1.3

Geological characteristics of hydrocarbon reservoirs

1.3.1 Reservoir rocks

Hydrocarbons accumulate below the Earth's surface in deposits known as reservoirs. All accessible and commercially viable reservoirs feature two essential elements: reservoir rock and a hydrocarbon trap.

The *reservoir rock*, which is porous and permeable, contains the hydrocarbons; determining the nature of this rock and its geometry is the goal of hydrocarbon exploration. The boundaries of the rock may coincide with the actual accumulation of hydrocarbons, although the latter are usually concentrated in a well-defined portion of a more extensive formation. Reservoir rocks must have pores (empty spaces): the percentage of empty space in the total volume of the rock is known as porosity. The pores must be communicating, and of a dimension which allows the hydrocarbons to move around. Permeability is the measure of fluid's capacity to move around within the rock.

The *hydrocarbon trap* is a particular distribution of rocks in the subsurface that keeps the hydrocarbons inside the reservoir rock until they have been reached by the drilling and can therefore be extracted. The top of the trap consists of impervious rock (sealing rock) which prevents the hydrocarbons, generally lighter than the fluids they are mixed with, from migrating towards the surface. The bottom limit of the reservoir is the generally flat and horizontal surface that separates it from the underlying fluid, normally salt water, which accompanies hydrocarbons in their marine origin. Less commonly, when the water is in motion, the separating surface may be inclined; depending on the type of hydrocarbons present, this surface is called either oil-water contact or gas-water contact, or more simply water level. The bottom of the reservoir is often also bounded by impervious rock which the hydrocarbons are unable to penetrate.

Aspects studied during exploration include the reservoir's shape, size, gas and oil contents, and its physical parameters such as temperature, pressure and solubility of the gas in the oil. The porosity and permeability of the hydrocarbon-bearing rocks, their vertical and lateral variations, and, finally, the amount of fluids to be extracted in the times deemed suitable for full development of the reservoir, are also studied.

The reservoir's size and shape depend on its sedimentary origin and, above all, on the sedimentary environment in which it originated. Generally, reservoirs are not homogeneous: variations in the rock's characteristics are normally due to primary depositional processes.

A reservoir's sedimentary environment is characterized by physical, chemical and biological processes that are different from those of adjacent depositional areas, and are the result of climate, flora and fauna, lithology, geomorphology, tectonic context and, in marine environments, water depth, temperature, and chemism. In general, continental (subaerial) environments are more exposed to erosion, while marine environments are mostly depositional areas.

Determining the environment in which the rock has deposited is essential in reconstructing the reservoir's geometry and other characteristics. The environment determines the sediment facies, defined as the lithological (lithofacies) and biological (biofacies) characteristics of a stratigraphic unit, linked to the sedimentary process forming it. A facies does not indicate an environment but one or more processes through which the sediment was deposited (Mutti and Ricci Lucchi, 1972). In order to define the sedimentation environment, it is essential to consider the association of various facies or, in other words, how the facies are vertically and laterally positioned.

Facies analysis takes into consideration the following sedimentary aspects (Zimmerle, 1995): *a*) inorganic sedimentary structures such as cross-bedding, graded beds, sole marks, palaeocurrents, etc.; *b*) the presence of flora and fauna and their habitat, along with the organic sedimentary structures (fossil moulds); *c*) granulometric distribution and sedimentary textures; *d*) mineralogical composition; *e*) geochemical composition (trace elements and stable isotopes); *f*) stratigraphic relations (morphology of the environment, unconformities, magnetic polarity).

A sedimentary sequence shows the vertical development and environmental evolution over time, and can be studied using sequential stratigraphy methods. Lateral facies variations highlight the environment's distribution in space according to the principle, expressed by Johannes Walther in 1894 (Ricci Lucchi, 1978), that: “only facies that deposit in contiguous environments can overlie in sedimentary continuum”. This concept was successfully applied also to interpret the complex stratigraphic sequences of the Alpine formations, where different overlying and heteropic units can be identified.

Analysis of the sedimentary environment, indispensable in stratigraphical analyses applied to oil exploration, requires in-depth knowledge of sedimentary processes and is based on the concept that current sedimentary environments provide the key to the past; that is, we can interpret ancient environments by applying the principle of actualism. Along with the study of lithofacies and biofacies, performed in the field through direct observation by field geologists, subsurface geologists exploring for oil may also carry out studies based on deep exploration (Ori *et al*., 1993). This involves the analysis of electrical properties (electrofacies) and radioactive characteristics obtained from electrical and radioactive well logging, and from seismic surveying (seismofacies).

Analysis of electrical and seismic diagrams must naturally be accompanied by observation of the same formations in the field. However, the structures involved in oil exploration are mostly buried and only in extremely favourable cases do they offer comparable outcrops. The two study methods (surface observations and the study of electrical, radioactive, and seismic diagrams) are complementary because interpretation of subsurface data allows for physical analysis of quantitative parameters that cannot normally be applied to outcrops.

In particular, analysis of electrical and radioactive well logs offers the following advantages, some of which are obviously the result of three-dimensional study that only a subsurface analysis can provide:

- Absolute objectivity of data, being obtained exclusively with the use of instruments.
- Possibility of evaluating, even on the basis of a single test well, a stratigraphic sequence of some thousands of metres and, therefore, a picture of the sedimentary vertical evolution.
- A picture, through correlation of data obtained from various wells, of the lateral variations of individual stratigraphic units; data correlation provides a perfect view of the way in which single formations or sequences of formations develop even over great distances.
- Precise stratimetric evaluation of formations, sequences, megasequences and, in general, of units of all ranges, bearing in mind that logs are registered on various scales. Knowing the dip of formations allows corrections of thickness.
- Determination of important physical parameters such as porosity, permeability, and resistivity, which are of great importance when exploring for oil.
- Information about the fluids contained in the reservoir rock.
- Speed in using diagrams, if a full set of logs is available, when exploration is at an advanced stage or completed.

The most important reservoir rocks are sedimentary rocks of clastic origin and those of chemical origin, especially carbonate rocks. Both types, when subject to deformations, can fracture and give rise to a third type of reservoir rock. In the description that follows, in accordance with a distinction that is commonly drawn in the literature on petroleum, the sedimentary environments of clastic rocks and of rocks of chemical origin are dealt with separately, even though some sedimentary environments can give rise to both types of rock.

Clastic rock reservoirs

Most hydrocarbons accumulate in clastic rocks which also contain most of the reserves in the largest known reservoirs. Reservoirs are located mostly in sands that have undergone varying degrees of cementation; cemented sands are called sandstone. Less frequently, reservoirs may be found in deposits of coarser clastic rocks, such as gravel and conglomerates. The nature of the particles forming a clastic rock is prevalently siliceous, though clastic sediments of carbonate or, more rarely, gypsum composition are also widespread.

A typical characteristic of silicoclastic reservoirs is the hydrocarbons' migration velocity, from 1 to 1,000 km per million years, decidedly greater than in carbonate rocks. Most reservoirs are contained in structural traps. Until 1970 it was believed that only 10% of the reservoirs discovered were contained in stratigraphic traps, but as stratigraphic-sedimentological know-how improved, especially as regards the interpretation of sedimentation environments, the estimated percentage rose considerably.

We will describe the typical continental and marine environments of silicoclastic rock deposition (Ricci Lucchi, 1978; Reineck e Singh, 1980; Selley, 1988; Zimmerle, 1995), and set them in relation to the originating transport agent.

Reservoirs in fluvial deposits (alluvial environments)

These are contained either in braided or in meander deposits, which result from the wandering of river beds. The former are coarser, especially at the low end of the sedimentary sequence, and become finer towards the top, with truncations caused by erosion of successive, laterally-migrating channels. In river deposits with meandering morphology, sand deposits have lateral accretion.

Fluvial deposits are often texturally immature, especially close to the source where they may be connected with alluvial fans and therefore do not have high porosity levels. This is not the case, however, in channel deposits that constitute the best reservoirs and also have more favourable conditions for the formation of stratigraphic traps. Excellent reservoirs of this type are to be found in the Nubian Cretaceous sandstones that extend from Algeria to Egypt, and are amply exploited in Libya, and in the Muribeca sandstones of Brazil, also Cretaceous.

Reservoirs in eolian deposits (desert environments)

These consist primarily of medium or fine sands that sedimented after being carried by the wind, an exogenous agent mainly acting in zones with a desert climate, whether tropical (Sahara, Kalahari, Australian deserts) or in the mid-latitudes (Gobi), as well as in coastal areas (Atacama, in northern Chile). They consist of:

- Hamada deposits, belonging to rocky terrain characterized by large blocks or angular-edged pebbles, often deposited directly on the basement.
- Serir deposits, with pebbles of various sizes irregularly scattered on sandy terrain as a result of the action of the wind that has removed the finer elements.
- Wind-carried dunes, which constitute classic sand seas. They are easily recognizable by the high-angle cross-bedding, and have good level of porosity due to the absence of argillaceous matrix and the high degree of sorting (grains of the same size). The vastness of these sediments can give rise to large reservoirs, often sealed by black shales resulting from marine transgression, which provide a good cap; in this case, stratigraphic traps originate as a result of unconformity.
- Wadi deposits, named after the watercourses that cross the deserts, and which flood during sporadic storms; in these deposits the transport mechanism is fluvial.
- Löss deposits, originating from extremely fine sands removed from desert areas, kept in suspension for long periods of time and deposited at great distances over vast areas.

Reservoirs in desert environments are widespread in Palaeozoic rocks, as in the Permian (Rothliegende) of the North Sea, in the Pennsylvanian of Wyoming (USA) and in the eolian sands of the North-American Jurassic (Navajo, Nugget Sandstone).

Reservoirs in lacustrine deposits

These are less widespread than the types described above and are linked to deposition of turbidite sediments at the margins of lakes, especially in deltas and deeper areas, and therefore have marked turbidite depositional characteristics. Reservoirs of this type are found in Utah (Uinta Basin) and in China.

Reservoirs in delta deposits

These are typical of the transition between a continental environment (delta plain) and a marine environment (delta front). In the delta plain, sediments are the same as those of the alluvial type in their upstream portion, while in the downstream part they are often influenced by tidal motion. Delta morphology is often characterized by lobes or digitations, each of which behaves like a single delta-like apparatus, with its system of channels separated by fine interlobe deposits. The coarser sediments deposit on the prograding part of the delta (**Fig. 1**) which, if affected by the destructive action of the waves and tides, may assume a classical delta-type configuration (e.g. the Nile). If the constructive deposition action prevails, as along the coasts of inland seas or gulfs where the erosive efficiency of waves is low, the body advances with marine regression and the formation of lobed (Po) or bird's foot (Mississippi) deltas. Lobes may be abandoned, with avulsion of the corresponding channel, while the river builds a new one either to the side or above. In this way, sand deposits with a highly articulated horizontal and vertical distribution are created (16 partly overlapping digitations have been counted in the Mississippi delta). This can represent an ideal condition for the presence of reservoirs in sand or gravel deposits with the transition to finer prodelta deposits. Caps are represented by successive marine transgressions with clay deposits. Other reservoirs

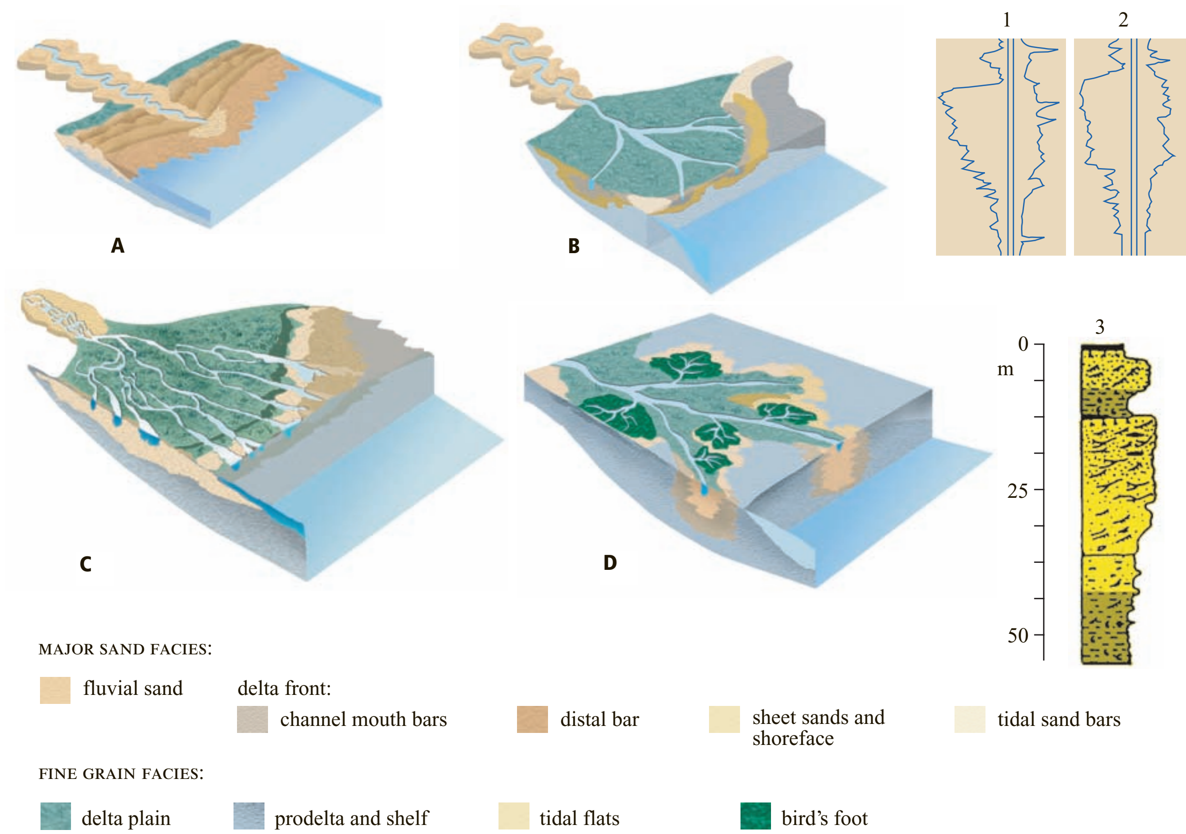


Fig. 1. Deposition of deltaic sediments. A and C, deltas affected by the destructive action of waves or tides; B and D, constructive deltas with lobed or bird-foot deposits prograding into the sea; 1-2, electric logs; 3, lithological column of bar and deltaic-plain sand deposits. The broken lines indicate marine or swamp clays; sands are indicated by dotted lines (Magoon and Dow, 1994).

may form, due to the instability of the prodelta, accompanied by landslides, slips and flow of detrital material. Also syndepositional deformations, such as the grow-faults common to the Gulf of Mexico, represent opportunities for the formation of traps. A delta’s progradation is favoured by a lowering of the sea level, producing what is also known as ‘low stand’ according to terminology based on studies of sequential stratigraphy (Vail *et al.*, 1977), which determines an increase in volume with significant implications for the interpretation of the sedimentation environment of hydrocarbon reservoirs.

These types of reservoirs are of considerable volume, such as the Triassic ones of Prudhoe Bay in Alaska, the Jurassic ones in the North Sea, the Jurassic-Cretaceous ones of western Siberia, the Cretaceous ones in Kuwait and Saudi Arabia, and those in the present deltas of the Niger and Mississippi rivers.

Reservoirs in coastline and shallow-sea deposits

These are formed by the action of the waves and tides, can extend for hundreds of kilometres interrupted only by river mouths or tide channels, and can be of a considerable thickness as a result of variations in the sea level (**Fig. 2**). Also in this environment, the low stand favours the accumulation of sediments, while storm waves determine their shape and granulometric variations.

Deposits with this origin are characterized by good porosity but their volumes are not comparable to delta deposits. The largest are located in western Siberia and in the central-Asiatic countries (Tajikistan), as well as in the North Sea, in Upper Jurassic-Cretaceous rocks.

Reservoirs in deep-sea deposits

These consist of sediments with considerable lateral and vertical extension that are largely the result of the sedimentation of turbidity currents generated through the action of subsea currents of clay and sand mud, which slide along the slopes of continental margins. The mechanism that gives rise to the turbidity current depends on the sediment’s angle of repose: when that angle is exceeded as a result of the progressive accumulation of material on the slope, the material slides down, giving rise to a high-density current. The current is often triggered by a seismic shock and it is for this reason that turbidity currents are typical of tectonically unstable basins, especially foredeep ones.

The motion occurs as a result of gravity since the material in suspension is denser than the surrounding waters. The currents gain speed as they descend along the slope, then disperse and lose transport efficiency in the open sea, giving rise through settling to the corresponding clastic deposits known as turbidites.

The same depositional mechanism repeats itself, giving rise to a series of sedimentary bodies consisting of individual overlying turbidite bodies which form hundreds or thousands of layers. The sedimentary bodies settle at the bottom and, above all, at the base of the continental slope, giving rise to a fan that widens with an ever-decreasing dip towards the open sea (**Fig. 3**), of a shape similar to that of deltas but with broader geometry. The continuous superposition of sedimentary bodies and their development towards the open sea result in the progradation of the fan (Mutti and Ricci Lucchi, 1972). Within this, on the basis of the facies associations, it is possible to identify an internal part towards the fan apex, comprising the channeled bodies that contribute to the fan accretion, along with an intermediate and an external part in which the turbidite beds have uniform and continuous development over great distances. The largest fans, such as the one in the Gulf of Bengal fed by the delta of the Ganges, cover millions of square km.

Each turbidite event gives rise to a sedimentary sequence: the faster settling of coarse material (normally sand) determines a major concentration of coarser material at the lower part of the sequence; grain size decreases vertically and the finer, clay part is deposited in the upper portion (graded sequence). A turbidite succession will therefore have hydrocarbon accumulations concentrated in the coarser, porous-permeable portions of each sequence, while the finer portions may represent individual caps. Porosity is never very high because of the presence of an argillaceous matrix in the sands, but volumes can be remarkable as a result of the extensions of the fans and the presence of numerous superposed pools separated by beds of clay.

When turbidity currents are deposited in relatively restricted sections (foredeep basins), they form deposits that are laterally confined and longitudinally highly developed. In these contexts, the currents may cover an entire basin, no longer giving rise to fan-type progradation, but to a vertical

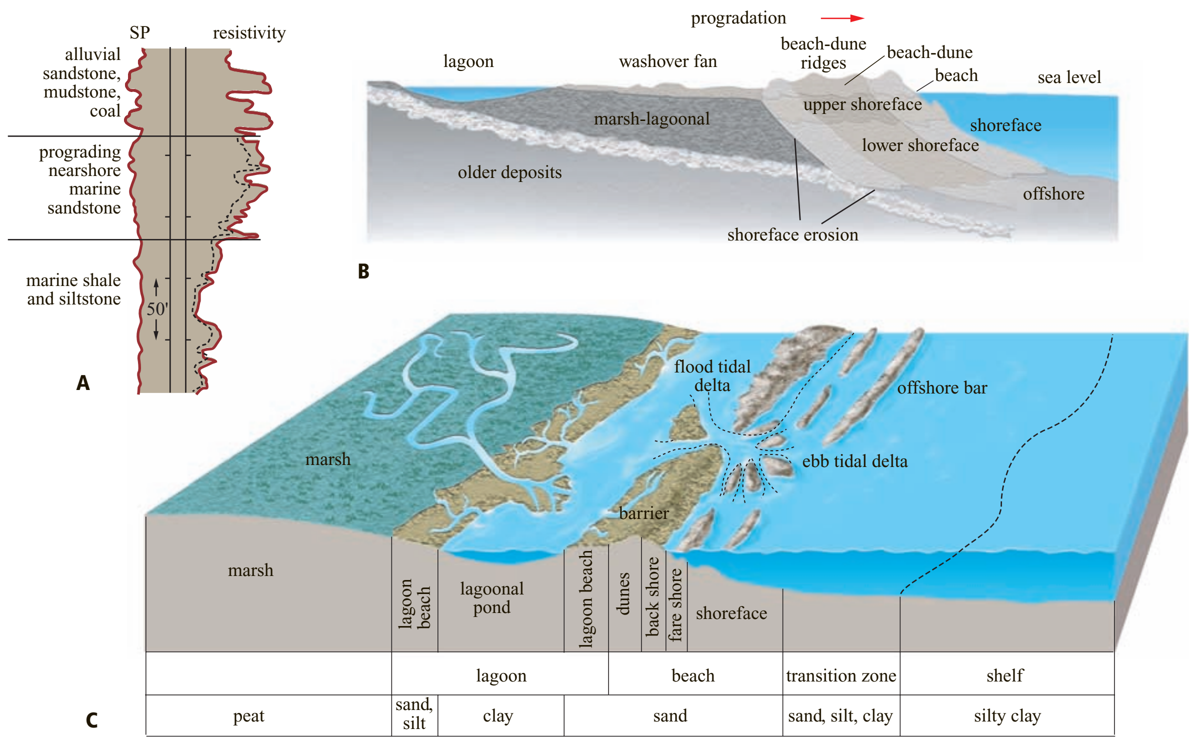


Fig. 2. Shallow-sea sediments. A, electric log of shelf deposits moving upwards to coastal and alluvial ones following a regression; B, section representing the vertical and lateral distribution of regressive coastal-beach dune deposits; C, distribution of shallow-sea deposits (Magoon and Dow, 1994).

DIAGNOSTICAL TRAITS OF MAIN ASSOCIATIONS OF TURBIDITIC FACIES

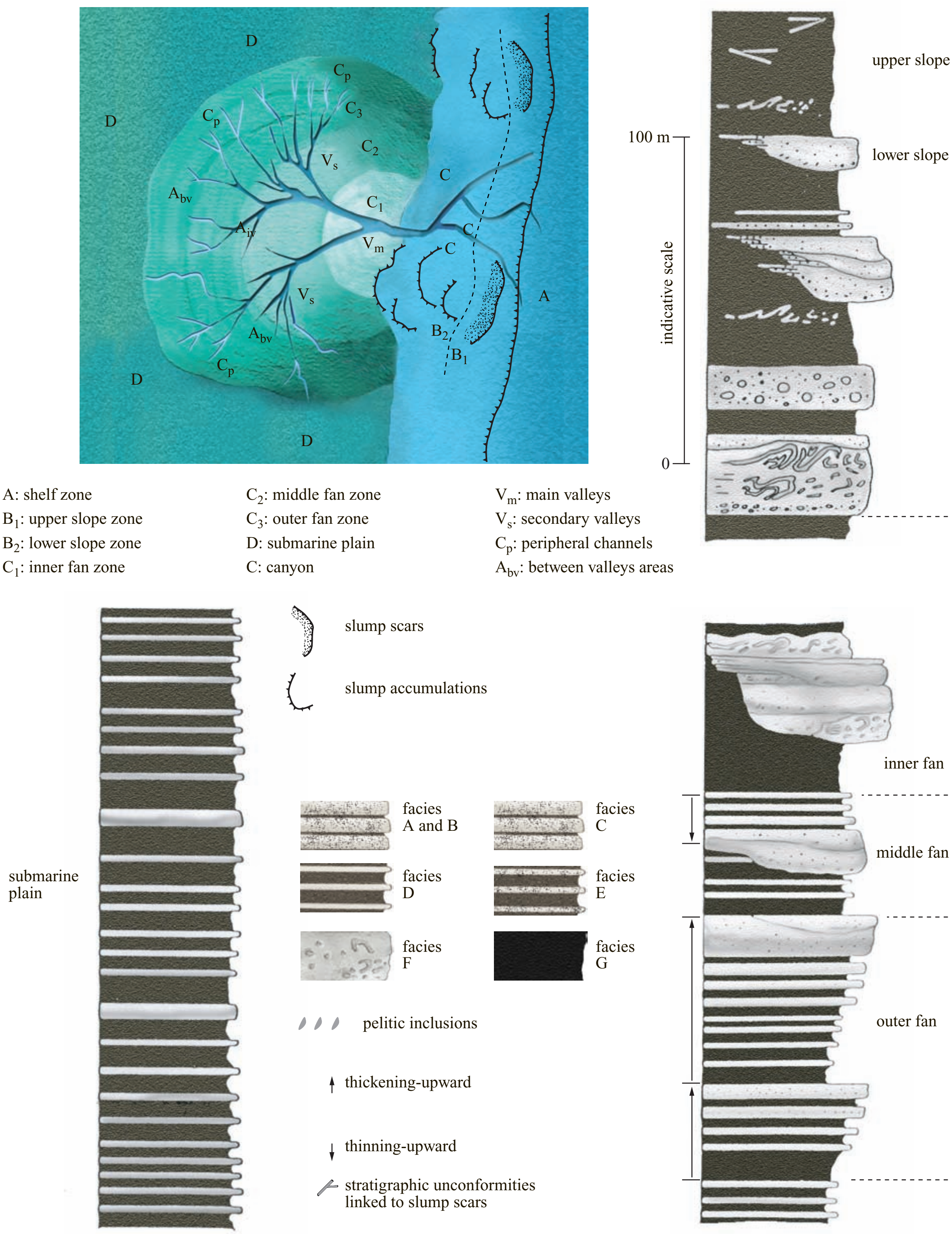


Fig. 3. Turbidite deposition environments: the reservoirs with the largest volumes occur in the channels of the lower slope, in the internal and intermediate fan and in the sands of the external fan. The latter, which have a great lateral extension, contains good reservoirs in foredeep basins, where the compression phases accompanying and following sedimentation create anticlinal structures with their corresponding traps (Mutti and Ricci Lucchi, 1972).

accretion of marked thickness. This is the case of the Adriatic Foredeep, the site of the largest gas reservoirs in the Mediterranean area. Other large turbidite reservoirs have been discovered in the North Sea, California, along the Brazilian continental margin etc., predominantly located in Tertiary deposits which originated in the disintegration of mountain chains.

Carbonate reservoirs

Carbonate rocks too, can contain large hydrocarbon reservoirs, especially those that have undergone dolomitization, which determines a notable increase in porosity and permeability.

The sedimentation environments of rocks of chemical origin are mainly marine and the result of evaporation processes, since decreases in the carbon dioxide content of water favour the precipitation of calcium carbonate; the presence of organisms that have fixed calcium carbonate in their shell gives rise to rocks of biochemical origin. The most favourable sedimentary environment for the precipitation of carbonates is the continental shelf and its reefs.

The internal shelf, connected to coastal deposits, includes tidal and sub-tidal environments resulting from the action of the tides, with sand bars and coastal lagoons. Lateral variability causes a mosaic of sands (consisting of carbonate minerals if due to the disintegration of reefs) and calcareous muds (algal plains with stromatolites). These formations can have marked lateral development on shelves with low seabed gradients, or encircle islands, especially atolls. The intermediate and external shelves host finer deposits (grainstones and mudstones; Bosellini, 1991) which, in zones subject to the effects of strong tides, are reworked by the marine currents.

In hot climates, the formation of reef mounds also known as bioherms, with highly porous and permeable deposits (a characteristic that becomes even more pronounced as a result of subsequent dolomitization phenomena), is important in the formation of reservoirs. The development of shelf and reef deposits is associated with marked subsidence phenomena (**Fig. 4**) and with the corresponding marine transgressions that allow for the vertical grading of the sedimentation and its lateral progradation (highstand in sequence stratigraphy).

These deposits have highly variable facies, from the bioconstructed body of the reef to the back-reef, where shallow water aggrading calcareous formations with algae and molluscs dominate, to the fore-reef, where waves break more intensely.

At present, the main reef-building organisms are algae and corals, whereas in fossil reefs we find stromatoporoidea and rudists. Many of these organisms have an inorganic calcite part, but some, such as Codiaceaen algae (for example, *Halimeda*) and numerous molluscs, also contain aragonite. The dissolution of aragonite produces precipitation of calcite with low magnesium content, until the latter partially dissolves, with a resulting increase in porosity. The thinnest, ramified corals are broken by the waves, especially during storms, and form a highly porous coralligenous breccia all around the reef.

The morphology of these sediments can vary greatly: some reef systems run parallel to the coast, like the Australian Great Barrier Reef, others surround islands (atolls) as in the Maldives, often encircling volcanic systems as is the case in Polynesia; in these contexts, the disintegration caused by storm waves generates a broad ring around the island. This variability influences the shape of deposits associated with back reefs, which in atolls cover their entire internal circumference, and in volcanic islands take the shape of a circular crown. The growth of reefs (Bosellini, 1991) in the external zone, where they represent a barrier to the waves, can give rise to a fringing reef that encircles the land, emerging from the water when the shelf is narrow and the reef grows attached to the coast. If the shelf is relatively wide, the reef forming at the margin and separated from the coast by water (lagoon) is referred to as a barrier reef. The tides create channels in the reef, which thus tends to form numerous independent islands.

The vertical shape is determined by the relationship between the subsidence of the sea bed and the vertical accretion caused by bioconstructing organisms that find an optimal habitat a few metres below the surface. If subsidence is rapid, the organisms must grow vertically to offset the progressive deepening of the water; if it is slow, the organisms develop slowly, allowing for the progradation of the reef, while the sides are the seat of detrital sediments resulting from the partial disintegration of the reef itself. If, finally, subsidence either slows down or comes to a halt, the organisms tend to develop at their ideal depth, widening the bioconstruction until it assumes a mushroom-shaped appearance. Dolomite reefs, for example, can be of notable thickness, as is the case in the Ladinian and Carnian outcrops in the Trentino-Alto Adige region, which are around 1,000 m high.

The sediments of the carbonate shelf, which are also often dolomitized, have a greater lateral development than that of reefs, and a similar thickness. In the eastern Dolomites, the ‘Dolomia Principale’ (main dolomite) deposits outcrops extensively; the fact that the northern edge of the Gondwana supercontinent, the site of Triassic carbonate sedimentation, developed uninterruptedly all the way from Europe to northern India, gives us an idea of the size of this shelf.

Shelf deposits develop vertically to compensate for the effects of subsidence. The reservoirs are larger than those in reefs and the cap can be represented by the development of terrigenous shelves with a high percentage of clay, or by compacted limestones.

Reservoirs in Devonian shelf and reef deposits are widespread in Alberta (Canada), with spectacular outcrops in the Rocky Mountains. All of North America is rich in carbonate reservoirs, in internal-shelf facies (tidal plains) and Ordovician to Permian reefs. Large reservoirs are also present in the Jurassic calcareous sand bars of Saudi Arabia and Cretaceous ones of Iraq. Carbonate reservoirs from the Tertiary are to be found in the Persian Gulf and in California.

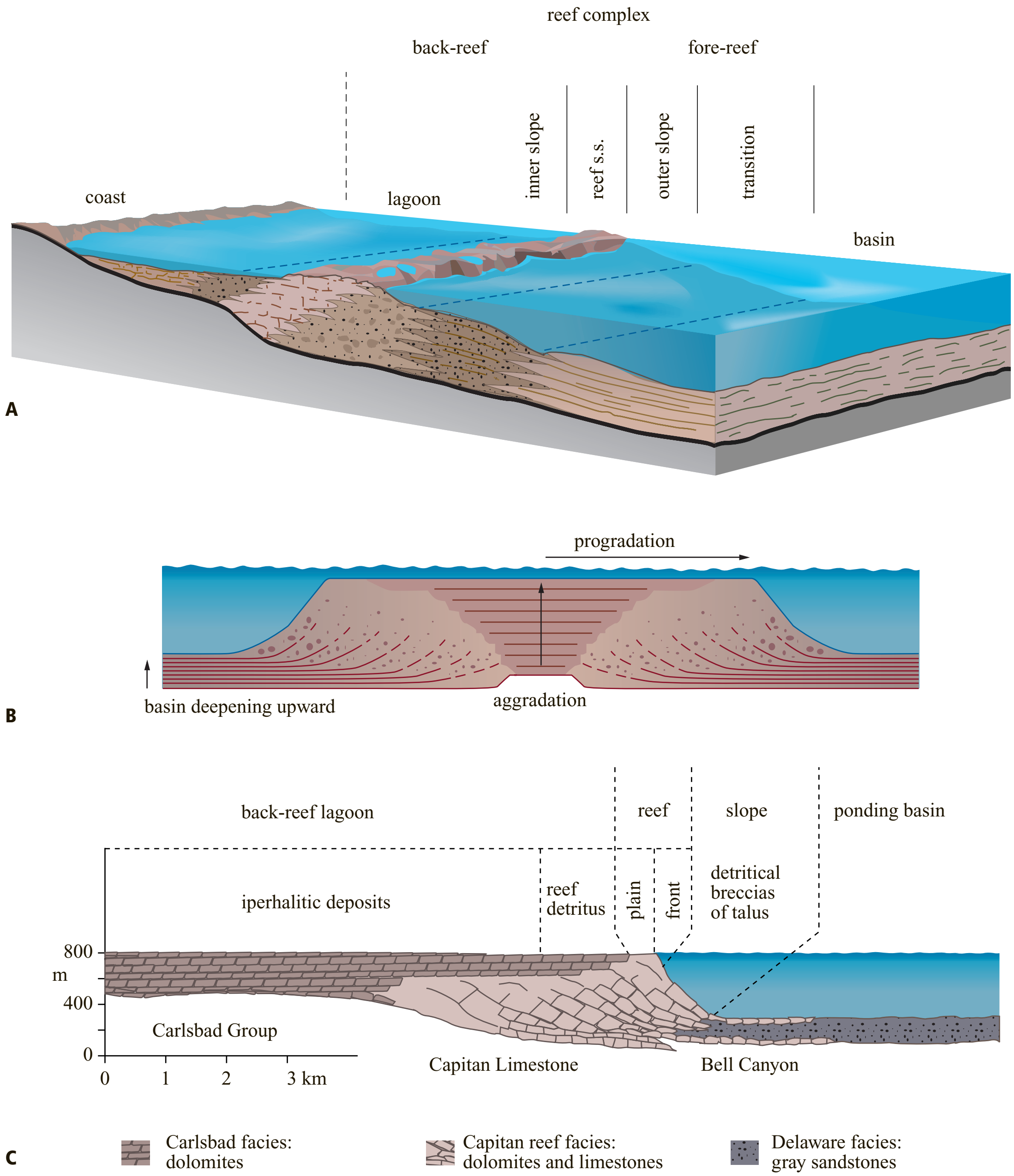


Fig. 4. A, reef complex with its associated depositional systems; B, stratigraphic evolution of the Ladinian shelves in the Dolomites in a subsidence regime; C, stratigraphic section of the Permian Reef Complex in Texas-New Mexico (Bosellini, 1991).

Fractured-rock reservoirs

Almost all rocks, including sedimentary ones, with the exception of evaporites, are fragile enough to fracture during deformational processes. The force needed to fracture rock is much greater in a compressed regime than in an extension one; therefore fractured-rock reservoirs are usually present in the latter context. The fracturing of a rock body does not necessarily imply a regionally extensional regime and can also take place in a localized extent.

Fracturing takes place in compact rocks. In sandstones, fracturing normally affects the cement, as it is rare for fractures to cross granules except in the case of siliceous cemented rocks such as quartzites, which are, however, poor reservoirs. In carbonate rocks, fractures develop throughout the entire sedimentary body. Porosity and permeability are both strongly affected, but above all the latter, since the migration of fluids tends to concentrate along the fracture surfaces.

In originally impervious rocks such as highly-cemented or matrix rich clastic formations and compact limestone, fractures determine secondary porosity and, above all, effective permeability. In a context characterized by frequent and open fracturing, the latter parameter may be practically infinite. In carbonate rocks, moreover, fractures can be migration channels for solutions that are rich in carbon dioxide and therefore have strong dissolving effects which tend to widen open fractures considerably.

The effects of fracturing, on the other hand, depend on the depth at which the phenomenon takes place. Indeed, below a certain depth - depending on tectonic stress, the type of rock and type and quantity of fluid - fractures do not remain open, and are cemented again by chemical precipitation from solutions flowing underground. When the phenomenon precedes hydrocarbon migration, a new deformation stage is required to re-establish a network of fractures: if the cement can be dated, it is possible to reconstruct the deformational history of the reservoir rock.

Causes of fracturing

The areas where this phenomenon is most frequently observed are those close to major faults, followed by those close to zones where folding occurs and, finally, by those in regions characterized by homoclinal dip. The most common causes of fracturing are the following (North, 1985):

- Forces that run parallel to bedding (*buckle folding*), which mostly affect massive rocks or ones with thick bedding and little tendency towards plasticity. Fracturing is facilitated by the presence of a plastic substratum and is concentrated along the crests of anticlines, which are subject to local tension.
- Forces orthogonal to bedding (*bending folding*), resulting from an extension that gives rise to differential subsidence and the consequent formation of horst and graben structures. The fractures propagate upwards at the sides of each block and also affect the folded part that drapes the faults.
- Extension faults with associated fracturing that increases logarithmically as it approaches the fault surface (these can be formed also in a regime of compression when faults and folds are interconnected).
- Pressure of fluids, associated with a solution (*pressure solution*) in carbonates. In a compressional regime, discontinuities (stylolites), together with microfractures (tension gashes) that run perpendicular to them, are formed.
- Differential lithostatic pressure due to uplift and erosion.

Other factors that cause fracturing are dehydration, washouts (especially in erosion surfaces that underlie unconformities), and the cooling of igneous rocks that may serve as a reservoir.

Examples of reservoirs in fractured rocks

The best-known and studied example of a reservoir in fractured carbonates is located in the Iranian Asmari Limestone (Oligo-Miocene). The reservoir, situated in limestone structures more than 300 m thick, was deformed in a wide-radius fold with a net of laterally and vertically connected fractures that favour a high rate of production. Mexico owes its oil production mainly to reservoirs in fractured Mesozoic limestone (Tamaulipas Limestone): the fracturing is of the second generation type and took place during folding that occurred as a result of the structures being raised during the Tertiary. In Venezuela (Maracaibo Basin), the reservoir is situated in cretaceous limestone structures, in anticlines that were formed between the Cretaceous and the Miocene. Permeability has been amplified by the flow of solutions along the fractures, some of which were later reduced as a result of the precipitation of calcite. Other examples are to be found in the Cambro-Ordovician of Texas, the Permo-Triassic of China, and in the Mississippian of western Canada, at the foot of the Rocky Mountains.

Large reservoirs situated in fractured siliceous rocks are found in diatomite deposits in California (the Monterey Formation of the Miocene). Oil is also produced by the dolomite interbedded with diatomite, and by the fractured rocks of the basement.

Fractured black shales also make excellent reservoirs, such as the Devonian in the Appalachians;

the shales there are the source rock, the reservoir rock, and the cap rock, but production requires artificial fracturing on a vast scale.

Examples of deposits in fractured sandstone reservoirs are found in the Oriskany Sandstone, one of the first reservoirs to be exploited in the Appalachians. A more important reservoir is located in Texas (the Spraberry Formation of the Lower Permian); there, however, the fractures function more as flow channels than as reservoirs.

Igneous rocks and basement rocks, if they are intensely fractured, can also be exploitable reservoirs, as is the case in Argentina (Mendoza Basin, in Triassic tuffs), in Arizona (fractured syenite veins of the Paradox Basin), and in Russia (metamorphic rocks of the Hercynian basement in the Don depression).

Physical parameters of a reservoir rock

Various physical parameters characterize a reservoir. In addition to porosity and permeability (see below), also temperature, pressure, density, and the phase that characterizes individual fluids, i.e. gaseous, liquid, or solid, come into play. The above-mentioned factors interact with one another: for example, a change in temperature or pressure can determine a change of phase. Reservoir rocks are usually full of water at the time of deposition and, subsequently, after their migration, the hydrocarbons fill up the pores and replace the water.

Temperature varies directly with depth. The geothermic gradient (on average, 1°C every 30 m of depth) is influenced by geographic location and other local factors such as the possible presence of volcanic activity or the flow of underground waters. Reference temperatures are often obtained during drilling or production, and they are largely influenced by those operations. In these conditions, the temperature of the sediment and of the fluid it contains are not in equilibrium, and the measured gradient is lower than the real one.

The minimum *pressure* of a reservoir is the hydrostatic one or, in other words, that of the water column, which is equal to 1 atm for every 10 m of depth. That value is hardly ever reached in practice as a result of the presence of the lithostatic (or geostatic) load of the superposed sediments, which influences the bottomhole pressures and always produces higher gradient values, usually of about 1.5 atm and, in exceptional cases, up to 2 atm.

Another important physical characteristic of reservoirs is *gas saturation*. The oil in the subsurface always contains a certain percentage of dissolved gas, and this percentage may be greater than the amount of gas soluble in oil at the existing temperature and pressure. In this case, the force of gravity causes the gas to concentrate towards the summit (gas cap). If the percentage of dissolved gas is lower, the gas remains in solution until a decrease in pressure, resulting from the exploitation process, frees a certain amount of it, which then accompanies the oil that has been produced or fills the spaces in the reservoir that have been evacuated by the extracted oil and gas. The overpressure that characterizes gas cap hydrocarbons facilitates the extraction of oil which rises towards the surface as a result of the push effect when the gas expands (gas drive).

Porosity

Porosity is determined by the ensemble of empty spaces (i.e. the volumes that are filled with fluid) present in the reservoir rock, which are normally represented by the rock's own pores, but also by empty spaces, interstices or fractures, that intersect the rock. Porosity is measured in terms of the ratio of the volume of the empty spaces to the total volume of the rock. In practice, in order for a reservoir to be producible, porosity must normally be greater than 5%, but at great depths with accompanying high pressures it is possible to work even at lower porosity levels.

A distinction is made between total porosity and effective porosity: the former is defined above, even if it must be taken into consideration that many pores in a reservoir may not be interconnected, that hydrocarbons will therefore be unable to migrate through them, and that others are partly reduced because the rock fragments that surround them contain interstitial water that cannot be displaced. This is the case of clays that have overall porosities of more than 50% but which are to a great extent filled with interstitial water. Effective (or efficient) porosity is therefore represented by the volume of the pores in which the fluid is also effectively able to flow. Pumice, for example, which has a total porosity of more than 50%, has no effective porosity; the pores it contains are not interconnected and fluids are therefore unable to infiltrate and penetrate it. This is why it floats on water.

Porosity can vary considerably inside a reservoir rock, both vertically and laterally, as a function of variations in the nature of the rock itself. Porosity is in fact influenced by the sedimentation environment both in space (lateral variation) and over time (vertical variation). Porosity can be primary, when formed during the deposition of the sedimentary rock, or secondary, when formed in the wake of processes that have affected the subsequent transformations or deformations of the rock itself.

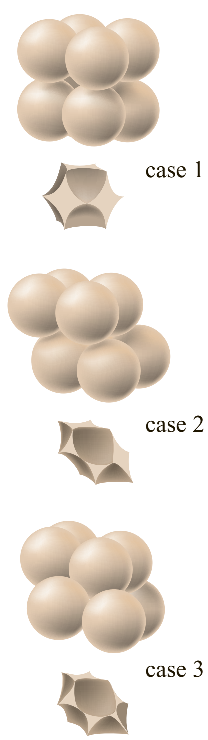
Primary porosity

This is characteristic of clastic rocks; fragments deposited by settling leave open spaces that are sometimes filled with particles of smaller dimensions, often of a clayey nature (the matrix). The spaces that remain empty constitute the porosity, which is influenced by the sediment texture. The parametres of sediment texture are: size and shape of the fragments; their arrangement in space; diagenesis, essentially in the form of compaction, both during and after deposition, and in the form of cementation.

The dimensions of the fragments play an important role regarding porosity, not so much as a function of their size as of their granulometric distribution. In fact, if they are of similar size, porosity may be quite high; in this case, we speak in terms of a well-sorted sediment. If the sizes of the particles differ considerably, the opposite occurs; the smaller-sized fragments fill up the spaces left open by the larger-sized ones and, as a result, the porosity diminishes (poorly-sorted sediment).

Oil companies quantify the degree of sorting by carrying out laboratory analyses on the distribution of the fragment sizes (granulometry). A clastic sediment's granulometry is represented graphically by a diagram showing the dimensional classes of the grains in a logarithmic scale on the x-coordinate, and their percentages on the y-coordinate. In the graph, a well-sorted sediment will show a characteristic 'acute' maximum, corresponding to the most highly represented class (also known as mode) of fragments. In this case, porosity will be high. However, if the graph is flat, and all classes are uniformly represented, the sediment is poorly sorted (highly assorted granulometrically), and porosity is limited.

Fig. 5. Three types of spatial disposition of spherical grains of equal size with their respective empty spaces (North, 1985).



Finer sediments normally have higher porosities because they consist of grains of similar sizes, even if the latter are often not interconnected. For example, clays will contain spaces occupied by interstitial water, which cannot be removed under static conditions, and if they have not been compacted they can reach porosities of around 50-80%. Sands, too, offer good degrees of porosity (20-40% if they are not cemented), whereas coarser clastic rocks (conglomerates, gravels, etc.) have statistically lower porosities since the sizes of their elements are highly heterogeneous and the smaller clasts fill up the spaces between the larger-sized ones.

Porosity is also affected by the fragment shape: the highest degrees of porosity are reached with fragments with an almost spherical shape (or a *high coefficient of sphericity*), which are found in sediments that have undergone a long rolling process during transport. The spatial arrangement of grains also affects the degree of porosity: a cubic distribution (joining the centre of each sphere, a cube is obtained) can reach 47.6%, an orthorhomboidal one 39.5%, and a rhombohedral one 26.0% (**Fig. 5**). These are always theoretical maximums that can be reached with uncemented spherical grains of equal size. In practice, the grain distribution varies over time as a result of the lithostatic load that causes the grains to compact more, and the porosity to decrease.

The highest porosities (which can theoretically reach a level of just less than 48%) therefore correspond to loose fragments that are of equal size, spherical, and with a cubic spatial distribution.

The sedimentation environment affects primary porosity. The most porous clastic rocks are the sands of desert and beach origin, which are highly sorted, especially if they have been affected by the wind. Sands from terrigenous shelves or deltaic sands, being affected by the presence of a clay matrix, are fairly porous. Turbidites are far less porous, since their mass transport in subsea environments does not separate the sand from the clay. Compaction, cementation and, in general, all diagenetic processes are important factors that have a negative effect on the degree of porosity.

Diagenesis determines a change in the mineralogical composition, and is of great interest to the petroleum geologist since it modifies porosity, permeability, entry pressure, and saturation in irreducible water. Deep-set sandstone deposits are subject to pressure as a result of the lithostatic load, and therefore experience a decrease in porosity. This condition may reverse locally below the unconformities, where dismantling and washout can lead to dissolution, especially in carbonate cements, with a resulting increase in porosity and permeability. Furthermore, carbonate cements can dissolve during subsequent burial, as a result of the presence of carbon dioxide, while the decarboxylation of organic matter in adjacent source rock is underway (Taylor, 1977).

The lithostatic load due to the weight of sediments which deposit over time on top of the reservoir rock favours its *compaction*, affecting clastic rocks in particular. Sands and coarse sediments are only slightly affected by this phenomenon (2% reduction in porosity per 1,000 m load of sediment): this factor can have an appreciable effect only after very long periods of time.

Clays, however, can be reduced in volume by as much as 50%; their behaviour whilst subject to load is very different from that of sands, first of all because of the high water content that accompanies their sedimentation. This is the case of clay mud, in which solid particles represent less than half of the total volume. During the compaction process, water is squeezed out of the pores, which then progressively diminish in volume. Clay minerals are phyllosilicates, with a planar reticulate, and they do not assume a parallel arrangement in the mud. Moreover, these minerals contain reticular water that must be added to the water present in the pores. During compaction, the water is expelled, the mineral reticulates change, become smaller, and align themselves with an orientation in parallel planes. Furthermore, the pores,

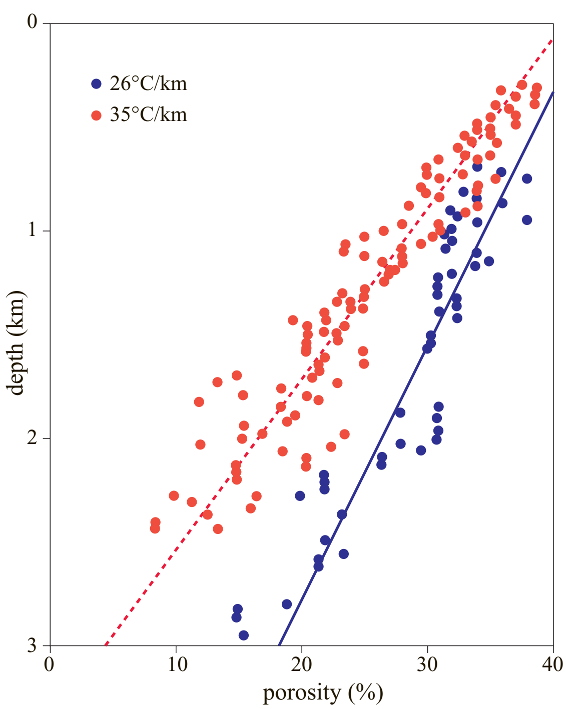


Fig. 6. Relations between porosity and depth as a function of two different thermal gradients (measurements carried out in sandstones of the Pacific Northeastern Arc) (North, 1985).

especially the larger ones, lose much of their volume. The sediment's density progressively increases from values of just more than 1 kg/dm^3, typical of mud, to a level of about 2 kg/dm^3: a clayey sedimentary sequence may therefore be reduced to a thickness that is close to half of its original one. Compacted clays are best defined as shales. Deformations tend to reduce porosity even further; for example, as of result of the rock's plasticity, a fold in shale beds will have limbs that are thinner and therefore less porous than the zone of its crest.

A considerable lithostatic load, accompanied by high temperatures, can transform clays into slates or phyllites. These are true metamorphic rocks; they have no porosity and their density is the same as clay minerals, i.e. up to 2.6-2.7 kg/ dm^3. In foredeep sedimentation, consistent sedimentary accumulations of turbidite, resulting from the disintegration of mountain chains, deposit on top of clay sediments often interbedded with sands. Here, the geostatic load may reach many thousands of metres of thickness and cause the sediments to sink. Lithostatic load increases with depth, and so does temperature, which becomes yet another factor contributing to compaction. A high geothermic gradient favours compaction at great depths and will produce an accentuated diminution in porosity (**Fig. 6**).

Carbonate rocks, too, are subject to compaction processes. At first, the carbonate sedimentation gives rise, in a basin-type environment, to a water-rich calcareous sludge. The percentage of water is less in sediments that are rich in organisms, especially in reefs, which are a largely bioconstructed type of rock. Compaction determines a pressure solution that accompanies the diagenesis of carbonate rocks, with the formation of particular irregular seams known as stylolites.

Cementation, too, has the effect of reducing porosity in clastic rocks. Immediately after its deposition through settling, the sediment is crossed by circulating solutions that precipitate substances which either partially or totally occlude the pores, lithifying the sediment and transforming it into a compact rock: sand, for example, will thus be turned into sandstone. The cement can be made of calcite, silica, or, more rarely, gypsum. Its composition will depend on the nature of the grains of the rock: a quartz and feldspar-based sand (arkose) will usually be cemented by silica (silicon arenite), a calcareous sand by calcite (calcarenite). Solutions, however, especially those that contain soluble components which are widespread in rocks such as calcium carbonate, may originate from adjacent rocks, so that sandstone with quartz and feldspar-based grains that are cemented by calcite is also quite common. Many minerals can play the part of cement, but only a small number of them exist in sufficient quantities to be of interest to petroleum geologists. These include quartz and the carbonates calcite, dolomite, to a lesser extent siderite, and, under particular circumstances, anhydrite, barite, fluorite, halite, iron oxides, and pyrite, all of which make up common cement. Secondary feldspar often accompanies secondary quartz. Clay minerals such as kaolinite, illite, chlorite and smectite grow as authigenic compounds. The cementation process generally concerns only permeable rocks; that is, ones through which these solutions are able to flow. In impervious rocks such as clays, only compaction, and not cementation, processes are observed.

Carbonate rocks present a primary porosity when they undergo a clastic-type sedimentation process (clastic carbonate rocks). Primary porosity may also be due to the instability of some minerals that have precipitated or have been fixed by calcareous organisms. Aragonite, for example, is an unstable element that soon turns into calcite with high magnesium content. Because of their high solubility in carbon-dioxide-rich water, limestones that have just been deposited are often immediately dissolved by meteoric water, with a resulting increase in porosity that, since it is almost simultaneous with sedimentation, can still be defined as primary. Deposited grains differ from those of the silicoclastic rocks due to their greater roughness and irregularity. The polyconcave pores are larger in grainstones such as calcarenites, especially if they have deposited in back reefs. In ooliths, in which the elements have a subspherical shape, high porosities are evidenced. Reduced porosities are characteristic of packstones, wackestones and mudstones, and their porosity is further decreased during diagenesis. Even with only a few hundred metres of load, compaction reduces the volume by 25-30%, and thus decreases the porosity, especially if the carbonate is still in a dissolved, uncemented state. Cementation in carbonate rock occurs through precipitation of spar-calcite from dissolved carbonate originating from the limestone due to pressure solution.

Secondary porosity

This is the result either of chemical processes, which can dissolve soluble fragments or cement and generate empty spaces, or of physical ones, resulting from deformations that crush the lithified rock which is no longer capable of being deformed plastically, and thereby produce fractures. In clastic rocks, secondary porosity develops as a result of the circulation of solutions with a high carbon dioxide content and consequent high dissolving power; for example, some sandstone is cemented with calcite, which is partially dissolved, generating empty spaces.

Secondary porosity resulting from chemical processes, however, is characteristic of carbonate rocks. The dissolving process that takes place along preferential paths, such as fractures for example, tends to make the fractures wider and thus favour the increase in porosity and permeability. The end result is the onset of a karstic morphology. These events are favoured by phases of regression that expose the limestones to the action of meteoric water, which is rich in carbon dioxide; subsequent transgression invades the washed-out and dissolved zones, creating an unconformity which, if characterized by the deposition of impervious rocks, can provide an excellent cap for a possible porous and permeable reservoir.

The most important chemical process is dolomitization; i.e. chemical transformation caused by calcium/magnesium exchange (metasomatism) with recrystallization of the rock. Many of the largest carbonate rock reservoirs are located in dolomitic rock reservoirs. This phenomenon is observable in 80% of North-American Palaeozoic hydrocarbon reserves, where the process has had more time to take place and been favoured also by the presence of organisms with shells, which are more suited to transformation. However, the phenomenon can be witnessed only in 20% of the reserves in the Persian Gulf, where carbonate reservoirs are made up of more recent formations.

The process takes place after sedimentation of carbonate, at any stage of diagenesis and over considerably long periods of time: the possibility of synthesizing dolomite at low temperatures has not been verified in the laboratory, so the existence of primary dolomites is doubtful. Current carbonates comprise metastable minerals such as aragonite and Mg-calcite, whereas ancient carbonate rocks are made up of calcite and dolomite. It is possible to distinguish early dolomitization, as observed in tidal environments, from a late metasomatic one that erases the rock’s original textures and produces crystalline dolomites which are usually rather coarse, with large automorphic crystals and saccharoidal textures (Bosellini, 1991).

The conversion of aragonite and Mg-calcite into calcite is a mineralogical stabilization process that involves the reduction of only a small quantity of magnesium. The conversion of calcite and aragonite into dolomite, on the other hand, requires a fundamental chemical and mineralogical transformation. The replacement of calcite with dolomite entails an increase in porosity of around 12%. Since the dolomitization process may be only partial, the increase in porosity will only take place in part of the carbonate rock, and it is in that part that most of the hydrocarbons will be stored.

Dolomitization occurs in various phases: in the initial phase, rhomboids of linear dimensions ranging from 20 to 100 μm are formed, of the same size in each layer. After this, the spaces between the rhomboids are created, with the formation of a saccharoidal texture. In addition to absolute porosity, effective porosity is also increased in the process, since rhombohedrons of dolomite are characterized by planar surfaces. Moreover, a dolomite reservoir is more resistant to compaction compared to a limestone one, and the highest porosities among carbonate rocks are therefore found in dolomites.

Dolomitization is particularly intense in reef limestone and especially in back-reef environments, where there is more evaporation. These limestones are bioconstructed and the process is therefore favoured by the abundance and nature of fossils. Dolomitization affects fossils selectively, insofar as aragonite, which forms a part of corals and of gasteropods and cephalopods, has a crystal lattice that is volumetrically similar to dolomite and, therefore, the process is faster in these fossils. More time is required for the transformation of calcite with a high content of magnesium derived from the shells of brachiopods (organisms that are very widespread in Palaeozoic reefs), and also of echinoderms, bryozoa, pelecypods (including rudists, the organisms that bioconstructed the Cretaceous) and ostracods.

As regards plants, calcareous algae undergo a rapid dolomitization process since some are aragonitic and others are formed from calcite with a high magnesium content. Furthermore, they themselves reduce the sulphate that slows down the process. The high frequency of Palaeozoic dolomites, therefore, is due to the development of algae in that era.

The great volume of the sediments involved in dolomitization (in the region of the Dolomites, their thickness is greater than 1,000 m and they cover extremely vast areas) requires a mechanism and driving force which maintain enormous quantities of dolomitizing fluid in motion over long periods of time. Various circulation systems capable of transporting the necessary magnesium have been hypothesized (Bosellini, 1991).

Porosity measurements

Quantitative evaluations of porosity levels performed in the laboratory on field and core samples are carried out using an instrument designed *ad hoc*, the porosimeter. This measures the total rock volume, i.e. that of the liquid displaced by immersing the sample, whose external surface has been previously sealed with a plastic material, and the total volume of the pores (the volume of liquid required to completely saturate the sample). Porosity can also be measured using subsurface methods, above all by means of a sonic log and radioactive well logging (neutron log and formation density).

Porosity levels (in percentage) may thus be classified as follows: *a*) 0-5, minimum, typical of well-cemented sandstones and compacted limestone; *b*) 5-10, poor, in partially-cemented sandstones and calcarenites, scarcely fractured or fissured limestones; *c*) 10-15 fair, in poorly-cemented sandstones, conglomerates, highly fractured and fissured detritic limestone, dolomites; *d*) 15-20, good, in deposits of sands with a low level of cohesion, gravel, fractured dolomites; *e*) above 20, excellent, in loose and well-sorted sand and vuggy, highly fractured and fissured dolomites.

Permeability

This is the property that allows fluids to pass through rock without moving its constituent particles or causing structural modifications. Whereas porosity affects hydrocarbons under static conditions, permeability is a dynamic function which enables rocks to release fluids and not only to contain them. Fluids pass through a rock by filtration through pores (permeability by porosity) or by direct transmission through discontinuities (permeability by fracturing or fissuring).

Permeability is quantified by determining the amount of fluid that passes through a rock surface under stable, differential pressure conditions. In order for a fluid, and in particular for an oil or gas, to cross or flow through a rock, there must be a difference (gradient) in pressure. Over very long periods all rocks will present a certain degree of permeability, but in practice a reservoir's commercial potential depends on there being a significant level of permeability in very brief periods of time.

Darcy's law (1856) links the velocity of the filtering fluid to permeability according to the equation: $q=(k/m)\cdot(dp/dx)$, where q is the velocity of the fluid (in cm/s), k is the permeability in darcys, m is the viscosity (dynamic) in centipoises and dp/dx is the difference in pressure (p) in the direction of flow (x) or pressure gradient. *Viscosity* expresses the fluid's internal resistance; i.e., the resistance encountered by the fluid's particles moving at different rates. Once viscosity is known, the rock's permeability can be measured. The practical unit of measurement of permeability is the darcy (equivalent to $9.87\cdot10^{-13}$ SI units). According to the definition of the API (American Petroleum Institute), a darcy is the permeability of a porous medium in which a single fluid phase with a viscosity of 1 centipoise, which entirely fills up the medium's empty spaces, flows through the medium under laminar regime conditions at a flow rate of 1 cm/s per cm^2 of cross-sectional area, under a pressure of 1 atmosphere per cm. Since the darcy is too large a unit to be used in practice, the petroleum industry tends to express permeability in millidarcys.

Absolute permeability

Absolute permeability does not depend on the nature of the fluid but entirely on the rock's characteristics. It can be calculated as $k=Nl^2$ where N is a dimensionless number (constant for each rock) that sums up the rock's characteristics, such as its shape and the arrangement of its fragments, and l is the length of the pore structure. The relevant factors are thus pore size and the tortuosity of the fluid's path – in other words, the size, sorting and compaction of the clasts (North, 1985).

Darcy's law is based on the assumption that only one fluid is present in the rock. When the reservoir contains gas, oil and water, absolute permeability values are less indicative; in fact, the fluids interfere with each other and effective permeability must be calculated for each fluid in the presence of the others.

Relative permeability

Relative permeability is the ratio between effective permeability at a given fluid saturation, and absolute permeability at 100% saturation of that specific fluid; saturation means the volume of fluid expressed as a fraction of the total volume of the pores. In practice, relative permeability levels are calculated until the rock is 100% saturated with a single fluid.

Most reservoirs contained water before the migration of hydrocarbons. When hydrocarbons penetrate they occupy the larger pores and force the water into the smaller ones, where it is already present as a result of capillarity. Oil mixed with water may be extracted during the production stage.

When saturation in hydrocarbons increases, the relative permeability to water gradually decreases and may reach zero values when the saturation in water is around 45%, depending on the nature of the reservoir rock and the fluids' physical properties. The reservoir may then produce hydrocarbons that are water-free because the hydrocarbons have displaced all of the water except the amount withheld by way of capillarity in pores that are too small for the hydrocarbons to penetrate (irreducible saturation in water which can reach values of up to 30% in fine-grained rocks). If both oil and gas are present, production will depend on the percentages of the two different hydrocarbons: mixed production can occur, or only gas may be produced when permeability to oil is zero as a result of the high level of gas saturation.

Statistically, high porosities correspond to high levels of permeability: a theoretical relation exists between the two parametres but, at a given porosity, permeability can vary greatly as it decreases with the roughness of the fragments and the length (tortuosity) of the path. Clearly, it will also depend on pore geometry and size. The relation therefore depends on the nature of the rock. Clays, for example, especially if they are poorly consolidated, are very porous but entirely impervious because the pores are very small and often filled with interstitial water through capillarity, preventing the passage of fluids; in fact, they are excellent rock caps. Gravels are highly permeable; the fluid's path follows large-radius curves (reduced tortuosity), although they are less porous than sands as a result of their low degree of sorting, and therefore the smaller grains fill the spaces between the pebbles. As a result, a sand reservoir will usually contain more hydrocarbons than a gravel one of the same size, even though the former is less permeable.

In rocks of chemical origin, high porosities may be associated with high levels of permeability. This occurs especially in carbonate rocks when both parameters are a result of fracturing, fissuring, recrystallization or dissolution, and assume unidirectional characteristics. Dolomites are particularly hard but brittle, when subject to deformations, so dislocations cause them to shatter and to crumble; higher levels of permeability are measured in these cases, often exceeding 1,000 millidarcys.

Permeability measurements

Absolute permeability can be measured in the laboratory using a permeameter. This instrument consists of a cylindrical core-sample holder, a pump that forces fluid through the core sample, pressure gauges upstream and downstream of the sample to measure the drop in pressure, and a flow meter to measure the rate of flow of the fluid in the core sample. Measurements are standardized so that statistically comparable data can be obtained: core samples are cylindrical, of a diameter of 2 cm and a length of 3 cm.

Relative permeability measurements, usually referring to two fluids, require more complex apparatus in which the sample is exposed to the flow of the two fluids in varying percentages. Permeability is calculated on surface samples but more often on subsurface core samples, from which the rock plugs to be tested are extracted. In order to calculate effective permeability levels under reservoir conditions, formation tests have to be carried out by analyzing pressure buildup curves, i.e. the pressure trend over time from the moment in which production is interrupted.

Certain peculiarities of permeability must be considered when preparing core samples for the test: in fact, a horizontal (or lateral) permeability exists due to the fluid's motion along the bedding plane. This is calculated by testing core samples collected parallel to the bedding plane. Vertical permeability, across the bedding planes, is usually smaller, and is affected by the beds' planar arrangement and lithological discontinuities along the vertical axis. This holds true for vertical wells that cross horizontal formations, otherwise the relative dips have to be evaluated.

High vertical permeability can occur in dislocated beds: a fault can be a surface with greater permeability due to the rock's fracturing, especially in the case of hard rocks such as cemented limestone and sandstone. In other cases, when the fault fracture is filled with soluble cement (such as carbonate rock and calcite-cemented sandstone reservoirs), dissolution planes that favour permeability may be present along its surface. In non-vertical but dipping faults or fractures, the presence of discontinuities is a decisive factor for high permeability values (directional permeability), because it is along these surfaces that movement takes place, and not through the pores. Fissure-related permeability, especially through fractures that have widened as a result of dissolution, can be hundreds of times greater than porosity-related permeability.

The permeability of rocks, expressed in millidarcys, is classified as follows: *a*) up to 15, weak; *b*) 15-50, moderate; *c*) 50-250, good; *d*) 250-1,000, very good; *e*) above 1,000, excellent.

It is impossible to evaluate rock types belonging to the various categories because permeability is dependent on fractures and fissures. According to data obtained from 1,000 tests, 80% of all sedimentary rocks have practically zero permeability (up to 10^{-3} md); for example clays or shales, which are the most common cap rocks, followed by evaporites. 13% of sedimentary rocks have permeability values of up to 1 md, 5% from 1 to 1,000 md, while only 2% have excellent permeability.

Main reservoirs

As described above, reservoir rock is generally formed of porous and permeable sedimentary rock. The main reservoirs are thus contained either in clastic rocks, principally sands or sandstones, or in rocks of chemical origin, usually carbonate rocks such as limestones and dolomites. Many deposits contain reservoirs of both clastic and carbonate rocks interbedded in vertical stratigraphic succession.

More than 60% of the world's oil reserves are located in the Middle East, above all in Saudi Arabia, the country with the greatest oil reserves, while Russia has the greatest gas reserves.

An overview of the world's main reservoirs by geographical area (North, 1985; Barnaba, 1998) is given below, along with a brief description of those called supergiants (containing more than 5 billion barrels of oil; that is more than 700 million tonnes or more than 850 billion cubic metres of gas), and giants (between 500 million and 5 billion barrels or between 85 and 850 billion cubic metres of gas).

Europe

In Europe, the largest reservoirs are located in the North Sea and Russia. In the North Sea and Netherlands offshore, oil and gas are produced from Permian to Palaeocene reservoir rocks. Gröningen, in the north of the Netherlands, is the largest European gas field; the reservoir rock is Permian Rothliegende (upper red sandstones) and the cap is Zechstein with frequent saline rocks. In the North Sea, the Brent and Piper oil reservoirs are in Jurassic sands, while the oil at Ekofisk is in Cretaceous-Palaeocene (Danian) limestones capped with Tertiary clays. In the Forties, reservoir oil is contained in Palaeocene sands.

In European Russia, the largest reservoirs are located in the belt from the Urals to the Caspian Sea (Volga Basin). The reservoir rocks are mostly Palaeozoic and consist of arenaceous deltaic Devonian rocks (oil) and fractured dolomitic Permian limestones (gas). In the Ukraine, reservoirs are located in rocks from the Devonian to the Permian, in Romania, in the Pliocene sandstones of the Moreni-Guna Ocnitei field in the Carpatian Basin.

In Italy, gas reservoirs are found in clastic rocks of the Tertiary Apennine foredeep (Mattavelli and Novelli, 1988), from the Po river valley to the Adriatic offshore, to the Bradano Trough (Casnedi, 1991). Oil reservoirs are found in Mesozoic carbonate rocks (Milano and Novara Provinces, the Adriatic offshore, Basilicata and Sicily).

Smaller reservoirs, which are nonetheless important due to the industrial context in which they are located, can be found in Carboniferous sandstones in northern Great Britain, and in the Permian Zechstein formations in southern Great Britain, northern France and Germany. There is another oil field in Germany, in the Hanover Basin, in Mesozoic sandstone.

Other small reservoirs are located in the Rhine trench and in the Anglo-Parisian basin. Many Jurassic and Cretaceous formations take their name from locations of this basin. There are also further reservoirs surrounding the Pyrenees; the French ones are in the Aquitaine Basin, in Triassic and Jurassic limestone and dolomites with evaporites (Lacq gas field), and are more limited on the Spanish side. The most important Spanish reservoirs are in the Tarragona Basin, in Jurassic dolomitic limestones.

Asia

The world's largest reserves are in the Middle East (Iran, Iraq, Saudi Arabia, and other countries of the

Arabian Peninsula). The stratigraphic succession has many productive levels, from the Ordovician to the Tertiary, in various groups of formations: the Khuff Group, where the reservoir rock is Permian dolomitic limestone and Permian and Lower Triassic sandstone; the Arab-Zone Group, with Upper Jurassic limestone and dolomite reservoirs; the Cretaceous Group, with limestone, sandstone and sand reservoirs; and the Asmari Group, whose reservoir rock is very permeable as a result of the fracturing and fissuring of Oligo-Miocene detritic and organogenic limestone, into which hydrocarbons migrated from Cretaceous rocks.

Other important Asiatic reservoirs are located in Siberia, mainly in Upper Jurassic to Cenomanian sands, mostly containing gas. From western Siberia to the Barents Sea offshore, oil and gas reservoirs are located in Permian-Triassic clastic rocks. Very ancient reservoirs (Proterozoic and Lower Cambrian clastic rocks and carbonates) are located between the Lena and Tunguska rivers, and other giant hydrocarbon deposits have recently been discovered in Kazakhstan, north of the Caspian, in Palaeozoic carbonate reservoirs.

Further large reservoirs worthy of mention are the Chinese ones in Tarim (Xinjiang-Uigur), in Lower Palaeozoic limestones and dolomites, carboniferous limestones and Miocene deltaic sands. There are other productive basins in eastern China and Manchuria where continental sediments prevail.

Africa

The sedimentary basins in and around Africa have excellent hydrocarbon potential. In the Algerian Sahara there is the Hassi Messaoud field with a Cambrian sandstone reservoir and other smaller Ordovician to Lower Carboniferous sandstone reservoirs. Cretaceous-Eocene sandstone and organogenic limestone reservoirs have been discovered in the Sidra Basin in Libya, and in Tunisia there is the el-Borma field (oil) in Lower Triassic sandstones. In Egypt, there are reservoirs in the Nile delta (gas) and in the western Red Sea-Sinai Peninsula (oil). The Niger delta basin in central Africa, Nigeria and the Gulf of Biafra contains large reservoirs. The oil formations there (Akata, Agbada and Benin) are Tertiary deltaic sands. Other important reservoirs are located in Gabon, Congo and Angola.

North America

North America has enormous oil-producing potential and is the continent that has been most carefully studied in geological terms, with reservoirs discovered back in the Nineteenth century. In the north, Alaska has large reservoirs but climatic conditions make exploration and development very costly. The Prudhoe Bay field in the Arctic Sea, probably the largest in the North American continent, has various pay levels, the deepest of which is the Permian-Triassic limestone. In the same area oil is also found in Cretaceous rocks, while gas-bearing levels are found in Tertiary reservoirs.

In western Canada (Alberta) there are large reservoirs in the Devonian limestone reefs that outcrop extensively throughout the Rocky Mountains. On the eastern side of the Rockies, between Edmonton and Calgary, limestone deposits are capped by impervious evaporite formations. The extension of the Devonian reefs in that area was favoured by palaeoclimatic factors: indeed, in that period the area was crossed by the equator. The Upper Palaeozoic carbonates of northern Alberta contain significant heavy oil reservoirs. In the same area there is also a giant deposit of Cretaceous bituminous oil sands (*tar sands*).

In the Appalachian Basin there are reservoirs which were discovered back in 1859 (Edwin Drake drilled the first well, with the geological and chemical consultancy of Benjamin Silliman, in western Pennsylvania). Many are Palaeozoic levels: from the Ordovician carbonate rocks to the Silurian sandstones, and the shallow sea Devonian clastic rocks covered with black clays, rich in organic matter, which constitute the source rock and also reservoirs through fracturing. There are also the shallow-sea sandstone deposits, and shelf and reef limestone and dolomites formed during the Carboniferous and Permian. These have good production levels, especially of gas.

West of the Rocky Mountains, in California, the largest reservoirs are in the Cretaceous to Quaternary sandstones of the Los Angeles, Ventura, San Joaquin and Sacramento basins. The largest reservoir is Wilmington, in Upper Miocene and Upper Pliocene sands deformed into a wide anticline. A vast oil-bearing region extends from east of the Rocky Mountains to the Gulf of Mexico (the Mid-Continent). Many reservoirs are located there, especially in the Upper Palaeozoic carbonate rocks and sands. The reservoirs in Texas and Louisiana, which are often related to saline structures, are lithologically highly diversified (mainly sands), and are located in rocks dating from the Cretaceous to the Tertiary.

Another important oil-bearing region is the Gulf Coast, in Texas and Louisiana, with one third of the entire production of the United States. Sedimentation starts in the Triassic (the area emerged during the Palaeozoic) with evaporites, followed by a thick sequence of clastic and carbonate rocks in a basin with a high rate of subsidence: the reservoirs are located in traps formed by faults cutting a Cretaceous-Miocene homocline south-dipping with numerous salt domes.

In Mexico, the most productive area is the south-east of the country, on the coast of the Gulf of

Mexico, with reservoirs in Upper Jurassic fractured dolomitic limestones, in reef and shelf facies, and in calcareous sands that deposited on the sides of the structures.

South America

In South America the largest reservoirs are in Venezuela, mainly in Cretaceous, and above all, Eocene to Miocene sands; the most important of these are in the eastern part of the Gulf of Maracaibo. In eastern Venezuela, to the north of the Orinoco, there is a vast outcropping belt (30,000 km^2) with an enormous volume of Cretaceous to Eocene and Oligocene bituminous sands (*Orinoco oil or tar belt*). The relatively low viscosity, poor compaction of the sands, high geothermic gradient and warm climate allow traditional steam injection wells to be used.

Other important reservoirs are located in Colombia, Ecuador, Peru, Chile, and above all in Brazil and Argentina. In Brazil, the Reconcavo Basin reservoirs (which extend to the Baia de Todos os Santos near Salvador in the offshore Atlantic) are located in Jurassic to Cretaceous sediments; in Argentina, the Comodoro Rivadavia field is located in Jurassic to Palaeocene sand lenses.

Australia

Australia has small reservoirs in the Cambrian-Ordovician fractured sandstones of the Amadeus Basin (central Australia) and in the Devonian rocks of the Canning Basin (western Australia).

1.3.2 Cap rocks

These are impervious rocks that prevent the upward migration of the hydrocarbons. Since oil and gas are lighter than water, they tend to rise through the reservoir rock until they reach an impervious barrier that blocks their vertical migration (**Fig. 7**). This impervious rock is usually concave in shape if observed from below and so it also prevents lateral migration of the hydrocarbons, thereby constituting the reservoir rock cap.

Oil geologists often prefer to call the cap rock *roof rock*, using the term cap rock only for impervious rock that seals salt domes. Another widely-used term is *seal rock*. If bedding favours the hydrocarbons' lateral movement, the cap rock can represent a lateral barrier to their migration (*wall rock*).

Characteristics of cap rocks

There is no such thing as a perfectly impervious sedimentary rock, but if a rock's permeability is less than 10^{-4} darcys then it may be assumed to be an effective cap; by nature it must be compact or have pores that are either not interconnected or too small to allow the passage of fluids. The efficiency of a cap rock, measured by the width of the column of oil or gas that it can seal, is a function of its integrity (lack of open fractures), its continuity, thickness and the size of its pores. Another decisive factor for a cap rock's efficiency is its pressure gradient: extremely high gradients can affect the rock's seal.

The quality of a cap is affected by the physical state of the hydrocarbons: if they are in liquid state, the cap efficiency is greater; if they are in gaseous state, and the cap in question is only slightly porous-permeable, with pores filled with water, the gas will be able to gradually displace the water and spread through the cap. In this case, even if the cap is very thick, the gas will be able to cross it over long periods of time. Caps able to maintain their integrity over time can provide a reservoir with an effective seal for hundreds of millions of years.

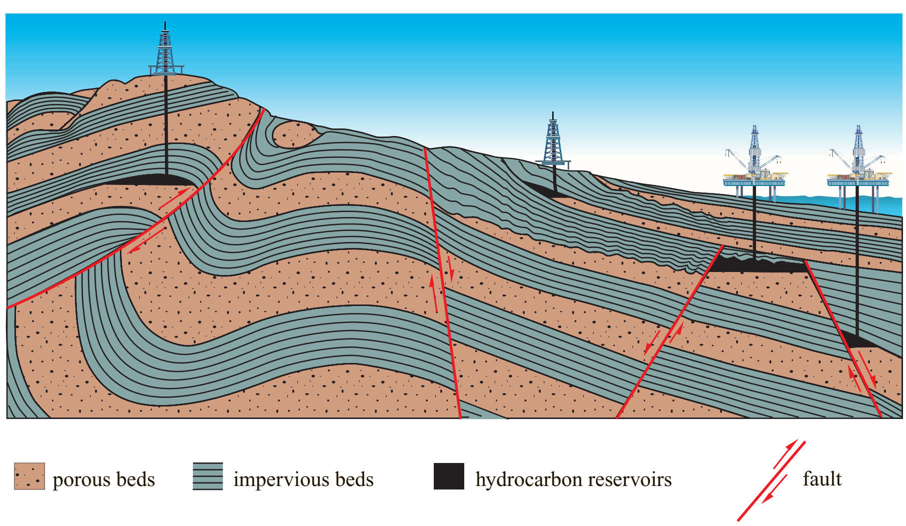


Fig. 7. Various typologies of deposits with impervious cap rocks and reservoirs in porous rocks (Source: Eni).

If a rock is saturated with water, its capacity to prevent the passage of hydrocarbons within a given time-frame depends on the minimum amount of pressure required to remove the connate water from the seal's pores or microfractures, thus enabling filtration. This pressure, known as *capillary entry pressure*, is a function of the water-hydrocarbon interfacial tension (oil and gas have different interfacial tension), inversely proportional to the maximum radius of the interconnected pores, and able to confine the hydrocarbons within the reservoir. The hydrocarbons' upward drive, which is due to their low density, is quantifiable as the height of the hydrocarbon-bearing column by the difference in density between them and water (Downey, 1994). This drive must be counterbalanced by the capillary pressure of the cap rock; otherwise, when the drive is greater than the capillary pressure, the hydrocarbons will cross the rock. These parametres can also be measured in the laboratory but it is difficult to extrapolate the behaviour of an entire cap rock and its reservoir from a sample.

The cap rocks that offer the best seal against hydrocarbon migration have vast lateral continuity, are lithologically uniform, have a good level of ductility, and represent a significant part of a basin's filling.

Ductility is the property of rock that favours plasticity to deformations, and which increases with the organic content (kerogen), pressure and temperature. Clays and evaporites are the most ductile rocks and react to stress by deforming plastically without fracturing. Arenaceous and carbonate rocks, on the other hand, are harder and, when subject to deformation, they are more likely to shatter, creating open spaces into which the hydrocarbons can migrate.

Lithology of cap rocks

The most common cap rock is clay, which seals over half of the clastic rock reservoirs, whether it is interbedded with them (as in the case of sand or sandstone and clay interbeddings that form turbidite sequence), or represents the end of a sedimentary cycle due to the deepening of a basin. Clay beds, which are common in turbidite sequences as a result of their continuity and lateral uniformity over great distances, provide excellent caps that lie on top of one another in innumerable layers. Moreover, turbidite sequences are usually deposited in a geodynamic context that favours the accumulation of very thick sediments (several thousands of metres). This thick accumulation results in the compaction of the rock (especially clay), which renders it entirely impervious. Marl (clay with variable quantities of calcium carbonate) behaves in a similar way to clay and can therefore also represent a good cap rock.

Evaporites are ideal cap rocks. Halite, gypsum or anhydrite usually come at the end of an evaporitic cycle, often formed at the base by carbonate rocks which can be good hydrocarbon reservoirs with an impervious and plastic evaporite cap. In the Permian-Triassic, evaporite sequences with carbonate sedimentary successions that have been sealed by evaporites are common and form innumerable giant hydrocarbon reservoirs.

A one-metre-thick bed of cap rock is sufficient to seal a reservoir hundreds of metres thick. For example, a clay whose pores are less than one-tenth of a millimetre in size can have a theoretical capillary entry pressure that can seal an oil column of 1,000 m. It is unlikely, however, that such a thin bed would be characterized by sufficient lateral continuity without lithological variations or fractures to allow it to act as a cap for an economically exploitable reservoir.

Lateral permeability variations are fairly common in clastic rocks; for example, a sand bed can become laterally more clayey to the point of losing its permeability characteristics. If the bed is inclined, the hydrocarbons migrate through the sand until they are blocked by the increased percentage of clay, which therefore forms a permeability barrier. The same effect can be seen as a result of a lateral increase in the cementation of a sandstone bed, with a consequent decrease in permeability.

In exceptional circumstances permafrost can act as a cap rock, as seen in the Siberian taiga, where the gas-bearing reservoir rock is Cretaceous sandstone.

Cap rocks can form as a result of diagenetic processes that render a previously permeable rock impervious, such as: cementation through precipitation of salts dissolved from carbonate, siliceous or evaporitic rocks; recrystallisation; compaction due to lithostatic load; and redistribution of ductile minerals. The degradation of oil can result in the formation of asphalt or impermeable tar, and in the reservoir rock being saturated with insoluble products: if these are concentrated at the top of the reservoir, they can act as caps.

Opposite processes can cause an impervious rock to lose its efficiency as a cap. The most common is fracturing as a result of dislocations, but dolomitization can render a compact limestone cap permeable and enable hydrocarbons to leak through it.

In addition to the common vertical type of cap, or top seal, there are also lateral seals that prevent hydrocarbons from migrating laterally and which are also considered cap rocks. These phenomena are the result of facies variations, from a porous-permeable rock to an impervious rock with greater capillary pressure or differential diagenesis. Lateral seals formed by the displacement of rocks from different environments, such as those deposited in an impervious rock after an erosion cycle, are also very common. In these cases, the shape of the seal plays an important role; there is always a vertical component to every migration process that the cap rock must seal.

Identification of cap rocks

Reservoir rocks sealed by potential cap rocks can be identified through regional studies aimed at pinpointing the areas where impervious cap rocks overlie porous-permeable formations. Lithofacies cartography is essential in these studies: lithofacies, porosity and permeability properties must be established for each stratigraphic unit. The superposition in stratigraphic order of the maps obtained will identify the areas where an impervious unit overlies a porous-permeable one, an indispensable requirement for the presence of reservoirs. More detailed maps of the regional distribution and stratigraphic-structural characteristics of cap rocks, along with identification of underlying source rocks, are used to interpret an oil system. Field studies carried out with the aim of identifying seepages may also allow identification of the possible lack or poor quality of a cap.

Regional study of an area's potential starts with a stratigraphic study to determine: the presence and distribution of source rock; the existence and spatial configuration of the cap rock; favourable conditions for the presence of traps above or close to the source rocks. Of course, hydrocarbons can migrate across a rock which was believed to be a cap and encounter another cap above it.

Deformation of cap rocks

Most structural traps are the result of folds or faults that cause deformations in the cap rock which, if ductile, will react plastically to the tension and deform without fracturing or creating spaces that would allow the hydrocarbons to leak through them.

Anticline deformations can affect a sequence in which porous-permeable rocks alternate with impervious ones which provide a series of caps, forming reservoirs in vertical succession. If an impervious level is not an effective cap, there may be an effective one at a higher level.

A fault-induced dislocation can be an excellent trap if the uplifted wall forms an effective seal. For example, if the dislocation of dipping formations displaces a permeable sand bed under an impervious clay, the latter will act as a cap rock. In other cases a fault surface may represent a slight discontinuity where the capillary properties, nature of the fluids and bed dip allow the hydrocarbons to filter through and migrate towards the surface. In this case the fault behaves like an open fracture. When the fault crops out, the hydrocarbons are dispersed in the atmosphere; the majority of surface shows are found along these fracture lines. The effects of migration over time should not be underestimated, as permeability along the fault surface can annul the sealing capacity of the adjacent rock. The origin of the fault is usually decisive when evaluating its effect on the cap: a tensional (normal) fault will produce an open fracture far more readily than a compressional (reverse or thrust) fault.

A fault's effects on lateral hydrocarbon migration must also be taken into account. A fault rarely impedes migration when it brings two porous-permeable formations into contact; for example, it cannot act as a seal between two displaced beds of sand on either limb of the fault. Exceptions to this rule may arise when a very plastic rock (clay, evaporite), sometimes set in motion by high temperatures, has infiltrated along the fault plane and sealed it, and when the relative motion of the two limbs of the fault induces diagenetic or recrystallisation phenomena, blocking the rock pores along the fault plane.

To sum up, study of the petrophysical nature, areal distribution and stratigraphic-structural configuration of the cap rock is essential for the identification of a hydrocarbon reservoir. Evaluation of individual caps is often far more complex than that of the regional cap, especially in zones affected by fault systems, and requires detailed analysis, supplemented with cartographic representations and cross-section plans produced with the aid of seismic surveys to obtain a three-dimensional picture of the cap.

1.3.3 Hydrocarbon traps

As stated above, the essential factors for the presence of hydrocarbons are a porous and permeable reservoir rock and a trap in which they can accumulate. This is defined as the geometric configuration of the rocks in the subsurface able to preserve their accumulation. In brief, any subsurface structure able to receive hydrocarbons and preserve them over time, until they are extracted, can be called a trap.

The presence of hydrocarbons, although fundamental for the development of reservoirs in economic terms, is not taken into consideration in the description of the various types of traps. In other words, traps may contain potential reservoirs, but certain elements, primarily the source rock in which the hydrocarbons must form in order to migrate into the trap, may be missing. As a result, the accumulation of hydrocarbons will not take place. A geological structure can, therefore, be a trap even if it does not contain hydrocarbons (Magoon and Dow, 1994).

The main goal of oil exploration, therefore, is to identify traps in the subsurface. The term 'trap' was coined in 1934 by R.A. McCollough, who extended the concept of anticline used until then to a variety of geological conditions in the subsurface favourable for the accumulation of hydrocarbons. The anticlinal theory originated from a statistic which indicated that hydrocarbons accumulated along the axes of anticlines in culminations. In this context, White (1885) published the anticlinal rule according to which "hydrocarbons move upwards as long as an anticlinal structural deformation does not block their ascent". As exploration technologies advanced, reservoirs were discovered in areas not necessarily linked to the presence of anticlines. The more general concept of a 'hydrocarbon trap', which can refer to situations that are not only structural but also stratigraphic, was introduced: hydrocarbons move upwards as long as a tectonic or sedimentary event does not prevent their movement and cause them to accumulate.

Traps are classified on the basis of their characteristics, although some traps are very particular and do not fit into any particular scheme. Some authors consider the trap's geometry, some the mechanism that led to its formation, and others the nature of the reservoir and cap rock. The simplest classification, accepted by the majority of authors, is the one proposed by Levorsen (1956), which divides traps into three types: structural, stratigraphic, and mixed, the latter being a combination of the first two types.

Structural traps

These are the result of deformations occurring at the same time or, more often, after the reservoir rock deposited (**Fig. 8**) and are the easiest to identify because in some cases they are visible on the ground,

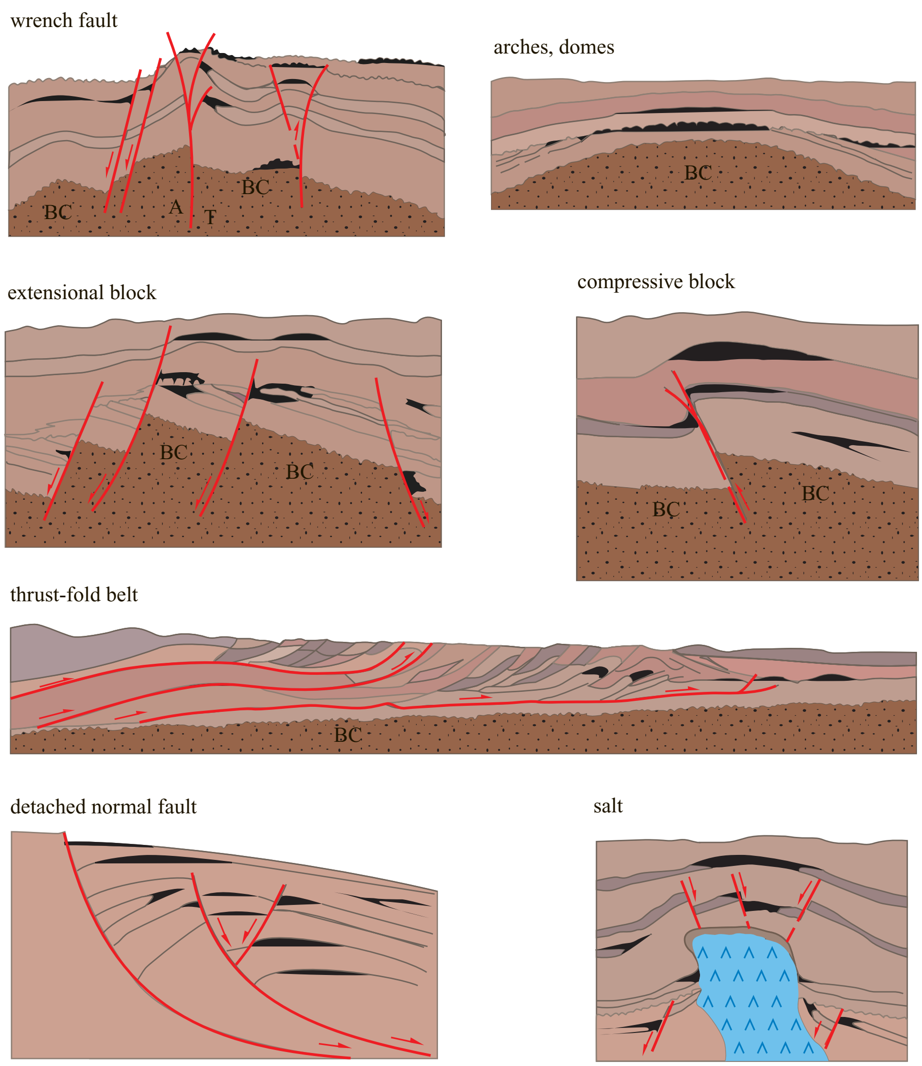


Fig. 8. The most common types of structural traps. A, dislocation towards the viewer; T, dislocation in the direction opposite to that of the viewer; BC, basement (North, 1985).

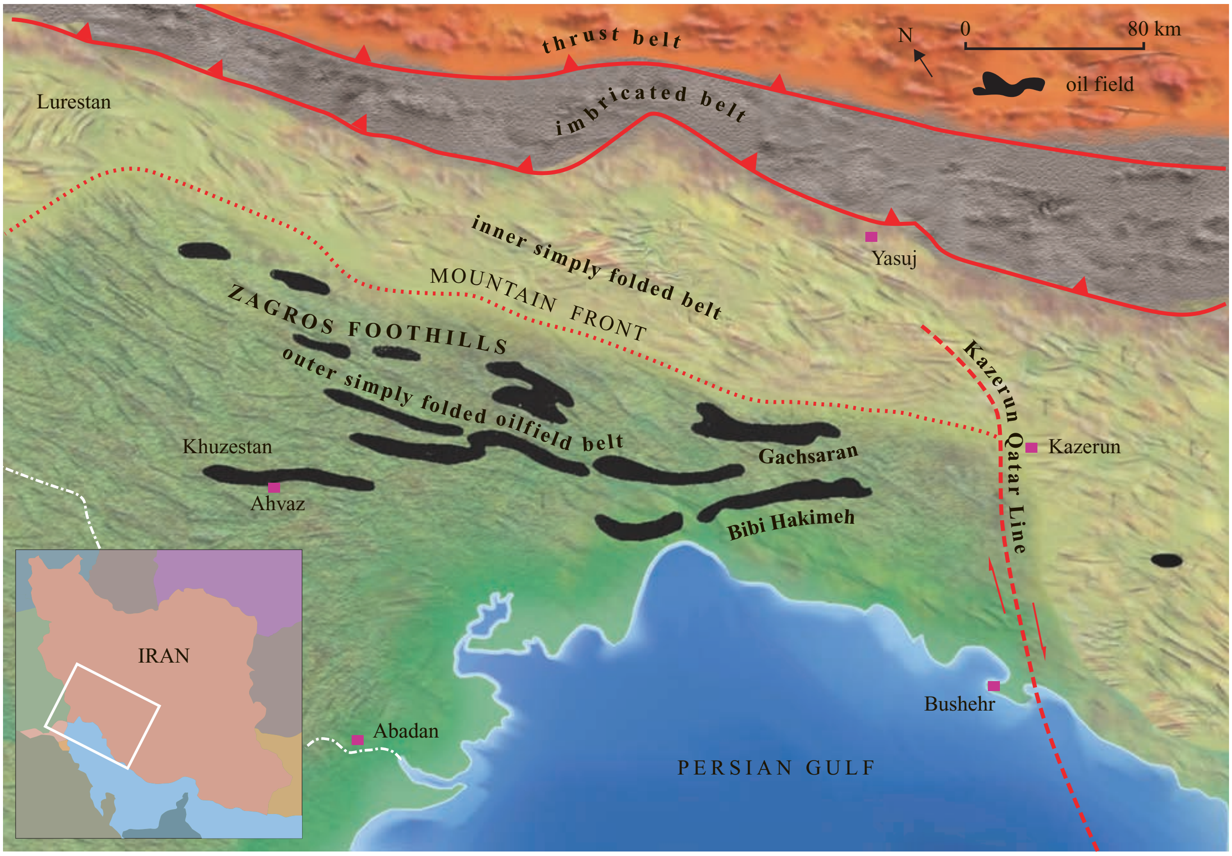


Fig. 9. On the right, an outcropping anticline on the Zagros mountains in Iran: the porous-permeable limestone deposits of the Asmari Formation are visible along its hinge, at the axial culmination, and on the sides, the impervious evaporites of the Gachsaran Formation, with their badland morphology. On the map above, the oil reservoirs of the Asmari Formation, in the hills facing the Zagros mountains, are indicated in black (McQuillan, 1985).

when the structure crops out (**Fig. 9**). Even if they are buried, they can be identified using geophysical methods (**Fig. 10**). They were thus the first to be exploited.

Structural traps are the result of folds, faults, a combination of the two (as is often the case), or regional dipping of bedding. However, when they are sealed by an unconformity, it is considered preferable to classify them as stratigraphic traps, even if deformations occurring after the unconformity can make their classification ambiguous.

In a structural trap there is a top and spill point. The *top* is the trap's highest point, i.e. the point of the reservoir to be reached at the minimum depth. The *spill point* is the highest point from which hydrocarbons can escape from the trap. The *trap closure* is the space between the top and spill point (**Fig. 11**): if the entire interval is hydrocarbon-bearing it is called *pay*, otherwise the term is used to refer only to hydrocarbon-bearing stratigraphic intervals.

Traps caused by folding

Although generally used to indicate the result of tectonic deformation, the term fold is purely a geometric description and refers to a curving or non-planar arrangement of geological surfaces,

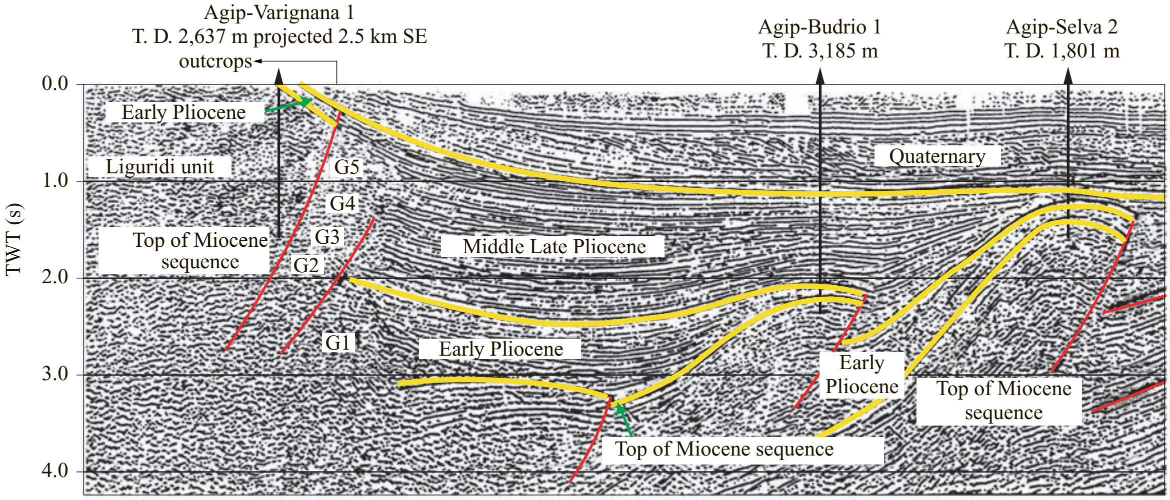


Fig. 10. Anticlinal traps faulted in a compressive regime, identified using seismic methods (Agip division in the Po River Plain) (Ricci Lucchi, 1986).

usually beds. The genesis of a fold need not be deformation, and it may be sindepositional, as is the case of folds due to differential compaction or those due to slumping.

The most common and important traps caused by folding are convex traps, which often imply the folding of a thick stratigraphic sequence usually characterized by various overlying reservoir rocks. Convex traps, which vary in nature, geometry and genesis (although the typical convex trap is an anticline, many fault traps and salt domes also belong to this category), contain most of the hydrocarbon reservoirs.

Under static conditions, oil occupies the upper part of the reservoir, unless the quantity of gas exceeds the amount required to saturate the oil at reservoir temperature and pressure; in this case, the excess gas rises to the top of the reservoir and forms a gas cap, with the oil below it. The structure may be filled with hydrocarbons up to its spill point: below that point, identified by the first open isobath on structural maps, the oil and gas spill out sideways towards an adjacent structure. If the quantity of hydrocarbons present in the reservoir is not sufficient to reach the spill point, water (usually salt water) collects beneath them.

The forces that can cause a reservoir rock to fold are widely discussed in geology and may be summed up as the result of tangential compressions acting on plastic rocks. Faults are created when their plasticity limit is exceeded; in the majority of reservoirs, folds are associated with faults.

Exploitation is easiest when the anticline represents the deformation of a continuous stratigraphic series. It may contain various overlying

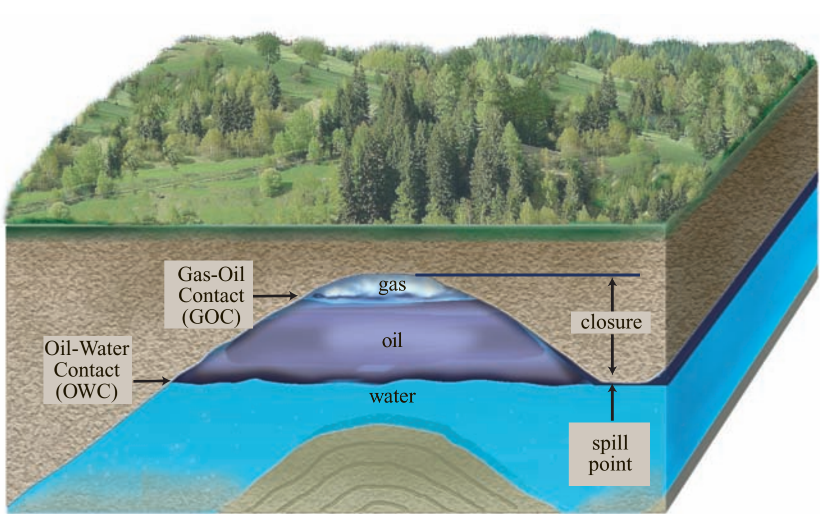


Fig. 11. Reservoir with closure and spill point (Source: Eni).

reservoirs, with their impermeable caps. Drilling can cross the reservoirs one after the other and make them all economically exploitable.

When an anticline extends to the surface, the structure can be identified above ground level: if there are reservoirs in the subsurface, the hydrocarbons are produced from wells positioned along the axis of the anticline. In the area north of the Persian Gulf, for example, outcrops of the deformed stratigraphic sequence have led to the identification of several potential hydrocarbon reservoirs, along with their thickness, lithological characteristics, porosity and permeability levels, and presence of cap rocks. In most cases, however, the structure can not be identified on the surface because it is covered by other discordant sequences or alluvial deposits: it is therefore referred to as a buried structure and can be identified using geophysical methods.

The axial culminations or depressions of an anticline can be identified by analyzing its geometry, the best area to explore being the zone of axial culmination, where the reservoir expands, increasing in volume (**Fig. 12**). When a culmination is particularly extensive and raised, it is called a structural dome whose bedding does not dip symmetrically to the limbs of the anticline but radially from the top; in this case development wells will be positioned concentrically.

Of course, there are many types of convex traps and the shape, width and general morphology of the fold may change with depth. In these cases, the interpretation of the results of the preliminary geophysical study must be reviewed in the light of data obtained during exploration drilling. Convex traps can be classified on a genetic basis:

- Tangential compression, which can take place without the basement necessarily being affected (*buckle and thrust fold traps*). These traps are said to be ‘suspended’ because they end or are cut off at the bottom.
- Vertical movements, which do not necessarily imply a shortening of the crust (*bending fold traps*), and usually involve the basement.
- Traps whose convexity is the result of geological events preceding the overlying sequence. Convexity may result from the covering of a residual relief (buried hills) or an existing sedimentary body (principally a reef). In both cases, the beds cover the reliefs, draping over them on account of their convexity (*drape folding*), and thinning gradually towards the top.

It is important to determine an anticline’s axial plane: if the plane is vertical, wells remain aligned along the axial plane even at a depth. Overlying reservoirs, on the other hand, will be reached by wells at increasing depths, but always at their culmination,

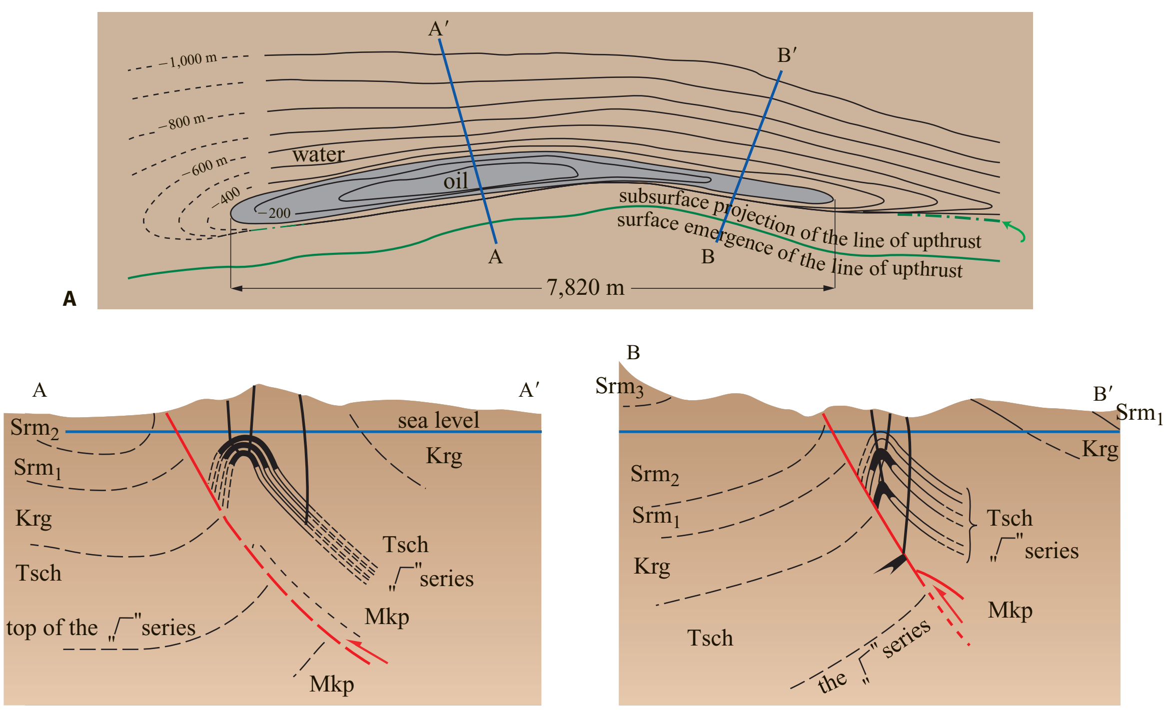


Fig. 12. Traps in a faulted anticline, illustrated with a structural map (A) and sections (B, C). Grozny reservoir, Chechen (Russia). The abbreviations refer to the formations crossed (Levorsen, 1956).

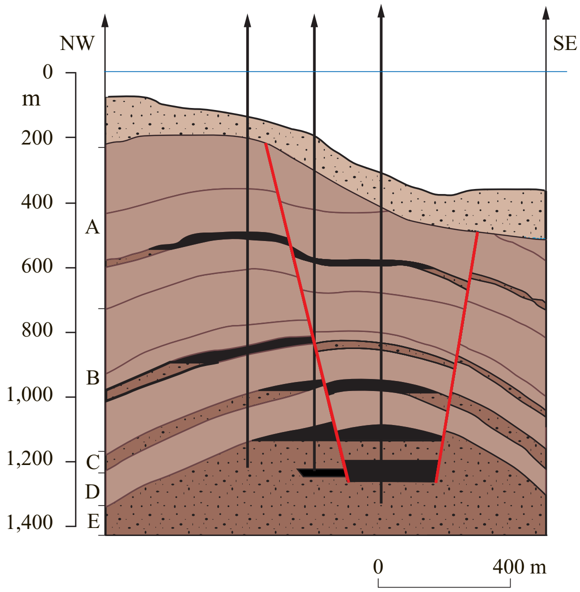


Fig. 13. Anticline in Adriatic foredeep rocks (Cellino field, Abruzzo), with numerous reservoirs superposed in the hinge. Since the axis is not vertical, the reservoirs are out of alignment, with structural highs in the direction of dip of the axial plain (Casnedi *et al*., 1977).

and exploitation will therefore be easier and more cost-effective.

If the axial plane is inclined, drilling will reach the culmination at points that shift gradually in the direction of the axial plane's dip (**Fig. 13**). In this case, development is less economical since a greater number of vertical wells, or directional wells parallel to the axial surface, will be required to reach the pools.

The anticline may be asymmetrical: in this case, the reservoir rock will be more developed towards the lesser dipping of the fold's two limbs. If there is convergence, i.e. a thinning of the beds in one direction, the position of the structural high may vary considerably, and the volume of the reservoir rock can change accordingly.

The radius of the fold may also change vertically, as is the case when a deformation tends to progressively reduce in intensity over time. The fold will therefore be more pronounced in the older beds, which as a result may contain reservoirs that are thicker but aereally smaller than the younger ones.

Overturned folds, with an axial surface close to horizontal (recumbent folds), are often peculiar structures. The reservoir may be located either in the fold's upper portion or underneath, in the overturned part of the fold itself. In the second case, the reservoir will be part of a succession of overturned beds which, in turn, may be located at the structural high (false anticline). This type of trap is only rarely exploitable because the presence of intense dislocations makes structural interpretation more difficult.

Drag folds, caused by friction in the brittle layers during folding or by the slip of allocthonous units, are known as minor folds, and influence the formation of traps to a lesser extent.

The most spectacular example of anticlinal traps is the folded structure situated in Iranian and Iraqi territory close to the Zagros mountains (see again Fig. 9); the 300-metre-thick Asmari Limestone (Oligo-Miocene) has been deformed in folds with a wavelength of between 10 and 20 km, and an amplitude of 2 to 5 km. The overlying sediments contain evaporites that have reacted plastically to compression and have slid down the anticline crests.

Other traps of great importance in oil exploration are salt domes, traps whose structural genesis is connected to particular stratigraphic conditions, and are therefore normally classified as mixed traps (see below).

Homoclinal dips are common and economically exploitable structures. They may correspond to a fold limb, even if its dip is slight. The trap is formed when porous-permeable beds in the homoclinal succession are sealed in their upraised side either by faults (see below) or by sharp decreases in porosity or permeability (permeability barrier). The latter case may occur also when the beds crop out: the formation of asphalt or bitumen in their outcropping portion can create an impervious plug that prevents the hydrocarbons from migrating upwards and dispersing in the air. The transformation occurs as a result of oxidation of the oil, which is favoured by the presence of surface water. This type of trap may be classified as stratigraphic or mixed.

Understanding a reservoir's geometry and, in particular, the configuration of its top part is of fundamental importance for its exploitation. This configuration is commonly represented on maps by isobaths that indicate the depth of the reservoir top, often with the highest point marked with the + plus sign (structural or contour map). In an anticline, the curves are subparallel and are spaced out in culmination zones, whereas they tend to be concentric in the case of domes.

The structural closure is the vertical distance between the highest point of the hydrocarbon-bearing fold and the structure's deepest isobath; in this context gas, oil and water are bedded, and hydrocarbons can partially or totally occupy the interval above the lowest closure contour line. If the surfaces separating gas, oil, and water, known also as gas-oil contact and oil-water contact (either gas or oil may be missing) are horizontal as in many reservoirs, they are graphically represented as isobaths enclosing the productive area. The producing wells are placed within this area.

Traps caused by faulting

These are common, but statistics show that they tend to create smaller reservoirs than those generated by folds, with which they are often associated, along with other structural modifications such as homoclines, bending of beds or stratigraphic variations. Traps due to faults are formed when a porous-permeable level is displaced below an impermeable one, which acts as a seal.

In certain cases, the fault crops out: when it is associated with hydrocarbon reservoirs, and does not act as a seal because the fracture is open, surface oil shows or gas leakages may be observable on the ground. In order for a trap to be formed, the fault plane must be impervious. This happens in evaporite formations if they contain porous levels, and in clastic sequences with clays which, as a result of their plasticity, seal the fault surface. In carbonate rocks, the seal is sometimes the result of calcite precipitation along the fault plane.

Fault traps may be classified, depending on the nature of the fault, as follows: those caused by normal, or gravity, faulting (extensional origin), and those caused by reverse, or thrust faulting (compressional origin).

The simplest normal fault trap interrupts a homoclinal dip which usually corresponds to the limb of a fold; the most important reservoirs of this type are associated with successions characterized by a regional, homoclinal (or, as is often the case, bow-shaped) dip, interrupted by a fault contact with impervious formations or beds.

Normal faults are usually associated with the formation of sedimentary basins. They are mostly syndepositional and dip towards the subsiding part of the basin; their dip thus conforms with the regional dip (synthetic faults or grow faults). They begin to form by flexuring when the basin flexes as a result of the lithostatic load of the sediments, and then develop with throws of increasing size in the direction of the basin, while sedimentation becomes notably thicker on the lowered sides. A classic example is the coast of the Gulf of Mexico, where the faults are still active and affect populated areas facing the sea.

Other associations of normal faults cut the homoclinal series with an opposite dip to the regional dip (antithetic faults); they do not grow over time and are only the result of the compensation of an extensional process.

The most common normal fault traps are related to antithetic faults. In these cases the reservoirs are located in the upper part of the uplifted side, when the dislocation places these reservoir rocks in contact with impervious beds on the lowered side. Naturally, hydrocarbon accumulation occurs after fault displacement. Numerous traps are also often found in combination with grow faults on the fault's lowered side; only a few of them, however, have a seal on the fault plane. An additional factor is required, such as an intersection of faults or a thinning of formations (pinch out, with reference to stratigraphic traps), in order for a trap to be created.

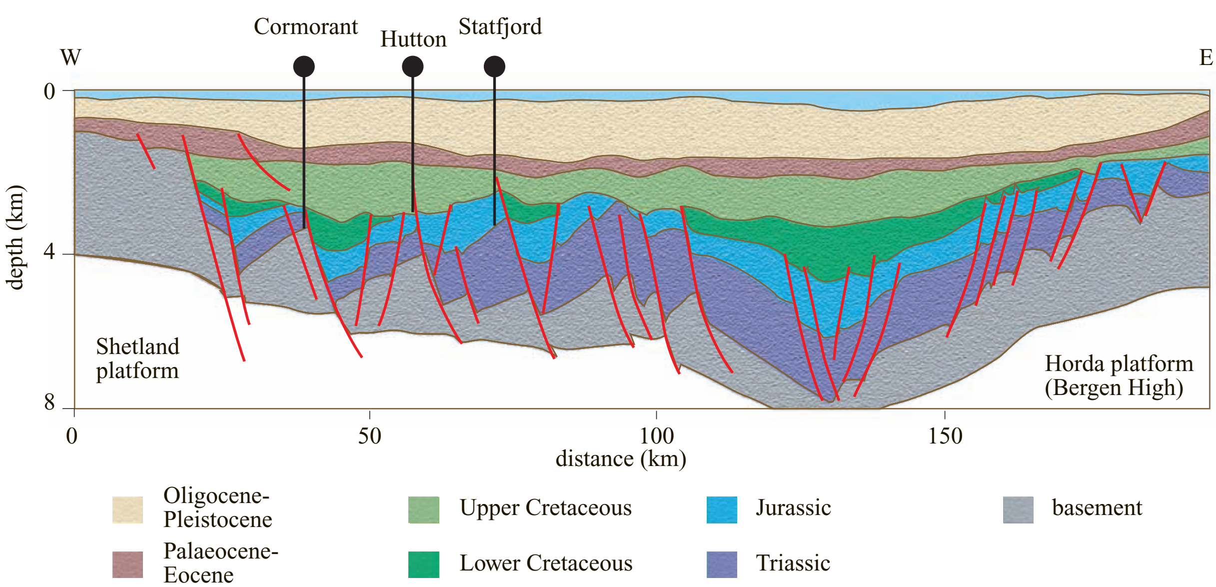


Fig. 14. Traps in the Viking Graben, in the North Sea. The faults generating the traps do not extend into the cap, which is slightly bent (North, 1985).

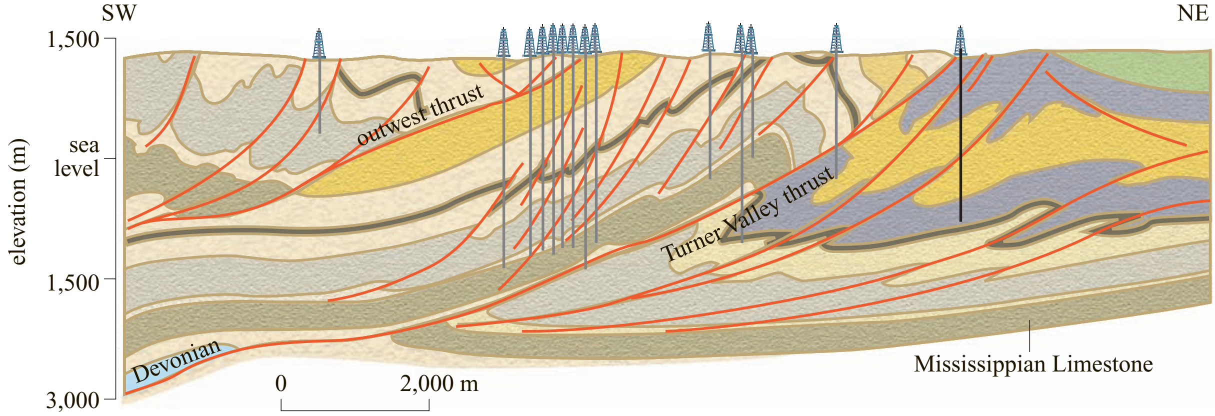


Fig. 15. Structures created as a result of compression (anticlines and reverse faults) generate traps with reservoirs in the Carboniferous (Mississippian Limestone, at the foot of the Rocky Mountains in Alberta) (North, 1985).

A factor favourable to the accumulation of hydrocarbons is the association of normal faults which determines the formation of a tectonic horst. The most uplifted zone is often the site of a reservoir, sealed by the faults that border it; the zone can also host a series of reservoirs, each of which is sealed by one of the faults that make up the association itself. Reservoirs in tectonic troughs (*grabens*), located on the uppermost sides of the structure, are rarer (**Fig. 14**). In this context there are well-known traps (Red Sea, North Sea) that have formed only on one side of the trough, when it has dropped just on one side (*half-graben*).

Reverse faults form structural traps that are mainly associated with folding, which also occurs as a result of compressional regimes. Their dip is usually less than that of normal faults (even less than 45°). When compression is greater the fault plane dip tends to approach the horizontal: in these cases, the term overthrust is preferred.

The most common traps due to reverse faults have a reservoir in folded formations associated with the fault, and a seal at the lowered side, over which the hydrocarbon-bearing side has slipped. Another pool of the same reservoir may be located on the lowered side, corresponding to the fold's limb, and sealed by the fault itself.

The presence of overthrusts can give rise to traps, especially when they originate in a fold: the upper part of the fold may constitute the reservoir, which may be sealed by the thrust-faulted lowered side. At the same time, the latter may also contain another reservoir that is capped and sealed by the overthrust side (**Fig. 15**).

Faults with movement along the direction of the fault plane (*strike-slip faults*) can also trap hydrocarbons if permeable rocks have displaced below impermeable ones.

Genesis by compression, which characterizes reverse faults, is also the cause of intense fracturing of the rock when the moving limbs consist of hard and brittle rocks (especially carbonates). The entire fractured zone, in the presence of adequate cap rock, may constitute an excellent reservoir. As already described, reverse faults tend to have sealed surfaces more frequently than normal faults because of their compressional genesis. In normal faults, the fracture can stay open more easily and fail to seal the reservoir.

Stratigraphic traps

Stratigraphic traps are caused by a lateral variation in the lithology of the reservoir rock or by an interruption of the stratigraphic succession (**Fig. 16**). Lateral variations may be connected to a lithological change, with consequent variation of petrophysical characteristics such as porosity and permeability, or to an interruption in the sedimentation against a structural high (for example, by an onlap). In these

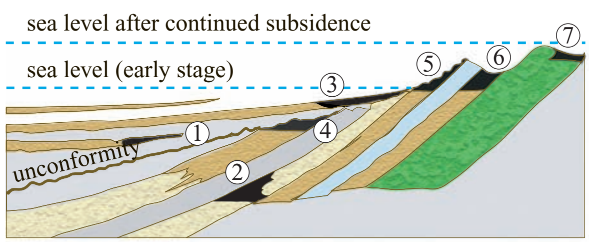


Fig. 16. Typology of stratigraphic traps:
1 and 2, real stratigraphic traps;
3 and 4, traps that are positioned, respectively, above and below an unconformity;
5 to 7, paleogeomorphic traps in buried hills (North, 1985).

cases, to have a real trap, the seal must be along the direction of the beds.

A vertical stratigraphic interruption may entail the presence of an unconformity with an impervious cap rock which seals the trap. Statistically, stratigraphic traps have smaller volumes and are harder to identify using geophysical methods than structural ones. Although their existence has been ascertained since the Nineteenth century, they have only been explored in more recent times, not least because they imply a thorough and detailed knowledge of the stratigraphic succession.

Purely stratigraphic traps are found in reef formations or in lens or channelled deposits. However, a structural component such as porous-permeable dipping beds discordantly capped by impervious rock, is generally also present. For this reason, it is preferable to describe traps that are characterized by both components separately, as belonging to the category of mixed traps.

Classification of stratigraphic traps will distinguish the primary ones – which depend on the geometry of the reservoir that, in turn, is the direct consequence of the characteristics of its sedimentation – from the secondary ones, formed after sedimentation.

Primary stratigraphic traps

The different sedimentation processes existing between rocks with clastic origin and those with a chemical-organogenic one give rise to traps with different geometries. Clastic genesis forms traps of lens deposits – often sands and sandstones deposited in particular sedimentation environments within impervious clay rocks. In some cases they may be resedimented deposits of breccias of igneous or metamorphic rocks. They will usually be alluvial or marine deposits that are the product of currents with a high transport capacity along their main axis that gradually decreases on the sides. For this reason, coarse deposits pass laterally to fine ones, and this lithological passage determines either a gradual or sharp decrease in permeability.

In delta or turbidite deposits, the sand bodies are mainly located in the upper, internal part of the fans and derive from the filling of the channels dew to the flow of the currents. The lateral passage between these lens deposits and the rock that contains them may be sharp, as is the case of channels that have been previously eroded and filled with coarse clastic materials only slightly more recent than the surrounding rock.

The hydrocarbons may fill up the coarse body entirely or only occupy its upper portion. If the beds have a homoclinal dip, the hydrocarbons will be concentrated in the upper part of the bed and trapped by the permeability barrier that the more clayey, lateral part can provide (**Fig. 17**). These sand lenses are often vertically repeated and have an irregular lateral diffusion, giving rise to reservoirs that are small in size but very numerous, and difficult to locate using geophysical methods (e.g. the complex of channels in bird's-foot deltas).

Channelled currents may overflow from the channel axis, covering non-eroded surrounding deposits. In this case, extremely thin layers of sands whose grain size is much finer than that of sands deposited in the channels, but with a particularly broad lateral extension (*overbank deposits*), may be found. The tightly-packed interbedding of thin layers of sands and clays, which are known as *shoestrings* because of their ample, ribbon-shaped lateral development, may be the result, not only of the above-mentioned overflowing phenomena, but also of coastal sedimentation in longshore bars.

Of great importance are the reservoirs contained in deposits of chemical-organogenic origin, mainly in carbonate rocks – especially in those that have undergone dolomitization with a notable increase in porosity and permeability. Although this process is of secondary origin, traps of this type may be classified as primary stratigraphic ones because they are tied in with the sedimentation environment.

The presence of hydrocarbons in reef formations is favoured by the fact that the rock that contains them may have been the source rock; they migrate to the upper part of the formation, into a trap with a cap rock of clay sediments that deposited when the reef ceased to develop. The lateral seal is often made up of the

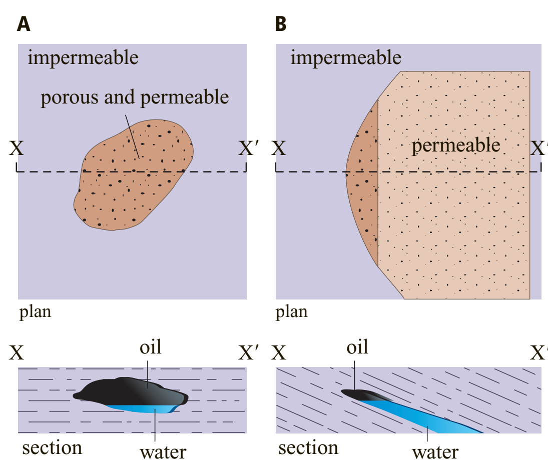


Fig. 17. Primary stratigraphic traps: A, porous-permeable lens in an impermeable rock; B, lens in a homoclinal regional dip with trap caused by the passage to an impermeable rock (Levorsen, 1956).

impermeable basin sediments deposited in heteropy during the growth of the reef.

Carbonate shelf sediments, which are also often dolomitized, are widespread as well; they have a much more ample lateral development than reef sediments, and are of a similar thickness, given that they too develop vertically to compensate subsidence. Reservoirs located in the above-mentioned sediments are more ample than those found in reef formations, and their cap may take the form of terrigenous platforms with a considerable clayey matrix on top, or limestones that have not undergone dolomitization and have therefore maintained their impervious properties.

Stratigraphic traps associated with unconformities (or of the secondary type)

A stratigraphic unconformity occurs as a result of an interruption in the sedimentation process (a sedimentary hiatus). The surface distinguishing an interruption is erosive if the most recent part of the succession has been dismantled or carried away by erosion agents, in particular when an uplift has moved the rock into a subaerial environment. In this case, the surface may be irregular and highly articulated, with fluvial incisions, reliefs and depressions. After a transgression, the marine sedimentation resumes and covers the unconformity with a new cycle which, as a result, constitute a cap rock. Stratigraphic studies and basin analysis are the first steps in recognizing unconformity traps within the basin itself.

Usually, the part that was uplifted will also have been dislocated, and bedding is deformed in different ways with folds and faults; a new undeformed succession is deposited on top of it (angular unconformity). The truncation of beds folded below the unconformity, which is followed by the deposition of impermeable layers, generates a typical stratigraphic trap. In other cases, erosion may act on an area that has been uplifted at the regional level, even without deformation (disconformity).

Finally, an interruption of the sedimentation process, especially if the succession remains in a marine environment, may be followed by a new sedimentation cycle without the succession suffering either erosion or deformation as a result (paraconformity). In this case it is recognized only by the absence of a chronological interval, which may be palaeontologically identified. At the transition between old and new sedimentations only incrustations formed during the non-deposition interval or, if the surface has been exposed to atmospheric agents, a hardened palaeosol (*hard-ground*), may be observed.

If the succession on top of the unconformity has an impervious base, the latter will constitute a cap rock for the underlying portion. By migrating along the porous-permeable formations, the hydrocarbons may accumulate in one or more reservoirs at the porous-permeable intervals, which are separated from one another by the impervious layers of the succession. Other traps may be located just below the unconformity in the part that was eroded, exposed to atmospheric agents, and, therefore, altered and porous. Finally, sands or gravel contained in the palaeochannels of rivers or coastal deposits overlying the unconformity may give rise to good reservoirs.

The erosion profile presents buried hills or landforms that constitute palaeogeomorphologic traps. A stratigraphic succession may contain various unconformities (in some cases, an upper one may cut through a lower one), and each of these may give rise to overlying traps representing the result of the migration and accumulation processes below each unconformity. In particular, the uplift of an anticline may occur in various phases that are progressively attenuated, each separated from the older one by an unconformity.

Mixed (stratigraphic-structural) traps

These are traps in which both structural deformations and stratigraphic variations occur. The most important of these are related to the existence of salt domes, which result from the uplift of relatively light rocks, usually halite and gypsum of evaporitic origin. Halite has a density of about 2.2 and gypsum of about 2.4. Experiments conducted in the Gulf of Mexico have shown that, as a result of the geostatic load, the density of sediments associated with salt increases progressively with depth and that, at a depth of 700 m, it is already greater than that of salt, which is incompressible and therefore always maintains the same density.

In the presence of water and at high temperatures, salt and gypsum become extremely plastic. Therefore a slight deformation, such as an anticline, and even one with a wide radius, may cause an uplift in the salt layers known as a diapir, starting from the fold's hinge. The salt formations, because of their plasticity, literally pierce the overlying rocks with an upward hydrostatic thrust, as described by Archimedes' principle which establishes the tendency towards equilibrium of lighter and heavier masses: a salt dome is thus created. Its structuring, and above all the speed at which the light salts rise, are proportional to the volume of the masses involved in the process.

As a result of their increased density the sediments contouring the salt structure begin to exert a lateral pressure that affects the shape of the dome, often causing it to become narrower at the bottom. In other

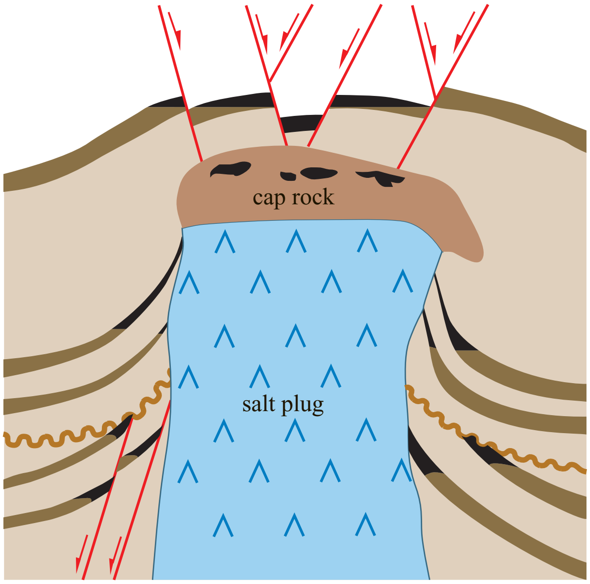


Fig. 18. Idealised section of a salt dome in the Gulf of Mexico. In black, the oil contained in traps of various types (by fault in the cap rock; by unconformity at the dome's sides). The seals may consist of salt or impermeable rocks interbedded in the sedimentary succession (Levorsen, 1956).

words, the dome may have a wider diameter at the top, where it is less influenced by lateral pressure, than at greater depths.

The rise of the salt is favoured in corrugated zones where the diapiric salt masses have varied shapes because the overlying rocks, which have suffered folding and fracturing, offer different amounts of resistance to the upward thrust of the salt, depending on the direction of the discontinuity. Favoured by its own plasticity, the salt tends to proceed along the easiest paths, intruding into the weakened zones and acquiring irregular shapes.

Salt rocks are impervious and the formations that contour the dome may be the site of important reservoirs, sealed by the salt itself (**Fig. 18**). The upward motion of the salt provokes an uplift of the surrounding beds which, as a result, are generally more inclined. In the case of porous-permeable rocks, these beds give rise to reservoirs with a limited lateral extension but a pronounced vertical development, and are marked by an anomalous pressure, greater than that considered normal at those depths. It should be noted that the salt domes, which only rarely reach the surface, are, as a result of their low density, easily identified in the subsurface by means of gravimetric surveys. Their shape is that of a truncated cone or irregular cylinder, often with a mushroom-shaped upper part, diameters of around one kilometre and heights of up to several thousand metres. Hydrocarbons are produced from wells positioned around the dome and, in part, on the cap rock on the dome itself.

The formation of a salt dome may cause a number of normal faults to be associated with the blocks that the dome has uplifted; in this case, the traps are not sealed by the salt walls but by the impermeable formations that are interbedded with the porous-permeable ones of the succession.

Much has been written about salt domes owing to the frequency with which they occur on the coast of the Gulf of Mexico, in Louisiana and in Texas. The salt domes in this area are known as *salt plugs*, and are formed by halite associated with anhydrite; because of its high density, however, anhydrite does not give rise to diapirs. Free sulphur derived from the anhydrite, and potassium salt are also often present. The formations that cover the salt domes are marked by numerous faults that radiate out from the centre of the dome, with vertical dislocations of several hundreds of metres. These highly dipping faults lead to the formation of reservoirs in separate blocks, some of which are true tectonic troughs (grabens) mostly localized above the domes. In these cap rocks, excellent reservoirs are formed in interbedded sands (for example, the Frio Formation in Texas).

The upward-thrust phenomenon gives rise to some extremely complicated structures, in which the faults are associated with squeezing and truncation of the sand formations that contour the dome; these structures may contain ten or more pools. Exploration is therefore very complicated, and the drilling stage may be problematic due to the overpressure of the clays.

In addition to the Gulf of Mexico, there are many other production areas related to salt domes: the Hanover zone (Germany), the region to the north of the Caspian Sea, and various areas in the Middle East, especially in Iran.

Other typical mixed traps occur when the dislocation takes place during the sedimentation process (syntectonic sedimentation). This can occur in basins that are only partially affected by deformations: while one part rises, forming a structural high, the rest is subject to sedimentation. The basin's sands onlap the upraised part, and change lithofacies, becoming thinner, more clayey and less permeable. The end acquires a characteristic lens or pinch-out shape. Bearing in mind that this, too, may have been lifted, the sand layer may end by arching upwards and becoming a reservoir blocked by the passage to the clayey facies or by the flank of the structural high. In practice, the structural high is contoured by these pinched-out lens sands that can lie on top of each other, separated by layers of clay, and give rise to several overlying reservoirs.

The structural high may be represented by a salt dome that has risen after the sedimentation of the surrounding basin (in which case it may form a trap of the kind already described), or during it, in which case it may form mixed traps with pinched-out sand terminations.

Other mixed traps may occur when a fault plane produces a slope along which the sediments previously deposited on the uplifted flank either slump down or landslide (megabreccias).

If the water in a reservoir rock is in motion, the oil-water contact assumes the same dip as that of the water's movement. Hydrodynamic traps of various shapes and sizes, depending on the characteristics of the porous-permeable rock in which the reservoir is located, may thus be generated (**Fig. 19**).

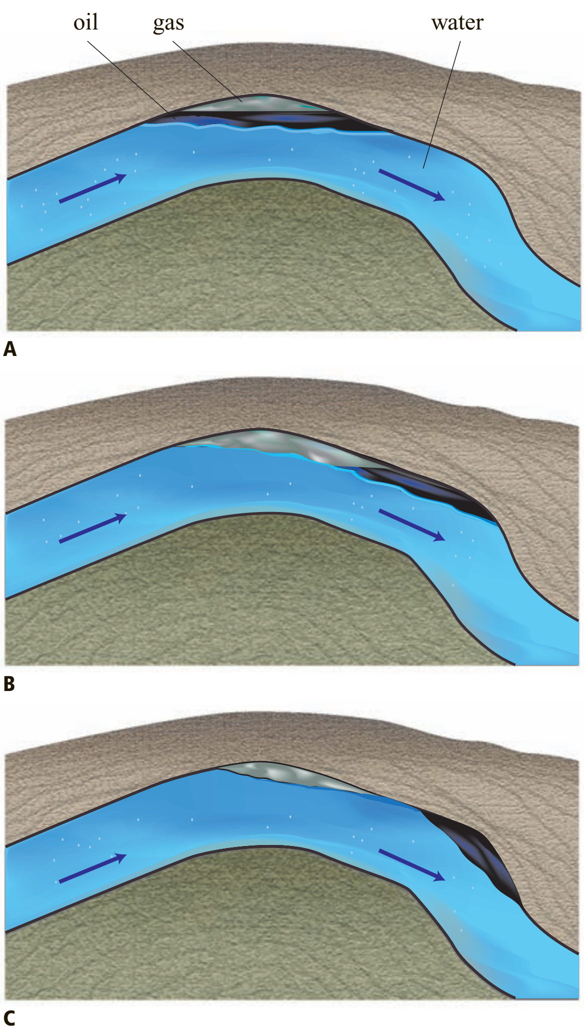


Fig. 19. Types of hydrodynamic traps in a thick and deformed anticlinal sand body: A, gas and oil in complete superposition; B, gas in partial superposition; C, the gas and oil accumulations are separate (Magara, 1977).

Other mixed traps are associated with anticlines formed, not as a result of tectonic actions, but of the buried hills mentioned above: the beds, dipping radically over the hills, forms reservoirs along their borders, often where there are accumulations of coarse products produced by the disintegration of the hills.

In other cases, the trap originates as a consequence of differential compaction under lithostatic load, as clays are more compressible than other rocks, such as sand. In a covering succession with high clay content, the sequence is more compact where the thickness is greatest. As a result, there will be a culmination on the buried hill, where the cover is less thick, while the clays, which are more abundant on the borders, will be more compact, thereby simulating an anticline.

The buried hill may also not be erosive in nature: for example, a reef covered by a thin bed of clay (which may have determined the extinction of the reef itself) will usually be flanked by basin deposits of a clayey nature that are subject to compaction; they too simulate an anticline that may be the site of reservoirs separated from the reef.

The variety and complexity of the geological conditions related to the presence of hydrocarbon reservoirs and their relative caps, together with the existence of traps, are the basis of oil exploration. Once an oil region has been identified, exploration usually involves the following steps:

- Identification and drilling of structural traps, which are easier to identify by means of geophysical surveys. At this point, subsurface exploration will have provided useful stratigraphic information for the next step.
- Search for and drilling of mixed traps.
- Exploration of stratigraphic traps, carried out on the basis of an accurate stratigraphic study based on data collected during the first two steps.

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