4 Generation and migration of petroleum

4.1 Origin of petroleum: abiogenic versus biogenic genesis of petroleum
In spite that Jupiter, Saturn, and some of the satellites of the outer planets contain methane; carbonaceous chondrites (meteors) contain traces of hydrocarbons; solid and liquid hydrocarbons are reported in some Precambrian basement rocks, the inorganic or abiogenic origin of petroleum is now not accepted by all geologists.

This abiogenic origin is refuted because unquestionable cases of indigenous oil in basement rocks are rare and not commercially important. Not only are the volumes of hydrocarbons trapped in basement rocks insignificant but the “reservoirs” are impermeable unless fractured. Moreover, commercial accumulations of hydrocarbons in igneous and metamorphic rocks occur only when the igneous rocks intrude or are unconformably overlain by sediments.

It is now clear that commercial accumulations of oil are restricted to sedimentary basins. Petroleum seeps and accumulations are absent from the igneous and metamorphic rocks of continental shields.

Gas chromatography (finger printing) is now routinely used to match the organic matter in shales with petroleum in adjacent reservoirs. Therefore, geologists conclude that commercial quantities of petroleum are formed by the thermal maturation of organic matter. This thesis will be examined, beginning with an account of the production and preservation of organic matter on the Earth’s surface followed by evolution of this organic matter through burial in the crust.

4.2 Modern organic processes on the Earth’s surface
Through photosynthesis accomplished by plants and algae, inorganic carbon, CO$_2$ is converted into organic carbon (glucose, a sort of hydrocarbons) and water as the following reaction:

$$6\text{CO}_2 + 12\text{H}_2\text{O} = \text{C}_6\text{H}_{12}\text{O}_6 + 6\text{H}_2\text{O} + \text{O}_2$$

This glucose is further manufactured into complex carbon compounds, and even other organic compounds, such a protein, lignin by plants or animals that feed on the producing plants. Upon death of plants and animals, organic matter is oxidized into CO$_2$ and water, thus closing the carbon cycle (Fig. 4.1).
Fig. 4.1: The carbon cycle within the Earth’s crust. The primary source of C is from weathering of crustal rocks, together with mantle-derived CO$_2$ and methane.

In certain exceptional circumstances, however, the organic matter may be buried in sediments and preserved, although in a modified state, as coal, oil or gas. As mentioned above, gas chromatography can be used to “fingerprint” petroleum and to correlate it with the source rock from which it was derived and to determine the type of organism and depositional environment in which it lived.

To follow the evolution of living organic matter into crude oil and gas, we should know that four major types of chemical groups occur in living organic matter, that are: proteins, carbohydrates, lipids, and lignin.
The proteins are found mainly in animals and less commonly in plants. They contain the elements H, C, O, N, with some S and P that constitute the amino acids.

The carbohydrates occur in both plants and animals, and include the sugars, such as glucose, and their polymers—cellulose, starch and chitin.

The lipids are also present in plants and animals, and include the fats, oils, waxes and steroids.

The lignin occurs only in higher plants and consists of various types of aromatic carbon rings. Fig. 4.2 shows the distribution of these four organic groups in living organisms and in recent shallow sediments.

4.2.1 Productivity and preservation of organic matter

Most of organic matter is destroyed at Earth’s surface and a small fraction is preserved in the sediments. Such organic-rich sediments are produced due to a high rate of production of organic matter and a high preservation of the organic matter. These two factors will be discussed below. The preservation of organic matter is different between marine and continental environments. Therefore, these two environments will be considered separately.

4.2.1.1 Organic productivity and processes in seas and oceans.

Organic matter in seas is produced by photosynthesis accomplished by pelagic phytoplankton and benthic algae. The biological productivity is controlled by physical and chemical factors. Among the first are temperature and light. Temperature decreases
with latitude, whereas amount of light decreases with increasing water depth and turbidity. Thus the amount of organic productivity is highest in the shallow photic zone and decreases with increasing water depth and decreasing temperature and amount of light.

Chemical factors influencing organic productivity are mainly phosphates and nitrates that are essential for the growth of plants and animals. Oxygen is important for animals that feed on plants. However, phytoplanktons produce oxygen through photosynthesis, thus increasing it in the oceans.

Figure 4.3 illustrates the organic productivity in present day oceans of the world.

![Figure 4.3](image)

**Fig. 4.3: Production of organic matter in the present day oceans. Note the low production in the Polar Regions and the high productivity along eastward sides of the oceans.**

It is obvious from the figure that low organic productivity characterizes Polar Regions, whereas high organic productivity occurs along westward sides of the continents because of high-latitude upwelling currents. These cold upwelling currents carry large amounts of nutrients, mainly phosphates and nitrates, from deeper part of the ocean towards the ocean surface. In the photic zone these nutrients are utilized by the phytoplanktons, giving rise to high organic productivity characteristics to western regions of North America, South America and Africa.

The preservation of organic matter, which could be in other regions where there is a high organic productivity, is favored by anaerobic bottom conditions and high rate of sedimentation. Aerobic conditions cause the oxidation and complete decay of the organic matter. The same is applied on the low rate of sedimentation that is accompanied by complete decomposition of the organic matter, and thus low chance of preservation.

A third condition influencing preservation of organic matter is water stratification in depositional environments. There are four settings in oceans that favor formation of organic-rich sediments in anoxic environments (Fig. 4.4).
The first setting is freshwater lakes, where stratification is gravitational due to low density of warmer surface water and denser colder water at bottom of the lake (Fig. 4.4A). Phytoplanktons perform photosynthesis, and thus thrive in the upper photic zone. The oxygen produced by this process makes the surface water oxygenated opposite to deeper part of the lake which is oxygen-poor (anoxic) because of absence of photosynthesis and the consumption of oxygen by decomposing dead fish and other biota. Therefore, the deep sediments of the lake become enriched with organic detritus.

The second setting occurs in barred basins (Fig. 4.4B). Here, seawater enters a semi-restricted lagoon or gulf or sea in an arid climate. Due to evaporation salinity increases causing higher density of surface water that sinks down to bottom of depositional environment. This sinking water is replaced by water of normal salinity coming from the ocean across the bar and floating above the denser water. The bar also prevents the denser water to return to the sea. Therefore water stratification occurs similar to the previous lake setting but due to salinity layering rather than temperature layering. However, similar anoxic conditions develop at bottom of the barred basin and organic matter will be preserved. The Black Sea is a recent example of anoxic barred basins.
The third setting occurs now on the western margins of continents in low latitudes where deep upwelling currents rise to the photic zone of the oceans. These cold upwelling currents are rich with nutrients (Fig. 4.4C) that cause blooms of phytoplanktonic life which in turn give rise to very rich faunal life, mainly fishes. Again upon death of the biota and fall to sea bottom, anoxic conditions are developed at ocean bottom that make the sediments enriched with organic matter.

The fourth setting is anoxic ocean basins (Fig. 4.4D). No recent example is present since all ocean bottoms are oxygenated by the deep oceanic currents. The deep ocean currents start from Polar Regions where the water has a high density because of low temperature and high salinity, thus water sinks down to the ocean bottom and moves directly above ocean bottom towards higher latitudes as deep oceanic current. It is proposed that in the geological past, particularly in late Mesozoic, there were no such deep oceanic currents, probably due to a uniform equable climate on Earth without polar ice caps of today. At such times global anoxic events may have responsible for the worldwide deposition of organic rich sediments (Fig. 4.4D).

4.2.1.2 Organic productivity and preservation in continental environments

Only in swamps organic matter, mainly as terrestrial plants, can be preserved. Otherwise, very high rate of oxidation and complete decomposition cause the rate of decay of organic matter to be more than the rate of formation, thus preservation of organic matter could not be achieved. However, accumulation of terrestrial plants in swamps leads to formation of coal, but it is of little concern to formation of fluid hydrocarbons.

4.3 Formation of kerogen

What happens to the organic matter preserved in the sediments when buried in a steadily subsiding sedimentary basin? As time passes, burial depth increases, exposing the sediment to increased temperature and pressure. There are three major phases in the evolution of organic matter in response to burial.

1- Diagenesis phase that occurs in shallow subsurface at near normal temperatures and pressures. It includes both biogenic decay, aided by bacteria, and abiogenic reactions. Methane, carbon dioxide, and water are given off by the organic matter, leaving a complex hydrocarbon called kerogen. The net result of diagenesis of organic matter is the reduction of its oxygen content, whereas the hydrogen:carbon ratio remains largely unaltered.

2- Catagenesis phase that occurs in the deeper subsurface as burial continues and temperature and pressure increase. Petroleum is released from kerogen during catagenesis, first oil and later gas. The H:C ratio declines, with no significant change in the O:C ratio.

3- Metagenesis phase that occurs at high temperatures and pressures verging on metamorphism. The last hydrocarbons, generally only methane, are expelled. The H:C ratio declines until only carbon is left in the form of graphite. Porosity and permeability become negligible.
The evolution of surface organic matter into kerogen and the ensuing generation of petroleum are discussed below.

4.3.1 Shallow diagenesis of organic matter.
In stratified water an oxygenated zone (+Eh) overlies a reducing zone (-Eh). The interface between oxidizing and reducing zones could be within the water, or coinciding with water:sediment interface, or, if the sediments are permeable (and a high rate of organic matter production), below the sea bottom.

In the upper oxidizing zone oxidizing bacteria genus *Thiobacillus* oxidizes sulfur, whereas in the reducing zone the bacteria genus *Desulfovibrio* reduces sulfur from sulfate ions releasing free sulfur. This free sulfur might react with organic matter to form hydrogen sulfide (H\(_2\)S), or may combine with iron in ferrous hydroxide to form pyrite (FeS\(_2\)). Thus both of hydrogen sulfide and pyrite characterize reduced sediments-rich with organic matter, as known from recent swamps.

Regarding the marine organic matter (having a composition of carbon, nitrogen, phosphorus in the ratio of 106:16:1), it will be in the first stage decomposed biologically by oxidation releasing water, carbon dioxide, nitrates and phosphates:

\[
(\text{CH}_2\text{O})_{106}(\text{NH}_3)_{16}\text{H}_3\text{PO}_4 + 138\text{O}_2 = 106\text{CO}_2 + 16\text{NH}_3\text{O}_3 + \text{H}_3\text{PO}_4 + 122\text{H}_2\text{O}
\]

In the next stage, reduction of nitrates and nitrites occurs which will be followed by sulfate reduction giving rise to generation of hydrogen sulfide and ammonia.

The organic compounds that have undergone these reactions were originally diverse and complex, consisting mainly of proteins, carbohydrates, lipids and lignin. They will be attacked by the enzymes of microbes to produce various biomonomers. For example, carbohydrates, such as starch and cellulose, are broken down into sugars. Cellulose is also converted into methane and carbon dioxide.

Methane is a major by-product of the bacterial decay of not only cellulose but many other organic compounds. As this biogenic methane moves upward from the decaying organic matter, it may cross the -Eh:+Eh surface and be oxidized into CO\(_2\) and water. Or, in environments characterized by a high rate of organic matter deposition and a rapid decay, free methane will seep to the surface as bubbles of marsh gas. Also here, the sulfate ions will react with organic matter to produce hydrogen sulfide.

Within the top few meters of the sea bottom sediments other changes for the other organic compounds (proteins, lipids and lignin) will take place.

With gradual increasing burial depth, the physical environments of sediments change, where increasing overburden pressure causes compaction accompanied by decreasing porosity and expulsion of water. Also other inorganic reactions take place, such as formation of authigenic minerals as pyrite, siderite (FeCO\(_3\)), and early calcite cement.
With increasing burial depth, temperature increases leading to several inorganic reactions and processes. On the other hand, the role of bacteria in biogenic reactions declines as they die out (but some of them survive to a large burial depth). Thus the generation of hydrocarbons now declines as the production of biogenic methane ceases. However, important changes continue to take place within the preserved organic matter where water and carbon dioxide continue to be expelled as the formation of kerogen begins.

4.3.2 Chemistry of kerogen
Kerogen is a term applied to disseminated organic matter in sediments that is insoluble in normal petroleum solvents, such as carbon bisulfide. The soluble fraction of organic matter in sediments is termed bitumen. Kerogen consists of carbon, hydrogen, and oxygen, with minor amounts of nitrogen and sulfur (Tab. 4.1).

<table>
<thead>
<tr>
<th>Tab. 4.1: Chemistry of kerogens</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Type</strong></td>
</tr>
<tr>
<td><strong>C</strong></td>
</tr>
<tr>
<td>TYPE I Algal (7 samples)</td>
</tr>
<tr>
<td>TYPE II Liptinic (6 samples)</td>
</tr>
<tr>
<td>TYPE III Humic (3 samples)</td>
</tr>
</tbody>
</table>

Three types of kerogen are present, based on chemical composition and the nature of the original organic matter. They could generate different types of hydrocarbons, thus they are important and will be discussed below.

Type I kerogen is essentially of algal origin (Fig. 4.5). It has a higher proportion of hydrogen relative to oxygen than the other types of kerogen have (H:O is about 1.2-1.7). The H:C ratio is about 1.65 (Tab. 4.1).
Fig. 4.5: Photomicrographs of different types of kerogen at various maturation stages.
Lipids are the major compounds in this kerogen, with derivates of oils, fats, and waxes. This algal kerogen is characteristic of many oil shales, source rocks, and cannel or boghead coals. The basic chemical structure of type I algal kerogen is shown in Fig. 4.6A.

![Chemical structures of kerogens](image)

**Fig. 4.6:** The molecular structure of A) type I, or algal kerogen, B) type II, or liptinic kerogen, and C) type III, or humic kerogen.

Type II, or liptinic, kerogen is of intermediate composition (Fig. 4.5). The original organic matter of this type of kerogen is algal detritus with materials derived from zooplankton and phytoplankton. It has an H:C ratio of greater than one (1.28). The chemical structure is shown in Fig. 4.6B.

Type III, or humic, kerogen has a much lower H:C ratio (<0.84) (Fig. 4.5). The basic molecular structure is shown in Fig. 4.6C. It is produced from the lignin of higher woody plants, which grow on land. It is this humic material that, if buried as peat, undergoes diagenesis to coal. Type III kerogen tends to generate mainly gas and little, if any, oil.

### 4.3.3 Maturation of kerogen

During the phase of catagenesis, kerogen matures and gives off oil and gas. When kerogen is immature, no petroleum has been generated; with increasing maturity, first oil and then gas are expelled; when the kerogen is overmature, neither oil nor gas remains. Fig. 4.7 shows the maturation paths for the three types of kerogen.
Fig. 4.7: Graph showing the maturation paths of the three different types of kerogen.

The rate of maturation depends on temperature, time, and possibly, pressure. Regarding temperature, significant oil generation occurs between 60 and 120 °C, and significant gas generation occurs between 120 and 225 °C. Above 225 °C the kerogen is inert, having expelled all hydrocarbons; only carbon remains as graphite (Fig. 4.8). The temperatures just cited are only approximate boundaries of the oil and gas windows.
4.3.3.1 The chemical laws of kinetics

The chemical laws of kinetics, as expressed in Arhenius equation, state that the rate of a chemical reaction is related to temperature and time. Reaction rate generally doubles for each 10 °C increase. Therefore, many geologists have considered that kerogen maturity is a function of temperature and time (Fig. 4.9).
Petroleum may thus have been generated from old, cool source rocks as well as from young, hot ones.

Several techniques have been developed that try to quantify the relationship of temperature and time to kerogen maturity. These techniques are mainly based on a burial history curve, which is a graph on which burial depth is plotted against geological time for a particular area (Fig. 4.10).

Fig. 4.10: Burial curve for the Central Graben of the North Seas. Source rocks (Kimmeridge age). Since present-day isotherms are used, the graph gives a rough idea when the source rocks entered the oil and gas window.

Two maturation indices are commonly used which are the time-temperature index (TTI) and the level of organic maturation (LOM). The TTI was first proposed by Lopatin (1971) and developed by Waples (1981).

The TTI is calculated from a formula that integrates temperature with time spent in each temperature (in increments of 10 °C) as a source rock is buried. The length of time spent in each temperature increment is established from the burial curve.
The LOM is based on the assumption that reaction rates double for each 10 °C increment of temperature. Oil generation occurs between LOM values of 7 and 13, and gas generation occurs between values of 13 and 18.

TTI and LOM curves must be used carefully. Since that they assume that the geothermal gradient is constant through time, which is not always the case. Moreover, the present burial depth of a source rock is actually influenced by compaction, uplift, and not equal balance between sedimentation and subsidence.

4.3.4 Paleothermometers
Since there is an important relationship between petroleum generation and temperature, it is vital to measure the kerogen maturity.

To evaluate a certain source rock in a sedimentary basin, we should know: Are there actually organic-rich source rocks in the basin? Is their volume large enough to generate commercial hydrocarbons? Are they oil prone or gas prone? Are they mature enough to generate hydrocarbons, or are they supermature (barren)?

To measure the temperature at bottom of the borehole does not answer the question of kerogen maturity. This measurement indicates the present-day temperature, which could be much less than that of the past. Therefore, it is necessary to have a paleothermometer that can measure the maximum temperature to which the source rocks were ever subjected.

Two major groups of techniques are used to measure the maximum paleotemperature to which a rock has been subjected:
1- Chemical paleothermometers:
   a- Organic: carbon ratio, electron spin resonance, pyrolysis, and gas chromatography.
   b- Inorganic: clay mineral diagenesis, and fluid inclusions.
2- Biological paleothermometers:
   a- Pollen coloration
   b- Vitrinite reflectance.

4.3.4.1 Chemical paleothermometers
Pyrolysis is the heating of kerogen or source rock to produce petroleum from oil shales. The technique can also be used as a paleothermometer by gradual heating of the kerogen or source rock and analyzing the released hydrocarbons at different heating temperatures that could indicate the maturation level of the kerogen.

Gas chromatography is used to study the distribution of n-alkanes that evolve with increasing temperature and burial depth. The gas chromatographs of immature source rock of n-alkanes show a broad “whaleback”, with a bimodal distribution of unsolved components (Fig. 4.11).
Fig. 4.11: Diagram of gas chromatographs that show the evolution of n-alkanes with increasing temperature and burial depth. Immature source rocks show a broad whaleback with bimodal distribution of unsolved components. As the temperature increases and the source rock matures, the whaleback submerges and the unsolved components form a single peaky mode. Degraded oils are characterized by a broad low whaleback that is devoid of spikes.

As the temperature increases and the source rock matures, the whaleback submerges and the unsolved components form a single peaky mode (Fig. 4.11). Degraded oils are characterized by a broad low whaleback that is devoid of spikes.

Clay mineral analysis is an inorganic paleothermometer that could be used to indicate the kerogen maturity. In recent and young sediments, the clay minerals present include: smectite group, and particularly montmorillonite member, illite and kaolinite. Upon increasing burial depth temperature increases and upon reaching a depth corresponding to a temperature of oil generation (80-120 °C), smectite dewater and recrystallizes to form illite. Upon increasing burial depth, and reaching the temperature of the upper limit of oil and gas generation, kaolinite and illite recrystallize into serecite (a mineral related to muscovite). If there is a source for iron and magnesium in this burial environment, such as ferromagnesian minerals, kaolinite and illite could be converted into chlorite.

Another inorganic paleothermometer is the study of fluid inclusions. This method is used widely by igneous petrologists to find the temperature of crystallization of a certain mineral from magma. Now, it is used in oil industry to understand the diagenetic processes occurring in petroleum reservoirs.
4.3.4.2 Biological paleothermometers

Color of the organic matter in the source rock could be utilized as a paleothermometer. Kerogen has many colors and shades depending on both maturation and composition (Fig. 4.5). Spores and pollens begin life essentially colorless. As they gradually heated, they change to yellow, orange, brown (light to dark), and then to black. These colors are also related to degree of maturation of the associated kerogen. Different techniques are employed, such as the 10-point Spore Color Index, the 5-point Thermal Alteration Index, and the simple brewer’s index.

Using the simple brewer’s color code, the following relationship between pollen color and hydrocarbon generation has been observed: water: immature; larger: oil generation; bitter: condensate generation; Guinness: dry gas. The technique is fast and economical.

The vitrinite reflectance is a well-established technique used by coal petrographers to determine the rank of coal. In principle, the reflectance, or shininess, of coal increases with rank of coal from peat to anthracite. The reflectance can be measured by using a reflecting-light microscope after preparing a polished surface for the coal.

Vitrain, the coal maceral used for measurement occurs throughout sedimentary rocks. Kerogen, which similarly contains vitrain, is separated from the source rock sample by solution with hydrofluoric and hydrochloric acids. The residue is mounted on a slide, or in a resin block with a low temperature epoxy resin and then polished. The degree of reflecting, or reflectance, termed $R_o$ is measured by the reflecting-light microscope.

An empirical relationship has been noted between vitrinite reflectance and hydrocarbon generation. Crude oil generation occurs for $R_o$ values between 0.6 and 1.5. Gas generation takes place between 1.5 and 3.0. At values above 3.0 the rocks are graphite and devoid of hydrocarbons.

The measurement of vitrinite reflectance is one of the most important techniques used to determine the maturity of a potential source rock in an area. By plotting $R_o$ against depth in a certain borehole the interval in which oil or gas has been generated can be determined. Abrupt shifts in $R_o$ with depth may indicate faults or unconformities. An abrupt increase $R_o$ with depth followed by a return to the previous gradient may be caused by igneous intrusives.

After review of the different paleothermometers, it should be stated that all of them require careful operation, and interpretation. Probably, pollen coloration and vitrinite reflectance are the most reliable and widely used maturation indices now. Fig. 4.12 shows the relation between $R_o$, pollen coloration and hydrocarbon generation.
4.4 Petroleum migration

After maturation of kerogen into petroleum it migrated from the source rock to the reservoir. This migration is proved to have taken place through many lines of evidence, including:

1- Organic matter is easily destroyed by oxidation if it remained in porous, permeable sediments at Earth’s surface. Therefore, it must have invaded the reservoir rock after burial to a large depth of elevated temperature.

2- Oil and gas occur in solution pores and fractures that must have been formed after the burial and lithification of the source rocks.

3- Oil and gas are trapped in the highest points (structural culmination, or stratigraphic pinchout) of a permeable rock, which implies upward and lateral migration.

4- Oil, gas and water occur in porous, permeable reservoir rocks stratified according to their densities. This stratification implies that they were, and are free to migrate vertically and laterally within the reservoir.

According to above points, it can be concluded that hydrocarbons migrate into reservoir rocks at a considerable depth below the surface and some time after burial.

There are two types of migration, primary and secondary. Primary migration is the migration of hydrocarbons from source rocks (clay or shale) into permeable carrier beds (generally sandstones or limestones). Secondary migration is the subsequent movement of oil and gas within permeable carrier beds and reservoirs.
It is clear that secondary migration occurs by buoyancy due to different densities of the respective fluids and in response to differential pressures. Also it is well-known that secondary migration occurs when petroleum is clearly identifiable as crude oil and gas, although gas may be dissolved in oil but not in connate water.

On the other hand, primary migration is still a matter of debate. For many people, primary migration of hydrocarbons is a great mystery of petroleum geology.

Since oil and gas originated from impermeable source rocks (mainly shales), then how did the fluids emigrate? It can be proposed that oil and gas were squeezed from source rocks before compaction then they migrated away from the now compacted, becoming impermeable source rock to the reservoir rocks. Unfortunately this is not true, since the temperature needed for hydrocarbon generation can not be reached until compaction has reduced permeability significantly.

Another suggestion is that expulsion of pore water may flush the hydrocarbons which can be further migrated to the carrier beds and reservoir rocks. Fig 4.13 clearly shows that most of the water loss due to shale compaction occurs at a depth below 2 km, which is less than the depth required for generation of oil. Thus this water that is squeezed from pore spaces can not cause the primary migration of hydrocarbons, since they are not generated yet.
Fig. 4.13: Shale compaction curves. Note that there is minimal water loss through compaction over the depth range of oil window.

Another suggestion is the water expelled from the smectite interlayer during its conversion into illite that could help in flushing generated hydrocarbon and in their primary migration. This conversion occurs at a temperature of some 100 to 110 °C, right in the middle of the oil generation window.
Moreover, various theories for primary hydrocarbon migration can be proposed:
1- Expulsion as protopetroleum
2. Expulsion as petroleum
   a. In solution
      i. Dissolved in water (derived from compaction, expelled from clays, or dissolved from meteoric flushing)
      ii. Within micelles
      iii. Solution of oil in gas
   b. Globules of oil in water
   c. Continuous phase

4.4.1 Expulsion of hydrocarbons as protopetroleum
It is suggested that hydrocarbon migration occurs before the hydrocarbons are recognizable crude oil, that is, while they are in the form of ketons, acids and esters, which are soluble in water. This transitional phase is called protopetroleum.

4.4.2 Expulsion of hydrocarbons in aqueous solution
An obvious possibility to consider is that hydrocarbons migrate from source rocks fully formed, yet dissolved in water. The solubility of hydrocarbons is very low at Earth’s surface, but may be enhanced by temperature or presence of micelles, as discussed next.

4.4.2.1 The hot oil theory
Fig. 4.14 illustrates the solubility of various crude oils plotted against temperature.

![Graph showing the solubilities of various crude oils plotted against temperature in degrees centigrade.](image)

It can be seen from this graph that the solubility of hydrocarbons is negligible below a temperature of 150 °C, but becomes significant above 150 °C. We know that optimum temperature for oil generation is 120 °C, at which temperature solubility of oil varies from 10 to 20 ppm.
Still this solubility is not helpful to account for primary hydrocarbon migration. However, from Fig. 4.15 it can be seen that the solubility of hydrocarbons increase dramatically by decreasing number of both normal alkanes (paraffins) and aromatic series.

Accordingly, gaseous hydrocarbons can emigrate from source rocks dissolved in water, and exsolution may then occur when they reach the lower temperature and pressure of carrier beds.

But there are heavy hydrocarbons that are insoluble in water, such as naphthenoaromatics and resins. For these hydrocarbons, presence of pressured salty water and gases may increase their solubility and assist their primary migration.

**4.4.2.2 The micelle theory**

Micelles are colloidal organic acid soaps whose molecules have hydrophobic (water insoluble) and hydrophilic (water soluble) ends. Their presence may thus enhance the solubility of hydrocarbons in water by acting as a link between OH radicals on their hydrophilic ends and hydrocarbon molecules on their hydrophobic ends.

The particle sizes of micelles in crude oils have a bimodal log-distribution. This distribution is related to two basic micelle types: the small ionic and large neutral micelles. The proportions of different hydrocarbons in crude oil should be related to their micellar solubility. The naphthenic and aromatic fractions are present in monomodal log-normal frequency distribution. Whereas, the paraffins, both normal and branched, show a frequency distribution suggesting that they are solubilized by both ionic and neutral micelles.
Hydrocarbons of low atomic weight (C_5 or less) show a normal frequency distribution which is related to the fact that they are naturally soluble in water and do not need the assistance of micelles.

4.4.3 Expulsion of oil in gaseous solution
Gases could act as catalysts or transporting media facilitating primary hydrocarbon migration. CO_2, driven off during kerogen maturation, may have a direct or indirect influence in hydrocarbon migration. Indirectly, by combining with calcium ions it precipitates calcite cement, which diminishes pore volume and thus increases pore pressure. The presence of CO_2 gas in solution lowers the viscosity of oil, thus increasing its mobility. Also, it causes the precipitation of N-S-O heavy ends of oil, thus making the residual oil lighter and increasing the gas:oil ratio.

But on the other hand, the precipitation of calcite diminishes permeability. Also the concentration of CO_2 at the time of petroleum generation may be too low to assist migration in the ways mentioned above.

However, gas may play a direct role in oil migration in another way. Hydrocarbon gases in deep wells carry oil in gaseous solution. The oil condenses when pressure and temperature drop as the hydrocarbon gases are brought to the surface. Therefore, oil may possibly migrate in this manner from the source beds.

4.4.4 Primary migration of free oil
There are many theories postulating that oil emigrates from the source bed not in any kind of solution but as a discrete oil phase. Two types of migration are proposed: the expulsion of discrete droplets associated with pore water; and the expulsion of a three-dimensional continuous phase of oil. But the diameter of oil droplet is actually larger than that of pore throat which makes the first type of migration not likely to happen.

However, it is possible that organic-rich source rocks are not water wet, but oil wet. In this situation petroleum would not migrate as discrete globules of oil in water, but as a continuous three-dimensional phase. Such mechanism may work for rich source rock, but is not possible to occur in very thin source rocks, which are probably water-wet.

4.5 The petroleum system
After concluding in previous parts of this chapter that commercial quantities of petroleum are of the organic origin, and the process of primary migration of petroleum from the source rock to the carrier bed, we should move to the discussion of the petroleum system. Petroleum system is the integration of the petroleum migration with the thermal and tectonic evolution of a sedimentary basin. It includes consideration of the distance of secondary migration of petroleum, and the mathematical modeling of the time and amounts of petroleum that may have been generated within a given sedimentary basin.

4.5.1 Measurement of the distance of petroleum migration
The lateral distance to which petroleum can migrate is a difficult parameter to measure. Theoretically, it is the distance between petroleum accumulation and the nearest mature
source rock. Where oil is trapped in a sand lens surrounded by shale, the migration distance must have been short. Where oil occurs in traps with no obvious adjacent source rock, extensive lateral migration may have occurred.

Correlation between source rock and oil reservoir can be carried out by fingerprinting using gas chromatography. Tab. 4.2 cites some reported examples of long-distance lateral petroleum migration.

Tab. 4.2: Some published long distances of petroleum migration.

<table>
<thead>
<tr>
<th>Basin</th>
<th>Migration distance (km)</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Athabasca Tar Sands, Canada</td>
<td>100</td>
<td>Tissot and Welte (1978)</td>
</tr>
<tr>
<td>Magellan basin, Argentina</td>
<td>100</td>
<td>Zielinski and Bruchhausen (1983)</td>
</tr>
<tr>
<td>Pennsylvanian Oklahoma, USA</td>
<td>120</td>
<td>Levorsen (1967)</td>
</tr>
<tr>
<td>Gulf Coast, Pleistocene</td>
<td>160</td>
<td>Hunt (1979)</td>
</tr>
<tr>
<td>Illinois basin, USA</td>
<td>200</td>
<td>Bethke et al. (1991)</td>
</tr>
<tr>
<td>Paris basin</td>
<td>200</td>
<td>Gaullier et al. (1991)</td>
</tr>
<tr>
<td>Phosphoria Formation, Illinoise and Idaho, USA</td>
<td>400</td>
<td>Claypool et al. (1978)</td>
</tr>
<tr>
<td>Alberta basin, Canada</td>
<td>1000</td>
<td>Garven (1989)</td>
</tr>
</tbody>
</table>

It can be seen from the table that distances of more than 1000 km are recorded for some petroleum occurrences.

4.5.2 The petroleum system and basin modeling

It is useful to determine the amount of petroleum that has been generated in a sedimentary basin. Knowledge of the quantity of remaining reserve is important for deciding whether to continue exploration if the quantity has an economic value.

The volume of oil generated in an area may be calculated using the following geochemical material balance method. The basic equation may be expressed as:

\[
\text{Volume of oil generated} = \text{Basin area} \times \text{Average total thickness of source rocks} \times \text{Transformation ratio}
\]

The volume of source rocks can be calculated from isopach maps. The average amount of organic matter can be determined from the geochemical analysis of cores and cuttings, and also from extrapolating data from wireline logs.

The genetic potential of a formation is the amount of petroleum that the kerogen can generate. The transformation ratio is the ratio of petroleum actually formed to the genetic potential. These values can be determined from the pyrolysis of source rock samples.
The transformation ratio must exceed 0.1 for significant oil generation and is usually in the range of 0.3 to 0.7 in major petroleum provinces.

Petroleum systems can be classified according to three parameters: the charge factor; the style of migration (vertical or lateral); and the entrapment style. The charge factor is calculated on the basis of the richness and volume of the source rock in a basin. This is measured according to the source potential index (SPI):

\[
SPI = \frac{h(S_1 + S_2)P}{1000},
\]

where

- \(SPI\) is the maximum quantity of hydrocarbons that can be generated within a column of source rock under 1 m\(^2\) of surface area;
- \(h\) is thickness of source rocks
- \(S_1 + S_2\) is the average genetic potential in kilograms hydrocarbons/metric ton of rock;
- \(P\) is the source rock density in metric tons/cubic meter.

The style of migration drainage could be lateral or vertical, if this is possible, it might vary with space and time through the history of one basin.

The style of entrapment depends on the length and continuity of carrier beds, the distribution and effectiveness of seal, and the tectonic style. All of these factors together control the degree of resistance of the basin to the dispersion of the petroleum charge. Thus entrapment style may be categorized as high or low impedance.

Tab. 4.3 lists examples of the different types of petroleum system classified according to these three parameters.

**Tab. 4.3: Examples of the different types of petroleum system**

<table>
<thead>
<tr>
<th>Type of drainage</th>
<th>Charge</th>
<th>Impedance</th>
<th>Example</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lateral</td>
<td>Super</td>
<td>High</td>
<td>North slope of Alaska, USA</td>
</tr>
<tr>
<td></td>
<td>Normal</td>
<td>Low</td>
<td>Williston basin, USA</td>
</tr>
<tr>
<td>Lateral</td>
<td>Super</td>
<td>Low</td>
<td>Venezuela foreland basin</td>
</tr>
<tr>
<td>Vertical</td>
<td>Super</td>
<td>High</td>
<td>Central Graben, U.K. North Sea</td>
</tr>
<tr>
<td>Vertical</td>
<td>Normal</td>
<td>High</td>
<td>Tertiary Niger Delta</td>
</tr>
<tr>
<td>Vertical</td>
<td>Super</td>
<td>High</td>
<td>Los Angeles basin, USA</td>
</tr>
</tbody>
</table>

The concept of petroleum system can be usefully applied to the computer modeling of sedimentary basins. The object of this discipline is to try to discover how much petroleum a sedimentary basin may have generated and where it may be located. Basin modeling may take place in one, or two, or three dimensions. Basin modeling is done by computer and several software packages that are available and new versions are constantly appearing.
One dimension modeling involves no more than construction of a burial history curve for a particular point in a basin, such as well location (Fig. 4.10). This may be used to establish the maturity of a source rock interval using present-day geothermal gradient, or calculating one based on the tectonic history of the region.

A two-dimensional model consists of a cross-section. This may be constructed by “backstripping” the geological history, based on a seismic section, calibrated with well data, if available. To do so, we need to estimate the depositional depth and compaction history of the sedimentary sequence. Then a geohistory scenario can be plugged in. This can be used to establish the pressure system of the section and the migration and entrapment history of the petroleum (Fig. 4.16).

![Geological Section](image)

Fig. 4.16: Three computer generated cross-sections to illustrate how a sedimentary basin may be modeled to predict the distribution of pressure and petroleum.
A three-dimensional model involves the same operation as just described, however not for a cross-section, but for a volume of rock.