3.1.1 Introduction

The term drilling indicates the whole complex of operations necessary to construct wells of circular section applying excavation techniques not requiring direct access by man. To drill a well it is necessary to carry out simultaneously the following actions: a) to overcome the resistance of the rock, crushing it into small particles measuring just a few mm; b) to remove the rock particles, while still acting on fresh material; c) to maintain the stability of the walls of the hole; d) to prevent the fluids contained in the drilled formations from entering the well. This can be achieved by various drilling techniques. In this chapter rotary drilling rigs will be examined. These are, in practice, the only ones operating today in the field of hydrocarbons exploration and production. The drilling rigs used on land are complexes of mobile equipment which can be moved in reasonably short times from one drill site to another, drilling a series of wells. In particular, the typical rotary rig for drilling onshore medium to deep wells, indicatively more than 3,000 metres, will be described below. Rigs for shallower depths use analogous but somewhat simpler techniques because of the smaller stresses to which the rig is subject. See Chapter 3.4 for offshore drilling.

In rotary drilling the rock is bored using a cutting tool called the bit, which is rotated and simultaneously forced against the rock at the bottom of the hole by a drill string consisting of hollow steel pipes of circular section screwed together. The cuttings produced by the bit are transported up to the surface by a drilling fluid, usually a liquid (mud or water), or else a gas or foam, circulated in the pipes down to the bit and thence to the surface. The rotation is transmitted to the bit from the surface by a device called the rotary table (or by a particular drive head), or by downhole motors located directly above the bit. After having drilled a certain length of hole, in order to guarantee its stability it has to be cased with steel pipes, called casings, joined together by threaded sleeves. The space between the casing and the hole is then filled with cement slurry to ensure a hydraulic and mechanical seal. The final depth of the well is accomplished by drilling holes of decreasing diameter, successively protected by casings, likewise of decreasing diameter, producing a structure made up of concentric tubular elements (see Section 3.1.9). Apart from the difficulties of drilling the rocks encountered, the number of casings also depends on the depth of the well and on the reason for drilling.

The drilling rig consists of a set of equipment and machinery located on the so-called drilling site. Normally the rig is not owned by the oil company but by drilling service companies, which hire out the rig complete with operators and which construct the well according to the client’s specifications. The most important items of equipment are set out in Fig. 1. It has already been mentioned that the bit is rotated by a set of hollow pipes ending with a special pipe of square or hexagonal section (the kelly) which passes through the rotary table and transmits the rotational movement. The kelly is screwed to drilling swivel which in turn is connected to the hook controlled and operated by a hoist and a derrick. The drilling swivel serves to let the drilling fluid pass from the surface hydraulic circuit to the interior of the pipes. The drill string is operated with a hoisting system formed by a hook connected to a series of sheaves (crown and travelling blocks) operated by a wire rope (or drilling line) and a hoist (or drawworks). The crown block is located at the top of the derrick, which is the most striking and characteristic feature of the drilling rig. The function of the derrick is to support the crown
1 crown block  14 weight indicator  27 degasser  
2 mast  15 driller's console  28 reserve pit  
3 monkey board  16 doghouse  29 mud pits  
4 traveling block  17 rotary hose  30 desander  
5 hook  18 accumulator unit  31 desilter  
6 swivel  19 catwalk  32 mud pumps  
7 elevators  20 pipe ramp  33 mud discharge lines  
8 kelly  21 pipe rack  34 bulk mud components storage  
9 kelly bushing  22 substructure  35 mud house  
10 master bushing  23 mud return line  36 water tank  
11 mousehole  24 shale shaker  37 fuel storage  
12 rathole  25 choke manifold  38 engines and generators  
13 drawworks  26 mud gas separator  39 drilling line  

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**Fig. 1.** Main components of a drilling rig.
block, and it is tall enough to permit the useful vertical operation of the travelling block, and therefore of the drill string in the hole. The drilling fluid circulates in a closed circuit: it enters by way of the swivel, flows through the drill string and the bit, cleans the bottom of the hole, then rises through the space between the drill string and the hole, reaching the shale shaker which separates the cuttings from the fluid, and then arrives to the mud tanks. It is subsequently conveyed to the mud pumps which circulate it to the drilling swivel once more via a rigid pipe (standpipe) and a flexible one (hose), closing the circuit. Circulation of the drilling fluid, commonly known as mud, is the characteristic element of rotary drilling, as it permits the continuous clearance of the cuttings from the bottom of the hole. Deepening the well calls for the periodic addition of new drilling pipes, while replacing the bit when it is worn down requires the extraction (or trip-out) of the whole drill string. This operation, which takes a great deal of time, is called the roundtrip.

Nowadays, hydrocarbon exploration and production are based on the drilling of wells whose depth, in a few cases, has even exceeded 10 km. In the last few decades the need to limit the costs entailed by considerable technical problems has led to noteworthy progress in optimizing drilling techniques, in knowledge of the problems connected with drilling and with the stability of rocks at great depths, and in the formulation of muds for high pressures and temperatures. In drilling the main concern is achieving high rates of penetration under safe conditions, and reducing the idle (or down) time. Indeed, it is recalled that at depths of around 3,000 m, it takes approximately 7 hours to trip-out the drill string from the hole and subsequently to run it back in (for example, to change the bit); and this increases to some 12 hours if the depth is around 4,000 m. These are rather lengthy times when it is considered that the average life on bottom of a bit at such depths is something like 50-100 drilling hours, and that the hire cost (or rig rate) of a large onshore drilling rig is in the range of 25,000 euro/day, while for offshore rigs it can exceed 200,000 euro/day.

### 3.1.2 Rotary drilling rigs

Every drill rig is constructed in type, size and capacity according to the aims and the characteristics of the hole to be drilled. Operatively, the choice of the type of rig is based on the well requirements, considering that the hire cost is proportional to the capacity and the technological characteristics of the rig. The simplest criterion for the classification of drilling rigs is based on the type of location (for drilling wells on land or offshore), and on their capacity, i.e. the effective drilling depth that can be attained. According to this classification, onshore drilling rigs fall into four groups: 

- **a)** light rigs, down to 2,000 m;
- **b)** medium rigs, to 4,000 m;
- **c)** heavy rigs, to 6,000 m; and
- **d)** ultra-heavy rigs for greater depths. Increasing capacity is matched by increasing both maximum hook load capacity and derrick strength. Another criterion for classification is the power installed on the rig, which for oil well drilling is in the range of at least 10 HP every 100 feet in depth, equal to approximately 250 W/m. According to this criterion, the preceding classification becomes: 

- **a)** light rigs, up to 650 HP;
- **b)** medium rigs, up to 1,300 HP;
- **c)** heavy rigs, up to 2,000 HP; and 
- **d)** ultra-heavy rigs, 3,000 HP and more.

The drilling rig is transported to and set up on a levelled area called the drilling site, which contains the derrick, the service equipment, the stores and the living space (crew quarters). The drilling site, with a surface area of some 1 to 2 hectares is thus transformed into a full-scale operative site, which is eventually dismantled at the end of drilling operations. This period could last from just a few weeks to more than a year in the case of exploratory wells in difficult situations. After constructing the access road to provide a link to the ordinary road system (if such exists), the cellar, the foundations for the drilling rig, and the water, mud and waste pits/tanks are constructed within the drilling site area. The spaces where the containers for the offices, the warehouse, the workshop, the services and the crew quarters will be located are then organized, if the site is far away from inhabited centres. It is self-evident that these areas have to be arranged in a rational manner, occupying the least possible space, and fenced in to keep out persons not engaged in the operations. The site is provided with drainage ditches to collect rain water and any liquids accidentally split, and is fully waterproofed.

Drilling site preparation entails earthworks and levelling, with the removal of the topsoil and placing a 30-40 cm thick layer of coarse gravel, a sheet of PVC (Poly Vinyl Chloride) for waterproofing purposes, and finally a 40-50 cm thick layer of sandy gravel. These granular materials must be well compacted, as it has to support heavy trucks bringing in personnel, materials and utilities to the site. A rectangular or square shaped cellar is dug in the centre of the site vertically above the well and is lined with thrust-bearing walls and a reinforced concrete slab, leaving a hole where the well is to be positioned. This cellar serves to create a clear work area where the future wellhead will be located, and its depth must be in keeping with the height of the safety equipment necessary in the drilling stage. The
size of the cellar varies according to the type of rig and wellhead, and will be between 2 and 3 m in depth, with an area of about 10 to 15 square metres. The waste pits are excavated with sloping sides, 2-3 m deep, and measure up to 100 square metres or more in area; they are waterproofed with sheets of PVC and sometimes with layers of bentonite. When the drilling site preparation works have been completed, the first well-construction operation will be carried out, i.e. the installation of the conductor pipe, a 10-50 m long steel pipe having a diameter of 70-100 cm. If the subsoil is composed of loose sediments, the conductor pipe is fixed using a piledriver analogous to the one used in civil engineering for fixing foundation piles.

The site must, by law, be large enough to store inflammable or dangerous materials at a safe distance from the wellhead. Furthermore, it must enable a flare to be set up, to burn off any hydrocarbons that might come to the surface during drilling, and it must allow the safety line for the derrickman to be anchored at a safe distance (see Section 3.1.3). At the end of drilling operations, if the well turns out to be dry, the location is restored to its pre-existing environmental state and is handed back to its owner; if instead the well is productive, production equipment is installed on the wellhead and it is permanently fenced into a smaller area of a few hundred square metres.

During the drilling of a well, the most important function on site is supervising and verifying the drilling operations. This job is assigned to a representative of the operator, known as the drilling assistant. This person must be fully qualified and of proven technical and decision-making competence, and is assigned the task of implementing the well project as drawn up in the programming stage, fixing the working sequence for site activities. The drilling assistant orders and controls the proper implementation of every operation, supervising safety measures and informing the central control office of the progress of operations. Service companies (contractors) also frequently operate on the location for the execution of specialist operations (cementing, logging, geological assistance, etc.). A number of contractors have their own team on site with a representative; other contractors instead operate on a call basis, for short periods. The actual handling of drilling operations is assigned to a special drilling crew, whose numbers vary from rig to rig. Generally speaking, in onshore locations there is a foreman (crew chief), in charge of site equipment, a driller, a derrickman, three drill assistants, one site man, maintenance hands (electrician and mechanic) and one or more watchmen. The driller works on the derrick floor, in control of all drilling machinery and carries out the sequence of operations scheduled for making the hole. The derrickman operates on a platform inside the derrick and controls the pipes in the stem rack during tripping operations. The drill hands, headed by the driller, see to screwing on (break-in) and unscrewing (break-out) the joints of the pipes during drilling and tripping operations, and keeping the derrick floor clean. In offshore drilling rigs, the crew is more numerous and specialized, as higher standards are set for such operations. All drilling site personnel work in day shifts, generally of twelve hours each. In fact, drilling is never suspended, except in just a few of the phases, because of the high cost of renting the rig.

### 3.1.3 Hoisting system

The hoisting system is the set of equipment necessary for handling any material inside the well, in particular the drill string and the casing. It consists of a structural part (derrick and substructure), the complex of the crown and travelling block, the drawworks (hoist) and the drilling line. The substructure is the supporting base for the derrick, the drawworks and the rotary table, and constitutes the working floor for operations, or drilling floor, being elevated with respect to ground level. The substructure is a reticular structure of steel beams, that can easily be dismantled, and rests on concrete foundations or on a base of wooden planks around the cellar. Its height varies from a few metres up to 10 m in the largest rigs, and must be such as to permit the assembly of the safety equipment on the wellhead.

The derrick is an open-framework structure of steel beams, whose function is to hold the ensemble of sheaves at its top, known as the crown block, on which all of the items of equipment operated in the well or on the drilling floor are suspended. It must also contain the drill string during tripping, subdivided into lengths (i.e. 2-, 3-, or 4-piece sections of drill pipes screwed together called stands) depending on the height of the derrick. In fact, the height of the derrick must be such as to permit the vertical movement of the travelling block for a distance greater than the equivalent of one stand. For example, to handle a stand of 3 drill pipes (about 27 m long) the derrick has to be about 40 m high. The derrick is designed to resist the loads tripped in and out of the well in the operating phases, which induce both static and dynamic stresses. Every derrick has a rated load capacity, defined by API (American Petroleum Institute) standards, which establish the maximum hook load. On the basis of their construction characteristics, derricks may be classed as conventional ones (derrick) or mast type, according to the way in which they are assembled and dismantled.
A derrick (Fig. 2) is a structure of steel beams or tubes that can be completely dismantled and reassembled. The elements forming the derrick are relatively small and can easily be handled; nevertheless, the assembly of the entire structure requires quite a long time. Derricks, once made of timber, were the most usual type of structures until the 1930s, when they started to be replaced by mast-type structures, which were easier to operate. Facing one side of the derrick in the drilling site there is a pipe yard where all the tubular materials that have to be lowered into the well (pipes, casing, etc.) are placed on a rack. The pipe yard is connected to the drilling floor by an inclined slide, making it easier to pick up the pipes. About two-thirds of the height of the derrick is the derrickman’s platform, which stands out for about 1 m, and on which the derrickman works during tripping, helping to stack the pipe lengths tripped out from the well on a special pipe rack. The derrickman’s safety line is hooked onto this platform; this is a cable anchored to the ground at a suitable distance, enabling the operator to make a quick getaway with a cableway if there is danger of a blowout. Nowadays derricks, although more stable and robust than masts, are only used on platforms for offshore drilling, where the structure never has to be dismantled.

The mast (Fig. 3) is a structure of modular, preassembled steel beams, hinged with lock-pins, which can be raised or dismantled in a few hours. Obviously the mast possesses all the functional capacities of a derrick. Masts are generally self-elevating. After the girders of the substructure and of the drilling floor have been placed above the cellar (these also having been preassembled in modules), and the various parts of the mast have been assembled horizontally on the site, alongside the substructure, the mast is raised into a vertical position using cables and the drawworks supplied with the rig. Light and medium rigs, with reclinable masts, can also be self-propelled (portable masts) as they are mounted on trucks. They are used to carry out maintenance jobs on wells in production, or to drill water wells, that is, operations that do not take much time, and that therefore require the use of a rig that can be transferred rapidly. Portable masts have less resistance to horizontal loads (e.g. due to the wind) and so it is necessary to guy them with steel cables. For particular situations of difficult logistics, e.g. drilling in inaccessible or high mountain areas, block-assembled rigs are available, as they are easier to transport by helicopter or by plane.

As has been mentioned, the sheaves of the crown block are situated at the top of the derrick. The mechanism, with a fixed (crown) block and a mobile (travelling) one, consists of an ensemble of sheaves linked by a wire rope, worked by the drawworks (Fig. 4 B). The crown block bears the load applied at the hook and its function is to reduce the wire rope tension required to pull the tubular material used to drill the well. It at the top of the rig consists of a set of sheaves (usually from 3 to 7) supported by a framework of steel beams. The travelling block consists of another set of sheaves (one fewer than for the crown block), mounted on an axis connected to the hook (Fig. 4 A). The number of sheaves in the crown and travelling block is chosen on the basis of the rated capacity of the tower and the rate of pulling, which is inversely proportional to the number of lines of wire rope connecting the travelling block and the crown block; the number of lines also defines the tension to be supplied by the drawworks. The hook consists of an upper section, fixed to the travelling block, and a lower section, which is the actual hook. The two sections are not rigidly joined, but connected by a spring resting on a bearing, which allows the hook to rotate and damps hook load during lifting. In modern rigs the travelling block and the hook form a single unit. The hook is characterized by its rated load capacity, which in the largest rigs can even exceed 500 t.

The drawworks is the machine that transmits the power to operate the equipment in the well. The basic
components of the drawworks are an engine, one or more drums containing a steel cable, and the brakes (Fig. 5). Apart from the engine, described below, the drawworks is made up of the following elements: a main drum (hoisting drum), around which the drilling line (used for tripping the drill string and the casing elements and for raising and lowering the mast) is wound; a fast drum, smaller in diameter than the hoisting drum, around which a smaller wire rope (used for the rapid manipulation of relatively light material) is wound: and the braking system, consisting of a main brake and auxiliary brakes, placed at the sides of the hoisting drum shaft. The main brake is a strongly-built, band brake, used to stop the drill string as it is being lowered, or to release it slowly during drilling. The band brake is the only device that can stop the drum completely, and is used mainly for this purpose. Its use as an energy dissipator is limited, as the ribbons would become worn out too quickly. To limit wear on the ribbons, the hoist also has auxiliary brakes. Normally a hydraulic brake and an electromagnetic brake are used, although these cannot stop the hoisting drum completely and they cannot be used alone. The advantages of using the electromagnetic brake are that there are no parts in contact and therefore subject to wear and tear, that it is easier to adjust than the hydraulic brake and that it exerts a braking action even at slow speeds. But it must be kept in mind that lack of electric current causes the instantaneous interruption of the braking effect. Finally, very often the drawworks is fitted with a gear change and a clutch, to permit a power uptake also at low speed. The mechanical or hydraulic gear change serves to optimize the use of the power supplied by the engine.

The drilling line contained in the hoist drums consists of helically-wound steel-wire strands around a plastic, vegetable fibre or steel core. The first end of the drilling line (fast line) is wound around the hoist drum, after which it passes alternately over the sheaves of the travelling block and of the crown block, while the other end (dead line) is anchored to an element of the substructure. The tension of the line is measured on this anchorage, and this makes it possible to calculate the weight of the equipment suspended from the hook (e.g. drill string, casing, etc.). Through being wound around the drum and over the block sheaves, the line is subject to wear and tear, to weakening of the wires (due to local overheating) and to fatigue due to cyclical variations of tension in the winding over the sheaves and the drum. One method of assessing the state of wear and tear of the drilling line is visual inspection, but this is uncommon because of the uncertainty involved, the
practical difficulties and the time required. A more objective method is to associate the wear and tear of the drilling line with the work actually performed, which can be calculated as a function of the distance travelled under load, and fixing a maximum admissible limit. The work done by the line varies between very broad limits and depends on the number of operations carried out. So as to have a line that is always new in the points of greatest wear and tear, it is periodically allowed to slip along its route, winding one section around the hoist drum and unwinding an equal section from a back-up drum containing new line, situated below the anchorage of the dead line. This operation, called slipping and cut-off, is performed when a given value of the work carried out by the line has been reached. After repeated slipping, there is no more space available on the drum and cut-off takes place, which consists of removing 2 or 3 layers of the drilling line wound up in the slipping. The time required to perform a slipping is minimal, whereas that for a cut-off is much longer.

3.1.4 Rotation system

The system of rotation is intended to cause the drill string to rotate, and it consists of the rotary table, the kelly and the swivel (Fig. 6). In modern rigs there is often also a top drive which groups together the functions of the three items of equipment mentioned above. In particular cases it is preferred to make only the drill-bit rotate by means of a downhole motor (as these motors are an integral part of the drill string, they will be described together with the other components thereof).

The rotary table, located on the drilling floor (or rig floor), is composed of a fixed base which supports, by means of bearings, a rotating platform with a central hole. The lower part of the rotating platform has a crown gear into which fits a pinion, operated by a motor. The rotary table makes the drill string rotate and supports its weight during operations or during the connection of a new drill pipe, when it cannot be borne by the hook. During the connection of a new drill pipe (or of a section of casing), the string is suspended over the central hole of the rotary table by means of slips and the entire load supported by the hook is transferred from the derrick to the drilling floor supporting beams. The rotating platform of the rotary table houses the master bushing which can be removed to allow equipment with a large diameter to pass through. The master bushing, when in its normal working position, enable the slips to be lodged for hanging the drill string during tripping or new pipe connection, and permit the insertion of the kelly bushing which causes the kelly to rotate, the kelly bushing (or four-pin drive kelly bushing) being plugged into holes in the master bushing. The rotary table, standardized to API regulations, is defined by the nominal diameter going through the central hole (usually between 20" and 50") and by the load it is able to bear. The power of the rotary table depends on the depth of the hole (most of the power required to make the drill string rotate is in fact dissipated in viscous friction in the mud and in sliding friction against the walls of the hole) and ranges from a few tens up to a few hundred kW, while the velocity of rotation depends on the drilling operation and can be regulated from a few tens up to about 140 revs per minute.

The kelly is a pipe of square or hexagonal section that transmits the motion of the rotary table to the drill string. It receives this motion from the kelly bushing, to which it is joined through a sliding coupling, so that it can move vertically also when it is engaged in transmitting the rotation. Thanks to this it is possible to continuously regulate the weight on the bit without interrupting the rotation. Until the 1940s square kellys were used, but now hexagonal kellys have replaced them. The latter are stronger and are also balanced dynamically so as not to vibrate during rotation. The kelly is longer than a drill pipe, because the vertical movement in the rotary table must allow a new pipe to be added, at the same time keeping the bit at a safe...
distance from the bottom of the well. Kellies are normally 12-16 m long, to which corresponds a useful sliding length of 11-15 m, respectively. For safety reasons the kelly is fitted with two internal valves, one at the bottom and the other at the top, which are useful in the well control phase.

The kelly is screwed to the swivel, which is the point of connection between the rotating drill stem (or drill string), the hook and the non-rotating mud hose. The swivel has a fixed and a mobile part, and has the twofold function of supporting the rotating drill string and of connecting the mud hose with the inner part of the pipes. The swivel is a very robust mechanism, able to support a strong rotating axial load, through an oil-bath thrust bearing, guaranteeing, at the same time, a perfect hydraulic seal. The mud injection pressure can in fact exceed 30 MPa and the weight of the drill string 200 t. The swivel, suspended from the hook by means of a robust steel handle (or bail), follows the vertical movements of the hook and therefore must be connected to the standpipe by a flexible pipe made of steel-wire reinforced rubber (mud hose).

The top drive is a relatively recent piece of equipment, introduced towards the mid-1980s, grouping together in a single unit the equipment for connecting the drill pipes, rotation of the drill string and circulation of the fluid (Fig. 7). By using the top drive, it is no longer necessary to have a kelly and a swivel, and in theory the rig could even do without the rotary table. The basic parts of the top drive are a small injector head (swivel), an electric or hydraulic motor which enables the drill string to rotate, and an automated pipe handling system. The top drive unit is suspended from the hook and is guided by two vertical rails fixed to the derrick, which provide the reactive torque necessary to prevent the rotation of the whole complex and to allow free vertical movement.

The use of the top drive instead of the rotary table offers numerous advantages, including: a) the possibility of ‘drilling by stands’ (adding the pipes by stands, and not individually), allowing greater control of drilling; b) the reduction of the time required to connect the pipes, with less risk of accidents for drilling operators; c) the possibility of performing the trip-out operation while circulating mud and rotating the string (back reaming), impossible with the rotary table and useful for preventing the drill string from becoming stuck; and d) the possibility of obtaining

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**Fig. 6.** System of rotation with rotary table: A, kelly inside the rotary table with details of the drill string; B, close-up of rotary table components.
longer cores, as intermediate connections are eliminated. However, the system has a number of disadvantages, such as the structural modifications that have to be made to the rig to be able to house the top drive (the rails, strengthening the derrick to withstand torsional stresses, the greater height of the derrick due to the fact that the top drive system is longer than the swivel), the presence of superelevated live loads and electrical and hydraulic service equipment. Moreover, as the system is quite complex, the top drive is rather costly and subject to frequent maintenance. In spite of this, the top drive represents the major technological advance in rotary drilling in the last half century, and its use—absolutely essential in modern rigs—has enabled drilling times to be significantly reduced.

**Equipment for handling the drill string**

On the rig floor there are certain supplementary items of equipment not strictly forming part of the rotary system, but which serve for tripping the drill string when the rotary table is in use, or for connecting a new pipe. To be able to carry out these operations, it is necessary to suspend the drill string inside the master bushing of the rotary table using special slips. These are a sort of collar that can be opened, and are composed of metal segments with internal dies having hardened steel teeth, and of external truncated cone shape. Slips of traditional type are positioned by hand inside the master bushing; by slightly lowering the drill string, the slips are forced to grip the outer surface of the pipe, enveloping it and supporting it with a clamping effect (Fig. 8). In modern rigs automatic slips are operated hydraulically, however, to fasten and unfasten the pipes, wrenches called tongs are needed, which is a sort of big adjustable spanner. Two tongs are necessary to fasten the pipes, one of them fixed to one of the derrick legs, which blocks the lower drill pipe suspended from and wedged in the rotary table, and the other one mobile, operated by a cable running from a winch or by a hydraulic piston. The latter grips the upper pipe and rotates it, so that it
can be screwed (break-in) and unscrewed (break-out). In modern rigs, pneumatic or hydraulic power tongs are used, these having the advantage of applying exactly the torque required for breaking-in, limiting the wear and tear on the thread.

### 3.1.5 Circulation system

The circulation system consists of mud pumps, distribution lines, and the mud cleaning and accumulation system (Fig. 9). It is the closed hydraulic circuit which allows the mud to flow from the surface to the bottom of the hole, inside the drill string, and subsequently back to the surface, in the drillstring-borehole annulus. The mud from the hole has to have the cuttings removed before being reinjected to the bottom of the hole.

The mud pumps supply the energy necessary for circulation. They are generally positive-displacement piston pumps, because of the greater head these provide compared with other types of pump, e.g. centrifugal pumps. Mud pumps, with 2 or 3 pistons (duplex or triplex pumps), may be single – or dual-acting, and receive their power from an electric motor independent from other uses. The pistons are of rubber-lined steel to obtain a good seal and to lessen the wear and tear on the cylinders, due to the abrasive cuttings suspended in the mud. The pump cylinders and pistons are interchangeable, with different diameters, so as to be able to vary the flow rate and adjust it to the requirements of the well. Obviously, the flow rate is a function of the piston diameter, of the stroke and of the rate of rotation of the driving shaft, and is in the range of a few m³/min. The ever-increasing depth reached by the wells and the

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**Fig. 9.** System of mud circulation.
The items of equipment that separate the cuttings, removed by the mud at the bottom of the hole, are called shale shakers and hydrocyclones. The mud exits from the well through a large pipe and is first conveyed to the shale shakers which separate the majority of the cuttings. The shale shaker is a device fitted with one or more overlapping screens of various mesh sizes, slightly tilted and caused to vibrate by rotating shafts unbalanced by eccentric masses. The form, amplitude and frequency of the vibrations depend on the characteristics of the mud to be treated, and must be easily adjustable so as to optimize the minimum time on the screen. The dimension of the cuttings removable by the shaker depends on the mesh size used, even if in practice it never goes below 100 μm. The finest particles (fine sand and silt) are removed downstream of the shakers, by means of the hydrocyclones. In the more sophisticated rigs, two batteries of hydrocyclones in series are adopted. The first series is employed for separating the fine sand (down to 70 μm); usually these are two hydrocyclones, called desanders, arranged in parallel, and are able to treat the entire circulation flow. The second series serves to separate the silt (down to 30 μm), and is formed by several smaller-diameter hydrocyclones, called desilters, which perform a more accurate separation. To eliminate even smaller solid particles (e.g. to recover the barite, the material used to increase the density of the muds), centrifuges are used, i.e. cylinders rotating at high speed, which are also employed for dehydrating the exhausted drilling mud and cuttings before they are conveyed to the dumps. The cuttings are stored in waste tanks or in a concrete pit constructed under the shale shaker. They are transported periodically to authorized dumps, possibly after being treated in conformity with their degree of contamination by chemical agents or by hydrocarbons.

During drilling the gas contained in the pores of the rocks might enter the well and form a solution or emulsion with the mud. The in-flow of small quantities of gas is inevitable when drilling through gas-saturated rocks, but there could be appreciable in-flows when the pressure of the mud at the bottom of the hole becomes less than that of the gas contained in the rock pores. Small quantities of gas in muds of low viscosity are liberated on the shaker, by simple aeration. If this is not sufficient, the entire mud load is sent to specific units called degassers. These are special vessels that operate according to two different principles, either by depression with a vacuum pump or by mechanical agitation and turbulence. The separated gas is then burnt in the flare installed at a safe distance from the rig.

Downstream from the mud cleaning system there are various storage pits or tanks. The active mud pits, as they are called, contain the mud that circulates in the well. The reserve pits contain the mud to make up any circulation losses, while other pits contain the heavy mud, ready for prompt use in the event of loss of hydraulic control of the well. These pits are robust rectangular containers of sheet steel, each with a capacity of 30-40 m³. For safety reasons the overall capacity of the mud pits must be more than half the volume of the well, which is in the order of some hundreds of cubic metres. Each pit is provided with mechanical or pneumatic agitators or stirrers to keep the mud homogeneous. At the outlet of the active pits the mud is scooped up by a centrifugal pump which sends it back to the mud pumps at a pressure of a few bars, to improve the volumetric efficiency. It is recalled that during operations the volume of the mud in the well must be compensated for the volume of the pipes removed or added so as to keep the hydraulic head at the bottom of the hole constant. A cylindrical filling tank called possum belly, which is located alongside the shaker, is used for this purpose. During tripping-out operations, the level of the fluid in the well sinks and is made up with the fluid contained in the possum belly, which is fitted with a level gauge in
order to determine the correct make-up volume. Obviously the opposite is the case for tripping-in operations.

### 3.1.6 Power generation and distribution system

In a drilling site power is needed to run the machines driving the main components of the rig, such as the drawworks, the pumps, the rotary table and the engines of the various auxiliary facilities (compressed air, safety systems, centrifugal pumps, lighting, services, etc.). Ideally, it would be convenient to obtain electricity from the public network, but this is rarely possible, because of the remote location of the majority of the sites, and it is therefore necessary to produce power on the various sites using prime movers. In the past the prime movers used in drilling sites were steam engines, which, while having certain undoubted advantages (characteristic curves suitable for direct connection to users, robust construction, ease of use), have been abandoned due to their low efficiency, heavy weight and huge water consumption.

At present the prime movers used are Otto or diesel cycle internal combustion engines, or else turbogas units, used only where low-cost methane is available. The disadvantage of internal combustion engines is that they cannot be directly coupled with user facilities, but this is offset by their easy transport, high efficiency and convenient fuel supplies. Drilling rigs are classified by the way in which power is transmitted from the prime movers to the main facilities, distinguishing between mechanical and electrical drive rigs (diesel-electric if the prime mover is diesel).

In drilling rigs with mechanical drive the power produced by the prime movers is transmitted to the main users by a system of chains and sprockets, or belts and pulleys. This transmission system is controlled with the help of clutches and gearboxes, which allow power to be conveyed to the required unit. The engines must be located close to the main user units, thus making the layout of the rig more complicated. Moreover, the characteristic curve of internal combustion engines is not suitable for direct connection to user units and therefore it is necessary to insert a gearbox, which enables the characteristic curve of the engine to be approximated to that of the user unit. Another problem is the power take-off at low running speed, as internal combustion engines do not supply power at a low number of revolutions. It is thus necessary to insert a clutch (only on small rigs, as beyond a certain power it is quickly burned out), or else a hydraulic joint or a torque converter. The hydraulic joint is a component formed by two rotors immersed in an oil bath, placed between the engine and the user unit. During start-up, the engine shaft can supply a constant torque even if the user shaft is stopped (slippage of the joint equal to 100%, efficiency nil), hence allowing a gradual power off-take. During normal operation, however, the slippage of the clutch is low (2 to 8%) and therefore the efficiency is high. The torque converter is a sort of hydraulic joint which, in addition to allowing a gradual power take-off, makes it possible to vary the speed and the torque, thanks to the insertion of a stator between the rotors. The hydraulic torque converter acts in practice as a gearbox, which, however, vies against the efficiency, which during normal operation does not exceed 85%. Mechanical-drive rigs were very widely used in the past, but nowadays their use is limited to rigs of low and medium potential. The mechanical drive efficiency varies between 75 and 85%, according to whether or not there is a torque converter.

In high-capacity rigs more flexibility in the layout of the equipment and precise control of the power supplied are required. For this reason more flexible electric (or, more precisely, diesel-electric) rigs have been developed, which are less bulky and lighter than mechanical-drive rigs. In diesel-electric rigs, the main user units (the drawworks, the pumps and the rotary...
The following are therefore the components that permit the generation, distribution and use of power: prime movers, which transform the fuel into mechanical power, generators, which convert the mechanical power into electrical energy, a power control cabin, electricity lines, and lastly the DC (Direct Current) or AC (Alternating Current) motors of the various units. Usually the motors of the main units are DC, and are preferred to AC motors because of their capacity to vary the speed continuously, supplying a high torque value whatever the running conditions.

Two types of electric drive exist: the first with DC generation and DC user units (DC-DC drive), and the second with AC generation and DC user units (AC-DC drive). In the case of DC-DC drive, the electric engine of each main unit is connected directly to a DC generator, worked by a prime mover (usually diesel). In a medium-size rig there are 4 prime movers and 3 or 4 motors for the user units (one for the drawworks, one for each pump and, sometimes, one for the rotary table). In large-size rigs there may be as many as 8 motors. The advantage of the DC-DC drive system is its excellent efficiency, as the current does not have to be rectified. The disadvantage, however, is that of being a rigid system, as each DC generator is connected to its own user unit, and passage from one unit to another is not very flexible. In contrast, the AC-DC drive is a system formed by prime mover units (usually diesel motors) connected to AC generators, which supply all the user units without being linked to a specific one, through an power control cabin (Fig. 10). In this way the power of the prime mover can be used rationally, stopping some units when the power required diminishes. Moreover, AC generators, although larger in size, are less complicated and costly than DC generators. If the main user units have DC motors, for ease of control of the rate of rotation, it is necessary to rectify part of the current by means of a rectifier. However, nowadays DC motors are more and more often being replaced by AC motors controlled by an inverter, which allows the rate of rotation to be controlled very effectively.

3.1.7 The drill string

The drill string is an assemblage of hollow pipes of circular section, extending from the surface to the bottom of the hole. It has three functions: it takes the drilling bit to the bottom of the hole, while transmitting its rotation and its vertical load to it; it permits the circulation of the drilling fluid to the bottom of the hole; and it guides and controls the trajectory of the hole. Starting from the surface, it consists of a kelly, drill pipes, intermediate pipes, drill collars and a number of accessory items of equipment (stabilizers, reamers, jars, shock absorbers, downhole motors, etc.), and it ends with the bit (Fig. 11).

The drill pipes are hollow steel pipes of various types, with two tool joints welded at their ends (Fig. 12). They are standardized according to API standards and classified on the basis of their length (usually about 9 m), their outside diameter, their linear weight and their steel grade. The most common drill pipes are the following: 3.50" (13.30 lb/ft), 4.50" (16.60 lb/ft) and 5" (19.50 lb/ft), in which the first figure indicates the outside diameter of the pipe body and the one in brackets the linear weight. The grade of the steel is expressed by a letter, indicating the type of material, followed by a number which indicates the minimum yield strength. The tool joint is the element that enables the pipes to be joined and it has a large-pitch conical thread and a triangular profile, allowing a fast and secure connection with just a few pipe rotations. The tool joints are not manufactured in the body of the pipe, but separately, and are connected by friction welding. They can be threaded a number of times; in this way, having to replace pipes in good
condition because of damaged threads is avoided. The tool joints have a slightly larger outside diameter than that of the body of the pipes, this being necessary to guarantee an adequate wall thickness in correspondence to the thread. They have to ensure hydraulic seal between two connected tool joints: this hydraulic seal takes place at the precision-ground annular surface at the end of the thread. The seal is a metal-to-metal type, established by the make-up torque. The threads of the tool joints are periodically checked and can be reground on site.

During drilling operations the weight of the drill string is sustained by the hook, except for a small part transferred to the bit. The weight necessary for the bit depends on the type of rock, the characteristics of the bit, the velocity of rotation, etc., and is in the region of 10-20 kN per inch of the hole’s diameter. Operating in this way, when the bit is drilling, the top part of the string is in tension, while the lower part is in compression; the length of the two sections depends on the weight applied on the bit. Drill pipes, being relatively slender and thin-walled, are affected by buckling and cannot withstand compression, and so they bend and break through axial compression. It is therefore necessary to assemble the lower part of the drill string, that subject to compression, with stronger pipes, suitable to safely withstand compression. This is achieved by using pipes of larger wall thickness, called drill collars, which are stiffer and have more linear weight compared to drill pipes. So as not to risk compressing the drill pipes, it is good practice to oversize the length of the string of drill collars (also known as the Bottom Hole Assembly, BHA) usually by 30-50% compared with the length necessary to provide the weight on the bit. In this way the neutral section is always inside the stretch of the drill collars, at about 2/3 of the length of the BHA. The drill collars have a thick wall, are made out of solid steel bars, rounded externally, bored on the inside and with threaded ends directly on the body, with threading analogous to that used for ordinary pipes. The drill collars are 9 to 13 m in length and their outside diameter is between 3.125” and 14”. They are also standardized (API), with the most common diameters being 9.50”, 8” and 6.50”. Drill collars made of non-magnetic steel also exist, and are used in directional drilling so as not to influence the sensors that measure the earth’s magnetic field. They are manufactured with stainless steels (alloys of K-Monel type) or with chrome-manganese steel alloys.

Connecting pipes having very different diameters leads to concentrations of tensions and to fatigue in the area where the cross-section varies. This coincides with the location of the threading, which is already a weak area. Therefore, it is not possible to join drill pipes directly with drill collars, as this would create a weak area in correspondence to the joint. To avoid the danger of breaks in the drill string, a short stretch of intermediate heavy-wall or heavy-weight drill pipes is inserted. These pipes, connected by long, strong tool-joints, can even withstand compressive stresses. Using heavy-wall drill pipes allows drill pipes and drill collars to be connected without any abrupt diameter changes. The heavy-wall drill pipes are normally made with the same outside diameter as the drill pipes, but with a smaller inside diameter. In practice, they are drill pipes with thick walls, having a linear weight two or three times greater.

Fig. 12. Section of a tool joint.

Fig. 13. Stabilizer (courtesy of Eni).
Accessory equipment

The drill string is very often fitted with accessory items which serve to resolve technical problems due to the wide variety of drilling conditions. The most common accessory items of equipment are stabilizers, reamers, jars and sock-absorbers, which do not form part of the rig facilities, but are hired from special service companies.

Stabilizers are placed along the BHA, in between the drill collars, to make the string more rigid in the presence of the instability due to combined compressive, buckling and bending stresses, and they are fundamental for controlling the borehole trajectory, both in vertical and in directional wells (Fig. 13). They consist of a body to which rib blades are applied, expanding the outside diameter of the tool to the nominal diameter of the bit. The blades are of spiral shape to help the flow of the mud. By changing the composition of the BHA, and in particular the positioning of the stabilizers, the mechanical behaviour of the drill string can be varied, which is useful in controlling the directional drilling operations.

Reamers are special stabilizers featuring roller-cutters instead of blades (Fig. 14). On the rollers, usually from 3 to 6 in number, steel cutters or tungsten carbide inserts are mounted. They serve the purpose of reaming wall of the hole, taking it to the nominal diameter of the bit, and in the process eliminating the small variations in diameter and any possible stepped profile there might be in the hole, which could make the application of the weight on the bit uncertain (the stabilizers might settle on them) or cause problems with running-in the casing. Reamers are used chiefly in drilling through streaks of hard and abrasive rocks.

The jar is a mechanical or hydraulic piece of equipment, positioned on the neutral point of the BHA (i.e. the point where the stress acting on the drill string changes from tension to compression), making it possible to give upward bumps in the case of the drill string getting stuck (the equipment is known as a bumper if it is able to give downward bumps). It consists of two sliding liners ending in a hammer and an anvil. The jar is activated by pulling the drill pipe. Under tension load, the hydraulic jar becomes elongated, as between the two liners there is a system consisting of two oil-filled communicating chambers separated by a piston. Because of the shape of the cylinder and the piston, the fluid flows slowly through the first part. After which, a change of section of the piston causes the remaining part of the stroke to occur suddenly, giving the hammer an acceleration so that it knocks against the anvil, discharging the elastic energy accumulated. The mechanical jar functions according to the same principle, but the operation is regulated by a clutch system.

Downhole motors

In traditional rotary drilling the bit is set in rotation, together with the whole drill string, by the rotary table or by the top drive. Bottomhole motors, of relatively recent use, allow the rotation to be applied to the bit alone. They are hydraulic machines at the end of the string, screwed directly onto the bit, and the entire mud flow goes through them, part of
the mud pressure being converted into rotary motion and torque. In this way, the rotation necessary for operating the bit is supplied by the downhole motor, while the whole drill string can remain stationary, or may be rotated, if necessary, with the rotary table or the top drive. The use of such motors is essential both for directional drilling and for the application of modern techniques for controlling the vertical trajectory of wells. Downhole motors, an integral part of the BHA, are axial-flow machines of tubular shape and are similar in size to a drill collar. There are two types of downhole motors: turbines and PDMs (Positive Displacement Motors). These motors do not form part of the standard equipment of the rig, but are hired from service companies, which also supply the personnel specialized in using them and which look after their maintenance. The use of these motors has to be justified from the economic standpoint.

Turbines are rotating, open-type turbo-machines fitted with rotors and stators arranged in series in a multistage pattern (Fig. 15). The mud stream flows through the entire turbine and, alternating between a rotor vane and a stator vane, is deviated, thus causing the motor shaft to rotate. Naturally, the power supplied by the turbine is produced at the expense of a decrease in the mud pressure when it leaves the turbine, and is a function of the number of stages of the machine, which is proportional to its length. The turbine shaft is fitted with axial and radial bearings to support the loads in the drilling phase. Turbines develop high power and above all a high rate of rotation, which is often incompatible with the use of three-cone bits; for this reason turbines are being developed with a mechanical speed reducer. They have a very long bottomhole life (in the order of hundreds of hours) and can also be used in very deep wells, having no particular limitations with regard to operating temperature.

PDMs are rotating, closed-type volumetric machines, characterized by a drive section different with respect to that of the turbines (Fig. 16). Their internal architecture is in fact the evolution of the Archimedean screw pump. PDMs are Moineau pumps made to operate in the opposite direction, whereby the motor shaft is caused to rotate by forcing the mud through it under pressure. The drive section of a PDM consists of two elements, the rotor and the stator. The rotor is a spiral shaft made of steel, with one or two lobes. The stator is a rubber tubular sheath internally shaped like a spiral but with one lobe more than the rotor. Furthermore, it houses the rotor, and is integrated into the outer housing of the motor. When the rotor is inserted in the stator, the geometrical difference between the two components creates a series of cavities. The mud, which is forced past the stator and the rotor, fills these cavities, and causes the rotor to rotate continuously. The special geometry of this machine enables it to be operated with all drilling fluids, including gaseous ones. In general, PDMs rotate appreciably slower than turbines (in fact, they are also compatible with three-cone bits), they are shorter than turbines (which is an advantage in numerous applications of directional drilling) and they are easier to maintain, even though the rubber stator can have limitations due to temperature and to its incompatibility with some oil-based muds.

3.1.8 Bits

The bit is connected on to the end of the drill string. The bit is the tool that bores the rock, transforming it into fragments called cuttings, which are then transported to the surface by the drilling fluid. The choice of the type of bit depends on the hardness, abrasiveness and drillability of the rock formation. There are three basic
rock-cutting mechanisms (Fig. 17): compression (suitable for rocks with an elastic behaviour); shear (suitable for rocks with a plastic behaviour); and shear and abrasion (suitable for abrasive rocks). The bit is designed to drill in various ways, according to the behaviour of the rock, which may be of elastic or plastic type, or – far more frequently – a combination of both, and according to the drillability and the abrasiveness of the formations. It follows from this that there is an extremely vast range of bits, all different from each other, which are able to respond effectively to the most varied drilling conditions.

The first bits used in rotary drilling (which asserted itself industrially in the early part of the Twentieth century) were similar to those used in cable-tool drilling, but adapted to the different drilling mechanics. They were fixed blade bits, referred to as ‘fishtail’ bits due to the shape of the blades, which were very effective in drilling soft formations, but entailed problems related to the rate of drilling and wear and tear in hard formations. In 1909 the first roller cone bit, which proved very effective in drilling through hard rocks, was produced and tested. At the beginning of the 1930s, the three-roller (or tricone) bit was introduced, and in the course of the years has undergone countless modifications and improvements. In the early 1950s, bits with natural diamonds were also produced. In spite of this, the tricone bits were the most commonly used in rotary drilling until the mid-1980s. Towards the end of the 1970s, studies and experiments started on Polycrystalline Diamond Compact (PDC) type bits, and from the beginning of the 1990s these became a viable alternative to tricone bits. However, competition with PDC bits stimulated intense research and technological development of the tricone bit in the 1980s and 1990s. At the start of this millennium the PDC bit became more popular than the tricone type, at least as far as the commercial value of the tools produced was concerned. In spite of this, tricone bits are high technology tools, and in drilling operations they still have a sufficient number of applications to indicate that their obsolescence on the market is still a long way off.

All bits are made in API standardized nominal diameters, from 3.75" up to 26". It should be observed that beyond 17.50" tricone bits are almost the only existing type. It is recalled that there are also coring bits, used in coring operations, i.e. during drilling to obtain cylindrical samples, commonly called cores. Coring bits are characterized by their ability to drill only an annular cross-section of rock, leaving intact the core. Coring operations are described in Chapter 3.3.

**Tricone (three-cone) bits**

The tricone bit drills the rock by means of chipping and crushing, combined with shearing and scraping, and is also well suited to drilling hard rocks (Fig. 18). The tricone bit consists of three legs and three cones (fitted with cutters) assembled on special journals machined on the legs, with a bearing in between that allows the cone to rotate freely. The three legs, once the cones (or roller cutters) have been mounted, are welded together to form the bit. The legs and the cones are manufactured by a series of precision mechanical operations (forging, milling and grinding), in order to make the bearing and the cutting structure according to the geometrical shapes of a cone and a journal, respectively, which, during use, privilege scraping to crushing. During drilling, the weight of the bit causes the cutter to hit the rock, while the rotation forces the cones to rotate and the cutters to scrape along the bottom, producing the cuttings.

The cutting structure of a tricone bit may be either of the ‘milled tooth’ or tungsten-carbide insert type. The shape, material and pattern of the cutters on the cones depend on the drillability of the formation. In general, soft formations are drilled with long and slim cutters with a low spacing. The extension of a
The cutter (long or short) is defined as the distance between the tip of the cutting edge and the base of the cone, while its being slim or flat is a function of the angle at the top of the cutting edge and the spacing (or pitch) is the distance between one cutting edge and the next one, which expresses the total number of cutters that may be located on each row of the roller cutter. Steel teeth are produced by milling the cones and are subsequently hardfaced with a hard metal deposited by fusion, while the tungsten-carbide inserts are pressed into special holes bored in the cones.

The bearing is the mechanical coupling system between the cone and the journal, and allows the free rotation of the roller cutter. Bearings are designed to rotate under conditions of very high loads, and have to stand up to the wear and heat generated by friction without suffering damage (Fig. 19). If, due to excessive wear, the mobile parts of the bearing (balls, rollers or other elements) get out of position, they can cause the bearing to become blocked or even the loss of the cone at the bottom of the hole. The most critical point of the bearing is the rotating seal, a mechanical device constructed from either rubber or metal parts. Recent technology has made available numerous engineering variants both in the design and in choice of materials, all covered by international patents. Tricone bits are compatible with the typical speed of rotation of the rotary table, in the region of 100-150 rpm, and sometimes do not adjust well to applications with downhole motors.

The drilling fluid issues from the bit through nozzles located in the space between the cones. These nozzles are made of tungsten-carbide with a tapered shape and with a calibrated central hole which makes it possible to accelerate the outlet velocity of the mud (up to about 50-100 m/s) and to achieve an adequate head loss at the bottom of the hole, according to the well hydraulic design. The mud issuing from the nozzles is useful also to cool the bit, to remove the cuttings from the cones and from the bottom of the hole, and to increase the rate of penetration (especially in not well consolidated formations) thanks to the sweeping action of the high-velocity jet at the bottom of the hole.

Tricone bits are classified according to standards fixed by the International Association of Drilling Contractors (IADCs). Their purpose is to compare bits having similar technical features but which are produced by different manufacturers, each of which adopts its own nomenclature. The IADC code for tricone bits consists of three numbers. The first one expresses the hardness of the rock that the bit is able to drill, adopting a scale of 1 to 8, with an increasing difficulty of drilling. The second number distinguishes a further subdivision within the class identified by the first number (scale of 1 to 4) according to the drillability of the rock. The third number indicates a special technological feature of the bit (e.g. roller or friction bearing, reinforced diameter, air-circulation bits, etc.). A second IADC code assesses the bit wear at the end of a run. This is particularly important, as it provides useful indications on choosing the next bit and, generally speaking, for optimizing the bit programme in future wells in the same area. The type of wear of tricone bits, by now well known, bears witness to specific drilling problems that can be avoided with a correct bit selection. The code used in assessing wear is quite complex, and consists of a series of 8 numbers and standard letter-codes, describing the wear mode of the cutting structure and of the bearing, as well as the general state of the bit at the end of the run.

Natural diamond drill bits

Known since the 1950s, the natural diamond drill bit was for a long time the only alternative to tricone
bits in hard, abrasive formations, in which the latter wear out all too quickly, making drilling extremely costly. Furthermore, diamond drill bits were for a long time the only bits that could be used with the first downhole turbines because, not possessing parts in motion, they can be run even at a high number of rpm. Subsequently, the use of diamond drill bits was extended also to rocks of medium hardness, especially if abrasive, where they proved to be competitive with tricone bits, in view of their longer bottomhole life. In this type of bit the cutters are natural diamonds varying in size between 0.1 and 3 carats, appropriately embedded in the matrix of radial ribbing of a monobloc tungsten-carbide head (Fig. 20). The diamond acts on the rock only by a shearing action, removing rock fragments of thickness proportional to its depth of penetration, depending on the weight applied to the bit. The diamonds are set in the matrix for 2/3 of their diameter, and during drilling they penetrate the rock for no more than 10% of their residual diameter, while in the remaining space the mud circulates for cooling and for removing the cuttings. In practice, this type of bit the cutters are natural diamonds varying in size between 0.1 and 3 carats, appropriately embedded in the matrix of radial ribbing of a monobloc tungsten-carbide head (Fig. 20). The diamond acts on the rock only by a shearing action, removing rock fragments of thickness proportional to its depth of penetration, depending on the weight applied to the bit. The diamonds are set in the matrix for 2/3 of their diameter, and during drilling they penetrate the rock for no more than 10% of their residual diameter, while in the remaining space the mud circulates for cooling and for removing the cuttings. In practice, this type of bit functions by abrading the rock, and the cuttings produced are very fine, almost dustlike. It is recalled that natural diamond, although extremely hard, is very fragile and does not stand well up to impacts or vibrations. Moreover, at 1,455°C it becomes transformed into graphite, and it is thus necessary to keep the cutting face well cooled. In diamond drill bits, the mud does not issue from calibrated nozzles, but from a central outlet of fixed area, and is distributed radially along the ribs around the cutting surface, cooling it. Nowadays, natural diamond drill bits are of relatively limited use.

**PDC bits**

PDC bits are characterized by a cutting mechanism similar to that of natural diamond drill bits, but they possess special cutting elements made of a particular synthetic material called polycrystalline diamond compact. PDC cutters have a greater cutting depth than the small dimensions of a diamond. They drill solely by shearing and are therefore suitable for rocks which are not abrasive and have a predominantly plastic behaviour. The first PDC bits immediately showed that they could compete with tricone bits, due above all to their intrinsic reliability, as they have no moving parts (which could wear out, become detached and remain at the bottom of the hole), and due to the possibility of running them on all downhole motor applications. The PDC bit (Fig. 21) has a monobloc steel or tungsten-carbide head, on which cylindrical cutters are mounted, and a threaded body in order to allow it to be connected to the drill string. The head is rounded, according to a specific profile and is equipped with protruding radial ribs also known as blades. The cutters, which are arranged along the blades, consist of a cylindrical tungsten-carbide support on which a few mm thick layer of polycrystalline diamond compact is deposited, which constitutes the actual cutting part (Fig. 22). The PDC layer is produced by mixing metallic cobalt with synthetic diamond powder crystals having an average dimension of about 100 μm. The mixture is subjected to a pressure of approximately 10⁴ MPa and to temperatures close to 1,350°C. These conditions, together with the catalysing effect of the cobalt, bring about a partial sintering of the diamond grains. The final product is a layer of interconnected diamond

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**Fig. 21. PDC bit (Hughes Christensen).**

**Fig. 22. Typical cutter for PDC bits.**
crystals, in which the intergranular spaces are filled with cobalt. The characteristics of hardness and of resistance to abrasion of the PDC are comparable to those of natural diamond.

The cutters of PDC bits have a diameter of between 5 and over 10 mm, and they are arranged on the blades with precise cutting angles, which characterize the aggressiveness of the bit and the efficiency of cleaning the well bottom. Holes are made in the bit head for the nozzles, their functions being analogous to those of tricone bits. Their number varies according to the diameter of the bit, from a minimum of 3 to more than 8.

PDC bits show excellent performances mainly in soft and not very abrasive formations. The fact that they can drill at very high rates of penetration (if the right bit for a certain type of formation has been chosen, although this is not always foreseeable), together with the long life of the cutters, has made them extremely competitive with tricone bits in unconsolidated clayey or sandy formations. The number of PDC bits varies according to the diameter of the bit, from a minimum of 3 to more than 8.

The technique for producing this type of material is similar to that used for PDC, with the difference that it is not constructed on a base of tungsten carbide, and that at the end of the manufacturing process the catalyst (cobalt) is removed, obtaining TSP diamond compact. Cobalt, in fact, has a greater thermal expansion than that of the diamond, and when heated it tends to destroy the polycrystalline structure. The TSP material is thermally more stable than PDC (it remains unchanged up to about 1,200°C), and can be produced in larger sizes than natural diamonds, in the range of several mm. TSP cutters are produced in round or triangular shapes and are used to produce tools similar in concept to natural diamond bits (Fig. 23). They are set in the ribbing of a monobloc head of tungsten carbide, and have the advantage of making a deeper penetration than natural diamond bits, but shallower than PDCs. They are suitable for drilling relatively hard formations or streaks of soft and hard rocks. In soft rock their cutting action is like that of the PDCs, while in hard rock they act like natural diamonds. Clearly, given the small size of their cutters, the penetration rate of the TSP bits is less than PDC bits, but they can drill for a longer time. Their hydraulics is analogous to that of natural diamond bits.

**TSP bits**

As has been seen above, PDC cutters are very sensitive to temperature, and are not suitable for drilling hard rocks. A possible alternative to using PDC cutters is TSP (Thermally Stable Polycrystalline) diamond. The technique for producing this type of material is similar to that used for PDC, with the difference that it is not constructed on a base of tungsten carbide, and that at the end of the manufacturing process the catalyst (cobalt) is removed, obtaining TSP diamond compact. Cobalt, in fact, has a greater thermal expansion than that of the diamond, and when heated it tends to destroy the polycrystalline structure. The TSP material is thermally more stable than PDC (it remains unchanged up to about 1,200°C), and can be produced in larger sizes than natural diamonds, in the range of several mm. TSP cutters are produced in round or triangular shapes and are used to produce tools similar in concept to natural diamond bits (Fig. 23). They are set in the ribbing of a monobloc head of tungsten carbide, and have the advantage of making a deeper penetration than natural diamond bits, but shallower than PDCs. They are suitable for drilling relatively hard formations or streaks of soft and hard rocks. In soft rock their cutting action is like that of the PDCs, while in hard rock they act like natural diamonds. Clearly, given the small size of their cutters, the penetration rate of the TSP bits is less than PDC bits, but they can drill for a longer time. Their hydraulics is analogous to that of natural diamond bits.

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tungsten-carbide matrix, in which powdered synthetic diamonds with a grain size of less than 100 μm have been distributed. These segments, generally with a rounded profile, are welded to the body of the bit by high-temperature processes. Impregnated bits thus do not possess cutters in the strict sense of the word, but destroy the rock by abrasion, because when the segments containing powdered diamonds wear down, they guarantee the exposition of a certain quantity of new diamond powder (Fig. 24). From the hydraulic standpoint, this type of bit does not have nozzles either, but a central mud outlet. The only disadvantage of impregnated bits is that, in view of the small cutting depth of diamond powder, it is not always possible to attain high penetration rates.

### 3.1.9 Casing

Drilling a well modifies the mechanical and hydraulic equilibrium of the rocks around the borehole. Periodically this equilibrium has to be restored, by inserting a well casing. Casing is a steel tube that starts from the surface and goes down to the bottom of the hole, and is rigidly connected to the rocky formation using cement slurry, which also guarantees hydraulic insulation. The casing transforms the well into a stable, permanent structure able to contain the tools for producing fluids from underground reservoirs. It supports the walls of the hole and prevents the migration of fluids from layers at high pressure to ones at low pressure. Furthermore, the casing enables circulation losses to be eliminated, protects the hole against damage caused by impacts and friction of the drill string, acts as an anchorage for the safety equipment (BOPs, Blow Out Preventers, see below) and, in the case of a production well, also for the Christmas tree. At the end of drilling operations, a well consists of a series of concentric pipes of decreasing diameter, each of which reaches a greater depth than the preceding one (Fig. 25). The casing is a seamless steel tube with male threading at both ends, joined by threaded sleeve joints. The dimensions of the tubes, types of thread and joints are standardized (API standards). Special direct-coupling casings, without a sleeve joint, also exist. The functions and names of the various casings vary according to the depth. Starting from the uppermost and largest casing, first comes the conductor pipe, then the surface casing and the intermediate casing, and finally the production casing.

As stated, the first casing is called the conductor pipe, and is driven by percussion to a depth normally of 30 to 50 m. It permits the circulation of the mud during the first drilling phase, protecting the surface unconsolidated formations against erosion due to the mud circulation, which could compromise the stability of the rig foundations. The conductor pipe is not inserted in a drilled hole and is not usually cemented, and therefore it is not considered a casing in the true sense of the word. The first casing column is next, and protects the hole drilled inside the conductor pipe. It is also called the surface casing and its functions are to protect the fresh water aquifers against potential pollution by the mud, to provide anchorage for the subsequent casing, and to support the wellhead. To increase its stiffness and make it capable of bearing the compressive loads resulting from the positioning of the subsequent casings, the surface casing is cemented up to the surface. Its length depends on the depth of the aquifers and on the calculated well-head pressure following the entry of fluids from the bottomhole into the casing. In fact, as the surface casing is the first casing on which the BOPs are mounted, it has to be positioned at a depth where the formation fracturing pressure is sufficiently high to allow the BOPs to be closed without any risk (see Section 3.1.13).
The successive casings are known as technical or intermediate columns and vary in number according to the specific requirements of the well. The casing depth of the intermediate columns depends on the pore pressure profile of the underground fluids. As the hole goes deeper, when the hydrostatic pressure of the mud necessary to drill safely equals the fracturing pressure of the weakest formation present in the open hole (which would cause its hydraulic fracturing), the well has to be cased. The weakest formation is usually the one nearest the surface, immediately under the last pipe of cemented casing. In this way it is possible to drill every phase of the well with drill fluids of different densities. The intermediate casings are cemented along the entire length of open hole, up to about a hundred metres in the preceding casing.

Finally, there is the production casing, which is the last one placed in the hole; it reaches the top of the pay formation, if the completion is open-hole, or it goes right through all of it, if the completion has a cased borehole. Inside this casing is the completion equipment which enables the underground fluids to reach the surface. This is the most important casing and must not collapse since it has to remain efficient for the entire productive life of the well. The design of this casing must ensure its resistance to the maximum pressure exerted by the fluids to be produced, and guarantee its resistance to any corrosion that might be induced by the chemical composition of the fluids.

This last casing may be partial: it might not reach the surface at the full diameter, but might end and be anchored at the lower end of the preceding casing. In this case one no longer speaks of casing, but instead, of a liner, which is fixed to the preceding casing by means of a liner hanger which ensures the hydraulic and mechanical seal (Fig. 26). The liner and its hanger are lowered into the well with a drill string, and its length is such that when the operation is completed the hanger is about 100 m inside the preceding casing. The choice of a liner rather than a casing depends on economic and technical considerations, e.g. the decrease in the weight on the hook during the running-in of the liner into the well. This factor is important especially in deep wells, or when the rig has a limited hook load capacity. Moreover, the liner also leads to improved borehole hydraulics, as the decrease in length of the small-diameter annulus reduces circulation head losses. If necessary, the liners may be backed up to the surface with a casing run downhole in a special seating in the head of the hanger.

### 3.1.10 Cementing

Cementing is the operation of pumping a cement slurry between the casing and the formation, and can be performed by injection into the annulus from inside the casing. As mentioned, the cementing – in this case called primary cementing – serves to rigidly connect the casing to the formation and to guarantee the hydraulic insulation of the various formations, preventing the migration of the fluids from layers at high pore pressure to those at low pressure. The success of cementing depends on the effective displacement of the slurry, which has to replace the greatest possible quantity of mud present in the annulus. This depends on numerous factors, such as the flow regime in the annulus, the density and viscosity of the mud and of the slurry, the casing centralization, etc. The centralization of the casing is particularly important, as the geometry of the well is seldom regular, but tortuous and with a variable diameter. All other cementing operations carried out after the primary operation, either to correct an earlier not very effective cementing operation, or for other purposes (repair of a damaged casing, setting cement plugs, squeeze operations, and so on), is called secondary cementing (see Chapter 3.6). From the operative standpoint, when the casing depth of a certain section of the hole has been reached, the true borehole diameter is determined by means of a log, from which the volume of slurry necessary for cementing can be calculated. Meanwhile the casing pipes are prepared, providing them with centralizers.
and scratchers; the centralizers serve to keep the casing centred in the hole while the scratchers are for removing the mud cake from the wall of the hole, improving the setting of the cement on the formation. The cementing shoe, a pipe with the same diameter as the casing, with a rounded end and fitted with a check valve which prevents the fluid contained in the annulus from flowing back into the casing, is mounted as the first pipe of casing. At a distance of one or two pipes from the shoe, two collars are fitted to hold the cement plugs. The lowering of the casing into the well takes place by connecting the pipes on the rig floor and running them in the hole with the help of the hook, in the same way as the drill string is run in.

Cement slurry
The material used for cementing is slurry, a mixture of cement, water and chemical additives. A cement slurry is obtained by mixing Portland cement, obtained from appropriate mixes of lime and clay material roasted in special rotary kilns, with various proportions of water. The mix gives rise to a series of chemical reactions which cause a gradual setting and hardening of the slurry. Setting occurs in a few hours after mixing, while hardening is a slower process which can even take some months. The composition of drilling cements is regulated by API and ISO (International Standards Organization) standards. They are divided into various classes (indicated by the letters from A to H) according to the depth at which they are used. High sulphate resistant cements are generally employed and, for obvious reasons of logistics and cost economy, one or two types are adopted (in general, classes G and H). These, with the appropriate additives, can be used in all drilling situations. In particular, the additives serve to control the density, setting time, circulation losses, filtration, and viscosity. In the same way as the muds, slurry is also subject to control of its physical and rheological characteristics, such as density, free water, consistency, setting time, etc. These controls are carried out under the temperature and pressure conditions existing in the well. The cement is selected to ensure that the slurry will develop adequate mechanical properties in a sufficiently short time, and so to reduce the idle time of the rig at the end of cementing (i.e. the waiting time for the cement to set). In contrast, it is necessary for the slurry to remain fluid long enough to complete the pumping, which takes several hours in particularly deep wells. It is therefore important to estimate precisely the volume of cement slurry needed, the bottomhole temperature, and the total time required for cementing. In fact, even a modest variation in the temperature causes an appreciable reduction in the setting time (this especially being the case with wells having high temperatures, above 100°C), and thus necessitates a very precise formulation and laboratory control of the cement slurry. The use of retardants or accelerators enables this to be achieved, as they allow the slurry setting time to be regulated appropriately. In this way it is possible to use even a single type of cement for the most varied drilling situations. In a similar way to drilling fluids, the slurry must have a density that will prevent underground fluids from entering the well, and will not lead to fracturing of the formations.

Single-stage cementing
Single-stage cementing is carried out by pumping the calculated volume of slurry into the casing, through a special three-way cementing head mounted on the casing, thus enabling the cementing plugs to be released into the casing (Fig. 27). For the displacement of the slurry, special pumps are used with greater head and smaller flow capacity than mud circulation pumps. At the start of the operation, the well is filled with mud; to improve the displacement within the annulus, where there might be cuttings and scraps of mud cake,
a separator pillow consisting either of water plus additives or diesel oil is first pumped into the casing from the lower line of the cementing head, to fluidify the mud and separate it from the slurry pumped in afterwards. The slurry is then pumped through the middle line of the cementing head, care being taken to separate the water pillow from the slurry by means of the first cementing plug (a rubber plug with a diameter equal to the inside diameter of the casing, which is hollow and is closed by a central diaphragm that easily splits). After the calculated volume of slurry has been pumped, a second plug, made of solid rubber, is inserted into the casing, and pumping of ordinary mud above the second plug continues through the upper line of the cementing head, preceded possibly by a second water pillow. When the first plug reaches the collar, the pumping pressure increases, indicating that the plug has landed on the collar and that there is slurry behind it. By increasing the pumping pressure the diaphragm of the first plug is split open, permitting the displacement of the slurry into the annulus. Finally, when also the second plug lands on the first one, the pressure again increases, showing that all of the slurry has been pumped into the annulus and that the inside of the casing is filled exclusively with mud. This means that the primary cementing has been completed, and the wait for the cement to set starts. This takes a few tens of hours, during which the wellhead operations are completed, and after which drilling is resumed. Clearly, the plugs, the collar, and the shoe have to be made of easily drillable materials, in order to continue drilling with an ordinary bit. Single-stage cementing presents some uncertainty in the calculation of the height up to which the slurry has been taken, as there may be caving formations in the well not taken into account in calculating the volume of slurry. With an analogous technique the liners can also be cemented.

**Double-stage cementing**

The choice of single-stage cementing is linked to the length of casing to be cemented, to the formation fracturing pressure and to the time for which the slurry can be pumped. This method is not applicable in very deep wells, where the pumping times are reduced by the accelerating action of the temperature, or in wells with long formation intervals having a low fracture gradient. In these cases multiple cementing (usually double-stage) has to be applied, which involves injecting the slurry into the annulus through special cementing valves located at suitable distances in the column. In double-stage cementing, the deepest part of the casing is cemented with the single-stage technique, after which cementing is completed in the upper part by pumping in another calculated volume of slurry through a special circulating valve (known as a ‘divertor valve’) with holes that can be opened and closed by two internal sliding sleeves. These holes, closed during the first cementing stage, are opened using a special plug released inside the casing, which is eventually blocked on a special landing sleeve, thus making a hydraulic seal. By pressurizing the inside of the casing, some shear pins are severed and the landing sleeve slides, opening the circulating valve. After circulating the mud, to displace any slurry that might have risen above the valve, the slurry is pumped in the same way as in single-stage cementing. The last cementing plug also closes the holes in the circulating valve, concluding the operation.

At the end of the cement setting time, before resuming drilling, the effectiveness and quality of the cementing should be checked. It is recalled that the minimum setting time is defined as the time necessary for the slurry, in downhole conditions, to reach a viscosity of 10 Pa·s. A first test, conducted after having drilled the plugs and the shoe, consists of pressurizing the casing to a value equal to the hydrostatic pressure foreseen for drilling the successive phase, thereby checking the seal. A second test assesses the rise of the cement in the annulus, by recording a well temperature profile. If there is cement behind the casing, the heat generated by the strongly exothermic setting reaction, causes a temperature rise, which does not occur if mud is present. Another more reliable and more precise test for estimating the quality of the mechanical coupling between casing and hole is a sonic log performed inside the casing. The attenuation of the sound wave is greater, the better the cementing, that is the more rigid the mechanical coupling between casing, cement and rock.

### 3.1.11 Drilling fluids

The drilling fluid, also called ‘mud’, is a water, oil or gas-based fluid. It is one of the key factors in the success of a well and has a strong impact on the total cost of the operations, above all due to regulations governing its disposal once the well is completed. The choice of drilling fluid is dictated mainly by the characteristics of the formations to be drilled, by their drillability and reactivity to water, and by problems of disposing of the spent fluid. During drilling, the mud is subjected at least daily to chemical, physical and rheological analyses, and if necessary it is corrected, as contact with the cuttings can modify its characteristics which must always be kept within design limits. Drilling fluids, which circulate in the well as shown in the schematic representation in **Fig. 28**, have many functions to perform, including:
The removal and transport to the surface of the cuttings produced by the bit. The transporting capacity is influenced by the characteristics of the fluid (in particular viscosity and density) and by the geometry of the cuttings. Usually a minimum uplift velocity of about 0.8-1 m/s is sufficient, and has to be checked in the section of the greatest flow area (the annulus between the last casing and drill pipes). The rapidity with which the cuttings are removed from the bottom of the hole influences the rate of penetration and the life of the bit.

The control of the formation pressure. This has the function of preventing underground fluids from entering the well. This is achieved by always keeping the hydrostatic pressure of the mud column higher than the pore pressure, by regulating the mud density. Usually, the latter is kept 5-10% above the density necessary to offset the pressures foreseen, creating a differential pressure between the hole and the formation; the hydrostatic pressure must in any case never exceed the fracturing pressure of the formations already drilled.

The prevention of caving and collapse of the borehole walls. The hydrostatic pressure of the mud acts as a sort of temporary support, as it partly balances the stresses that existed in the surrounding rocks prior to drilling. Furthermore, in areas of permeable rock, the mud creates a ‘mud cake’, a sort of layer of hardened clay on the walls of the hole, which further stabilizes the well. The mud cake forms by separation of the colloidal part of the mud from the liquid (filtrate) part, which instead penetrates the formation due to the differential pressure. A good mud cake has to be tough, thin and impermeable, and must not reduce the hole diameter, thereby increasing the risk of the drill string getting stuck.

The slowing down of the sedimentation of the cuttings when circulation stops. A good drilling fluid, passing from a state of motion to one of rest, should rapidly gel, to slow down or stop the cuttings in suspension from falling back. If this does not take place, the drill string could become stuck due to the sedimentation of the cuttings at the bottom of the hole. The property of some fluids to form a jelly-like mass when at rest and to return to the liquid state when in motion, is called ‘gel strength’, and is typical of numerous bentonite-based muds. Unfortunately a rapid gelation hinders the effective separation of cuttings at the surface on the shale shakers.

The cooling and lubrication of the drilling equipment. Especially those of the bit and the drill string, which can come into contact with the borehole at many points.

The limitation of reservoir damage. During the formation of the mud cake, the filtrate penetrates the formation radially, forming an ‘invaded (or flushed) zone’, in which the relative permeability to oil or gas diminishes; if clays are present, there can also be a decrease in the permeability of the formation. To prevent overly extensive invasions, the properties of the mud can be regulated so that a thin, impermeable cake will form rapidly.

The sources of geological and stratigraphic information. Sampling and analysis of the cuttings separated by the shale shaker, monitoring the gases dissolved in the mud, and control of its physico-chemical variations (temperature, pH, chloride content, etc.), form a basic part of the in situ geological survey, which supplies precious indications on the course of drilling.

Classification of drilling fluids

Drilling fluids are subdivided into three major classes, according to the type of continuous phase that constitutes them. The first class is that of water-based muds: the continuous phase is water (fresh or salt), to which natural clays of the bentonite group are added, so as to form a homogeneous, viscous suspension. Water-based muds were the very first drilling fluids
used, and were called ‘muds’ because of their aspect, being composed only of water and clay. Afterwards this term was extended to all liquid-based drilling fluids. The physical and rheological characteristics of muds are adjusted by adding chemical additives and weighting materials. The filtrate of a water-based mud is water with a part of the chemical additives in solution, and is potentially capable of damaging hydrocarbon-bearing formations. The second class is that of oil-based muds: the continuous phase is oil, by this term meaning hydrocarbon based natural or synthetic products. Also in this case chemical additives, weighting materials and viscosity enhancers are necessary to regulate the physical and rheological characteristics. The filtrate of an oil-based mud is oil, which does not damage the formations. Lastly, the third class is that of gas-based drilling fluids, usually air, possibly mixed with other fluids. These are characterized by low density and are unable to create an adequate hydrostatic pressure to control layer and formation pressures; they are used for drilling through formations having a low pore pressure gradient.

Apart from the base fluid, drilling fluids consist of viscosity enhancers, weighting materials, chemical additives and possibly plugging materials.

The most common viscosity enhancers used in preparing muds are particular clayey minerals or else natural or synthetic polymers; they are necessary to improve the cutting transport capacity. The clayey minerals most used are those in the bentonite group. Bentonite, dispersed in fresh water, becomes strongly hydrated and produces muds with good viscosity and gel strength characteristics, which form an elastic, impermeable cake. Other viscosity enhancers are organic (natural or synthetic) polymers and organophilic oil-wettable clays.

Weighting materials are fine mineral powders (10–40 μm) dispersed in the mud to increase the density. They must have a high density and be chemically inert, easy to mill, not very abrasive, non-polluting and economic. The most widespread material is barite (natural barium sulphate, density about 4,250 kg/m³), which allows the mud to reach a density of about 2,200 kg/m³. Analogous properties are typical also of siderite, galena and haematite. Weighting can also be obtained with soluble salts, such as sodium, calcium or potassium chloride, or even potassium, calcium or zinc bromide, which are used in particular for the preparation of fluids for well completion. They are clear fluids, without any solids in suspension, which limit the damage to the formation.

There are numerous chemical additives. The best-known are thinning agents (fluidizers), used to control the viscosity and the gelling of the mud. The viscosity of a mud can in fact be reduced by means of dilution, the mechanical removal of solids, or by the addition of fluidizers (tannins, lignosulphonates, chromolignite, etc.) which modify the chemical and physical interactions between solids and fluids, in particular between clay and water. Other types of additives are those used to reduce the volume of filtrate (carboxymethylcellulose, starches, etc.); others are surfactants, which are used as emulsifiers, defoaming agents, which reduce the foam that forms in brackish muds, lubricants (gas-oil, synthetic oils, asphalt compounds) and bactericides, which limit the development of bacteria, algae and moulds. The anticorrosives category is important, to protect the drill string and tools. Polymers are a special class of additives. They are substances with a macromolecular structure of natural origin (guar gum, xantan gum, tannins, starches, etc.) or of synthetic origin (polyacrylates, polyacrilamides, etc.), which can behave as viscosity enhancers, flocculants, defloculants, filtrate reducers, stabilizers, etc. Their use is particularly common in the preparation of modern drilling fluids. Another important class of additives is formed by materials used to stabilize the reactive clays of the formations: these are polymers, asphaltic hydrocarbons, or calcium and potassium salts, which are employed to make what are termed ‘inhibiting’ muds, which limit clay hydration and swelling.

Lastly, there are the plugging materials, used to limit circulation losses which can occur in fractured formations or, more rarely, in very permeable layers. These are solid materials which are mixed with the mud in massive quantities. They may be fibrous (processing waste of cotton, hemp, jute, animal bristles, sawdust), in scale or flake form (cellophane strips, mica chips, wood shavings), or granular (crushed walnut shells).

Characteristics and use of drilling fluids
Water-based muds are the simplest drilling fluids, in which water is the continuous phase and solids the dispersed phase. The solid phase consists mostly of clays, possibly with the addition of polymers for controlling filtration and the rheological properties, of weighting materials to control the density, and of caustic soda for pH control. With the use of additives, various types of water-based muds, suitable for a range of drilling conditions, can be produced. Generally, the more complex formulations try to make the properties of water-based muds more like those of oil-based muds. The advantages of water-based muds are their low cost, the good cleaning of the hole, and the low environmental impact. On the other hand, their disadvantages are linked to the interaction of water with the clays of the layers (which can give rise
to instability of the walls of the hole), their low 
resistance to high temperatures, and the difficulty of 
keeping the percentage of solids within acceptable 
limits. For this, frequent dilutions are necessary, 
which cause the volume of the mud in circulation to 
increase considerably. Many formations lose their 
mechanical stability when they come in contact with a 
water-based mud, and vice versa many muds 
deteriorate in the presence of clayey cuttings. For this 
reason inhibiting muds were introduced; they 
cecapsulate the cuttings and limit the expansion of 
reactive clays. The most common inhibiting materials 
are potassium or calcium chloride, diethylene or 
triethylene glycol, certain calcium or potassium 
silicates, formiates or acetates, or certain 
encapsulating polymers.

Oil-based muds consist of a base fluid that may be 
just diesel oil or a mixture of water and diesel oil. The 
latter are water-in-oil emulsions, in which the oil is 
the continuous phase and water the dispersed one, and 
they are sometimes called inverted oil emulsion muds. 
The liquid phase is constituted by water and oil 
(diesel-oil, white oils with a low aromatic content, 
etc.), to which are added emulsifiers (sodium and 
calcium soaps), viscosity enhancers (oil-wettable 
clays), filtrate reducers, and weighting materials. The 
most common oil/water ratios are 80/20, 85/15 and 
90/10, but ratios of up to 50/50 and even beyond can 
be reached. In oil-based muds the continuous phase is 
not polar and does not cause any swelling in the clays. 
Moreover, the oil renders the system little sensitive to 
contaminants (salt, anhydrite, cement, carbon dioxide, 
hydrogen sulphide, etc.) and the filtrate, which is only 
oil, does not damage the productive formations. The 
advantages of oil-based muds are the greater stability 
of the hole (because of the lack of interaction with 
clays), the formation of a thin cake, and its greater 
lubricating and anticorrosive action on steel. In 
contrast, its disadvantages are the high initial cost of 
the base fluid, the greater environmental impact of 
possible spills or circulation losses in surface 
formations, and the cost of disposing of the spent 
fluid and the cuttings. Lastly, it is recalled that there 
are also muds that use non-polluting synthetic fluids 
as the continuous phase, but these are still extremely 
costly.

Gas-based drilling fluids consist of compressed air 
or inert gases, possibly mixed with foam agents, and 
are used when it is wished to reduce bottomhole 
pressure, to avoid circulation losses in surface layers, 
or to limit damage to productive formations. Gas-
based drilling fluids, due to their low density, are 
unable to create the hydrostatic pressure necessary to 
counterbalance the pore pressure and to support the 
borehole walls. In order to be able to use them, it is 
necessary to install costly and complex compression 
units on the rig site. The advantage of gas-based fluids 
is however the increase in the rate of penetration, due 
to the ease of removing the cuttings created by the bit, 
thanks to the negative pressure differential 
(underbalance drilling). However, air-based drilling 
has the disadvantage of the difficult handling of the 
cuttings at the surface (which is, in practice, 
pulverized rock dispersed in air), which induce a great 
deal of abrasion on the drill string: in fact, the annular 
velocity necessary to lift up the cuttings can be as 
much as 900 m/min. To overcome this problem, a 
small quantity of mud with a foam agent can be 
jected into the compressed air flow; this creates a 
compact, stable foam which has a better transport 
capacity. The annular velocity necessary for the foam 
is about 90 m/min. The application of foam is 
convenient down to moderate depths, between 1,000 
and 2,000 m. In fact, as the system cannot be recycled, 
the extent of its use is determined by the increased 
volume of foam to be disposed of. If the entry of 
formation fluids prevents the use of air or foam, 
aerated mud can be used, but this is not strictly 
speaking a gas-based fluid, being a common mud 
mixed with compressed air to reduce its density. It has 
advantages both in the rate of penetration and in 
reducing circulation losses. Aerated mud can be used 
in a continuous cycle, like an ordinary mud, and is 
widely used in underbalanced drilling, i.e. a drilling 
technique based on the use of a fluid that maintains, at 
the bottom of the hole, a lower pressure than that of 
the formation fluids, thus provoking the reservoir into 
a regime of slow fluid production. This technique 
makes it possible both to have greater rates of 
penetration and to avoid damage to the production 
formations, which is the most important aspect.

The current trend in developing innovative systems 
in the field of drilling fluids is mainly aimed at 
meeting the requisites of the regulations to safeguard 
the environment, of safety and of reducing damage to 
production formations. In fact, while traditional 
systems (especially oil-based muds, which are often 
 extremely toxic) perform excellently in many 
operative conditions, the restrictions linked with 
environmental impact and safety make it necessary to 
develop base fluids and additives having little impact 
and which can equal the performances of traditional 
systems at acceptable cost. Moreover, research today is 
also very active in the field of non-damaging fluids, 
formulated for drilling inside the reservoir, and 
characterized by a limited interaction between fluid 
and formation. In the sector of oil-based muds, the 
innovations tend instead to focus on using less toxic 
base fluids than traditional oils such as olefins, 
synthetic oils, esters, etc.
3.1.12 The wellhead

The wellhead and the safety equipment are the valve units that allow the well to be insulated from the outside environment. In this way it is possible to control effectively and safely the pressures that develop in the well when it is in hydraulic communication with the subsurface formations. In fact, the pressure of the fluids contained in these formations is very often greater than normal hydrostatic pressure. The wellhead is a fixed unit that connects the various casings set inside the well. If it is a producing well, this unit remains there until the end of drilling, and is completed with the production head or Christmas tree. The safety equipment consists of devices mounted directly on the wellhead and are used only during drilling.

Traditionally, wellheads are classified in two general categories: surface wellhead and subsea wellhead. The feature of the surface wellhead is that it is accessible. In onshore wells it is located at the bottom of the cellar, and is integrated into the surface casing. In offshore drilling it is used in all rigs standing on the seabed (e.g. fixed or jack-up platforms). The subsea wellhead, on the other hand, is located on the seabed and is used in wells drilled offshore in deep waters (by semisubmersible platforms or drilling ships), and is designed to be without direct access by man either in the assembly stage or during operation (see Chapter 3.4). The elements comprising a surface wellhead are the base flange, intermediate bodies, the anchorage slips, the seal units, and the upper body (Fig. 29). The base flange is the lowest element of the wellhead. It stands on the ground of the cellar and is welded or screwed onto the surface casing. The intermediate bodies are cylindrical elements with flanged ends, used to cover the head of the preceding casing and to bear the weight of the subsequent casing. The intermediate body contains the sealing unit, a truncated cone-shaped part in which the slips for hanging the casing string are housed, and the seat for the seal gaskets. The mechanical coupling of two overlapping intermediate bodies takes place with bolted flanges or with clamps, ensuring a hydraulic seal with a round metal gasket. The base flange and the intermediate bodies have lateral outlets fitted with a double valve for control of pressure in the annulus.

Fig. 29. Surface wellhead.

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Fig. 29. Surface wellhead.

Fig. 30. Wellhead complete with Christmas tree.
spaces and if necessary for pumping fluid into the well. The hanging slips are the elements that enable the end of the casing string to be anchored to the wellhead. The internal profile of the slips is cylindrical, while the external profile takes the form of a truncated cone, and wedges into the corresponding truncated-conical part of the intermediate body. On the internal cylindrical surface of the slips there are teeth that hold the external part of the casing, firmly hanging it to the wellhead. The sealing units, usually a primary and a secondary unit, are formed by steel rings with rubber gaskets: when the rings are compressed, the rubber dilates and guarantees a hydraulic seal. The setting of the casing into the intermediate body takes place after the casing has been subjected to suitably calculated tension, which is rendered permanent by the hanging. The purpose of this pre-tensioning is to prevent the buckling of the string during the productive life of the well, which could be caused by increased temperature in the production phase. In fact, in view of the depths reached today in developing hydrocarbon fields, the underground fluids can be very hot even in areas having a normal geothermal gradient. As the casing is restrained in two points, at the bottom of the hole (at the cementing end) and at the wellhead, the thermal expansion resulting from bringing fluids with a high temperature into production tends to subject the casing to combined compressive and bending stress and could cause a breakage due to buckling. In the case of a productive well, it is necessary to install equipment in its interior (known as ‘well completion’) to produce subsurface fluids, and to connect the Christmas tree (Fig. 30) to the wellhead. After running-in the production casing, the last upper body is connected with a flange; this enables the production tubing to be hanged and the annulus between tubing and production casing to be isolated. Finally the Christmas tree – a system of valves allowing the flow of fluids produced at the wellhead to be regulated – is mounted on the wellhead.

3.1.13 Safety equipment

The safety equipment, otherwise known as Blow Out Preventers (BOPs), are large valves located on the wellhead during drilling operations (Fig. 31), able to fully shut-in the well in just a few tens of seconds, whatever the working conditions. BOPs on onshore rigs and fixed offshore rigs (platforms, jack-ups) are installed on the surface wellhead, while for floating rigs they are located on the seabed, on the subsea wellhead; this means that the floating rig can always be removed from the wellhead, under safe conditions, e.g. following marine and weather emergencies, due to damage to the mooring lines, etc. The overlapping of various BOPs constitutes the BOP stack, which is the assembly of equipment for shutting-in the well in an emergency situation, and then reopening it under safe conditions. The shut-in of the well is necessary when hydraulic control is lost, i.e. when the pressure of the underground fluids is greater than that of the bottomhole mud. In this case, the underground fluids can enter the hole without control. It could be necessary to shut-in the well in any drilling situation, even when the drill string, a casing, a cable, etc., is present. For this reason it is necessary to have a valve available that can shut the well at any time. A standard BOP stack consists, starting from below, of: a) one or more spools for connection to the wellhead; b) a dual-function ram preventer; c) a single-function ram preventer; d) an annular blowout preventer; e) a lateral tube, which conveys the outgoing mud from the well to the shaker. There are also a number of lateral connections (kill line and choke line), necessary for operations to restore hydraulic balance after well control problems. The BOP stack has the following functions: to shut-in the well around any type of equipment; to permit pumping of the mud, with the well closed by means of the kill line; to discharge through the choke line any fluids that might have accidentally entered the well; and to allow the vertical movement of the string, upwards or downwards, when the well is closed (i.e. stripping of drill pipes).

The composition of the BOP stack, or the choice of the single elements, depends on the maximum estimated pressure at the wellhead, as established by the geological investigations conducted during the
The single BOPs are characterized by the maximum working pressure, the inside diameter, the type of section on which they form a seal, and the presence of acid gases. There are two main types, annular and ram, described below.

The annular BOP, also known as a ‘bag-type’ blowout preventer due to the geometrical shape of the sealing element, is always installed at the top of the stack (Fig. 32), and has a toroidal rubber sealing element, reinforced with steel inserts. The sealing element is activated by a piston controlled hydraulically, which compresses it, forcing it to expand radially, in such a way as to squeeze around any tool that happens to be in its way. If there is nothing in the well space, the annular BOP permits the full closure of the hole, although this is not recommended as it puts an anomalous stress on the rubber of the sealing element. It may also be activated at low shut-in pressure, to carry out stripping operations, necessary for certain particular well-control procedures. In the well shut-in procedure the annular BOP is normally first activated, as its closure mechanism allows the mud flow to be gradually stopped, avoiding a ‘water hammer’.

Ram blowout preventers (Fig. 33) consist of valves with two symmetrically opposed rams, which close the well with a horizontal movement. They may be of fixed or variable diameter; in the latter case the sealing element is contained in a segmented ring which forces it to conform around the section on which it makes the seals. There are also shearing rams, designed to shut-in the well in emergency situations, shearing through any tubular materials that might be contained in the well. Lastly, there are also ‘blind’ rams, i.e. not shaped, which shut in the well when no tubular material is present. The special features of ram blowout preventers are: their rapidity of shutting-in, performed hydraulically in just a few seconds; the possibility of operating them manually in emergency situations; and the presence of a device that keeps the rams closed under pressure, even in the case of loss of pressure in the operating circuit. The body of a ram blowout preventer can house one or else two overlapping rams (double BOP), permitting various shut-in functions.

BOPs are controlled and operated hydraulically, through an oleodynamic system that receives energy from a pressure accumulator unit located at a distance from the wellhead. Each BOP can be operated separately. The BOP drive and control system is arranged so as to function independently of the energy available in the rig, to guarantee that it will operate even in emergency situations. The accumulator system consists of a series of vessels under pressure in which hydraulic oil and inert gas (nitrogen) are stored at working pressures of around 20 MPa. There are also reservoirs for storage of reserve fluid and fluid returning from the BOPs, a pump unit for pressurizing the hydraulic oil, and the distribution lines for the

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**Fig. 32.** Annular BOP: A, the sealing element seals the annulus between the kelly, the drill pipes or the drill collars; B, with no pipe in the hole, the sealing element closes on the open hole.

**Fig. 33.** Ram preventer.
dangerous consequences for the vessel
floating rig could lead to a loss of buoyancy, with uncontrolled flow of gas in the water column below a particularly dangerous in offshore drilling, when the uncontrolled flow of gas behind the well. This is which have a low fracture gradient and could cause an transmitted to the bottom, in case of well shut-in, the drilling of the surface phase, as the back pressure completely closes the well, is not recommended during the drilling of the surface phase, as the back pressure transmitted to the bottom, in case of well shut-in, could lead to the fracturing of the surface formations, which have a low fracture gradient and could cause an uncontrolled flow of gas behind the well. This is particularly dangerous in offshore drilling, when the uncontrolled flow of gas in the water column below a floating rig could lead to a loss of buoyancy, with dangerous consequences for the vessel’s stability.

3.1.14 Well control

During drilling it is necessary to carefully monitor the execution of any operation, above all to avoid blowouts. Blowouts are uncontrolled discharges of underground fluids (oil, water, gas) from the wellhead, after such fluids have entered the hole through one of the drilled formations. Blowouts are fairly uncommon occurrences, but when they do happen they are both spectacular, and harmful to personnel, the surrounding environment, the drill rig and have negative effects on public opinion, and so they have to be carefully prevented. For this purpose, all drilling personnel are specifically trained to spot the beginning of possible problems, and to decide what measures to adopt in each specific case. The key to well control is understanding the mechanisms that regulate the downhole pressures. The hydrostatic pressure of the mud along the depth of the hole depends directly on its density: light muds exerting less pressure along the walls and at the bottom of the hole than a heavy mud. The well is under hydraulic control when the mud pressure is greater than the pore pressure exerted by the fluids contained in the porous and permeable formations drilled (in this case the differential pressure is positive, and the well is in a condition of overbalance). In this way, the mud keeps the underground fluids confined within the formations, exercising what is called primary or hydraulic control. The pore pressure depends on the density of the formation fluids, and on the depth and geology of the subsoil. There is said to be a drilling kick, or that the well is discharging, when formation fluids start entering the well due to a decrease in hydrostatic pressure (i.e. when the differential pressure is negative, and the well is in a condition of underbalance). One of the basic tasks of the drilling personnel is to ascertain that during any operation the well is always full of a mud whose density is such as to exert a hydrostatic head at the bottom that will avoid a kick. Sometimes, however, in spite of all the measures taken, the well might start kicking for natural or operational reasons. The causes that can initiate a kick are: a) insufficient density of the mud; b) drilling a formation in overpressure not promptly recognized; c) swabbing, namely the underpressure due to the piston effect during a rapid trip-out operation; d) not filling the well when tripping out; and e) circulation losses, which can lead to a sudden lowering of the mud level in the well and therefore of the hydrostatic pressure on bottom. The formations that can cause circulation losses are fractured, karst formations or those with less pressure than foreseen. It is recalled that a rapid trip-in can cause an increase in the bottomhole pressure (surging), with the possibility of fracturing the formation, which causes circulation losses, lowering of the head of mud, and therefore the triggering of a kick.

A kick can be recognized in various ways. The most reliable method is monitoring the behaviour of the mud coming out of the well. The commonest kick indicators are an increase in the mud flow rate, an increase in level of the mud pit, an increase in the rate of penetration, mud outflow from the well when the pumps are switched off, the anomalous presence of gas in the mud outflow, etc. Whatever the reason, in all of these cases the drilling personnel must rapidly take the appropriate actions to halt the kick, stopping it from developing into a full-scale blowout. All drilling rigs are provided with systems of detection and cross control, which help in recognizing the build-up of a kick. These systems, often automated in such a way as to set off an alarm, are always under the surveillance of the driller on the rig floor and are often replicated in the geological control cabin and in the offices of the rig supervisor and of the drilling assistant.

When a kick occurs, the drilling personnel execute the safety procedures so as to bring the well under control, known as secondary control. The first operation is to shut-in the well through the BOPs,
preventing any further formation fluids from entering the well. Once the well has been closed, there is a transitory stage in which the formation fluid goes on entering the well. During this stage, at the surface a gradual increase is observed in the pressures inside the drill pipes and the annulus, until the transitory stage has ended and the pressures have become stabilized, indicating the hydraulic rebalancing of the well. The value of the stabilized pressure in the drill pipes and in the annulus is used to calculate the density of the mud which, when pumped into the well, will succeed in controlling the new formation pressure. Furthermore, based on considerations of the hydraulic balance, using the stabilized pressures it is also possible to estimate the density of the fluid that had entered the well, and thus its nature. In this situation, i.e. with the well closed, it is not possible to continue drilling, as the wellhead is under pressure. Procedures then have to be initiated with the following two objectives: bringing to the surface, in safe working conditions, the fluids under pressure that have entered the hole, by means of controlled mud circulation; restoring the conditions of hydrostatic balance in the well, replacing the original mud with new mud of such density as to bring the well back under hydraulic control. The two best-known and used standard methods are the Driller’s method and the Wait and Weight method, which differ chiefly in the ways in which the objectives described above are achieved.

### 3.1.15 Drilling problems

The generic expression drilling problems refers to a series of anomalous operative situations that have to be adequately resolved in order to be able to carry on drilling in safe conditions. In particular, problems relating to circulation losses and to drill strings getting stuck will be examined, and in conclusion a brief mention will be made of ‘fishing’ and milling of drilling material that has been lost, by falling into or in some way remaining at the bottom of the hole.

Circulation losses indicate anomalous absorption or complete losses of mud circulation. They may be partial, if mud does in any case return to the surface, or total, when the circulating mud no longer returns. Circulation losses can occur in rocks of considerable permeability, in formations of abnormally low pressure, in fractured or karst formations, or in formations fractured by excessive mud density. There are many negative effects of circulation losses. The most dangerous one is certainly linked with the lowering of the mud level in the well, which can trigger a kick. Moreover, if the circulation does not return to the surface, it is not possible to analyze the cuttings, with loss of stratigraphic information, while appreciable circulation losses in shallow formations can contaminate the aquifers. Lastly, it is recalled that circulation losses also strongly influence the well costs, as the average price for a water-based mud is in the range of 1,000 euro/m³, and can increase to the double or the triple of this for synthetic oil-based muds. To stop circulation losses, mud mixed with plugging material is injected into the hole, and usually succeeds in closing small fractures measuring in the order of a millimetre. The use of this technique is however not always possible, because of restrictions present in the string (downhole motors, MWD, bit nozzles); in this case it is necessary to trip-out the drill string and to pump in plugging material through a string without a bit, or with a bit without nozzles. If such a measure should be insufficient, a cement plug has to be set corresponding to the thief formation.

‘Drill strings getting stuck’ refers to any type of pipe string which, for various reasons, is stuck in the well, and which cannot be rotated, pushed down or pulled up. In other terms, the string is stuck when the maximum pull exerted by the drawworks is no longer able to pull out the string, due to friction or to jamming of the tubular material in the hole. One of the commonest jamming mechanisms is the one called ‘key seating’: the rotation of the drill pipes under tension, which rub against the wall where there are variations in hole curvature, can create a recess having a diameter less than that of the hole, in which the drill collars can get stuck during trip-out operations. Another such mechanism is when the string gets stuck because of differential pressure. This can occur when drill collars remain stationary for a long time at a depth corresponding to permeable formations. In such a case, under conditions of strong overbalance, a mud cake can accumulate between the pipe and the borehole wall that is so thick that it can block the string. The string can also get stuck when running in a new bit into a section of hole drilled using a worn (undergauge) bit. It is recalled that the reduction in hole diameter can also be caused by the swelling of plastic formations (clay, salt, etc.). Finally, other possible reasons for jamming are the collapse of the hole in unstable formations, the sedimentation of the cuttings or large cavings; the latter are particularly pernicious because they block the drill string and interrupt circulation.

In case of stuck pipe, the first operation is applying a strong pull by means of the drawworks and operating the jar, if present. Moreover, if circulation is not interrupted, a lubricating fluid can be pumped in, or else an acid solution, in order to remove the mud cake. Such measures, which can even take several hours, are often successful when the pipe is not completely stuck.
If it is not possible to free the string in this way, to be able to resume drilling it is first necessary to disconnect the pipes at the tool joint closest to the stuck point. This point is determined by the method of differential pulling, or with a specific log recorded inside the pipes. There are three methods of disconnecting the string: by unscrewing anti-clockwise; by unscrewing anti-clockwise and firing a small explosive charge inside the last free joint (back-off); by severing the pipe using mechanical or chemical systems. Once the free string has been disconnected, an attempt is made to recover the part remaining in the hole (called the ‘fish’) using ‘fishing’ techniques, which are not always effective. If the fish remains in the well it is milled, or, if it is too long, a sidetrack is made, that is, a new hole is drilled alongside the preceding one, using techniques typical of directional drilling. During drilling, fishing is carried out quite rarely. In fact, whereas it is easy to estimate the times of execution (and hence the costs) of a sidetrack, it is much harder to estimate the time required for fishing, which might or might not be successful.

The term fishing indicates in general all the techniques used to recover metal items lost or stuck in the hole. It is carried out with a series of tools manipulated by a pipe string possessing mechanical parts formed in such a way as to grasp the various possible shapes of the fish in the well. Typical cases are fishing up the drill string when it has broken off or has become accidentally unscrewed during drilling. Fishing tubular items is carried out with die collars or taper taps, or with more refined tools, called the overshot and the releasing spear (Fig. 34). The overshot is a sort of die collar that grasps the outside of a vertical tubular fish, permitting circulation. It consists of an upper part for connection to the string and a central sleeve shaped inside to contain the grapple, which is shaped like a steel spiral or dilatable basket. The fish, on entering the overshot, widens the grapple which then grasps it by means of a wedge-shaped mechanism, and holds it firmly when the tool is pulled. The releasing spear has the opposite sort of mechanism, gripping the internal diameter of a tubular fish. Its use is limited to material having a large internal diameter. If instead the fish is a long string stuck due to a large caving, it is possible to clean the annulus with special washerover pipes, which are very much like long, strong core barrels. The operation is carried out in two stages, cleaning about a hundred metres of pipes at a time, and subsequently lowering a fishing string fitted with an overshot. Recovery of metal fragments (normally difficult to mill), which have been lost or which have fallen into the well, is carried out using magnetic fishing tools or special core barrels known as junk baskets. There are fishing tools equipped with permanent magnets, lowered by cable or by means of pipes (which therefore allow circulation for cleaning of the fish head), or with electromagnetic fishing tool, lowered together with an electric cable, and activated only at the bottom of the hole. The latter have a greater force of attraction than permanent magnets, but they cannot be rotated because of the electric cable, and they do not allow circulation. The junk basket, with direct or reverse circulation, serves to fish junks of all types. However, it can be used only in easily drillable formations. It has an upper part for connection to the string, a central body and terminal cutting shoe, whose purpose is to cut and collect a rock sample. The core barrel shoe cuts the formation, forming a core 60-80 cm in length. After this, on pulling the string, a wedge mechanism (called a ‘core catcher’) grasps the core and detaches it from the bottom, so that both the core and the fish trapped above it can be recovered.

If the fishing operations are not successful, in order to free the hole milling can be carried out, that is destroying the fish, by reducing it to chips using special mills with cutting faces. The key point for successful milling is a study of the hydraulic transport characteristics of the chips using mud. In fact, the milled steel chips are of thin, smooth laminar shape, more or less curled, and very heavy. Hence, they tend to drop and form heaps at the points where the section of the annulus broadens, thus forming inextricable

Fig. 34. Fishing equipment: A, overshot; B, releasing spear.
tangles. Mills are tools very similar to diamond bits, possessing a head shaped in various forms, depending on the fish to be milled. The cutting face of a mill contains large sintered tungsten-carbide grains connected by a metal matrix and acting as real cutters. Naturally, there are holes in the cutting face of the mill, allowing the mud to circulate.

**Bibliography**


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