along curved (listric) fault planes and are typical of sedimentary sequences such as deltas deposited with relatively rapid sedimentation. The fault plane is often (though not always) sealing and can stop oil and gas from migrating further upward. However, oil traps are equally often formed in anticlines on the upper side of the fault plane. These are rollover anticlines. Because the faulting is active during sedimentation, the layers on the downthrown side will be thickest. The name growth fault goes back to the early days of oil exploration without seismic data. It was noticed that the layers had "grown" in thickness in the wells on the downthrown side of the fault. The displacement of the beds decreases upwards along the fault plane. Smaller, antithetic faults often develop in the opposite direction in the beds which are turned inwards towards the main fault plane. Growth faults tend to have low permeability and may contribute greatly to reduced porewater circulation in sedimentary basins, and we often find undercompacted clay, which can turn into clay diapirs in association with growth faults.

1.8.2 Stratigraphic Traps

These are traps which are partially or wholly due to facies variation or unconformities, and not primarily the result of tectonic deformation. Porous and permeable sands which pinch out up-dip in less permeable rocks, e.g. shale (Figs. 1.11 and 1.12) are good examples. Barrier islands often form stratigraphic traps because they may be separated from the coast by fine-grained lagoonal facies. The main types are:

(a) Fluvial channel sandstones may be isolated and surrounded by impermeable clay-rich sediments, or they may be folded so that we obtain a combination of stratigraphic and structural traps (Figs. 1.9 and 1.10).
(b) Submarine channels and sandstone turbidites in strata rich in shale. Here we will often find pinch-out of permeable layers up-dip from the foot of the continental slope. This will result in stratigraphic traps without any further folding being necessary.
(c) Reefs often form stratigraphic traps. A reef structure projects up from the sea bed and often has shale sediments surrounding it, so that oil could migrate from the shale into the reef structure.

Fig. 1.13 Natural oil seep at Carpenteria State Beach, California. Oil is flowing on land, on the beach and also offshore on the sea floor

(d) Traps related to unconformities. Sandstones or other porous rocks may be overlain with an angular unconformity by shales or other tight sediments, forming a trap underneath the unconformity (Fig. 1.12). Topographic highs in the basement overlain with shales can also provide good traps in fractured basement rocks. Remember that oil can migrate upwards into stratigraphically lower rocks. In China there are numerous examples of this type of trap.

Much of the oil generated in sedimentary basins has not been trapped in reservoirs but reached the surface on the seafloor or on land. There it is then broken down by bacteria and becomes heavy oil, which is not very toxic. In California there are many examples of natural oil seeps which can be observed along roads, on the beach (Fig. 1.13) and also offshore.

1.9 Other Types of Trap

More unusual kinds of trap can be encountered. If the porewater in a sedimentary basin has sufficiently strong flow of meteoric water into the basin, the oil/water contact may diverge markedly from a horizontal plane due to the hydrodynamic stresses. This has implications for calculations of oil volumes within a structure, and in some instances oil can accumulate without being sealed in, within a so-called hydrodynamic trap. The circulation of fresh (meteoric) water down into oil-bearing rocks will, however, lead to biodegradation and the formation of asphalt. Asphalt can then become a tight cap rock for the oil.

At greater depths, beyond the reach of meteoric water, water movement is limited and any deflection of the oil/water contact is more likely to reflect pressure differences within the reservoir. Water will also flow then because of the pressure gradient, but unless there are low permeability barriers the pressure will soon equalise. Tectonic tilting will also tilt the oil/water contact.

Reservoir Geology is not a well-defined discipline. It includes many aspects of geology that are of special relevance to the production of petroleum. It is also linked to engineering aspects of petroleum production. *Reservoir geophysics* has in recent years become very important and is now well integrated with reservoir geology.

1.10 Porosity and Permeability

Any rock with sufficiently high porosity and permeability may serve as a reservoir rock provided that there is a source of petroleum, a structure, and a tight cap rock.

Sediments consist of solid grains and of fluids which for the most part are water but may be oil and gas.

Porosity (φ) is an expression of the percentage (or fraction) of fluids by volume (V_f) compared to the total rock volume with fluids (V_t), so that $\varphi = V_f / V_t$. Porosity is often expressed as a percentage, but in many calculations it is easier to express it as a fraction, for example 0.3 instead of 30% porosity.

The v*oid ratio* (VR) is the ratio between pore volume (φ) and the volume of the grains ($1–\varphi$).

$$\mathrm{VR} = \varphi / (1 - \varphi)$$

Void ratio is often used in engineering and it has certain advantages in some mathematical expressions.

If we assume that we know the density of the mineral grains, the porosity can be found by measuring the density of a known volume of the sediment. The density of the sediments (ρ_s) is the sum of the density of the grains, which are mostly minerals ρ_m, and the density of the fluids (ρ_f).

$$\rho_s = \varphi \rho_f + \rho_m (1 - \varphi)$$

Well sorted, rounded sand grains are almost spherical in shape. If we have grains of the same size, which are all quite well rounded and with a high degree of sphericity, we will be able to pack the grains so as to get minimum porosity. Rhombic is the densest packing, resulting in 26% porosity, but this can not be obtained naturally. Cubic packing, where the grains are packed directly one above another, results in about 48% porosity and this does not occur in nature either. Most well sorted sandstones have a porosity which lies between these two values, typically around 40–42%. Poorly sorted sand may have lower primary porosity and will also compact more at moderate burial depths. Clay-rich sediments have a much greater porosity immediately after deposition, typically 60–80%. This means that immediately following deposition a sand bed is denser than a bed of clay or silt. However, clay and silt lose their porosity more rapidly with burial. Porosity may be classified into different types depending on its origin.

Pore space between the primary sediment grains is often referred to as *primary porosity. Intergranular porosity* simply means porosity between the grains whereas *intragranular porosity* means porosity inside the sediment grains. The latter may be cavities in fossils, e.g. foraminifera, gastropods, molluscs, but also partly dissolved feldspar and rock fragments. Pore space formed by dissolution or fracturing of grains is called *secondary porosity*.

Cavities formed by selective solution of sediment grains or fossils are classified as *mouldic porosity*. A typical example is when dissolution of aragonite fossils like gastropods leaves open pore spaces (moulds).

Particularly in carbonates we may also have porosity on a large scale i.e. as caverns (karst) and in reefs.

Pore space produced by fracturing is called *fracture porosity*.

Permeability is an expression of the ease with which fluids flow through a rock. It will depend on the size of the pore spaces in the rocks, and in particular the connections between the pore spaces. Even thin cracks will contribute greatly to increasing the permeability.

Permeability can be measured by letting a liquid or gas flow through a cylindrical rock sample under pressure. The pressure difference $P_1 - P_2$ between the two ends of a horizontal cylinder is ΔP, the cylinder length L, and the flow rate of water (or another fluid) through the cylinder, is Q (cm^3/s). A is the cross-section and μ the viscosity of the fluid

$$Q = \frac{k \cdot A \cdot \Delta P}{L \cdot \mu}$$

where k is the permeability, which is expressed in Darcy.

The volume of water which flows through each surface unit in the cross-section A is thus equal to the flux $F = Q/A$. F can be measured in $\mathrm{cm}^3/\mathrm{cm}^2/\mathrm{s}$ or in $\mathrm{m}^3/\mathrm{m}^2/\mathrm{s}$. This is equal to the Darcy velocity which is m/s.

Well-sorted sandstones may have a permeabilities exceeding 1 Darcy and values between 100 and 1,000 mD are considered to be extremely good. Permeabilities of 10–100 mD are also considered to be good values for reservoir rocks. Permeabilities of 1–10 mD are typical of relatively dense sandstones and limestones, so-called tight reservoirs. There are also examples of rocks with even lower permeabilities being exploited commercially for oil production, for example in the Ekofisk Field where the generally low permeability of a chalk matrix is enhanced by fractures which increase the overall permeability.

In the great majority of rocks, the permeability differs according to flow direction. In sedimentary rocks the permeability is much higher parallel to the bedding compared with normal to the bedding. Channel sandstones can also have a marked directional impact on the permeability.

In well-cemented sandstones and limestones, and also in certain shales, the matrix permeability is extremely low and the effective permeability may be mostly controlled by fractures if they are present.

Claystones and shales have very low permeability and can be almost completely tight. In the laboratory shale permeabilities as low as 0.01 nanodarcy have been measured. Samples from cores or outcrops can contain minute fissures formed in response to unloading during retrieval to the surface and these must be closed to replicate the *in situ* permeability prior to unloading.

Most rocks are far from homogeneous. We may measure the porosity and permeability of a hand specimen or core plug, but it is not certain that these are representative of a larger volume. Fractures occur at varying intervals, and range in size from large, open joints down to microscopic cracks which can barely be seen in a microscope.

Rocks with low porosity and permeability may fracture and sufficiently increase their porosity, and particularly permeability, to form large oil reservoirs. This means that reservoirs may be good producers despite relatively low porosity.

Occasionally we find petroleum in fractured metamorphic and igneous rocks but reservoirs normally consist of sedimentary rocks. Sandstones make up about 50–60% of the reservoirs in the world and carbonate reservoirs may account for almost 40%. Many of the reservoirs in the Middle East are carbonate rocks but in the rest of the world the percentage of carbonate reservoirs is lower.

The most important aspects of reservoir rocks include:

(1) The external geometry such as the thickness and extent of the reservoir rock in all directions.
(2) The average porosity, pore size and pore geometry.
(3) The distribution of permeability in the reservoirs, particularly high permeability conduits and low permeability barriers to fluid flow.
(4) Mineralogy and wettability of the pore network.

The properties of sandstones and carbonate reservoirs are primarily linked to the depositional environment, the textural and mineralogical composition and the burial history. A good background in general sedimentology, facies analysis and sequence stratigraphy is therefore important.

Nevertheless, many of the important properties of reservoir rocks linked to changes in facies and smaller faults are below the vertical resolution of exploration seismic (15–30 m) and it is important to establish relationships between facies models, diagenetic processes and reservoir properties. The properties of faults are also very important factors determining oil flow during production.

1.11 External Geometry of Reservoir Rocks

The external geometry of reservoir rocks is largely determined by the depositional environments, but faulting and diagenesis may define the lateral or vertical extent of a reservoir.

Fluvial sandstones typically represent point bar sequences in a meandering river system. The lateral accretion of the point bar will deposit a sandstone layer extending to the width of the meander belt in the valley. The thicknesses of channel sandstones are limited by the depth of the river. The primary thickness at the time of deposition is, however, reduced by 10–30% or more by compaction.

The overbank muds will become tight shales which will reduce the vertical permeability. Fluvial channels are characterised by fining-upwards sequences with the highest permeability near the base. This makes it more likely that water will break through along the basal part and the oil will be by-passed in the finer-grained upper part during production.

Braided stream facies will tend to have higher sand/shale ratios and will normally have better lateral and vertical permeabilitites on a larger scale.

The ratio between the intervals with high enough porosity and permeability to be produced (net or pay), and the total sequence (gross), will be mostly determined by the primary facies relationships. The net/gross ratio is often taken to be approximately equal to the sand/shale ratio but even at moderate burial depths many sandstones are not reservoir rocks, due to poor sorting or carbonate cement.

Aeolian dunes also have specific external geometries and there are many different types. Here the net/gross will be very high. Aeolian sand is often reworked by transgressions, accumulating as marine sediments in drowned topographic depressions (valleys).

Marine sandstones deposited as delta mouth bars, shoreface accretion and barrier islands have thicknesses controlled by the wave energy (wave base depth). In protected environments, particularly interdistributary bays, the shoreface sandstones may be very thin. Each shallow marine unit has a limited thickness controlled by fair-weather wave base. Local subsidence or transgressions can increase the thickness of these sand deposits.

The tidal range is very important in determining the thickness and the length of tidal channel sandstones. Tidal channels and also fluvial channels in deltas tend to be oriented perpendicular to coastlines.

Drilling into shallow marine sandstones, it would be very important to determine whether it was a barrier island which would represent an elongated reservoir parallel to the coastline, or a tidal sandstone which tends to be oriented perpendicular to the coastline. In some cases dipmeter logs could help to determine the orientation of cross-beddding and progradation direction of sand bars.

Turbidites may be laterally very extensive, but may also be confined to narrow submarine channels. In either case they may form very thick sequences because there is ample accommodation space. We may have very thick sequences of stacked sandstone reservoir rocks in slope and deepwater facies and this may compensate for the lower porosity and permeability compared to beach deposits.

Turbidites and fluvial sandstones form fining-upwards units while marine shoreface and mouth bar sandstones are coarsening-upwards. This becomes very significant during production because oil and gas will be concentrated in the upper part. Coarsening-upwards sandstones therefore have the best properties for flow of oil and gas during production.

1.12 Changes in Rock Properties During Burial and Uplift (Diagenesis)

The changes in properties are due to increased burial and also to uplift. Both sandstone and carbonate reservoirs undergo diagenesis, which will cause a reduction in porosity and permeability as a function of increasing burial.

The reduction in porosity (compaction) may be mechanical in response to increased effective stress from the overburden, or chemical as a result of the dissolution and precipitation of minerals. The porosity of reservoir sandstones or carbonates may increase with depth in certain intervals, but this is because of the changes in the primary sediment composition. Each lithology has a different porosity depth curve. In a uniform primary lithology the porosity and the density will be reduced as a function of burial depth (temperature and stress). Overpressure causes reduced effective stress resulting in mechanical compaction. Near the surface, meteoric flow may cause dissolution and a net increase in the porosity in carbonates (karst) and even, to a certain extent, in sandstones.

In continuously subsiding basins, open faults and fractures will be rare because of the progressive compaction processes.