

**A Drilling Handbook for  
Geologists**

DCSS : J.N. FURGIER

## **Preface**

This document has been compiled by a drilling engineer working in the Operations Geology Department.

Its aim is to explain the techniques and the vocabulary used in drilling operations for people who have had little contact with such operations.

The first section of the document describes the operations carried out on a well and the equipment used. The more brief second section mentions the methods and equipment used for well production. At the back there is a glossary with the page on which the explanation can be found.

This handbook should remove the mystery surrounding drilling and allow people coming from all fields to work hand in hand with the drilling profession.

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# 1st Section : Drilling

## 1 The drilling rig

### 1.1 The different types of rig

#### 1.1.1 Land rigs

- Conventional rigs.
- Wheel mounted rigs (mainly used in the desert).
- Helirigs.
- Truck mounted rigs.

#### 1.1.2 Swamp barges

The drilling rig is mounted on one (or several) barges that is towed onto location, then submerged so as to sit on the bottom. This rig is used only in rivers or swampy areas.

#### 1.1.3 Offshore rigs on a fixed base

##### 1.1.3.1 Jack-ups

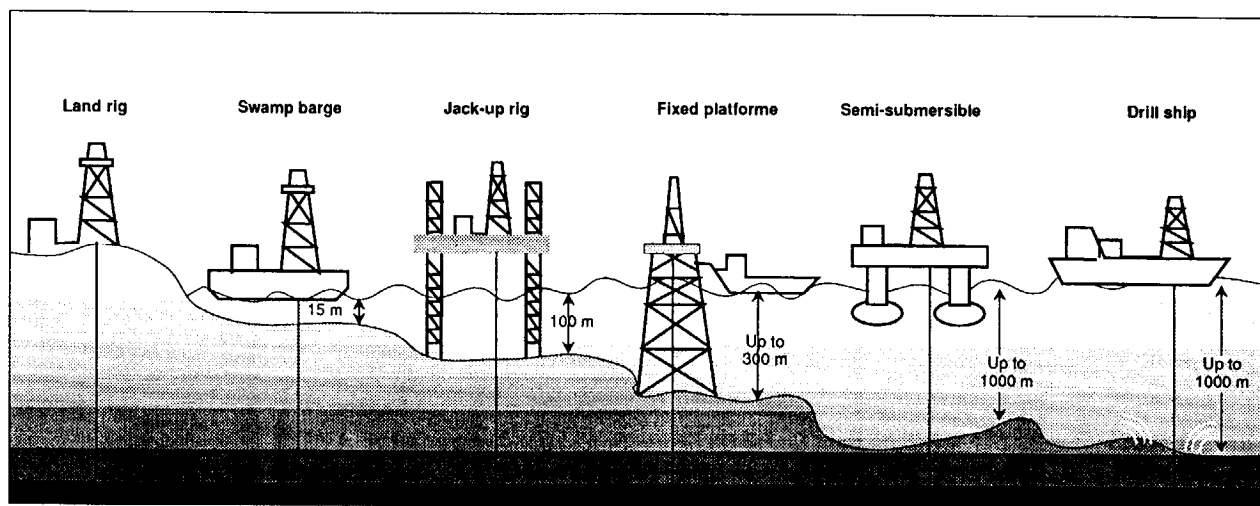
These are the most common offshore rigs. The rig is moved while floating, and for drilling, it is jacked-up on its legs that sit on the sea bed, so that the rig hull is high enough in the air to be out of reach of waves and swell.

There are slot or cantilever jack-ups. On slot jack-ups, the hole is drilled through an opening in the middle of the rig hull, which means that a well head cannot be installed and the rig cannot operate on a production platform. This type of rig is hence used for exploration drilling.

On cantilever jack-ups, the derrick is located on a deck (*cantilever*), that slides on rails to an overhanging position over the side of the rig hull (*skidding*). This type of jack-up can operate on existing installations.

Jack-ups can be used in water depths up to around one hundred meters.

# DRILLING RIGS



### **1.1.3.2 Tenders**

The mast and the drilling floor are installed on a production platform, the rest of the operations being carried out on an assisting boat (*tender*).

## **1.1.4 Floating drilling rigs**

### **1.1.4.1 Drill ships**

The drilling rig is fitted on a standard ship.

### **1.1.4.2 Semi-submersibles**

The drilling rig is fitted on a floating platform. Once on location, the platform is ballasted so that the floats at the base of the legs are below the seas surface which means that the rig is less sensitive to rolling and pitching.

Drill ships and semi-submersibles are held in position either by fixed or dynamic anchors, or by a dynamic positioning system (no link to the sea bottom).

Floating drilling rigs are generally used for drilling in deep water for exploration wells or production wells with sub-sea well heads.

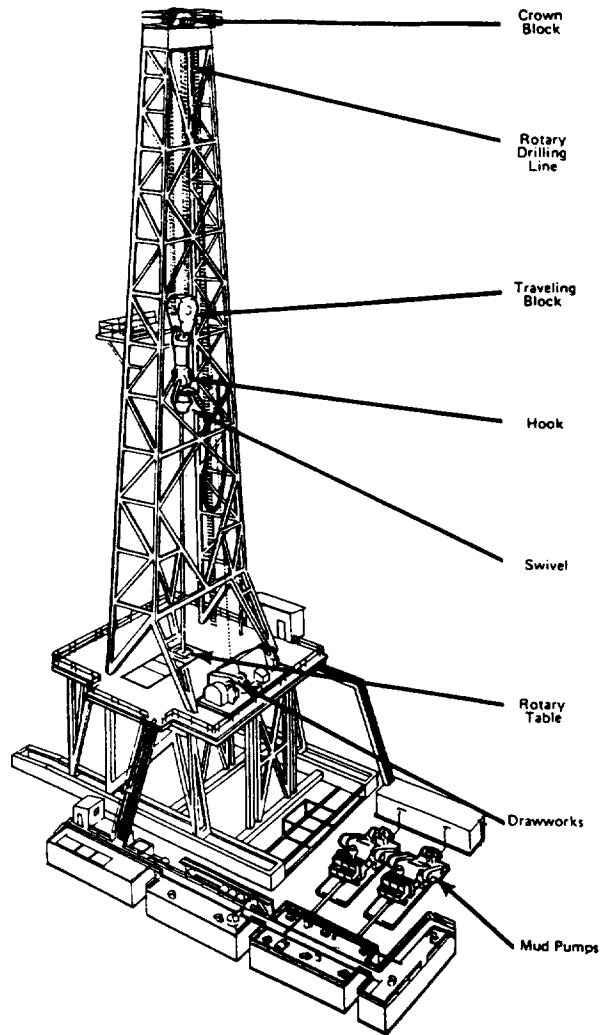
## **1.2 Lifting**

### **1.2.1 The derrick or the mast**

- The derrick is a pyramidal fixed metallic structure. It is only used on offshore rigs.
- The mast has the same function as the derrick but it can be dismantled or folded back, it is used on land rigs or tenders.

A derrick or a mast is defined by its API capacity (from 400.000 to 1.400.000 lbs), or its operational capacity (125 to 450 tons which is the maximum allowable load), by its height which limits the length of the stands used (50 m from the ground for three lengths of drill pipe), by the number of stands it can accomodate, and the possibility of fitting a power swivel.

# LAND RIG



### **1.2.2 The crown block**

This is a group of sheaves located at the top of the derrick. The drilling line goes round these sheaves to make up the reeving.

### **1.2.3 The travelling block**

This is a group of sheaves around which the line is wrapped and under which the hook is situated.

### **1.2.4 The hook**

The hook carries either the swivel (powered or not) during drilling, or the drill string during tripping, by the elevator links connected to the hook ears.

### **1.2.5 The drawworks**

The drawworks can be driven electrically or mechanically. Its power (between 400 and 3000 HP) determines the maximum drilling depth as well as the maximum weight of casing that can be lifted. It is fitted with a manual band brake that can stop the load, with an auxiliary brake, either electromagnetic or hydraulic, to control the load speed, with a bailing pulley to slip the drilling line, and catheads to pull the drilling tongs.

- An electric drawworks is fitted with one or several electric motors powered by the rigs generators. In some cases the drawworks drives the rotary table.
- A mechanical drawworks (in the case of a compound rig) is directly driven by diesel engines. The operations are controlled by a series of drives and clutches for the rotary table and the pumps.

### **1.2.6 The drilling line**

The drilling line is wound around the drawwork's drum, goes round the blocks, comes back down to the mast base where it is fixed to the sheave of the dead line anchor (which also allows the weight to be measured), then is wrapped on the spare cable drum. The line must be slipped on a regular basis to ensure even wearing. A little line is wound onto the drawworks drum and unwound from the spare cable drum ; when the drawworks drum is full after slipping several times, the line is cut and the drum emptied.



### **1.2.7 The motion compensator**

Floating rigs that are subject to swell and to tides, are fitted with a motion compensator that allows a constant weight to be kept on the drill bit.

This motion compensator can be fitted under the crown block or between the travelling block and the hook. In the first case the crown block is installed on a framework allowing for vertical movement, and driven by a hydraulic system.

In the second case, hydraulic jacks allow the hook to move below the travelling block.

For both systems, the pressure in the hydraulic circuit is kept constant no matter how much the motion compensator moves, through a gas accumulator that allows the weight on the bit to be kept constant.

The motion compensator is obviously only employed when the bit is on bottom.

## **1.3 Rotation**

### **1.3.1 Rotary table**

The rotary table can be driven by an electric motor, by an electrical drawworks, or by a mechanical drawworks. Its power is between 200 and 1000 HP, it can rotate up to 300 rpm with an opening diameter of 0,5 to 1 m.

The rotary table moves the kelly bushings, which in turn drive the kelly (square or hexagonal section). The kelly is screwed into the swivel below the hook.

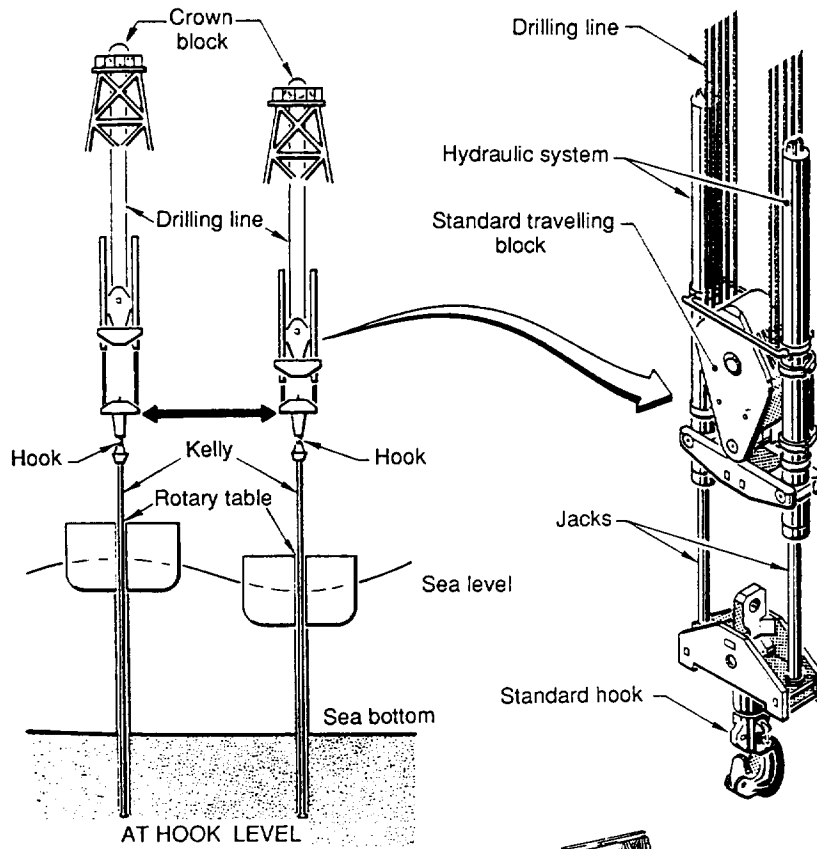
Using the kelly means that single drill pipes have to be added while drilling, and means that the string cannot be rotated while pulling out of the hole.

The rotary table supports the string when it is set in the slips.

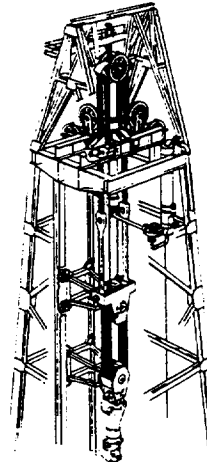
### **1.3.2 Power Swivel PS, or Top Drive System TDS**

The string is driven at its upper end by an electric or hydraulic motor fixed below the hook and guided by rails on the mast. Its power varies between 600 and 1000 HP. The use of a power swivel allows for string rotation and circulation during tripping, over the whole length of the mast.

# MOTION COMPENSATOR



AT CROWN BLOCK LEVEL



## 1.4 Pumping

Pumping is often carried out by two or three rapid single action triplex pumps, with a power of between 600 and 1600 HP that can give flow rates up to 4000 l/min with pressures up to 400 bar. The flow/pressure selection is made by changing the liner and piston diameters.

## 1.5 The mud circuit

The mud is stored in pits.

- Suction pits or active pits (30 to 50 m<sup>3</sup>)
- Mixing pits (or diluting or treatment) (30 to 50 m<sup>3</sup>).

The mud products are mixed by a mixer (or hopper) and a mixing pump.

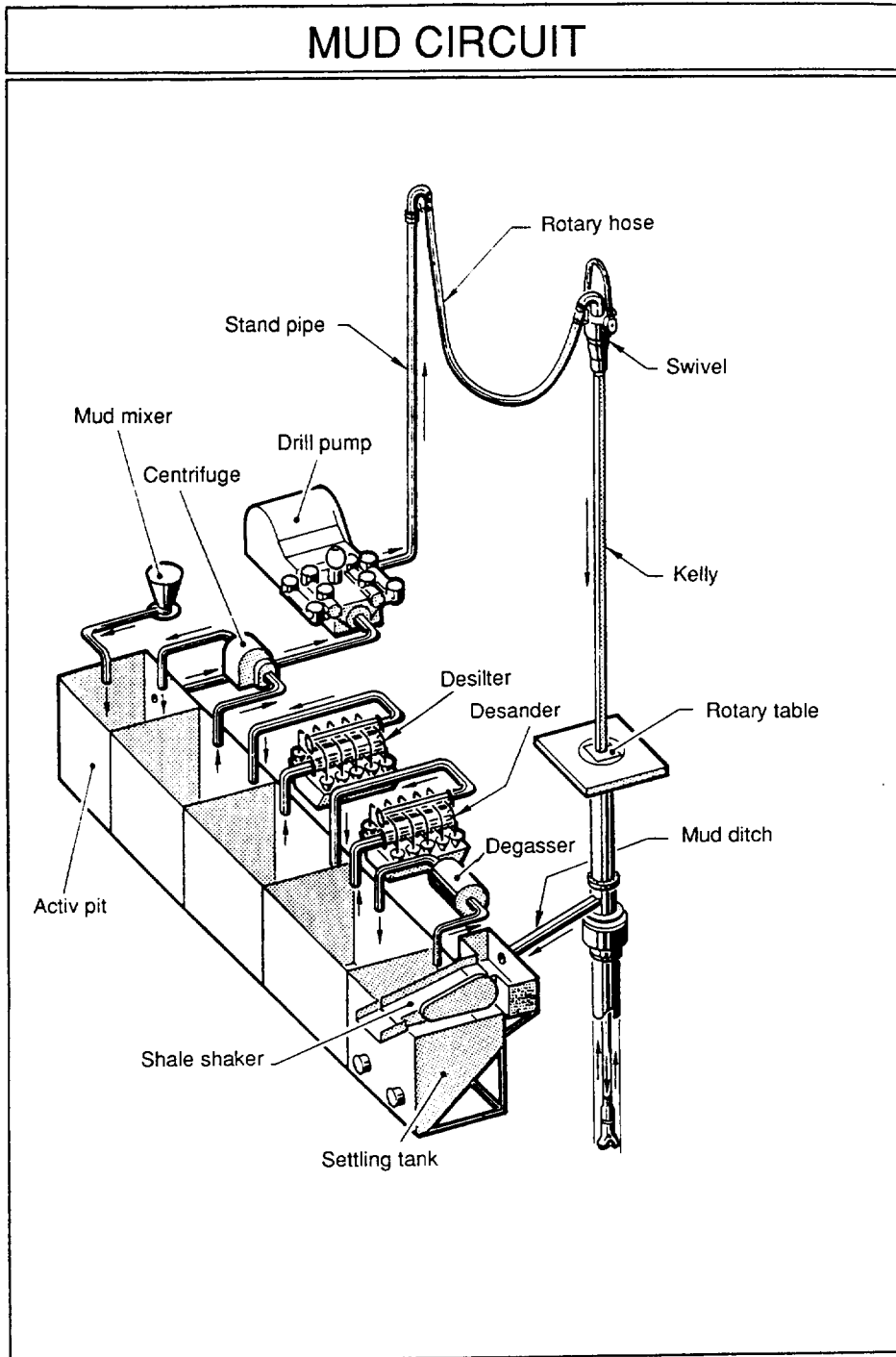
- Settling tank (or solid removal)
- Reserve tank containing heavy mud (kill mud)
- Slug pit (< 10 m<sup>3</sup>)
- Trip tank (< 10 m<sup>3</sup>)

The total volume of the pits must be at least equal to the well volume. The mud is sucked out of the active pits by booster centrifugal pumps that supply the drilling pumps. It is injected into the stand pipe manifold, goes through the stand pipe, through the rotary hose, down the string, out of the drill bit by the jets or nozzles, moves back up the annulus and exits through the bell nipple. From there it follows the return flow line to the shale shakers and into the settling tank where it is treated by different pieces of equipment for solids control. From there it is pumped back into the active pits.

## 1.6 Equipment for solids control

- The shale shakers, that are made up of several overlaid screens, finer and finer from top to bottom. The size of the holes is given as a "mesh" (the number of holes per unit of surface area).
- The desanders are made up of hydrocyclones under which are fitted vibrating screens. They retain solids larger than 20 microns.
- The desilters, in the same fashion as the desanders, eliminate particles greater than 15 microns.
- The centrifuges retain solids greater than 5 microns.

# MUD CIRCUIT



The shale shakers are supplied by the return flow line, the other pieces of equipment are fed by pumps sucking out of the settling tanks. The mud is sucked from the same tank that receives the returns.

### **1.7 Blow Out Preventer, BOP**

They enable the well to be " shut in " in case of a blow out. They are defined by their series (which is their maximum operating pressure : 3000 to 15000 psi) and by their diameter. The typical BOP stack is as follows (Elf Aquitaine standard) :

- above the well head, one to three sets of pipe rams with fixed or variable diameters (variable rams),
- one set of shear or blind rams,
- an annular preventer or Hydrill.

Several lines are connected to the BOP : a kill line, that allows heavy mud to be pumped into the well and one or two choke lines that help blow out control by directing well fluids to a choke manifold.

The rams are operated hydraulically by a Koomey unit which includes a pump and several air/oil accumulators which are kept permanently under pressure.

The operating panels are located on the rig floor, in the tool pushers office, on the Koomey unit, and another one away from the rig floor.

While drilling after setting the conductor pipe, if there is risk of meeting pockets of shallow gas, the BOPs cannot be used. This is the case because surface formations would not withstand the pressure. A crater would develop with dramatic consequences including possibly the loss of the rig.

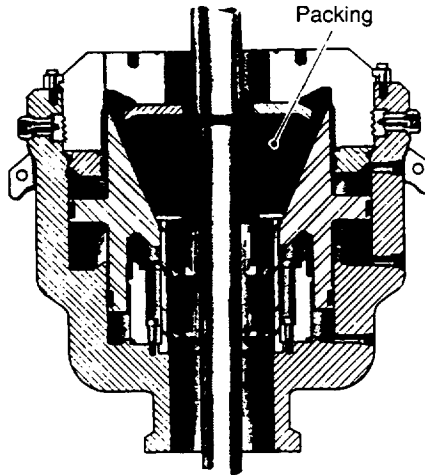
In this case a diverter is used. It is an annular BOP that closes on the drill pipe. It has two lateral outlets that deviate any gas flow away from the rig until the pocket has bled off.

### **1.8 The choke manifold**

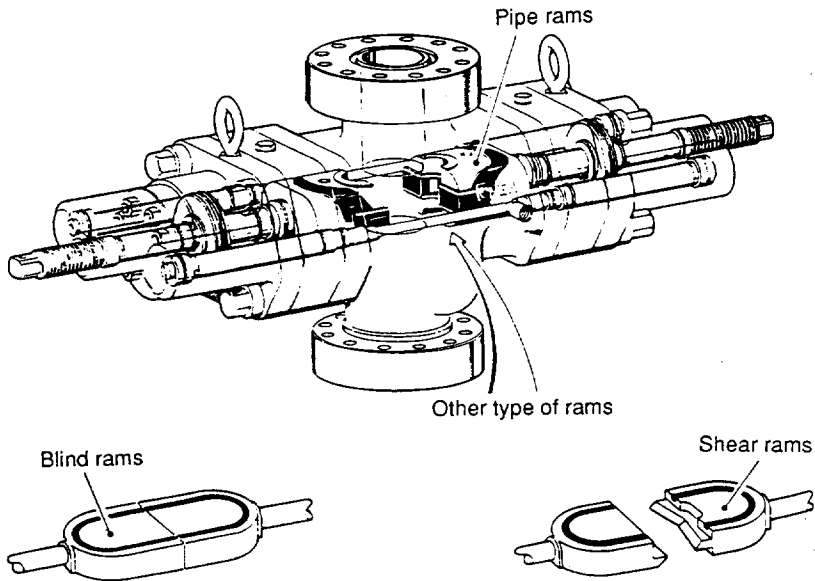
The choke line is connected to the choke manifold which usually has three chokes, two of which are automatic and one of which is manual.

# BOP'S

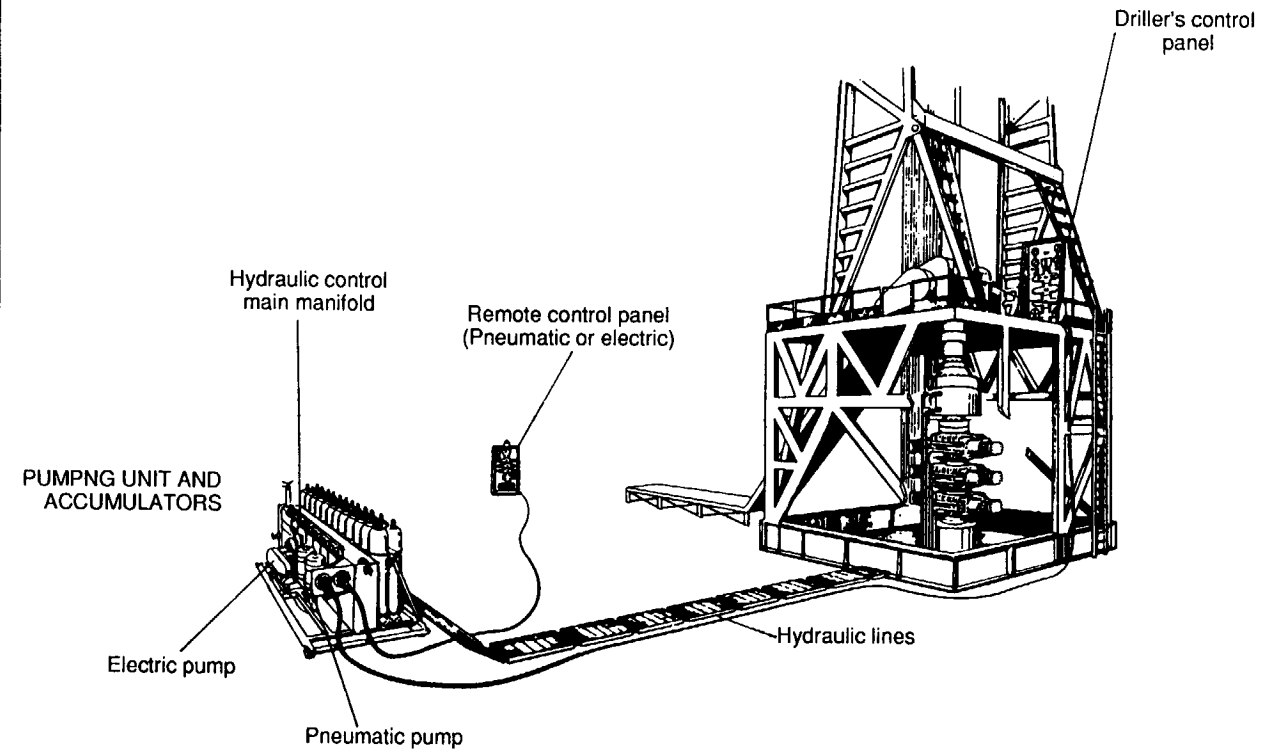
## ANNULAR PREVENTER



## RAM BOP



# BOP CONTROL CIRCUIT



The chokes allow well pressure to be controlled while evacuating kicks.

After the chokes there is the buffer chamber that is connected to the flare, to the vertical degasser and to the return flow line. The choke manifold must be of the same series as the BOP.

### **1.9 The cementing pumps**

In general the cementing unit belongs to a cementing company. It has two rapid, high pressure, single action triplex pumps, tanks ( $\approx$  10bbl) containing the liquid to be pumped (supplied by the mud system) and a pre-mix tank in which the slurry is mixed with cement from the silo.

The cement pumps also carry out pressure tests of equipment and the open hole, and special operations (acidifications, gravel-packs).

### **1.10 Drilling crews**

Personnel supplied by the drilling contractor :

- a tool pusher ;
- a night pusher ;
- a secretary ;
- two or three crews made up as follows ;
  - . a driller,
  - . an assistant driller,
  - . a derrickman,
  - . three roughnecks ;
- a surface crew made up of roustabouts and in some cases a crane operator.  
Offshore this crew is managed by a barge master ;
- one or two mechanics ;
- one or two electricians ;
- a materials man.



## 2 Drilling bits

There are two main groups of drilling bits :

### 2.1 Roller cone bits (Rock bits or jet bits)

Tricones are the most common.

**Action :** The cones roll on the rock which is destroyed as the teeth impact it. Furthermore, if the cone axes are not converging (they are offset), the teeth have a skidding movement on the rock, which is thus subjected to a shearing effect. The softer the rock, the higher the possible " offset " .

There are two groups of tricones :

- tricones with milled teeth : the teeth are cut in the cones (soft rock, non-abrasive),
- tricones with inserts : the teeth are tungsten carbide inserts (hard rock, abrasive rock).

### 2.2 Diamond bits

There are two types of diamond bits :

- bits with natural diamond stones, set in a tungsten carbide cast monobloc. This type of bit operates by abrasion and is used for drilling hard rock.
- bits with cylindrical synthetic diamond (PDC) plaquettes with a diameter of several millimeters. This type of tool operates by cutting and is used for soft rock.

Diamond bits must operate at high speeds, low weight and generate a high torque.

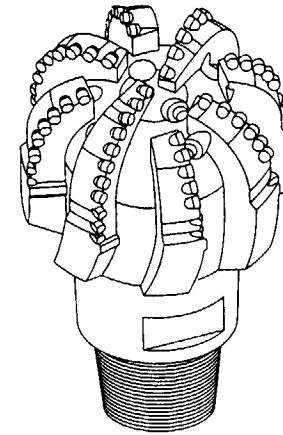
### 2.3 Drilling parameters

The weight on the bit : rough guide : 2T/inch of diameter. In fact this rule must be adapted depending on the diameter, the rock, the deviation, and the bit life.

## TYPES OF BITS



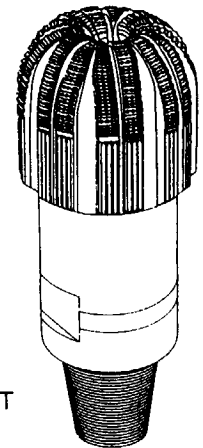
MIDDLE TEETH  
TRICONE



PDC BIT



INSERT TRICONE



DIAMOND BIT

Example : bit diameter 12"1/4 :

	Weight	RPM
Milled tooth bit	15 to 35 T	60 to 120
Insert bit	30 to 40 T	40 to 60
Natural diamond bit	12 to 25 T	180 to 300 or more with a motor or a turbine
PDC bit	6 to 15 T	

## 2.4 IADC Classification of bits and bit wear

Tricone bits are classified using three numbers and one letter.

- **First Number**

The numbers 1, 2, & 3 define steel tooth bits and correspond to increasing rock hardness.

The numbers 4, 5, 6, 7 & 8 define tungsten carbide insert bits and also correspond to increasing rock hardness.

- **Second Number**

The numbers 1, 2, 3 & 4 define a sub-classification of rock hardness in each of the eight classes defined by the first number.

- **Third Number**

The numbers 1 to 7 define the type of bearing and state whether there is or not a protection by a tungsten carbide insert, on the cutting edge of the bit rollers :

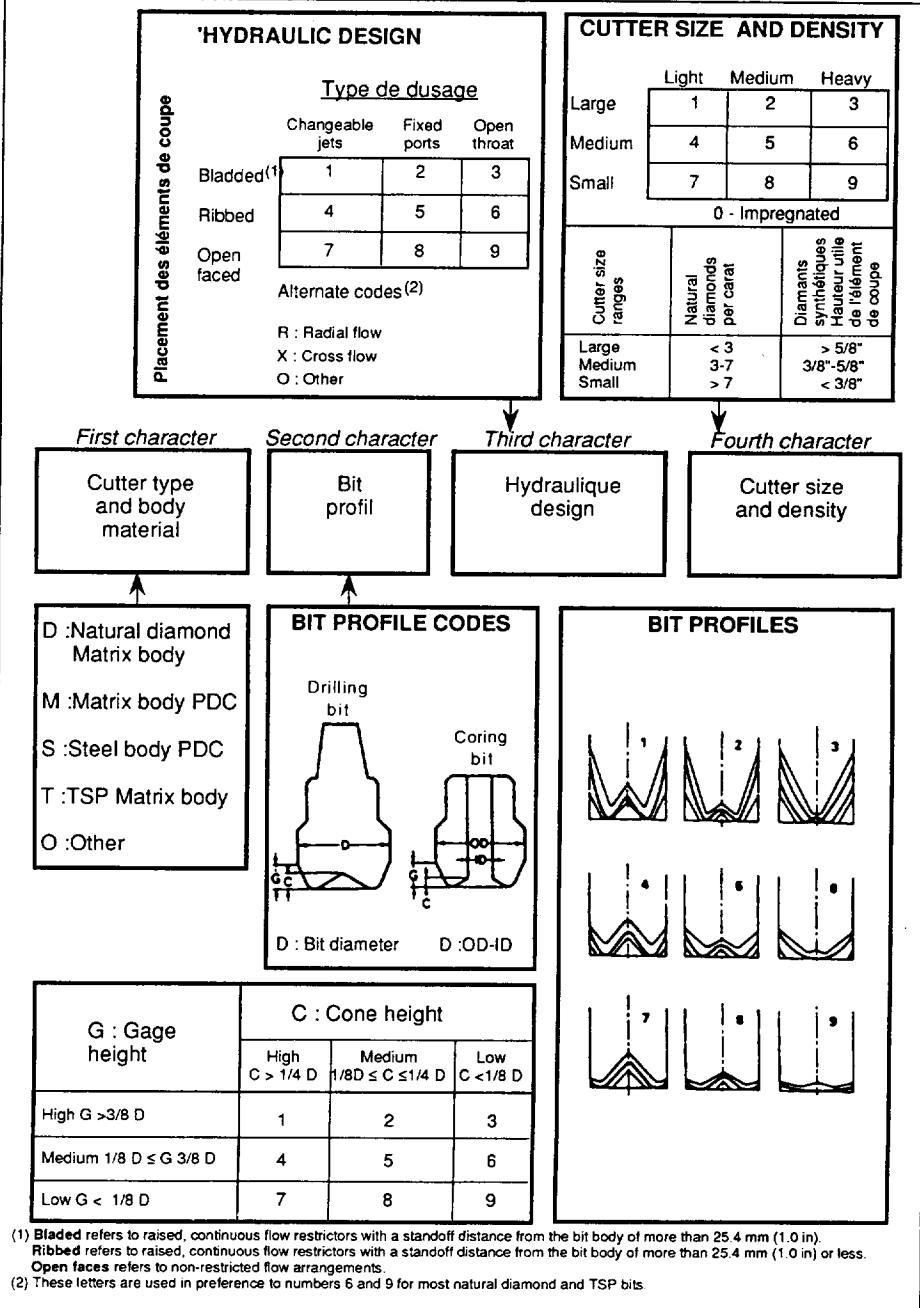
- Number 1 : unsealed bearings - without protection
- Number 2 : unsealed bearings for air drilling
- Number 3 : unsealed bearings - with protection
- Number 4 : sealed bearings - without protection
- Number 5 : sealed bearings - with protection
- Number 6 : sealed sleeve bearings - without protection
- Number 7 : sealed sleeve bearings - with protection

The numbers 8 and 9 are reserved for future use.

**Additional letter**

- A : bit with sleeve bearings for air drilling
- C : jet bits with central nozzle
- D : special bits for directional drilling
- E : jet bits with extended nozzles
- G : bits with reinforced protection
- J : inclined jet bits
- R : bits with reinforced welds for percussion use
- S : standard steel tooth bits
- X : bits with wedge shaped inserts
- Y : bits with conical inserts
- Z : insert bits ; shapes other than wedges or cones.

# IADC CLASSIFICATION OF BITS WITH FIXED CUTTERS( DIAMONDS, PDC, TSP, ...)



# USED BIT DULL GRADING SYSTEM FORMAT AND CODES

The dull grading system applies both to roller bits and diamonds bits, PDC, TSP and core bits. The system is flexible enough for use in the bit reports, daily reports and database.

Cutting structure				B	G	Remarks	
Inner rows	Outer rows	Dull characteristics	Location	Bearing /Seals	Gage 1/16 in	Other dull	Reason pulled
Table 1	Table 1	Table 2	Table 3	Table 4	Table 5	Table 2	Table 6

**TABLE 1**

Inner : inner 2/3 of bit Outer: outer 1/3 of bit
0 : No wear . . . 8 : No usable cutting structure

**TABLE 2**

BC : broken cone BT : broken teeth/ cutters BU : balled up CC : cracked cone CD : cone dragged CI : cone interference CR : cored CT : chipped teeth/ cutters ER : erosion FC : flat crested wear HC : heat checking JD : junk damage LC : lost cone LN : lost nozzle LT : lost teeth/ cutters OC : off-center wear PB : pinched bit PN : plugged nozzle/ flow passage RG : rounded gauge RO : ring out	SD : shirrtail damage SS : self sharpening wear TR : tracking WO : washed out-bit WT : worn teeth/ cutters NO : no major/ other dull characteristics
---	---

\* Show cone number(s) under location.

**TABLE 3**

Outils à éléments de coupe fixes	Tricônes
C : cone N : nose (row) T : taper S : shoulder G : gauge A : all areas/ rows M : heel row	N : nose rows cone N°1 M : middle rows N°2 H : heel rows N°3 A : all rows

**TABLE 4**

<b>Nonsealed bearing:</b> 0 : no life used . . . B : all life used  <b>Sealed bearing:</b> E : seats effective F : seats failed  X : fixed cutter bit (diamonds, PDC, TSP)
---

**TABLE 6**

BHA : change Bottom Hole Assembly DMF : downhole motor failed DSF : drill string failure DST : Drill Stem Test DTF : downhole tool failure LOG : run logs RIG : rig repairs CM : condition mud CP : core point DP : drill plug FM : formation change HP : hole problem HR : hours on bit PP : pump pressure PR : penetration rate TD : total depth/ CSG depth TQ : torque TW : twist-off WC : weather conditions WO : washout drill string
---

**TABLE 5**

I : in gage 0 : to 1/16" in under gage 1/16 to 1/8" in under gage . . .
--

## 2.5 Drill Bit hydraulics

Drill bits are designed with orifices (nozzles or jets) that increase the mud velocity at the cutting face (100 to 120 m/s) : this is called jetting. Jetting serves to help the bit destroy the rock and to clean the hole by removing the cuttings. The cross section of the orifices is chosen as a function of the flow required. On tricones the jets can be removed and are measured in thirty seconds of an inch ; on diamond bits, the jets cannot be removed, and the total flow area, TFA, is measured in square inches.

## 2.6 The geologist's role

At the base (subsurface) or on the rig, the choice of a new drill bit should normally be decided between the drilling engineer and the geologist.

This should apply because a drill bit will be chosen not only because of its expected " performance " but also because of the expected types of formation to be drilled (hard or soft rock, homogeneous or alternating, any chert or pyrite, etc) and the degree of detail required in the formation descriptions.

Each type of drill bit gives different cuttings. Thus a roller bit gives good sized chips whereas diamond bits give fine cuttings that rapidly become a " sticky paste " that is hard to analyse.

It follows that when large size cuttings appear during the use of a diamond bit, it always means that the bore hole is unstable (caving), inversely, " powdery " cuttings with a roller bit indicates that there is a re-crushing effect as the cuttings come up the annulus due to an eccentric rotation of the drill string. These two situations may indicate an anomaly that should be brought to the attention of the drilling supervisor.

Re-crushing can also produce cuttings that are so fine that they cannot be seen as cuttings. In this case, if no other parameter changes, the only indication will be the reduction in the quantity of cuttings.

### 3 The drill string

The drill string is made up of drill pipe and a bottom hole assembly (BHA).

#### 3.1 The drill pipe DP

Drill pipe supports the weight of the bottom hole assembly, transmits the torque and the mud to the bit. The drill pipe never works in compression. Each joint of drill pipe (single) is about 9 meters long.

Classification of drill pipe :

- diameter : the most common are 5" and 3"1/2
- the nominal weight (lbs/ft)
- the tool joint : IU - EU - IEU (strengthening of the joint by : Internal Upset, External Upset, Internal and External Upset)
- the grade E - X - G - S
- the range : class I (new drill pipe), premium, class II to class IV by increasing order of wear.

#### 3.2 Heavy weight drill pipe

Heavy weight drill pipe acts as an intermediary between the drill pipe and the drill collars in order to avoid changing cross section or flexibility too rapidly.

They can also be used as drill collars in directional drilling because of their greater flexibility.

#### 3.3 Drill collars DC

The drill collars apply weight to the bit and give vertical guidance. They must be as heavy and as rigid as possible. The length of drill collars is chosen to give the neutral point at 2/3 of their length up from the bottom, the lower portion being in compression, the upper portion in tension. Certain drill collars can have a spiral profil on their outside in order to reduce the risk of differential pressure sticking by reducing the surface area in contact with the well bore.

Drill collars are classified by their external diameter (the most common diameters are 6"3/4, 8", 9"1/2).



## **3.4 Accessories**

### **3.4.1 K-Monels**

The K-monel is a drill collar made out of a non-magnetic alloy, in which deviation azimuth measurements are made.

### **3.4.2 Stabilizers**

Stabilizers have the same diameter as the bit and centralize the BHA in the hole. A stabilizer placed just above the bit is called the near bit stabilizer.

For vertical drilling the BHA must be stiff and usually includes 3 or 4 stabilizers. Modifying the position and the number of stabilizers changes the rigidity and the behaviour of the BHA and allows deviated holes to be drilled.

### **3.4.3 The bit sub**

This connection (sub) is located between the bit and the BHA. It often includes a check-valve to avoid blow-outs through the drill pipe. This check valve is always used by Elf.

### **3.4.4 Jars**

Jars allow longitudinal shocks to be delivered to the drill string when it is stuck in the well. They can strike upwards and/or downwards.

**Upward jarring :** The jar is set by increasing weight to close it, then it's put into tension. A hydraulic circuit delays the opening of the jar. When it opens, it does so violently, using the energy stored in the elasticity of the drill pipe, delivering an upward blow to the drill string.

**Downward jarring :** The jar is set by pulling on it. Then weight is set down on it. The blow is downwards.

### **3.4.5 Jar accelerators**

A slip joint that has a pressurized nitrogen chamber that acts as a spring, and placed above the jar, amplifies the shock.

### **3.4.6 Shock absorber**

This tool dampens the longitudinal shocks and twisting during drilling.

## **3.5 Tripping the drill string**

Tripping means running the drill string into the hole or pulling it out. Either tripping in (Run in the Hole, RIH) or tripping out (Pull Out of the Hole, POOH).

The string is tripped in stands, normally made up of three joints of drill pipe, depending on the height of the derrick.

### **3.5.1 RIH**

The stands are stored in the derrick. They are handled using elevators hung below the hook, by the derrickman who works up in the derrick and the roughnecks on the rig floor. The operations and the drawworks are run by the driller.

Every time a stand is added, the string is set in the slips that are supported by the rotary table. The top joint of drill pipe sticks up above the table by about one meter.

Each stand is screwed into the string and tightened with the drilling tongs. The string thus increases in length. It is picked up by the hook, the slips are removed and it is RIH over the length of the newly added stand, set again in the slips, etc.

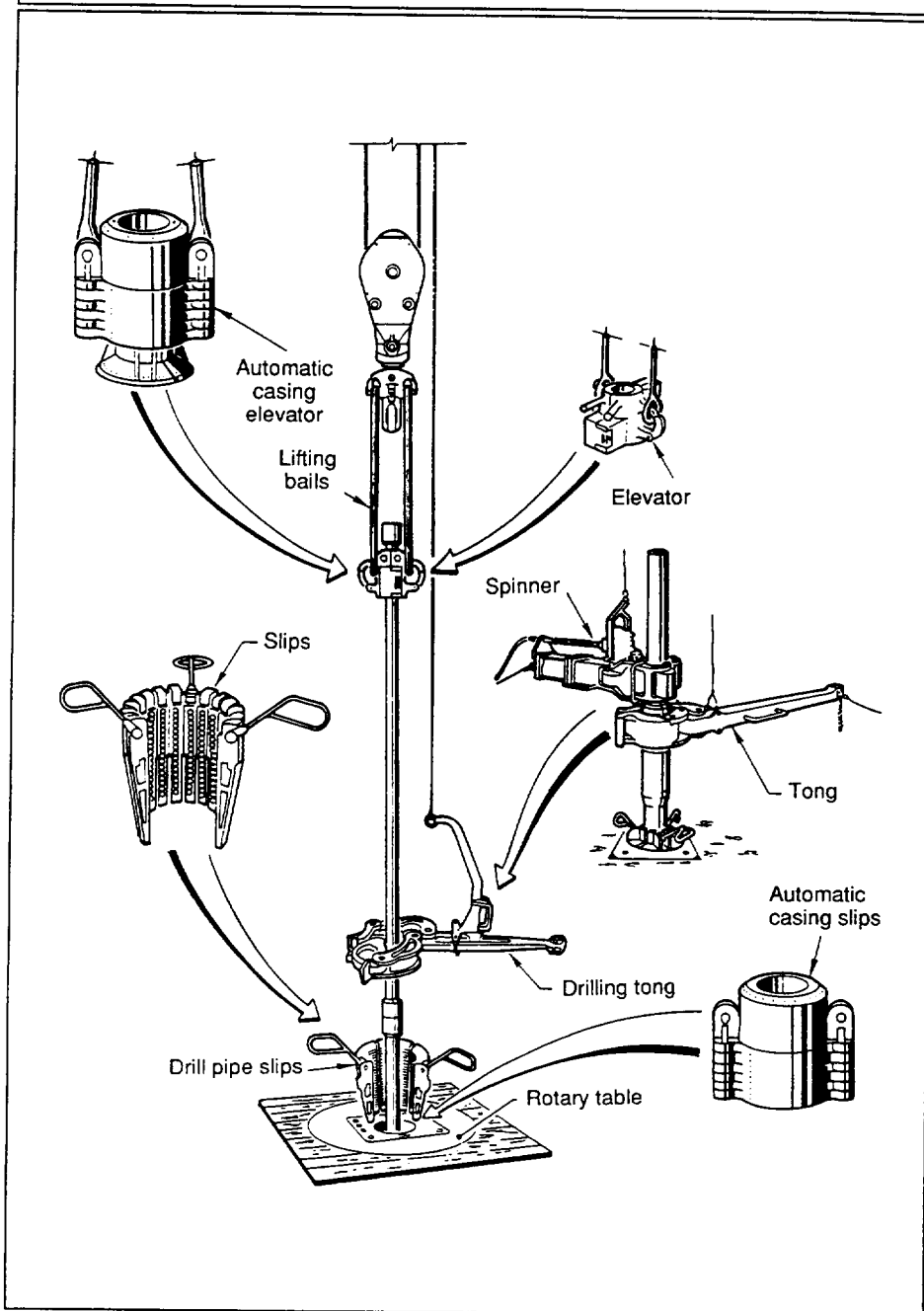
### **3.5.2 Adding drill pipe**

Whilst drilling, when the hook gets to its lowest position, a new joint of drill pipe is hoisted onto the rig floor using a winch. It is put vertically into the mouse hole so that its upper connection is at the level of the rig floor. The string is set in the slips, the power swivel or the kelly is unscrewed, and then screwed onto the new joint of drill pipe. This joint of drill pipe is then removed from the mouse hole and screwed onto the string which is then taken out of the slips to allow drilling to continue.

### **3.5.3 POOH**

POOH is carried out by reversing the operations for RIH. The stands are stored in the derrick after unscrewing.

# HANDLING TOOLS FOR DRILL PIPE AND BHA



If the drill string is not going to be used for the ensuing operations, it is **laid down** by removing joints, rather than **stands**, that are stored on the pipe racks.

## **4 The drilling mud**

### **4.1 Its role**

The mud (or drilling fluid) has the following functions :

- carrying the cuttings up the annulus
- jetting,
- lubricating and cooling the bit,
- retaining the borehole walls,
- maintaining a counter pressure on the formation fluids.

### **4.2 The different types of mud**

There are two main types of mud :

- water based muds,
- oil based muds.

A mud is made up of a continuous phase (water, that can contain oil as an emulsion for water based muds, and the opposite for oil based muds), viscosifying agents (usually clay based, often bentonite), weighting materials (usually barium sulphate called barite) and other additives.

There is a wide range of additives that have various effects. The majority are used to modify the physico-chemical characteristics of the mud. There are also plugging materials used in case of losses (Lost Circulation Material, LCM), and lubricants used for drilling highly deviated wells and when the string is stuck.

TYPES OF MUD	AVERAGE COMPOSITION (/m <sup>3</sup> )	CHARACTERISTICS	CONTAMINATION STABILITY	FIELD OF USE
Bentonitic mud with FCL/LC	Bentonite : 50-100 kg FLC : 20-40 kg Caustic Soda : 2-4 kg CMC : 0-5 kg + possibly LC : 10-20 kg + anti-foam 1-3 ‰	pH > 9 Good temperature resistance up to 200°C	good Cl <sup>-</sup> from 50 to 70 g/l	- Depth up to 6000 m - Wide field of use : adjust FCL/LC concentration as a function of contamination problems (gypsum, anhydrite, clay, etc.)
Gypsum mud	Bentonite : 50-70 kg FCL : 12-15 kg Caustic Soda : 3-4 kg Gypsum : 10-20 kg CMC : 5-10 kg + possibly LC	pH > 9 good temperature resistance 200°C	good Cl <sup>-</sup> up to 70 g/l	- Gypsum or anhydrite horizons - Clay horizons - Slightly saliferous horizons
Salt saturated mud	Salt : 350 kg Clay : 50 kg (saline muds) Starch : 30-40 kg Lime : 0-10 kg	d > 1.20 corrosive	Good : gypsum, anhydrite, average : clays	- Saliferous horizons - Clay zones that are not or only slightly dispersing
Natural polymer mud	Guar gum : 10 kg (seal water or soft water)	initial d 1.02 pH 7 Viscosity > 80	low	- Spudding mud offshore - Very viscous mud plugs to clean large diameter , deep holes < at 500/600 meters
Oil based mud Emulsion mud	oil : 715 l water : 205 l CaCl <sub>2</sub> : 55 kg Emulsifier : 15 l Fluid loss : 18 l Lime : 30 kg Thickener : 15 kg Weighting : (f) density Wetting : (f) solids	ratio oil/water : 80/20 % Plastic viscosity : 16/18 cps yield value : 16/18 lbs/100ft <sup>2</sup> electric stability : 600 Volts	very good	- Highly deviated wells - High pressure wells - High temperature wells - Fragile formation

TYPES OF MUD	AVERAGE COMPOSITION (/m <sup>3</sup> )	CHARACTERISTICS	CONTAMINATION STABILITY	FIELD OF USE
Salt saturated mud with organic thinners	Salt : 350 kg Clay : 50 kg Starch : 20-30 kg Caustic soda : 4-6 kg FCL : 30-45 kg LC : 10-15 kg (Made by conversion of a salt saturated mud without thinners)	d > 1.20 corrosion resistance at temperature > 140°C	Good	- Saliferous horizons - Clay zones with high dispersion
Water based emulsion mud	Water based mud + 5 to 10 % oil	Those of water based mud + filtrate lubricating properties friction	Those of water based mud	Those of water based mud + - Marls - possibility of sticking
Sea water mud	Polymer : 4 kg Chromic Chloride : 1.2 kg Caustic soda : 8-10 kg Bactericide : 0.3 kg Bentonite : 15 kg + possibly FCL and CMC	Very low solid content. Minimum density (< 1.03) Filtrate > 12 cm <sup>3</sup> usable in sea water	Average	For formations with few problems : improves penetration rate
Simple bentonitic mud	Bentonite : 40-60 kg CMC - 0 - 5 kg	low initial d (1.03 to 1.05) pH : 8.5 to 9	Low	- Spudding mud - Few contamination problems
Bentonitic mud with tanning agents	Bentonite : 40-60 kg Tannin : 2-4 kg Caustic soda : 0.5 - 1 kg CMC : 1 - 5 kg	pH < 11 filtrate from 2 to 4 cm <sup>3</sup>	Average Ca <sup>++</sup> < 300 mg/l Cl <sup>-</sup> < 20 g/l	- Depth < 3000 m - Low contamination zones (gypsum, anhydrite, clays)

The parameters to be monitored are as follows :

- flow rate,
- the density,
- the viscosity
- the thixotropy (gel formation),
- the filtrate (water loss)
- the chemical composition.

#### 4.3.1 Choice of flow rate

The flow rate is determined by the mud velocity required in the annulus (AV). Successful cutting removal requires a velocity of around 30 to 45 m/min. It can happen that the mud, with the associated cuttings and gas, gets to the surface later than the theoretical time (up to 20% difference). This may indicate that the well volume is greater than the theoretical volume (caving). Thus it is important to monitor the lag-time by observing the time taken for a gas peak generated by calcium carbide or rice grains inserted in the drill pipe at connection.

Too high a lag-time leads to cutting dispersion in the mud and an increase in the concentration of solids in the mud.

The flow regime depends on the mud velocity and on its viscosity

- AV < 15 to 20 m/min : plug flow
- 30 < AV < 45 m/min : slow laminar flow
- AV > 100 to 125 m/min : turbulent flow

Turbulent flow should be avoided in open hole, as it increases pressure losses and increases overbalance on the open hole. It also deteriorates the mud cake and aggravates breakouts and caving.

**Attention :** The cross sections of the mud circuit being extremely variable (especially in the annulus) velocities and flow regimes are not constant.

In the case of small diameter drilling with a riser (on a floating rig) mud can be injected at the bottom of the riser to increase the flow velocity (using a *boosting line*), which dilutes the hydrocarbon shows and the concentration of cuttings, and changes the lag-time.



### **4.3.2 The role played by the mud density**

#### **4.3.2.1 Stabilizing the well bore**

The part of the well that has just been drilled (or open hole) and that is in contact with the mud has a general tendency to increase in size for mechanical reasons (unbalance of the initial stresses that can result in a breakout and caving of the walls) and for chemical reasons (solubility of certain rocks that can result in swelling, breakdown, dissolving, etc). The open hole can also have a tendency to close up (the case of salt, certain "flowing" or "swelling" clays).

The mud used must therefore have a density sufficient to replace the destroyed formation and maintain the borehole stability, and physico-chemical characteristics adapted to the formations drilled.

Maintaining stability of the open hole is more difficult as the section increases in length.

The mud's characteristics cannot always be compatible with several different formations. This means that the borehole instability can define when a drilling phase has to end.

#### **4.3.2.2 Reservoir balance**

When drilling into the reservoir, the mud density must be adjusted in order to stop fluids flowing into the well bore. Adapting the density exactly is impossible because of the dynamic pressure variations (pressure losses, swabbing, etc...). The static mud column must always exert an overbalance on the reservoir, and this can result in mud losses and plugging. This overbalance must be kept to a minimum to avoid differential pressure sticking. While drilling the reservoir, the mud filtrate must be as low as possible in order to avoid pollution of the reservoir fluids.

- **Reservoirs containing liquids**

Drilling through reservoirs containing a liquid, in general is not a problem.

Drilling through several reservoirs during the same phase is possible provided they have similar equivalent densities.

Drilling through several reservoirs of different equivalent densities, especially if the equivalent densities decrease with depth, is dangerous. This can result in kicks or losses, depending on the mud density, or even worse, an internal blow out (one reservoir flowing into another of slightly lower equivalent density).

- **Reservoirs containing gas**

Drilling through a gas reservoir is usually difficult. On one hand, the exchanges between the gas and the mud are greater, on the other, the low density of the gas creates an equivalent reservoir density drop as a function of the depth, and hence, an abnormal pressure at the top of the reservoir. In a thick gas bearing reservoir it becomes difficult to adjust satisfactorily the mud density.

In addition, a gas blow out happens faster and is more difficult to control, especially as gas in the annulus lightens the mud column.

#### **4.3.3 The problem of cutting sedimentation : the role of thixotropie**

When circulation stops, the sedimentation velocity of the cuttings is a few meters/min. Afterwards, the mud gel increases rapidly, and the gel measured after a ten minute shut down (Gel 10) is about 2 to 3 times higher than the initial gel (Gel 0).

The large cuttings are more of a problem than the smaller ones (the weight/surface ratio increases with volume). The large cuttings are often re-crushed before reaching the surface.

Attention : in the case of the deviated wells, the sedimentation problem is worse, the sedimentation height is reduced (becoming less than the hole diameter in a horizontal well).

##### **4.3.3.1 Mud filtration**

When the mud is in contact with borehole wells that are more or less porous, the liquid part filters into the formation whereas the solid part is deposited on the bore as the mud cake, until this cake stops further filtration. So that, the faster the cake is formed, the less liquid enters the formation.

The " external cake " made up of particles of different thickness, is deposited on the wall. The " internal cake " is made up of finer particles that invade the porous network of the formation and plug its permeability.

The cake has the advantage of plugging porous formations and avoiding mud losses. However, too high a filtration can lead to the breakdown of delicate formations, to reservoir invasion and to a cake too thick that can stick the drill string.

The invasion depth depends on the type of mud (speed with which cake forms), the petrophysical characteristics of the formation and the amount of differential pressure.

#### 4.3.4 The geologist's role

The Mud-logging cabin must be advised of any voluntary modification to the mud, such as diluting, transfer, additions, etc. The different types of added products must also be communicated to the geologist. In the case of "exotic" products, it is recommended that a sample be taken for analysis. It must be remembered that numerous products can have a significant effect on future operations.

To mention only the most common :

- barite makes reading the Pef very difficult,
- Potassium chloride (Kcl) can increase the percentage of potassium read by the NGT (Spectral Gamma Ray - Schlumberger Trade Mark),
- ligno-sulfates, due to their concentration in the cake, can influence resistivity measurements,
- all shell or calcium carbonate based plugging agents will give false calcimeter readings,
- soltex, or any other diesel based product, can lead to parasite gas shows,
- vertrasol is unfortunately fluorescent,
- lubriguid (lubricant) is made up of minute balls that rapidly accumulate on the shale shakers instead of the cuttings.

This list is unfortunately incomplete but demonstrates the necessity to maintain permanent communication with the people in charge of the mud.

Numerous additives will make later laboratory analysis difficult, especially in organic geochemistry or even in biostratigraphy. If they have to be used, then samples must systematically attached to the cuttings samples before dispatching (see Recommended practices, RME 8-2).

#### 4.4 Mud losses

**Partial losses** : the formation absorbs part of the mud pumped into the well, which means that the mud level in the annulus drops more or less when circulation is stopped. Partial losses generally take place in the matrix of a porous rock.

**Total losses** : there are no mud returns and the well can be significantly emptied. Total losses take place generally in fractures, either pre-existing or induced.

Losses are detected by monitoring pit levels, or by using a flow meter if the rig has one.

When losses take place, plugging agents (Lost Circulation Material) must be added to the mud, and it may even be necessary to inject cement slurry.

## 5 The Casing

### 5.1 Role

The aim of the casing is to isolate one part of open hole from the next phase, and to isolate the critical parts of a stretch of open hole one from the other.

A typical well design is as follows :

- a 30" conductor pipe (CP), that supports the well head and the other casings,
- a 20" surface casing to maintain the unconsolidated surface formations,
- several intermediate or technical casings (13<sup>3</sup>/<sub>8</sub>, 9<sup>5</sup>/<sub>8</sub>, 7"),
- the production casing, the last casing before completion,
- in some cases a liner, which is a production casing that is hung from the bottom of the previous casing and that doesn't go all the way to the surface.

### 5.2 Description

A casing string is made up of a series of tubes about twelve meters long, threaded at both ends, of which one (at the top when RIH) is fitted with a double box collar.

A casing (and its threads) is subjected to tension, bursting, collapsing, bending (in deviated wells) stresses that are often combined.

### 5.3 Classification

A casing is defined by :

- its external diameter (in inches),
- its nominal weight (in lbs/ft),
- its grade (1 letter followed by a number that represents the elastic limit of the steel in thousands of pounds per square inch, (PSI)),
- its thread.

## 5.4 Calculation

A casing is calculated to withstand :

- its own weight in the mud (maximum stress in the upper part),
- the collapsing effect of the mud from the previous phase, casing empty,
- the burst effect, casing full of gas (maximum stress at the top of casing).

The calculation assumptions vary for each case, but are based on strict procedures.

## 5.5 Running the casing

A casing is run in the same fashion as a drill string, joint by joint. The first joint is fitted with a hemispherical shoe, that strengthens the end of the casing while running in the hole. The shoe often includes a no-return system to stop the cement from coming back into the casing at the end of the cement job, and to prevent a possible blow out inside the casing string. A cementing collar (or float collar) is installed a few joints above. It contains another no-return system and retains the cement plugs. The shoe and the collar are made out of drillable material (except for a production string which will not be drilled out). All the threaded connections from the shoe to the collar are glued with Baker Lock in order to avoid unscrewing while drilling out the float collar and shoe.

The casing string is fitted with centralizers over all the cemented part(s), at the shoe of the previous casing, and at the mud line suspension (MLS), if it exists. It can also have scratchers that scrape the cake from the borehole walls.

Offshore wells that will be temporarily abandoned are fitted with a mud line suspension. At the sea bed, a piece is put in the string, with a seat inside from which the next casing will be hung, and on the outside it is designed so as to sit in the previous casing hanger. The upper part of the hanger can be dismantled so as to allow the recovery of the casing from sea bed to well head.

## 5.6 Running a liner

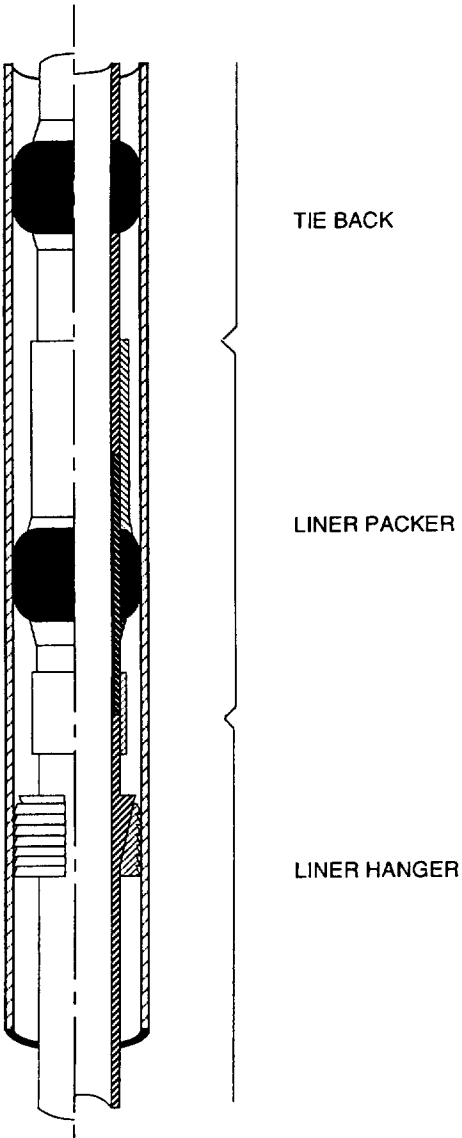
The liner is run with drill pipe and then anchored about 150 m above the shoe of the previous casing (either mechanically by rotation and setting down weight, or hydraulically by applying pressure in the drill pipe).

The liner hanger includes anchor wedges and a sealing system. After pressure testing, if the system leaks, a pack-off can be put in the liner hanger that gives a second seal off.

If the last casing is defective, a tie-back is run, connecting the liner hanger to the surface, transforming the liner into a normal casing.

A tie-back can also be necessary for production testing of reservoirs covered by the liner.

LINER HANGER





## **6 Cementing**

### **6.1 Role**

A cement job is designed to bind the casing to the formation, and to seal off the annular space between them so as to isolate the open hole behind the casing from the next phase drilled.

### **6.2 Principle**

The cement slurry is pumped into the casing then displaced by mud to come back up the annulus for about 300 m. Normally a spacer is pumped before and after the slurry to avoid contamination with the mud. The spacers have rheological characteristics between those of the slurry and the mud. The CP (when it is cemented) and the surface casing are usually cemented to surface.

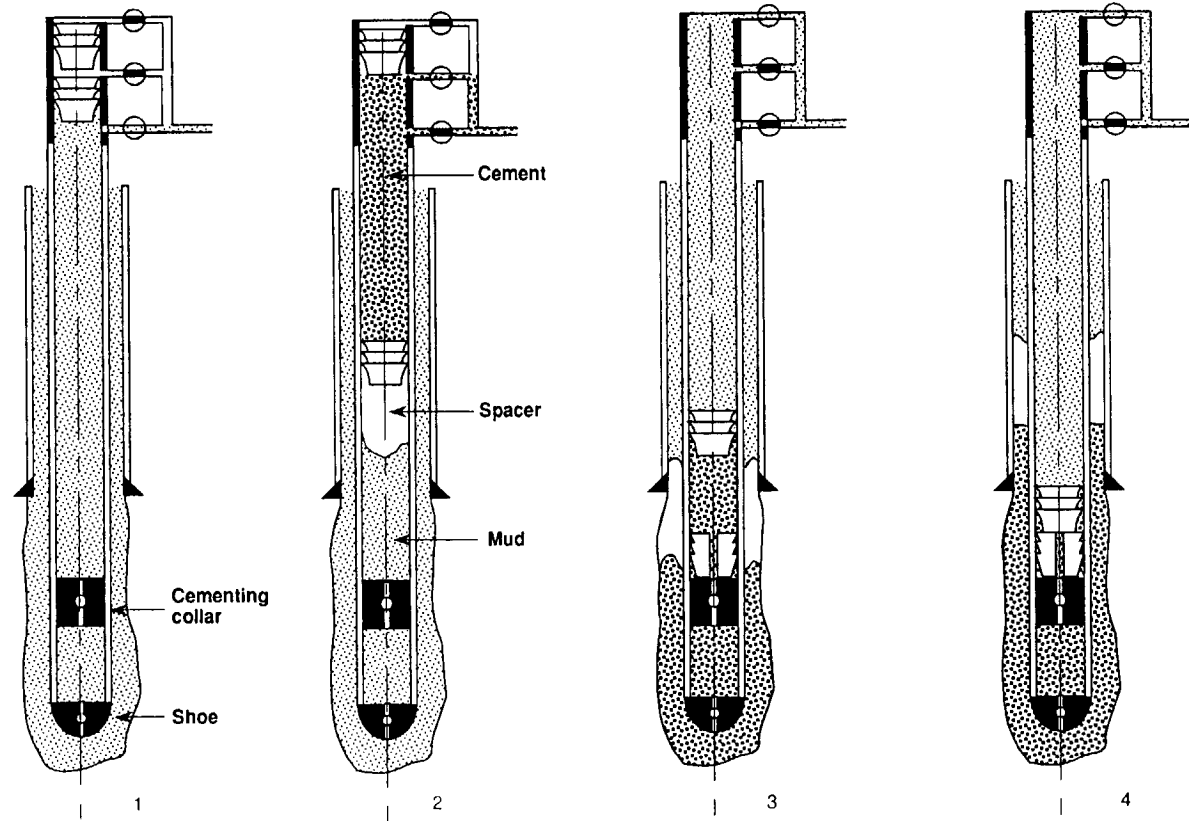
### **6.3 Cementing with a stinger**

For large diameter, shallow casings, the slurry is pumped through the drill pipe, the end of which stabs into the shoe, fitted with a check-valve. Another solution is to run the drill pipe to the shoe and seal off at the surface between the drill pipe and the casing. This method allows the pressures to be balanced on the casing and so avoid collapse.

### **6.4 Single stage cementing**

The casing is equipped with a shoe and a collar separated by one or two joints, both of which have check-valves. The slurry is pumped through a cement head containing the cement plugs that can be released quickly without dismantling the head.

# SINGLE STAGE CASING CEMENTING WITH BOTTOM AND TOP PLUGS



**Procedure :**

- Circulate at high flow rate to clean the hole.
- Pump the spacer.

The spacer has the same base fluid as the mud with rheological characteristics between the mud and the cement. When oil based muds are used, two consecutive spacers are used, the first is oil based, the second is water based with detergents.

- Release the bottom plug that scrapes the inner walls of the casing to avoid slurry contamination.
- Pump slurry.
- Release top plug that isolates the slurry from the displacement fluid.
- Pump tail spacer.
- Displace.
- When the bottom plug hits the collar, the pressure increase bursts the plug and lets the slurry go through.
- When the top plug hits the bottom plug, the casing is pressured up to test it.

### **6.5 Double stage cementing**

If the formations are weak, or if there is a long stretch to cement, double stage cementing can be used.

At the base of the second stage, a stage cementing collar or differential valve (DV) is installed.

The first stage is run normally. When the slurry has hardened, a bomb is released that opens the DV (giving communication between the inside of the casing and the annulus). The lead spacers are pumped, the top plug is released and displaced by the tail spacer and the mud. When the top plug lands in the DV, it closes, isolating the inside of the casing from the annulus. The casing is then pressured up to test it.

## 6.6 Cementing a liner

The cement job is done through drill pipe without the bottom plug.

### Procedure :

- Circulation.
- Pump the lead spacer.
- Pump the slurry.
- Release the pump down plug that pushes the wiper plug, previously placed in the top of the liner.
- Displace until pressure build up.
- Pressure test the liner.
- Unscrew the setting tool (it can also be unscrewed just before cementing).

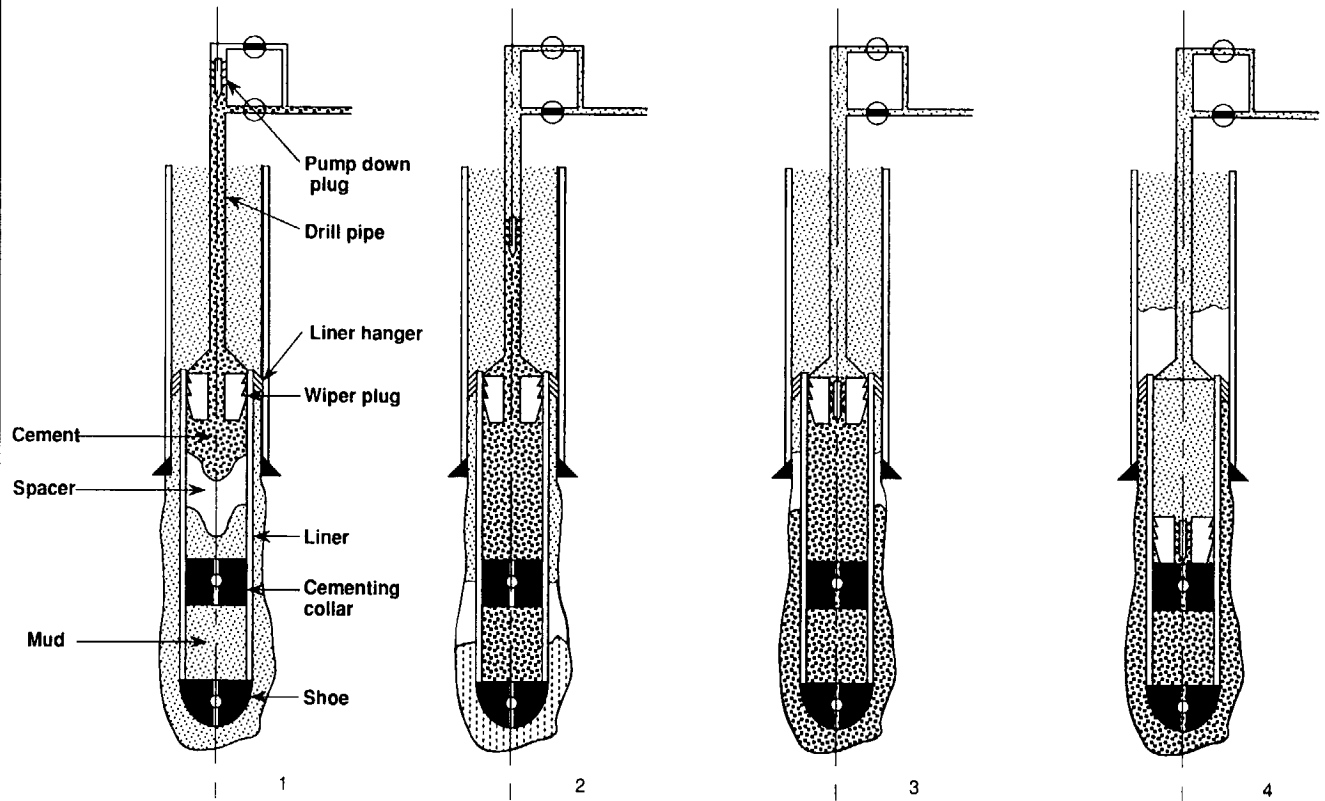
## 6.7 The key to successful cementing

A successful cement job must give a complete fill-up, leaving no annular space or channeling (vertical communication between different levels) with good adhesion to both the casing and the formation. To do this, the following conditions must exist :

- the hole must be clean and well calibrated,
- the casing must be in the center of the hole,
- the slurry must displace all the mud with no inter-mixing,
- the operation must not create losses, due to a high equivalent circulating density.

To enable the slurry to displace the mud correctly, it must be pumped either in turbulent flow, or plug flow if turbulent flow demands too high flow rates. For this to be the case, the cross section of the space through which the slurry flows (i.e. the annulus casing - formation) must be even. A poorly centered casing or a poorly calibrated hole will result in flow regime changes, the mud will be poorly displaced and mix with the slurry or remain trapped in washouts.

# LINER CEMENTING



Thus, the drillers have to do their best to produce a calibrated hole. The casing string is run with centralizers, and even scratchers that clean the sides of the hole. When the string is in position, the annulus is cleaned by circulation.

## **6.8 Repairing cement jobs**

If a cement job is considered poor, repair work can be done. To do this, the casing is perforated at the point to be repaired using perforation guns run on electric line. A cement retainer is set above the perforated zone. This is a redrillable packer with a check valve. Cementing is done with a stinger, and the slurry is squeezed behind the casing.

## **6.9 Slurry make-up and characteristics**

The slurry is made up of cement (commonly class G, cements are classified from A to J depending on their characteristics), water, and various additives.

**Density** : The most common is a slurry density of 1.90, made with 44 lts of water for 100 kg of class G cement.

By varying the quantity of cement the density changes (1.90 to 1.97). To obtain a heavier slurry weighting materials can be used (hematite, barite, etc.). To obtain a lighter slurry (gel cement) materials are used to lighten it, most commonly bentonite.

**Rheology** : addition of dispersants and viscosifying agents to adapt the slurry rheology to that of the mud to be displaced.

**Filtrate, free water** : as a slurry doesn't form a cake, cementing across a porous formation can lead to slurry dehydration that makes it less fluid, and then the cement more friable.

**Pumpability** : addition of accelerators or retarders allows the pumping time to be adjusted to comply with the duration of the cement job.

**Compressive strength** : addition of silica if the bottom hole temperature is high.

## **6.10 Checking cement jobs**

### **6.10.1 Temperature log (wireline log)**

This tool measures the temperature of the well versus depth. A cement job leads to heat being given off, so that a discontinuity in the temperature gradient indicates the top of the cement. This measurement doesn't allow the quality of the cement job to be evaluated.

### **6.10.2 CBL Cement bond log**

This tool transmits ultrasonics to the casing and a receiver lower in the tool records the echo from the casing. A well cemented casing dampens the echo, the quality of the cement job is inversely proportional to the amplitude of the signal.

### **6.10.3 VDL Variable Density Log**

This tool is always used with the CBL, therefore it's complementary. A graphic representation of the signals allows typical anomalies in the cement job to be detected.

### **6.10.4 CET Cement Evaluation Tool**

This tool gives an expanded graphic representation of the casing. The quantity of white and black allows the quality of the cement job to be evaluated (black : good ; white : bad).

### **6.10.5 USIT Ultra Sonic Imaging Tool**

This tool gives an expanded graphic representation of the casing. The quantities of the different colours allow the quality of the cement job and the corrosion of the casing to be evaluated.

## **6.11 Problems encountered**

- **Bubbling** : bubbles of gas trapped in the cement.
- **Channeling** : un-cemented channel allowing communication between several intervals.
- **Micro-annulus** : the cement does not adhere to the casing, allowing fluid to pass.

## **7 Formation pressure tests**

After the casing has been set and the cement has hardened, the collar and the shoe are drilled out until the bit penetrates a short distance into the formation. Here, a formation pressure test is carried out. The aim of this test is to check that the cement at the shoe and the surrounding formation will withstand the hydrostatic pressure of the mud for the next phase. Taking this test further, it is possible to establish the formation injectivity pressure or its fracture pressure.

### **7.1 Formation Integrity Test**

When the bit is in the formation, the rams are closed and pressure is applied by pumping into the drill pipe with the high pressure cement unit. The pressure is increased until the equivalent density at the shoe is equal to the highest mud density planned for the next phase. The pressure is maintained for several minutes then bled off. If the pressure cannot be maintained, this means that the shoe will not withstand the mud density planned. In this case a repair job has to be done (squeeze cement at the shoe).

### **7.2 Leak off Test**

This test is carried out in the same fashion. During the pressure build up, the pressure curve is plotted as a function of the volume pumped. When the line of the curve breaks, the formation injectivity pressure is reached. The test is stopped : the pressure is maintained for several minutes, then bled off. The volume of fluid recovered is measured.

### **7.3 Fracturation Test**

This test is identical to the previous one, but pumping continues after having reached the injectivity pressure. When the pressure drops violently, this indicates that the formation has been fractured and that pumping is taking place directly into the formation. The maximum pressure reached is the fracture pressure.



## 8 Well heads

The well head is the assembly of all the parts that support the casings and seal off the annuli. The production head (or christmas tree) is fitted onto the well head.

The casing head housing is fitted on the first surface casing . It can be welded (exploration) or screwed (production). This part supports the whole well structure. Generally the casing head housing sits on a base plate on the conductor pipe. It is designed with a conical bore to receive the casing hanger of the next casing.

A casing spool is fitted to the following casings. The lower part is fitted with a flange whose diameter and series are the same as the previous casing, and the upper part with a flange whose diameter and series are the same as the next casing. Inside the casing spool, in the upper part, a conical bore is designed for the casing hanger of the next casing, and in the lower part a cylindrical bore is designed to receive a pilot bit and a sealing device (bushing). Sealing is obtained either by compressing a series of neoprene and steel disks, or by inflating a neoprene packing by injecting small sticks of plastic grease.

The casing hanger is an anchoring and supporting device for casing made up of a series of wedges that bite into the casing to be set, and fits into the conical bore of the head. It also has a sealing assembly that can be part of the set of wedges or be separate.

Casing hangers can be manual (tightened by hand ; meaning that the BOP has to be removed) or automatic (tightened automatically as the casing is set. The BOPs don't normally have to be removed, as it can be dropped over the last casing from the rig floor). In order to set the casing on the hanger, it is put into tension, the hanger is set in place, the string is released and it sits on the hanger.

When fitting a new casing spool, it has a wear bushing that protects the conical bore from damage by bits, BHA, tool joints running through it and by string rotation.

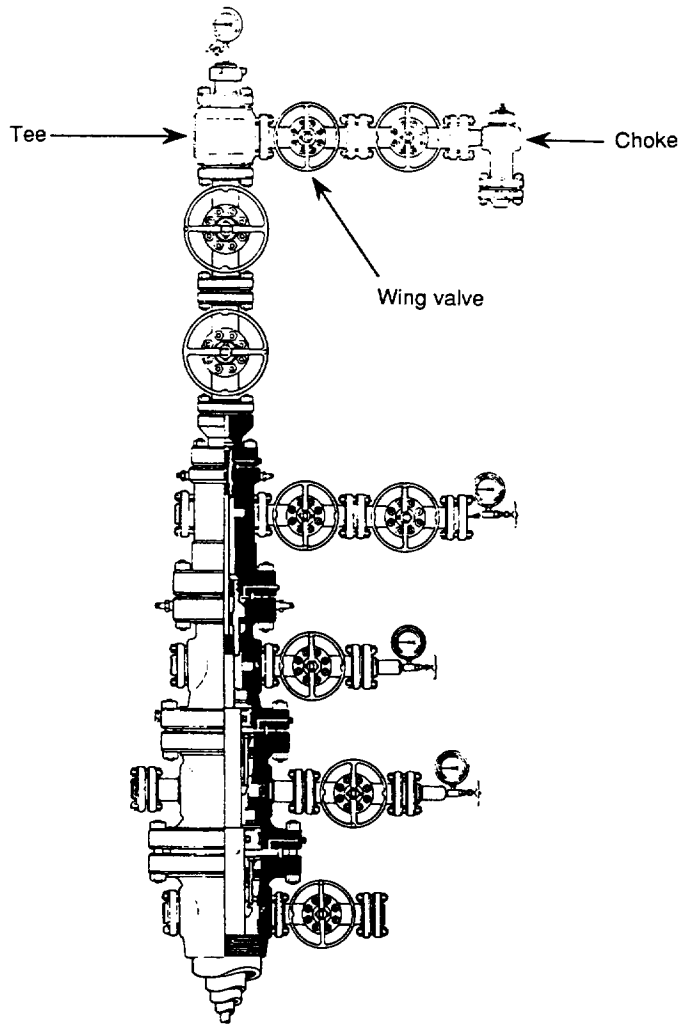
Casing spools are designed with test ports that allow the different seals to be pressure tested.

The production casing (the last casing) receives the tubing head which will receive the production tubing. Tubing heads work on the same principle as the casing spool. The hanging system is screwed onto the production string and has a set of seals, and it fits into a conical housing in the tubing head.

A christmas tree is fitted above the tubing head. It has two master valves that close the well, two side valves, one of which is connected to the production network, and an upper valve (a swab valve) through which light work over operations are carried out (wire-line, coiled tubing, etc.).

Wellheads also exist that are far more compact, made up of a single body, the number of levels depending on the casing program. These heads are normally used only for development wells, mainly offshore.

# WELL HEAD



## 9 Driving the conductor pipe

Conductor pipes can either be run into a drilled hole, then cemented, or they can be driven.

The lengths of casing are screwed or welded. The conductor pipe is driven using a hydraulic or diesel driven hammer set on the last piece of pipe. The pipe is driven generally until it can go no further, which is when the number of strokes per meter becomes too high (normally at 200 strokes per meter).

If however the pipe stops at what is estimated as being too shallow a depth, the conductor pipe can be drilled out to the shoe or beyond before continuing the hammering.

## **10 Directional drilling**

To drill a deviated well, rotary drilling can be used with a deviating BHA, or turbodrilling can be used with a down hole motor or turbine.

### **10.1 Rotary drilling**

This type of drilling is used when the trajectory doesn't have to be accurate, especially for the azimuth, and it is only for short lengths.

In rotary drilling, the deviation is obtained by changing the position of the stabilizers in the string so as to make it flex in the required direction. Another parameter is the diameter of the lowest stabilizer.

#### **10.1.1 A lock-up BHA**

This type of BHA allows for straight line drilling (vertical or inclined). It is a stiff BHA with four stabilizers. The first is the near bit stabilizer just above the bit, the second is one short drill collar above.

#### **10.1.2 A Build up BHA**

This BHA has three stabilizers. The first is just above the bit, the second is very far from the first, so as to make the string flex between these two points of contact, giving the bit a tendency to go in the opposite direction of the flexing.

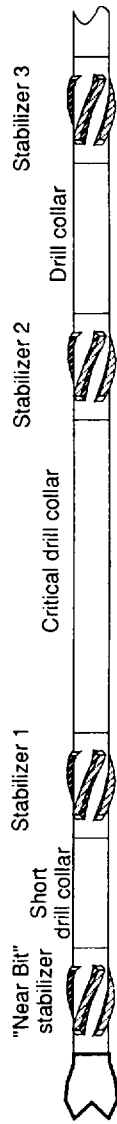
#### **10.1.3 A Drop-off BHA**

This BHA has two stabilizers, far from the bit so that the bottom portion of the string acts as a pendulum with a tendency to drop off.

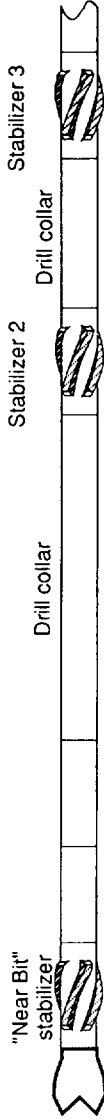
### **10.2 Deviated turbodrilling**

This is associated with a directional MWD, which allows the bit to be guided to give an accurate well trajectory.

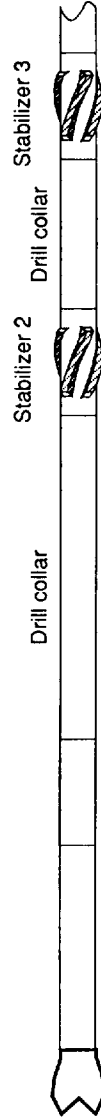
# DIRECTIONAL BHA



**LOCK-UP  
BHA**



**BUILD-UP  
BHA**



**DROP-OFF  
BHA**

### **10.2.1 Turbines**

They are made up of a stator and a rotor fitted with blades. The stator blades direct the mud, the rotor blades drive the rotor when mud circulates in the turbine. Turbines have a high rotation speed (1000 rpm) and a low torque.

### **10.2.2 Motors**

They are positive displacement type with an eccentric rotor with one or more spiral shaped lobes and a stator with one extra spiral lobe.

Motors are slower than turbines (from 50 to 100 rpm) but have a higher torque.

### **10.2.3 Deviation**

The deviation can be obtained using :

- a turbine (or a motor) with an offset shaft,
- an eccentric stabilizer,
- a bent sub above the motor,
- a bent sub below the motor fitted with a coupling, that can have two bends so that the bit center remains centered on the motor (double tilted unit, DTU) or a single bent sub. The angle of the bend can be fixed or variable. Certain bent subs can be adjusted whilst drilling by a pressure build up cycle (steerable), which means that a complete trajectory can be made with the same string.

## **10.3 Measuring the deviation**

### **10.3.1 Single shot (or TOTCO)**

A measuring tool dropped in the drill pipe, that falls onto a seat located above the bit sub, and which is fished by wire line. This tool only gives the inclination. A pendulum swings over a graduated paper disk, a timer sets off the perforation of the paper by the pendulum. Two perforations are made to ensure the measurements' precision.

### **10.3.2 Multishot**

Also a tool that is dropped into the drill pipe, but it gives inclination and azimuth.

A timer takes a photo of a compass and a pendulum. This measurement has to be taken in an anti-magnetic drill collar (K-Monel).

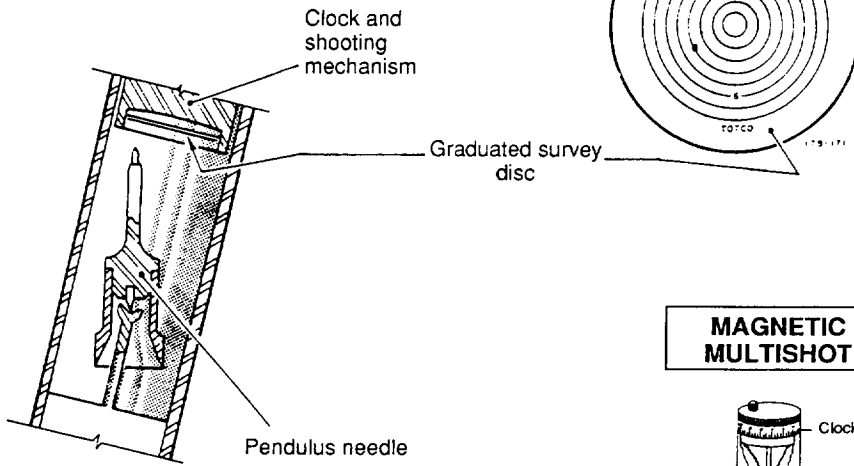
### **10.3.3 MWD**

MWD gives continuous inclination, azimuth and bit orientation (tool face) measurements. Guiding the deviated hole is done by orienting the drill pipe if a bent sub is used, or by changing the inclination of the steerable sub.

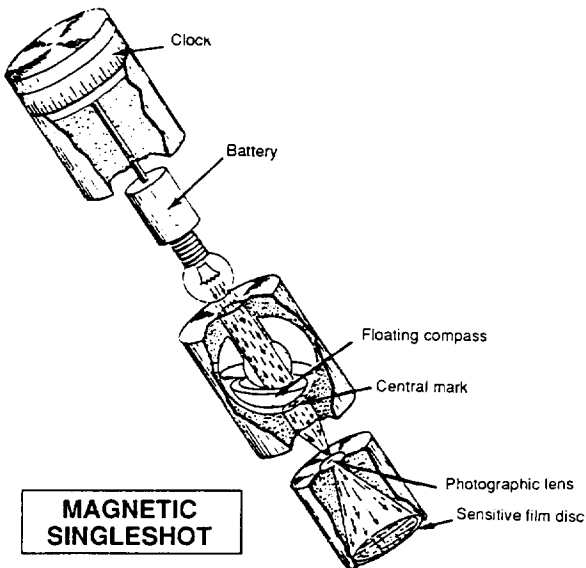
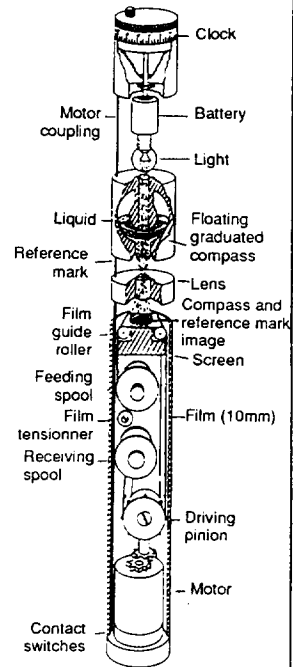


# DIRECTIONAL SURVEY TOOLS

## INCLINOMETER



## MAGNETIC MULTISHOT



## MAGNETIC SINGLESHOT

## 11 Blow out control

A kick is an influx of formation fluid into the well.

It is due to formation pressure being higher than the pressure exerted by the mud column, either because the column has been reduced in height (well emptying by losses, for example), because the bit drills into a high pressure zone (an under compacted zone for example), or due to swabbing while pulling out of the hole.

It can also be due to the expansion of gas coming from the formation drilled in the case of a high pressure well.

If the influx is not stopped, the formation fluid displaces the mud, reducing the hydrostatic pressure exerted at the bottom of the hole, increasing the influx : this is a blow out.

The formation fluid can be water, oil, or gas, the latter being the most dangerous, because, on one hand, gas expands as it moves up the annulus displacing more and more mud, and on the other, as it's density is low, the hydrostatic pressure it exerts is low. Therefore gas kicks are the most violent.

Kick detection is carried out by monitoring mud volumes entering and leaving the well, either using differential flow metering, or by measuring pit levels, which is the method most frequently used.

While tripping, the volumes are monitored by circulating on the trip tank (or the possom belly tank on a floating rig). Mud is pumped from this trip tank into the bell nipple that empties into the return flow line, the returns coming back to the same tank. Any change in volume in the well is mirrored by a volume change in the tank.

While tripping, the driller must check that the change in volume in the trip tank corresponds to the change of volume of the steel displacing mud in the well

When a kick is detected (the pit volume increases), the driller carries out a flow check, meaning that he pulls the bit off bottom, checks at the return flow line whether mud continues to flow (this is very important : never observe the well by looking at the bell nipple through the rotary table : a kick can result in a pocket of H<sub>2</sub>S coming to surface!). If the well is flowing, the driller closes the BOP, preferably the pipe rams, having previously checked that there isn't a tool joint in the BOP. When the well is safely shut in, the pressures are monitored on the annulus and in the drill pipe.

If the string has a check valve at the bit, it must have a small orifice that doesn't let through large volumes, but allows pressure transmission from the bottom of the well to the surface. If this is not the case, then mud has to be pumped very slowly (a few strokes per minute) until the check valve opens (increasing annular pressure). The drill pipe pressure is read right at that moment.

The pressure at the top of the drill pipe is equal to the pressure difference between the reservoir pressure and the mud hydrostatic pressure, indicating the minimum pressure to be applied at surface to stabilize the well.

The next step is to stabilize the well by applying a balancing pressure and to evacuate the formation fluids.

The well is stabilized initially by circulating through a choke, which applies a balance pressure from the surface, and afterwards by pumping a heavier mud.

If the bit doesn't have a check valve, a blow out can happen through the drill pipe if the string is pulled out of the hole too quickly swabbing the well. The drill pipe must be closed with a valve designed for this purpose (safety valve, grey valve).

This operation is difficult as the valve must be screwed on by hand whilst mud is flowing, perhaps violently, from the drill pipe. The swivel is then connected to the valve which is opened. The blow out can then be controlled in the normal way.

It is safer to use a power swivel as it is easier and faster to screw on.

### **11.1 Circulating through a choke**

When circulating through a choke, the well remains closed. The mud comes out through the choke line, goes through the choke manifold, through a remote controlled choke that exerts a balance pressure. The mud then goes back to the pits, to the flare or can be put through the vertical degasser.

When starting circulation through a choke, a low flow rate is used and the choke is adjusted so that the annulus pressure increases by the difference between the reservoir pressure and the bottom hole pressure plus a safety margin. When this pressure is reached, the pressure at the top of the drill pipe is noted, and the choke is then adjusted so as to maintain this pressure.

Circulation is continued until all formation fluids are eliminated. When this is done, mud with the required density is pumped.

If heavy mud can be prepared quickly, it can be pumped while eliminating formation fluids. When this heavy mud is pumped, the pressure in the drill pipe must not remain fixed, but must drop off gradually (choke control is based on an estimated graph - pressure as a function of the number of pump strokes).

The annulus pressure is monitored to avoid fracturing at the shoe. If the pressure increase is too great in the annulus, it must be bled off so as to reduce pressure at the shoe which would increase the influx. In this case, heavy mud has to be pumped rapidly.

If a kick is detected when the bit is not on bottom, the annular preventer is closed (with a low pressure), the string is run in through the BOP, (stripped in) so as to be able to circulate at the lowest possible point (the volume of fluid below the bit cannot be displaced).

### 11.2 Specific problems to be avoided at all costs

- Kicks while running casing : the annulus volume being very small, the well fluids get to surface very quickly.
- Too high a pressure can push the string upwards while tripping. It becomes impossible to strip-in.
- If a kick happens with the bit out of the hole, the string must be pushed through the BOP. If this is impossible, the only solution is to kill the well through the kill line by pumping heavy mud into the closed well to try and squeeze the well fluids back into the formation (Bull Heading).
- If the well head pressure goes above the critical pressure, there is a risk of fracturing at the shoe which creates a very difficult situation.
- In general, if a kick leads to a pressure higher than the fracturing pressure at the shoe, a catastrophe is not far off!!

### 11.3 The geologist's role

As a kick is never an easy problem to solve, it is always advisable to have the best evaluation of the pressures expected...

The speed with which the problem is dealt with can make the difference between a minor upset and a catastrophe. So it is vital to let the driller or supervisor know **immediately**, when any modification in the mud is recorded in the mud logging cabin (density, resistivity, etc...). It is also recommended to fit sensors on all the pits including the trip tank. With this in mind, it is a shame not to use the differential flow meter, which is a modern device, even though it's use is limited to water based muds,.

Despite this aspect, where possible, the mud density should be not be increased above requirements (safety margin above the minimum control density) in order to be able to monitor the oil and gas shows, and to avoid losses.

When circulating through a choke it becomes very difficult, if not impossible, to identify the reservoir fluids (oil, water, gas in water, etc.). With this in mind it would be a good idea to discuss with the supervisor before starting to drill, about taking samples in this case and make sure the required material is available.

## **12 Coring**

### **12.1 Conventional core barrel (or double tube)**

The conventional core barrel has an outer tube, an inner tube attached to a pivoting head, a core catcher housed in the base of the inner tube and a core bit. It also has safety joint.

Whilst coring, the inner tube remains fixed when the core is being taken. It is connected to the outer tube by a ring bearing. The outer tube is turned by the string. The core bit is screwed onto the base of the outer tube and turns with it. When the inner tube is full, the rotation is stopped, the string is pulled which breaks the core. The core cannot fall out of the core barrel because it is held by the core catcher. The tool is then tripped to surface.

Conventional core barrels are manufactured in 30 ft. lengths. Depending on the length of zone to be cored, one or several lengths can be used. Currently, 27 m is a common length, but more than 100m has been recorded (long barrel coring).

### **12.2 The heavy duty or marine service core barrel**

This is a conventional core barrel with a thicker outer tube.

The disadvantage of this tool is that the core is smaller than the conventional core barrel of the same size.

The "Marine" core barrel cannot be used with a third tube or with a glass fiber tube.

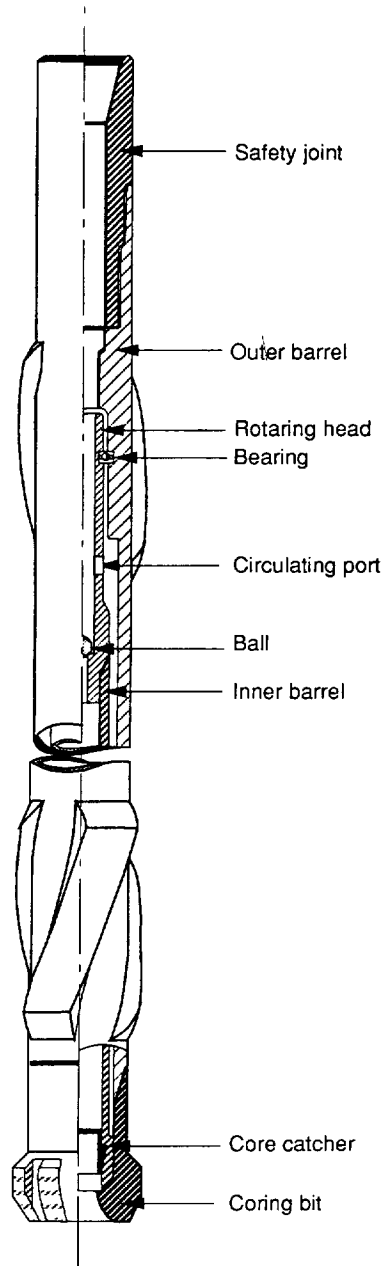
During a drilling programme that has no specific problems, the conventional core barrel is recommended.

### **12.3 Wire line core barrel**

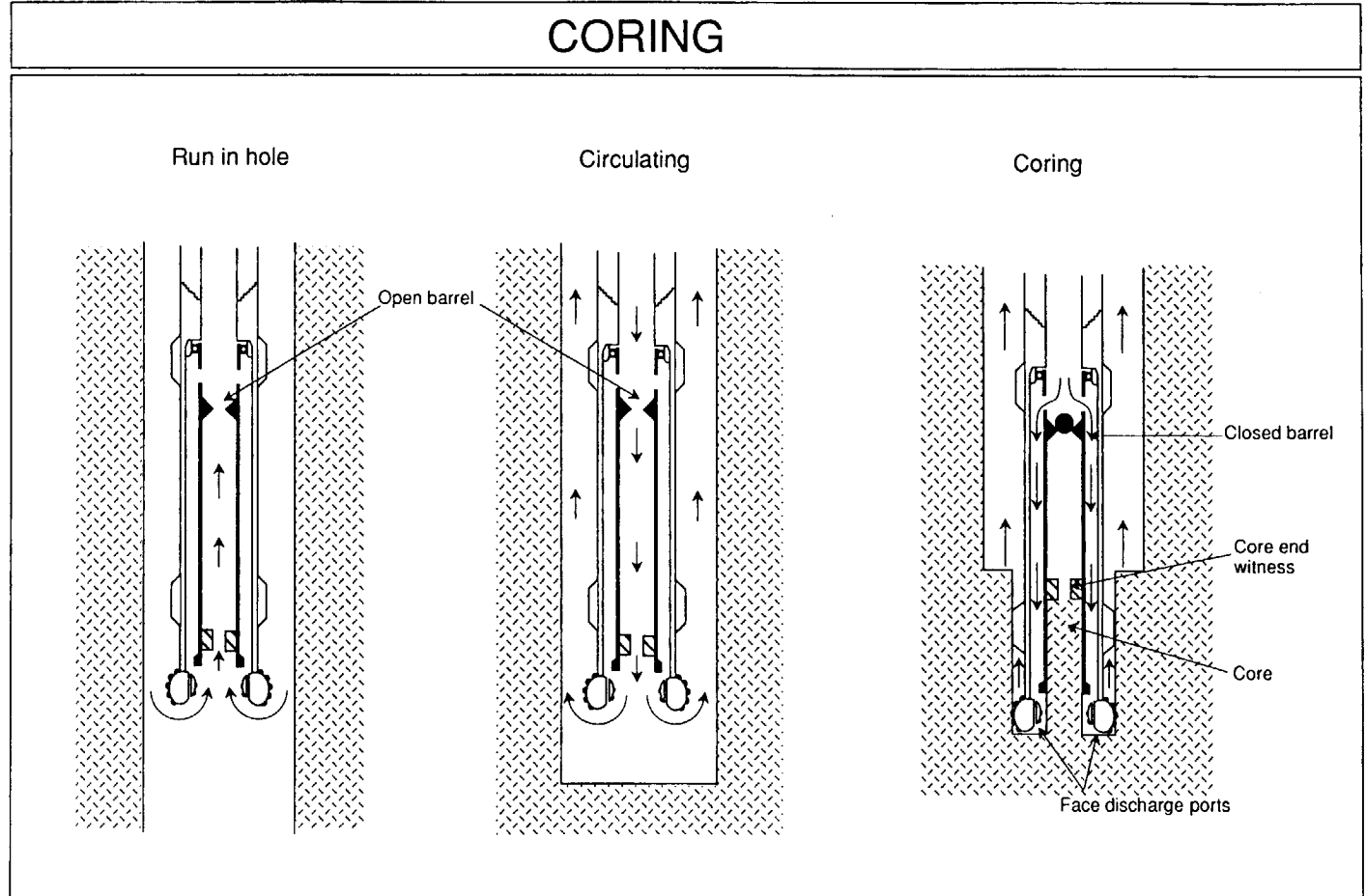
This tool is a core barrel that allows the core to be recovered without tripping the string. The inner tube is pulled out of the hole by wire line inside the drill pipe. Two assemblies are possible :

- The coring assembly, the inner tube is fixed in the core barrel.
- The drilling assembly, a plug replaces the inner tube transforming the core bit into a full diameter bit.

# CONVENTIONAL CORE BARREL



# CORING





The inner tube is dropped in the drill pipe and pumped down. It is recovered by the sand line or wire line.

Safety material must be used during the fishing operation in order to be able to close off the drill pipe and circulate in case of a kick. This is possible because when recovering the inner tube there is a risk of swabbing because the annulus between the outside of the inner tube and the inside of the outer tube is small.

In addition, the cores have a small diameter, less than or equal to 2".

#### **12.4 The directional core barrel**

Directional coring is a complementary technique to conventional coring that allows the initial orientation of a core to be identified on surface. This technique allows directions to be attributed to all the physical measurements taken on the core. Examples : dip, fracture and fault orientation, detrital rock granulometric orientation, permeability orientation.

The method consists of putting a longitudinal mark on the sample during coring. The mark is made by a blade located in the shoe of the core catcher parallel to the coring axis. There are three marks, made in such a fashion that one of them can serve as a reference mark.

An instrument that records the deviation of the core barrel and the azimuth of the reference mark is connected to the inner tube by a shaft called the Extension Rod. The instrument is above the core barrel in an anti-magnetic sub with a K-Monel drill collar above. Before the operation, the instrument must be lined up with the reference blade of the marking system.

The measuring instrument has a photographic recording system of the " Multishot " type that goes off at regular intervals. The pictures on a microfilm are only clear when there is no vibration. Therefore rotation and pumping have to be stopped every time a measurement is taken.

The time calculated in relation to the initial start up of the instrument is monitored on the core progress diagram using a timer in order to correlate the portions of the core with the microfilm pictures.

### **12.5 The slim hole core barrel**

This is simply a small diameter conventional core barrel without a safety joint, designed for coring through a 5" liner.

A core barrel of this type has been specially designed by DBS for the Foraslim rig used for drilling slim-hole wells.

### **12.6 The vented system core barrel**

Here again this is a modification of the conventional core barrel that allows the fluid in the inner tube to vent towards the core barrel/ hole annulus by a vent tube rather than leaving by the inside of the drill pipe.

In poorly consolidated formations, this system has the advantage that the mud trapped in the inner tube doesn't have to lift the ball to leave, i.e. overcome the  $\Delta P$  corresponding to friction losses due to the mud circulating in the core barrel annulus. In addition, the pressure in the annulus being less than the pressure in the inner tube, a suction effect develops that tends to help the core move up the barrel.

### **12.7 The Triple Tube core barrel**

This type of core barrel is designed for formations that are difficult to recover. Again it's a modification to a conventional tool : A third, thin walled tube is put inside the inner tube. A special shoe holds it in place. The third tube can be in PVC, aluminium or steel. The OD of this liner is slightly less than the ID of the inner tube.

During the operation, the core enters the third tube. On recovery, this tube is pulled out of the inner tube. In this fashion, the core remains protected.

Then the core and its envelope are cut up as required. The liner can be sawn up lengthwise for analysis on site, or cut into sections and sent to the lab.

### **12.8 The core barrel with a fiberglass or aluminium inner tube**

This core barrel meets the same requirements as the triple tube version. In this case it's the inner tube itself that is in fiberglass or aluminium. This system is simpler but more expensive than the triple tube core barrel. Here the inner tube is directly cut up as required. The advantage is that the core

diameter is bigger but more importantly the recovery is better as the friction coefficient is lower in fiberglass or in aluminium.

### **12.9 The rubber sleeve core barrel**

Only CHRISTENSEN manufacture this core barrel in 6<sup>7</sup>/<sub>8</sub> x 3" x 20'. It is designed for poorly consolidated or fractured formations.

A rubber sleeve surrounds the core as it rises up the core barrel tube during coring. At the end of the operation the core is completely wrapped in the sleeve. The whole thing is removed from the inner tube and cut up as required as with the triple tube or with a fiberglass tube.

It should be noted that the rubber sheath is more fragile than a fiberglass or an aluminium tube.

### **12.10 The Hydro-Lift (full closure core catcher, INTEQ) or Posiclose (DBS) core barrel**

Whilst coring, it operates like a conventional core barrel in which the core catcher is hidden behind the inner tube. It's mainly while pulling out that it is different to other tools.

When the core barrel is run in, the inner tube is open like a conventional core barrel.

After circulating, a ball is released in the drill pipe. It plugs the inner tube forcing the mud to pass in the inner tube/ outer tube annulus like a conventional core barrel.

When coring is finished, the inner tube is full and the core broken off. A second ball is dropped (its diameter is larger than the first) in the drill pipe. It locates on its seat plugging the mud flow passage. The pressure exerted by the mud lifts the inner tube inside the core barrel which frees a clapper valve (full closure catcher) that plugs the inner tube. If the core is consolidated, the clapper valve cannot plug off the tube, but the core catcher is exposed and moves to maintain the core in position.

The core can thus be recovered with no risk of losing it whilst tripping out.

This system can prove useful in very poorly consolidated formations such as sands, provided they have in fact been cored.

### **12.11 The pressure core barrel**

This is a core barrel that allows cores to be brought to surface at bottom hole pressure. In effect it stops the gas and the fluids from escaping from the sheath whilst pulling out. Once on surface, the core is frozen which fixes the fluids inside the core sleeve.

Then the pressure is released and the core is taken out.

The pressure core barrel cores like a normal core barrel. At the end of coring, after breaking the core, a ball is released. A ball valve closes off the base of the core barrel, and a pressurized nitrogen chamber pressurizes the core. The core barrel can then be brought to surface.

On surface the core is put in a freezer at -80°C. At this temperature, the liquids in the core become solid whereas the nitrogen remains gaseous. It is then possible to bleed off the pressure and recover the core.

The problem of this core barrel remains the realistic nature of the fluids recovered and especially the complex logistics required for its operation.

### **12.12 Sponge coring (DBS)**

Initially it was a conventional 6<sup>3</sup>/<sub>4</sub> x 4" core barrel.

In the inner tube, a third tube is located. It is in PVC or aluminium, and its insides are covered with a synthetic sponge (polyurethane). When it is pulled out of the hole, the fluids have a tendency to leave the core, and are trapped by the sponge. The sponge's properties mean that it accepts oil in preference to water.

### **12.13 Gel coring (INTEQ)**

This core barrel is run with the inner tube filled with a special gel. While coring, the core, as it moves up the inner tube, is coated by the gel. It is a viscous gel that does not invade the core, which remains protected from any mud contamination.

### **12.14 Mud for coring**

Borehole stability is very important before and during coring. The core bit stands up badly to reaming. In addition, crumbling borehole walls are liable to plug the core bit nozzles and the core inner tube

whilst running in. Finally such instability is liable to prevent the core barrel running in or to get it stuck while pulling out. These tools are particularly sensitive to this problem at the stabilizers.

Before running the core barrel, the hole must be clean to avoid the inner tube or the core bit being plugged when it gets on bottom. With conventional core barrels it is possible to circulate vigorously through the inner tube before dropping the ball. However this is impossible with almost all the other core barrels where the ball is already put in place before running in.

When coring, the mud creates two problems :

- in circulation the core suffers erosion at its base,
- in static conditions, the core is contaminated by filtrate invasion.

To carry out certain functions such as lubricating and cooling the core bit, evacuating cuttings, the mud must reach the core with a given flow rate. Therefore it has a negative effect on the core, it arrives right where the core is taking shape, and if the formation is friable, the core is destroyed by washing. For this type of formation core bits exist with a face discharge, in which only a portion (30 %) of the flow goes to the base of the core, the rest mainly cleans the core bit, or low invasion core bits, in which the mud doesn't come into contact at all with the core.

The second problem relating to the mud is the contamination of the core by filtrate invasion. This phenomena can give erroneous results in lab tests carried out later. To be efficient, the mud filtrate must not invade the sample, therefore it should have the lowest fluid loss possible.

To reduce the mud filtrate, a fluid loss additive, the most common being carboxymethylcellulose (CMC) and starch for water based muds is added.

It should be noted that a mud used for coring should have the minimum surface active agents and caustic soda, these additives can modify the sample wettability.

Core contamination by invasion is due to the pressure differential between the mud column and the formation. The higher this differential, the higher the invasion.

For a core with a large cross section, this contamination will have less effect than for a core with a smaller cross section.

Coring mud requires the same care as drilling mud. The characteristics must be maintained during the operation using the shale shakers, desanders and desilters.

If the combination of a PDC core bit and an oil based mud can be attractive for its rate of penetration, the use of this type of mud can cause problems when it comes to evaluating reservoirs in exploration wells :

- attenuation or even disappearance of shows,
- limits the choice of logging tools,
- errors in log interpretation,
- geochemical measurements affected by the base oil.

Using water based mud is not without its disadvantages. It modifies the recovery of water sensitive rocks that can be situated between reservoirs. Result : the cores are recovered as sections that are not easily positioned.

## **12.15 Core bits**

There are three types of core bit :

- with rollers,
- with natural diamonds,
- with synthetic diamonds.

### **12.15.1 Roller bits**

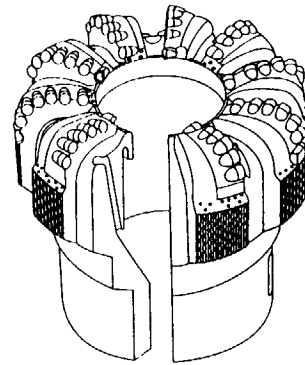
These were the first coring tools. These core bits had the disadvantage that the drilling mud had too great a washing effect on the core meaning the bits performed badly in poorly consolidated formations. They were virtually abandoned when natural diamond bits appeared.

Roller bits are virtually no longer used in the oil industry.

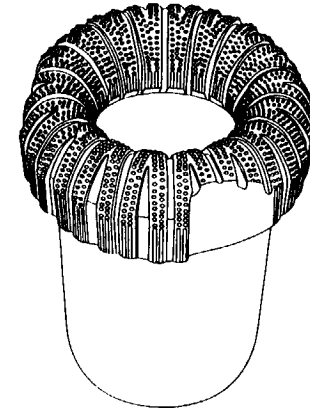
### **12.15.2 Natural diamond core bits**

Depending on the size of the diamonds, these core bits can be adapted to all types of formation. Large diamonds are used for soft formations, and the small ones for hard formations. But since PDCs have appeared, these bits are only run in hard formations, the PDCs being far more efficient in soft and semi-hard rock.

## CORING BITS



PDC CORING BIT



DIAMOND CORING BIT

The core bit is made up of three parts :

- the cutting portion : the diamond,
- the matrix in tungsten carbide,
- the body made out of steel.

The shape of core bits is more or less pointed depending on the hardness of the formations to be cored.

Natural diamond core bits stand up well to abrasion. However, reaming, especially in abrasive rock like sandstone, rapidly damages the outer bit protection.

### 12.15.3 Synthetic diamond core bits

The synthetic products currently used on drilling and core bits are available in two forms :

- Low temperature synthetic diamonds, PDC, (Polycrystalline Diamond Compact), the best known being General Electric's Stratapax, that usually is used as a thin sliver of synthetic diamond (th : 0.5 mm) set on a tungsten carbide stud.
- High temperature synthetic diamonds, TSD (Thermally Stable Diamond), the best known makes being Geoset, Ballaset, Tripax, etc. It is also made from synthetic diamond but is available in several forms.

These two products have the same basis, and stand up to abrasion better than natural diamonds, but are not as hard.

With the first product, the tungsten carbide stud is brazed onto the desired area of the core bit matrix. The method used for fixing the second type is the same as for natural diamonds.

PDC bits obtain excellent results with oil based mud. They are particularly successful in soft and semi-hard formations. PDC bits act as a cutting tool requiring a good and efficient lubrication which is given by oil based mud.

TSD's performance lies between PDC and natural diamonds, having better results than PDC in hard formations.

**Comment :** Core bit classification is the same as the one used for drilling bits.



Today, antiwhirl core bits are available with a special design that avoids lateral vibration that improves core quality.

### **12.16 Turbocoring**

Combining a turbine or a positive displacement motor with a core barrel can give an improved rate of penetration. The operation is more expensive, but offshore for example, it can prove worthwhile. Using a turbine gives a very high rotation speed getting close to coring conditions in mining. In a hole with dog legs, this combination can be useful to reduce the friction effect of the string on the well sides.

Turbocoring is the technique normally used for coring in horizontal wells.

The problems relating to the stability of the trajectory indicate that short sections should be envisaged with standard single core barrels (30' of core) or with short core barrels of 4 m (13' of core).

### **12.17 Operating precautions**

Due to the core's importance and its cost (one meter of core costs up to 10 times the cost of drilling one meter), coring must be done with great care.

- Before running in, tighten all threads with care, the tubes are thin and relatively weak.
- Adjust the position of the shoe with respect to the core bit, check that the inner tube rotates correctly.
- Check the wear of the bearing in the rotating head after each run.
- Check the alignment of the inner and outer tubes.
- Clean all grease from the inner tube.

Running in must be done carefully so the core barrel stabilizers do not scrape the well bore, and so that cuttings don't plug the inner tube.

On bottom, circulate to clean the well then release the ball in the drill pipe.

When starting to core, use slow rotation speed and reduced weight. Normal parameters will be used after the core bit has made its impression.

## **Connection**

It is preferable, if possible, to adjust the string so as to core 9 m without a connection. If not, rotation and circulation are stopped, and the core is broken by pulling. If it doesn't break, circulating weakens the base of the core by washing. After the core is broken, a check is made that it is in the inner tube by lifting then going back down over the length of the core. Drill pipe can be added. Going back to bottom is done without rotating and with reduced circulation, setting down 50 % more weight than for normal coring so as to move the core up and allow the new core to enter the core barrel.

## **12.18 The geologist's role**

The mud flow rate while coring must be decided between the driller and the geologist. Too high a flow rate could result in an excessive washing of porous and permeable zones meaning that shows could be lost.

While coring, don't forget to collect the cuttings (no matter how few) because, if the core is badly recovered, they could be the only information available.

Interrupting the coring (ex : due to very slow penetration) must be a joint decision by the driller and the geologist.

Extracting the core is a critical operation that requires the geologist's intervention. With a conventional core barrel, the sudden falling of the core pieces onto the rig floor must be avoided, and care taken in putting the pieces in to the boxes. A short " briefing " of the roughnecks, defining their individual roles is the best way of avoiding mistakes. In the same way, preparing the required material, paying special attention to marking the boxes, must be done with extreme care. (see Recommended practices, RME 8.3).

When coring with a fiber glass and/or aluminium tube, care must be taken to avoid buckling the inner tube whilst laying it down. If the core is opened on the rig, the saw must be perfectly adjusted to avoid damaging the core.

## **13 Fishing**

Fishing after any string or casing failure, or having lost a bit, roller, or anything else requires the use of a wide selection of fishing tools. The following list gives the most common tools. Frequently fishing tools are adapted to, or even made specifically for a particular problem.

### **13.1 Tools for recovering pieces of steel**

#### **13.1.1 Junk subs**

This tool is put in a drilling or milling string above the bit. It has a shaft surrounded by a skirt that is open at the top making an annulus in which heavy pieces are trapped as the mud velocity drops above the skirt.

#### **13.1.2 Junk baskets**

A junk basket is a tool that carries out a "mini-coring" operation to recover any lost object at the well bottom.

#### **13.1.3 Magnets**

#### **13.1.4 Rope spears**

### **13.2 Fishing tools by external catching**

#### **13.2.1 Overshots**

They have a bell on the end with a grapple inside that catches the fish when the overshot moves over it. The fish's head must be clean. To achieve this, the tool can have a milling bit that corrects the shape of the fish.

#### **13.2.2 Die collars**

These tools are conical collars that are threaded, and are screwed into the fish using the drill string. They can be right hand or left hand (for unscrewing).

### **13.3 Fishing tools by internal catching**

These are usually tools used as a last chance because they are difficult to release and rarely allow the use of wire line tools.

#### **13.3.1 Pin-tabs**

They are slightly conical threaded tools adapted to the thread of the fish (such as an unscrewed drill pipe).

#### **13.3.2 Taps**

Taps are screwed into the internal diameter of the fish.

#### **13.3.3 Spears**

These tools are used for fishing casing or tubing by the inside. They are equipped with grapples that expand and latch onto the tube.

### **13.4 Jarring tools**

#### **13.4.1 Bumper subs**

Bumper subs are slip joints that are used for jarring upwards or downwards, to compensate for movement on a floating rig or to identify exactly the neutral point.

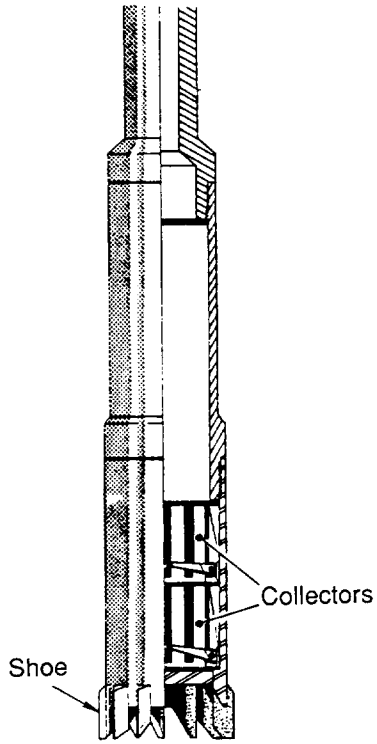
#### **13.4.2 Mechanical or hydraulic jars**

They can hit upwards or downwards.

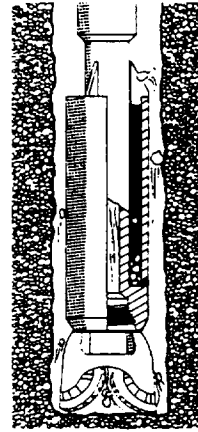
#### **13.4.3 Jar accelerators**

They are used to increase the power of the jars.

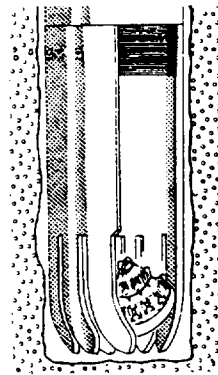
# FISHING TOOLS



CORING TYPE TOOL

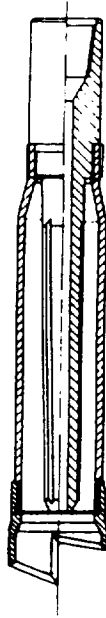


JUNK SUB

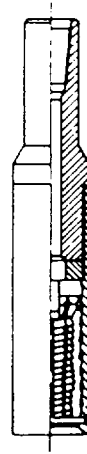


SPIDER TYPE TOOL

# FISHING TOOLS



TAP



OVERSHOT



SPIRAL GRAPPLE

### 13.5 Milling and washover tools

They have different shapes to adapt to different problems. They are made of tungsten carbide elements set in a softer matrix.

- **Crusher mill** : a strong tool with a wide cutting face. It crushes by pounding.
- **Junk mill** : a strong tool where the cutting faces have been replaced by wide interconnected blades. An all purpose tool.
- **Junk mill (standard and economill)** : a very aggressive but brittle tool.
- **Pilot mill** : a blade mill with a guide to get into the fish.
- **Skirt mill** : a mill making an annular cut used to recut the head of a fish, and to work in casing without damaging it.
- **Tapered mill** : a reaming tool used to recaliber the inside of tubular fish.
- **Section mill** : a tool with several blades that can retract into the sides. It is used for cutting casing or opening windows.
- **Washover shoe** : it is a cylindrical shoe, with either teeth or a wavy profile with tungsten carbide or diamonds, screwed onto the end of a washover string. It is used to clean the annular space around a fish.

## **14 Drilling from a floating vessel**

Because a floating drilling rig moves so much with respect to the sea floor, it is impossible to install well heads at surface.

For this reason, the well is drilled with a sub-sea well head connected to the rig by a riser that has enough flexibility to allow limited rig movement.

This technique requires the use of specific material :

- base plate, casing spools and hangers,
- sub-sea BOPs,
- riser.

### **14.1 Temporary base plate**

This is a ballasted box with a 42" opening and a conical guide, placed on the sea bed and connected to the surface by four cables that act as guides for various pieces of equipment.

### **14.2 Conductor pipe**

The 36" hole is drilled with lost returns using sea water. The bit is guided by the base plate cone.

The 30" casing is then run and cemented. At the top it has a casing spool that will receive the casing spool of the 20" casing, and a guide that will help direct the 26" drill string and then install the BOP.

If the sea bed is muddy, the conductor pipe can be run directly without the base plate or drilling. An extension on the drill pipe is centered in the tube and is fitted with a "jetting tool", made up by six or seven jets. The hole for the casing is made by jetting.

### **14.3 Surface casing**

The 26" phase can be drilled with lost returns using sea water if there is no liability of a blow out (known formations). Otherwise it is drilled with the riser connected to the 30" casing spool. At the extremity of the riser is situated the diverter that can close on the drill pipe and divert an eventual gas kick to the flares. The hole can then be drilled with mud returns.



The 20" casing is run equipped with a casing spool that locates in the 30" casing spool. This casing spool is fitted with a connector that will receive the BOPs, and that is designed to support the hanger and packings for the next casings.

#### **14.4 The following casings**

The next phases are drilled through the BOP. Two situations are possible :

- The well is drilled with two different BOPs. The first sits on the 20" spool and enables the 17"1/2 phase to be drilled. The 13"3/8 casing is set with the casing spool that can receive the second BOP.
- The well is drilled with the same BOP. It is connected to the 20" casing spool in which all the hangers and packings for the following phases are set.

#### **14.5 Setting the casings**

The casings are run equipped at the top with the hanger, on the end of the drill pipe equipped with a setting tool.

The hanger lands in a seat in the well head. This means that the casing must be set at the depth planned.

#### **14.6 Cementing**

The cement plugs are run in the casing. They have central holes that allow for circulation. The cement head is attached to the drill pipe. To release the first plug a ball is released that lands in the bottom plug and plugs the hole. The pressure increase breaks the split pins that hold the plug in place, releasing the plug. When the plug lands at the bottom of the casing, the ball is ejected. To release the second plug, a plug, the size of the drill pipe is released which cleans the drill pipe and lands in the top plug which is released in the same fashion as the bottom plug.

The drill pipe is disconnected and pulled out after cementing, then re-run to set the packing above the hanger.

## 14.7 Sub-sea BOPs

They have a similar design to normal BOPs. They are equipped with hydraulic accumulators, with three remote control systems and control distributors and regulators.

Two of the remote controls are identical and redundant. They are either hydraulic or electrical. Each one is connected to the surface by a hose that also supplies the hydraulic energy.

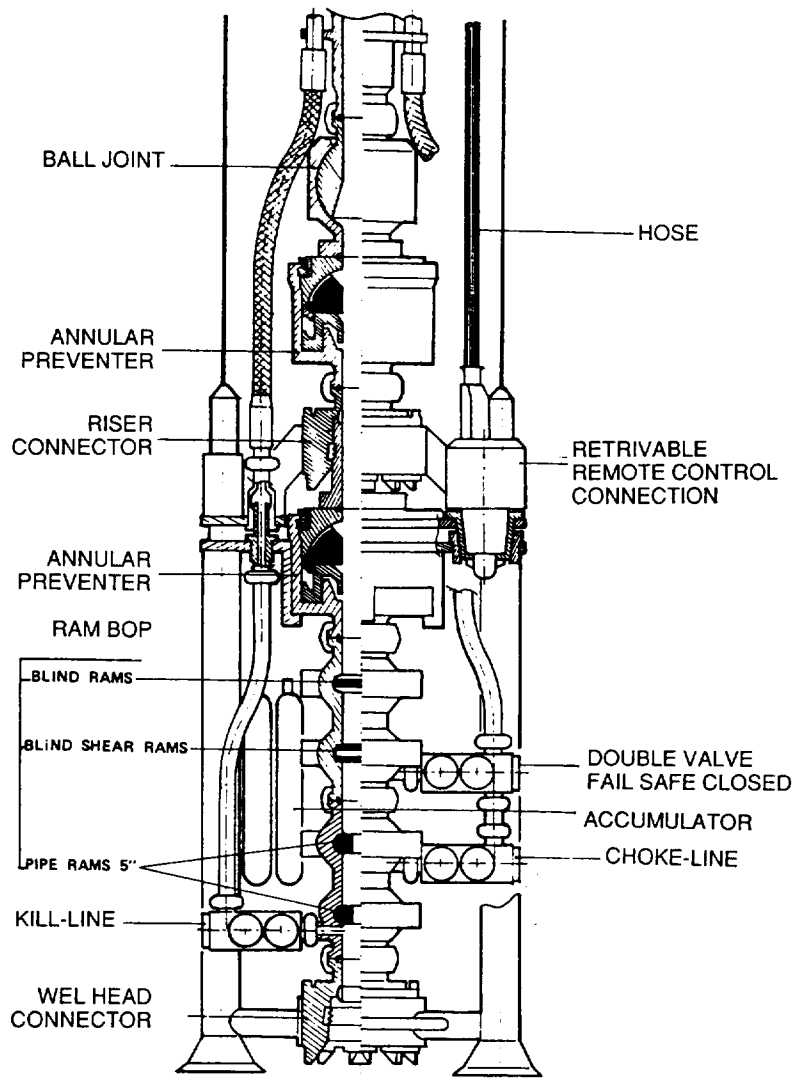
The third remote control system is acoustic and only operates the emergency functions (closing and disconnecting).

## 14.8 The riser

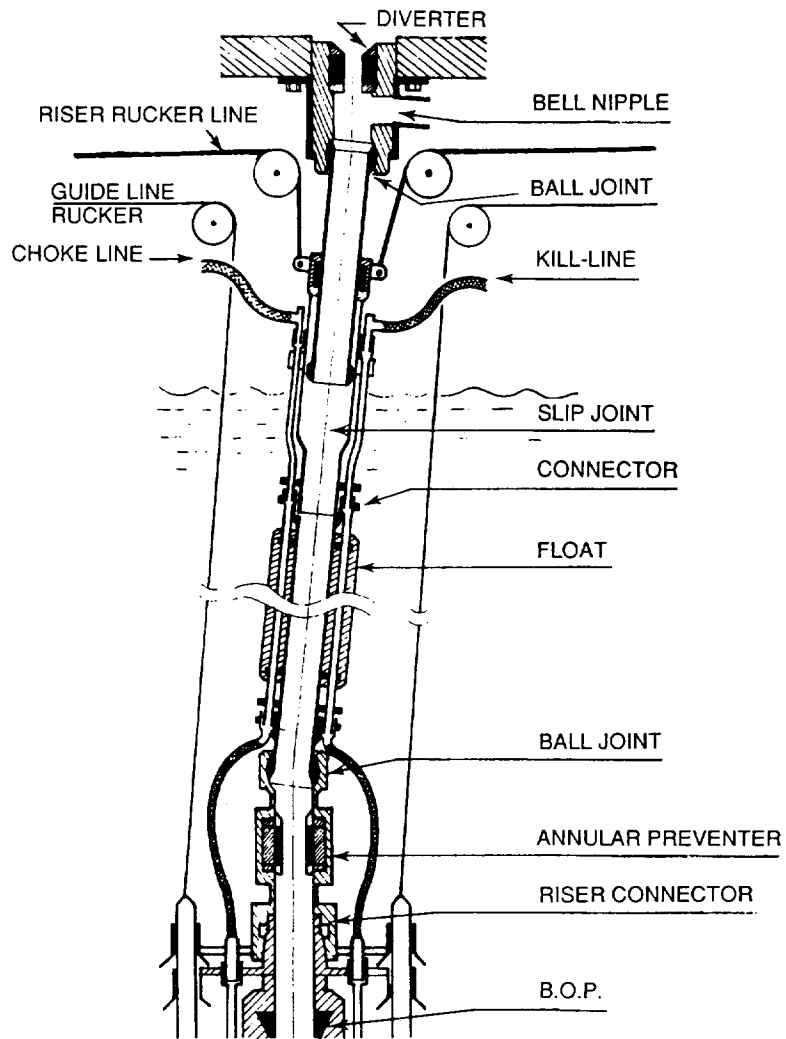
**Make up** (from bottom to top)

- A **hydraulic connector** to connect to the BOPs.
- A **flexible joint**, to absorb the angular movements of the riser due to the lateral movements of the floating rig or the currents.
- Riser **tubes** fitted with quick couplings, around which are attached the well control lines (choke line and kill line). Sometimes supplementary lines (boosting lines) and the remote control lines are also attached.
- A **slip joint** with a long travel to absorb the vertical movements of the floating rig (tides, heave).
- An **bell nipple** with a **deviator** fixed on one end to the slip joint and on the other to the structure under the rotary table.
- A **tensioning device** that supports the riser at the slip joint by cables connected to adjustable, hydro-pneumatic jacks keeping a constant tension (ruckers).
- Equipment that measures the stress on the riser as well as its position.

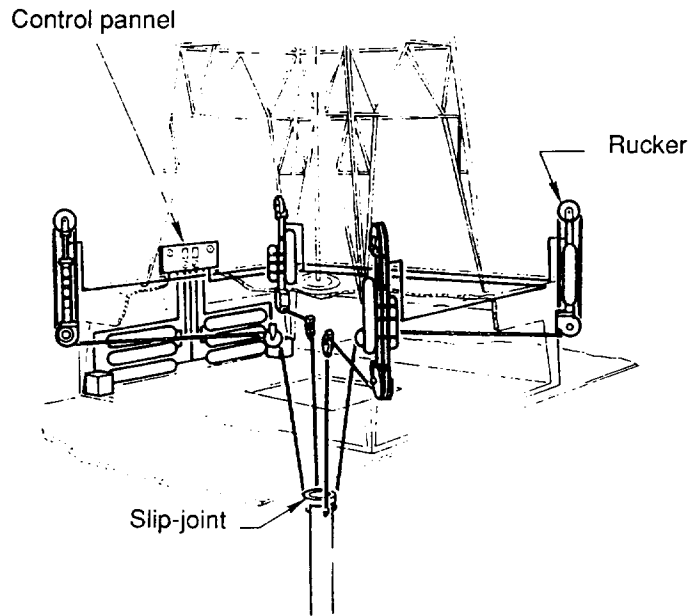
# SUBSEA BOP



# INTEGRAL RISER



# RISER TENSIONING SYSTEM



## **15 Well abandoning**

### **15.1 Temporary abandoning**

#### **15.1.1 Onshore or sub-sea wells**

The well head is left in place. A permanent packer (bridge plug) is set at the bottom of the well. A cement plug is set above the bridge plug, and another on surface.

#### **15.1.2 Offshore wells with surface well head**

A bridge plug is set at the well bottom and covered with a cement plug. The casings are disconnected at the mud line suspension (MLS) and pulled out. The MLS is covered by a corrosion cap.

### **15.2 Permanent abandoning**

The last casing is plugged with a bridge plug and a cement plug. Then each casing is cut above the previous shoe, and a cement plug is set at each cut.

The last cement plug comes back to the surface. For onshore wells the location must be returned to its initial condition.

## 2nd Section : Production

As this document is not designed to be a production handbook, only the general principles will be mentioned.

### 1 Perforations

The reservoir can be left remain uncased if it is sufficiently consolidated or be covered by a screen tube or by a casing or a liner which is cemented. In this case, the casing and the cement have to be perforated to let the reservoir produce into the well.

Perforations are made using guns run on electric line or on the drill pipe. The most common guns are the jet perforating guns. They can be recovered or released and abandoned in the well.

The number of shots can vary from 1 to 8 per foot, and the jets can be spread at 90°, 120° or 180° around the gun. The perforations have a diameter of about 1/4 of an inch and a penetration of several inches depending on the type of casing, cement job and formation.

Just after firing, the perforations are usually plugged due to solids and filtrate that have invaded the formation whilst drilling and cementing, but also due to the crushed rock, the residue from the guns and the localized squashing of the rock.

So in certain cases, underbalanced perforating is done. The guns are run under a test string, or in a completed well, and the hydrostatic head in the well is decreased by displacing in a lighter fluid (water, diesel, etc.).

When the shots are fired, as the reservoir pressure is higher than the hydrostatic head in the well, the formation flows into the well bore, cleaning the perforations.

### 2 Acidizing

The aim of acidizing is to restore good reservoir-well bore communication, by destroying the plugging or opening the perforations, but also to improve the near bore permeability especially in carbonate formations.

An acidification is done systematically after perforations or a sand control.

The most commonly used acid is hydrochloric acid (HCl), with a concentration of 5 % to 28 %. Hydrofluoric acid is also used.

After an injectivity test, the acid is displaced in front of the perforations through the test string or completion tubing, then it is squeezed into the formation.

In general, the acid does not penetrate deeply through the matrix of the reservoir. Its action is usually to create holes or to increase the size of existing fractures through which most of the acid flows.

### **3 Formation fracturing**

To improve a reservoir's productivity, the formation can be fractured. To do this, a fluid is squeezed into the formation rising to a pressure higher than the reservoir fracture pressure so as to create a network of fractures around the well bore connected to the perforations. Propping agents are added to the fracturing fluid whose role is to prevent the fractures re-closing. These agents can be sand, synthetic materials based on bauxite, alumina or zirconium, walnut shells, or even glass or aluminium beads. The fracture fluid is chosen to be compatible with the formation and the formation fluid. It can be water based, oil based, or even an emulsion of acid in oil (frac acid).

To avoid the fracture developing preferentially from a few of the perforations, several fracs are done over a small length, zone by zone. Balls can be used in the fracture fluid. They close off perforations as soon as fluid flows through to divert flow to other perforations in order to open a maximum number.

### **4 Sand control**

Sand control is carried out when a well is finished and sand is expected in the produced reservoir fluids, or during a work over when a zone has started producing sand.

The most common processes used are physical or chemical.

#### **4.1 The physical processes**

These processes consist of producing the formation through screens, single or multiple, or through a gravel pack. The operation is carried out in cased hole with perforations, with a window cut in the casing, or in open hole.



The screens can be tubes with open slots, or made by winding wire on a support, the latter solution has the advantage of having a larger through flow area.

Putting the sand or gravel in place is done by circulating a slurry of water and calibrated sand behind the screens. The slurry is then compacted by squeezing until the pressure increases (screen out).

## **4.2 The chemical processes**

These methods consolidate the sand in the formation by injecting heat sensitive resins or gravel coated with resin.

The heat sensitive resins are injected through the matrix, then enough time is left for hardening. Then the well can be completed and put on line.

The coated gravel is coated on surface by mixing with the resin then injected until screen out. After solidification, the bottom is drilled out and the well completed.

## **5 Completions**

### **5.1 Role**

The completion is the bottom hole equipment that allows wells to produce.

Generally, the producing zone is isolated by a packer set in the production casing, and connected to the surface by the production tubing.

The production tubing allows operations to be carried out on the well safely with the possibility of circulating.

It protects the production casing from erosion, corrosion and the effect of pressure and temperature on the cement.

It can be changed or modified following damage or wear, or a change of zone or production conditions.

The completion can be run in open hole, in which case the packer is set in the bottom of the production casing at the top of the reservoir. It can also be run in a cased and perforated hole, in which case the packer is set above the perforations.

## 5.2 Types of completion

A completion can be single, multiple, selective.

- A single completion produces a single zone.
- A multiple completion produces several zones, separated by different packers. Each zone produces through a different tubing. In practice up to four tubings can be run.
- A selective completion isolates several zones and allows one to be chosen for production.

## 5.3 Activated wells

If the well is not eruptive or sufficiently eruptive, it is activated either by gas lift or by pumping.

Gas lifting consists of filling the tubing/casing annulus with gas, that moves into the tubing by gas lift valves (gas lift mandrels), so as to lighten the oil column.

Pumping is done by a reciprocating down hole pump, driven from the surface in general by a pendulum type system, or by an immersed electrical or hydraulic pump.

## 5.4 Description

The casing/tubing annulus is filled with completion fluid (diesel, brine, etc.) through the circulating valve situated above the packer and operated by wire line.

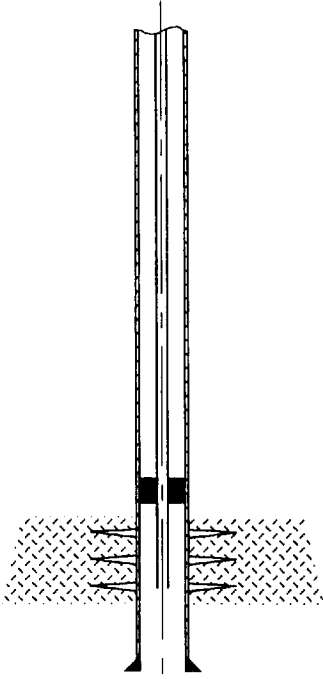
The tubing string includes a safety valve situated about fifty meters from the surface and operated by a control line connected to the surface. In case of an accident the control line pressure is bled off to stop production.

The string also includes various seats allowing wire line tools to be set to isolate different parts of the tubing for circulation, pressure testing, activating a hydraulic packer, etc.

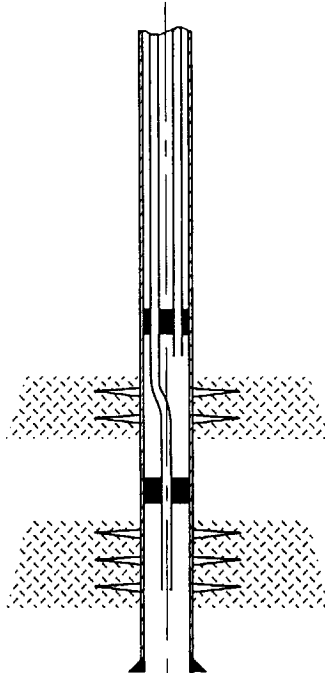
The string is hung in the tubing head by a hanger that also seals off the annulus. The christmas tree is then screwed onto the tubing head.

# COMPLETIONS

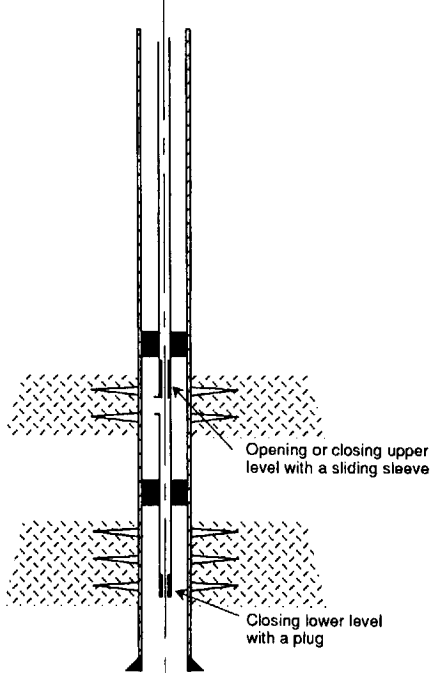
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Simple string

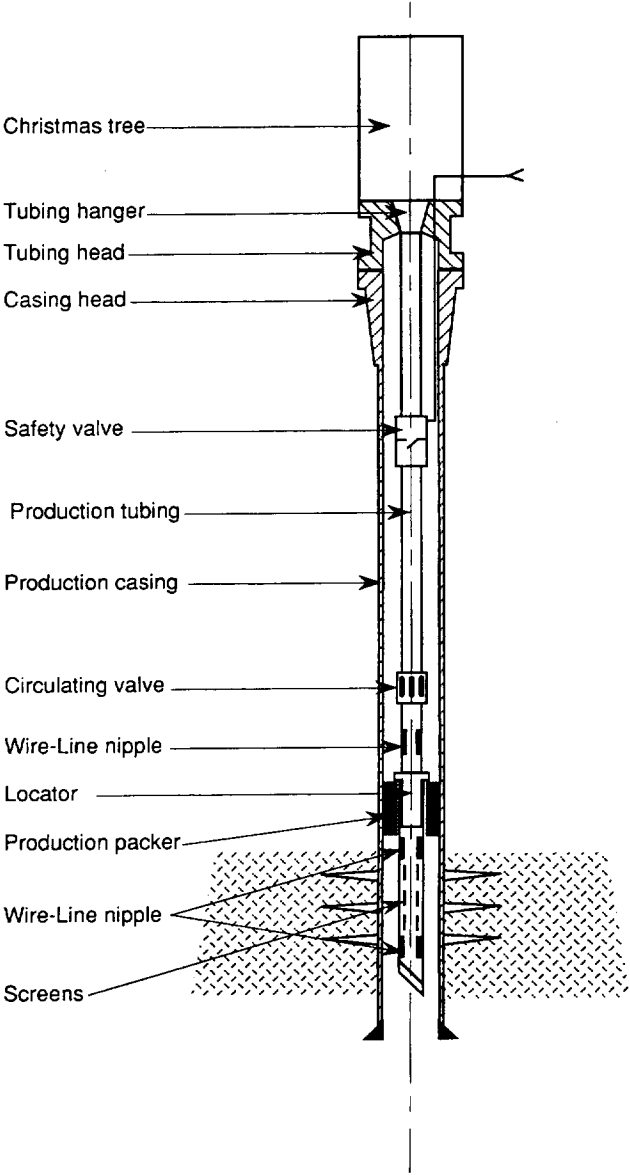


Double string



Selecting completion

# SINGLE STRING COMPLETION



## **6 Well testing**

During a well test, a reservoir is put into production in order to recover the maximum petrophysical information.

### **6.1 Down hole equipment**

#### **6.1.1 Cased hole testing**

A test is run in cased hole when the reservoir is not sufficiently consolidated to support setting an open hole packer or to remain stable during the test.

For an easy well, the test can be made with a temporary completion. However, in general a test string is used.

The aim of the test string is to isolate the reservoir using a packer connected to the surface by tubing and to produce the well by opening the downhole valve. Down hole recorders monitor the pressure and temperature during the test.

The packer can be a permanent packer with a tail pipe. The test string is then fitted with a locator that stings into the packer.

The packer can also be retrievable being run on the test string. It is anchored by rotating and setting down weight.

Above the recorders and the packer, a down hole valve operated by annulus pressure allows the bottom of the well to be opened to the surface and hence to produce.

Above the down hole valve, a circulation valve operated by annulus pressure allows the well to be killed at the end of the test by circulating mud in the tubing.

The packer has a by-pass that avoids swabbing whilst tripping out, and allows the volume below the packer to be squeezed before disanchoring.

The perforations can be made either with guns run below the test string, or run on wire line through the down hole valve.

#### **6.1.2 Open hole testing**

An open hole test allows a zone to be tested during the drilling phase, or at its end when the objective is reached. In certain cases, this type of test can avoid setting the last casing of an exploration well if

the results are negative. The test procedure is the same as for a cased hole test except for setting the packer. In addition, as the test is short, the well fluids are burnt or removed by tank, and complex surface equipment is not required.

It should be noted that the decision to test in open hole is taken by the rig geologist or by the Subsurface Geologist with the agreement of the Drilling/Completion department (see Well Site Surveillance Techniques and Methods Manual).

#### **6.1.2.1 Testing with an open hole packer**

An open hole packer can be used if the well bore is well calibrated and the sufficiently consolidated. An open hole packer cannot withstand a high differential pressure.

- **Single packer test with tail pipe**

The packer is set by pushing down on a rigid tail pipe that sits on the well bottom.

- **Single packer test with side wall anchor**

If the length of open hole to be tested is too long, the test can be carried out with a packer and a side wall anchor.

- **Straddle test**

When a specific zone is to be tested, it can be isolated by two packers.

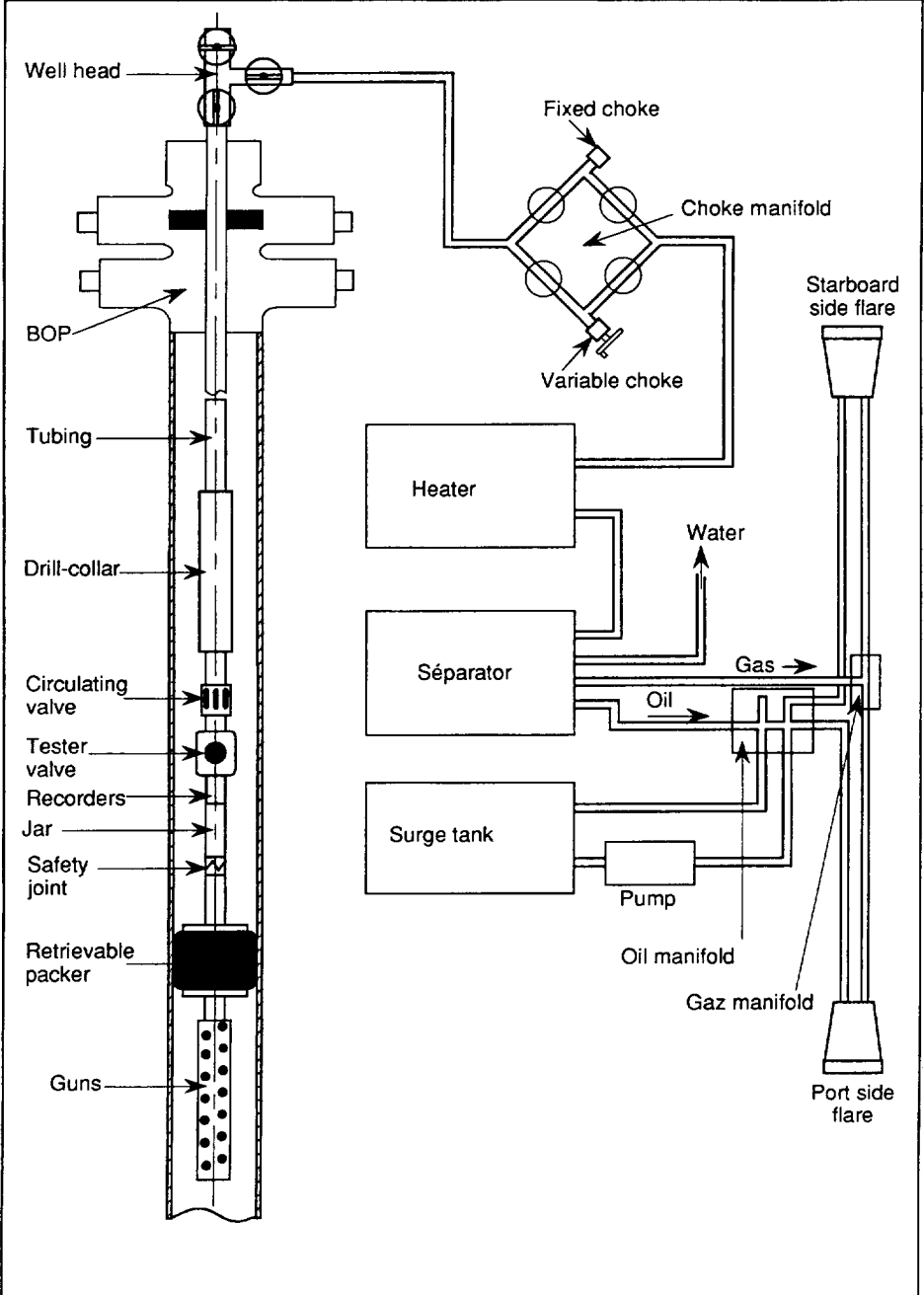
#### **6.1.2.2 Testing with a cased hole packer**

When the zone to be tested is not far from the shoe of the last casing, especially if the well bore is in poor condition, or the packer has to set for a long period, the packer can be set in the casing just above the shoe.

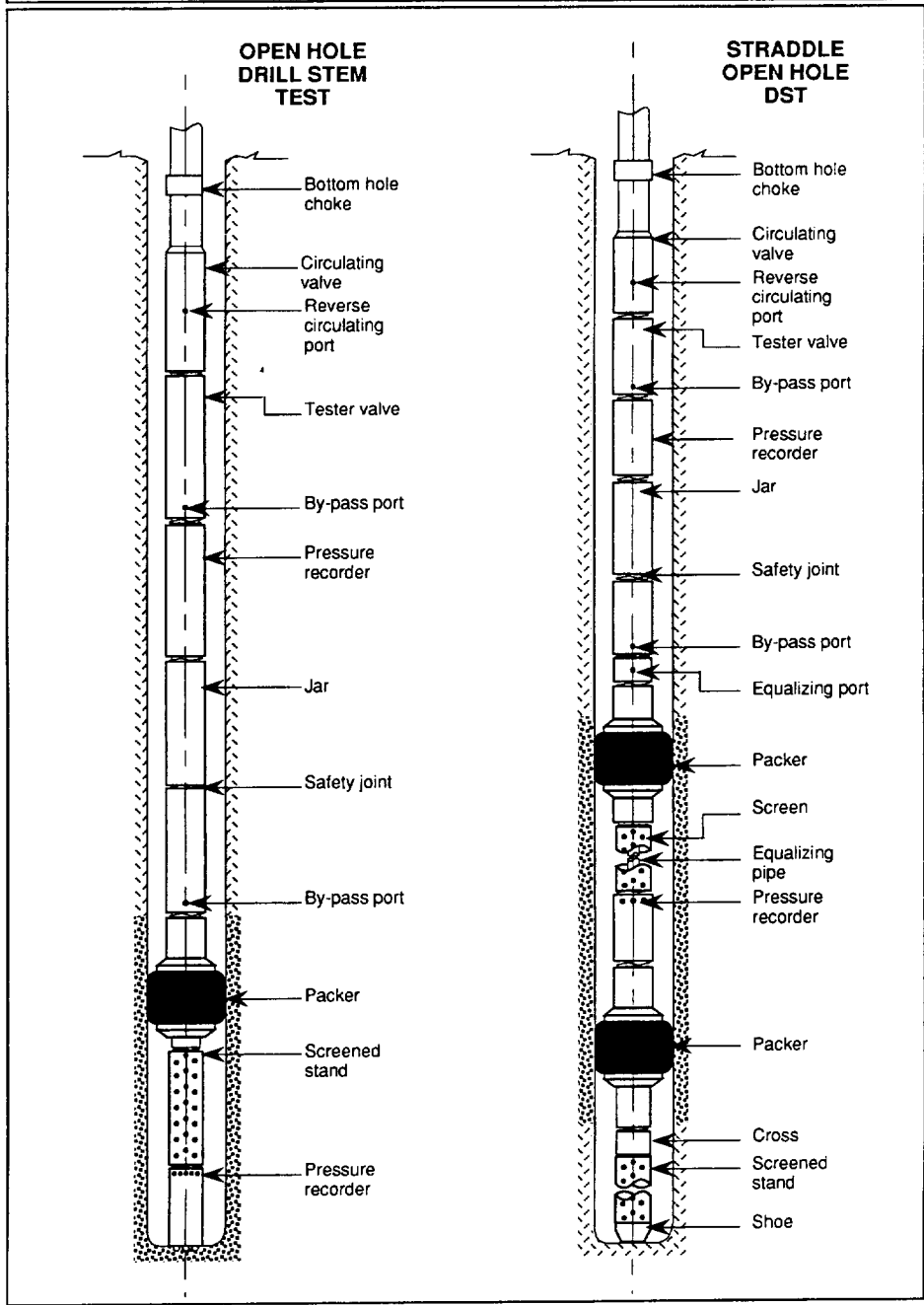
## **6.2 Surface equipment**

The tubing/casing annulus is closed off by the BOPs. A production head is screwed on to the tubing and connected to a choke manifold fitted with a fixed choke and an adjustable choke.

# DRILL STEM STRING AND SURFACE EQUIPMENT



# WELL TEST





The manifold is connected to a heater, then to a separator, that separates the water, the oil and the gas. The gas is directed to the flares, the water is removed, and the oil sent to a surge tank that gives accurate flow measurements. From here, transfer pumps send the oil to the flares.

### **6.3 Test procedures**

The test string is run with the down hole valve closed, filled with a fluid (water, diesel, air) whose density is sufficiently low so that when the down hole valve is opened, the hydrostatic pressure will be less than the reservoir pressure.

If the packer is run with the test string, it is set and the by-pass is closed. The BOPs are closed on the tubing, the production head is screwed on and connected to the surface equipment.

The down hole valve is opened. It is operated by pressure cycles in the annulus.

The well is first cleaned up : eliminating fluids in the tubing, the mud from below the packer, then the fluids that had invaded the formation (filtrate water). Then a pre-flow is made (3 to 10 mins).

From this point, the test is a series of pressure build ups with no flow, and production periods with a flow controlled by the choke manifold, that can last several hours.

The pressure is monitored on surface before the choke, and at the well bottom by recorders with a timer.

Fluid samples can be taken. The flow is measured at the surge tank and by flow meters.

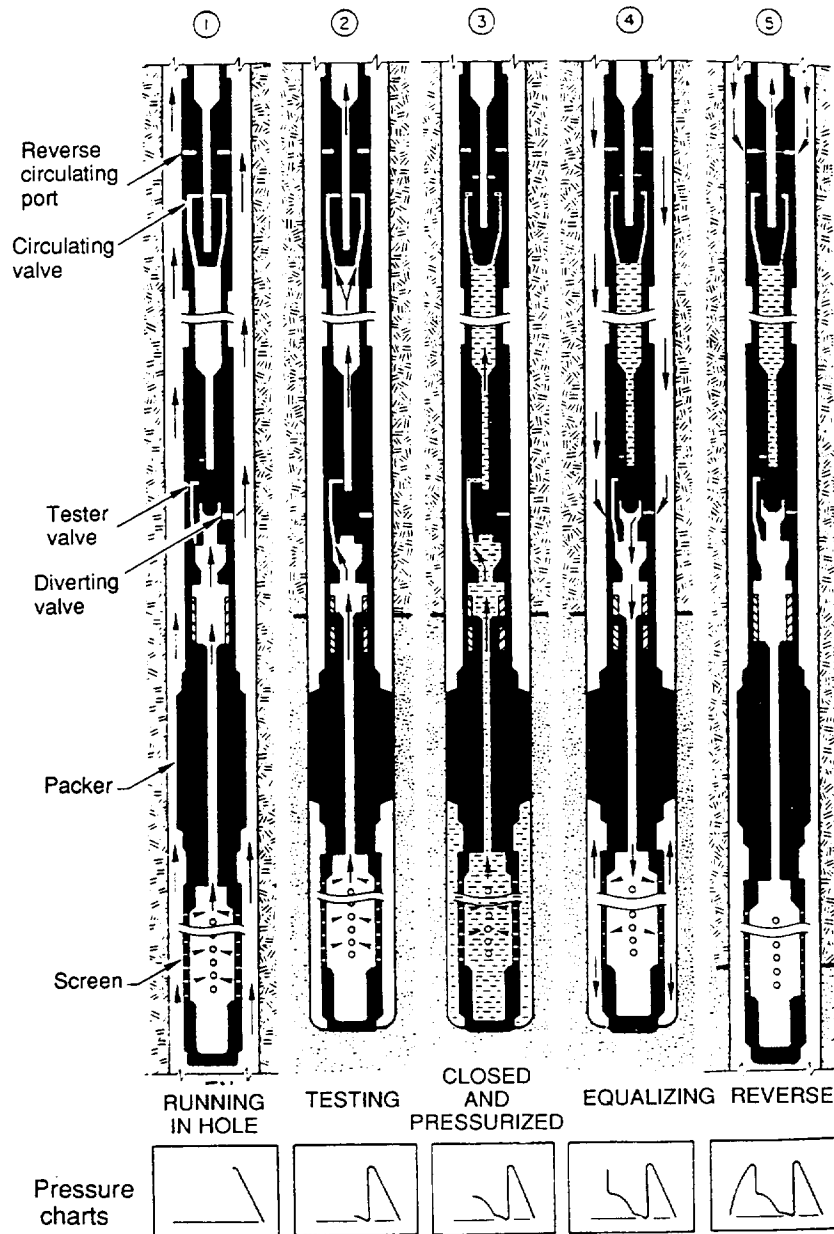
Pressure build up curves are plotted on semi-log paper that reservoir characteristics to be interpreted.

### **6.4 The geologist's role**

The test string composition must be noted in detail.

While running in, the sampling equipment must be prepared : test box with glass bottles (plasma type) ; vacutainers ; time/flow rate data sheets ; check the surface flow meter ; with the supervisor (especially for open hole testing) decide on sampling points on surface.

# DST



The test program must be followed. However this program must be flexible depending on the formation's reaction. For example, if the flow rate is low and sampling the formation fluid is vital, the flow period must be increased and build up time reduced ; on the contrary, if the well " comes in " quickly, it is possible to reduce the flow time to improve the build up period.

This flexibility in the program means having permanent contact with the base, or having authority delegated by subsurface to carry out such changes.

In all cases, the test procedure must be noted in detail, the periods, flows, pressures, sampling times, the volumes recovered, where and how, etc.

Carry out density-salinity-pH tests on samples taken, including samples of mud preceding and following formation fluids.

If the bottom hole sample chamber is opened on the rig, the geologist must be present with the adequate recipients to recover the sample fluid (test box).

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