a water environment. As this organic debris is deposited, other materials are also deposited which, through lithification, will lead to the formation of sedimentary rocks such as shale and limestone. With continuing sedimentation and increasing overburden pressures due to increasing weight, sediments containing the organic debris move deeper into the earth. With increasing depth, temperature increases, geologic time passes, and chemical action occurs, converting the organic debris into hydrocarbons.

Note that the same four factors (pressure, temperature, time, and chemical action) which lead to lithification of the sediments forming solid rock are also converting organic materials into hydrocarbons. Source rock is defined as rock formed through lithification, from original sediments containing organic debris. In most geologic situations, the resultant hydrocarbons formed have been forced out of the sediments during lithification. For example, shale is one of the dominant source rocks for hydrocarbon, yet is seldom ever a rock from which hydrocarbon can be produced. Once lithification has been completed to form the shale, any hydrocarbons remaining will be trapped within the sedimentary bed and cannot be produced.

In order for hydrocarbons to be generated from organic deposition, temperatures must rise above 104ºF (40ºC) but not exceed 662ºF (350ºC). Higher temperatures than these will destroy any remaining organic materials or hydrocarbons already generated. This temperature range illustrated in Figure 12 is called the hydrocarbon temperature window. In order for hydrocarbons to be generated, a proper sequence of geologic events and conditions must occur. The theory that significant hydrocarbon volumes are generated by straight chemical reaction between carbon and hydrogen, without the necessity for organic materials being present, is not generally accepted within the industry.

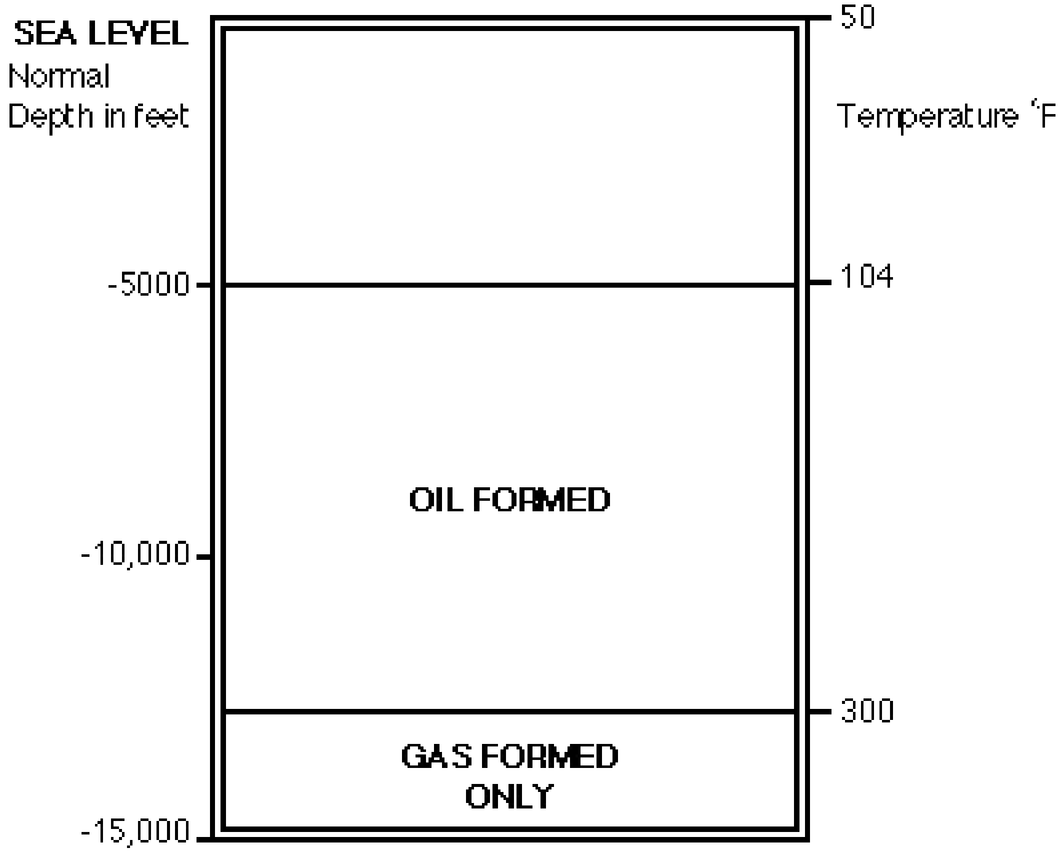

Figure 12. Temperature Window for Generating Hydrocarbons

Most major source rocks are shale’s and biogenic limestone’s. Coal may also be considered as a source rock, even though it is present in relatively small quantities within the earth when compared to shale’s and biogenic limestone’s. Essentially all shale’s and limestone’s result from water deposition.

STORAGE OF HYDROCARBONS

Reservoir Rock

The term “reservoir” implies storage. Reservoir rock is rock where hydrocarbons are stored and from which they can be produced. This reservoir rock may or may not be source rock. The fluids of the subsurface migrate according to density. The dominant fluids in hydrocarbon regions are hydrocarbon gas, hydrocarbon liquids, and salt water. Since hydrocarbons are the less dense of these fluids, they will tend to migrate upward, displacing the heavier salt water down elevation. Hydrocarbons may therefore be forced from their source rock during lithification, and migrate into the reservoir rock in which they are stored. The fluids present will separate according to density as migration occurs.

In order for a rock to be a potential reservoir rock, two properties, *porosity* and *permeability*, must exist of sufficient magnitudes to justify economic development of the hydrocarbon reservoir.

Porosity

Porosity is defined as the percentage of the total volume (bulk volume) of the rock that is void space. This volume is often referred to as the pore volume. Porosity is normally represented by the Greek letter ϕ and is an indication of the potential storage space for hydrocarbons within the rock structure itself. Consider Our Reservoir, as discussed in Module 2.

Properties of Our Reservoir, which have been given, may be summarized as follows:

- Onshore reservoir
- Datum depth = 5,750 ft
- P_R = 3,500 psia
- t_R = 160 °F
- B_o = 1.310 RB/STB
- BPP = 2,500 psia
- 36^o API
- $(S.G.)_o$ = 0.845

- $\gamma_o = 52.7 \frac{lb_f}{ft^3}$
- GOR_S = 567 SCF/STB
- μ_O = 0.6 cp

Assume that the well which discovered this hydrocarbon reservoir was drilled vertically, and a vertical core was taken through the rock containing the hydrocarbons (the reservoir rock). A core is a rock cylinder, normally 4" to 6" in diameter, ideally taken through the entire thickness of the reservoir rock containing the hydrocarbons. This core is retrieved to the surface and transported to the core laboratory for analysis. It is determined from the core analysis of the core from the discovery well for Our Reservoir that the rock containing this hydrocarbon reservoir is a Permian Beach Sandstone with ϕ = 22%. This provides information indicating that this rock was originally deposited as a beach sand during the Permian Period of geologic time (approximately 200 to 235 million years ago) and, during the passage of time since its original deposition, lithification occurred, changing the original beach sand sediment into sandstone.

Based on the core analysis, 22% of the total volume of this rock is void space. Note that this determination is made based on a core analysis from a single well. The porosity may not be uniform over the entire hydrocarbon reservoir.

Consider a cube of this beach sandstone 10 ft ∞ 10 ft ∞ 10 ft, as it exists naturally in the reservoir at reservoir conditions. Its total volume is 1,000 ft^3 and, with ϕ = 22%, there will be 220 ft^3 of void space within this cube. For a typical reservoir rock such as sandstone, these void spaces will be extremely small in size. It is common for sandstones to have porosities in the range of 20% to 30%.

Fluid Saturations

Within the earth there is no such condition as a perfect vacuum. Any void space in the rock will be 100% filled with fluids or other materials. Ideally, hydrocarbons dominate this pore volume within the rock. The fluids within these void spaces may include gases at low pressures, consequently with low densities. Porosity is a rock property. Properties indicating fluids or other materials present within that porosity, however, are not rock properties but reservoir properties.

Relative presence of fluids within the porosity is indicated by the fluid saturations. Assume that in Our Reservoir the only fluids or materials present or potentially present within the porosity are hydrocarbon liquid, hydrocarbon gas, and water. This water is normally salt water, but since the salt is in solution within the water, it is not considered separately. The relative presence of these three fluids within the void spaces is given by:

- *Oil saturation*, S_o - the percentage of the void space containing liquid hydrocarbons at reservoir conditions.
- *Gas saturation*, S_g (implying hydrocarbon gas) - the percentage of the void space containing gaseous hydrocarbons at reservoir conditions.
- *Water saturation*, S_w - the percentage of the void space containing water at reservoir conditions.

If these should be the only fluids present or potentially present, they will tend to separate according to their densities, although degree of separation will be limited by surface tension and capillary pressure effects. If all three fluids should be present, the hydrocarbons will tend to migrate upward, with the gas accumulating above the oil and the salt water below the oil, as shown in Figure 13. Under this condition, there is a gas zone (gas cap), oil zone, and water zone.

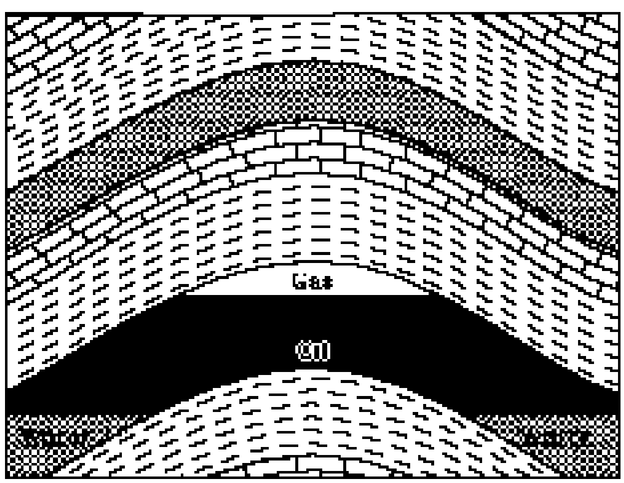

Figure 13. Hydrocarbon Reservoir with Gas Cap, Oil Zone, and Water Zone

Assume that for Our Reservoir, the only fluids present or potentially present are hydrocarbon liquid, hydrocarbon gas, and water. For Our Reservoir, since the reservoir fluid pressure (P_R) is significantly higher than the bubble point pressure (BPP) of the hydrocarbon liquid, no gas cap should exist. Figure 14 is representative of Our Reservoir.

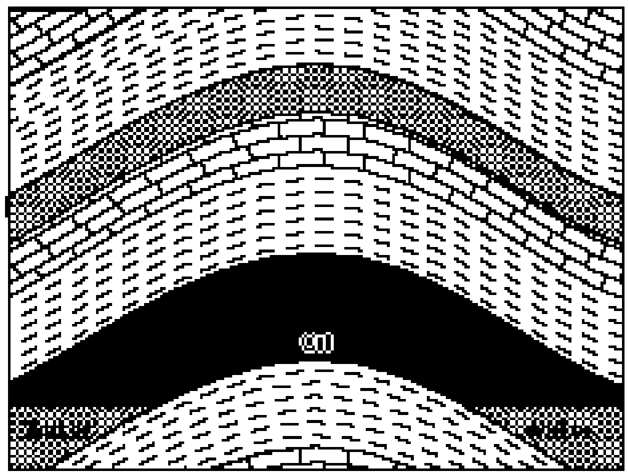

Figure 14. Hydrocarbon Reservoir with No Gas Cap (Oil Zone and Water Zone Only)

Consider the oil, gas, and water saturations in the oil zone of Our Reservoir. Assume that, after completion of the discovery well, logs were run in the well to determine various hydrocarbon reservoir properties, including rock properties and reservoir fluid properties. A well log is measured information relative to depth within a well. Assume that from these logs, it is determined that at the selected datum depth of 5,750 ft in the oil zone of this reservoir, S_o = 80%. There should be no gas present originally within Our Reservoir, since the BPP is significantly less than the reservoir fluid pressure. Therefore, S_g = 0%. Since the only fluids present or potentially present are assumed to be hydrocarbon liquid, hydrocarbon gas, and salt water, S_w should equal 20%.

In summary, for Our Reservoir, S_o = 80%, S_g = 0%, and S_w = 20% in the oil zone. Note that a simple, yet fundamentally important equation applies to this condition:

$$S_o + S_g + S_w = 100\%$$

If other fluids or materials are present within this reservoir, their saturations must also be considered. Other fluids often found in hydrocarbon reservoirs are hydrogen, helium, oxygen, nitrogen, carbon dioxide (CO_2) and hydrogen sulfide (H_2S). The presence of CO_2 and H_2S in the reservoir is undesirable, because both provide a corrosive environment in the presence of water and H_2S is also toxic and potentially deadly.

In some reservoirs, excess salt may be present within the void space. Salt is not soluble in hydrocarbon. The water might be salt saturated at reservoir temperature, so that excess salt not dissolved within the water may be present. This must be considered as taking up a portion of the void space otherwise available for storage of hydrocarbons. In Our Reservoir, however, assume that only the three fluids mentioned are present or potentially present.

Figure 15 is a microscopic view of sandstone. The sand grains are smooth, well rounded, and relatively uniform in size. Apparently, at the time of deposition of the fragments, an extraneous material was also being deposited which has served as a cementing material during lithification. This sandstone is probably well consolidated, meaning that it has undergone good lithification and is therefore solid rock. It does not come apart easily. The extraneous material deposited might have been a mud or carbonate material. According to this microscopic view of the sandstone sample, there are open spaces in the rock that provide for potential storage of hydrocarbons. This sandstone sample therefore has porosity.

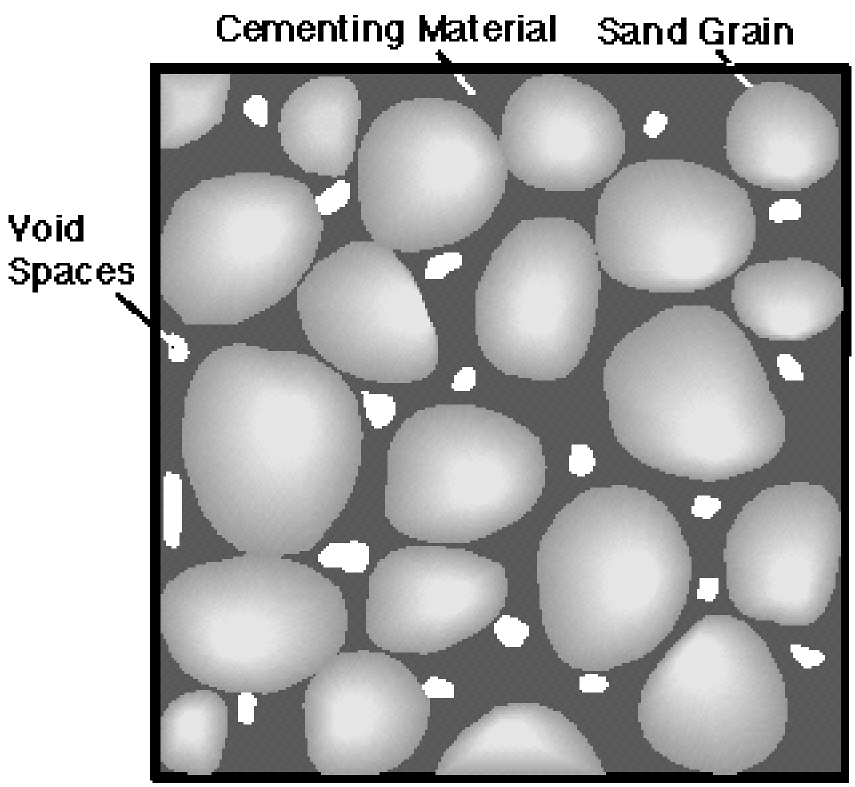

Figure 15. Graphical Representation of Microscopic View of Sandstone: Sample A

Permeability

The sandstone in Figure 15 would not be an acceptable reservoir rock, regardless of the value of its porosity and the hydrocarbon saturations: each void space is isolated from the other void spaces. The only way the hydrocarbon present in a particular void space could be produced back to the surface would be to penetrate that void space while drilling. Hydrocarbon in other void spaces not penetrated, therefore, would not be available for production back to the surface because the hydrocarbon could not flow to the well. This sandstone has a high absolute porosity, but a zero effective porosity.

Effective porosity is the important porosity, because it indicates the percentage of the total volume of reservoir rock that is void space connected by flow channels. This would permit flow of hydrocarbon fluids present into the wells drilled.

In addition to porosity ϕ, a second property is of primary importance in order for a rock to be considered a reservoir rock. That property is permeability. Permeability will be represented by the symbol “k”.

Concept - Permeability is the rock property that indicates the presence of flow channels. The higher the permeability, the greater the presence of those flow channels and the greater the potential for maximum recovery of hydrocarbon from the reservoir rock.

The concept of permeability was developed, ironically, three years prior to the drilling of Drake’s well in Pennsylvania. This concept was developed in 1856 by a French engineer, Henri Darcy, in Dijon, France. Darcy, the utilities engineer for the city of Dijon, noted that when pipelines transporting water became compacted with sand, the flow rates decreased if other flow conditions were held constant. The greater the compaction, the less the flow rate. He developed an equation, where the concept of permeability is introduced, relating the flow characteristics for this flow through porous media. The oil industry has applied this “Darcy Equation” to hydrocarbon reservoirs, and it has become one of the most important equations in Petroleum Engineering.

The larger the permeability value, the greater the presence and/or size of flow channels within the reservoir system, and, in the case of reservoir rock, the more easily hydrocarbons stored within that rock can be produced. The sandstone represented in Figure 15 has a large absolute porosity, but a zero effective porosity and therefore zero permeability (k = o).

Consider the sandstones presented in microscopic view in Figure 16 and Figure 17. Note that these figures are two-dimensional graphical representations of a three-dimensional situation. The rock particles illustrated in the figures are actually in contact with one another, so that the rock structure is supportive of itself. In this two-dimensional representation, the sand grains are not shown as touching in order to illustrate the presence of void space and flow channels within the actual three-dimensional system. In general, the rock does not collapse when fluids present within the void space are removed by production. Each particle, therefore, is supporting other particles and is itself being supported. However, within the three-dimensional system, there are void spaces with flow channels connecting those void spaces. The overburden pressure within the rock structure itself is not equal to the fluid pressure of those fluids within the rock's void spaces. That overburden pressure is dependent upon depth of overlying sediments, the various densities of those sediments, and the fluids present within them. The fluid pressure within the reservoir, referred to as the formation fluid pressure or, in the case of a hydrocarbon reservoir, the reservoir fluid pressure, will be less than the overburden pressure. Reservoir fluid pressure will be affected by the magnitude of the overburden pressure and by other factors of the geologic and fluid system.

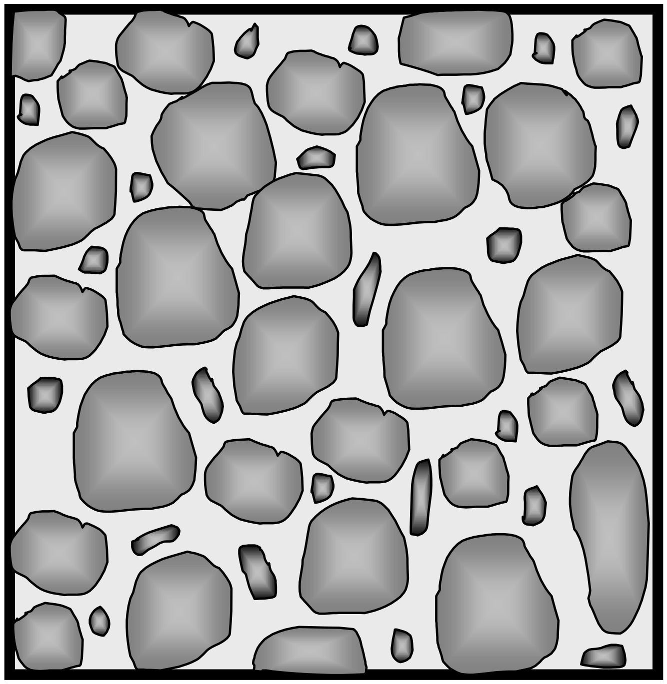

Figure 16. Graphical Representation of Microscopic View of Sandstone: Sample B

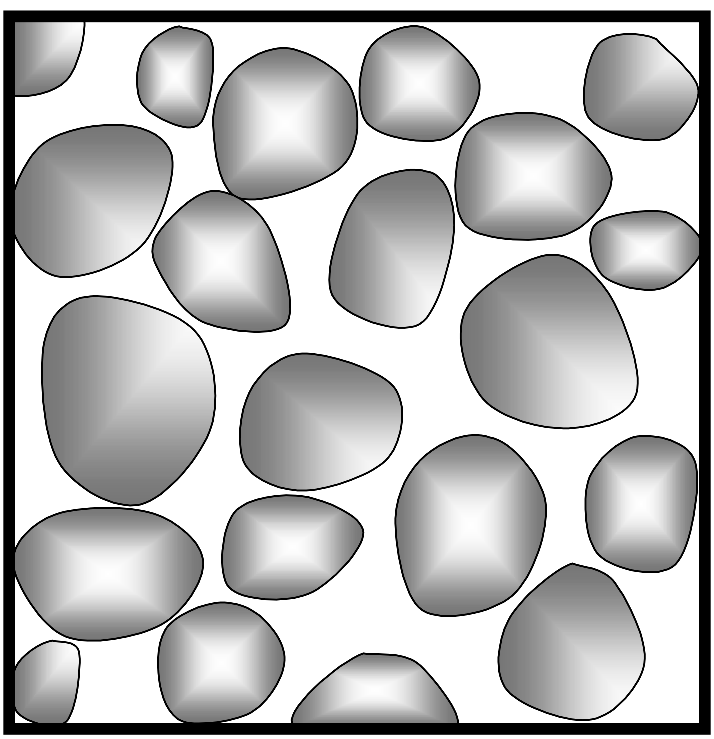

Figure 17. Graphical Representation of Microscopic View of Sandstone: Sample C

For the sandstone represented in Figure 16, the rock particles are certainly not smooth and well rounded and are not uniform in size and shape. Many have sharp points and are jagged in configuration. Void space is present, however, providing the potential for storage of hydrocarbon and flow channels interconnecting those void spaces that will permit production of those hydrocarbons into wells drilled.

The sandstone represented graphically in Figure 17 would be an ideal reservoir rock. The particles are smooth, well rounded, and of uniform size, with porosity present and flow channels interconnecting that porosity. Note that, as a result of the uniformity of the particle size, smaller particles do not tend to fill the available void space, which reduces the porosity. The more uniform the size of the rock particles, the higher the potential value of porosity if extraneous materials are not present within the rock.

In order for a rock to be considered a reservoir rock, it must have adequate porosity and adequate permeability for the conditions present. Porosity and permeability, however, are quite different in characteristic. Porosity, along with oil saturation, indicates Oil-in-Place, or Reserves, while permeability indicates the ability to produce those reserves. If a well has been drilled vertically through the reservoir, the flow into that well during production will, ideally, be horizontal, radial flow. Under these conditions, the horizontal permeability of the reservoir rock will be of primary importance.

Geologic Traps

In addition to the requirement that source rock exists for the generation of hydrocarbons, and that reservoir rock exists for the storage and production of the generated hydrocarbons, traps must also exist to trap, or seal, the hydrocarbon in place forming a hydrocarbon reservoir.

The fluids of the subsurface migrate according to density. As previously discussed, the dominant fluids present or potentially present are hydrocarbon gas, hydrocarbon liquid, and salt water. Since the hydrocarbons are less dense than the salt water, they will tend to migrate upward to the surface, displacing the heavier water down elevation. These fluids will continue to migrate until they encounter impermeable rock, which will serve as a reservoir “seal” or “trap.” These impermeable rocks serving as reservoir seals, of which shale’s are among the most common, are referred to as *confining bed*s or *cap rocks*. Traps exist because of variations in characteristics of rocks of the subsurface. If impermeable rock does not exist, the hydrocarbons will migrate to the surface and dissipate into the environment. In order for a hydrocarbon reservoir to exist, a proper sequence of events must have occurred in geologic time.

Five types of hydrocarbon traps will be discussed. Most traps encountered by a petroleum geologist will be a combination or variation of these five types.

- Anticlinal traps
- Fault traps
- *Salt dome* traps
- Stratigraphic *unconformity*
- *Facies change*

Anticlinal Traps

This trap may exist as a simple fold or as an *anticlinal dome*. Sedimentary beds are generally deposited in horizontal parallel planes over a geographic region, so that many of these sediments will be of essentially uniform thickness over that region. If geologic activity should occur, resulting in the folding of these sediments, the result may be the formation of hydrocarbon reservoirs in anticlinal traps. Two major potential advantages of the anticlinal trap reservoir are the simplicity of the geology and the potential size of the trap and therefore of the hydrocarbon accumulation. The high part of the fold is the *anticline*, and the low part of the fold is the *syncline*. Since the hydrocarbons are the less dense of the subsurface fluids, they will tend to migrate to the high part of the fold. Consider the hydrocarbon reservoir illustrated in Figure 18. Hydrocarbon exists in an anticlinal trap within sandstone as its reservoir rock, where shale is the cap rock.

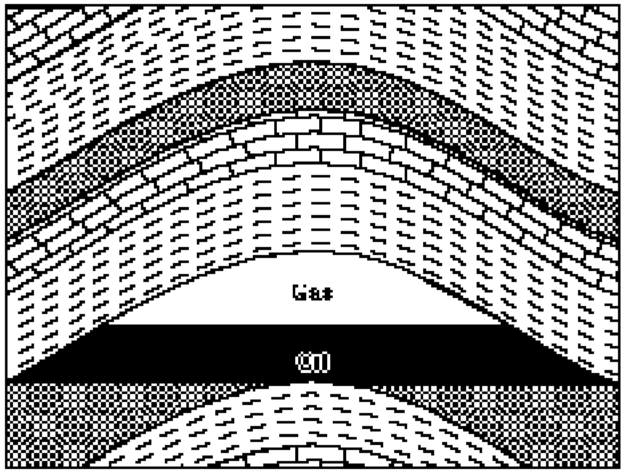

Figure 18. Anticlinal Hydrocarbon Trap with Gas Cap

Imagine a possible sequence of geologic events leading to the formation of this hydrocarbon reservoir. Sedimentary beds are deposited in a water environment, as indicated by the presence of limestone's and shale's. During or after lithification, geologic activity causes folding of the sediments. After folding and lithification, the sandstone has a 100% *connate* water saturation. Millions of years later, hydrocarbon generated in source rock down elevation from this anticlinal fold is forced from its source rock into the water-saturated, permeable sandstone. Since hydrocarbon is less dense than the water, it begins to migrate up elevation, displacing the heavier water down elevation. As it migrates upward, pressure decreases. At some point in this migration, the reservoir fluid pressure might equal the bubble point pressure of the original hydrocarbon combination. From this point upward, gas is being released from the hydrocarbon. Since the gas is so much less dense than the oil or the water, it will migrate more rapidly toward the top of the anticlinal trap. This process of migration and fluid separation according to density may continue over millions of years in geologic time, until finally, equilibrium is achieved as the hydrocarbon fluids accumulate within the trap formed by the impermeable shale cap rock.

When this condition of equilibrium is finally achieved, there will be a gas zone (gas cap) on top of an oil zone and then a water zone beneath the oil zone. The gas and oil are separated at the gas-oil interface or the gas-oil contact. Since the gas is so much less dense than the oil, this contact will be essentially a distinct plane, usually with little oil saturation above it in the gas cap, except that which may exist due to capillary pressure effects. However, since the oil is not significantly less dense than the water, the oil-water contact will be a transition zone instead of a distinct plane. A common definition of oil-water contact, often used in reservoir analysis, is that the oil-water contact is the lowest elevation of 50% oil saturation. This definition may not be appropriate for all reservoirs, because some reservoirs may have maximum oil saturation less than 50%.

If, when equilibrium exists, the final reservoir fluid pressure is less than the bubble point pressure of the original hydrocarbon combination, a gas cap will exist as shown in Figure 18. Molecules will have been released from solution to form the gas until, at conditions as determined by the final reservoir fluid pressure and temperature, the liquid hydrocarbon in contact with gas at the gas-oil contact will have a bubble point pressure equal to the equilibrium reservoir fluid pressure. This balance determines final equilibrium conditions.

If the hydrocarbon liquid is trapped at an equilibrium reservoir fluid pressure greater than the bubble point pressure of the original hydrocarbon combination, a gas cap will not exist. The reservoir will then be one as illustrated in Figure 19. Figure 20 illustrates an anticlinal dome as a hydrocarbon reservoir trap.

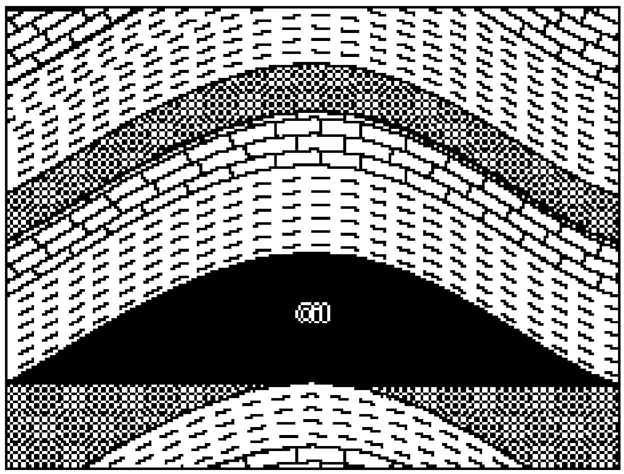

Figure 19. Anticlinal Hydrocarbon Trap with No Gas Cap

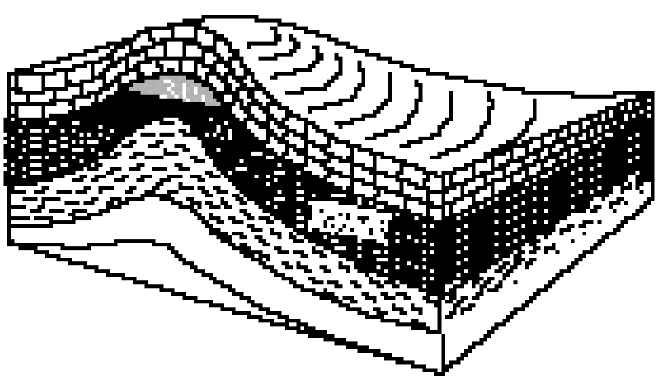

Figure 20. Anticlinal Dome Hydrocarbon Trap

Fault Traps

Fault implies fracturing of rock and relative motion across the fracture surface. Consider a possible sequence of geologic events that, in geologic time, could lead to the formation of the hydrocarbon reservoir, as illustrated in Figure 21. Sedimentary beds are deposited in a water environment, as indicated by the presence of shale's and limestone's. During or after lithification, geologic events result in uplift of these original horizontal sediments, and fracturing and tilting above sea level, so that the surface rocks are exposed to erosion. During uplift, the rocks are fractured and slippage occurs along the *fault plane*. This brings the shale across the fault so that it seals the tilted sandstone below the fault. Millions of years later, hydrocarbon generated in its source rock down elevation from the fault is forced into the connate water-saturated sandstone. Since the hydrocarbon is less dense than the water, it will migrate up elevation, displacing the heavier water down elevation. This upward migration will continue until it reaches the fault and is trapped by the impermeable shale. If the faulting had not occurred, the hydrocarbon would have continued to migrate upward until it was dissipated at the surface into the environment. Since faulting occurred, the shale provides the necessary seal, resulting in the existence of the hydrocarbon reservoir.

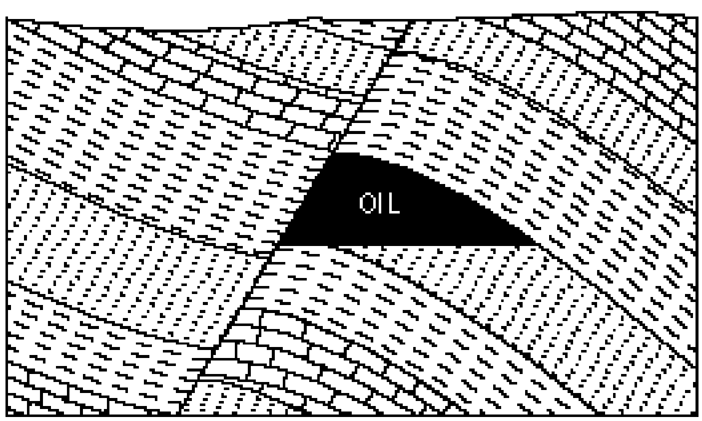

Figure 21 Fault Trap

Notice that, in this example, if slippage had occurred to a greater extent, there would have been flow into the permeable sandstone above the fault. The hydrocarbon would have been lost to the surface, and no reservoir would have been formed. This situation illustrates the significance of geologic probability. What is the probability that the relative motion across the fault would have resulted in a reservoir seal being formed?

Geologic events must occur in the proper sequence, resulting in the proper geologic conditions for a reservoir to exist. The North Sea hydrocarbon environment is an excellent example of the significance of this geologic probability. Of the hydrocarbon generated in the source rock of the North Sea, it is estimated that less than 10% was trapped. Over 90% of the hydrocarbon was lost back to the surface in geologic time and dissipated into the environment because traps were not present. Fault traps leading to the presence of hydrocarbon reservoirs are often difficult to define because of the complexity of the geology.

Salt Dome Traps

Consider the salt dome geologic system illustrated in Figure 22 and a possible sequence of geologic events that could lead to the formation of this salt dome environment. A major portion of a continental plate was below sea level at a point in geologic history. Due to geologic events, this region rose above sea level, trapping inland a salt water sea. As geologic time passed, the climate changed to a desert environment. This event could have resulted from movement of the continental plate near to the equator. In this arid desert environment, water evaporated from the salt water sea, leaving the salt residue on the dry sea bed. As millions of years passed in the desert environment, sand blew over the salt to cover and protect the salt sediment. Later geologic events resulted in the sinking of the region below sea level, followed by tens of millions of years of sedimentation in the resulting water environment. As time passed, lithification occurred. The desert sand became sandstone, and the salt became rock salt (sedimentary salt).

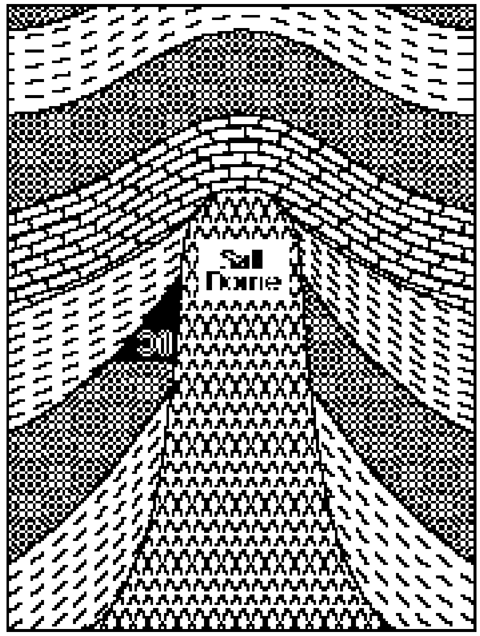

Figure 22. Salt Dome Traps

After lithification, this salt bed was impermeable. It also had two properties significantly different from typical shale, sandstone or limestone:

- It was less dense, with a measurably smaller specific weight.
- At subsurface overburden pressures and subsurface temperatures, the rock salt was a plastic solid (it was highly deformable).

The combination of this lesser density and plasticity resulted in a buoyant effect if flow possibilities existed. Geologic events caused fracturing of overlying confining rocks. The salt, forced upward by the overburden pressures, began to flow plastically back to the surface, intruding into the overlying rock structures to lift, deform, and fracture them. The intruding salt was solid, yet geologically deformable. It might intrude at an average rate of only 1 inch per 100 years, yet on a geologic time basis, such deformation is highly significant. This rate would result in 10 inches in 1,000 years, or 10,000 inches (833 ft) in 1 million years. In a geologic time period of only 10 million years, this salt dome could intrude to a height of over 1.5 miles into the overlying structures. Obviously, a vertical subsurface structure 1.5 miles high is geologically significant. Since the salt is impermeable, the region around the perimeter of the salt dome is an ideal geologic environment for hydrocarbon traps. The tendency of the intruding salt to uplift the rocks as it intrudes enhances the separation of the less dense oil from the more dense salt water by reducing the area of the oil-water contact. The fracturing of surrounding rocks due to the intruding salt and the lifting of the rocks above the salt dome also provide an environment for the existence of fault traps and anticlinal traps in addition to the salt dome traps around the perimeter of the dome. A salt dome region, therefore, is an excellent geologic environment for all three types of traps discussed so far.

An excellent example of a salt dome trap is Spindletop near Beaumont, Texas. The first major discovery and resultant initial oil boom at Spindletop occurred in 1901. Through the 1890s, Patillo Higgins had promoted drilling for oil outside Beaumont. He concluded that it was an excellent geologic environment for hydrocarbon reservoirs, because he noted a location near Beaumont where the surface elevation was 15 ft higher than the surrounding land. This rise was a circle approximately 1 mile in diameter. He concluded that this indicated high points in the underlying geology. In 1901, Captain Anthony Lucas drilled a wildcat well at this location, resulting in the Spindletop discovery. Future drilling confirmed that this reservoir existed as an anticlinal dome trap, with the dome created by the uplift of overlying rocks by an intruding salt dome in the subsurface, creating the surface indication of what the subsurface geology might be.

The second oil boom at Spindletop began in the mid-1920s. When further wells were drilled, it was discovered that fault trap and salt dome trap reservoirs existed around the circumference of the salt dome. The drilling pattern for the wells drilled during this later activity was almost a perfect circle as these circumferential reservoirs were developed.

Stratigraphic Unconformity

Consider the sequence of geologic events summarized in Figure 23. Sedimentation occurs over millions of years in a water environment, resulting in horizontal, parallel, sedimentary beds. Lithification occurs, followed by uplift and tilting above sea level. As a result of being uplifted above sea level, erosion occurs over millions of years, removing rocks down to an erosional surface, or unconformity. Following erosion, the region subsides again below sea level and is followed by millions of years of sedimentation in a water environment. After lithification, the first sediment on top of the unconformity is impermeable shale. The unconformity represents a discontinuity in the geologic system, because there is a geologic time discontinuity between the rocks above the unconformity and those below it.

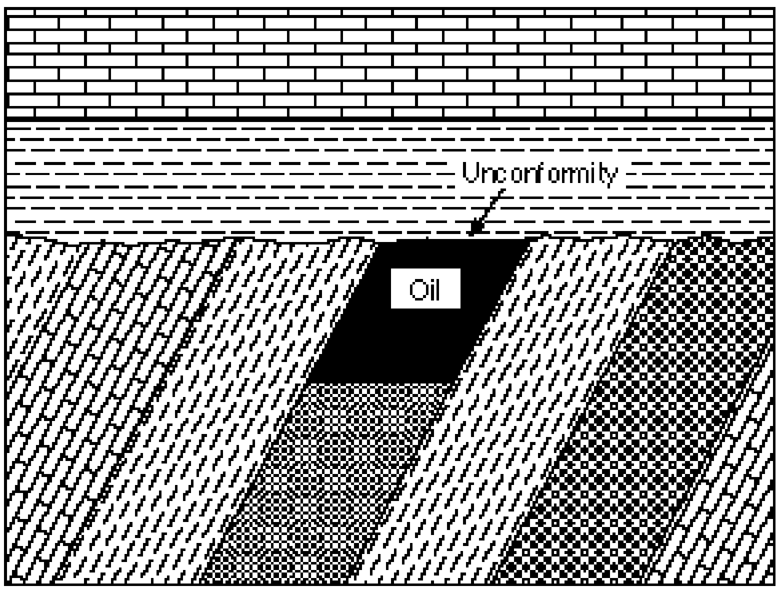

Figure 23. Unconformity

Millions of years after this sequence of events, hydrocarbon that is generated in source rock at lower elevations is forced into the *connate water*-saturated sandstone. Due to its lesser density, it migrates upward through the permeable sandstone, displacing the heavier water down elevation. When the hydrocarbon reaches the unconformity, it is trapped. This trap is a stratigraphic trap, and this particular type of stratigraphic trap is referred to as an unconformity, or “truncation.” The specific type of unconformity illustrated here is an angular unconformity. Notice that the hydrocarbon trap would not have existed had the first sedimentary bed above the unconformity not been impermeable after lithification. Again, the proper sequence of geologic events was necessary in order for the trap to exist.

Facies Change

Consider the deposition near a shoreline of a continent, as distance from the shoreline increases. From the shoreline out into the body of water, the particle size decreases from gravel to pebbles, to sand, to silt, to mud. When lithification occurs, the sand-to-larger-silt size particles form sandstone, and the smaller silt-to-mud size particles, form shale. Therefore, in the same sedimentary bed, as distance from the original shoreline increases, the rock grades from sandstone, through a transition zone, to shale. Assume that, after lithification, with further sediments having been deposited on this original sediment, a geologic event results in uplift and tilting of this sediment, so that the shale is "up dip" from the sandstone, as illustrated in Figure 24. The dip of a bed is the angle its plain makes with the horizontal.

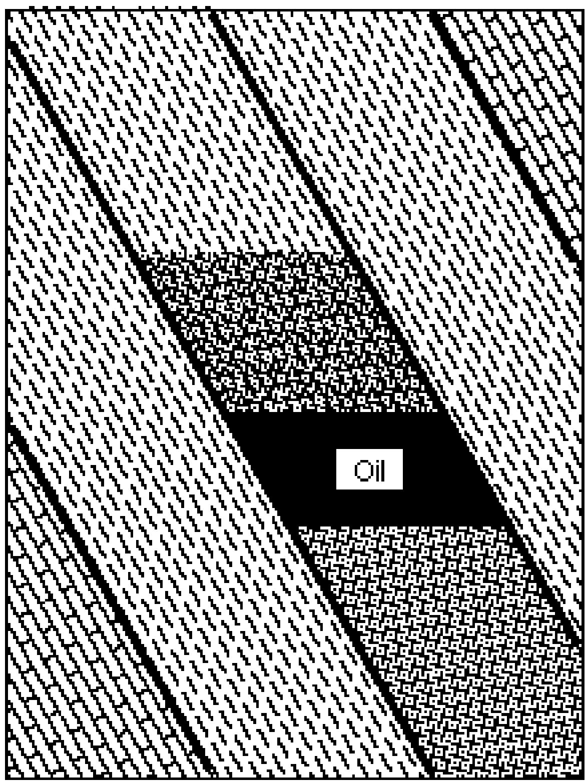

Figure 24. Facies Change

Later in geologic time, hydrocarbon generated in its source rock at lower elevations is forced into the connate water-saturated sandstone and begins to migrate up elevation, displacing the heavier water down elevation. This hydrocarbon will continue to migrate until it encounters the impermeable shale at the transition zone within the rock. It is trapped as a result of the change of permeability within the sedimentary bed, as the transition occurs from sandstone to shale or from permeability to no permeability. This transition of properties within the rock sediment is called a facies change.

Through the transition zone, the transition occurs from sandstone to shaley sandstone, to sandy shale, to shale. As to the distinction between"shaley sand" and"sandy shale," as long as the rock has sufficient porosity and permeability to be considered an acceptable reservoir rock, it is classified as sandstone. However, when either property has reduced sufficiently within the transition zone so that the rock can no longer be considered an acceptable reservoir rock, it is considered shale.

Types of Reservoirs

Three types of hydrocarbon reservoirs will be considered. Variations of these types might exist in specific geologic situations. In order for any reservoir to exist, however, source rock must have been present for the hydrocarbon to have been generated, reservoir rock must exist for storage of the hydrocarbon, and a trap must exist to trap the hydrocarbon. The three major types of hydrocarbon reservoirs are

- Oil reservoir (no gas cap)

An oil reservoir with no gas cap implies that the reservoir fluid pressure is higher than the bubble point pressure of the hydrocarbon present, so gas is not expected to exist initially within the reservoir. The oil zone of this reservoir will probably have 10% to 20% irreducible water saturation and is probably water-wet. Dependent upon the development plan and therefore the production history of the reservoir, a gas cap may come to exist during its productive life. The advantage of this type of reservoir is the relative ease of maintaining the flowing bottomhole pressures of the producing wells above the bubble point pressure, for a longer period during the productive life of the reservoir.

- Oil reservoir (with gas cap)

A second type of hydrocarbon reservoir is the oil reservoir with a gas cap. Since the gas cap exists naturally, the reservoir fluid pressure in the natural state must be less than the bubble point pressure of the original hydrocarbon combination (before hydrocarbon molecules were released from solution to form the gas). If a gas cap exists, the gas-oil contact will be essentially a distinct plane, compared to the oil-water contact, which will be a transition zone. There will probably not be significant oil saturation above the gas-oil contact. The oil zone of this reservoir will probably have 10% to 20% irreducible water saturation.

- Gas reservoir

The third major type of hydrocarbon reservoir is the gas reservoir. The gas volume at reservoir conditions is extremely large, compared to any hydrocarbon liquid volume. The reservoir is essentially a gas zone above a water zone. A gas-water contact could exist.

From the original reservoir fluid sample, collected at datum depth using the bottomhole sampler, the P-V-T analysis will provide a P-T (Pressure-Temperature) Diagram. This P-T diagram is more commonly known as a “Phase Diagram.” Based on the Phase Diagram for the particular hydrocarbon reservoir fluid and its initial pressure-temperature conditions, the reservoir can be categorized as a particular type reservoir.

Figure 25 is the Phase Diagram for the hydrocarbon of Our Reservoir. Liquid, gas, and two-phase regions are identified. This diagram can be used to predict changing conditions within the reservoir over its productive life. For most reservoirs, the production process is a constant temperature (isothermal) process, so that a vertical line on the Phase Diagram will predict reservoir history during production, dependent upon factors within the reservoir development plan (such as artificial maintenance of reservoir fluid pressures by fluid injection). Also, an exception to this isothermal process might exist due to application of thermal techniques for enhanced recovery during the productive life of the reservoir. As seen from this Phase Diagram, a reservoir identified by P-T conditions at point A would be an oil reservoir with an initial gas cap, point B identifies an oil reservoir without a gas cap, and point C identifies a gas reservoir. A reservoir containing a particular hydrocarbon combination with this Phase Diagram, representing the hydrocarbon present, could be any of these types of reservoirs, dependent upon its original natural pressure-temperature condition. In summary, the Phase Diagram for the reservoir hydrocarbon and the pressure-temperature condition at which it exists will determine the classification of the hydrocarbon reservoir.

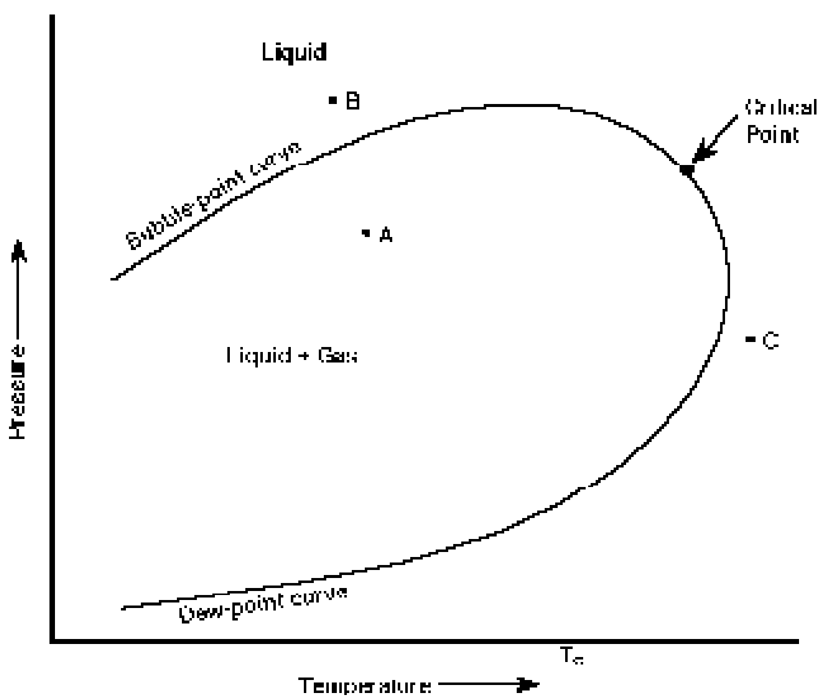

Figure 25. Phase Diagram for Our Reservoir (P-T Diagram)

PRODUCTION OF HYDROCARBONS

In order for the hydrocarbon trapped in a reservoir rock to be produced, the rock must have sufficient permeability so that hydrocarbon production rates will justify the economies for development of the reservoir.

The Darcy Equation

In its primary differential form, the Darcy Equation is

$$\frac{q}{A} = -\frac{k}{\mu}\left(\frac{dP}{dx}\right) \qquad \text{(Equation 1)}$$

where

q	=	Volume flow rate
A	=	Area perpendicular to flow direction
k	=	Permeability
μ	=	Dynamic viscosity of the flowing fluid
$\frac{dP}{dx}$	=	Pressure gradient in the flow direction x

This is the basic form of the equation. It assumes steady-state *laminar*, *incompressible flow*. In the case of its application to producing wells, assume that the choke size in the wellhead for flowing wells will be such that the flowing bottomhole pressure is above the bubble point pressure, so that fluid flowing from the reservoir into the wellbore will be liquid. Unless otherwise specified, if liquid flow exists, that flow will be considered as incompressible flow.

Absolute Permeability

From the original vertical core taken from Our Reservoir during drilling operations, many small horizontal cores will be taken for laboratory analysis processes. Consider the core represented graphically in Figure 26.

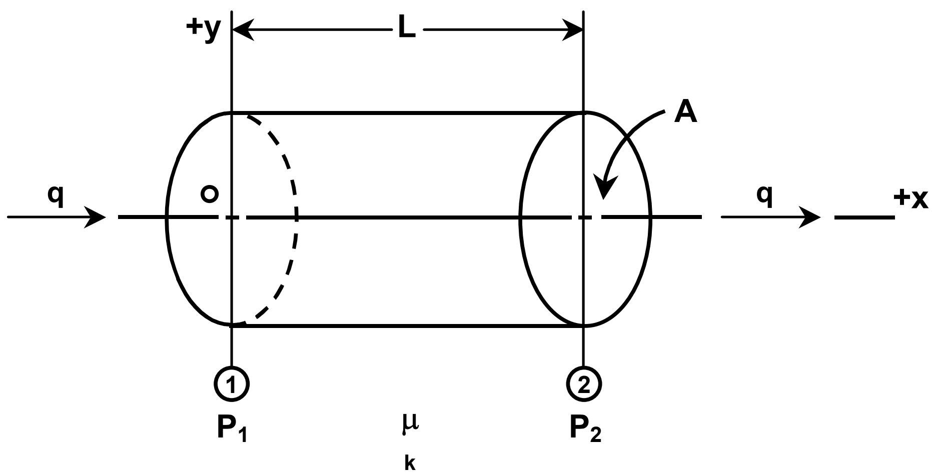

Figure 26. Rock Core Sample with Symbols for the Darcy Equation

where

q	=	Volume flow rate
k	=	Permeability
A	=	Core area perpendicular to flow direction
P_1	=	Upstream pressure at location 1
P_2	=	Downstream Pressure at Location 2
μ	=	Dynamic viscosity of flowing fluid
L	=	Distance over which pressure drop (P_2 - P_1) occurs

Chemical solvents can be used to remove all original reservoir fluids from the core samples so that experiments can be run with various fluid saturations within the core. For this particular reservoir, cores are prepared for laboratory analysis in this fashion. After removal of all original reservoir fluids, one of these cores is given 100% pure water saturation. It is now placed in a pump system so that the surface of the core cylinder is sealed. An equivalent one-dimensional (linear) steady-state, incompressible flow experiment is run using this core. All liquid entering the upstream face of the core, as shown in the figure, must be discharged at the downstream face of the core, so that a one-dimensional axial flow exists. This flow could not be achieved with the external surface of the core cylinder not sealed, because some liquid would seep through the cylindrical walls, reducing discharge flow rates downstream.

Once steady-state, incompressible flow conditions have been achieved, flow parameters are measured. Steady-state conditions are determined to exist by monitoring flow rate, upstream pressure, and discharge pressure until they remain constant with time. The length and diameter of the core are known, so that the core area can be calculated. The dynamic viscosity of the water under flow conditions has been determined in a viscometer prior to the experiment (the dynamic viscosity of pure water at standard conditions is 1 cp). A viscometer is a laboratory device used to experimentally measure dynamic viscosity μ. Pressure gauges measure upstream face pressure P_1 and discharge face pressure P_2.

For this particular flow condition, the Darcy Equation may be expressed as

$$q = \frac{kA(P_1 - P_2)}{\mu L} \qquad \text{(Equation 2)}$$

where

q = Volume flow rate
k = Permeability
A = Core area perpendicular to flow direction
P_1 = Upstream pressure at location 1
P_2 = Downstream pressure at location 2
μ = Dynamic viscosity of flowing fluid
L = Distance over which pressure drop (P_1 - P_2) occurs

This equation is the Darcy Equation for Linear, Steady-State Incompressible Flow. From this experiment, all parameters are measured or calculated except the volume flow rate q and the flow system permeability k. Note that A in this equation is not the same as the area appearing in the Continuity Equation for Steady-State Incompressible Flow, to be discussed in Module 5. In the Continuity Equation, “A” is the total area available for fluid flow, while the area in the Darcy equation is the core area perpendicular to the flow direction. Since a considerable portion of that area is taken up by the rock structure itself, the actual flow area available to flowing fluids through the core will be significantly less than the core area. This is the reason the original Darcy Equation (Equation 1) was expressed using q/A instead of a velocity term. This ratio q/A, where A is the core area perpendicular to the flow direction, is therefore not an application of the Continuity Equation for Steady-State Incompressible Flow.

Once *steady-state flow* has been achieved as indicated by constant P_1 and P_2 for the above experiment, a container can be placed on the discharge side of the flow system and the time required to fill its volume measured. By dividing that volume by the time required to fill the volume, the volume flow rate q can be calculated. Therefore, from this particular one-dimensional flow application of the Darcy Equation, permeability can be calculated, since the permeability k is the only remaining unknown in the equation.

The Darcy Equation applies for all unit systems. However, this equation is used to define the traditional oilfield unit of permeability: the Darcy. The basic definition of the Darcy as a unit of permeability is

If, for a flow system with a core area of 1 cm^2 for a fluid flowing of viscosity 1 centipoise, with a pressure gradient in the direction of flow of 1 atmosphere per cm of distance, the volume flow rate is 1 cm^3/sec, then, by definition, the permeability is 1 Darcy.

This unit is not the permeability unit which would apply to any of the standard unit systems (English Gravitational, English Absolute, Metric Absolute, or Metric Gravitational) because, based on the definition, the units involved are not consistent with any unit system. For example, the pressure unit of atmospheres is used in the definition, while in the English Gravitational System the unit of pressure is lb_f / ft^2. In the Metric Absolute (SI) System it is Newton/m^2, or Pascal. The Darcy unit for permeability is the most common used in the oil industry even though it does not apply to the standard unit systems.

Table 4 shows the unit comparisons for application of the Darcy Equation in the most common unit systems.

PROPERTY	METRIC ABSOLUTE	ENGLISH GRAVITATIONAL	DARCY UNITS
q	m^3/sec	ft^3/sec	cm^3/sec
k	m^2	ft^2	Darcy
A	m^2	ft^2	cm^2
P_1	Newton/m^2	lbf / ft^2	Atmosphere
P_2	Newton/m^2	lbf / ft^2	Atmosphere
μ	Newton • sec/m^2	lbf • sec/ft^2	Centipoise
L	m	ft	cm

Table 4. Unit System Comparisons

For a core sample from Our Reservoir, permeability for the flow system for this core for steady-state incompressible flow is calculated to be 0.161 Darcy. This calculation is made after the values obtained from the experiment are substituted into Equation 2, with the core 100% saturated with pure water and with pure water flowing in the system. Since 1 Darcy is a high rock permeability (even though not unusual), the millidarcy (mD) is commonly used to express reservoir rock permeabilities: 1 Darcy = 1,000 mD. The permeability for this particular rock core, under these experimental conditions, is therefore equal to 161 mD.

Assuming that the small horizontal cores taken from the original large vertical core from Our Reservoir are essentially identical in characteristics (the reservoir rock has uniform properties throughout its thickness), a second core is taken and given 100% oil saturation with the crude oil from Our Reservoir. A steady-state incompressible flow test is conducted at the reservoir temperature of 160ºF with all pressures maintained above the bubble point pressure (BPP). At this condition, the dynamic viscosity of the oil has been determined from the viscometer to be 0.6 cP.

Substituting the measured results from the laboratory tests into Equation 2, for this test condition, the permeability of the flow system is again determined to be 161 mD. In fact, if this experiment should be repeated with identical core samples, each 100% saturated with a single flowing liquid, the permeability obtained from each test for the flow of that particular liquid would equal 161 mD. This experiment indicates that, for a particular rock system 100% saturated with a single liquid, the permeability to flow of that liquid is dependent only on the rock structure itself and not upon the flowing liquid. This permeability is identified as the *absolute permeability* ($k_{absolute}$).

For this particular Permian Beach Sandstone for Our Reservoir, its absolute permeability is

$$k_{absolute} = 161 \text{ mD}$$

Relative Permeability

The oil zone of Our Reservoir is not 100% saturated with a single liquid, because S_o = 80% and S_w = 20%. In fact, most oil reservoirs in the oil zone will have water saturations in the 10% to 20% range and will not have oil saturations of 100%. The 20% water saturation in the oil zone of Our Reservoir is water distributed throughout the oil zone and is not the water beneath the oil in the water zone. Ideally, a typical void space within the oil zone of this reservoir rock has 20% by volume water present at reservoir conditions.

Figure 27 graphically represents a microscopic view of a sample of the Permian Beach Sandstone from Our Reservoir. As noted in the figure, water is distributed along with the oil throughout the pore space and flow channel system, and yet, because of surface tension, the water is separate from the oil. Obviously, oil and water do not mix well. Therefore, in reservoir rock systems, surface tension and capillary pressure effects are significant. If a well is completed in this reservoir, it will be a flowing well. Oil with a density of the oil in Our Reservoir, if permitted, will flow naturally back to the surface if the reservoir fluid pressure is 3,500 psia at a datum depth of 5,750 ft. This situation implies that production casing has been run through the reservoir and cemented, the wellhead has been attached, including the master valve and the choke valve, and the casing and cement have been perforated in the oil zone to provide flow access into the well. Within limits, the choke size in the wellhead manipulates the flowing bottomhole pressure. If desired, for a well in Our Reservoir, that flowing bottomhole pressure at the datum depth can be maintained above the bubble point pressure. Suppose this well is put in production with the flowing bottomhole pressure greater than the bubble point pressure so that only liquid is entering the wellbore. The production from the oil zone into the wellbore under these liquid flow conditions will not be 80% by volume oil and 20% by volume water.

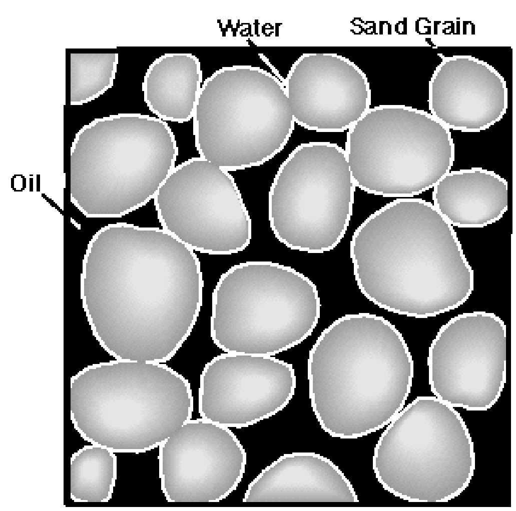

Figure 27. Graphical Representation of Microscopic View of Sandstone Sample for Our Reservoir (S_W = 20%, S_O = 80%)

Figure 27 shows a water-wet sandstone, in contrast to the oil-wet sandstone in Figure 28. Our reservoir rock is water-wet. Water is entrapped within the rock system due to surface tension wetting the rock particles This water will not flow. If the water would flow, it would already have settled down into the water zone beneath the oil because of its density being greater than that of oil. In this system the 20% water saturation, referred to as the irreducible water saturation, is present because surface tension and capillary pressure effects are dominant over density effects. When the well is put into production under the conditions specified, it will initially produce essentially 100% oil.

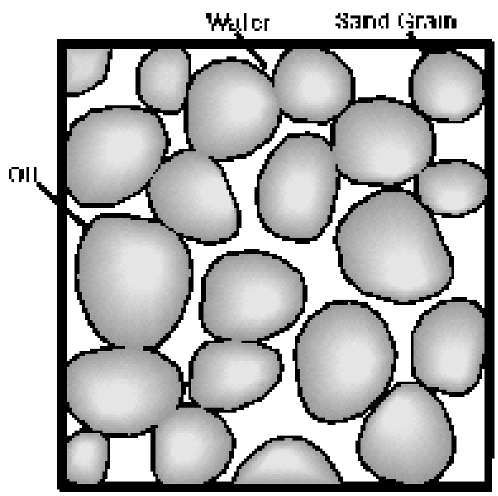

Figure 28. Graphical Representation of Microscopic View of Oil-Wet Sandstone

Consider a series of experiments on cores taken from the original core where the core is water-wet when water is present, as is the case with the beach sandstone of Our Reservoir. With this system, under water-wet conditions where both oil and water are present within the rock, it is often difficult to maintain steady-state conditions through the experiment and, in particular, to monitor and control the maintenance of the required conditions for the experiment being conducted. These experiments will be run, as shown in Figure 29, for various degrees of water saturation ranging from 0% to 100%. Obviously, when S_w = 0% and S_o = 100%, the rock will be oil-wet. As the experiments proceed from S_w = 0% to S_w = 100%, in 10% increments of increasing water saturation, the complexity of the experiment increases. The water-wet system must be maintained with the specified saturation conditions for that particular water saturation. In order to maintain steady-state conditions when both water and oil are present, the total flow rate for the system q_{total} will be the sum of the oil flow rate in cm^3/sec and the water flow rate in cm^3/sec. Oil and water are being injected simultaneously through the core. The relationship between q_o and q_w will not, in general, be in the same ratio as oil saturation to water saturation under steady-state conditions within the core. The necessary $q_{total} = q_o + q_w$ will have to be determined by trial and error during the experiment to maintain the required steady-state oil and water saturations.

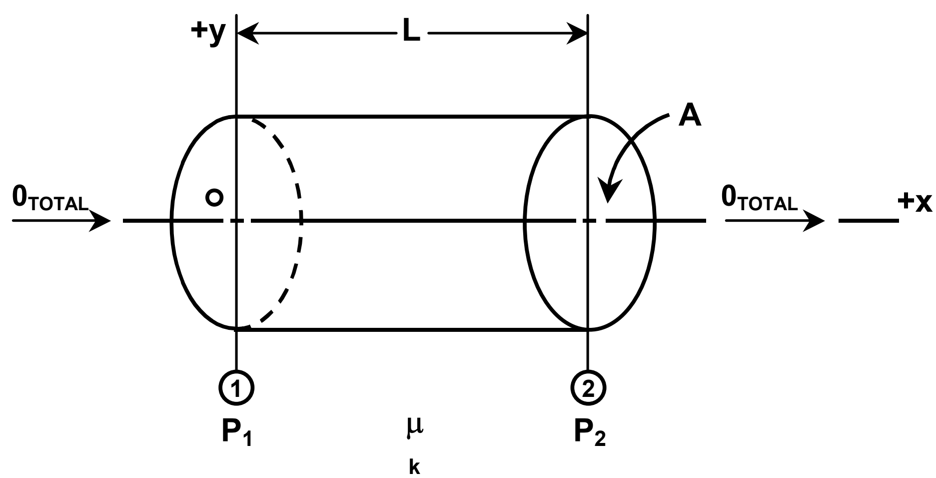

Figure 29. Rock Core Sample with Symbols for the Darcy Equation, for Combined Flow of Oil and Water

Once steady-state conditions have been achieved for a particular saturation condition, q_{total} is measured by filling a container on the discharge side of the core and measuring the time required for that volume to be obtained. The water volume and oil volume collected are then separated. Each volume is divided by the time required to fill the container, obtaining, for steady-state conditions, q_o expressed in cm^3/sec and q_w expressed in cm^3/sec.

For the flow conditions, the dynamic viscosity of the oil and water have been obtained with a viscometer prior to the experiment. The Darcy Equation for Linear Steady-State Incompressible Flow is now applied separately for the water flow and the oil flow, even though they were flowing simultaneously through the core. As an example for Our Reservoir, consider that experiment in the experimental sequence where S_o = 40% and S_w = 60%, and the rock is water-wet.

Equation 2 as applied becomes:

$$q_o \frac{k_o A(P_1 - P_2)}{\mu_o L} \qquad \text{(Equation 3)}$$

$$q_w = \frac{k_w A(P_1 - P_2)}{\mu_w L} \qquad \text{(Equation 4)}$$

$$q_{total} = q_o + q_w \qquad \text{(Equation 5)}$$

where

- q_o = Oil volume flow rate
- q_w = Water volume flow rate
- k_o = Permeability to the flow of oil under the fluid saturation conditions
- k_w = Permeability to the flow of water under the fluid saturation conditions
- μ_o = Oil dynamic viscosity
- μ_w = Water dynamic viscosity
- A = Core area perpendicular to flow direction
- P_1 = Upstream pressure at location 1
- P_2 = Downstream pressure at location 2
- L = Distance over which pressure drop (P_2 - P_1) occurs

For each of these applications of the Darcy Equation, the diameter of the core to obtain area and the length of the core will have been measured prior to the experiment. P_1 and P_2 will have been measured once steady-state flow conditions were achieved. μ_o and μ_w will have been determined from the viscometer. q_o and q_w were obtained from the experimental information. The only unknowns in these two equations are k_o and k_w. Applying the equations using the experimental results for the core from Our Reservoir at S_o = 40% and S_w = 60%, k_o is calculated to be 19 mD and k_w is calculated to be 35 mD. Note that each of these values is less than the absolute permeability. In fact, the sum of the two will always be less than the absolute permeability if two liquids are present in the flow system. These results permit the calculation of the relative permeability to the flow of oil K_{RO} and the relative permeability to the flow of water K_{RW} for the specified saturation conditions. These are defined as:

$$K_{RO} = \frac{k_O}{k_{absolute}} \qquad \text{(Equation 6)}$$

$$K_{RW} = \frac{k_w}{k_{absolute}} \qquad \text{(Equation 7)}$$

For this particular reservoir rock:

$$K_{RO} = \frac{19mD}{161mD} = 0.12$$

$$K_{RW} = \frac{35mD}{161mD} = 0.22$$

If this series of experiments should be conducted in 10% increments of increasing water saturation from S_w = 0% to S_w = 100%, the results as tabulated in Table 5 will be obtained, where the k_o and k_w values are obtained from the experimental results. K_{RO} and K_{RW} values are then calculated based on their definitions.

S_w	S_o	K_w (mD)	K_o (mD)	K_{RW}	K_{RO}
0%	100%	0	161	0	1.00
10%	90%	0	159	0	0.99
20%	80%	0	150	0	0.93
30%	70%	3	97	0.02	0.60
40%	60%	8	56	0.05	0.35
50%	50%	19	39	0.12	0.24
60%	40%	35	19	0.22	0.12
70%	30%	58	8	0.36	0.05
80%	20%	84	2	0.52	0.01
90%	10%	116	0	0.72	0
100%	0%	161	0	1.00	0

Table 5. Results of Relative Permeability Experiment for Sandstone Core for Our Reservoir

When the water saturation S_w = 0%, since

S_o = 100%, then

$k_o = k_{absolute}$ = 161 mD, and

k_w = 0.

At the other extreme, when S_w = 100%,

k_w = 161 mD, and

k_o = 0.

From these experimental results comes a general equation:

$$(k_o + k_w) \leq k_{absolute} \qquad \text{(Equation 8)}$$

The equality holds when either S_o or S_w equals 100%.

Relative Permeability Curves

From the above relative permeability data, the relative permeability curves for Our Reservoir can now be plotted, as shown in Figure 30.

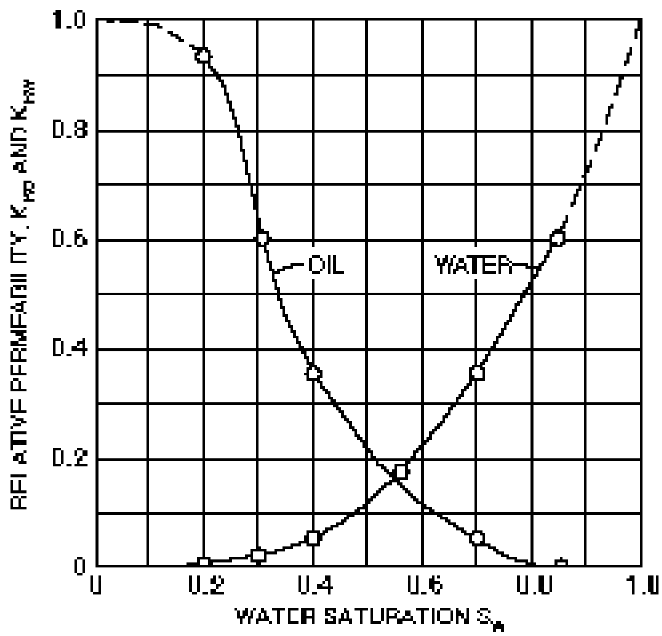

Figure 30. Relative Permeability Curves for Our Reservoir Sandstone

From this curve, at S_w = 20%, K_{RW} = 0 and therefore k_w = 0. The water within the reservoir will not flow. It is entrapped within the rock, wetting the rock particles. For this water, surface tension and capillary pressure effects are dominant over density. The entrapped water will not be produced, consequently the term: "irreducible water saturation." Since this condition represents the initial conditions of the oil zone of Our Reservoir, when the wells are first put into production, ideally, they will be producing 100% oil. At this condition, K_{RO} = 0.93, so k_o = 150 mD. From Figure 30, at S_w = 85%, S_o = 15%, k_{RO} = 0 and k_o = 0. If this condition should be achieved during the production life of this reservoir, the well would be producing 100% water and zero oil. This S_o = 15%, where k_o = 0, is referred to as the “residual oil saturation”. In practice, however, this reservoir would have been abandoned long before this condition is achieved, because oil production relative to water production would have been so low that further oil production activities could not have been economically justified.

From the relative permeability curves for this reservoir, increasing water saturation will have considerable adverse effect on permeability to flow of oil k_o and on the ability to recover remaining oil from the reservoir. The dominant source of natural energy (primary recovery) to produce the oil into the wellbore is water encroachment from the water zone into the oil zone. The normal history of production results in continually increasing water saturations within the oil zone as produced oil is replaced by encroaching water. Note that, from the relative permeability curves, it is important to have the water “sweep” the oil in front of the encroaching oil/water contact so that minimum oil saturation remains after this encroaching waterfront has passed.

For many reservoir rocks, the relative permeability for the flow of oil will decrease drastically with only a small increase in water saturation S_w. For example, in a particular sandstone, an increase in water saturation from S_w = 20% to S_w = 25% may cause the permeability to the flow of oil to decrease to 1/10 of its original value. Therefore, if a reservoir exhibits these relative permeability characteristics, the development plan should not permit encroachment of water from the water zone into the oil zone during oil production. Instead, alternative procedures should be used to maintain pressure within the reservoir without permitting encroachment of the water. A possible approach to achieve this condition would be to drill gas injection wells into the top of the oil zone and perforate those wells so that gas injection occurs at the top of the oil zone as oil is being produced. The injected gas results in reservoir fluid pressure maintenance in the oil zone, preventing encroachment of the oil/water contact. If a gas cap does not naturally exist in the reservoir, one would result in time from this gas injection process. By preventing water encroachment, a significantly higher percentage of Original Oil-in-Place will be recovered during the productive life of the reservoir. This illustrates the importance of knowing the reservoir properties before production is initiated.

For Our Reservoir, at its original conditions where S_w = 20% and S_o = 80%, the permeability to the flow of oil k_o = 150 mD. Figure 31 shows why the permeability to the flow of oil decreases at greater water saturations. This figure represents a microscopic view of the Permian Beach Sandstone of Our Reservoir with an initial S_w = 20% and S_o = 80%. The presence of the water wetting the sand grains results in a water film due to surface tension. As a result of the thickness of this film, the area available to the flow of oil through the permeability channels is restricted compared to the area available for oil flow if the water had not been present.

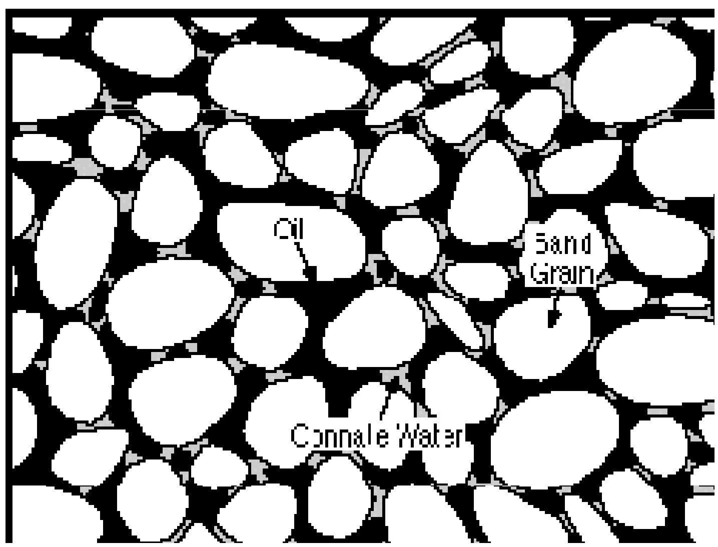

Figure 31. Graphical Representation of Microscopic View of Sandstone Sample for Our Reservoir Conditions (S_w = 20%, S_o = 80%)

For the water-wet sandstone, as the water saturation increases due to encroachment of water from the water zone or, possibly, as a result of water injection for pressure maintenance or enhancement of oil recovery, the thickness of the water film wetting the sand grains increases, further restricting the flow channels available for flow of oil. As this process continues, surface tension of the water will finally bridge across flow channels, blocking those channels to further oil flow and further reducing the permeability to the flow of oil.

For an example of rock properties that might lead to large decreases in k_o, with small increases of S_w, consider two *sandstones* that have equal absolute permeabilities. One of these sandstones has large numbers of small diameter flow channels per unit area perpendicular to the direction of flow, while the other sandstone has a smaller number of larger diameter flow channels per unit area perpendicular to the direction of flow. Yet, their absolute permeabilities are the same. As water saturation increases in each, the water wetting characteristics within the sandstone with smaller diameter flow channels will have a greater effect on restricting the flow channel area available to the flow of oil per unit increase in water saturation than on the sandstone with the larger diameter flow channels. In this sandstone with the smaller diameter flow channels, increasing water saturation will have a greater adverse effect on permeability to the flow of oil. For many reservoir rocks, increasing water saturation is a significant concern when preparing the development plan for the reservoir. Understanding reservoir characteristics is important before any development plan is accepted and initiated.

Fortunately, most reservoir rocks are water-wet. Consider two identical sandstones, each with S_w = 20% and S_o = 80%. Sandstone A is water-wet, and sandstone B is oil-wet. The Original Oil-in-Place per unit volume is the same since the porosities are equal. In general, total oil production over the productive life of the reservoir will be greater from the water-wet sandstone than from the oil-wet sandstone, because more of the oil is entrapped in the oil-wet sandstone due to surface tension and capillary pressure than is entrapped in the water-wet sandstone. Consequently, water-wet conditions are desirable in this instance.

There are basically two reasons that most reservoir rocks are water-wet:

- The water providing the S_w value is normally connate water. “Connate” comes from the Greek language and means “together from the birth or from the beginning,” referring to the water and rock particles. Essentially all shale’s and limestone’s, and most types of sandstones (a major exception is desert sand) have resulted from water depositional environments or water-related depositional environments. If the water present in the reservoir rock is truly connate water, it was present at the time of deposition of the particles that, through lithification in geologic time, has led to the formation of the *sedimentary rock*. This is a primary reason that wells produce salt water. Since the majority of the earth's surface is salt water sea or salt water ocean, the dominant water depositional environment in geologic time is a salt water environment. If the water in Our Reservoir rock is connate water, it has been in place since the Permian Period of geologic time.

- *Oil-wet rock* in the presence of water is unstable while *water-wet rock* in the presence of oil is stable. The tendency for equilibrium is toward water-wet when both oil and water are present. Water has better wetting characteristics for the rock than does oil. In some instances, rocks may have originally been oil-wet, with water encroaching later in geologic time, followed by proper conditions for reversing the wetting liquid from oil to water.

Porosity Versus Permeability

Porosity and permeability are very different types of properties. Both must be present with acceptable magnitudes for a rock to be considered reservoir rock. Three differences between porosity and permeability as properties are

- Porosity is not generally an indicator of permeability. A rock can have an extremely high porosity, but the permeability may be 0 if all pore spaces are isolated. In this instance the rock would have a high absolute porosity but zero effective porosity. There is an exception to this statement, if porosity is 0 or extremely low, permeability will be 0 or extremely low, because there must be void spaces in order for there to be flow channels.

  In contrast, permeability may be an indicator of porosity. If a rock has a high permeability, it must have a relatively high porosity, because flow channels cannot exist without void space. This is one of the principles used by many well logging tools to identify the presence of potential reservoir rock. These tools indicate the presence of permeability, which implies that porosity also exists. The next procedure will be to identify the fluids present within this porosity. There is also an exception to this statement because zero or very low permeability does not indicate porosity. The absolute porosity could be high with zero or low effective porosity.

- Porosity cannot be measurably increased. Yet, if there is good porosity and good hydrocarbon saturation but insufficient permeability, the permeability may be increased to an acceptable level. There is no process that can be applied to a reservoir to measurably increase its porosity. Porosity is increased when wells are drilled because rock is being removed. This process, or any similar process, has an insignificant effect on overall reservoir porosity. However, if a reservoir rock has acceptable porosity and hydrocarbon saturation, but insufficient permeability, permeability may be improved. This is the justification for acidizing a well or purposely fracturing a reservoir, by hydraulic fracturing, acid fracturing, nitrogen fracturing, or foam fracturing. These processes, however, are not effective if the permeability is originally zero or near zero.
- A third difference between porosity and permeability as reservoir rock properties is illustrated in Figure 32.

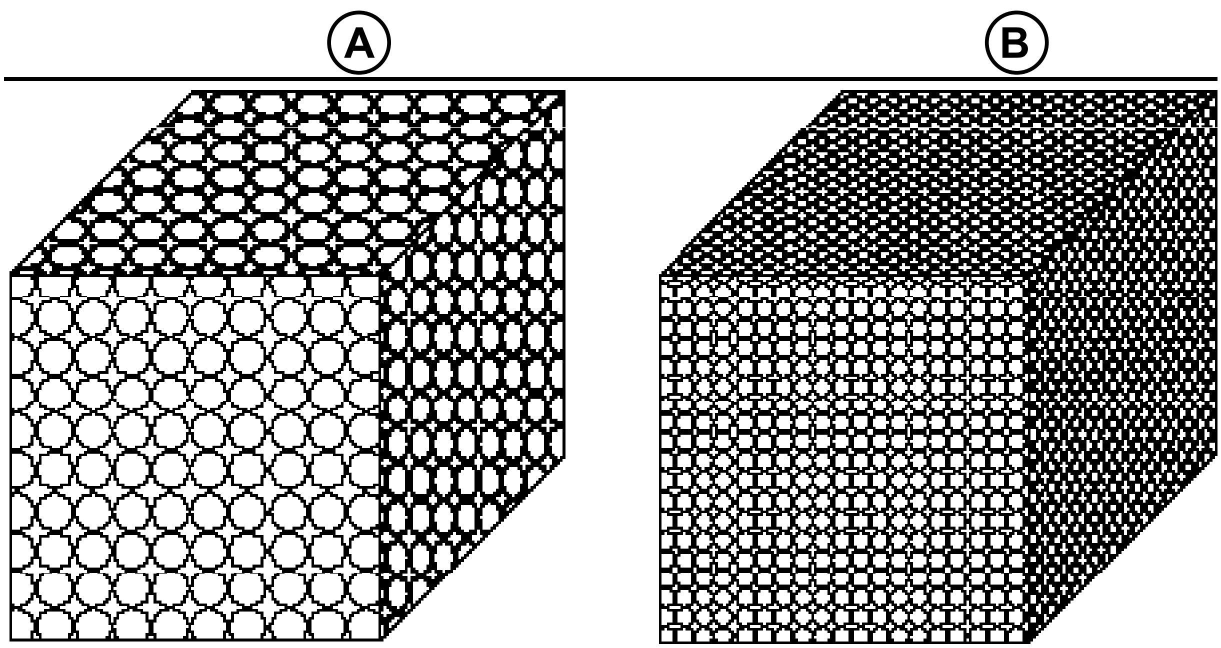

Figure 32. Idealized Porosity and Permeability Comparisons

Each box has inside dimensions 1 ft ∞ 1 ft ∞ 1 ft, or an inside volume of 1 ft^3. In the bottom of each box is a valve that is initially closed. Box A is filled with 1" diameter spheres, with one layer placed on top of the previous layer until the box is filled. Twelve layers of 144 spheres per layer, or 1,728 total, will be required to fill Box A. Box B is filled similarly with 1/4" diameter spheres. Therefore, 48 layers of 2,304 spheres per layer, or 110,592 total, will be required to fill Box B. Once the two boxes are filled with the spheres, if the definition of porosity is applied, the porosity of A will equal the porosity of B. In equation form,

$$\phi_A = \phi_B$$

This equation has major implications for reservoir considerations. For example, in the ideal case, shale could have the same porosity as beach sandstone. The primary difference distinguishing the sandstone from the shale is the original particle size resulting from the difference in environment of deposition, because larger sand particles were deposited near the shoreline and the smaller silt or mud particles were deposited into the body of water away from the shoreline. This example assumes, however, an ideal depositional environment without the presence of extraneous materials such as organic debris within the shale.

However, even though the porosities of A and B are equal, the absolute permeability for the system of Box A will be considerably greater than the absolute permeability for system of Box B or, in equation form:

$$k_A > k_B$$

This example illustrates a specific ideal situation because the actual values of porosity and permeability are both affected by the stacking arrangement of the spheres.

ESTIMATION OF HYDROCARBON VOLUMES

Before decisions are made regarding the development of the hydrocarbon reservoir, there must be economic justifications requiring estimates of initial oil and gas resources present. In order to estimate the hydrocarbon present, the reservoir must be defined as accurately as possible, based on information gathered by applications of various exploration and appraisal technologies. These technologies and their applications will be discussed in Module 4.

Reservoir Mapping

Reservoir maps will be developed. Reservoir characteristics will determine appropriate mapping that is most applicable to the particular reservoir under consideration.

Structural Contour Map

A *structural contour map* indicates variations of elevations over the geographic region, relative to sea level, of the top surface of the reservoir rock. A contour line connects points on top of the reservoir rock that are at equal elevation relative to sea level. The contour intervals selected are determined by the dip of the formation. Figure 33 is a Structural Contour Map of sandstone in a region. It indicates, for this sandstone structure, the existence of an anticlinal dome. If variations of the reservoir rock thickness over the region can also be determined by applying exploration technologies, it will then be possible to estimate the total volume of the reservoir rock over any portion of this region where the sandstone exists.

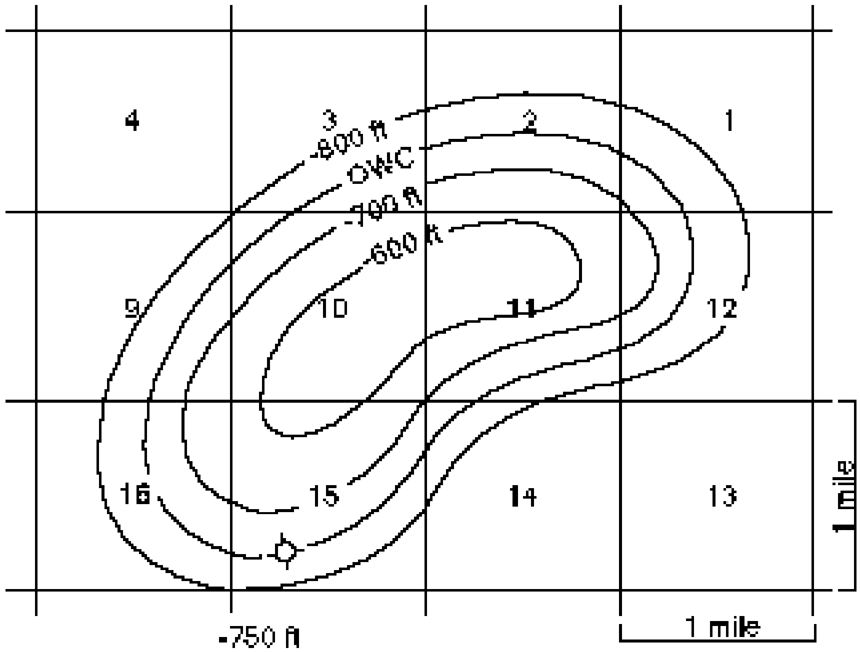

Figure 33. Structural Contour Map for a Sub-Surface Rock Structure of Uniform Thickness

Isopach Map

If the thickness of the reservoir rock changes over a geographic region, the *Isopach map* is important in preparation for estimating the hydrocarbon present in the reservoir. An Isopach Map indicates the variation in thickness of the rock over the geographic region. Figure 34 is an Isopach Map of a sandstone, where each line indicates locations of constant thickness for the sandstone, increasing from 0 ft to thicknesses of at least 30 ft. Figure 35 is a geologic cross-section along the line AA across the sandstone, showing the isopach line on the surface of the sandstone relative to the thickness of the sandstone at that location. The Isopach Map is a necessity for calculation of total volume of a reservoir rock that has major variations of rock thickness.

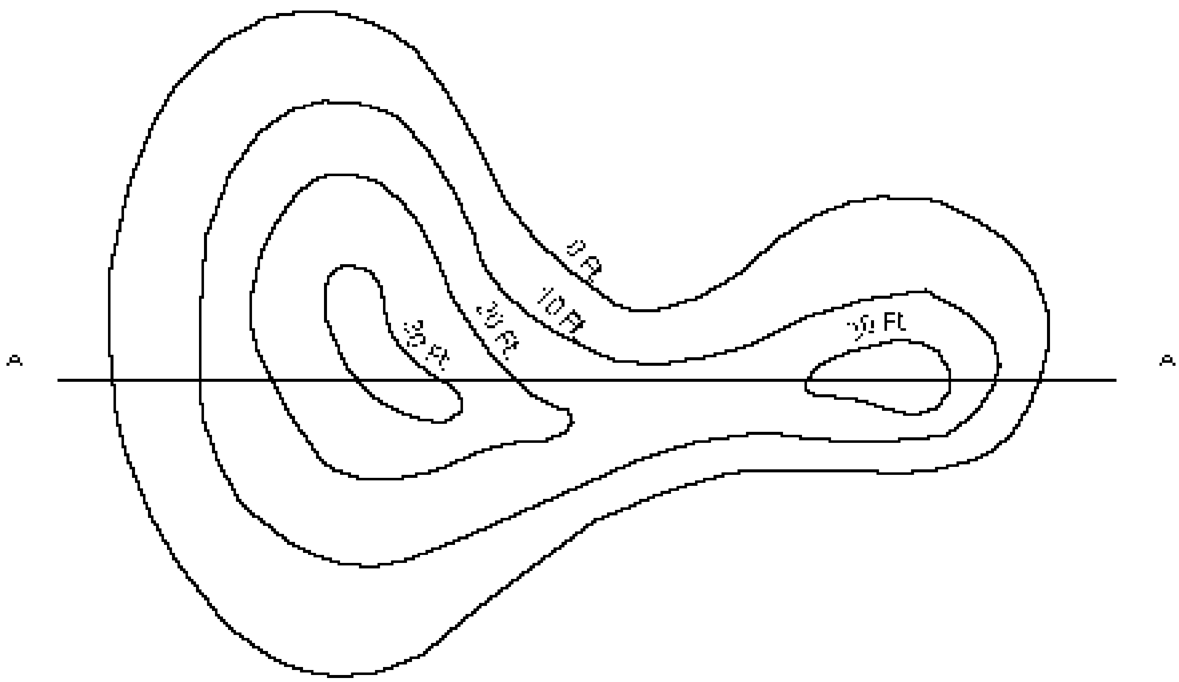

Figure 34. Isopach Map for a Sub-Surface Rock Structure of Varying Thickness

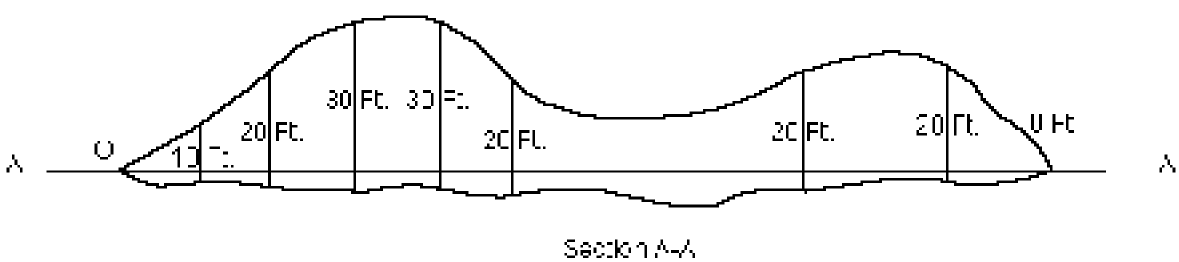

Figure 35. Geologic Cross-Section of the Sub-Surface Geologic Structure of Figure 39

In the reservoir situation, where the rock is of essentially uniform thickness over the geologic/geographic region, the Isopach Map would have no meaning. In fact, isopach lines would not exist, since the entire surface area would represent constant thickness.

Estimating Original Oil-in-Place

An estimate of Original Oil-in-Place (*OOIP*) is important as the hydrocarbon reservoir is defined and analyzed. The major difficulty in obtaining a meaningful estimate is in properly defining the geology of the reservoir rock so that its reservoir volume may be calculated within acceptable limits. Once this volume determination has been made and the volume of that portion of the reservoir rock containing hydrocarbons has been identified, if the properties of the reservoir rock system have been defined, then estimating Original Oil-in-Place is a straightforward calculation that uses the definitions of porosity, oil saturation, gas saturation, and oil formation volume factor.

Once the total volume of the rock containing oil has been obtained, that volume, when multiplied by the porosity ϕ, will provide the volume of the void space within the reservoir that may contain oil. If that volume is then multiplied by oil saturation and proper conversion factors are applied to convert the resultant volume into barrels, the value will be Original Oil-in-Place (OOIP) expressed in reservoir barrels (RB), since oil saturation is based on reservoir pressure and reservoir temperature conditions. Once this value is obtained, the oil formation volume factor can then be used as if it is a conversion factor, even though it is actually a reservoir fluid property. If the Original Oil-in-Place expressed in reservoir barrels is multiplied by the reciprocal of the oil formation volume factor, the result will be Original Oil-in-Place expressed in stock tank barrels (STB).

This calculation is summarized as the equation:

$$\text{Original Oil-in-Place} = \text{(Bulk Volume of Reservoir Rock Where Oil Is Present)} \, (\phi)\, (S_o) \,/\, (B_o) = \text{OOIP}$$

The resultant value is referred to as the OOIP of the reservoir expressed in STB. This result, however, is accurate only within the limits of accuracy of the calculation of the original volume of that portion of the reservoir rock in the oil zone and the uniformity of porosity, permeability, and oil saturation, distribution and continuity throughout that volume of reservoir rock.

Estimating Original Gas-in-Place

In the case of an oil reservoir without a gas cap, the Original Gas-in-Place (*OGIP*) can be calculated by multiplying the OOIP of the reservoir expressed in STB by the solution gas-oil ratio (GOR_S). The resultant value will be the Original Gas-in-Place expressed in standard cubic feet (SCF). This may be summarized as the equation:

$$\text{Original Gas-In-Place} = (\text{OOIP})\,(\text{GOR}_s) = \text{OGIP}$$

If the oil reservoir has a gas cap or, if the reservoir is a gas reservoir only, either the gas-oil interface or the gas-water interface must be identified from the available exploration information, so that the volume of that portion of the reservoir rock containing gas (S_g greater than O) may be properly defined in a similar fashion to the estimation of volume for that portion of the reservoir rock containing oil. Once that volume has been determined, the Original Gas-in-Place can be obtained by multiplying the volume of that portion of the reservoir rock in the gas zone times the porosity, times the gas saturation, times the reciprocal of the *gas formation volume factor* (B_g) where B_g is expressed in RB/SCF. This is expressed in equation form as follows:

$$\text{Original Gas-In-Place} = (\text{Bulk Volume of Reservoir Rock Where Gas is Present})\,\phi\,(S_g) / (B_g) = \text{OGIP}$$

The total Original Gas-in-Place will be that number of SCF in the gas zone plus the solution gas present in the oil zone expressed in SCF. This calculation assumes accuracy of estimated volumes, as well as uniformity of porosity, permeability, and gas saturation distribution and continuity throughout the volume of reservoir rock.

GLOSSARY

absolute permeability	The permeability of a flow system when that system is 100% saturated with a single flowing liquid.
anticlinal dome	The peak of a domelike structure, formed from layered sedimentary rocks by geologic activity causing sufficient forces to create the dome structure. An anticlinal dome is normally caused by an uplift or intrusion phenomenon.
anticline	The peak or high elevation of folded, layered sedimentary rocks resulting from geologic activity (folds concave downward).
basement rock	Igneous rock which is a part of the crust of the earth lying beneath the surface sedimentary rocks. If rock is truly basement rock, then no sedimentary rock should be present at greater depths.
batholith	A massive intrusion of igneous rock into overlying rock structures, formed during volcanic activity.
biogenic source sedimentary rock	Sedimentary rock resulting from deposition of plant and animal remains in a sedimentary environment. Examples are coal and biogenic limestone (which includes chalk).
cap rock	Impermeable rock serving as a reservoir seal, resulting in a hydrocarbon trap. Cap rocks are also known as confining beds.
chalk	A form of biogenic source limestone (calcium carbonate).
clastics	Sedimentary rock resulting from lithification of rock fragments deposited in a sedimentary environment and exposed to conditions leading to lithification. These fragments or particles of previously existing rocks have been formed by erosion and chemical action during the weathering process, and have accumulated in a sedimentary environment. These may also be referred to as fragmental source sedimentary rocks.
coal	A biogenic source sedimentary rock, resulting from the lithification of plant organic residue.

confining bed	Impermeable rock serving as a reservoir seal, resulting in a hydrocarbon trap. Confining beds are also known as cap rocks.
conglomerates	Sedimentary rocks formed when large rock fragments are exposed to conditions that lead to lithification.
connate	Together from the birth or from the beginning.
connate water	Water present in the environment of deposition at the time of sedimentation of rock particles, which through lithification resulted in the formation of sedimentary rocks. This water is entrapped within the porosity of those rocks during lithification.
core	A rock cylinder, collected from sub-surface rock formations with a core sampling device and retrieved to the surface, for analysis of sub-surface rock characteristics and determination of fluid presence. A typical core is 4" to 6" in diameter and 30' to 90' in length, dependent upon limitations of the core collector (core barrel) used in taking the core.
dike	An essentially vertical intrusion or vein of igneous rock into overlying structures, during volcanic activity.
dolomite	A sedimentary rock with a chemical composition including magnesium and calcium carbonate.
extrusive igneous rock	Rock which has been formed as a result of magma being extruded to the surface during volcanic activity and exposed to atmospheric conditions during cooling.
facies change	The region of transition within a rock structure, over which properties change significantly within that particular rock. The facies change may exist as a result of decreasing size of deposited particles near a shoreline, with increasing distance away from the shoreline. After lithification, the resultant sandstone, through a transition zone, grades to shale within the same sedimentary layer. Through the transition zone, permeability decreases from its value within the sandstone to an essentially zero value within the shale.
fault	A fracture within rock structures where relative motion has occurred across the fracture surface.

fault plane	The rock fracture surface along which relative motion or faulting has occurred.
fossil	Plant and animal remains, or indications of plant and animal remains, that are present in rock formations.
gas formation volume factor	The reservoir volume at reservoir fluid pressure and reservoir fluid temperature, expressed in barrels, of hydrocarbon gas originally present as gas in the reservoir, resulting in 1 standard cubic foot (SCF) of gas when produced to the surface and taken to stock tank conditions. Gas formation volume factor is normally indicated by the symbol B_g, and is normally expressed in reservoir barrels per standard cubic foot (RB/SCF).
gas saturation	The percentage of the reservoir rock porosity containing hydrocarbon gas at reservoir conditions (reservoir fluid pressure and reservoir fluid temperature conditions).
geologic cross-section	A vertical plane cross-section of earth structure, where the horizontal axis represents surface position and the vertical axis represents depth.
granite	A crystalline structure rock formed from molten rock, with cooling and solidifying occurring without exposure to the atmosphere. Granite consists primarily of feldspar, quartz, and smaller amounts of other minerals.
hydrocarbon trap	A reservoir rock with hydrocarbon present in the porosity. Hydrocarbon is confined to the reservoir rock by confining rock with zero permeability, preventing migration from the reservoir rock.
igneous rock	Rock formed as a result of the cooling and solidifying of originally molten rock, often referred to as fire formed rock.
incompressible flow	Flow where mass density and therefore specific weight of the flowing fluid remains constant within the limits of pressure changes in the flow system.

index fossils	Fossils resulting from particular plants and animals that changed significantly through evolution in relatively short periods of geologic time. When found in rocks, index fossils identify the age of those rocks by the presence of these particular fossils that have been determined to have existed at a particular time in geologic history. Also referred to as *marker fossils*.
intrusive igneous rock	Rock that has been formed as a result of magma intrusions into overlying rock structures during volcanic activity, without exposure to atmospheric conditions. Upon cooling, this intruded magma solidifies to form intrusive igneous rock, also called plutonic igneous rock.
isopach map	A map drawn with a plan view of a rock surface, with isopach lines indicating locations of equal vertical thickness of the rock structure. A particular vertical surface of a specified thickness through the rock structure interfaces the rock surface along that particular isopach line, indicating locations of constant thickness of the rock.
laminar flow	Fluid flow along stream lines where the stream lines maintain their positions with time.
lava	Magma or molten rock extruded to the surface and exposed to the atmosphere during volcanic activity.
limestone	A sedimentary rock resulting from lithification of calcium carbonate ($CaCO_3$) particles. These calcium carbonate deposits may be of organic or chemical origin.
lithification	The process by which discreet fragments or particles deposited in a sedimentary environment are converted into solid rock, due to the effects of pressure, temperature, and chemical action over geologic time.
magma	Molten rock.
marble	Metamorphosed calcium carbonate (metamorphosed limestone).

marker fossils	Fossils resulting from particular plants and animals that changed significantly through evolution in relatively short periods of geologic time. When found in rocks, *marker fossils* identify the age of those rocks by the presence of these particular fossils that have been determined to have existed at a particular time in geologic history. Also referred to as index fossils.
metamorphic rock	Rocks formed from previously existing rocks by extremes of pressure, temperature, and geologic time, with chemical action having occurred as that time passed. When the conditions of lithification are carried to the extreme, metamorphism occurs.
OGIP	Original Gas-In-Place expressing the total volume of gas originally in the reservoir in standard cubic feet (SCF).
oil saturation	The percentage of the void space within reservoir rock containing hydrocarbon liquid at reservoir conditions (reservoir fluid pressure and reservoir fluid temperature conditions).
oil-wet rock	Rock where oil is in contact with individual particles of the rock structure, wetting that solid surface.
OOIP	Original-Oil-In-Place, expressing the total volume of oil originally in the reservoir in stock tank barrels (STB).
Pangaea	The earth supercontinent consisting of the major continental plates of the earth as they existed in combination during the period of geologic time from approximately 265 million years ago until approximately 200 million years ago, when Pangaea began to break apart and the plates began to separate, according to the Theory of Plate Tectonics.
permeability	The property of rock that indicates the presence of flow channels within the rock. The greater the permeability, the greater the presence of those flow channels, and the more easily fluid will flow from the rock.
plate tectonics	The continental plate and oceanic plate composition of the crust of the earth and the relative motion between those plates. Also considered to be the study of the concept of the existence of continental plates and oceanic plates, and the relative motion between those crustal plates.

plutonic igneous rock	Rock that has been formed as a result of magma intrusions into overlying rock structures during volcanic activity, without exposure to atmospheric conditions. Upon cooling, this intruded magma solidifies to form plutonic igneous rock, also called intrusive igneous rock.
porosity	The percentage of the total volume (bulk volume) of the rock that is void space.
quartzite	A metamorphic rock formed from previously existing sandstone of angular particle configuration.
reservoir rock	The sedimentary rock within which hydrocarbon can be stored as a result of the presence of porosity and from which hydrocarbon can be produced as the result of the presence of permeability.
salt dome	An intrusion of a solid, yet plastic, salt into overlying rocks, resulting in the formation of a dome-shaped salt structure.
sandstones	Sedimentary rocks formed when sand size to larger silt size rock fragments are exposed to conditions which lead to lithification.
sedimentary rock	Rocks formed through the process of lithification from deposited fragments or particles which have resulted from the erosion or weathering of previously existing rocks, chemical sedimentation of particles, or organic materials.
shale’s	Sedimentary rocks formed when smaller silt size to mud size fragments are exposed to conditions which lead to lithification.
sill	An essentially horizontal intrusion or vein of igneous rock into overlying structures, during volcanic activity.
slate	A metamorphic rock with significant cleavage planes formed from shale.
source rock	The sedimentary rock in which organic materials were deposited in the original sediments, resulting in hydrocarbon generation during the lithification process.

steady-state flow	Flow where all properties of the flow system, if monitored at all points within the flow system, remain constant with time, even though particular flow system properties at a particular point may be different from those properties at other points in the flow system.
structural contour map	A map drawn with a plan view of a rock structure, indicating contour lines connecting points on top of the rock surface of equal elevation relative to sea level. Each line indicates a different specific elevation of points relative to sea level. The structural contour map is therefore an indication of variations in elevation of the rock surface relative to sea level.
syncline	The trough or low elevation of folded, layered sedimentary rocks resulting from geologic activity (folds concave upward).
unconformity	A geologic discontinuity over a surface, resulting from removal of previously existing rocks by the process of erosion. The unconformity indicates a discontinuity in the geologic time record.
water saturation	The percentage of the porosity of the reservoir rock containing water at reservoir conditions (reservoir fluid pressure and reservoir fluid temperature conditions). The water present in the reservoir rock porosity is normally salt water. However, since the salt is dissolved within the water, forming a solution, the salt is not considered separately. The expression for the water saturation is therefore normally actually an expression of salt water saturation.
water-wet rock	Rock where water is in contact with individual particles of the rock structure, wetting the solid surface.