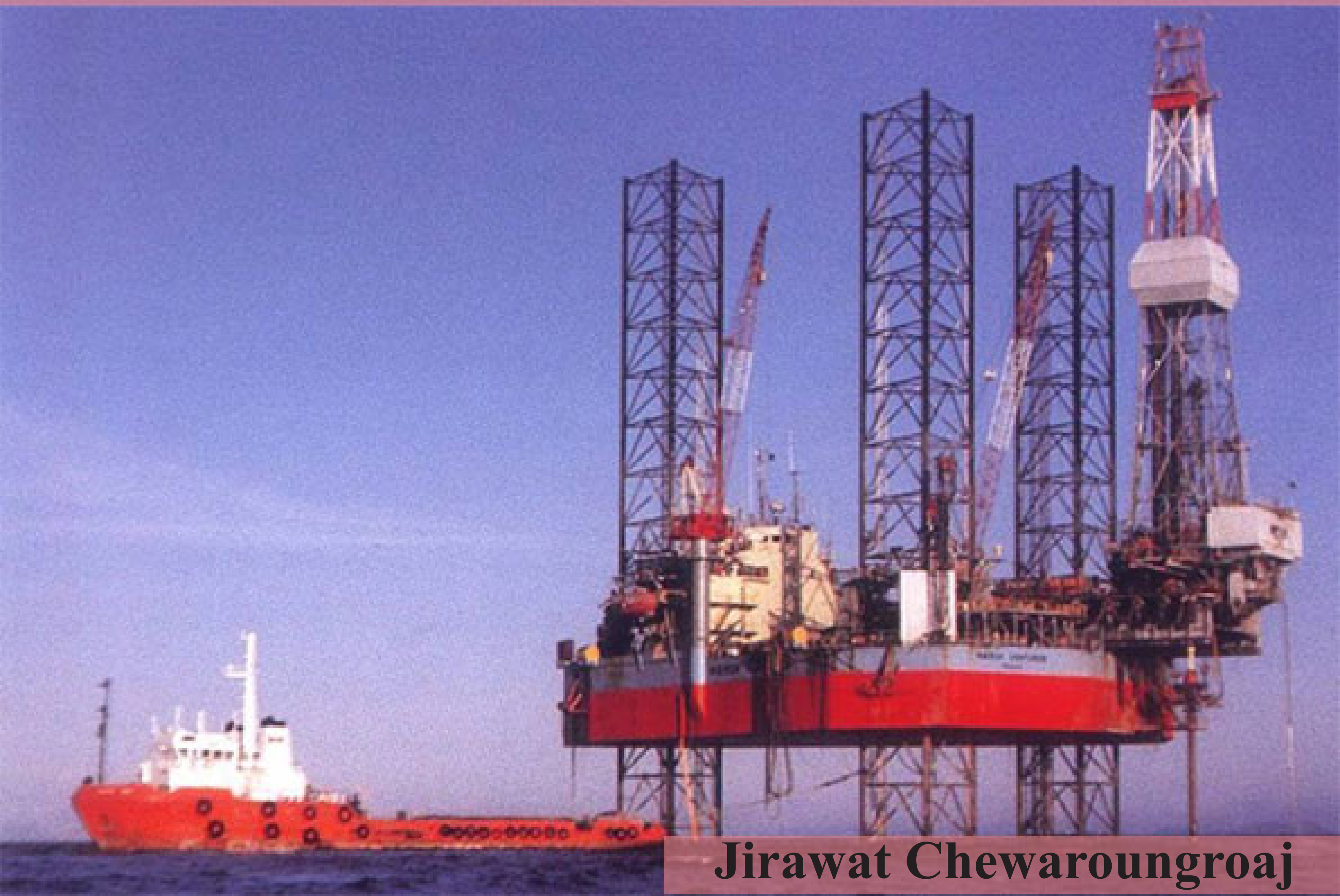
# PETROLEUM WELL DRILLING PRIMER



Jirawat Chewaroungroaj

# PREFACE

Petroleum Well Drilling Primer is thought to provide basic things in drilling operations with some words and pictures. Fundamental of making the hole down to the earth in search for petroleum still be the same as we made it in the last century. Although rotary drilling has been used since 1800s, evolution in some technologies are quite fast growing in the past decades, thanks to the advancement in material science and digital arena. The book does not cover all aspects and equipment used in drilling industry, nor does it provides detailed descriptions of procedures and techniques. Rather, the author tried to compile useful information to beginners for a basic understanding of the drilling fundamentals and operations. However, the language of the drilling industry is founded to have special words and jargons. It is quite easy to slip into using these words when trying to explain the technical issues.

Grateful acknowledgement is extended to endless lists of instructors that the author has come across in nearly forty years after introduced to the petroleum industry. They gave me not only the knowledge but also wisdom and insightful information which are presented in this book. Special thanks are also due unnamed friends who provide many photos to the book. Making a good-looking e-book out of typed manuscript is a hard work. Fortunately, my colleagues at Faculty of Engineering, Chulalongkorn University were more than up to the task and their works must be recognized, for without such efforts, this book could not exist in its present form.

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# INTRODUCTION

Petroleum well drilling is a highly complex and expensive process that requires extensive planning for success. Every well can be planned with the information from previous drilling in the area. Engineers try to anticipate problems and determine the best ways to deal with them. They utilize available engineering tools, such as computers and expert recommendations, to guide the development of the well plan. Their efforts result in a written well plan that describes in details the equipment, procedures, and type of completion to be used. In today's environment, health, safety, and environment (HSE) requirements play an equal role in the planning and implementation of drilling plans. Significant planning is required to protect operating personnel, retain licenses to operate, control costs, and coexist with the environment. Safety should be the highest priority in well planning. Accidents are costly, more so than the up-front costs to mitigate the risk to people, property, and environment. The objectives of well planning are to make a drilling program that takes safety, environmental standards, and cost efficacy in consideration. Development of projects today may require full environmental impact assessments (EIA) before approval. Most companies have management systems in place for environmental management of their operations. Drilling personnel are responsible for planning and conducting operations to ensure compliance. Determining the expected characteristics and problems encountered in the well plays important aspect during the preparation of well plan. Engineers work together with geoscientists to develop understanding of the expected drilling geology and geological anomalies as they may be encountered in drilling the prospect well. Selecting offset wells to be used in data collection is also important. In some cases, the plan must be altered during the course of drilling the well when unforeseen drilling problems endanger the personnel.

## Well Types

Drilled wells are typically classified into the followings:
**Exploration wells.** Well are drilled where little or no known geological information is available, sometimes called wildcats. The main objectives of this drilling well are to determine the presence of hydrocarbons, to provide a geological data for evaluation, to obtain reservoir fluid samples for laboratory analysis, and conduct flow test through the well to determine its production potential. There may be a single well or many wells drilled on a prospect in the exploration phase.
**Appraisal wells.** Wells are drilled after hydrocarbons are discovered to establish reservoir boundaries and get necessary information, e.g. fluid properties and mobility, to justify investment for development of the discovery field. Engineers will investigate the most cost-effective manner through which they can develop the field.
**Development wells.** Wells are drilled into a productive area of the petroleum field to produce hydrocarbons. These wells would normally focus on the optimum placement, efficient operations, and lowest cost. After many years of petroleum production it may be found that the field is yielding more or possibly less hydrocarbons than initially anticipated. Further appraisal and subsequent drilling in the field could be performed. Finally, if the field is no longer producing economically, wells that were drilled either to gather the information or produce hydrocarbons need to be abandoned to prevent possible environmental damages.

## Drilling Personnel

Drilling a well requires many different skills and involves many companies. The oil company who manages the drilling and/or production operations is known as the operator. There are many different management strategies for drilling a well but in most cases the oil company will employ a drilling contractor to actually drill the well. The drilling contractor owns and maintains the drilling rig and employs and trains the personnel required to operate the rig. During the course of drilling the well certain specialized skills or equipment may be required. e.g. logging, surveying. These are provided by drilling service companies. These service companies develop and maintain specialist tools and staff and hire them out to the operator. The operator will generally have a representative on the rig, sometimes called company man, to ensure drilling operations go ahead as planned, make decisions affecting progress of the well, and organize supplies of equipment. He will be in daily contact with his drilling superintendent who will be based in the head office of the operator. There may also be an oil company drilling engineer and/or a geologist on the rig. The drilling contractor will employ a toolpusher to be in overall charge of the rig. He is responsible for all rig floor activities and liaises with the company man to ensure progress is satisfactory. The manual activities associated with drilling the well are conducted by the drilling crew. Since drilling continues 24 hours a day, there are usually 2 drilling crews. Each crew works under the direction of the driller and assistant driller who man the drilling console on the rig floor from where instrumentation will enable them to monitor and control the drilling parameters. The crew will generally consist of a derrickman who handles the pipe up in the mast and also tends the pumps while drilling, 3 roughnecks working on rig floor, plus a mechanic, an electrician, a crane operator and roustabouts, i.e. general laborers. Service company personnel are transported to the rig as and when required. Sometimes they are on the rig for the entire well, e.g. mud engineer, or only for a few days during particular operations, e.g. directional drilling engineer, logging engineer.

# DRILLING RIGS

## Rig Types

The main equipment required to drill a well is collectively known as a drilling rig. Drilling rigs are classified according to what the rig is supposed to be standing on when it drills and how it is moved around. The main location to stand on is either land or marine.

Land rigs are for the working on solid flat ground area. They come in all sizes, from small trailer mounted rigs to very large rig systems requiring more than 100 truck-loads to move. One of the first criteria for design of a land rig is how to move it. An important consideration for land rigs is that they can be rig up and down, and moved to the next drilling location efficiently and safely. Some drilling rigs are built onto the back of trucks to simplify moving between well locations. In cases where a well-pad accommodates several wells, this is simply a matter of skidding the rig to a new well while not moving much of the other equipment on the wellsite. Newer land rigs are also designed for fast rig up and rig down as well as minimizing the impact on landscape and environment. One rig type that often classified as land rig is swamp barge. These drilling units are designed for drilling wells in very shallow water in inland swampy environments. They are typically floated between locations and are then ballasted down onto the swamp floor prior to drilling which then proceeds in a similar way to drilling a land well. The barges are not designed for rough water and are pinned in place with legs or posts that extend down to the swamp floor.

Fig 1: Land rig (www.parkerdrilling.com)

Fig 2: Truck mounted drilling rig (www.jereh-pe.com)

Drilling rigs used offshore are termed marine rigs. A common grouping system for marine rigs is based on the bottom support of the rig on the seafloor and floating. A bottom-supported rig rests on the seafloor or on pads built on the seafloor. Floating rigs rely on ballast systems similar to shipping vessels for support and do not rest on the seafloor. Water depth rating is commonly the first evaluative criteria. Bottom-supported units can operate in a maximum of 400 feet water depths; 250-300 feet is the typical maximum. Platforms can handle depths to about 1,000 feet, it could be deeper with today's emerging technology, but deep platforms are justified only for long term development drilling. Floaters can handle short term projects (like exploration) in water depths from 300-7,000 feet. The upper limit is being extended steadily; the lower limit depends on weather and the size of the drilling budget.

A platform rig is an immobile offshore structure. That is, once built, it never moves from the drill site. The platform comprises a support structure plus drilling rig, processing facilities, power generators, offices and living quarters. Hence the drilling rig is only one part of the overall platform and is in many ways very similar to a land rig. Between one and 60 wells may be drilled from a single platform, and at surface they are typically 5–10 feet apart. The rig is moved from one well to another by "skidding" along supporting beams along and across the platform. Platforms are used only for development wells, i.e. once the field has been discovered. Examples of platform rig are steel jacket fixed platforms, gravity based platforms, and tension leg platforms. Steel jacket platforms are supported by a steel jacket that sits on the seabed and is piled so that it cannot move after final positioning. The jacket is typically lifted and lowered onto the seabed using a heavy-lift barge or alternatively floated onto location and de-ballasted in a controlled way until it settles on the seabed. An alternative to the steel jacket is concrete gravity base which relies on its own weight resting on the seabed to support the topside equipment, which is essentially the same as for the steel-jacket platform. A third type of platform, the tension leg platform is essentially a floating structure that is linked to the seabed via steel tendons. The tendons are piled into the seabed and effectively hold the floating structure against its buoyancy.

Fig 3: Steel jacket platform rig (www.planete-tp.com)

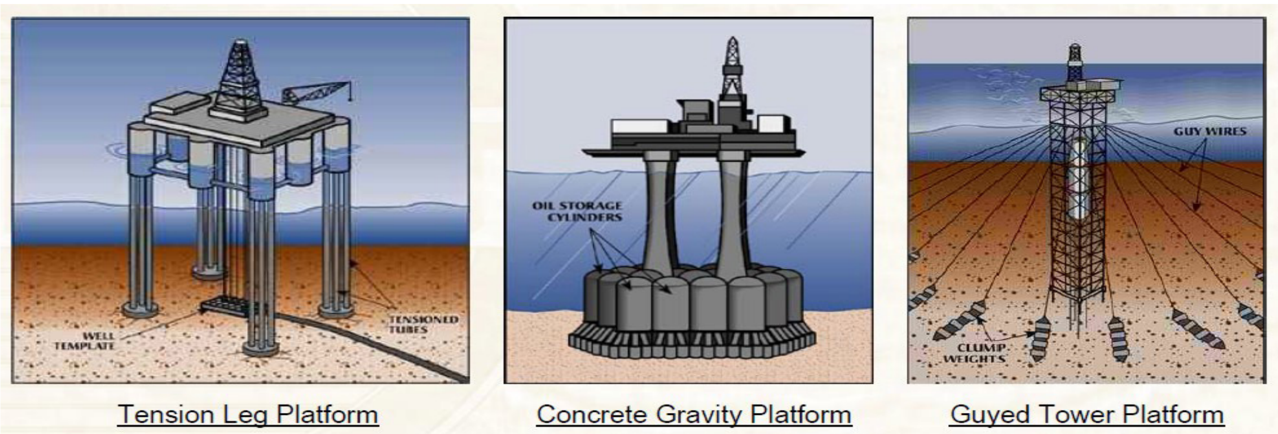


Fig 4: Other types of platform rigs (Courtesy of Petroleum Training Services)

Platform rigs can also be tender-assisted rigs. On all offshore structures however, the installation of additional weight or space is costly. Drilling is only carried out during short periods of time if compared to the overall field life span and it is desirable to have a rig installed only when needed. This is the concept of tender assisted drilling located on the tender, which is a specially built spacious barge anchored alongside. It is able to service a whole field or even several fields using only one or two tender assisted derrick sets. The tender is typically a moored barge or semisubmersible unit with a large crane that lifts the rig in parts or as a whole onto the platform. The tender floats next to the rigid platform, which is firmly pinned to the seafloor. Once on the platform, work is carried out as if the rig were permanently installed. Fluids, supplies and control of the well are provided by the tender unit. When operations are completed the rig is lifted off the jacket onto the tender and sailed to another location. This is only possible in benign wind and sea conditions due to the heavy lifting operations required.

Fig 5: Tender-assisted rig

A submersible rig rests on the sea floor when it is drilling. Workers flood compartments that cause the rig to submerge and rest on bottom. When ready to move, crew remove the water from the compartments. This makes the rig float. Boats can then tow the rig to the next site. Rig builders design submersibles to drill in shallow water and in water up to about 175 feet deep.

Fig 6: Submersible rig (www.parkerdrilling.com)

Jackup rig is a mobile drilling unit. It has typically 3 or 4 extendable legs that support a deck and hull. The hull of the rig is watertight and the unit is towed onto location using tugs. When positioned over the drilling site, the bottom of the legs rest on the sea floor then crew can adjust level the deck and hull height. When above the top deck of the platform, the drilling derrick is skidded outboard of the rig so that it is cantilevered vertically over the well to be accessed. Drilling proceeds in a similar way to the drilling of any well through the platform. Single wells, such as exploration wells, can also be drilled without the need for a jacket. Jackup rigs can drill in water depths ranging from a few feet or to more than 400 feet. Globally, they are the most common rig type, used for a wide range of environments and all types of wells.

Fig 7: Jackup rig

A semisubmersible rig is a floating offshore drilling rig. It has pontoons and columns. When flooded with water, the pontoons cause the unit to partially submerge to a predetermined depth. The working equipment is assembled on deck. The rigs are held in position either using anchors (typically 8 or 12) laid out in a "star" pattern or Dynamic Positioning (DP). DP systems comprise typically 4–8 motor/propeller azimuthing thrusters that can rotate by 360 degrees. The propellers are fixed or of variable pitch, and the units can be replaced as a single component. These devices enable the rig to be positioned vertically over the well at all times, overcoming current and wind forces. They are controlled by a sophisticated computer system that takes input from GPS, beacons on the seabed and other sensors. High reliability of these systems is essential for the successful deployment of this type of rig. Some dynamically positioned semisubmersibles can drill in water depths of more than 7,500 feet. However, anchor handling and the length of the riser eventually impose a limit on the operating depth. Their stability makes them suitable vessels for hostile offshore environments. The topsides of the rig are very similar to that of a jackup, with three important exceptions:

• The drilling derrick needs to compensate for vertical motion of the rig relative to the seabed.

• The BOPs for the semisubmersible rig are located on the seabed and hence are deployed, operated and maintained in a different manner to those on the jackup.

• The wellhead for a subsea well (i.e. one drilled by a semisubmersible) is at the seabed rather than at sur face.

Fig 8: Semisubmersible rig (www.maerskdrilling.com)

A drill ship is a self-propelled, floating offshore drilling unit. It usually uses a subsea blowout control system similar to the one on a semisubmersible. Drill ships have a number of advantages over semisubmersibles. They can move more quickly between locations and have a very significant deck-load capacity. This translates into an ability to drill an entire well, or even a series of wells, without replenishment of supplies. The downside is that they are more weather-sensitive than a semisubmersible, due to their hull design.


Fig 9: Drillship (www.maerskdrilling.com)

A well drilled from an offshore rig is much more expensive than a land well drilled to the same depth. The increased cost can be attributed to several factors, e.g. specially designed rigs, subsea equipment, loss of time due to bad weather, expensive transport costs (e.g. helicopters, supply boats).

## Rig Components

Although drilling rigs differ greatly in outward appearance and method of deployment, all rotary rigs have the same basic drilling equipment. The main component parts of a rotary rig can however be grouped together into six subsystems. These systems are: the power system; the hoisting system; the circulating system; the rotary system; the well control system and the well monitoring system. Although the pieces of equipment associated with these systems will vary in design, these systems will be found on all drilling rigs.
Power system. Without power nothing on a rig operates. Machinery must have an energy source to make it go. On virtually every drilling rig, the power comes from internal-combustion engines, which are called prime movers, and most engines use diesel as fuel. They are generally sub-classified as the diesel-electric type or the direct-drive type, depending on the method used to transmit power to the various rig system. Older rigs used mechanical transmission systems

but  modern drilling rigs use electric transmission since it enables the driller to apply power more smoothly, thereby avoiding shock and vibration.  The prime movers turn generators that produce easy to control and transmit alternating current (AC).  Silicon controlled rectifiers (SCR) convert or rectify the AC to direct current (DC) which flows to the motors that is easy to control.  Total power requirements for rigs are from 1,000 to 5,000 horsepower.

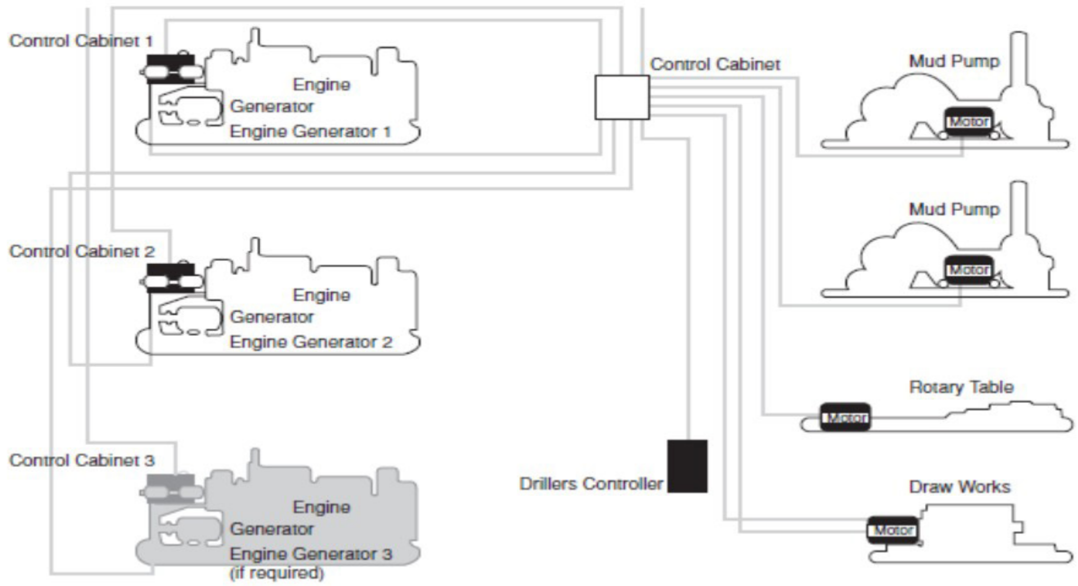


Fig 10: Power system (Courtesy of Heriot Watt)

**Hoisting system**.The hoisting system is a large pulley system which is used to lower and raise equipment into and out of the well.  It usually requires the heaviest power supply.  The function of the hoisting system is to provide a means of lowering or raising drill strings, casing strings, and other subsurface equipment into or out of the hole.  The principal components of the hoisting system are

- Derrick, mast and substructure
- Crown block and traveling block
- Drawworks
- Wire rope drilling line
- Ancillary equipment such as hook and elevators

The function of the derrick is to provide the vertical height required to raise sections of pipe from or lower them into the hole.  The greater the height, the longer the section of pipe they can be handled and, thus, the faster a long string of pipe can be inserted in or removed from the hole.  In additional to their height, derricks are rated according to their ability to withstand compressive loads and wind loads.  A standard derrick is a structure with four supporting legs resting on a 30 feet square base about 140 feet high and is capable of supporting 1,500,000 lbs weight.

The higher the derrick is, the longer stands it can handle which in turn reduces the tripping time. Derricks that are capable to handle stands of two, three or four joints are called to be able to pull “doubles”, “thribbles”, or “fourbles” respectively. The derrick is erected on top of a substructure which serves to support the rig floor that provides space for equipment and working place for all drilling operations and also to provide space for blowout preventer equipment and other associated equipment. A mast is used on all types of land rigs because it can be dismantled and reassembled quite fast and an also be raised and lowered as a complete unit by the drawworks.

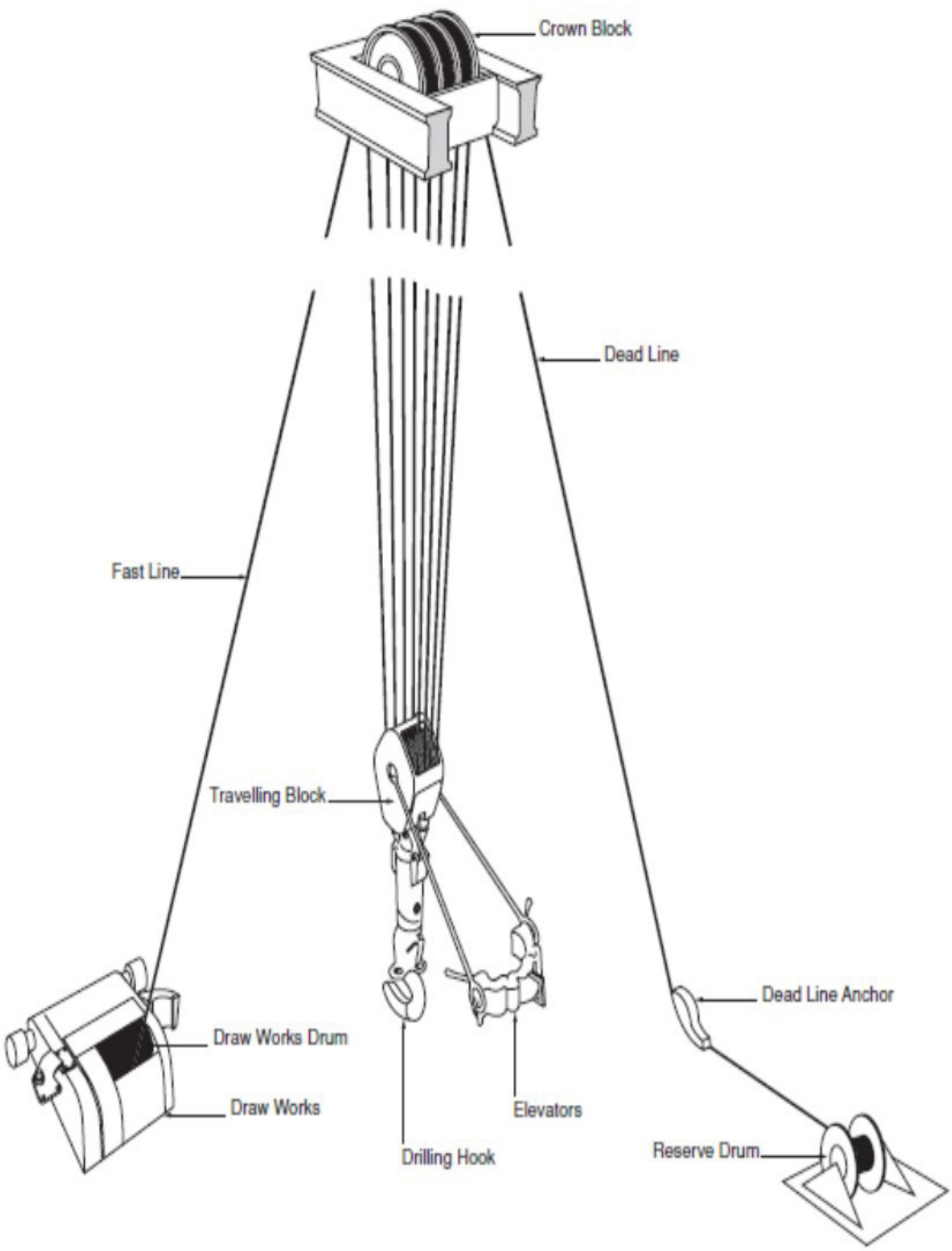


Fig 11: Hoisting system (Courtesy of Heriot Watt)

The crown block is a stationary metal framework on the top of the derrick that holds sheaves that rotate on a horizontal shaft mounted on bearing with a greased lubricating system.

The traveling block is set of sheaves moving up and down inside the derrick allowing tubular to be hoisted in and out of the hole and it is suspended in a derrick with drilling line from the crown block. The number of sheaves needed on the crown block is always one more than the number required in the traveling block.

The drawworks consists of a large revolving drum, around which a wire rope (drilling line) is spooled. Drawworks are also fitted with transmissions to make it possible to match speed and lift capacity as required. The drum of the drawworks is connected to an electric motor and gearing system. The gear shift device is also located on the drawworks console in the driller's cabin. The driller controls the drawworks with a clutch and gearing system when lifting equipment out of the well and a brake (friction and electric) when running equipment into the well. The drawworks provide the hoisting and breaking power required to raise and lower the heavy strings of pipe. Power from the engines or electric motors drives the drawworks drum. When the driller activates a control and releases the brake, the drum reels in drilling line. Reeling in drilling line raises the traveling block and whatever is attached to it. To lower the traveling block, the driller releases the drawworks brake. The force of gravity pulls the block down. The driller controls the descent by applying the brake to slow or stop the downward travel. It also stores the drilling line required to move the traveling block the length of derrick.

Fig 12: Drawwork

The drilling line goes through the crown block and traveling block. Having reeved the drilling line around the crown block and travelling block, one end of the drilling line is secured to an anchor point somewhere below the rig floor. Since this line does not move it is called the deadline. The other end of the drilling line is wound onto the drawworks and is called the fastline. The drilling line is usually reeved around the blocks several times until enough lines have been strung to give the lines enough lifting strength to support weight of the drill string.

The wire rope drilling line is usually braided steel wire that ranges in diameter between 0.5 to 2 inch and is commonly between 1 and 1.625 inch. The thicker a wire hosen for the job the more wear must be expected as the drilling line has to be strung through several sheaves in crown block and traveling block. It is maintained in good condition by following a scheduled slip-and-cut program. The parameter adopted to evaluate the amount of line service is the ton-mile. A drilling line is said to have rendered one ton-mile of service when the traveling block has moved 1 U.S. ton a distance of 1 mile. In the case of the slipping operation the traveling block is lowered to the rig floor, the dead line anchor is unclamped and some of the reserve line is threaded through the sheaves on the traveling block and crown block onto the drawworks drum. This can only be performed two or three times before the drawworks drum is full and a slip and cut operation must be performed. In this case the traveling block is lowered to the rig floor, the dead line anchor is unclamped and the line on the drawworks is unwound and discarded before the reserve line is threaded through the system onto the drawworks drum. The decision to slip or slip and cut the drilling line is based on an assessment of the work done by the line. Standard lengths of drilling line spooled onto big reels are 7,500 feet and 10,000 feet.

Fig 13: Drilling line

The hook is located beneath the traveling block. This device is used to pick up and secure the swivel and kelly. Modern drilling rig has a top drive system attached to the hook or even attached directly to the traveling block. It is also used to hang tools and equipment and is also used to raise and lower equipment in the hole and move up and down in the derrick. The elevators are used for latching on to the tool joint or lift sub of the drill pipe or drill collars. This enables the lifting and lowering of the drill string while making a trip. Crew members use many types of elevators. Which one depends on the kind and size of the tubulars. For example, most drill pipe and lifting subs require a center-latch bottleneck elevator, but some drill collars require a side-door collar type elevator. Casing requires a special, heavy-weight casing elevator. Tubing, a light-weight pipe used in completing wells, usually needs a slip-type tubing elevator. The elevators are connected to the hoisting system (traveling block) by means of bails.

**Rotating system.** The rotating (or rotary) system includes all of the equipment used to achieve bit rotation. On a conventional rig, the main equipment of the rotating system consists of a swivel, a special length of pipe called the kelly, the rotary table, drill string, and bit. Some contractors install a special system on their rigs called a top drive. It replaces many parts of the conventional rotating system.

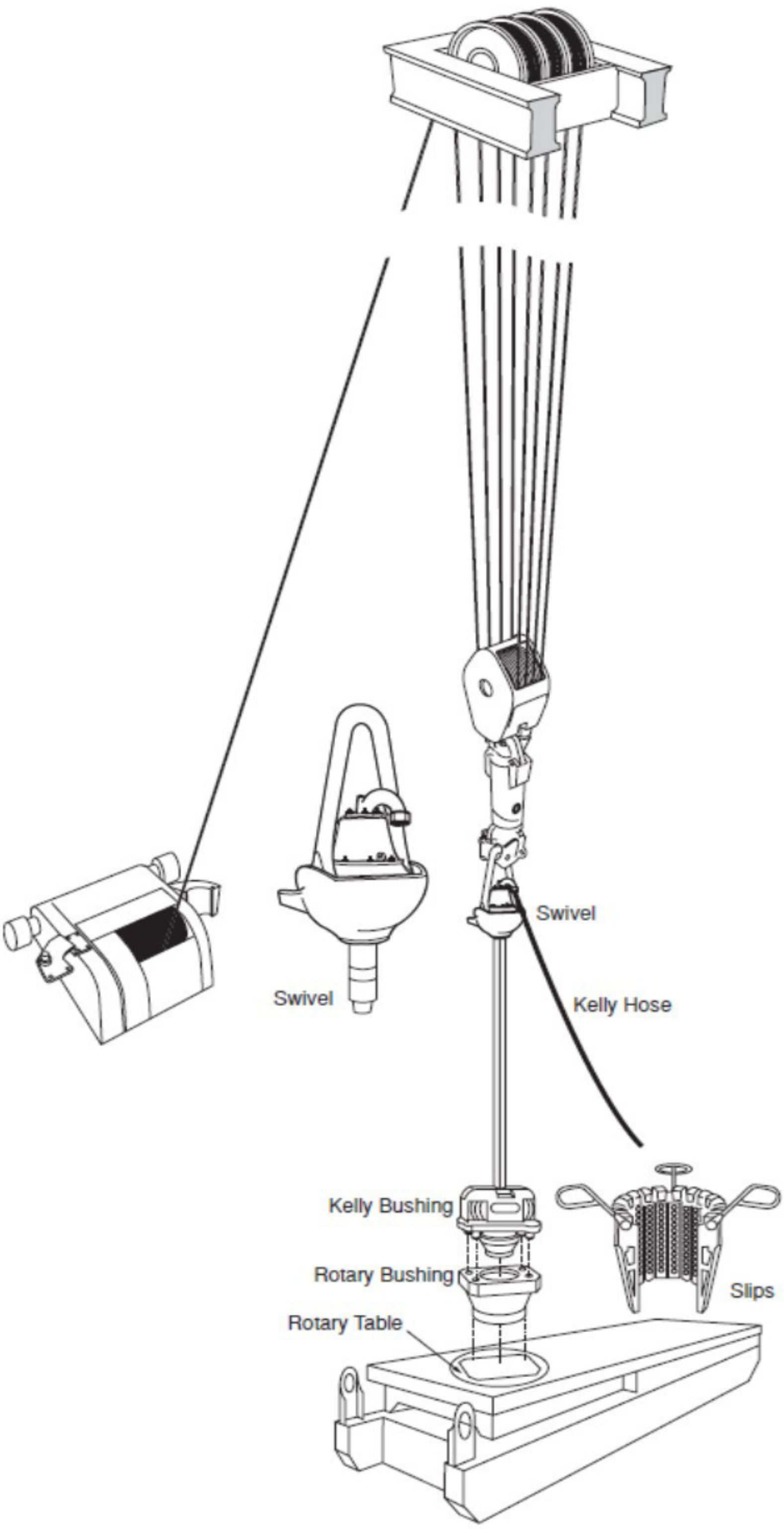


Fig 14: Rotating system (Courtesy of Heriot Watt)

Swivel is a device that sustains the weight of the drill string, permits it to rotate, and provides a passageway for drilling fluid to get into the drill string. It establishes a connection between hook and kelly. Kelly is the first section of pipe below the swivel. Most rigs use 40 feet kelly. The outside cross section of kelly is square or hexagonal to permit it to be gripped easily for turning. In general, a hexagonal kelly is stronger than a square kelly, hence tends to be used to drill deeper well as extra strength is needed. Driller lowers the kelly inside a corresponding square or hexagonal opening in the kelly bushing. The kelly bushing fits into another rotating equipment called master bushing. The master bushing fits inside the rotary table. Torque is transmitted to the kelly through kelly bushings, which fit inside the master bushing of the rotary table by turning the latter. Rotary table is a rotating steel-alloy platform that transfers motion to the kelly through the master and kelly bushing on a drilling rig. The compound, a drive mechanism from the drawworks, or an electric motor powers the rotary table. The rotary table also accommodates the slips, a tapered segmented device lined with strong tooth like gripping elements that hold the pipe suspended in the hole when the kelly is disconnected during a trip.

Most rigs are now fitted with a system whereby the drill string is rotated by a drive mechanism in the mast rather than by the rotary table at the rig floor level. Thus 90 feet sections can be drilled before connections need to be made, and the drill string can be rotated while pulling out of the hole in 90 feet sections. This improved system, which speeds up the operation and allows better reaming out of the hole is known as Top drive. The top drive unit hangs from the traveling block's hook in place of a conventional swivel. A powerful heavy-duty motor in the top drive turns a threaded drive shaft, thus it rotates the drill string. The electric motor delivers over 25,000 ft-lbs torque and can operate at 300 rpm. The conventional swivel, the kelly, and the kelly bushing are entirely eliminated. Rigs with the top drive system still need a rotary table and master bushing to provide a place for the slips to suspend the pipe. It also makes making up or breaking out pipe faster and safer. When tripping out of the hole the top drive unit can be easily stabbed into the string to allow circulation and string rotation when pulling out of hole.


Fig 15: Top drive

The term drill string is used to refer to various combinations of downhole tools. The main purpose of the drill string is to transmit energy from rig's surface equipment to the bit. Drill pipe is the major portion of drill string. It is hot-rolled, pierced, seamless tubing and is specified by its outside diameter, weight per foot, steel grade, and range length. American Petroleum Institute (API)) has developed specifications for drill pipe. The drill pipe is furnished in 3 length ranges (range 1, 18-22 feet, range 2, 27-30 feet, and range 3, 38-45 feet). Range 2 drill pipe is most commonly used, making the average length of a drill pipe joint about 30 feet. There are four standards for measuring drill pipe strength, namely torsional yield strength, tensile yield strength, collapse resistance, and internal yield. The drill pipe joints are fastened together in the drill string by means of tool joints. The female portion of the tool joint is called the box and the male portion is called the pin. Tool joints also vary according to the number of threads per inch, the amount of taper per foot and the overall length of the box and pin. Torsional yield strength is an important consideration in tool joint design, with respect to both tool joint make-up and the rotational force encountered while drilling.


Fig 16: Drill pipe

Drill collar is thick-walled heavy steel tubular, usually plain carbon steel but sometimes of nonmagnetic nickel-copper alloy or other nonmagnetic premium alloy, used to keep the drill string in tension (avoid buckling) and provide weight onto the bit. It is usually placed in the drill string below the drill pipe. Drill collars are commonly manufactured in 30 feet lengths. Manufacturers cut threads into each end of a drill collar so that it can be joined with another collar. The number of drill collars screwed together depends on the weight needed to make the hole efficiently, the type of formation to be drilled through, the weight of each drill collar, and other variables. Drill collar with spiral grooves helps prevent differential sticking by reducing the amount of drill collar surface area that contacts the sides of the hole. Differential sticking is a condition in which the drill string becomes stuck against the wall of the wellbore because of the difference in pressure between the drilling fluid in the wellbore and that of a permeable formation.

Fig 17: Drill collar

Stabilizer subs are often used to stabilize the drill string in the center of the wellbore. Type and placement of stabilizers in the drill string depends on local drilling conditions and well objectives. They can be used to ensure that the weight of the drill collars is concentrated on the bit; reduce torque and bending stresses in the drill string, prevent wall sticking or key seating of the drill collars; build, drop or maintain hole angle in directional drilling; maintain constant bit direction in straight hole drilling

Fig 18: Stabilizer sub

Drill bit is the cutting tool used in drilling. The bit is turned by the drill string or downhole motor to chip and flake the rocks at the bottom of the hole. Bit manufacturers make two types of bit for rotary drilling: roller-cone and fixed-cutter. Roller-cone bits have steel cone-shaped devices that roll, or turn, as the bit rotates. Most roller-cone bits have three cones. The most common fixed-cutter bit is the polycrystalline diamond compact (PDC) bit. PDC bits feature specially manufactured diamond cutters, or compacts. Drill bits come in a variety of types and standard sizes in diameter.

Fig 19: Roller-cone bit


Fig 20: PDC bit

**Circulating system.** Rotary drilling has two fundamental characteristics. One is the rotation and the other is the circulation of drilling fluid. The circulating system circulates drilling fluid downward through the drill string, around the bit, and upward in the annular space between the drill string and the wall of the hole or the casing. The main components of the rig's circulating system are the mud pumps, mud pits, mud-mixing equipment, and mud-cleaning equipment.

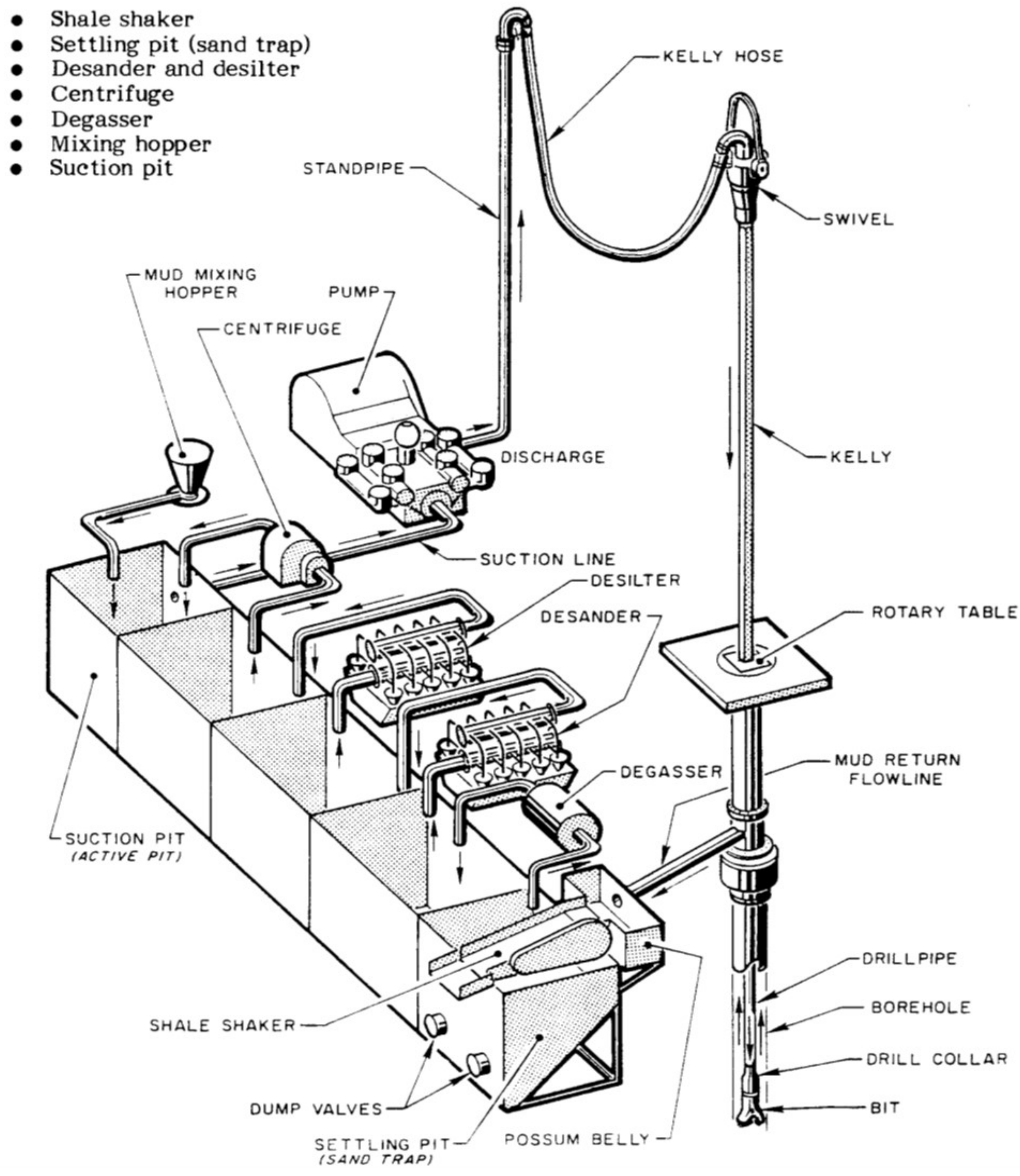


Fig 21: Circulating system (Courtesy of Baker Hughes INTEQ)

Mud pumps take in drilling fluid from the mud pits and send it out a discharge line to standpipe, a steel pipe mounted vertically on one leg of the mast or derrick. The mud is pumped up the standpipe and into a flexible, very strong, reinforced rubber hose called rotary hose or kelly hose, connecting to the swivel. The mud enters the swivel, goes down the kelly, drill string, exits at the bit and heads back up the hole in the annulus carrying drilled cuttings up to surface. Finally the mud leaves the hole through a steel pipe called the mud return line and before it re-enters the mud pits the drilled cuttings are removed from the drilling fluid by the solids removal equipment. Mud pumps are powered by electric motors attached directly to them or driven by the compound. The pumps can move large volume of mud at very high pressure. Most mud pumps currently used in the drilling industry are duplex or triplex positive-displacement pumps. The amount of mud and the pressure the mud pumps release the mud to the circulation system are controlled via changing of pump liners and pistons as well as control of the speed [stroke/minute] the pump is moving. The duplex double-acting pump has two cylinders with valves on both ends of the liners. Each of the two cylinders of this pump is filled on one side of the piston at the same time that fluid is being discharged on the other side of the piston. Fluid is displaced from the cylinder on the forward and backward strokes of the piston rod. Each complete cycle of a piston results in the discharge of a mud volume that is twice the volume of the cylinder, minus the volume of the piston rod. The triplex mud pump consists of three cylinders and is single-acting. Single-acting pumps put pressure on only one face of the pistons rather than on both sides, as double-acting pumps do. The triplex pumps are generally lighter and more compact than the duplex pumps and their output pressure pulsations are not as large. Because of this and since triplex pumps are cheaper to operate, modern rigs are most often equipped with triplex mud pumps. There will be at least two pumps on the rig and these will be connected by a mud manifold. When drilling large diameter hole near surface both pumps are connected in parallel to produce high flow rates. When drilling smaller size hole only one pump is usually necessary and the other is used as a back-up. Improved pumping characteristics can be expected when a pulsation dampener (surge chamber) is added to the discharge line. The surge chamber contains a gas in the upper portion, which is separated from the drilling fluid by a flexible diaphragm. The surge chamber greatly dampens the pressure surges developed by the positive-displacement pump. A dampener helps to utilize most of the available pump horsepower. It accomplishes this by increasing the speed at which the pump can run without the problems of knocking and accompanying pressure surges. Most operators prefer to run pulsation dampeners on the discharge end of the pump. The discharged drilling fluid is under high pressure and, as it is forced out of the liners it places significant surge pressures on the equipment. The pulsation dampeners are designed to absorb most of these surges and to reduce the wear of the other surface circulating equipment.

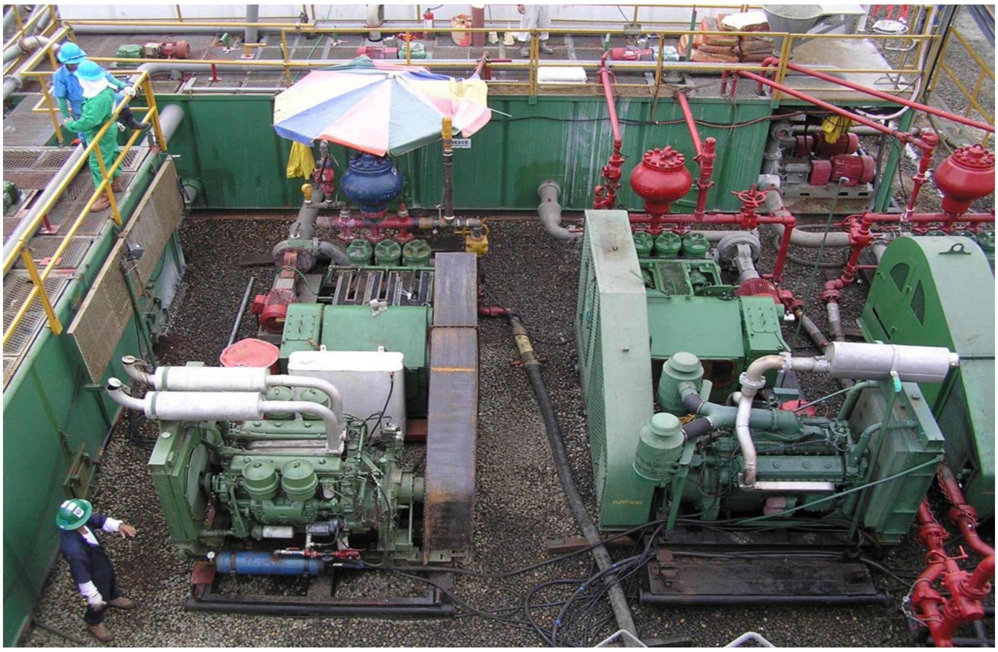

Fig 22: Mud pumps

The mud pits are usually a series of large steel tanks, all interconnected and fitted with agitators to maintain the solids, used to maintain the density of the drilling fluid, in suspension. Some pits are used for circulating (e.g. suction pit) and others for mixing and storing fresh mud. Most modern rigs have equipment for storing and mixing bulk additives (e.g. barite) as well as chemicals. Mud is mixed in the mud tanks with the help of a mud hopper, a big funnel-shaped piece of equipment, into which most of the dry chemicals for the mud are poured. The mixing pumps are generally high volume, low pressure centrifugal pumps.

Fig 23: Mud pits

The mud-cleaning system is a processing system to prepare mud for return to the bottom of the hole. Once the mud has been circulated round the system it will contain suspended drilled cuttings, perhaps some gas and other contaminants. These must be removed through several types of solids-removal equipment, including the shale shakers, degassers, desanders, desilters, centrifuges, and mud cleaners, before the mud is recycled. Shale shakers are the most important piece of solids removal equipment. In almost cases, shakers are the cheapest, most effective means of solids control. The mud passes over a shale shaker, which is basically a vibrating screen. This will remove the larger particles, while allowing the residue to pass into settling tanks. The finer material can be removed using other solids removal equipment. The shale shaker should be designed to use the finest screen possible with the least loss of whole mud. The shale shaker screens out the drilled cuttings and dumps them into the reserve pit after which they are dispersed. In environmentally sensitive areas, the shaker cuttings are collected and treated prior to disposal. Since the shale shaker screen is not fine enough to remove very small particles, the mud is sent through desanders and desilters so that any fine silt or sand can be removed. These hydrocyclones are essentially simple devices that convert pressure generated by a centrifugal pump into centrifugal force, causing suspended solids in the mud to be separated from the fluid. This separation is actually accelerated settling due to the increased gravitational force cause by the centrifugal action inside the cone. In drilling operations, hydrocyclones use these centrifugal forces to separate solids in the 15- to 80-micron range from the drilling fluid. Hydrocyclone sizes are designed arbitrarily by the inside cone diameter at the inlet. By convention, desanders have a cone diameter of 6 inches and larger; desilters have internal diameters smaller than 6 inches. Mud cleaner is a set of desilting hydrocyclones positioned over a very fine-mesh vibrating screen so that the underflow from the hydrocyclones is screened and the liquid cone overflow returns downstream to the mud system. It was originally designed to remove solids larger than barite from a weighted mud. When the barite is added, the desilter underflow is screened, most of the barite and some of the drilled solids are returned back to the mud. Decanting centrifuges are mechanical devices used for the separation of solids from slurries in many industrial processes. In drilling, centrifuges are used to condition drilling fluids by dividing the fluid into high-density and low-density streams, permitting one to be separated from the other. The division is achieved by accelerated sedimentation. As the drilling fluid is passed through a rapidly rotating bowl, centrifugal force moves the heavier particles to the bowl wall, where they are scraped toward the underflow (heavy slurry) discharge ports by a concentric auger, also called a scroll or conveyor, which rotates at a slightly slower rate than the bowl. The separation of the heavier particles divides the processed fluid into two streams: the heavy phase, also called the underflow or cake; and the lighter phase, which is called the overflow, light slurry, or effluent. Sometimes, small amounts of gas in a formation enter the mud as it is being circulated downhole. The gas is removed by a device called degasser. The degasser is a tank in which a vacuum and/or spray removes entrained gas from the mud system.

Fig 24: Shale shaker

Fig 25: Desanders

Fig 26: Desilters

Fig 27: Mud cleaner

Fig 28: Decanting centrifuges

Fig 26: Desilters

Well control system. The function of the well control system is to prevent the uncontrolled flow of formation fluids from the wellbore. When the drill bit enters a permeable formation the pressure in the pore space of the formation may be greater than the hydrostatic pressure exerted by the mud column. If this is so, formation fluids will enter the wellbore and start displacing mud from the hole. Any influx of formation fluids (oil, gas or water) in the borehole is known as a kick. The well control system is designed to detect a kick, close-in the well at surface, remove the formation fluid which has flowed into the well, and make the well safe. Mechanical devices such as pit level indicators or mud flowmeters which trigger off alarms to alert the rig crew that an influx has taken place are placed on all rigs. Safety and efficiency consideration requires constant monitoring of the well to detect drilling problem quickly.

Blowout preventers (BOPs), with other equipment and techniques, are used to close the well in and allow the rig crew to control a kick before it becomes a blowout. BOPs are basically high pressure valves which seal off the top of the well. They are a series of powerful sealing elements designed to close off the annular space between the pipe and the hole through which the mud normally returns to the surface. The crew usually installs several blowout preventers, call a stack, on top of the well, with an annular preventer at the top and at least two ram type preventers below. Annular preventer is designed to seal off the annulus between the drill string and the side of hole (may also seal off open hole if kick occurs while the pipe is out of the hole). These are made of synthetic rubber which, when expanded, will seal off the cavity. Ram type preventer is designed to seal off the annulus by ramming large rubber-faced blocks of steel together. Different types are available such as pipe rams sealing off around drill pipe, blind rams sealing off in open hole, shear rams cutting drill pipe. On land rigs or fixed platforms the BOP stack, called surface BOP stack, is located directly beneath the rig floor. On floating rigs the BOP stack is installed on the sea bed, called subsea BOP stack. In either case the valves are hydraulically operated from the BOP control panel on rig floor for easy access by the driller. Modern and safer rigs will have at least one other control panel located far from the rig floor. This panel will be used in case it is necessary, for safety reasons, to evacuate personnel from the rig floor. BOPs are closed and opened by hydraulic fluid, which is stored under pressure in an accumulator. Because the preventers must close quickly, the nitrogen gas in the unit's steel bottles puts the hydraulic fluid under 1,500 to 3,000 psi pressure. High pressure lines carry the hydraulic fluid from the accumulator to the BOP stack. The accumulator is capable of supplying sufficient high-pressure fluid to close all of the units in the BOP stack at least once and still have a reserve. By closing off the BOPs, the well can be "shut in" and the mud and/or formation fluids are forced to flow through the controllable choke, i.e. choke manifold, or adjustable valves. This choke allows the drilling crew to control the pressure that reaches the surface and to follow the necessary steps for "killing" the well, i.e. restoring a balanced system. A power-adjustable choke is operated pneumatically or hydraulically from a remote control panel on the rig floor. A manual adjustable choke has a variable choke size like the power-adjustable choke but is operated by hand, by turning a handle. A series of valves called the choke manifold is installed as part of the system. They are arranged to permit switching from one to another and connected to the blowout preventer stack with a choke line.

When the well is closed in with the BOPs, the mud and the influx are circulated out the choke line and through the choke manifold.

Fig 30: Surface BOP stack

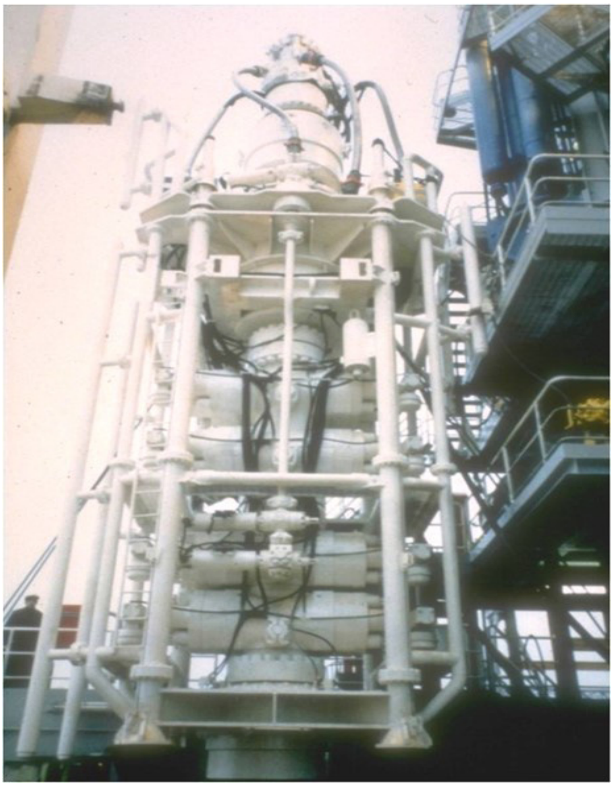

Fig 31: Subsea BOP stack

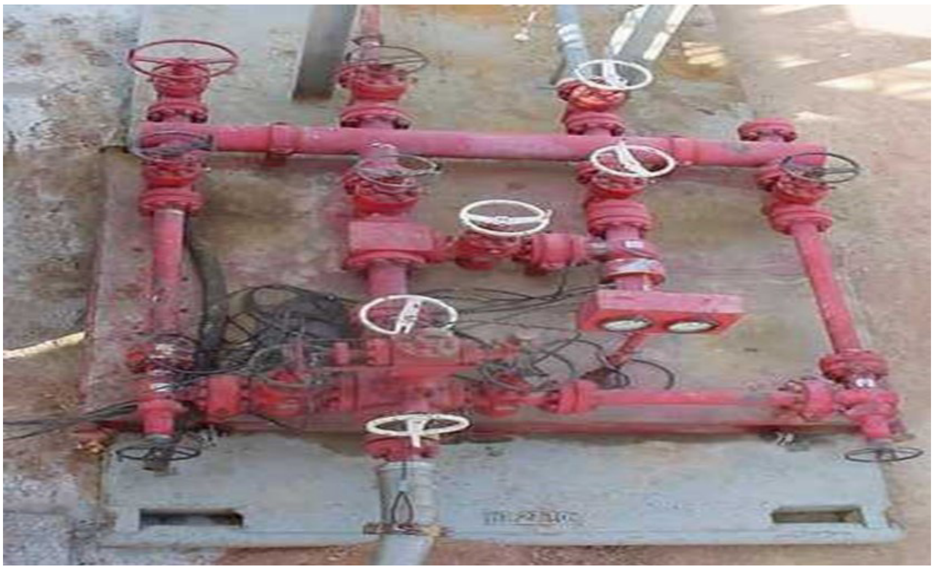

Fig 32: Choke manifold

Well monitoring system. Data collection system for drilling well needed to provide information and understanding concerning the physical properties of a well from the surface to final depth. If drilling problems are detected early remedial action can be taken quickly, thereby avoiding major problems. There are different sensors used for gathering surface data as well as downhole data. The surface sensors can be grouped as depth tracking, pressure tracking, flow-in and flow-out tracking, drill monitor, pit monitor and gas detection. The driller must be aware of how drilling parameters are changing (e.g. WOB, RPM, pump rate, pump pressure, gas content of mud etc.). For this reason, there are various gauges installed on the driller's console where he can read them easily. Another useful aid in monitoring the well is mudlogging. The mud logger carefully inspects rock cuttings taken from the shale shaker at regular intervals. By calculating lag time the cuttings descriptions can be matched with the depth and hence a log of the formations being drilled can be drawn up. This log is useful to the geologist in correlating this well with others in the vicinity. Mud loggers also monitor the gas present in the mud by using gas chromatography. Today, modern rigs carry centralized well-monitoring systems that can be housed in the engineer's office and/or in the geologist's office at the rig site. Besides, if desired, advancements in satellite communications allow installation of monitoring systems in places far from the rig site. Downhole measurement is firstly focused on directional measurement then expanded to measure formation parameters. The term MWD (measurement-while-drilling) refers to measurements taken downhole with an electromechanical device located in bottom hole assembly and the measurement data are transmitted to surface in real time or can be stored in tool memory and recovered when the tool was returned to the surface. These tools are run together with the bottom hole assembly and will constantly send information to surface regarding the position of the well. Measurement-while-drilling (MWD) tools normally use a mud pulser that sends information to the surface by means of coded pressure pulses in the drilling fluid contained in the drill string. All MWD systems typically consist of three major components namely power system, telemetry system and directional sensors. LWD (logging-while-drilling) was introduced in early 1980s to measure the formation parameters. Examples of formation parameters are resistivity, neutron porosity, gamma density, acoustic imaging and formation pressure, etc.

Fig 33: Driller’s console

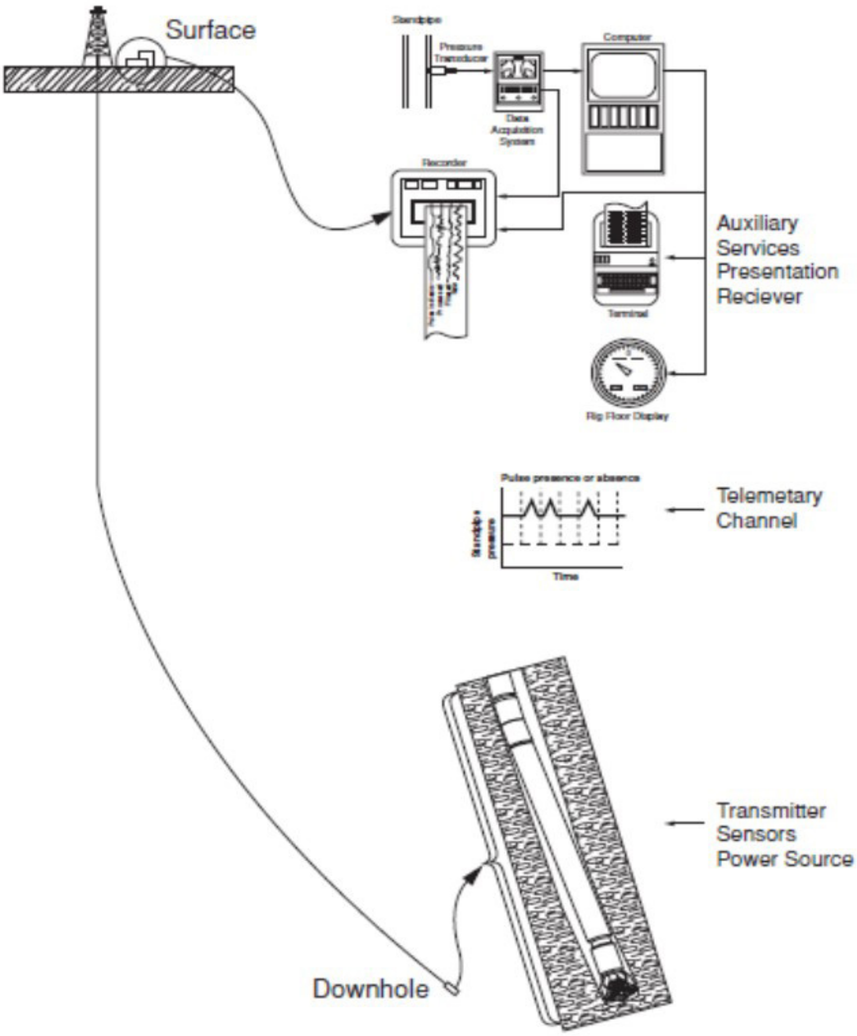


Fig 34: MWD system (Courtesy of Heriot Watt)

# DRILL STRING

## Functions

In general, the drill string provides multiple functions:

1. Medium to lower and raise the drill bit in the hole.
2. Imposes required weight on the drill bit.
3. Transmits rotary motion from the kelly or top drive to the drill bit.
4. Stabilizes the bottom hole assembly (BHA) and minimizes vibrations.
5. Provides fluid conduit from the rig to the drill bit.
6. Permits pressure and formation fluid testing through the drill string.
7. Allows through-pipe running of formation evaluation tools when they cannot be run in the open hole.

### Drill String Components

The physical properties of the various downhole components of the bottom hole assembly have a significant effect on how the bit will drill. In most drilling situations, the bottom 100 to 300 feet of the bottom hole assembly has the greatest influence on its behavior. The construction of the bottom hole assembly can be as simple as consisting of a drill bit, collars, and drill pipe, or may be as complicated as including a drill bit, stabilizers, collars of different sizes and materials, heavy-weight drill pipe, drill pipe etc.

Drill pipe. Drill pipe is a primary and important drill string member. It generally constitutes 90-95 percent of the entire length of the drill string. Drill pipe is made of high grade steel and the pipe body is a seamless pipe with outside diameter varying from 2 3/8 to 6 5/8 inch. Because the wall of the pipe body is relatively thin, usually less than half an inch thick, the manufacturers cannot cut threads into it. They produce tool joints to solve the problem of providing threaded ends so that the pipes can be screwed together. The wall thickness and the outer diameter of the tool joints must be larger than the wall thickness of the main body of the drill pipe in order to accommodate the threads of the connection. At one end of the pipe there is the box, which has the female end of the connection. At the other end of each length of drill pipe is the male end of the connection known as the pin. Each length of drill pipe is known as a joint or a single. Drill pipe dimensional and metallurgical specifications are defined by the American Petroleum Institute (API). Manufacturers make drill pipe in one of the three API recommended ranges of lengths, range 1, 18-22 feet, range 2, 27-30 feet, and range 3, 38-45 feet. They produce these three ranges of lengths because derrick heights vary. Range 2 drill pipe is the most commonly used, making the average length of a drill pipe joint about 30 feet. There are five common grades of drill pipe which define the yield strength and tensile strength of the steel being used, namely D-55, E-75, X-75, G-105, and S-135. The grade of drill pipe describes the minimum yield strength of the pipe, i.e. E-75 is grade E drill pipe has a minimum yield strength of 75,000 psi and a minimum tensile strength of 100,000 psi. If drill pipe is stretched, it will initially go through a region of elastic deformation. In this region, if the stretching force is removed, the drill pipe will return to its original dimensions. The upper limit of this elastic deformation is called the yield strength, which can be measured in psi. Beyond this, there exists a region of plastic deformation. In this region, the drill pipe becomes permanently elongated, even when the stretching force is removed. The upper limit of plastic deformation is called the tensile strength. If the tensile strength is exceeded, the drill pipe will fail. Tension failures generally occur while pulling on stuck drill pipe. As the pull exceeds the yield strength, the metal distorts with a characteristic thinning in the weakest area of the drill pipe (or the smallest cross sectional area). If the pull is increased and exceeds the tensile strength, the drill string will part. Such failures will normally occur near the top of the drill string, because the top of the string is subjected to the upward pulling force as well as the downward weight of the drill string. In most drill string designs, the pipe grade will be increased for extra strength rather than increase the pipe weight. This approach differs somewhat from casing design. Drill pipe is unlike most other oilfield tubulars, such as casing and tubing, because it is used in a worn condition. Casing and tubing are usually new when installed in the well. As a result, classes are given to drill pipe to account for wear. Drill pipe class defines the physical condition of the drill pipe in terms of dimension, surface damage, and corrosion. API has established guidelines for pipe classes in API RP-7G. Although the class definitions can be extensive, they are four common classes summarized as follows:

Class 1: No wear and has never been used.

Premium: Uniform wear and a minimum wall thickness of 80%.

Class 2: Allows drill pipe with a minimum wall thickness of 65% with all wear on one side so long as the cross-sectional area is the same as premium class; that is to say, based on not more than 20% uniform wall reduction.

Class 3: Allows drill pipe with a minimum wall thickness of 55% with all wear on one side.

Drill pipe classification is an important factor in drill string design and use since the amount and type of wear affect the pipe properties and strengths. API has established a color-coding system for drill pipe classification using number and color of bands, i.e. class 1 – one white band, premium – two white bands, class 2 – one yellow band, class 3 – one orange band. API RP-7G provides numerical tables that define the strengths for the various grades.

Fig 35: Drill pipe

**Tool joints.** Tool joints are short sections of pipe that are attached to the tubing portion of drill pipe by means of using a flash welding process. The internally threaded tool joint is called a “box”, while the externally threaded tool joint if the “pin”.

API specifications also apply to tool joints:

• Minimum Yield Strength = 120,000 psi

• Minimum Tensile Strength = 140,000 psi

Because tool joints are added to drill pipe, the weight of given to pipe in many tables is the “nominal weight”. The exact weight will require adding the weight of the tool joints to the tubing portion. Since two joints do not weigh the same, it is difficult to determine the weight of a joint of drill pipe and so an “approximate weight” is used in many calculations. The portion of the drill pipe to which the tool joint is attached has a larger wall-thickness than the rest of the drill pipe and is called “upset”. An upset is a decrease in the ID and/or an increase in the OD of the pipe which is used to strengthen the weld between the pipe and the tool joint. The upset can be shaped as: internal upset, external upset and internal and external upset. Hard-facing, or hard-banding, tool joints has become a common practice in the drilling industry. To minimize tool joint wear while rotating on abrasive rock, a band of abrasion resistant material is applied to the outside of the box tool joint. This material is usually sintered tungsten carbide particles in a welded metal matrix. The problem that often arises from the use of hard-faced tool joints is excessive wear on the internal diameter of the casing. The strength of a tool joint depends on the cross sectional area of the box and pin. With continual use the threads of the pin and box become worn, and there is a decrease in the tensile strength. The size of the tool joint depends on the size of the drill pipe but various sizes of tool joint are available. Tool joint life can be substantially extended if connections are greased properly when the connection is made-up and a steady torque applied. When two joints of pipe are being connected the rig tongs must be engaged around the tool joints and not around the main body of the drill pipe, whose greater wall thickness can sustain the torque required to make-up the connection. Part of the strength of the drill string and the seal for the fluid conduit are both contained in the tool joints. It is very important therefore, that the correct make-up torque is applied to the tool joints. If a tool joint is not torqued enough, bending between the box and pin could cause premature failure.

Also, the shoulder seal may not be properly seated, resulting in mud leaking through the tool joint, causing a washout. Exceeding the torsional yield strength of the connection by applying too much torque to the tool joint could cause the shoulders to bevel outward or the pin to break off the box. Proper make-up torque is a function of tool joint type, size, outside diameter, inside diameter and condition.

Fig 36: Tool joints

**Drill collars.** Drill collars are the predominant components of the bottom hole assembly. The primary function of the drill collars is to be able to apply weight to the bit without buckling the drill pipe. The functions of drill collars are to provide enough weight on bit for efficient drilling, to keep the drill string in tension, thereby reducing bending stresses and failures due to fatigue, and to provide stiffness in the bottom hole assembly for directional control. Part of that weight is applied to the wall of the hole depending on the amount of deviation. Drill collars are tubulars which have a much larger outer diameter and generally smaller inner diameter than drill pipe. Drill collars are produced in a large range of sizes with various types of joint connection. A typical drill string would consist of 9” OD x 2 13/16” ID drill collars and 5” OD x 4.276” ID drill pipe. The drill collars therefore have a significantly thicker wall than drill pipe. The collars are manufactured from chrome-molybdenum alloy, which is fully heat treated over the entire length. Monel collars are made of a special non-magnetic steel alloy. Their purpose is to isolate directional survey instruments from magnetic distortion due to the steel drill string. Drill collars are normally supplied in Range 2 lengths. The bore of the collar is accurately machined to ensure a smooth, balanced rotation. The external surface of a regular collar is round, although other profiles are available. The shape of the drill collar may have a circular or square cross section. A string of square collars provides good rigidity and wear resistance, but it is expensive, has high maintenance costs for certain conditions and may become stuck in key-seated dog-leg. When drilling through certain formations the large diameter drill collars can become stuck against the borehole (differential sticking). This is likely to happen when the formation is highly porous, a large overbalance of mud pressure is being used and the well is highly deviated. One method of preventing this problem is to reduce the contact area of the collar against the wellbore. Spiral grooves can be cut into the surface of the collar to reduce its surface area. Typically, standard and spiral drill collars with external grooves cut into their profile may be used to reduce the contact area between the bottom hole assembly and the formation. Since the drill collars have such a large wall thickness tool joints are not necessary and the connection threads can be machined directly onto the body of the collar. The weakest point in the drill collars is the connection and therefore the correct make up torque must be applied to prevent failure. The length of the drill collar string should be as short as possible but adequate to create the desired weight on bit. Since the collars are under compression, they will tend to bend under the applied load. The amount of bending will depend on the material and the dimensions of the collar. In deviated holes the total weight of the drill collars is not applied to the bit. In vertical holes, ordinary drill pipe must never be used for exerting bit weight. In deviated holes, where the axial component of drill collar weight is sufficient for bit weight, heavy weight drill pipe is often used in lieu of drill collars to reduce rotating torque. In highly deviated holes, where the axial component of the drill collar weight is below the needed bit weight, drill collars are not used, and heavy weight pipe is put high in the string in the vertical part of the hole. When this is done, bit weight is transmitted through the drill pipe. When possible, the drill pipe should be in tension. The lower most collar has the maximum compressive load, which is transmitted to the bit, and the upper most collar has a tensile load. This means there is some point in the drill collars between the bit and the drill pipe that has a zero axial load. This is called the neutral point. The design factor is needed to place the neutral point below the top of the drill collar string. This will ensure that the pipe is not in compression because of axial vibration or bouncing of the bit and because of inaccurate handling of the brake by the driller. The excess of drill collars also helps to prevent transverse movement of drill pipe due to the effect of centrifugal force. While the drill string rotates, a centrifugal force is generated that may produce a lateral movement of drill pipe, which causes bending stress and excessive torque. The centrifugal force also contributes to vibration of the drill pipe. Hence, some excess of drill collars is suggested. The magnitude of the design factor to control vibration can be determined by field experiments in any particular set of drilling conditions. Experimental determination of the design factor for preventing compressive loading on the pipe is more difficult. The result of running the pipe in compression can be a fatigue crack leading to a washout or parted pipe.

Fig 37: Drill collars

**Heavy weight drill pipe.** Heavy weight drill pipe (or heavy wall drill pipe, HWDP) is an intermediate drill string member, that is heavier, stronger and stiffer than regular drill pipe, but at the same time more flexible than drill collar. The pipe is available in conventional drill pipe outer diameters. However, its increased wall thickness gives a body weight two or three times greater than regular drill pipe. It is used to absorb the stresses being transferred from the stiff drill collars to the relatively flexible drill pipe. A significant amount of fatigue damage occurs in the drill pipe immediately above the drill collars. It can be placed in the transition zone between the stiffer drill collars and limber drill pipe. Because it has the same external dimensions as regular drill pipe, it is much easier to handle than drill collar. Heavy weight drill pipe was first used in directional drilling, which generally requires flexibility in the drill string. It should always be operated in compression. More lengths of HWDP are required to maintain compression in highly deviated holes. HWDP is now widely used in vertical and horizontal drilling as well. With less wall contact than drill collar, its usage reduces torque and wall sticking tendencies. Its smaller degree of wall contact, together with its greater stiffness relative to regular drill pipe, results in increased stability and better directional control. It is also useful in reducing hook loads, making it ideal for smaller rigs drilling deeper holes. In shallow drilling areas, where regular drill pipe is run in compression, the more rigid HWDP will allow more bit weight to be run with less likelihood of fatigue damage. The tool joints on some heavy weight pipe are larger than normal. This feature allows a specially designed heavy-duty application of hard metal equal to approximately three times the amount of hard-facing provided on conventional drill pipe and permits several repairs of the tool joint. One outstanding feature is the integral center wear pad which protects the pipe from abrasive wear. This wear pad acts as a stabilizer and is a factor in the overall stiffness and rigidity of one or more joints of heavy weight drill pipe.

Fig 38: Heavy weight drill pipe

**Stabilizers.** Stabilizers consist of a length of pipe with blades on the external surface. These blades may be either straight or spiral and there are numerous designs of stabilizers. The blades can either be fixed on to the body of the pipe, or mounted on a sleeve stabilizer, which allows the drill string to rotate within it. The function of the stabilizer depends on the type of hole being drilled. In vertical holes the functions of stabilizers may be summarized as follows:

• Reduce buckling and bending stresses on drill collars

• Allow higher weight on bit since the string remains concentric even in compression.

• Increase bit life by reducing wobble, i.e. all three cones loaded equally.

• Help to prevent wall sticking.

• Act as a key seat wiper when placed at top of collars.

Stabilizers are fairly short subs with blades attached to the external surface. By providing support to the bottom hole assembly at certain points they can be used to control the trajectory of the well. Drilling straight or directional holes requires proper positioning of the stabilizers in the bottom hole assembly. It is important to note that the position of the first stabilizer and the clearance between the wall of the hole and the stabilizers has a considerable effect in controlling the hole trajectory. Stabilizers can be grouped into rotating blade stabilizers and non-rotation blade ones. A rotating blade stabilizer can have a straight blade or spiral blade configuration. In either case the blades may be short or long. The spiral blades can give 360 degree contact with the bore hole. All rotating blades stabilizers have good reaming ability and good wear life. Non rotating rubber sleeve stabilizers are used to centralize the drill collars, where the rubber sleeve allows the string to rotate while the sleeve remains stationary. Since the sleeve is stationary, it acts like a drill bushing and does not dig or damage the wall of the hole. It is most effective in hard formation. However, it does have some limitations. The sleeve is not recommended to be used in temperatures over 250°F. It has no reaming ability and sleeve life may be short in holes with rough walls.

Fig 39: Stabilizers

**Roller reamers.** A roller reamer consists of stabilizer blades with rollers embedded into surface of the blade. The rollers may be made from high grade carbon steel or have tungsten carbide inserts. The roller reamer acts as a stabilizer and is especially useful in maintaining gauge hole. It will also ream out any potential hole problems, i.e. dog legs, key seats, ledges. Rolling cutter reamers are used for reaming and added stabilization in hard formations. Wall contact area is very small, but it is the only tool that can ream hard rock effectively. Anytime rock bit gage problems are encountered, the lowest contact tool should definitely be a rolling cutter reamer. A variety of roller reamer cutters are available for different formation types.

Fig 40: Roller reamers

**Shock subs** (Vibration dampeners). Vibrations and shock loads are produced as the bit rotates on bottom. Such vibrations can result in damage to the bit, drill collars, drill pipe and other components. A vibration dampener is a type of shock absorber designed to prevent vibration generated by the bit from travelling up the drill string to the surface. A shock sub is normally located above the bit to reduce the stress due to bouncing when the bit is drilling through hard rock. The shock sub absorbs the vertical vibration either by using a strong steel spring, or a resilient rubber element. When properly used, the vibration dampeners can result in faster drilling rates longer bit life, less damage to the drill string and surface equipment and reduce torsional impact.

Fig 41: Shock sub (Courtesy of Schlumberger)

**Drilling jars.** The purpose of these tools is to deliver a sharp blow upward or downward motion to free the pipe if it becomes stuck in the hole. They can be run on drilling bottom hole assemblies as a precautionary measure. They are especially appropriate for drilling in sticky, heaving, sloughing or crooked hole. Jars also have applications in controlled-weight directional drilling, as well as coring operations. There are a number of jar types available, and the type of jarring action utilized will depend on the jar being used and the specific operating conditions. For typical mechanical or hydraulic jars, upward or downward motion is initiated by pulling up or slacking off on the drill string until a preset triggering load is reached, initiating a sharp blow. Hydraulic jars are activated by a straight pull and give an upward blow. Mechanical jars are preset at surface to operate when a given compression load is applied and give a downward blow. A few such blows may be sufficient to free a stuck drill string without the expensive and risk of fishing job. Jars are usually positioned high in the drill collars, with some drill collars above them.

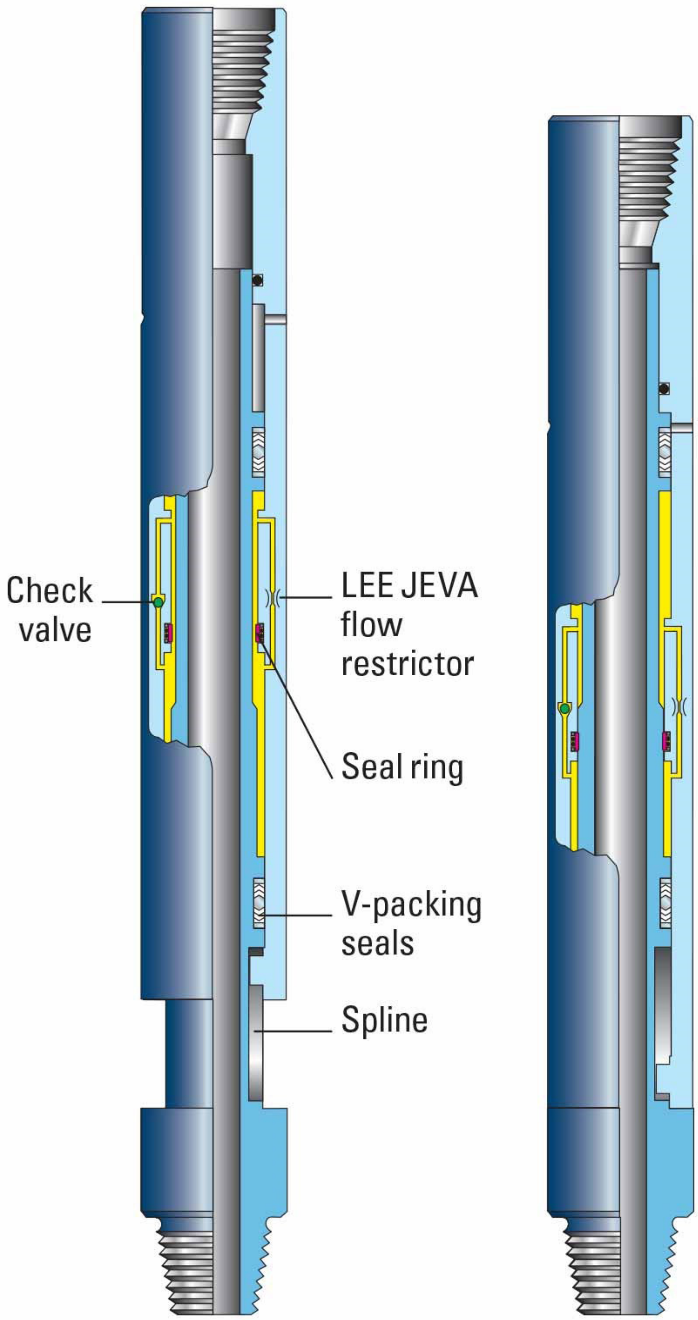


Fig 42: Drilling jar (Courtesy of Schlumberger)

## Drill String Design and Basic Rotary Bottom Hole Assemblies

The drill string design should determine the optimum combination of drill pipe sizes, weights, and grades for the lowest cost or incorporate the performance characteristics to successfully accomplish the expected goals. The drill string is subjected to many service loads that may exist as static loads, cyclic loads, or dynamic loads. These loads include tensile loads, torsional loads, bending loads, internal pressure, and compressive loads. In certain circumstances, the drill string experiences external pressure. In addition to the varied service loads the pipe will see, the designer must consider hole drag and the risk of becoming stuck. The designer should simultaneously consider the following conditions:

1. The working load at any part of the string must be less than or equal to the load capacity of the drill string member under consideration divided by the safety factor.

2. Pressure losses through the pipe going downhole and around the pipe going back to surface should be calculated so that the combination of pipe size and tool joint size are right for the diameter of the hole.

Selecting the size, weight, and grade of drill pipe and the tool joint OD and ID may be an iterative process, but the pipe size usually can be determined early on based on past experience and pipe availability. After calculating the strength requirements of the pipe and the lengths of each section of tapered strings, it may be necessary to choose a different pipe size from the one initially picked. Drill string design is more difficult on horizontal and deviated holes. Calculating frictional drag, the effects of compressive loading, and other factors by hand can be cumbersome and inaccurate. For these type holes, it is better to use torque and drag software for drill string design.
A bottom hole assembly is the arrangement of bit, stabilizer, reamers, drill collars, subs and special tools used at the bottom of the drill string. Rotary bottom hole assemblies are one of the least expensive methods used to deflect a well and should be used whenever possible. There are three basic types of assemblies used in directional drilling.
Building assemblies. This type of assembly is usually run in a directional well after the initial kick-off has been achieved using a deflection tool. A single stabilizer placed above the bit will cause building. The addition of further stabilizer(s) will modify the rate of build to match the required well trajectory. If the near bit stabilizer becomes under-gauge, the side force reduces. The amount of weight on bit applied to these assemblies will also affect their building tendencies. Normally the higher the bit weight the higher the building tendency.

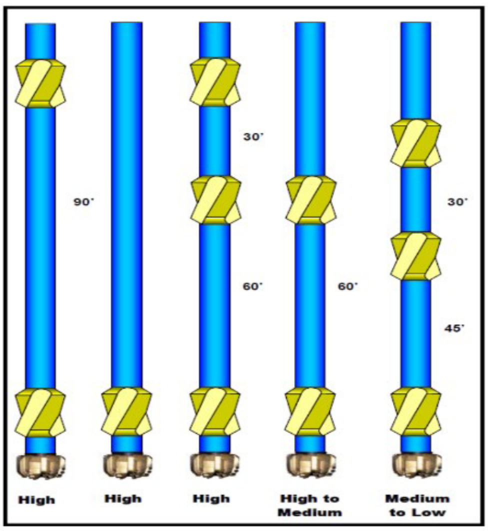


Fig 43: Building assemblies (Carden et al. 2007)

**Holding assemblies.** Once the inclination has been built to the required angle, the tangential section of the well is drilled using a holding assembly. Holding assemblies do not maintain inclination angle; rather, they minimize angle build or drop. Minimal tilt angle at the bit, as well as stiffness of the bottom hole assembly near the bit helps maintain inclination angle. Change in weight on bit does not affect the directional behavior of this type of assembly and so optimum weight on bit can be applied to achieve maximum penetration rates.

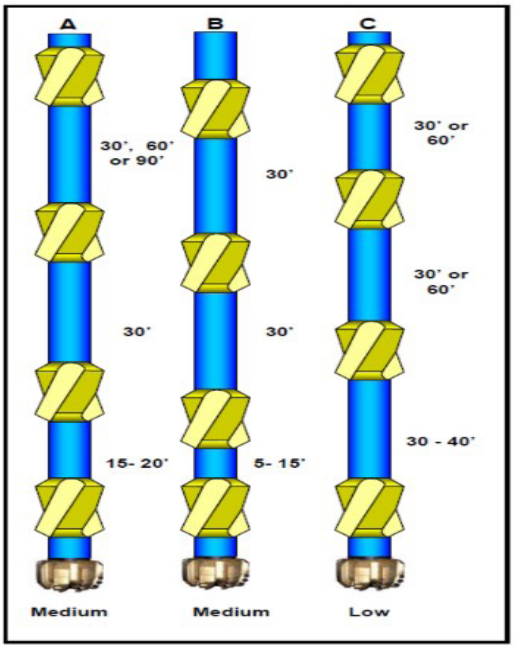


Fig 44: Holding assemblies (Carden et al. 2007)

**Holding assemblies.** Once the inclination has been built to the required angle, the tangential section of the well is drilled using a holding assembly. Holding assemblies do not maintain inclination angle; rather, they minimize angle build or drop. Minimal tilt angle at the bit, as well as stiffness of the bottom hole assembly near the bit helps maintain inclination angle. Change in weight on bit does not affect the directional behavior of this type of assembly and so optimum weight on bit can be applied to achieve maximum penetration rates.

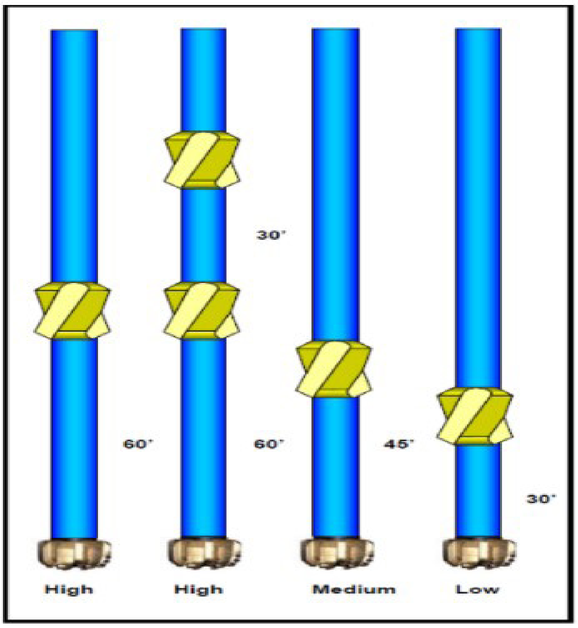


Fig 45: Dropping assemblies (Carden et al. 2007)

Rotary bottom hole assemblies can also be made with an adjustable gauge stabilizer. The adjustable gauge stabilizer is a stabilizer where the gauge can be adjusted while the stabilizer is downhole. They are usually adjusted by cycling pump pressure and weight. With the adjustable gauge stabilizer on top, the assembly can be made to hold, build or drop inclination. The adjustable gauge stabilizer makes the rotary assembly partially steerable. The gauge on the stabilizer will have a predictable effect on inclination but it does not have a predictable effect on direction.

# DRILL BITS

## Introduction

The process of making a hole in the ground requires the use of drill bits. A drill bit is the tool that conducts the cutting action located at the end of the drill string. A good geological prognosis is an invaluable aid in selecting the proper drill bit. The prognosis provides critical data on the formations and type of rock to be expected at depth. Rotary drilling uses two types of drill bits: roller-cone bits and fixed-cutter bits. Roller-cone bits are generally used to drill a wide variety of formations, from very soft to very hard. Milled tooth (or steel-tooth) bits are typically used for drilling relatively soft formations. Tungsten carbide inserts bits (TCI or button bits) are used in a wider range of formations, including the hardest and most abrasive drilling applications. Fixed-cutter bits, including polycrystalline diamond compact (PDC), impregnated, and diamond bits, can drill an extensive array of formations at various depths.

## Roller-Cone Bits

Roller-cone bits (or rock bits) have cones, mounted on rugged bearings and containing cutting elements, which rotate about the axis of the cone as the bit is rotated at the bottom of the hole. The cone rolls around the bottom of the hole as the drill string is rotated or as the it is turned by a downhole motor. A roller-cone bit with three cones (tri-cone bits) is the most often applied type of drill bit. These cones rotate on the bottom of the hole and drill hole predominantly with a grinding and chipping action. Roller-cone bits are classified as milled-tooth or insert. The cutting action is provided by cones which have either steel teeth or tungsten carbide inserts. In milled-tooth bits, the cutting structure is milled from the steel making up the cone. Steel tooth bits have long or short teeth all depending on the hardness of the formation they are expected to drill. Long teeth are for soft formations while shorter the teeth get the formations changes to medium-soft, medium hard respectively. In soft formation where the tooth scrapes and gouges the formation long teeth are desirable because they can remove a lot of rock. In harder formations where the tooth punches into the formation short teeth are desirable because they shatter the rock without breaking themselves. The longer teeth cannot absorb as much as the shorter teeth without breaking. These milled-tooth bits are very robust and tolerate severe drilling conditions but wear out relatively quickly. From this reason they are not well suited for deeper wells where tripping constitutes a large time factor. On some steel tooth bits the teeth are covered with tungsten carbide to minimize the wear in hard abrasive formations while other its only have tungsten carbide hard-facing on only one side of the tooth to make it self-sharpening. The side of the tooth without hard-facing wears faster than the hardened side thus enabling the hardened side to hold sharp edge. In insert bits, the cutting structure is a series of tungsten carbide inserts pressed into the cones. They have chisel-shaped, cone-shaped, or hemispherical cylinders in different type and forms made of tungsten carbide. The shape of the inserts will determine how hard a formation the bit can drill. The longer chisel-shaped inserts are very good for softer rock where they can scrape and gouge. Cone-shaped inserts are for medium hard formation where they combine scraping and gouging with penetration and finally hemispherical inserts are good for harder rock, where they penetrate and shatter the formation. These bits do not tolerate shock loadings but they can drill long sections before being worn out. In general, insert bits of the same bit seize are more expensive than milled-tooth bits. To increase the skidding-gouging action, bit designers generate additional working force by offsetting the centerlines of the cones so that they do not intersect at a common point on the bit. This “cone offset” is defined as the horizontal distance between the axis of a bit and the vertical plane through the axis of its journal. Offset forces a cone to turn within the limits of the hole rather than on its own axis. Offset is established by moving the centerline of a cone away from the centerline of the bit in such a way that a vertical plane through the cone centerline is parallel to the vertical centerline of the bit. Skidding-gouging improves penetration in soft and medium formations at the expense of increased insert or tooth wear. In abrasive formations, offset can reduce cutting structure service life to an impractical level. Both steel teeth and tungsten carbide inserts roller-cone bits have nozzles that eject high speed streams or jets of drilling mud. The jets of mud sweep cuttings out of the way as the bit drills. Most tri-cone roller bits have three jet nozzles on the side of the bit between the legs. The nozzles are made of special erosion-resistant material to minimize wear from the fast moving stream of abrasive drilling mud. Roller-cone bits have a large variety of tooth designs and bearing types, and are suited for a wide variety of formation types and applications. A bearing is the device sitting between the cone and the journal of the leg to reduce the force of friction as the cone rotates. Roller-cone bit bearings must withstand the high temperatures that friction produces without spalling. The bearing may be made of balls, rollers, or journals, or a combination of the three types. A ball bearing consists of metal balls inside a track or grooved called a race. Their rolling action is what reduces friction in both ball and roller bearing. The roller bearing consists of solid cylinders of metal packed side by side into a race. Journal bearing bits have a journal bearing (friction bearing) as the main bearing. Instead of rollers or balls the journal bearing consist of a flat polished area around circumference of the shaft to which each cone is attached. The highly polished surface reduces friction and special metal alloys are inserted into the part of the cone that contacts the journal. A journal bearing is stronger and can last longer than a roller bearing because it is a single large piece of metal that provides surface-to-surface contact over a relatively wide area.

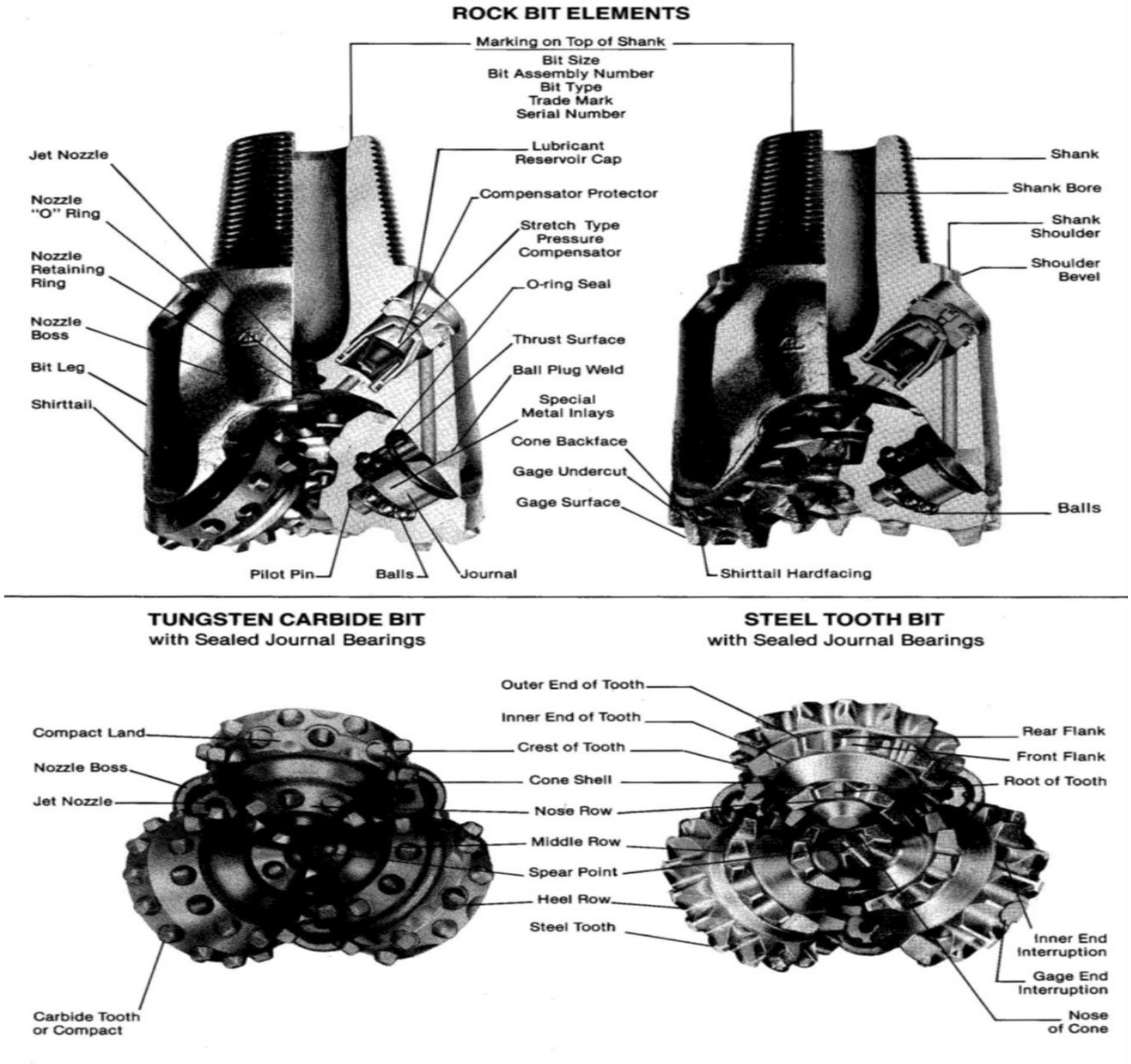


Fig 46: Roller-cone bits elements

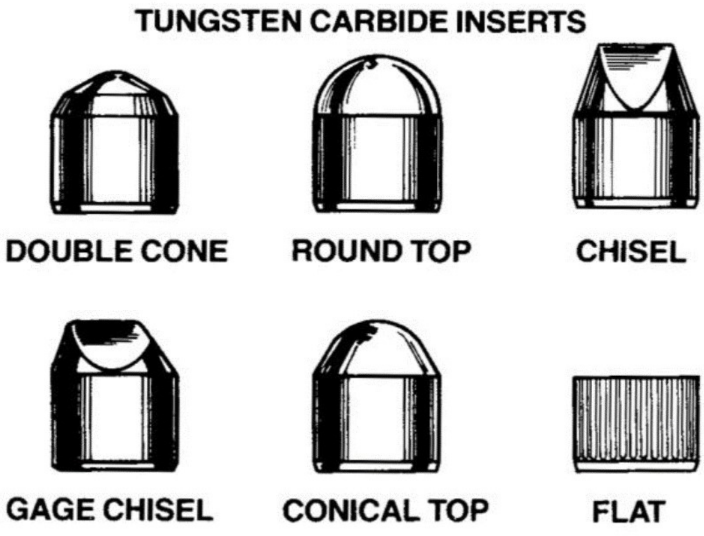


Fig 47: Tungsten carbide insert shapes

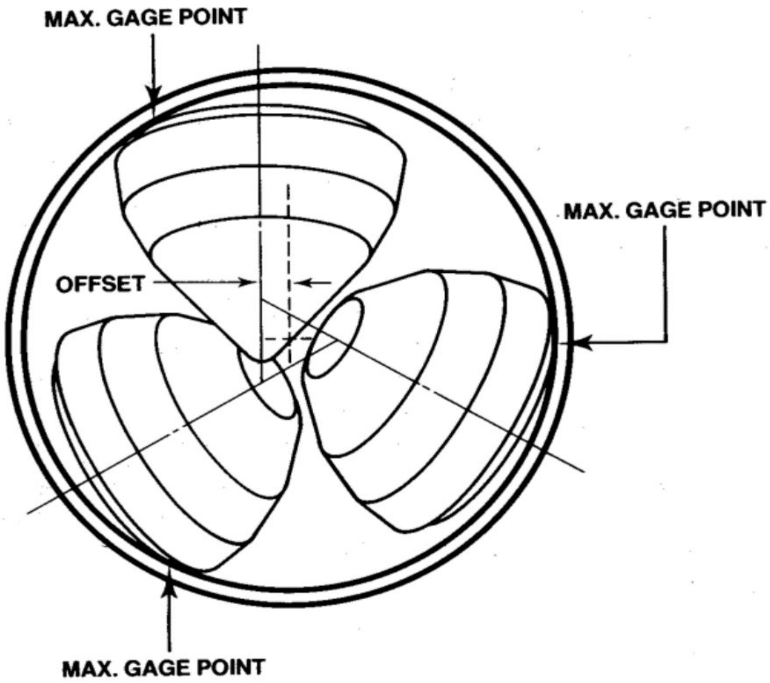


Fig 48: Cone offset (Courtesy of Heriot Watt)

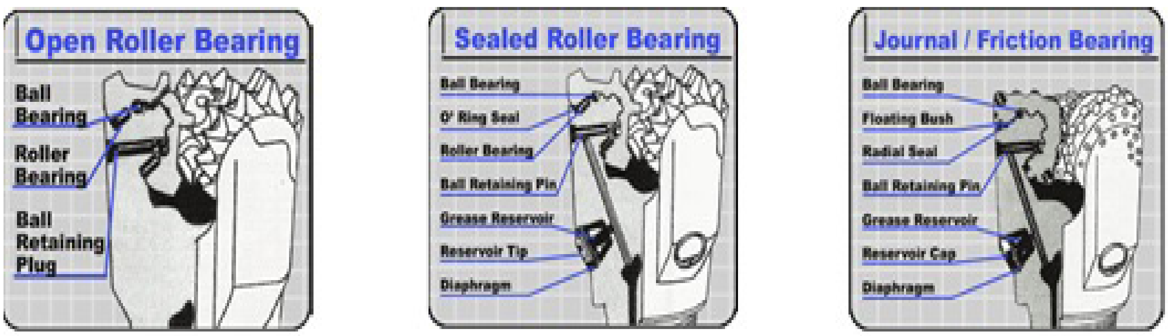


Fig 49: Roller-cone bit bearings (Courtesy of Bit Brokers International)

## Fixed-Cutter Bits

Major difference between fixed-cutter bits and roller-cone bits is that fixed-cutter bits do not have any moving parts, which is an advantage, especially with small hole sizes in which space is not available for the cone/bearing systems with proper teeth structure. Fixed cutter or drag bits have no moving parts and can drill very long hole sections when the proper drilling conditions are given. They exhibit higher bit rotation times at hard, abrasive formations. In general, fixed-cutter bits are categorized under two groups: polycrystalline diamond compact (PDC) bits and diamond bits made up of impregnated, natural-diamond and thermally stable polycrystalline (TSP) elements.

**Polycrystalline diamond compact bits (PDC).** Formations that are drillable with PDC bits fail in shear rather than compressive stress typified by the crushing and gouging action of roller-cone bits. Thus, PDC bits are designed primarily to drill by shearing. In shear, the energy required to reach plastic limit for rupture is significantly less than by compressive stress. PDC bits thus require less weight on bit than roller-cone bits. PDC is one of the most important material advances for oil drilling tools in recent years. A PDC cutter consists of a diamond table bonded to a carbide backing. The manufacturing process of a PDC starts by forming the synthetic diamond material. This is done by subjecting carbon to very high temperatures pressures in order to form small diamond grain. A PDC cutter is formed when the diamond grains are loaded in a special assembly with a tungsten carbide substrate and cobalt as a solvent/catalyst. It is then put back under diamond making condition of high temperature and pressure. The cobalt causes diamond to diamond bonds to form in the diamond table and also serves to bond with the cobalt in the tungsten carbide substrate, attaching the diamond table to the substrate. The resulting cutter has the hardness and wear resistance of diamond which is complemented by the strength and impact resistance of tungsten carbide. The most common PDC configurations are disc shaped cutter and stud cutter. Three principal cutter sizes are used: the ¾ inch (19 mm), ½ inch (13 mm) and 3/8 inch (8 mm). PDC bits are designed and manufactured in two structurally dissimilar styles: matrix-body bit and steel-body bits. "Matrix" is a very hard, rather brittle composite material comprising tungsten carbide grains metallurgically bonded with a softer, tougher, metallic binder. Matrix is desirable as a bit material because its hardness is resistant to abrasion and erosion. It is capable of withstanding relatively high compressive loads but, compared with steel, has low resistance to impact loading. Steel is metallurgically opposite of matrix. It is capable of withstanding high impact loads but is relatively soft and without protective features would quickly fail by abrasion and erosion. The strength and ductility of steel give steel-bit bodies high resistance to impact loading. Steel bodies are considerably stronger than matrix bodies. Because of steel material capabilities, complex bit profiles and hydraulic designs are possible and relatively easy to construct on a multi-axis, computer-numerically-controlled milling machine. A beneficial feature of steel bits is that they can easily be rebuilt a number of times because worn or damaged cutters can be replaced rather easily. This is a particular advantage for operators in low-cost drilling environments. Fortunately, both steels and matrix are rapidly evolving, and their limitations are diminishing. As hard-facing materials improve, steel bits are becoming extremely well protected with materials that are highly resistant to abrasion and erosion. At the same time, the structural and wear-resisting properties of matrix materials are also rapidly improving, and the range of economic applications suitable for both types is growing. The shape of the head on a fixed-cutter bit is called its profile. Bit designed for very soft formations have long, parabolic, sharp-nosed profiles, while harder-formation bits have compressed, wide-nosed profile. The location of bit nose, i.e. distance from center line, and the sharpness of the nose radius curvature indicate the prevalent type of cutting action and durability of the bit design. The closer the nose is to the center line of the bit, the more aggressive the bit cutting action will be. The more the bit's nose radius, the greater its durability.

Fig 50: Matrix and steel PDC bits

**Diamond bits.** The term "diamond bit" normally refers to bits incorporating surface-set natural diamonds as cutters. This bit type, which has been used for many years, was the predecessor to PDC bits and continues to be used in certain drilling environments. Diamonds are resistant to abrasion, extremely high in compressive strength but are low in tensile strength and have high thermal capacity. The low tensile strength reduces its ability to withstand impacts. The weight on diamond bits should be somewhat less than for roller-cone bits. Diamond bits are used in abrasive formations. They drill by a high-speed plowing action that breaks the cementation between rock grains. Fine cuttings are developed in low volumes per rotation. To achieve satisfactory penetration rate with diamond bits, they must, accordingly, be rotated at high speeds. Diamonds used in oilfield bits are of natural origin occurring industrial-grade ones and range from as small as 15 stones per carat to as large as seven carats per stone. The size of diamond that is used on the bit is dependent on the formation type, hardness, characteristics and the bit life required. Smaller diamond size (8-12 stones per carat) are used in harder range formations where increased frictional heat and wear are expected. Larger diamonds are used in softer-range formations where penetration rate is the drilling priority. Diamonds do not bond with other materials. They are held in place by partial encapsulation in a matrix bit body. Diamonds are set in place on the drilling surfaces of bits. Diamond bits can drill the hardest rocks (highest compressive strength) but they drill relatively slowly and are very expensive. For this reason they are used at very hard and very abrasive formations which would destroy other types of bits before making reasonable drilling progress.

Fig 51: Diamond bit

**Thermally stable polycrystalline diamond bits (TSP).** The TSP cutter was developed in order to expand the application range of PDC cutters. These bits are more stable at higher temperatures because the cobalt binder has been removed and this eliminates internal stresses caused by differential expansion. The process employed to manufacture a TSP is similar that of PDC. The TSP cutter, however does not have a tungsten carbide substrate. Without the substrate the TSP diamond is restricted to small sizes and must be set into a matrix similar to natural diamond.

TSP is formed like PDC and, except for thermal properties, behaves like PDC with one important exception. Because cobalt contained in PDC plays a key role in bonding PDC diamond tables to tungsten carbide substrates, attachment of TSP cutters to a bit is relatively difficult. Therefore, TSP is generally used only in applications in which bit operating temperature cannot be reliably controlled. TSP drills many of the same formations as natural diamond bit.

Fig 52: Thermally stable polycrystalline diamond bits (TSP)

**Impregnated bits.** Impregnated bits are a PDC bit type in which diamond cutting elements are fully imbedded within a PDC bit body matrix. Impregnated bit bodies are PDC matrix materials that are similar to those used in cutters. Both natural and synthetic diamonds are prone to breakage from impact. When embedded in a bit body, they are supported to the greatest extent possible and are less susceptible to breakage. However, because the largest diamonds are relatively small, cut depth must be small and penetration rate must be achieved through increased rotational speed. Thus, impregnated bits do not perform well in rotary drilling because of relatively low rotary speeds. They are most frequently run in conjunction with turbine motors and high-speed positive displacement motors that operate at several times higher than normal rotational velocity for rotary drilling. Impregnated bits use combinations of natural diamond, synthetic diamond, PDC, and TSP for cutting purposes. They are designed to provide complete diamond coverage of the well bottom with only diamonds touching the formation.

Fig 53: Impregnated bits

## Standard Classification System

The International Association of Drilling Contractors (IADC) has developed a standard system of classifying both roller-cone and fixed-cutter bits, based on formation type and design variations. Consisting of simple four-character codes, this system also simplifies comparison of different manufacturers' bit types. The IADC classification system is a valuable aid in bit selection, and a useful tool for comparing the general features and formation applicability of various bit types.

The IADC roller-cone bit classification system is a four-character design- and application-related code. The first three characters are always numeric; the last character is always alphabetic. The first digit refers to bit series, the second to bit type, the third to bearings and gauge arrangement, and the fourth (alphabetic) character to bit features. The first character in the IADC system, defines general formation characteristics and divides milled-tooth and insert-type bits. Eight series or categories are used to describe roller-cone rock bits. Series 1 through 3 apply to milled-tooth bits; series 4 through 8 apply to insert-type bits. The higher the series number is, the harder or more abrasive the rock type is. Series 1 represents the softest (easiest drilling applications) for milled-tooth bits; series 3 represents the hardest and most abrasive applications for milled-tooth bits. Series 4 represents the softest (easiest drilling applications) for insert-type bits, and series 8 represents very hard and abrasive applications for insert-type bits. The second character in the IADC categorization system represents bit type, insert or milled tooth, and describes a degree of formation hardness. Type ranges from 1 through 4. The third IADC character defines both bearing design and gauge protection. IADC defined seven categories of bearing design and gauge protection: (1) nonsealed roller bearing (also known as open bearing bits); (2) air-cooled roller bearing (designed for air, foam, or mist drilling applications); (3) nonsealed roller bearing, gauge protected; (4) sealed roller bearing; (5) sealed roller bearing, gauge protected; (6) sealed friction bearing; and (7) sealed friction bearing, gauge protected. Note that "gauge protected" indicates only that a bit has some feature that protects or enhances bit gauge. The fourth character used in the system defines features available. IADC categorization assigns and defines 16 identifying features. Only one alphabetic feature character can be used under IADC rules. IADC considers this category optional. This alphabetic character is not always recorded on bit records but is commonly used within bit manufacturers' catalogs and brochures. Bit designs, however, often combine several of these features. In these cases, the most significant feature is usually listed.

The IADC fixed-cutter bit classification system seeks to classify fixed-cutter PDC and diamond drill bits effectively so that they can be efficiently selected and used by the drilling industry. IADC classification codes for each bit are generated by placing the bit style into the category that best describes it so that similar bit types are grouped within a single category. The system leaves a rather broad latitude for interpretation and is not as precise or useful as the IADC roller-cone bits classification system. The system is composed of four characters that designate body material, cutter density, cutter size or type, and bit profile. The first character describes the material from which the bit body is constructed: M or S for matrix- or steel-body construction, respectively.

The second character is a digit that represents the density of cutting elements. Densities for PDC cutter and surface set diamond bits are described separately through use of numeric 1 through 4 for PDC bits and 6 through 8 for surface-set diamond bits. Numerals 0, 5, and 9 are not defined. Specifically, for PDC bits, density classification relates to cutter count; for surface-set bits, it relates to diamond size. A designation of 1 represents a light cutter density; 4 represents a heavy density. Within the classification rules, a density of 1 refers to ≤ 30 cutters; a density of 2 refers to 30 to 40; density 3 indicates 40 to 50; and density 4 refers to ≥ 50 cutters. The numeric 6 represents diamond sizes > 3 stones per carat; 7 represents diamond sizes from 3 to 7 stones per carat; and 8 represents diamond sizes < 7 stones per carat. Thus, diamond size becomes smaller as the density classification increases. The third character in the IADC classification designates the "size" or "type" of cutter. This again differs for PDC and surface-set diamond bits. For PDC cutter bits, the third character is a digit that represents cutter size: 1 indicates PDC cutters > 24 mm in diameter; 2 represents cutters from 14 to 24 mm in diameter; 3 indicates PDC cutters < 14 but > 8 mm; and 4 is used for cutters < 8 mm. For surface-set bits, the third character represents diamond type, with 1 indicating natural diamonds, 2 referring to TSP material, 3 representing combinations such as mixed diamond and TSP materials, and 4 indicating impregnated diamond bits. The fourth character describes the basic appearance of the bit based on overall length of the cutting face. The numeric 1 represents fishtail PDC bits and "flat" TSP and natural diamond bits; 2, 3, and 4 indicate increasingly longer bit profiles of both types (a virtually flat PDC bit would be identified by 2, whereas a long-flanked "turbine style" bit would be categorized as 4).

A key requirement in developing a bit program, and of making required modifications after drilling commences, is being able to evaluate or grade a bit. Accurate bit grading can reveal where changes are needed in bit selection, hydraulics, weight on bit, rotary speed and drill string configuration. The IADC and the Society of Petroleum Engineers (SPE) has developed a system that allows both fixed-cutter and roller-cone bits to be evaluated using compatible grading parameters. The intent of the system is to facilitate and accelerate product and operational development based on accurate recording of bit experiences. This system is called dull grading. IADC dull grading is closely associated with its bit classification systems, and the general formats for fixed-cutter bit and roller-cone bit dull grading are similar. IADC dull grading reviews four general bit wear categories: cutting structure (T), bearings and seals (B), gauge (G), and remarks. Cutting structures are subdivided into four subcategories: inner rows, outer rows, major dull characteristic of the cutting structure, and location on bit face where the major dull characteristic occurs. Measurement of roller-cone cutting structure condition requires evaluation of bit tooth/insert wear status. Wear is reported by use of an eight-increment wear scale in which no wear is represented by "0" and completely worn (100%) is represented by "8". PDC bit cutter wear is graded with a 0 to 8 scale in which 0 represents no wear and 8 indicates that no usable cutting surface remains. The cutting structure dull characteristic is the observed characteristic most likely to limit further use of the bit in the intended application. A two-letter code is used to indicate the major dull characteristics of the cutting structure. A two-letter code is used to indicate the location of the wear or failure that necessitated removal of the roller-cone bit from service. The last of the cutting structure-related wear grades, dull location, indicates the location of the primary dull characteristic. Possible locations include the cone (C), nose (N), taper (T), shoulder (S), gauge (G), all areas (A), middle row (M), and heel row (H).

Location grades are reported in the fourth space on the dull grading form. IADC provides separate protocols for estimation of bearing and seal wear in nonsealed and sealed bearing assemblies. Seal and bearing grading applies only to roller-cone bits. For nonsealed bearings, wear is estimated on a linear scale of 0 to 8: 0 is new, 8 is 100 percent expended. A grade for the seal and bearing system condition is as follow: E-seal effective, F-seal failed, N-not able to grade. Grade each seal and bearing assembly separately by cone number. If grading all assemblies as one, report the worst case. The gauge category of the dull bit grading system is used to report an undergauge condition for cutting elements intended to touch the wall of the hole bore. Measurements are taken at either the gauge or heel cutting elements, whichever is closer to gauge. Undergauge increments of 1/16 inch are reported. If a bit is 1⁄16 inch undergauge, the gauge report is 1. If a bit is 1⁄8 inch (2⁄16 inch) undergauge, the gauge report is 2. It should be rounded to the nearest 1⁄16 inch. Gauge rules apply to cutting structure elements only. The "remarks" category allows explanation of dull characteristics that do not correctly fit into other categories and is the category in which the reason a bit was removed from service is recorded.

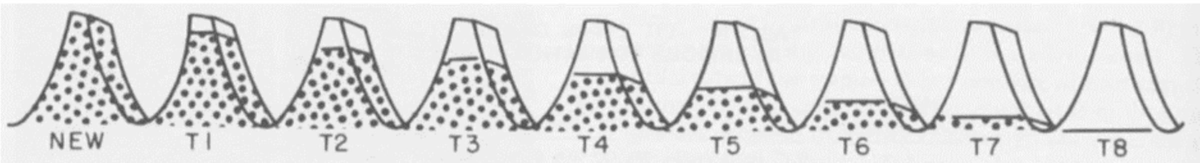


Fig 54: Tooth wear status for milled-tooth bit (Bourgoyne et al. 1991)

# DRILLING FLUIDS

## Introduction

Drilling fluid, or drilling mud as many people call it, is a vital element of the rotary drilling process. The term 'drilling fluid' includes air, gas, water, and mud. Mud refers to the liquid that contains solids in water or oil. Many requirements are placed on drilling fluid. The composition of the drilling fluid and control of its properties concern every member of the drilling crew because they affect worker safety as well as the success of the drilling operations. The cost of the drilling fluid itself is relatively small, but the choice of the right fluid and maintenance of the right properties while drilling profoundly influence the total well costs.

## Principle Functions of Drilling Fluids

Historically, the first purpose of the drilling fluid was to serve as a means to remove cuttings from the borehole, but now the diverse applications for drilling fluids make the assignment of specific functions difficult. The drilling fluid's primary functions include:

**Cuttings removal and transport.** Circulation of the drilling fluid causes cuttings to rise from the bottom of the hole to the surface. Efficient cuttings removal requires circulating rates that are sufficient to override the force of gravity acting upon the cuttings. Other factors affecting the cuttings removal include drilling fluid density and rheology, annular velocity, hole angle, and cuttings-slip velocity. In most cases, the rig hydraulics program provides for an annular velocity sufficient to result in a net upward movement of the cuttings. In large, washed-out vertical or near-vertical hole sections, the annular velocity may be less than the slip velocity, which is the difference between net rise velocity of cuttings and annular mud velocity of the particles to be removed. In this case, the cuttings or cavings settle and may cause problems such as bridging, fill-up, and stuck pipe. It is sometimes necessary to increase the mud viscosity to decrease the slip velocity of the particles to a point where the particles can be removed. Increasing mud viscosity, however, also increases the pump pressure necessary to circulate the mud at a given rate. This produces higher pressures on the walls of the hole and may result in loss of circulation. Where hole enlargement has occurred, the annular velocity calculated for a gauge hole is greater than the actual annular velocity. The actual average annular velocity may be determined by placing a marker such as carbide in the drill pipe when a new joint is added to the string. The time required to circulate the marker down the drill pipe, up the annulus and arrive on the return line is measured.

**Solids suspension.** There are times in drilling operations, e.g. during connections, trips, downtime while on bottom, that circulation is halted. Cuttings that have not been removed from the hole must be suspended, or they will fall to the bottom, or in highly deviated wells to the low side of the hole. The rate of a particle falling through a column of drilling fluid is dependent upon the density of the particle and the fluid, the size of the particle, the viscosity of the fluid, and the thixotropic, or gel strength, properties of the fluid. The controlled gelling of the fluid prevents the solid particles from settling, or reduces their rate of fall. High gel strengths also require higher pump pressure to break circulation. In some cases, it may be necessary to circulate for several hours before a trip in order to clean the hole of cuttings and to prevent fill in the bottom of the hole from occurring during a round trip.

**Subsurface pressure control.** Control of formation pressures depends greatly upon maintaining sufficient drilling fluid density, or weight. The normal pressure gradient of the earth is around 0.433 - 0.465 psi per foot of depth. By comparison, fresh water has a density of 8.33 pound per gallon and a gradient of 0.433 psi per foot. In many drilling areas, the weight of the water plus the solids accumulated from drilled formations is sufficient to balance formation pressures. It is nonetheless common to encounter abnormally pressured zones that require the addition of high-density material, usually barite, with a specific gravity of 4.2, to increase the fluid and the hydrostatic pressure of the column.

**Wellbore stabilization.** As the drill bit penetrates permeable formations, the liquid portion of the drilling fluid filters into the formation and the solids form a relatively impermeable cake on the borehole wall. The quality of this filter cake governs the rate of filtrate loss to the formation. Bentonite is the best base material from which to build a tough, low-permeability filter cake. The borehole walls are normally competent immediately after the bit penetrates a section. One cause of borehole instability is a chemical reaction between the drilling fluid and the formations drilled. In most cases, this instability is a result of water absorption by the shale. Inhibitive fluids, e.g. calcium, sodium, potassium, and oil-base fluids, aid in preventing formation swelling, but even more important is the placement of a quality filter cake on the walls to keep fluid invasion to a minimum.

**Cooling and lubrication of bit and drill string.** Friction at the bit, and between the drill string and wellbore, generates a considerable amount of heat. The circulating drilling fluid transports the heat away from these frictional sites by absorbing it into the liquid phase of the fluid and carrying it away. The laying down of a thin wall of "mud cake" on the wellbore aids in reducing torque and drag. Bentonite is known for reducing frictional torque through its excellent cake-building and lubricity characteristics.

**Assistance in collection of formation data.** There are several factors that need to be considered in selecting a drilling fluid to ensure that subsurface geological information, e.g. cuttings, mud pulse data and wireline logs, can be properly transported and evaluated. These include salinity of the fluid, filtrate invasion depth, pressure induced fractures, the nature of the continuous phase of the fluid, e.g. oil or water, and the stability of the fluid properties.

**Assistance in supporting drill string and casing weights.** With average well depths increasing, the weight supported by the surface wellhead equipment is becoming an increasingly crucial factor in drilling. Both drill pipe and casing are buoyed by a force equal to the weight of the drilling fluid that they displace. When the drilling fluid density is increased, the total weight supported by the surface equipment is reduced considerably.

**Transmission of hydraulic horsepower to the bit.** During fluid circulation, the rate of fluid flow should be regulated, so that optimum hydraulic horsepower is available to clean the face of the hole ahead of the bit. The rheological properties of the drilling fluid, i.e. plastic viscosity and yield point, have a considerable influence upon hydraulics, and should be monitored at all times. If too much of the available horsepower is expended because of increased drill string friction caused by solids, there could be insufficient horsepower to obtain the best performance.

**Prevention of formation damage.** If a large volume of drilling-fluid filtrate invades a formation, it may damage the formation and hinder hydrocarbon production. There are several factors that should be taken into consideration when selecting a drilling fluid, e.g. fluid compatibility with the producing reservoir, presence of hydratable or swelling formation clays, fractured formations, and the possible reduction of permeability by invasion of nonacid soluble materials into the formation.

## Classification of Drilling Fluids

The use of drilling fluids dates back to third-century Egypt, where quarry boreholes were drilled to depths of 20 feet using water to soften the rock and assist in cuttings removal. Since then, many other types of fluid have been used, including air, natural gas, water misted in air, foams, and a variety of natural and synthetic oils. The choice of drilling fluid for a particular well is based on several factors, such as the characteristics and composition of the formations to be penetrated, formation temperatures and pressures, anticipated drilling problems, and even the source and quality of the fluid and materials used to build the drilling fluid. This complicates any attempt to classify drilling fluids by particular types. It is, however, possible to establish some broad categories or classifications based on the continuous phase of the fluid and the components used to build and maintain the fluid. Using these criteria, there are three basic categories of drilling fluids: water-base, oil-base, and air or gas.

**Water-Base Drilling Fluids.** Water-base fluids are the most widely used drilling muds. They range from untreated native fluids to lightly treated fluids to highly treated inhibitive fluids that retard, or inhibit, the interaction between the fluid and the drilled formation. Water-base fluids can be inhibitive if the chemical makeup is such that it reduces or prevents hydration (swelling) or dispersion of formation clays and shales. A water-base fluid is one that uses water for the liquid phase and commercial clays for viscosity. The continuous phase may be fresh water, brackish water, seawater, or concentrated brines containing any soluble salt. The commercial clays used may be bentonite, attapulgite, or sepiolite. The use of other components such as thinners, filtration-control additives, lubricants, or inhibiting salts in formulating a particular drilling fluid is determined by the type of system required to drill the formations safely and economically. Some of the major systems include the following: fresh-water fluids, brackish or seawater fluids, saturated salt fluids, inhibited fluids, gyp fluids, lime fluids, potassium fluids, polymer-based fluids, and brines used in drilling, completion or workover operations including single-salt, potassium chloride, sodium chloride, calcium chloride, and two and three-salt brines.

**Oil-Base Drilling Fluids.** An important feature of any drilling fluid is that interactions between the fluid and the drilled formations should have minimal effects on the mechanical properties of the formations. Inevitably drilling in a consolidated formation relieves stress and creates unbalanced forces with respect to water equilibrium. If a water-base system is used, water enters the formation and changes its mechanical properties.

The changes may not be great enough to cause borehole instability, and we may be able to minimize their effects by using inhibitive water-base systems. However, these systems cannot prevent water-wetting of the rock. The only way this process can be stabilized is to contact the formation with a fluid that does not water-wet the rocks, and therefore does not enter the pores and change their mechanical properties. Therefore, oil-base fluids have been developed. An oil-base drilling fluid is one in which the continuous phase is oil. The terms “oil-base mud” and “inverted or invert-emulsion mud” sometimes are used to distinguish between the types of oil-base drilling fluids. Traditionally, an oil-base mud is a fluid with 0 to 5 percent by volume water, while an invert-emulsion mud contains more than 5 percent by volume water. However, most oil muds contain some emulsified water, have oil as the liquid phase, and if properly formulated, an oil filtrate.

Invert-emulsion drilling fluids are used to increase borehole stability. In addition, the inert nature of the fluid prevents cuttings from hydrating and dispersing, thus making them easier to remove with solids-control equipment and minimizing the need to dilute the fluid because of contamination by drilled solids. Near-gauge holes are therefore more easily obtained. The surfactants in the fluid and the stable hole tend to provide a high level of lubricity, which reduces torque and generally improves drilling conditions.

A properly formulated oil-base mud has several advantages over water-base muds. The fluid is non-polar and so is generally insensitive to chemical contaminants that affect water-base systems, e.g. salt, anhydrite, cement, carbon dioxide, and hydrogen sulfide. Oil-base muds can also stabilize troublesome shales. The oil and emulsifier film around each droplet of brine in an oil-base mud serves as a semipermeable membrane across which osmotic pressure may be generated. This osmotic pressure has a dehydrating effect that works to control water-wetting in drilled formations. Because shales are prevented from becoming water-wet and dispersing into the mud or caving into the hole, hole problems are reduced and a closer gauge hole may be drilled. The oil filtrate inhibits the swelling of formation clays and therefore does not reduce permeability. When properly treated with an emulsifier, a viscosifier, a suspension agent, and an oil-mud stabilizer, a stable oil-mud system can be formulated that is virtually unaffected by the high temperatures encountered in deep wells. Oil-base muds are also resistant to salt contamination during drilling of water-soluble formations. They minimize differential sticking problems, reduce torque and drag during drilling, and provide corrosion protection. While the initial make-up cost is higher for oil-base muds, maintenance is generally less expensive than for comparable water-base fluids, and the overall cost can be lower because the fluid can be reused on future wells. Unfortunately, however, environmental concerns preclude the use of oil-base muds in many areas.

**Air and Gas Drilling Fluids.** Air drilling is used primarily in hard-rock areas, and in special cases to prevent formation damage while drilling into production zones or to circumvent severe lost-circulation problems. Air drilling includes dry air drilling, mist or foam drilling, and aerated-mud drilling. In dry air drilling, dry air or gas is injected into the standpipe at a volume and rate sufficient to achieve the annular velocities needed to clean the hole of cuttings. Mist drilling is used when water or oil sands are encountered that produce more fluid than can be dried up using dry air drilling. A mixture of foaming agent and water is injected into the air stream, producing a foam that separates the cuttings and helps remove fluid from the hole. In aerated mud drilling, both mud and air are pumped into the standpipe at the same time. Aerated muds are used when it is impossible to drill with air alone because of water sands and/or lost-circulation situations.

## Properties of Drilling Fluids

**Mud Weight** (Density). Mud weight, or density, is the weight per unit volume of the drilling fluid. It is typically expressed in oil field units as pounds per gallon, but may have units of pounds per cubic foot or in terms of specific gravity. It may also be expressed in terms of pressure gradient, e.g. psi per foot. Pressure gradient units are convenient because they make it easy to calculate the hydrostatic head of the mud column at any depth, in the same units in which pump pressure and the formation pressure are calculated. The density of a drilling density must be high enough to provide sufficient hydrostatic head to prevent entry of formation fluids, but not so high as to cause formation damage, reduced penetration rates or lost circulation. Barite, or naturally occurring barium sulfate, is the standard mud weighting material because of its low cost, high specific gravity, cleanliness, inertness, and relative purity.

**Rheological Properties.** Rheology is a broad term that means the study of the deformation of materials, including flow. In oilfield terminology, the terms flow properties and viscosity are generally used to describe the behavior of drilling fluids in motion. The physical appearance of a high-viscosity drilling fluid may be described as "thick," and that of a low-viscosity fluid as "thin." Viscosity of a drilling fluid may be defined as its resistance to flow. The viscosity desired in a particular drilling fluid depends on several factors, including mud density, hole size, pump rate, drilling rate, pressure requirements, and hole conditions. The apparent viscosity of a drilling fluid is a one-point viscosity measure that is a function of three components, namely viscosity of the base liquid (the continuous phase); the size, shape, and number of solid particles in the mud (plastic viscosity); and interparticle forces (yield point). The viscosity of the base fluid (water or oil) is influenced by temperature. Although oil has a higher viscosity than water, temperature affects the viscosity of the oil much more than it affects the viscosity of water. A drilling fluid containing a given percent by weight of large solid particles has a lower viscosity than one containing the same percentage by weight of smaller particles. This is due to the increased number of particles and the greater total area to be wetted. The shape of the particles is also important, since a flat particle has a greater contact area than a rounded particle. The interparticle forces arising from the electrostatic fields that surround the clay platelets give rise to repelling and attracting forces between the charged platelets. The major viscosity-building agents in drilling fluids are clays (mainly bentonite), organic polymers, and oil-wetting clays in oil-base muds. Reducing the viscosity of a drilling fluid by diluting it is to reduce its solids content, by mechanical means, or by adding chemical thinners to neutralize the attractive interparticle forces.

**Filtration** (Filtrate Loss or Fluid Loss). The loss of liquid from a drilling fluid is controlled by the filter cake formed from the solid particles in the mud. To visualize this process, imagine pouring a cup of mud through a very fine screen. The screen holds the solids and allows the liquid to pass through. The layer of mud solids deposited on top of the screen is the filter cake, and the fluid passing through the screen is the filtrate. In water-base drilling fluids the filtrate is water; in oil-base drilling fluids it is oil. Filtration, filtrate loss, and fluid loss refer to the loss of this filtrate from the mud. Drilled formations perform like this screen. Mud solids are deposited on the walls of the hole, and filtrate invades the formation. This filtration process must be controlled in order for the drilling fluid to perform successfully. The object of proper filtrate-loss control is to form a thin, tough filter cake on the surface of permeable formations and to prevent excessive loss of filtrate. Control of filtrate loss is important in protecting producing formations, permitting interpretation of downhole logs, and maintaining wellbore stability. The quality, e.g. firm, soft, fluffy of the filter cake is an important influence on the drilling process. A thick, fluffy filter cake that exhibits satisfactory fluid-loss properties could be somewhat detrimental to drilling operations by increasing the risk of sticking the drill string.

**Alkalinity and pH.** The pH of a drilling fluid is a measure of the acidity or alkalinity of the mixing water. At each hydrogen ion (H+) concentration, there is an equilibrium concentration of hydroxyl (OH-) ions. By measuring the hydrogen ion concentration, we are, in effect, also measuring the hydroxyl ion concentration. The pH of a mud is seldom below 7 and in most cases, falls between 8 and 12.5 depending upon the type of mud. Maintaining an adequate pH in a mud is important for a number of reasons. The unbalanced pH of the muds affects the rate of mud mixing, borehole stability, mud properties, corrosiveness, viscosity, gel development, and filtration control. The alkalinity of a solution is related to pH in much the same manner as heat capacity is related to temperature. Alkalinity is the combining power of a base with an acid. It is a measure of the amount of acid required to reduce the pH of a solution to a specified value. Knowledge of the mud and filtrate alkalinity is important in many drilling operations. Mud additives, particularly some organic deflocculants, require an alkaline environment in order to function properly. Alkalinity arising from hydroxyl ions is generally accepted as being beneficial while alkalinities resulting from carbonates or bicarbonates may be detrimental to mud performance. For simple bentonite-based mud systems containing no organic thinners, the Phenolphthalein (Pf) and the methyl orange (Mf) alkalinities may be used as guidelines to determine the presence of carbonate/bicarbonate contamination and the treatment necessary to alleviate the problem.

**Salinity.** Salinity is another important part of the water chemistry of a mud. It is measured by titration of the filtrate for chloride ion concentration and is reported as chloride concentration in mg/l or as sodium chloride (NaCl) concentration in mg/l. The sodium chloride concentration is equal to 1.65 times the chloride concentration. The salt content of a mud has a great effect on the behavior of the clay solids. The degree of hydration of bentonite is reduced by increased salinity. This results in decreased plastic viscosity and increased fluid loss. When clays are hydrated in fresh water, addition of salt will cause flocculation and increased yield point and gel strength.

**Resistivity.** Mud resistivity is one of the most important electrical properties of the mud. The resistivity is measured in ohm-m. Drilling fluid is influenced by the dissolved salts and the insoluble solid material contained in the water portion. The resistivity of mud is inversely proportional to the dissolved salt concentration i.e. the greater the concentration of dissolved salts, the lower resistivity of the solution. Therefore, freshwater muds usually have high resistivity and saltwater muds have low resistivity. It is necessary to measure resistivity because the mud, filter cake, mud filtrate resistivity exert a strong effect on the electric logs taken in that mud.

## Composition of Drilling Fluids

Because there is such a wide range of drilling fluids, it is difficult to present a discussion on drilling fluid composition that would be completely accurate for all mud types in all drilling situations. The approach taken here is to describe drilling fluids as two-phase systems. The two phases are the liquid phase and the solids phase. The solids phase is further broken down into two parts: the colloidal fraction and the inert fraction.

**Phases of drilling fluids.** A drilling fluid normally consists of a liquid in which solids, and sometimes other liquids and gases, are suspended. The suspending liquid is called the continuous or liquid phase of the mud. The suspended solid particles or fluid droplets form the discontinuous or solids phase of the mud. For example, in a clay and water mud, water is the continuous phase and clay is the discontinuous phase. In an invert-emulsion mud, oil is the continuous phase and water droplets and solid particles form the discontinuous phase. There are important reasons for distinguishing between these phases. For example, the main source of viscosity in a drilling fluid is the discontinuous phase. Increasing the concentration of the continuous phase thins the mud. Filtrate comes mostly from the continuous phase, while wall cake is formed from the discontinuous phase. The continuous phase of a drilling fluid is always liquid. Solids, other liquid, and gases can be present in the discontinuous phase.

As mentioned earlier, the continuous phase of water-base mud is water. Dissolved salts such as sodium and calcium are also part of the continuous phase. A sufficiently high concentration of sodium or calcium ions inhibits the hydration (swelling) of clays. If these salts enter the continuous phase of a mud in which clays are already hydrated, flocculation results, followed over time by a dehydration of the clays. The concentration of hydroxyl ions in the continuous phase of the mud affects its pH. The more hydroxyl ions present, the higher the alkalinity and the pH. The presence of hydroxyl ions improves the dispersion of clays, reduces the effects of many contaminants, helps to solubilize some chemicals, and helps to inhibit corrosion.

The discontinuous phase of drilling muds consists of the solid particles and/or fluid droplets suspended in the continuous, or liquid, phase. Oil droplets in a water-base mud thicken the mud and reduce its density. Oil may enter the mud from drilled formations, or it may have been added as a lubricant or filtrate reducer. Water emulsified in an oil-base mud also thickens the mud. Therefore, the oil/water ratio in an oil-base mud is carefully controlled. The entry of formation water thickens the mud and, if great enough, can seriously destabilize an oil-base mud. Air or gas entrained in any mud thickens it and reduces its density. Some air always enters the mud at the surface, and drilled formations may release gas into the mud. Because solids play such an important role in the condition and maintenance of drilling fluids, solids are discussed separately as the colloidal fraction and the inert fraction of the discontinuous phase.

The colloidal fraction of a drilling fluid consists of small reactive solid particles. The solids carry surface electrical charges, which allow them to react to chemicals that are added to the mud. These solids, usually clay, also hydrate that is they attract and hold liquid from the continuous phase of the mud. In water-base muds, the water held by the clay particles becomes part of the discontinuous phase and accounts, in part, for the effectiveness of clays as viscosifying agents. Bentonite, for example, hydrates in fresh-water muds to approximately ten times its dry volume.

Other solids in the mud are relatively inert, or nonreactive. Barite, sand, silt, and other inert solids make up the inert fraction. Most solids are inert in oil-base muds, with the exception of some specialized oil-mud additives. All solids in a drilling fluid, whether reactive or inert, belong to its discontinuous phase. Solids play an extremely significant part in the performance of drilling fluids. For example, penetration rate and the stability of a mud tend to decrease as the percentage of solids increases. Many mud problems are caused by the failure to adequately control solids. Chemical treatment of the mud may increase its capacity to tolerate solids, but only to a limited extent. Solids are desirable only if they add enough to the mud properties to justify their presence. Barite and bentonite, if properly used, do this; drilled solids do not, and should therefore be removed from the mud.

**Drilling fluid ingredients.** The water, oil, or mixture of both needed to build the volume of a mud is added at the surface. Small solid particles that come from cuttings, sloughings, cavings, or the borehole wall also become part of the mud as do liquids or gases from porous formations. Salts may also enter the mud through formation water, or when salt sections are drilled. Various materials may be added at the surface to change or modify the characteristics of the mud. For example, weighting agents, usually barite, are added to increase the density of the mud, which helps to control subsurface pressures and build the filter cake. Viscosifying agents, i.e. clays, polymers, and emulsified liquids, are added to thicken the mud and increase its hole-cleaning ability. Dispersants or deflocculants may be added to thin the mud, which helps to reduce surge, swab, and circulating-pressure problems. Clays, polymers, starches, dispersants, and asphaltic materials may be added to reduce filtration of the mud through the borehole wall. This reduces formation damage, differential sticking, and problems in log interpretation. Salts are sometimes added to protect downhole formations or to protect the mud against future contamination, as well as to increase density. Other mud additives may include lubricants, corrosion inhibitors, chemicals that tie up calcium ions, and flocculants to aid in the removal of cuttings at the surface. Caustic soda is often added to increase the pH of the mud, which improves the performance of dispersants and reduces corrosion. Preservatives, bactericides, emulsifiers, and temperature extenders may all be added to make other additives work better.

## Clay Chemistry

Clays play a central role in drilling fluid technology. They can be classified chemically as aluminum silicates, and physically as heterogeneous mixtures of finely divided minerals of 2 microns or less, e.g. such as quartz, feldspar, calcite, pyrite, and other sedimentary materials composed of silica, alumina, and water. Since the elements that constitute clays account for over 80% of the earth's mass (aluminum 8.1%, silicon 27.7%, and oxygen 46.6%), it is clear that most drilled formations contain clay minerals. The type and quantity of these clays is one of the most important factors in the chemical and mechanical properties of the rock. Drilling fluid selection should be based in part on the possible reactions between the fluid and the rock, because these reactions affect the borehole stability. Clay minerals are present in most reservoir sandstones. These may react with the fluids that contact them in such a way as to completely block the formation. Therefore, knowledge of clay structures and chemical reactions is important in designing fluids that may be in contact with the producing zone. Formation clays are naturally incorporated into the drilling fluid during drilling, and are a principal source of viscosity. In addition, commercial clays such as bentonite and attapulgite are purposely added to the fluid to attain desired viscous flow properties. However, since the combination of formation clays and commercial clays frequently leads to excessive viscosity, chemicals often must be added to control the fluid's flow properties. An understanding of the chemistry of these chemicals and the clays is necessary to deploy the measures to control the fluid properties.

## Fundamental Structure of Clays

Clay minerals are crystalline in nature, and the atomic structure of their crystals is the prime factor that determines their properties. Clays are identified and classified mainly by analysis of X-ray diffraction patterns, adsorption spectra, and differential thermal analysis. Most clays have a mica-type structure, i.e. thin crystal platelets stacked face to face. A single platelet is called a unit layer, and is composed of atoms in a close packed octahedral or tetrahedral configuration that may alternate in different layers or sheets to form the unit layer or crystal platelet. Clays are hydrous aluminum silicates composed of alternating layers of alumina and silica. Silica is a tetrahedral structure with a silicon atom surrounded by four oxygen atoms at equal distance from each other. The silica tetrahedrons are joined in a hexagonal structure which is replicated to form a sheet. Alumina has an octahedral structure consisting of an aluminum atom with six oxygen atoms arranged in an octahedron around it. These alumina octahedra are then joined in a structure which is replicated to form a sheet or layer. In the octahedral arrangement, the oxygen or hydroxyls form two closely packed rows coordinated to aluminum, iron, or magnesium ions located at the octahedral center. When aluminum is present, only two-thirds of the possible positions are filled to balance the structure, which is the gibbsite structure, Al (OH)3. When magnesium is present, all the positions are filled and the structure is brucite, Mg (OH)2. In clays, this layer often contains more than one kind of metal ion. In the tetrahedral arrangement, a silicon atom is located equidistant from four oxygen atoms, or hydroxyls, to electrically balance the structure if necessary. The position of the oxygen or hydroxyls can be described as being at the corners of a geometric tetrahedron. The silica tetrahedral groups are arranged to form a hexagonal network, which is repeated infinitely to form a sheet of composition, Si4O6(OH)4. Different combinations of these sheets and modifications of the basic structure give rise to the range of clay minerals with different properties.

The two basic structural units are the alumina octahedral sheet and the silica tetrahedral sheet. The fundamental units of tetrahedral sheets and octahedral sheets are tied together to form a platelet by sharing common oxygen. When there are two tetrahedral sheets, the octahedral sheet is sandwiched between them. The tetrahedrons face inward, and share the oxygen atom at their apexes with the octahedral sheet, which displaces two of the three hydroxyls originally present. Different combinations and chemical modifications have given rise to different clay minerals. One of the modifications has to do with the number of metal atoms in the center of the octahedral layer. If only two out of three octahedral center sites are occupied by a metal atom, the layer is called di-octahedral. If all three sites are occupied, it is called trioctahedral. The clay minerals are built up by different ratios of silica sheet to octahedral sheet. The largest group is the 2:1 mineral; there are also 2:1:1 mineral and 1:1 mineral. The unit layers are stacked together face-to-face to form what is known as the crystal lattice. The sheets in the unit layer are tied together by covalent bonds, so that the unit layer is stable. On the other hand, the layers in the crystal lattice are held together only by Van der Waals forces (very weak electrical attraction caused by the polar nature of particles made up of unlike atoms) and secondary charges between juxtaposed atoms. Consequently, the lattice cleaves readily along the basal surfaces, forming tiny mica-like flakes.

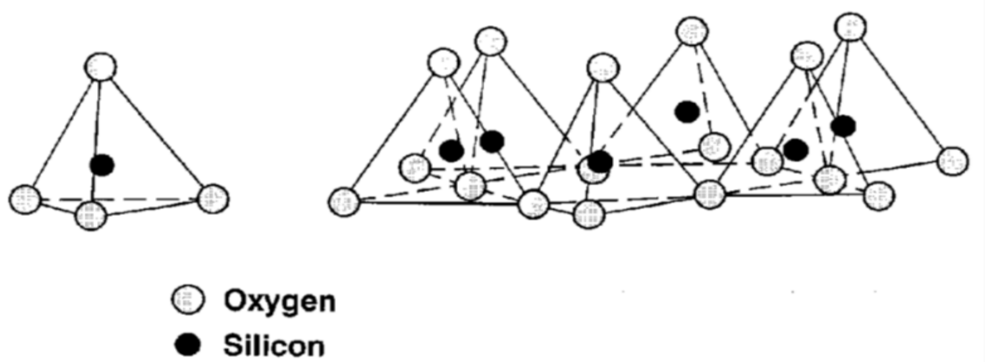


Fig 55: Silica tetrahedral sheet (Caenn et al. 2011)

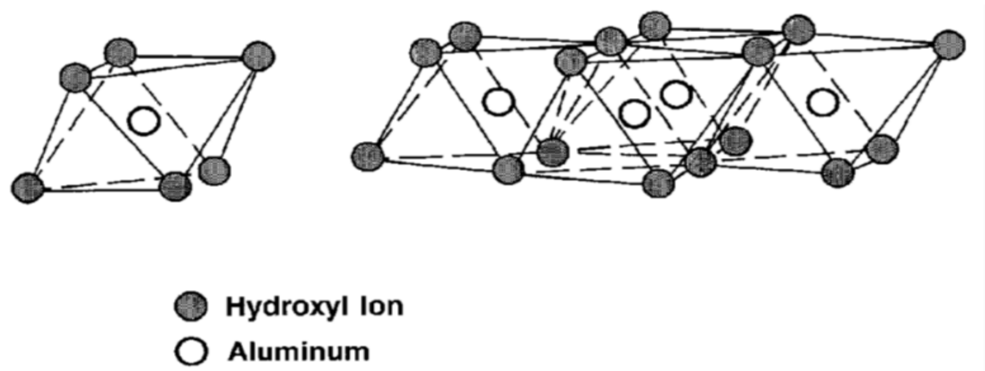


Fig 56: Alumina octahedral sheet (Caenn et al. 2011)

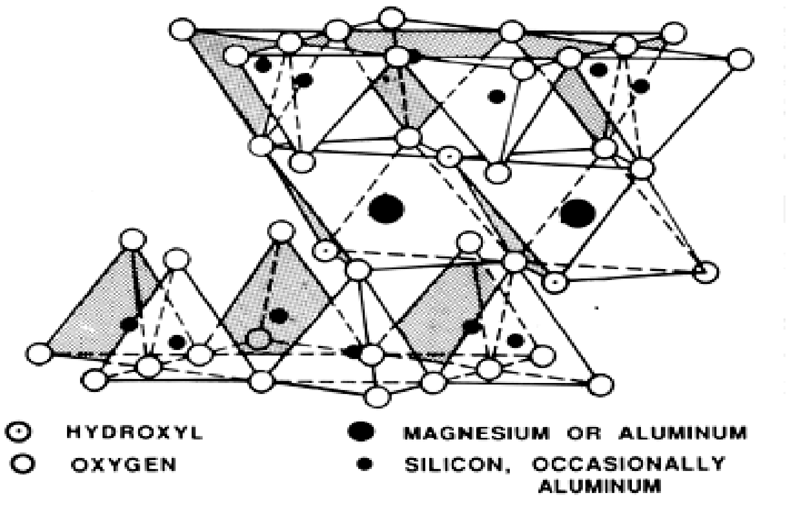


Fig 57: Bonding between one octahedral sheet and two tetrahedral sheets (Caenn et al. 2011)

The clay minerals of most importance and interest to drilling fluid engineering are kaolinite, mica, montmorillonite, attapulgite, and chlorite. Summary of structure and properties of the most common clay minerals is below.

| **Property** | **Kaolin** | **Mica** | **Montmorillonite-** | **Attapulgite** | **Chlorite** |
|---|---|---|---|---|---|
| Sheet Type | 1:1 | 2:1 | 2:1 | 2:1 | 2:1 |
| Crystal Structure | Sheet | Sheet | Sheet | Sheet | Sheet |
| Particle Shape | Hexagonal Plate | Extensive Plates | Flake | Needle | Plate |
| Particle Size (micron) | 5-0.5 | Large sheets to 0.5 | 2-0.1 | 1-0.1 | 5-0.1 |
| Cation Exchange Capacity,meq/100g | 3-15 | 10-40 | 80-150 | 15-25 | 10-40 |
| Viscosity in water | Low | Low | High | High | Low |
| Effect of salts | Flocculates | Flocculates | Flocculates | Little or none | Flocculates |

The varieties of specific clay minerals arise from differences in both structure and chemical composition. In the ideal combination of tetrahedral and octahedral sheets, a structure is formed in which the metal atoms in the octahedron are all of one kind and those in the tetrahedron are all of another kind. Where this is in fact the case, the mineral structure is balanced and electrostatically neutral. Structures of this type are considered prototypes for clay minerals, but are not themselves clay minerals. True clay mineral crystals carry a charge arising from the presence of a few metal atoms in the structure that are different from the predominant type and carry a different ionic charge. This isomorphous substitution occurs during the formation of the clay mineral. For example, if where an $Al^{3+}$ atom would be found in the ideal structure a $Mg^{2+}$ atom is found instead, a charge deficiency in the crystal of one results. This produces a negative potential at the crystal basal surface, which is neutralized by the adsorption of a cation, such as $Na^+$, from the environment. In the presence of water, the cat ions adsorbed naturally can exchange with cat ions of another species in the water, and they are therefore known as exchangeable cations. The actual capacity of a clay to exchange ions is a function of the isomorphous substitutions in the crystal lattice. The cation-exchange capacity (CEC) is an important characteristic of clays and varies from mineral to mineral. The property is often used to characterize clays, shales, and drilling fluid, and is determined by the measurement of the amount of adsorption of a cationic dye, methylene blue. The result is quoted as the milli-equivalent of dye adsorbed per 100 gram of dry clay. The pattern of isomorphous substitution causes variations in the resulting minerals, depending on tetrahedral or octahedral substitution; the extent of substitution; and the nature of the exchanged cations, i.e. $Na^+$, $K^+$, or $Ca^{2+}$. The extent to which any adsorbed cation will be exchanged depends on factors, e.g. effect of concentration, population of exchange sites, nature of anion, nature of cation, nature of clay mineral. This large number of variables creates a complex system to analyze. Different ions have different attractive forces for the exchange sites. The relative replacing power of cations is generally $Li^+ < Na^+ < K^+ < Mg^{2+} < Ca^{2+} < H^+$. Thus, at equal concentrations, calcium displaces more sodium than sodium displaces calcium. If the concentration of the replacing cation is increased, then the exchanging power of that cation is also increased. For example, high concentrations of potassium can replace calcium. Also, in some minerals such as mica, potassium is particularly strongly adsorbed and not easily replaced, except by hydrogen ions, which can be easily derived from acids. In the preceding discussion, only the adsorption and exchange of cat ions on the basal surface of the clay was considered. However, both cations and anions are adsorbed at the platelet edges because when the clay platelet is broken, unbalanced groups of charges are created at this edge. In aqueous suspensions, both sets of ions may exchange with ions in bulk solution. Some of the newly exposed groups have the structure of silica, a weak acid, and some have the structure of alumina or magnesia, a weak base. Therefore, the charge on the edge varies according to the pH of the solution. Thus, at low pH values the broken edges are more positive, and at high pH the edges are more negative. One of the reasons for the pH values of drilling fluid to be maintained on the alkaline side is to ensure that the clay particles are only negatively charged so that electrostatic interactions are kept to a minimum. Chemical treatment of drilling fluids is often aimed at a reaction with the groups on the broken edges. Since the edge surface is created by grinding or breaking down the clays, chemical treatment costs can be minimized by ensuring that the formation clays are removed as large cuttings, rather than broken down in the circulating system into finer particles.

## Examples of Clay

Kaolinite. Kaolinite is composed of a single tetrahedral sheet and a single dioctahedral alumina sheet. The tetrahedral sheet is tied to the octahedral sheet so that the hydroxyls on the face of the octahedral are placed side by side of the oxygen on the face of the tetrahedral. The charges within the structure are balanced, and there are very few lattice substitutions.

Very strong hydrogen bonding exists between successive layers of the basic building units, which prevents lattice expansion by preventing water penetration. The natural crystals consist of about 100 unit layers stacked one upon the other. The clay platelets are charged mainly due to the broken-edge charges, which are sensitive to the pH of the suspension. There are few, if any, cations adsorbed on the basal surfaces and the cation exchange capacity is therefore quite low, ranging from 3 to 15 meq/100g. Slurries of kaolinite are low viscosity because of the non-swelling structure of the clay. The characteristics of fine particle size, whiteness, and low viscosity are exploited in various industries, such as paper and ceramics. This clay is also abundant in shales and marine deposits. There is a tendency towards alteration to illite and chlorite at greater depth. Members of the kaolinite group, which differ in their stacking sequences, are frequently found in sandstone reservoirs.

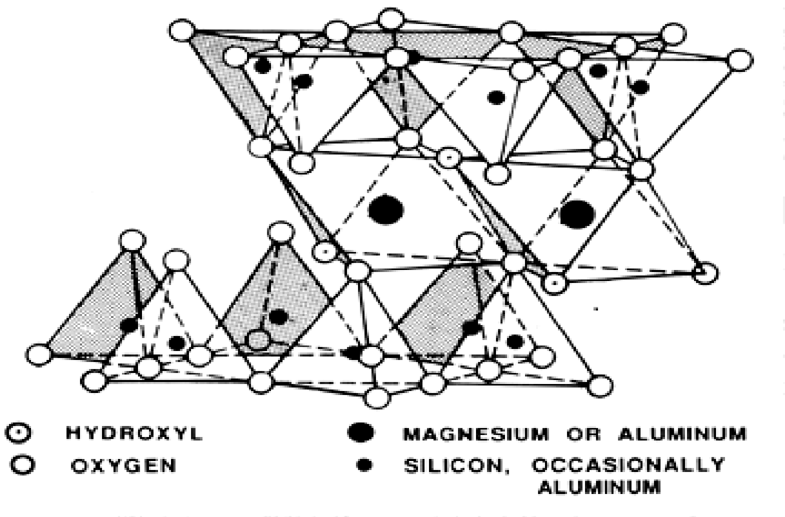


Fig 58: Kaolinite structure (Caenn et al. 2011)

Illite. Illite belongs to a class of minerals called micas. Mica is a 2:1 lattice-type mineral in which two silica sheets sandwich an octahedral sheet. The two important features of mica are that the isomorphous substitution is mainly in the tetrahedral sheet, where silicon is replaced by aluminum or iron, and that the charge deficiency thus produced is balanced by potassium ions. The average charge deficiency in the mica is relatively high, due to isomorphous substitution. In well-crystallized mica, about one in four of the silicon atoms is replaced by aluminum. It is important that in the well-crystallized mica, no imperfection in the regularity of stacking occurs. The mica used for lost-circulation material is of this type. An understanding of the role of potassium in the mica (illite) structure is fundamental for the use of potassium chloride brine in wellbore stabilization. One of the main characteristics of any cation is its total positive charge and its diameter. A small cation with a high positive charge with a high charge density has a high affinity for negatively charged species. In aqueous solutions, cations with a high charge density have a very strong attraction for polar water molecules.

Diameters of common cations in the dehydrated and hydrated states are shown below. A range is given because different techniques for measuring the ion diameter (in unit of Angstrom) result in different values.

| | Dehydrated | Hydrated |
|---|---|---|
| Sodium ($Na^+$) | 1.90 | 5.50-11.2 |
| Potassium ($K^+$) | 2.66 | 4.64-7.6 |
| Cesium ($Cs^+$) | 3.34 | 4.60-7.2 |
| Magnesium ($Mg^{2+}$) | 1.30 | 21.6 |
| Calcium ($Ca^{2+}$) | 1.90 | 19.0 |

Note that the potassium ion has a small hydrated diameter when compared with sodium, magnesium, or calcium. Because of its size, the potassium ion can fit neatly into the hexagonal holes in the silica sheet and very effectively neutralize the charge deficiency in that layer. Thus, strong interbonding results that prevents water from penetrating between the successive layers which produces a nonexpanding lattice and prevents the potassium ion from being exchanged with other cations. In general ion exchange and hydration is confined to the exterior surface of the clay aggregate. The illite clay mineral differs from the well-crystallized mica in several ways. There is less substitution of $Al^{3+}$ for $Si^{4+}$, and the net unbalance charge deficiency is reduced from 2 per unit cell to about 1.3 per unit cell. The unit layers may have between them, in addition to potassium, other cations such as $Ca^{2+}$, $Mg^{2+}$ or $H^+$. This alteration permits some interlayer hydration and lattice expansion and some interlayer ion exchange. Thus illite or mica may react with potassium ions and be stabilized to some extent. The smectite often degrades to mica or illite through reaction with potassium ions. Mica or illite concentrations tend to increase with age and depth.

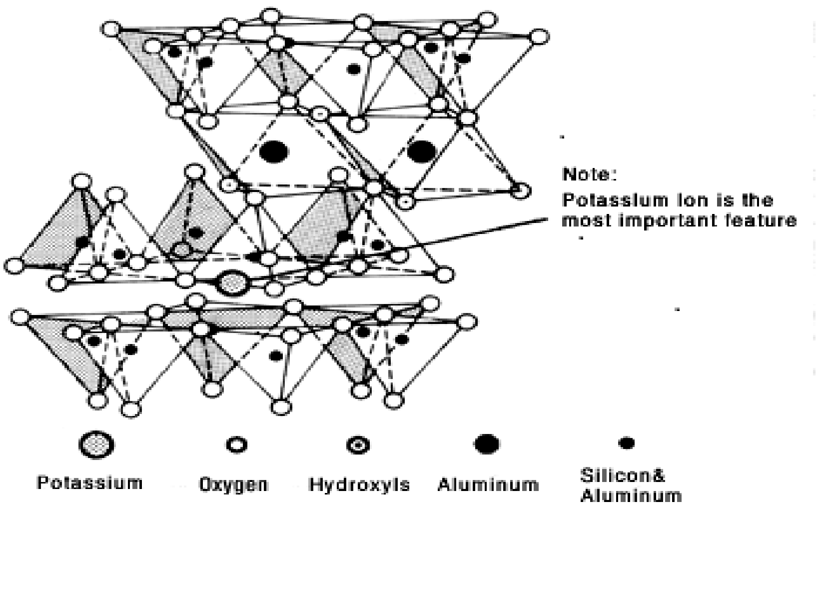


Fig 59: Illite structure (Caenn et al. 2011)

**Montmorillonite.** Montmorillonite is the major clay mineral in bentonite, or "fresh-water gel," and is the best known mineral in a group of minerals called the smectite because of its common occurrence and economic importance. Montmorillonite is the active component in the younger argillaceous formations that cause problems of swelling and heaving when drilled. The predominant isomorphous substitutions are Mg2+ and Fe3+ for Al3+ in the octahedral sheet, but Al3+ may be substituted for Si4+ in the tetrahedral sheet. The essential feature that gives rise to the expandable structure of montmorillonite is that the substitutions are mainly in the octahedral layer. Thus, the charge is in the center of the layer, so that the cations that are associated with the mineral to balance the resulting charge are unable to approach the negative charge sites closely enough to completely neutralize either the positive charge on the cation or the negative charge on the clay surface. This residual ionic character provides the attractive force for the adsorption of polar molecules, such as water, between the unit layers. Also, in the crystal lattice, the tetrahedral sheet on one layer is adjacent to the tetrahedral sheet of the next, so that oxygen atoms are opposite oxygen atoms. Consequently, bonding between layers is weak and cleavage is easy. There are two swelling mechanisms: crystalline and osmotic. Crystalline swelling, sometimes called surface hydration, results from the adsorption of mono-molecular layers of water on the basal crystal surfaces on both the external and, in the case of expanding lattice clays, the interlayer surfaces. The first layer of water is held on the surface by hydrogen bonding to the hexagonal network on oxygen atoms. Consequently, the water molecules are also in hexagonal coordination. The next layer is similarly coordinated and bonded to the first, and so on with succeeding layers. The strength of the bonds decreases with distance from the surface, but structured water is believed to persist to distances of 77 to 100 Angstrom from an external surface. The structured nature of the water gives it quasi-crystalline properties. Thus, water within 10 Angstrom of the surface has a specific volume about 3% less than that of free water. This structured water also has a viscosity greater than that of free water. The exchangeable cat ions influence the crystalline water in two ways. First, many of the cations, except NH4+ and K+, are themselves hydrated, i.e. they have shells of water molecules. Second, they bond to the crystal surface in competition with the water molecules, and thus tend to disrupt the water structure. Exceptions are Na+ and Li+, which are lightly bonded and tend to diffuse away. Osmotic swelling occurs when the concentration of cat ions between the layers is greater than that in the bulk solution. Consequently, water is drawn between the layers, thereby increasing the spacing and permitting the development of the diffuse double layers. Although no semipermeable membrane is involved, the mechanism is essentially osmotic, because it is governed by a difference in electrolyte concentration. Osmotic swelling causes much larger increases in bulk volume than does crystalline swelling. The swelling behavior is most dependent on the type of cation in the exchangeable sites. Since sodium and calcium are the most common soluble ions associated with drilling fluids, our discussion is limited to these two cations. A single cation, such as sodium (Na+), can associate with only one charge-deficient area on one layer, and as such has little influence on preventing dispersion in water. In fact, because of its relatively high hydration potential, it may encourage hydration and separation of the layers. In contrast, a divalent cation, such as calcium (Ca2+), cannot effectively associate with two negatively charged centers on one sheet, and thus must bind two sheets together. Contact with water can cause swelling, and mechanical dispersion may separate a layer, but the ultimate surface area available, and the volume of closely associated water, is considerably lower than with the sodium system.

The expanding lattice of the smectite greatly increases their colloidal activity and makes all of the layer surfaces as well as the exterior surface available for hydration and cation exchange. The unique properties of montmorillonite are due to the very large surface area available when the clay expands and hydrates fully to only single sheets. This creates a colloidal dispersion whose viscosity is controlled by surface phenomena, including surface potential. The greater the subdivision of a particle, the greater is its surface area per unit weight and the greater the effect of surface phenomena. The ratio of surface area per particle unit weight is called the specific surface. Montmorillonite has the greatest available area to the polar adsorbent. This clay is preferred as a drilling-mud additive because the desired viscosity may be obtained at low concentrations. The calcium clays are often chemically treated with sodium carbonate to convert them partially to the sodium form. Expandable montmorillonite can exist in substantial quantities in shales as the result of volcanic ash falling into a marine environment. The shales show the expected reaction to water: the clay expands; when drilled, the high surface area yields a plastic, sticky cutting. These clays are often termed “gumbo” shales.

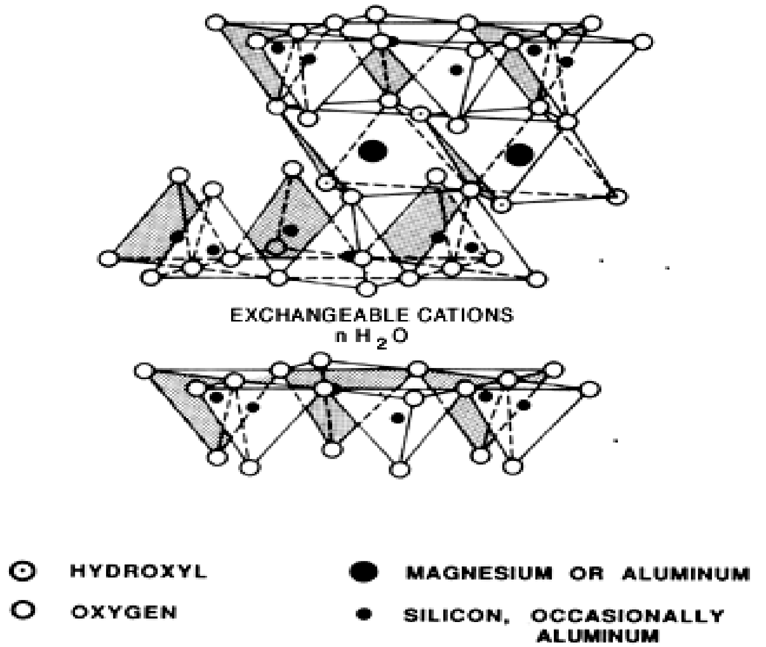


Fig 60: Montmorillonite structure (Caenn et al. 2011)

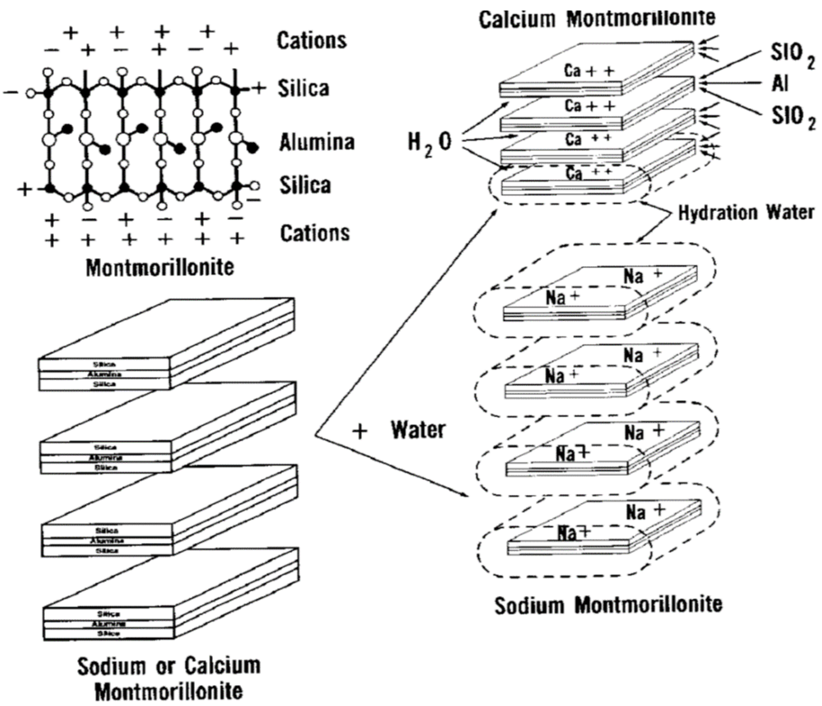


Fig 61: Clay swelling diagram (Courtesy of Amoco)

**Chlorite.** Chlorites are clay minerals that are structurally related to the three-sheet type clays. In these minerals, the charge-compensating cations between the montmorillonite-type unit layers are replaced by a sheet of octahedral magnesium hydroxide (brucite). Due to some replacement of magnesium by aluminum in the magnesium hydroxide sheet, the sheet has a net positive charge. Since the cation exchange capacity is very low (ranging from 10 to 40 meq/l00 g), the positive charge of the magnesium hydroxide layer apparently compensates for the net negative charge of the unit layers. The members of the chlorite group differ in the amount and species of atoms substituted in the two layers, and in the orientation and stacking of the layers. Normally, there is no interlayer water, but in certain degraded chlorites, part of the magnesium hydroxide layer has been removed, which permits some degree of interlayer hydration and lattice expansion. Chlorite tends to be associated with older sediments, so that kaolinite and smectite tend to be replaced by chlorite and illite.

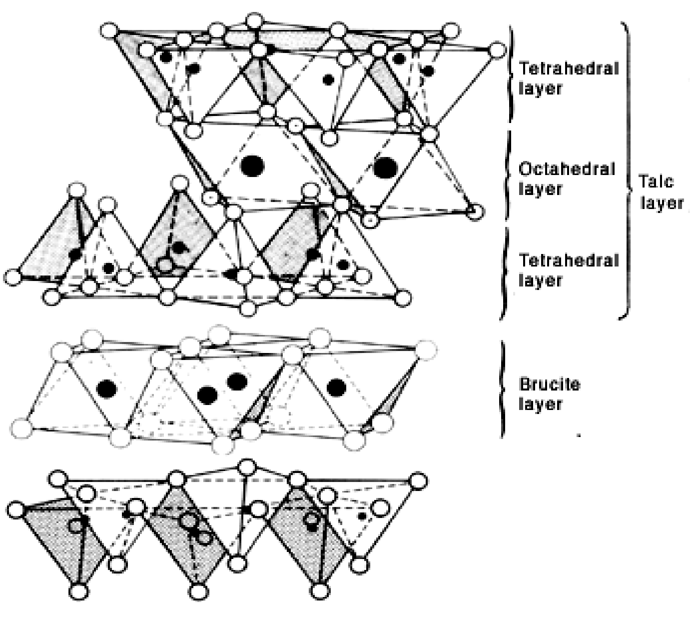


Fig 62: Chlorite structure (Caenn et al. 2011)

**Sepiolite and Attapulgite.** The clay minerals sepiolite and attapulgite are used to viscosify saltwater-based drilling fluids, and they are similar in structure. Attapulgite consists of double silica chains running parallel to the long axis. The chains form a network of strips that are joined together along the edges. The upper and lower parts of each chain are held together by aluminum and/or magnesium in octahedral coordination. The overall structure resembles a channeled wall where every second brick is missing. In sepiolite, the chains are formed from two silica chains to give wider channels. Attapulgite derives three unusual characteristics from its unique structure. First, because the structure consists of three-dimensional chains, it cannot swell like clays that have a sheet structure, such as montmorillonite. Second, there is a cleavage plane along the long axis, parallel to the silica chains, so that the mineral crystals have a needlelike shape, typically 1 micron long and 0.01 micron wide. Third, the mineral has a high adsorbtive capacity for water, where some is held loosely onto the surface and some is bound strongly in the channels, and is referred to as zeolitic water. It is from this crystalline needle-like structure that attapulgite and sepiolite imparts viscosity to any type of water. When sheared, the attapulgite forms a "brush-heap" stack of individual fiber-like crystals to impart a viscous slurry. Due to the brush-heap stacking of the particles, a compact, impermeable filter cake cannot be obtained. Therefore, filtrate-loss control must be supplemented by filtrate-loss additives. However, filtrate-loss control is more difficult to control with sepiolite than with attapulgite. Flocculation by salt water, with subsequent re-aggregation, does not occur with the needle-shaped particles. For this reason, these clays make excellent suspending agents in salt water. Sepiolite-based muds are recommended for use in deep wells because their rheological properties are not affected by high temperature.

**Mixed-Layer Clays.** Many clay materials are composed of more than one clay mineral, and the clay minerals may be mixed in several ways. These mixed layer structures are a consequence of the fact that the composition of the sheets of the different layer clay minerals are very similar, all being composed of silica tetrahedral sheets and closely packed octahedral sheets of oxygen and hydroxyl groups. Mixed-layer clay structures are of two different types. In the first type, the interstratification may be regular and uniform, in which case the unit cell is equivalent to the sum of the component layers. An example of a regular mixed-layer clay mineral is chlorite, which is composed of regular alternations of mica (three-layer clay) and brucite (magnesium octahedral sheet) layers. The other type of mixed-layer clay structure is due to a random irregular interstratification of layers in which there is no uniform repetition of layers. Mixtures of the various three-layer clays such as montmorillonite and illite are the most common, but occurrences of clay minerals composed of mixtures of illite-kaolinite and chlorite-kaolinite also occur. Usually, mixed-layer clays disperse in water to small units more easily than do single-mineral lattices, particularly when one component is of the expanding type.

## Clays in Drilling Fluids

Clays play a significant role in drilling fluids, particularly in water-base fluids. They may be added intentionally to control viscosity and to provide the colloidal properties required for filtrate-loss control, or they may build up through the drilling of formations in which they predominate. The flow properties and filtrate-loss control of clay-base fluids are modified by chemical treatment either added intentionally or present as a consequence of drilling through water-soluble formations, such as cement, anhydrite, salt, or magnesium salt. The associations between clay particles affect important properties such as viscosity, yield, and filtrate loss.

**Aggregated systems.** The clays consist of a basic sheet structure, and the crystals consist of assemblages of the sheets, one upon the other. The clay in its dry state has platelets stacked in face-to-face association, like a deck of cards. This is called aggregation system. In the swelling clay montmorillonite, the sheets can be separated from one another by hydration forces and by mechanical shear.

**Dispersed systems.** The dispersion of particles in a fluid is their subdivision, by mechanical force, from their aggregated state to hydrated colloid particles. In fresh-water dispersion, the clay platelets drift about independently or in very small clusters. Sometimes the platelets congregate together in random patterns. This usually occurs in a static condition, and is termed gellation. The random movement and drifting of a positively charged edge toward a negatively charged face happens slowly in the dispersed state. The positive sodium ($Na+$) ion cloud presents an effective shield around the clay, and further slows this movement. The ionized sodium surrounds the clay to form a weak crystalline barrier. A system in which the breakdown of the aggregate is complete is called a dispersed system.

**Deflocculated systems.** A system of suspended particles is described as deflocculated when there is an overall repulsive force between the particles. This is normally achieved by creating conditions in which the particles carry the same charge. In clay systems, under alkaline conditions, this is normally a net negative charge.

**Flocculated systems.** A system is described as flocculated when there are net attractive forces between the particles and they associate with each other to form a loose structure. Both the dispersed clays and the aggregates themselves may be flocculated or deflocculated. The clays may be regarded as sheets assembled in books, with an "edge" surface and a "face" surface. The edge may carry charges arising from broken bonds, which may be positive or negative and are dependent on pH. The face may also carry pH-independent negative charges. The forces acting on the clay particles can be described as either repulsive or attractive forces. The particles approach each other due to Brownian motion. Whether they agglomerate or not depends on the summation of these two forces. The repulsive forces are electrical double-layer repulsion and born repulsion. Clay particles have been described as small crystals that have a negatively charged surface. A compensating charge is provided by the ions in solution that are electrostatically attracted to the surface. At the same time, under the influence of the forces that cause random distribution, the ions tend to diffuse away from the surface towards the bulk of the solution. The action of the two competitive tendencies results in a high concentration of ions near the surface, gradually changing to lower concentrations farther from the surface.

The “thickness” of the layer is reduced by the addition of salt or electrolyte; this is related to the salt concentration and to the charge of the ions of opposite sign. Calcium chloride, therefore, compresses the double layer more effectively than sodium chloride. When two particles (each with its diffuse counter-ion atmosphere) approach each other, there is an interference that leads to changes in the distribution of ions in the double layers of both particles. A change infers that energy must be put into the system to force the particles together. In other words, there is a repulsion between the particles that increases as the particles approach each other. Because the electric double layer can be compressed by electrolytes, however, an increased electrolyte level allows the particles to approach more closely before the repulsive energies are significant. Born repulsion is a very short-term repulsion force generated when contact is close enough to distort the electrons in the atoms. It resists the interpenetration of the crystal lattices. The polar nature of the clay surface holds one or two layers of water tightly to the surface. Thus for the particles to approach closely to one another, energy has to be expended to desorb the water. This repulsive energy probably becomes appreciable at particle separations on the order of 10 Angstroms or less. Attractive forces, which bring the dispersed clay particles together, are called Van der Waals forces. These forces arise as the attraction of the spontaneous dipoles is created by distortion of the cloud of electrons around each atom. For two atoms, the attractive force decays very rapidly with distance (l/d7), but for two spherical particles, the force is inversely proportional to only the third power of the distance (l/d3). Thus, for a large assemblage of atoms, such as in a clay platelet, this force can be significant, since it is additive. The attractive force is essentially independent of the electrolyte concentration.

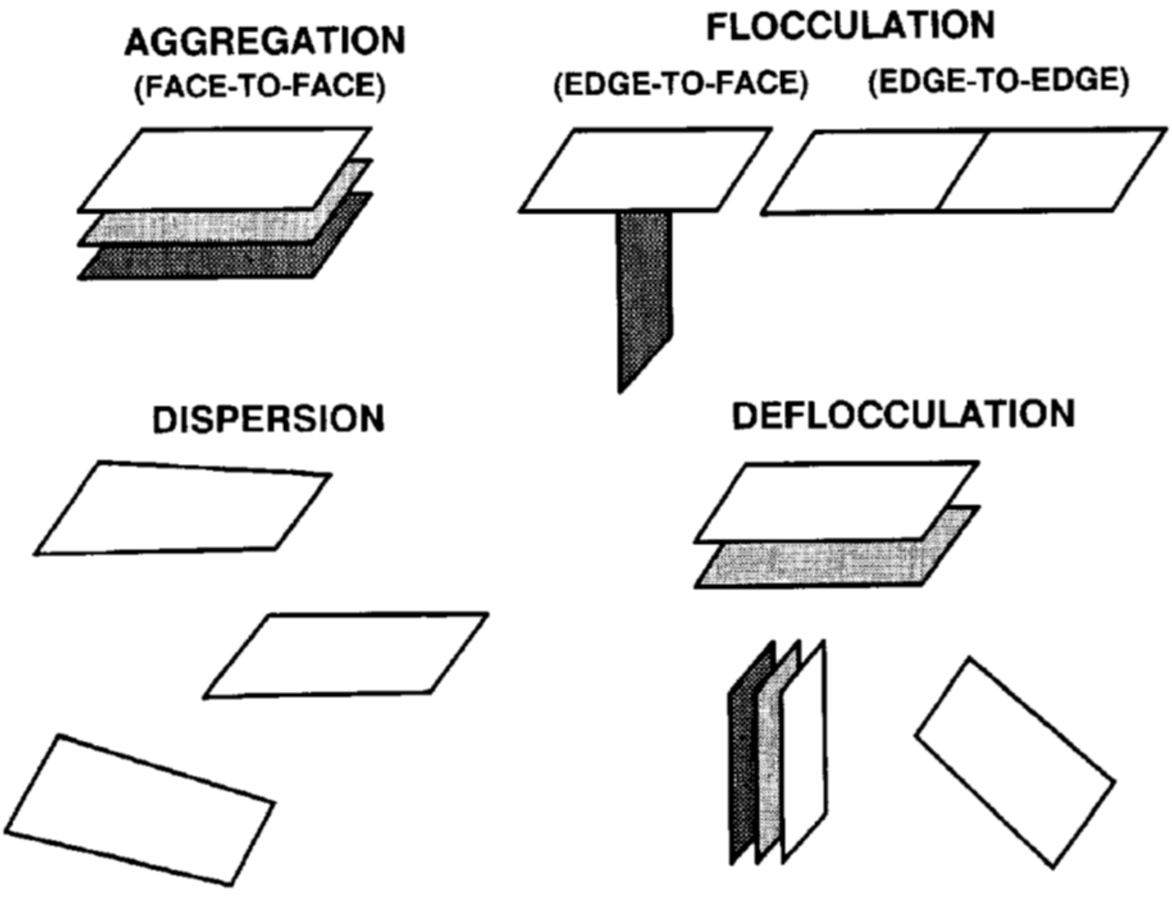


Fig 63: Associations between clay particles (Courtesy of Amoco)

**Deflocculation Mechanisms.** Repulsive forces must be maximized to maintain a system in a deflocculated state. This can be achieved by two mechanisms, namely maximize the electrostatic repulsions by minimizing the electrolyte concentration and maximize the negative charge on the clay platelets. The latter can be done in two ways. i.e. basic pH conditions and addition of deflocculants or dispersants. A pH above 8.0 increases the number of negative silicate groups on the clay edges. Thus, maintenance of alkaline pH conditions with caustic soda or sodium carbonate stabilizes the clay system. There is a large group of chemicals known as dispersants or thinners that have a wide range of chemical structure. However, they can all be described as negatively charged polymers. This has the net effect of increasing the overall negative charge density on the clay platelet. Then, the other negative groups increase the negative charge density on the clay platelet. Since deflocculants react with the positive sites on the edges, and the edge surface area is a relatively small proportion of the total, these chemicals can be effective at low dosages. Deflocculants tend to be acidic; therefore, caustic soda should be added along with the thinner. The effect of drilling fluid thinners on other fine particulate solids such as sand, calcium carbonate, or barites is essentially the same as with clay, but not as pronounced. Examples of thinner drilling fluid are Chrome Lignosulfonate, Lignite, Tannin, Sodium Acid Pyrophosphate, Tetrasodium Pyrophosphate.

**Flocculation Mechanisms.** There are a number of mechanisms by which interparticle attractive forces can be increased and repulsive forces decreased. These mechanisms often occur during drilling. Since in most drilling fluid systems the clays are deflocculated, the change to a flocculated condition can create problems by drastically altering the fluid properties. Increasing salt concentration allows the particles to approach one another closely enough for the shorter-range attractive forces to predominate. The upper limit of salinity for bentonite to yield satisfactorily is about 2 percent sodium chloride. In drilling practice, this reaction occurs when a fresh-water clay-based fluid is used to drill into a salt section, or when a fresh-water system has salt added to it in preparation for drilling evaporite formations. A soluble cation containing more than one positive charge can react with more than one exchange site on the surfaces of more than one clay platelet, forming an "ion bridge" between the clays to produce a flocculated structure. Calcium is the most common ion, although aluminum, magnesium, and zirconium are other examples. Calcium is often encountered in the form of gypsum (calcium sulfate) and cement. If the clays in the drilling fluid are in the sodium form, contact with calcium drastically alters their properties. Some mud systems avoid this problem by the use of excess lime or gypsum to ensure that the clays are already in the calcium form before the contaminant is encountered. Aluminum and zirconium ions have been suggested as treatments for production sands to flocculate the clay minerals and thus prevent their mobilization to block the pores of the production zone. The flocculation is followed by aggregation of the clays. Addition of polymers extend the concept of bridging the polyvalent cations to a polymer bridge between clay platelets. The main feature of the flocculants is a very high molecular weight, so that the molecule spans the distance between particles. The molecules must also adsorb onto the particles, so the presence of anionic or cat ionic groups often makes the molecules more effective. There are two cases where polymeric flocculants are used. One is in which the drilled solids are removed by the flocculants in order to keep the density low. In the other case, the polymer is added to selectively flocculate low-yielding fine solids from fresh-water-base systems. Since the edge charges are pH dependent, a $pH<7$ generates more positive sites and encourages face-to-edge association. Acids frequently are added to flocculate mud solids for well cleanup operations. At high temperatures, the adsorbed water tends to desorb, allowing the clay particles to approach each other more closely. At short range, the attractive forces become dominant and flocculation occurs.

The surfaces of clays contain hydroxyl and oxygen groups which form hydrogen bonds to water molecules. The exchangeable cations adsorbed on the clay surface also have an envelope of closely associated water molecules. Also, water forms a bond with negative sites on the edges. These interactions combine to create a zone of 10 to 15 layers of water closely associated with the clay, creating a hydration envelope. In the case of sodium montmorillonite, this edge may extend 60 Angstrom, or to about 20 layers of water. Thus the introduction of clays into water reduces the volume of free water, and builds structure and resistance to shear. The interactions between clay particles involve a net attraction or a repulsion between the particles flocculation and deflocculation, respectively. As might be expected, increased particle interactions tend to increase viscosity. Careful balance of the state of flocculation and deflocculation yields optimal flow properties and fluid-loss control. The reaction between clays and polymers depends on a number of factors, such as the molecular weight of the polymer and the adsorption of the polymer on the clay particle. There is a direct relationship between the molecular weight and the length of the molecule. A high-molecular-weight material, such as a synthetic polyacrylate with a molecular weight of 107, has a chain length of approximately 20 microns, which may be very much larger than the clay particles. Thus, it is possible for one molecule to adsorb onto more than one particle of clay and form an association of the clay particles. Thus, high-molecular-weight polymers can act as flocculants. Low-weight polymers can alter the charge on individual clay particles so that they may be equally charged and deflocculated. The strength of the adsorption and the site of adsorption depends on the chemical character of the polymer. Generally, negatively charged polymers can adsorb cationic sites generated on the edges. Most polymers used in drilling fluids are this type. Adsorption tends to be stronger for higher-molecular-weight materials. Other factors, such as charge density, salinity, and pH, make the situation too complex to generalize. Polymers can be used in very small quantities often less than 0.5% by volume to provide very precise control of flow properties.

## Drilling Fluid Components and Products

The use of drilling fluids to do more than aid in cuttings removal was proposed in the late 1800s, with clay, bran, grain, and cement with water being used to produce a plastic material that would plaster the borehole wall and reduce caving tendencies. Later it was discovered that high-density materials such as iron oxide (hematite), lead oxide (galena), and barium sulfate (barite) could be used to formulate pumpable fluids with densities of 15 to 18 ppg to control formation pressures. With the growing awareness of the relationship between mud properties and mud performance, and the realization that controlling these properties was important economically, the drilling fluids industry was born. The solutions to drilling problems represented by the birth of this industry created problems.

For example, the use of high-density weighting agents created the need for more effective viscosifiers for suspension; these often caused excess viscosity, which required thinning without affecting suspension. The search for drilling fluid additives to solve new problems has, over the years, resulted in the development of over 2000 trade name drilling fluid additives. Many of these products are the same materials with different trade names. Although each additive may perform several functions, when they are classified by chemical type the number of identifiably different additives is greatly reduced. However, even classifying drilling fluid additives by chemical type is not always unambiguous. For example, lignite may appear in several modified forms, and although its primary function is to disperse solids and reduce viscosity in water-base fluids, lignite and its modified forms are also very effective in reducing filtrate in both water-base and oil-base drilling fluids.
Functionally, drilling fluid components provide:

- density, or weight;
- viscosity;
- filtration control;
- rheology control, or thinning/dispersing;
- alkalinity, or pH-control;
- lost-circulation control;
- surface activity modification;
- lubrication;
- flocculation;
- shale stabilization;
- protection from toxic and/or corrosive agents;
- microbiocidal control and scale inhibition.

**Weight Materials**, or Densifiers. Weight materials are compounds that are dissolved or suspended in drilling fluid to increase its density. Weighted fluids are used to control formation pressures and to help combat the effects of sloughing or heaving shales that may be encountered in stressed areas. Any substance that is denser than water and that does not adversely affect other properties of the drilling fluid can be used as a weighting material. Cost is a factor in the selection of these materials, but there are other practical restrictions. For example, the solubility of salts, among other problems, limits their range of usefulness. Various finely ground solid materials, as listed below, have been used successfully to increase drilling fluid density. While the specific gravity of the weighting agent is of primary importance, especially in very heavy muds, the fractional volume occupied by the added solids is a major limiting factor in its use.

| Material | Principal Component | Specific Gravity | Hardness Moh's scale |
|---|---|---|---|
| Galena | PbS | 7.4-7.7 | 2.5-2.7 |
| Hematite | $Fe_2O_3$ | 4.9-5.3 | 5.5-6.5 |
| Magnetite | $Fe_3O_4$ | 5.0-5.2 | 5.5-6.5 |
| Iron Oxide (manufactured) | $Fe_2O_3$ | 4.7 | NA |
| Ilmenite | FeO TiC | 4.5-5.1 | 5.0-6.0 |
| Barite | $BaSO_4$ | 4.24.5 | 2.5-3.5 |
| Siderite | $FeCO_3$ | 3.7-3.9 | 3.5-4.0 |
| Dolomite | $CaCO_3$ $MgCO_3$ | 2.8-2.9 | 3.5-4.0 |
| Calcite | CaCO3 | 2.6-2.8 | 3.0 |

In addition to chemical inertness and specific gravity, several other factors affect the use of a substance as a weighting material. The substance should be available in large quantities, easily ground to the preferred particle size, and relatively nonabrasive, and should not be injurious or objectionable to the drilling crew or environment.

**Barite.** Naturally occurring barium sulfate is commonly known as barite (BaSO4). Barium sulfate's specific gravity ranges from 4.30 to 4.60, but is most commonly 4.50. The specific gravity of commercial barite is lowered by the presence of other minerals such as quartz, chert, calcite, anhydrite, celestite, and various silicates. When barite contains any of the several iron minerals, the average specific gravity of the product tends to increase. The color varies from white to light shades of gray, red, and brown. Barite for drilling-fluid use must have a minimum specific gravity of 4.20 and contain less than 250 ppm of soluble alkaline earth metals determined as calcium ion. Since pure barium sulfate has a specific gravity of 4.50, the lower density of barite ore admits about 10 to 15 percent alien material, depending on the density of the contaminant. Since barite is virtually insoluble in water and does not react with other components of the drilling fluid, the type and quantity of the contaminants ultimately determine whether the material will be suitable for use. Barite can be used to achieve densities up to 22 ppg in both water-base and oil-base drilling fluids. When densities approaching 19 ppg or higher are required, however, the increased solids content begins to adversely affect the fluid's rheological properties.

**Iron oxides.** Naturally occurring iron oxides (principally hematite, Fe203) were among the first materials used to increase the density of drilling fluids. Hematite can be used to attain densities up to 20 ppg in both water-base and oil-base drilling fluids. However, the use of iron oxides was discontinued in the early 1940's because ample supplies of barite were available at a lower production cost. Also, drilling crews objected to the staining of their skin and clothing by the dark red oxide.

Iron oxides are also more abrasive than barite, and can cause increased wear on the circulating equipment. As most natural iron ores are a combination of hematite and magnite, they have a strong ferromagnetic behavior. The weak magnetic field associated with rotating drill pipe is sufficient to attract and cause deposition of these iron ores on the drill pipe. Also, well logs based on magnetic methods are inaccurate and cannot be compensated when the magnetic permeability of the weighting material is as little as 10 percent greater than that of comparable nonmagnetic products. Pure iron oxides normally have excellent wettability in an oil-base medium, but are more difficult to bring into a stable water-base suspension. Therefore, ground iron ores have a greater tendency to settle than barite, especially in water-base muds.

**Iron carbonate.** The naturally occurring mineral is called siderite, which is basically ferrous carbonate (FeCO3). It usually contains small amounts of iron oxides, dolomite, calcite, and quartz. Siderite is readily soluble in hot hydrochloric acid, and it also dissolves in formic acid, a property considered desirable when used in completion fluids. Its specific gravity varies from 3.0 to 3.90. Both water-base and oil-base muds can be successfully weighted to 19 ppg with siderite.

**Iron titanate.** The mineral ilmenite, ferrous titanium oxide (FeTiO3), is a principal source of titanium. However, its inertness and relatively high specific gravity of 4.60 make it attractive as an alternative weighting material. Ilmenite is denser than barite, but it is also harder and more abrasive. Ilmenite can be used to attain densities up to 23 ppg in both water-base and oil-base drilling fluids.

**Calcium carbonates.** Calcium carbonate, or calcite, is proposed as a weighting material because the filter cake that it forms on a productive formation can be removed by treatment with hydrochloric acid. Calcium carbonate is readily available as ground limestone or oyster shells. Calcium carbonate is dispersed in oil-base muds more readily than barite. Its low specific gravity (2.60 to 2.80) limits the maximum density of the mud to about 12 ppg.

**Lead sulfide.** Galena (PbS), with a specific gravity of 7.4 to 7.6, is used only in the preparation of extremely heavy muds that are sometimes needed to control abnormally high pressures. Galena is expensive and toxic; consequently, barite is used with it in preparing muds to a density of about 30 ppg. Mud having a density of 32 ppg can be prepared with galena as the sole weighting material.

**Soluble salts.** Soluble salts are used primarily in workover and completion operations to formulate solids-free fluids. Fluid densities ranging from 9.0 to 21.5 ppg can be attained, depending on the salts used. The chart below outlines the maximum densities that can be attained for single-salt systems at 70° F.

| | | |
|---|---|---|
| Potassium chloride (KCl) | - | Weights up to 9 ppg |
| Sodium chloride (NaCl) | - | Weights up to 10 ppg |
| Potassium bromide (KBr) | - | Weights up to 11.6 ppg |
| Calcium chloride (CaCl2) | - | Weights up to 15.3 ppg |
| Zinc bromide (ZnBr2)- | | Weights up to 21.5 ppg |

Although sodium chloride and calcium chloride increase the density of water-base and oil-base fluids, they are usually added for reasons other than to increase density.

**Viscosifiers** (Clay Minerals). Viscosifiers improve a drilling fluid's ability to remove cuttings from the wellbore and to suspend cuttings and weight materials during periods of noncirculation. Clays and natural or synthetic polymers are the materials most commonly used as viscosifiers. Examples of clay minerals used to provide viscosity to drilling fluids are bentonite, attapulgite, sepiolite, and organophilic clays.

Bentonite consists of fine-grained clays containing not less than 85 percent montmorillonite, which belongs to the class of clay minerals known as smectite. In the oil field, bentonite is classified as sodium or calcium bentonite, depending on the dominant exchange cation. Bentonite that meets API specifications must have a maximum moisture content of 10 percent and leave no more than 4 percent residue after being washed through a 200 mesh screen. A 22.5 grams suspension in 350 cc of water must give a minimum viscometer reading of 30 at 600 rpm and a filtrate of 15 cc maximum. The yield point to plastic viscosity ratio must not exceed 3. Bentonite is added to fresh water or to fresh-water muds for one or more of the following purposes:

• to increase hole-cleaning capability;

• to reduce water seepage or filtration into permeable formations;

• to form a thin, low-permeability filter cake;

• to promote hole stability in poorly cemented formations; and

• to avoid or overcome loss of circulation.

Terms such as peptized, beneficiated, and extra-high yield describe bentonites to which organic polymers and sometimes soda ash have been added during processing. The resulting bentonite products give varying results depending upon the specific untreated bentonite and/or polymer added.

Attapulgus clay is usually called attapulgite, which makes up 80 to 90 percent of the commercial product. Montmorillonite, sepiolite and other clays, and quartz, calcite, or dolomite make up the remainder. As a drilling-fluid material, attapulgus clay is called gel salt, or brine gel, because it is used as a suspending agent in salt solutions. When placed in water, attapulgite does not swell like bentonite, but must be dispersed by vigorous agitation to separate the bundles of lath-like crystals. Stable suspensions result from the random structure that entraps water and from the large surface area available for adsorption of the polar water molecules. Attapulgite is used in drilling fluids solely for its suspending qualities. Its suspending qualities are not adversely affected by dissolved salts. Its usual application is in muds of higher salinity than sea water. Attapulgite does not afford filtration control, a feature that is used to advantage in the preparation of high-filtration slurries to combat loss of circulation. To meet API specifications for use in drilling fluids, attapulgite must have no more than 16 percent moisture and leave no more than 8 percent solids on a 200 mesh screen. A suspension of 20 grams in 350 cc of a saturated sodium chloride solution stirred 20 minutes must give a minimum reading of 30 at 600 rpm on a concentric cylinder viscometer.

Sepiolite is hydrated magnesium silicate that closely resembles attapulgite. Sepiolite gives stable viscosity to 300°F. It is apparently converted to a smectite when the temperature of the drilling fluid exceeds 300°F. Sepiolite is used in geothermal drilling as a viscous sweep for hole cleaning and as a substitute for attapulgite.

Organophilic clays can form gels in oil similar to those formed by bentonite in water. By a process of cation exchange, the normally hydrophilic clay reacts with aliphatic amine salts and with quaternary ammonium salts or bases to form a clay-organic product that can be dispersed in oil to provide suspending properties. The organophilic clay can be prepared from bentonite, attapulgite, or hectorite.

**Rheology-Control Materials.** Basic rheological control is achieved by controlling the concentration of the primary viscosifiers used in the drilling fluid system. However, when control of viscosity and gels cannot be efficiently achieved by this method, materials variously called "thinners," "dispersants," and/or "deflocculants" are used. These materials reduce the viscous and structure-forming properties of the drilling fluid by changing the physical and chemical interactions between solids and/or dissolved salts. In alkaline systems containing clay solids, all of these materials function by adsorption onto the clay particles, making them more negative. The net effect is to reduce attractive forces. Because of their action on clays and the nature of the materials themselves, thinners perform other important functions that are frequently of greater significance than just the improvement of the flow properties of the drilling fluid. Specifically, some of these substances are used to reduce filtrate and cake thickness, to counteract the effects of salts, to minimize the effect of water on the formations drilled, to emulsify oil in water, and to stabilize mud properties at elevated temperatures. In oil-base fluids, intentional overtreatment with emulsifiers and/or wetting agents reduces viscous properties.

Lignite is used as a thinner in water-base fluids for filtrate reduction, oil emulsification, and stabilization of fluid properties against high-temperature effects. Lignite is not a satisfactory thinner for calcium-contaminated muds, although it can be used to counteract the effects of cement by removing the calcium as a precipitate and lowering the pH by its acidity. Lignite also is not a thinner for salty muds. Lignite maintains stable filtration rates in the drilling of hot holes, and is an important constituent of muds used in geothermal drilling. It is recommended for use in all normal-pH muds, high-pH muds, and high-pH lime muds. Lignite is compatible with other thinners, especially lignosulfonate. Fluids treated with lignite are more resistant to salt water flow contamination.

Humate is an oil-dispersible lignite that reduces filtration from oil-base muds without affecting the viscous properties. The material also aids in the emulsification of water in oil.

**Filtration-Control Materials.** Filtration-control agents reduce the amount of filtrate lost from the drilling fluid into a subsurface formation because of the differential between the hydrostatic pressure of the fluid and the formation pressure. Bentonite, various manufactured polymers, starches, and thinners or deflocculants all function as filtration-control agents. Filtrate loss is controlled essentially by three different means. First, a deflocculated filter cake preferentially packs to form a thinner, less permeable cake; therefore, materials that act as deflocculants also reduce filtrate loss. Second, if the liquid phase that is being forced through the filter cake is viscous, lower filtration rates are effected. Viscosification of the liquid phase is most easily accomplished with high molecular weight polymers. A third means to control filtrate loss is to create a compressible filter cake. Colloidal materials, such as bentonite and some asphaltic derivatives that compress and/or deform to plug pore spaces in the filter cake, function in this way.

**Alkalinity and pH-Control Materials.** Alkalinity and pH-control additives are used to optimize pH and alkalinity in water-base drilling fluids. The control of many drilling fluid system properties is dependent on pH, e.g. the detection and treatment of contaminants such as cement and soluble carbonates. pH also affects the solubility of many thinners and divalent metal ions such as calcium and magnesium, and influences the dispersion or flocculation of clays. Among the most common materials used to control pH are the alkali and alkaline earth hydroxides e.g. $NaOH$, $KOH$, $Ca(OH)_2$ and $Mg(OH)_2$.

**Lost-Circulation Materials.** Lost-circulation materials can be broadly defined to include any material that seals or bridges against permeable or fractured formations to inhibit the loss of whole drilling fluid. An enormous variety of materials have been used to bridge, mat, and/or plug voids to combat loss of circulation. These materials can be divided into four categories: fibrous materials, flake materials, granular materials, and blends containing fibrous, flake, and granular materials.

Fibrous lost circulation materials (LCMs) are products such as shredded sugar cane, cotton fibers, hog hair, shredded automobile tires, wood fibers, sawdust, and paper pulp. These materials have relatively little rigidity and can be forced into large openings where they bridge over and form a mat or base. This mat effects a seal when solids from the drilling fluid deposit on it. If the openings are too small for the fibers to enter, a bulky external cake susceptible to easy removal may form on the walls of the hole. Fibrous materials are not recommended for use in oil-base muds.

Flake lost-circulation materials are products such as shredded cellophane, mica flakes, plastic laminate, and wood chips that are used to cover openings in the formation face, and may also be forced into large openings. In these instances, their sealing action is similar to that of fibrous materials. Cellophane flakes are not recommended for use in oil-base muds.

Granular lost-circulation materials are products such as ground nut shells and ground carbonates that are used to bridge and plug the openings in porous formations. The materials are available in fine, medium, and course grades. They tend to accumulate just inside the opening of the pore and form a bridge. To accomplish this, the materials must contain particles the approximate size of the opening and a gradation of smaller particles to effect the seal. Granular materials may be used in oil-base muds.

A blend lost-circulation material is a product containing a mixture or blend or fibrous, flake, and granular materials. Blended products containing cellophane flakes are not recommended for use in oil-base muds.

Slurries such as cement, diatomaceous earth, and diesel-bentonite mixtures are also used to combat loss of circulation by squeezing of the material into the thief zone. Slurries exhibit high filtrate loss, which results in the deposition of a thick filter cake that fills and plugs the void. Lost-circulation materials can be mixed in the slurry to increase its effectiveness.

**Surface Active Agents.** Surface active agents (surfactants) modify the interfacial tension or other surface properties between phase boundaries in the drilling fluid (water/solid, water/oil, water/air, etc.). Surfactants are used in drilling fluids as emulsifiers, wetting agents, foamers, and dehydration agents for clay particles. Surfactants usually consist of molecules that contain two dissimilar assemblies of atoms or groups. One group is polar and is thus attracted to a polar substance, such as water, and is called the hydrophilic group. The other group is a nonpolar, hydrophobic group. The function of the surfactant depends on the types of groups and the way they are combined. The important property of surfactants used in drilling fluids is the ability of these molecules to exist at the interface of hydrophilic and hydrophobic surfaces. The molecules bridging these surfaces lowers the energy of the system, making it stable. For example, oil would not by itself form a stable system of oil droplets within water. Mechanical energy would be sufficient to disperse the oil into small colloidal-size droplets, but in time they would separate again into two phases. However, the introduction of a surfactant that migrates to the oil-water interface stabilizes the system. The nature of the surfactant determines whether the system contains oil droplets within a continuous water phase (a direct emulsion) or water droplets within a continuous oil phase (an invert emulsion). Water-soluble surfactants, with a relatively large polar group, tend to give direct emulsions, and oil-soluble surfactants, with relatively large nonpolar groups, are used to form invert emulsions. Using surfactants, oils and lubricants can be incorporated into some water-base systems up to about 20 percent by volume to form direct emulsions. Invert emulsions containing as much as 60 percent water are used where the rocks need to be kept oil-wet, when, for example, water-sensitive rocks are being drilled or when water would impair the productivity of oil-bearing rocks. Drilling mud surfactant is a common water-base surfactant used to stabilize calcium-based fluids in high-temperature environments. Surfactants can be used in most water-base muds except saturated salt muds, which have an inherent tendency to foam. Emulsifiers are used to form stable oil-in-water emulsions. Dispersants such as lignosulfonates and lignites are also used to emulsify up to 10 percent oil without the use of additional emulsifiers. When sufficient stability of an emulsion is not achieved, liquid emulsifiers such as DME may be used to stabilize the emulsion. Soaps, polyamines, and ethylene derivatives are also used as emulsifiers. Overtreatment with some compounds can promote oil wetting of solids. Polyamines and fatty acid amines in petroleum solvents are used where sodium chloride or calcium chloride solutions, or both up to saturation, are to be emulsified into oil. Modified tall oil mixtures are also used as primary emulsifiers for water-in-oil emulsions; they also stabilize the emulsions, enhance suspension properties, and reduce filtration. Oil-wetting agents are surfactants that are used in oil-in-water emulsions to reduce the surface tension of the water, allowing the emulsion to more easily penetrate or spread over the surface of another material. Lecithin is a common wetting agent used in oil-base muds as a supplementary additive. Defoamers are used to reduce the foaming action that occurs in brackish and saturated salt muds, and to eliminate trapped or entrained air and gas bubbles. These materials reduce the surface tension of the membrane surrounding the bubble, allowing the gas to break the bubble and to escape. Defoamers work essentially on the surface bubbles and have only a small effect on internal bubbles. Aluminum stearate, castor oil, and silicone compounds are used as defoamers.

**Lubricating Materials.** Lubricating materials are designed to reduce torque and drag between drill pipe and the formation. They are incorporated into the filter cake and/or are attracted as a film to metal surfaces. The resulting oil film and slick filter cake substantially reduce torque during pipe rotation and drag during trips. Diesel oil, asphaltic compounds, extreme-pressure lubricants, synthetic oils and long-chain alcohols are used to impart lubricity to drilling fluids. Diesel oil and synthetic oils, in amounts ranging from 3 to 10 percent by volume, are used on a limited basis. Vegetable oils, animal oils, and mineral seal oils are also used to impart lubricity, as are such products as graphite, polymer or glass beads, and gilsonite.

**Flocculating Materials.** Flocculating materials cause solids to coagulate so that they can be more easily removed from water-base systems. They also work to change the viscous properties of the drilling fluid. Salt, hydrated lime, gypsum, and synthetic polymers are often used to promote flocculation and the subsequent removal of colloidal-size drilled solids. Guar gum and some acrylic polymers are also very effective total flocculants when used in low concentrations in clear-water drilling fluids. Lime and gypsum are also used to increase the carrying capacity of water-base spud muds by flocculating the bentonite and drilled solids. Flocculation is promoted by modification of the surface charge of the solid particles, as with salts, or by adsorption and bridging between particles, as with high-molecular-weight polymers.

**Shale-Stabilizing Materials.** Shale-stabilizing materials are used to inhibit the hydration and swelling of water-sensitive clays, sloughing or heaving or fractured shales, and the dispersion and subsequent incorporation of drilled solids into the drilling fluid. Hydration of shales, as well as fluid invasion that relieves stress, contribute to tight hole, sloughing or heaving shale, fill on bottom, and hole enlargement. Hydration and dispersion of drilled solids can lead to viscosity problems and undesirably high solids content. Shale stabilization is a broad term that lacks precise definition. Depending on the nature of the shale, any number of materials may affect the desired result. Among the materials usually classified as shale stabilizers are certain high-molecular-weight natural or synthetic polymers, asphaltic hydrocarbons, potassium and calcium salts, and certain surfactants and lubricants. The mechanism by which polymers stabilize shale is not known for certain, but laboratory evidence indicates that polymers alone are not sufficient to prevent swelling, and that soluble salts must also be present in the liquid phase to stabilize hydratable shales.

**Inhibitors.** Corrosion of tubulars may occur because of oxygen, acid gases ($CO_2$ or $H_2S$) that may also be toxic, and/or other chemicals that create a spontaneous electromotive potential. Oxygen is always present in drilling fluids. It enters the system during mixing and routine maintenance operations. A few parts per million is sufficient to cause significant corrosion. Pitting, caused by the formation of oxygen-corrosion cells under patches of rust or scale in inhibitor films on treated surfaces, is characteristic of oxygen corrosion. The best method for preventing oxygen corrosion is to minimize the entrainment of air at the surface by using only submerged guns in the pits and arranging for returns from desanders or desilters to be discharged below the pit fluid level. The mixing hopper is a prime source of air entrainment, and it should be open only when mud conditioning materials are being added. When oxygen must be scavenged because of unacceptable corrosion rates, the usual method is to use easily oxidized materials that have minimal effect on drilling fluid properties. The most common oxygen scavengers are the soluble sulfite salts. Chromate salts and a few organic materials are used occasionally. When it is not practical to remove oxygen, chemicals may be added that coat the steel tubulars to minimize the attack by oxygen. The coating materials frequently are oily organic surfactants. Removal of $H_2S$ is accomplished with iron or zinc materials. These combine with $H_2S$ to form insoluble sulfides, which are not easily decomposed to reform into toxic $H_2S$.

**Biocides.** "Biocide" is a generic name given to any substance that kills or inhibits the growth of microorganisms such as bacteria, molds, slimes, and fungi. Biocidal compounds include chlorinated hydrocarbons, organometallic compounds, halogen-releasing compounds, heavy metal salts, organic sulfur compounds, quaternary ammonium compounds, phenolics, and carbamates. Biocides must be used before the problem microorganisms attain significant populations. Microorganisms produce enzymes that attack organic materials to cause their decomposition. The enzymes are not destroyed by the biocide and thus they continue to work even after all microorganisms have been destroyed. Only time, temperature, and dilution are effective in reducing the effect of enzymes on a drilling fluid.

**Precipitants.** Precipitants are used to cause soluble components of drilling fluid to fall out of solution so that they may be easily removed. Carbonates may be removed from water-base drilling fluids as calcium carbonate after the addition of lime or gypsum. Calcium may be removed by the addition of soda ash. Magnesium is removed by raising the pH above 10.0 with caustic soda.

**Scale-Inhibiting Materials.** A scale inhibitor is any material that can remove a scale-causing compound or interfere with scale formation in drilling fluid. These materials may be either organic or inorganic. Typical scale inhibitors are the low-molecular-weight acrylics and organic or phosphonates.

**Polymers.** Organic polymers used in drilling fluids may be broadly classified by origin and composition. Some, such as starches and guar gum, occur naturally, and are ready for use after slight processing. Others, such as xanthum gum, are produced by natural processes in a carefully controlled environment. Still others, such as derivatives of the starches and gums, and sodium carboxymethylcellulose, might be called semisynthetic. Another class of polymers includes petrochemical derivatives, such as the polyacrylates and ethylene oxide polymers, which are purely synthetic. The use of polymers in drilling fluids has become progressively more sophisticated, and the range and versatility of polymers is continually being extended. They are often specifically designed for a particular drilling situation, even to the extent that clays may be entirely replaced by polymers when drilling water-sensitive shales or water-producing zones. Polymeric materials are used as surfactants, emulsifiers, foaming agents, defoaming agents, mud detergents, stuck pipe additives, lubricants, and corrosion inhibitors in addition to functioning as flocculants, deflocculants, viscosifiers, filtration-control agents, and to improve rheological properties of the drilling fluid. The particular function of a polymer in a drilling fluid is dependent on the physical and chemical structure of its molecule. The relationship between the function of a polymer in a drilling fluid and the essential characteristics of its structure is summarized below.

| **Function** | **Main Characteristics** |
|---|---|
| Viscosity | High molecular weight |
| Viscosity and gelation properties | High molecular weight and highly branched structure |
| Viscosity in salt properties | High molecular weight and nonionic or highly substituted anionic types |
| Deflocculation | Low molecular weight negatively charged at alkaline pH values |
| Flocculation | High molecular weight with charged groups to adsorb onto clays |
| Surfactant | Hydrophobic group and hydrophobic group on same molecule |
| Filtrate loss additive | Form colloidal particles or bridging action with solids |

**Common Inorganic Materials.**

There are a number of inorganic acids, bases, and/or salts used for specific purposes in drilling fluids. Some of these chemicals are used in the preparation of other commercial products, and as such their identity as mud additives is obscured or lost. The chemicals listed below are available from most drilling fluid suppliers.

Ammonium bisulfite, $NH_4HSO_3$, used as an oxygen scavenger to reduce corrosion of iron.

Calcium chloride, $CaCl_2$, used in hole-stabilizing oil muds, in calcium treated muds, in the preparation of dense salt solutions for completion and workover and for lowering the freezing point of water muds.

Calcium hydroxide, $Ca(OH)_2$, used in lime muds, high-calcium-ion muds, and for the removal of soluble carbonates.

Calcium oxide, CaO, used in oil muds for the formation of calcium soaps and removal of water. Used mainly as slaked lime in water muds.

Calcium sulfate, $CaSO_4$, source of calcium ions in gyp muds.

Potassium chloride, KCl, primary source of potassium ions for potassium-polymer muds.

Potassium hydroxide, KOH, used to increase pH of potassium-treated muds and to solubilize lignite.

Sodium bicarbonate, $NaHCO_3$, used to counteract cement contamination of bentonite water muds.

Sodium carbonate, $Na_2HCO_3$, principal use is for removal of soluble salts from makeup waters and muds; some use in clay beneficiation.

Sodium chloride, NaCl, used as produced or as prepared brine in completion and workover operations to saturate water before drilling rock salt; to lower freezing point of mud; to raise the density (as a suspended solid) and act as a bridging agent in saturated solutions, and in hole-stabilizing oil muds.

Sodium hydroxide, NaOH, caustic soda, used in water muds to raise pH; to solubilize lignite, lignosulfonate, and tannin substances; to counteract corrosion, and to neutralize hydrogen sulfide. Strong irritant to tissues, toxic, produced by electrolysis of sodium chloride.

Sodium sulfite, $Na_2SO_3$, used as oxygen scavenger.

Zinc bromide, $ZnBr_2$, used to prepare dense salt solutions. Irritant to tissues.

## Classification of Water-Base Drilling Fluid Systems

When attempting to classify drilling fluid systems, one must remember that all drilling fluids are unique. Even though two muds may be initially identical, the formations drilled, surface handling of the fluids, product concentrations and quality, and other variables will alter their chemical and physical properties.

The following designations are normally used to classify water-base drilling fluid systems:

•Nondispersed-noninhibitive systems, e.g. spud muds, polymer/bentonite muds, extended bentonite muds;

•Nondispersed-inhibitive systems, e.g. salt muds, KCL-polymer muds;

•Dispersed-noninhibitive systems, e.g. lignite-lignosulfonate muds, phosphate-bentonite muds;

•Dispersed-inhibited systems, e.g. lime muds, gyp-lignosulfonate muds, seawater-prehydrated bentonite muds.

Nondispersed-noninhibitive fluids do not contain inhibiting ions such as chloride (Cl-), calcium ($Ca_2$+), or potassium (K+) in the continuous phase and do not utilize chemical thinners or dispersants to effect flow control. Nondispersed-inhibitive fluids do contain inhibiting ions, but do not utilize chemical thinners or dispersants. Dispersed-noninhibitive fluids utilize chemical thinners or dispersants, but do not contain inhibiting ions. Dispersed-inhibitive fluids contain both chemical dispersants and inhibiting ions.

**Nondispersed-Noninhibitive Systems.** When referring to a water-base mud system, the term nondispersed means that clay is free to find its own hydrous dispersed equilibrium in the aqueous solution. It also means that chemical acceleratives or dispersants have not been added to the system. The term noninhibitive refers to the lack of specific ions such as potassium, calcium, or chloride that would inhibit the ability of the formation to absorb water. These systems use native waters; they do not use chemical thinners to affect the solids remaining in the system, or inhibitive ions to prevent the solids from swelling. Spud Muds. Spud muds are used during drilling to clean the hole; prevent sloughing of the surface hole; provide a viscous sweep to clean gravel/sand from the borehole; and form a filter cake to prevent seepage to the formation. Spud muds are formulated in many different ways, based on the type of formation being drilled. Spud muds used in soft, gumbo-type shales, for instance, require different chemicals from those used in hard-rock formations (limestone, anhydrite, dolomite). Spud muds are normally formulated with Sodium bentonite in fresh water with 8.5 to 10.5 pH. For salt water attapulgite or prehydrated bentonite is prepared with 10.5 to 11.5 pH. Lime can be used if flocculation of solids is desired for better hole cleaning. In gumbo areas, high-pH of 12.0 water or prehydrated bentonite can be mixed in pills to promote hole cleaning;

Polymer/Bentonite Muds. Polymer/bentonite systems are used primarily in areas where the formations to be drilled contain low reactive solids. The systems can tolerate low concentrations of calcium. Water containing calcium in excess of 100 mg/L should be pretreated with bicarbonate of soda to precipitate the calcium.

Extended Bentonite Muds. Extended bentonite systems contain chemicals that extend the yield of bentonite and impart the desired properties to the mud while maintaining minimum solids content, which in turn improves penetration rates. Depending on the application, there are many other chemicals that can be used to impart viscosity and filtration control, such as polyanionic cellulose, xanthum gum, and starch. It is important to note that this system cannot tolerate calcium. The polymer used for extending the bentonite precipitates in the presence of calcium, and any solids, including barite, settle from the system along with the polymer.

**Nondispersed-Inhibitive Systems.** The systems described below are classified in this manner because prehydrated sodium bentonite finds its own equilibrium. Chemical dispersants (thinners) are not added to the systems. Included in these systems are certain muds containing salt ions (NaCl and KCl) that inhibit drilled formation solids from swelling and breaking into smaller particles as they are transported to the surface. This makes it easier for the solids-control equipment to remove these particles.

Attapulgite-Starch-Salt Muds. Salt muds are used to improve borehole stability through the inhibiting effects of the salts present in the makeup water, to minimize hole washout, and to prevent drilled solids from disintegrating as they are transported to the surface. Attapulgite does not contribute to filtration control; instead, polymers and/or starches must be used for this purpose.

Saturated Salt Muds. Saturated salt muds are used to prevent solution cavities from occurring in salt domes and stringers when they are penetrated by the bit, and to minimize hole washout in salt or carbonate beds. Attapulgite should be used when filtration control is not required. When drilling other types of formations, sodium bentonite pre-mix (sodium bentonite prehydrated in fresh water) can be added to achieve a quality filter cake. To prevent the salt from dehydrating the sodium bentonite clay, a small amount of lignosulfonate can be added to the pre-mix solution prior to adding it to the mud system. However, this converts the system to a dispersed system.

Potassium Chloride-Polymer Muds. Potassium chloride (KCl)-polymer muds inhibit clay swelling in thin, moderately active clay formations. A low percentage of $K^+$ inhibits the swelling and disintegration of drilled solids, minimizes hole enlargement, and promotes borehole stability. KCl-polymer muds are used hard-rock type formations, e.g. limestone, dolomite, containing reactive clay stringers. They are not appropriate for gumbo-type shales.

**Dispersed-Noninhibitive Systems.** In dispersed-noninhibitive systems, chemical thinners are added to encapsulate the sodium bentonite and reactive drilled solids. The systems do not contain inhibitive electrolytes; therefore, the cuttings are free to disperse as they are transported to the surface.

Lignite-Lignosulfonate Muds. Lignite-lignosulfonate muds are probably the most versatile exploratory drilling fluids in use today. Their rheological properties are easily controlled with chemical thinners, and this reduces the risk of detrimental effects of contaminants, such as salt, anhydrite, and cement, that may be encountered during drilling. Chemical thinners and filtration-control agents are used to control the high temperature/high-pressure fluid loss. As mud density and temperatures increase, clays may be complemented with organic or inorganic polymers. In general, the lignosulfonate system is very stable, but it shows severe thermal degradation at temperatures of 350°F and above. One common approach to this problem is the gradual decrease in the use of lignosulfonate as formation temperatures approach 350°F and conversion to a lignite-surfactant system.

Phosphate-Bentonite Muds. Phosphate-treated muds with mud weights less than 12 ppg are used to drill shallow wells in which bottom hole temperatures will not exceed 150°F. The phosphates normally used in these systems have specific limitations; therefore, the system should not be exposed to chlorides in excess of 5,000 mg/L or calcium in excess of 100 mg/L. The calcium can be controlled with soda ash or bicarbonate of soda. Flocculation may occur at temperatures above 150°F due to phosphate reversion; therefore, the system should be used for shallow-hole drilling only.

**Dispersed-Inhibitive Systems.** Dispersed-inhibitive systems contain chemical dispersants to disperse clays and drilled solids, along with inhibiting ions to prevent the hydration and the dispersion of formation materials. The fluids do not contribute to the hydration and dispersion of formation clays, and the cuttings are held together for removal at the surface. Drilled solids have a minimal effect on rheological properties in inhibited systems due to the presence of inhibiting electrolytes (e.g. $Ca_2+$, K+, $CaSO_4$, surfactants). These electrolytes suppress the ability of clays to subdivide into numerous interacting particles, making it easy to maintain the fluid's rheological properties with low treatment concentrations.

Lime Muds. Common mud contaminants such as cement, anhydrite, and salt do not normally affect inhibitive fluids as dramatically as they do conventional dispersed, noninhibitive fluids. The problems caused by non-pressured heaving shales and tight hole conditions are more easily handled. In general, inhibited systems have lower viscosities (except in the high-density ranges) and low gel strengths. These fluids are used principally in the drilling of shales or clay formations. Lime muds perform well up to bottom hole temperatures of 250°F, at which point the fluid loss becomes difficult to control. This leads to dehydration of the system, and solidification can occur. In most cases the calcium-inhibited system is made from the native mud used to drill the surface hole. Downhole temperatures aid in converting the system to an inhibited (calcium-bentonite) system. This procedure is called a breakover. Normally, there is a short period of time during the breakover when the viscosity may become very high. This is the hump, which is caused by the clay flocculating and converting to a calcium clay.

Gyp-Lignosulfonate Muds. Gyp muds function as inhibited systems at lower alkalinities than lime muds, and they contain more soluble calcium (700 mg/L) than lime muds. Therefore, gyp muds are more inhibitive. Gyp muds are also generally more tolerant of contamination than lime muds, and they have a slightly higher temperature stability (275°F). The gyp mud is an inhibited system in which gypsum (calcium sulfate) is used as the source of inhibitive electrolyte. Gyp systems are similar to lime systems in that both exhibit inhibitive properties derived from soluble calcium, and both require a chemical dispersant (lignosulfonate). The reactivity of formation clays and the availability of calcium compounds in a given area are the main considerations when choosing a system.

Seawater-Prehydrated Bentonite Muds. The primary advantage of a seawater-prehydrated bentonite system is the easy availability of its source water. Using seawater eliminates the need to transport large quantities of fresh water to an offshore drilling location. Another advantage is that the moderate amount of soluble salts in seawater inhibits the hydration and dispersion of clays. Shipping fresh water offshore is very expensive, however, and requires extra space and storage facilities

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**Invert-Emulsion (Oil-Base) Systems.** Invert- emulsion systems are those in which oil is the continuous phase and the filtrate is all oil. The water in the formulation consists of tiny droplets that are dispersed or suspended in the oil medium. Each water droplet then acts as a solid. Emulsifiers are used to tie up or emulsify the water droplets and make the liquid system stable. The emulsifiers used in these systems, therefore, must have both a water-soluble and an oil-soluble nature. Other organophilic materials are used to provide gelation and filtration-control properties.

The inclusion of water in oil muds is beneficial for the following reasons:

•Economy: Water is cheaper than oil, and the substitution of water for oil usually reduces mud costs;

•Viscosity and Gelation: Because water acts as a solid in invert emulsions, it helps to increase mud viscosity. Moreover, the presence of water helps disperse the organophilic clays that are routinely used to provide gelation properties;

•Filtration Control: Because the water droplets act as small suspended solids in these systems, their presence helps to reduce mud filtration;

•Stabilization: The inclusion of water in the systems allows us to dissolve salts in the water phase to aid in stabilizing reactive clays and shales;

•Safety: The presence of water in an oil mud increases the flash and fire points of the fluid. When high temperatures on surface are encountered, the water begins to evaporate from the system, thereby helping to insulate the system from oxygen.

Invert-emulsion muds can be formulated using a wide variety of oils. Diesel oil and kerosene have been used worldwide in invert-emulsion systems. However, their use in environmentally sensitive areas has fallen dramatically. Mineral oils have replaced diesel oil and kerosene in environmentally sensitive areas of the world. Mineral oils contain a much smaller percentage of aromatics than diesel or kerosene, and thus are less toxic to marine life. There is a wide range in aromatic content in mineral oils marketed today. Crude oil can be used in oil muds; however, it has some drawbacks. For example, crude oil usually has a significant fraction of light ends, and thus exhibits low flash and fire points. Crude oil may need to be weathered prior to use. Also, crudes often contain significant amounts of asphaltenes that may present problems during drilling or completion operations, and may affect the performance of invert emulsion additives. The primary reason for using an invert-emulsion or oil-base drilling fluid is to attain borehole stability beyond that which can be achieved through optimizing drilling fluid density and proper pressure control. This additional stability may be crucial in highly deviated wells, where rock stress effects are too difficult to control with fluid density alone, and where hole intervals may be open (uncased) for longer periods of time. Also, the inert nature of the fluid prevents cuttings from hydrating and dispersing; therefore, they are easier for the solids-removal equipment to remove, and the need to dilute the fluid because of contamination by drilled solids is almost eliminated. These systems also make it easier to drill near-gauge holes. The high concentration of surfactants in the fluid and in the stable hole provide a high level of lubricity that reduces torque and generally improves drilling conditions. In particular drilling situations, invert-emulsion drilling fluids have several advantages over water-base muds. The nonpolar nature of the oil ensures a system that is generally insensitive to chemical contaminants such as salt, anhydrite, cement, carbon dioxide, and hydrogen sulfide, all of which affect water-base systems. Invert-emulsion drilling fluids have the ability to stabilize troublesome shales. A properly formulated and maintained fluid can drill pressured shale at a 0.2 to 0.4 ppg lower mud weight than would be required using a water-base mud. The oil and emulsifier film around each droplet of brine in an invert-emulsion mud serves as a semipermeable membrane across which Osmotic pressure may be generated. Unstable formations, which usually contain reactive smectite clays as a component of the shales, usually begin to react with the drilling fluid when they are penetrated. In order to drill these formations successfully, the rocks' demand for water must be controlled. The mechanisms of surface compaction and osmotic pressure generation, as they apply to both water-base and oil-base systems, allow us to better understand how to control formation reactivity. Over a period of millennia, overburden forces slowly squeeze water from deeply buried clays and shales. When these formations are penetrated, they want to take up enough water to allow them to return to their original condition. To understand the magnitude of these forces, we may examine the principles of overburden pressures and matrix stresses. A formation's pore pressure plus its matrix stress equals its overburden load. If we know the overburden (usually given as 1 psi per foot) and the formation pore pressure, we can calculate the matrix stress.

The greater a formation's matrix stress, the greater its demand for water absorption when the rock is exposed to a drilling fluid. With water-base fluids, this water absorption cannot be entirely eliminated. Filtration-control and inhibition agents can slow down but never stop, the rate of water absorption. With invert-emulsion systems, on the other hand, the dissolved salts in the fluids aqueous phase can control and even reverse the water absorption forces. Because water is dispersed in the continuous oil phase, its transfer to formation rock can be blocked by the presence of a semipermeable membrane furnished by the emulsion film around the water droplets.

Salts dissolved in the water phase generate osmotic forces that are usually great enough to allow removal of water from the formation, thereby stabilizing it. The generation of these osmotic pressures depends on the kind of salt used. For reasons of economy and its ability to generate sufficient osmotic pressure, calcium chloride is usually the preferred salt for use in invert emulsion muds. Sufficient quantities of calcium chloride mixed in the water phase of the inverted emulsion provide enough osmotic force to dehydrate water-wet formations. Hole problems are thereby reduced. Because shales are prevented from becoming water-wet and dispersing into the mud or caving into the hole, a closer-to-gauge hole can be drilled. The all-oil filtrate inhibits the swelling of formation clays and therefore does not reduce permeability. The invert-emulsion mud also prevents water blockage, which can be caused by the water filtrate of water-base muds. Invert emulsion drilling fluids have a natural resistance to high-temperature gelation. When properly treated with an emulsifier, viscosifier, suspension agent, and oil-mud stabilizer, a stable mud system can be formulated that is virtually unaffected by the high temperatures encountered in deep wells. Invert-emulsion muds also offer good fire resistance, with typical flash point in the range of 170º to 200º F. The external phase of an invert-emulsion system is unaffected during drilling of water-soluble formations such salt, potash, and gypsum. The all-oil filtrate, thin filter cake, and excellent lubricity coefficient of invert emulsion muds also aid in the prevention of differential sticking in highly permeable formations and in deviated holes. Drill pipe torque and drag are also reduced. The external phase of the invert-emulsion mud provides maximum drill pipe corrosion protection in the presence of contaminants such as oxygen, hydrogen sulfide, carbon dioxide, formation fluids, and organic acids. Invert emulsion muds are expensive when compared to water-base muds, because the liquid phase usually ranges from 65 percent to 98 percent oil. The remaining 2 percent to 35 percent is water with a high chloride content (usually calcium chloride), in concentrations up to saturation. Oil is maintained as the continuous phase through the use of emulsifiers and wetting agents, while the addition of organophilic clays provides the desired gelation and suspension properties. While initial makeup cost is high, maintenance is generally less expensive than for comparable water-base fluids. Also, the overall cost can be lower due to the fact that the fluid can be reused on future wells. Other factors contributing to lower costs include a decreased need for frequent replacement of shaker screens and pump parts, the ability to maintain less mud volume due to a gauge hole, reduced cement requirements, reduced fishing-job costs, longer bit and drill pipe life, fewer trips, and sometimes faster penetration rates. Invert emulsion muds use a blended emulsifier for "tying up" or emulsifying water in oil to form and maintain a stable oil/water emulsion. The primary emulsifier is the basic component of these systems, normally a mixture of high-molecular-weight sodium and calcium soaps. It is slow acting, and requires high shear for dispersion. An oil-dispersible organic colloid is used to control the filtration properties. It also aids in solids suspension and provides temperature stability. Although organophilic colloids aid in emulsification, they are primarily filtration-control agents, and require the presence of the primary emulsifier to function properly. The primary viscosifier for invert-emulsion muds has a bentonitic structure that develops gel strength, and is therefore referred to as a gel-forming organophilic clay. This clay needs a polar additive, such as water, to develop maximum yield. Organophilic clays add body and suspension properties even at very high temperatures. The principal effect of adding organophilic clays is an increase in yield point and gel strength, which makes them especially useful for improving carrying capacity in low-weight invert-emulsion muds. A surfactant often is used to alter the wetting properties of invert emulsion muds. The surfactant is both water and oil dispersible, and is used in low concentrations to prevent water-wetting of solids. It may also be used to reduce the viscosity when large quantities of solids have been incorporated into the mud.

The secondary emulsifier is a polyamide surfactant and emulsifier for oil muds. Its emulsification properties are not affected by the type or amount of electrolyte in the water phase, making it useful in preparing low- or no-solids muds by emulsifying dense salt solutions into oil. Such emulsions, however, have no filtration control and must be treated to reduce filtration. The secondary emulsifier also has the ability to impart increased temperature stability, is effective as an oil-wetting agent, and provides quick oil-wetting and emulsification, which might be required if a salt water flow is encountered.

## Solids Control in Oilfield Drilling

Laboratory tests and practical field experience have shown that closely monitoring drilled solids in the mud and minimizing their concentration can result in large savings of both money and time. These savings manifest in three ways, i.e. increased drilling rate, increased bit life, and increased life of mud-pump parts. The key to solids control is minimizing the concentration of undesirable drilled solids. Formation pressures dictate the amounts of weighting agents, e.g. barite, calcium carbonate, that must be present in the mud; these types of solids are necessary and are not considered in this discussion. Undesirable solids are those that become incorporated in the mud during the drilling process e.g., salt, carbonates, and clays. The accumulation of these types of solids can cause mud property problems e.g. increases in viscosity and rheology, buildup of mud weight, etc. that in turn decrease the drilling rate, bit life, and the life of mud pump parts. Although small amounts of drilled solids incorporated into a drilling fluid are not generally considered detrimental, serious problems can develop if these particles are continually recirculated. Removal and treatment of drilled solids constitute the major portion of drilling fluid expense. Solids may be classified, as follows, by their particle size, expressed in microns.

Coarse Particles greater than 2,000 microns

Intermediate Particles from 250 to 2,000 microns

Medium Particles from 75 to 249 microns

Fine Particles from 45 to 74 microns

Ultra fine Particles from 2 to 44 microns

Collodial Particles less than 2 microns

**Principles of Solids Removal**

The mechanisms of separation of solids from liquids can be classified according to the nature of the forces that cause the separation.

• External forces are caused by external fields of acceleration, such as gravity, electrostatic, and magnetic fields.

• Internal forces occur within the fluid itself e.g., inertia, diffusion, electrostatic field of charged particles, thermophoresis, and diffusiophoresis.

• No force is a screening principle; filtration can also be regarded as an extreme case of screening. Screening.

Screening is a method of sorting particles according to their size. The solids are brought into contact with a screening surface that acts as a stop-go gauge. The undersize, or "fines, " pass through the screen openings; the oversize, or "coarse," do not. Woven wire screens are often referred to by their mesh number that is, the number of wires per linear inch. The 75 micrometer screen is 200 mesh screen having a wire thickness of about 50 micrometers and an open area of approximately 36 percent. The smallest mesh used in industrial screens is about 160 mesh. With finer mesh sizes, other methods of separation are usually more economical. Screens that vibrate rapidly with small amplitudes are less likely to blind than gyrating screens. In an ideal situation, complete solids separation is achieved at the cut point. In actual operation, the screen mesh size is usually chosen so that a balance is achieved between the capacity and the effectiveness of the screen. Effectiveness may be defined as the percentage of recovery of fines or of coarse solids, or a combination of the two. Capacity and effectiveness are opposing factors; increasing the former leads to a decrease in the latter. Granular materials are the easiest to screen; however, the effectiveness falls off with acicular particles, which only pass through the screen in certain orientations and tend to blind the screen. Cohesive materials also inhibit screening. Particle-size distribution also is important, because narrowly classified particles are more difficult to screen than particles of a wide size range. Screens are usually the first piece of equipment used in the removal of drilled solids. Screens may remove as much as 100 percent of the drilled solids, or as little as 10 percent, depending upon the following conditions:

• bit type (e.g., conventional or diamond, short-tooth or long-tooth);

• bit size (smaller bits make smaller cuttings);

• type of drilling fluid (oil muds tend to keep the cuttings intact and water tends to finely disperse the cuttings);

• resident time of cutting in the annulus;

• mesh size of shaker screens;

• formation type.

Reduction of screen size greatly improves solids removal. The efficiency of screening devices is influenced by such factors as the fluid's properties, the particle size of the solids to be removed, and the work input of the screen on the fluid.

Fluid Properties. A shear thinning fluid is the best fluid for the proper separation of drilled solids and mud. As the mud/cuttings are pounded, the high shear rates encountered allow for fast and efficient solids separation.

Particle Size. As the particle size of the solid approaches the screen size, the effective flow area is reduced and the screen tends to blind. If the solid particles are larger than the screen size, the fluid flows around the particles and then through the screen.

Centrifugal Sedimentation-Hydrocyclone. The basic separation principle employed in hydrocyclones is centrifugal sedimentation; i.e., the suspended particles are subjected to centrifugal acceleration, which makes them separate from the fluid. Unlike centrifuges, hydrocyclones have no moving parts and the necessary vortex motion is performed by the fluid itself. The flow pattern in a hydrocyclone has circular symmetry, with the exception of the region in and just after the tangential inlet duct. The velocity of flow at any point within the hydrocyclone can be resolved into three components: the tangential velocity, radial velocity, and vertical velocity. These can be investigated separately. A particle at any point within the flow in a hydrocyclone is basically subjected to two forces: one force created by both external and internal fields of acceleration (gravity and centrifugal forces), and the other force created by drag exerted on the particle by the flow. The gravity effect is normally negligible in a hydrocyclone; therefore, only centrifugal and drag forces are taken into account. The movement of the particle in both tangential and vertical (axial) directions is unopposed by any force, so that the velocity components can be considered equal to the corresponding flow components. Since the centrifugal force acts in the radial direction, it prevents the particles from following the inward radial flow. If the centrifugal force acting on a particle exceeds the drag, the particles move radically outward; if the drag is greater, the particles are carried inward. Hydrocyclone performance is particle concentration sensitive. The lower the inlet concentration, the closer the performance is to the theoretical. The separation efficiency of hydrocyclones depends on four general factors, namely fluid properties, particle properties, flow parameters, and hydrocyclone parameters. The fluid properties that affect the separation efficiency of a hydrocyclone are viscosity and density. The particle properties affecting hydrocyclone separation are density, and diameter or size. The flow parameters affecting hydrocyclone efficiency are flow rate, tangential velocity, and pressure drop across the hydrocyclone. The hydrocyclone parameters affecting the separation efficiency are too interrelated to be presented in a simple form. However, three parameters of special concern are the diameter of the hydrocyclone (maximum diameter of the cone), the diameter of the inlet, and the cone angle. The use of hydrocyclone centrifuges in the processing of weighted muds has been very limited during the past few years. One reason is that it requires high water dilution, which quickly strips the system of colloidal materials and results in a higher cut point.

Centrifuges. Decanting centrifuges create centrifugal force by a rotating horizontal conical bowl with an internal conveyor turning at a slightly different speed. The conveyor removes the settled solids, allowing continuous processing of the fluid. For efficient separation, dilute suspensions are needed. As the solids concentration increases, particle interference (hindered settling) occurs and reduces the settling rates

**Solids Control Techniques.** Treatment of muds that exhibit solids-related problems can involve any or all of the following:

**Settling.** Solids removal by the settling method involves retaining mud in a nearly quiescent state long enough to allow the undissolved solids, which are heavier than water, to "fall out" of the fluid. The relative success of this method depends on several factors, i.e. size and shape of the particles, density of the particles, density of the fluid, the overall retention time. The speed of settling can be increased by use of flocculant to increase the particle size, or by inducing centrifugal force to increase the gravitational effect.

**Dilution.** Dilution is most often used as a means of correcting mud properties that have been altered by the accumulation of drilled solids. By this method, the solids are not removed but their concentration is decreased. Since solids continue to build up in the mud as drilling progresses, the problems in mud weight, rheology, etc. usually reappear. Dilution is often expensive for the following reasons:

•The consumption of the products required to maintain desired mud properties increases;

•Lack of storage space for the increased mud volume often leads to the discarding of hundreds of barrels of valuable drilling mud;

•Extra cleanup and transportation costs are incurred in environmentally sensitive areas.

Mechanical Separation. Mechanical separation devices are available in two basic types: vibrating screening devices (shakers) and systems that use centrifugal force to increase settling rate. Mechanical treatment of solids buildup is often the most practical and cost effective of the four available methods; it does not alter essential mud properties and it decreases the need for dilution. Generally speaking, the greater the cost per barrel of a given mud, the greater the savings in using mechanical equipment to rectify mud properties. The equipment used to mechanically remove solids from the mud must be designed to fit the requirements of a given drilling operation; not every piece of equipment is appropriate in every situation. Furthermore, the equipment specifically selected to aid in mechanical removal of solids must be rigged up and maintained to ensure that the units operate at peak performance.

Solids removal equipment systems can consist of any of the following devices:

• Shale shaker can remove solids down to 150 microns with 200 mesh screens;

• Desander/desilter Depending on size of cone, can remove 50 to 70 micron solids;

• Mud cleaner Dual purpose (desilter over fine-screen shaker); can remove solids down to 75 microns and recover some barite;

• Centrifuge Can remove collodial solids down to about 2 to 5 microns.

Shale Shakers. Various high-speed shakers are available from different companies. The double-decker shale shaker has two screens mounted on a flat-bed construction. The screens can range down to 100 mesh with the mesh cross section varying from square to an exaggerated rectangle. A common combination of mesh sizes used is 30 mesh screen on the upper deck and 80 mesh screen on the lower deck, as the working life of very fine mesh screens is quite short. Drilled solids down to 177 microns are removed by 80 mesh screens, and 840 micron size particles by 20 mesh screens.

Desilters and Desanders. The selection of desilters and desanders for a particular job should be based on their ability to handle the anticipated volume of drilled solids at the fastest anticipated drilling rate. The desilters/desanders must be equipped with centrifugal pumps capable of providing sufficient pressure to the hydrocyclones to allow them to operate in the desired pressure range. In order to obtain the desired results from desanders and desilters, the following points must be observed:

• correct installation of the desilter/desander banks;

• provision of the correctly sized centrifugal pumps;

• operation of the hydrocyclone in the design pressure ranges;

• removal of large-particle-size solids upstream of the hydrocyclone bank, to minimize plugging of cones;
• regular inspection and replacement of cones.

When desanders and desilters are used with coarse-screen shakers, plugging of cones often occurs in the fast-drilling tophole sections, particularly when drilling formations containing plastic shales. Desilters and desanders are used for solids removal in unweighted mud systems having mud weights up to 11 ppg. Barite is ejected with the fine solids; therefore, desilters cannot be used in weighted mud systems, i.e., in systems with densities of 11 ppg or greater. Desilters and desanders should be used as early as possible during drilling with unweighted fluids so that the maximum amount of drilled solids can be mechanically removed on the first circulation. While making a trip, the mud in the pits can be circulated through the desilting equipment to remove the fine drilled solids. In general, the use of a centrifuge cannot be economically justified for mud weights under 14 ppg.

Mud Cleaner. The mud cleaner is designed for intermediate mud weight ranges of 11 to 14 ppg. It consists of an eight-cone desilter bank mounted over a small high-speed shaker. The mud cleaner combines the advantages of solids separation by means of centrifugal force and solids removal by screening. The first stage in the operation is the processing of the mud through the desilter bank. The overflow is returned to the circulating system and the underflow is discharged onto the vibrating shaker screen. This permits the recovery of the liquid phase, and most of the barite present in the underflow and the remainder of the solids are discarded. The screen sizes vary, but the size most commonly used is 200 mesh, which can remove fines down to 75 microns in size. It is impractical to use screen sizes much below 200 mesh because of excessive loss of barite over the shaker screen.

Centrifuge. In weighted mud systems it is often desirable to reduce mud maintenance costs by methods other than dilution. Since it is not practical to use desilting equipment in these systems, a centrifuge is often used. Mud centrifuges work on the decanting principle. The mud flow enters a chamber rotating at a high speed, and centrifugal force separates the mud stream into three components: fluid phase, low-specific-gravity solids, and high-specific-gravity solids.

Most centrifuges consist of three units: centrifuge, control panel, and power unit. Each unit usually is mounted on a separate skid, though in practice the centrifuge and control panel may be mounted together on a large combination skid. The control panel is equipped with flow-raters for mud and dilution water, and a tachometer to show the revolutions per minute of the decanting centrifuge. It is important that the mud and water throughput and the number of revolutions per minute of the centrifuge are kept in the correct operating ranges since the efficiency of solids removal depends directly on both of these factors. In unweighted mud systems, a high-volume decanting centrifuge removes low-specific-gravity drilled solids most efficiently and economically. The centrifuge can be operated on unweighted muds at speeds up to 2,200 to 2,400 rpm. The high-volume centrifuge can remove fine solids down to two microns, e.g. bentonite and clays.

**Chemical Treatment.** Chemical treatment involves the use of flocculants to drop unwanted solids out of the mud. This type of treatment is not recommended for use with many mud systems, however, because it may adversely affect mud properties.

# CASING

## Introduction

When establishing an oil and gas well, it is not enough just to drill a hole from the surface down to the hydrocarbon layers. The hole must be cased with thin-walled steel pipes, called casing, that are cemented to the formation. Casing is made by either a seamless manufacturing process, i.e. a steel billet being pierced and worked to the required dimension, or an electric welding process, i.e. flash or resistance welding, not involving the addition of weld metal to the seam. After forming the pipe is annealed and tempered to meet the metallurgical and strength requirements for the grade involved. The casings themselves fulfill multiple functions that can be summarized as:

- Prevent the hole from being washed out in weak formations or caving in,
- Protect weak formations from the high mud weight that may be required in subsequent hole sections. These high mud weights may fracture the weaker zones resulting in lost circulation;
- Seal off the lost circulation zones;
- Isolate zones with abnormally high pore pressure from deeper zones which may be normally pressured;
- Prevent near surface fresh water zones from contamination with drilling mud;
- Isolate porous formations with different fluid-pressure regimes from contaminating the pay zones;
- Provide a connection and support of the wellhead equipment and BOPs;
- Make the installation of completion equipment that is necessary to achieve an effective production (seals, pumps etc.);
- Be an alternative to drill sting.

## Types of Casing

Casings are named after the different tasks they have to perform. The types of casing currently in use are as follows.

**Conductor casing.** The conductor is the first casing string to be run, and consequently has the largest diameter. The normal size range for conductor pipe is from 16 to 36 inches of outside diameter. The conductor pipe must be large enough to allow the other casing strings to be run through it. The setting depth can vary from 10 feet to around 300 feet below the ground level or seabed. Purposes of conductor pipe are to prevent washouts in the near surface, normally unconsolidated formations and enable circulation of the drilling fluid to the shale shaker. The conductor casing also protects the subsequent casing strings from corrosion and may be used to support some of the well load structurally. Commonly a diverter is installed on top of the conductor casing to divert an unexpected inflow of formation fluids into the wellbore away from the rig-site and the personal.

**Surface casing.** The surface casing is run after the conductor and is generally set at approximately 300 – 1,500 feet below the ground level or the seabed, their diameters range from 24 to 13 3/8 inch. The function of the surface casing is to prevent cave in of unconsolidated, weak near-surface formations as well as protect the shallow, freshwater sands from contamination with drilling mud. Before the surface casing is set, no blow out preventers are installed. After setting the surface casing and installing the wellhead, a BOP is available to handle kicks when drilling the intermediate hole section. The setting depth of this casing string is chosen such that troublesome formations, thief zones, water sands, shallow hydrocarbon zones, and buildup sections of deviated wells may be protected. The setting depth of this casing string is important in an area where abnormally high pressures are expected. The surface casing should reach down to a formation that is sufficiently strong to hold the pressure from drilling mud with sufficient density to control the formation pressure down the next casing setting depths.

**Intermediate casing.** Intermediate casing strings are used to isolate troublesome formations between the surface casing setting depth and the production casing setting depth. The types of problems encountered in this interval include: unstable shales, lost circulation zones, abnormally pressured zones and squeezing salts. Intermediate casing is often referred to as "protective" or "drilling" casing. The number of intermediate casing strings will depend on the number of such problems encountered. The intermediate casing string is a purely technical casing and may also be necessary to realize the planned mud weight profile. The size of intermediate casing, will depend on the size of the surface casing, normally are between 9 5/8 and 13 3/8 inch. Good cementation of this casing must be ensured, to prevent communication behind the casing between the lower hydrocarbon zones and upper water formations. Multi-stage cementing may be used to cement long strings of intermediate casing.

**Production casing.** Production casing is usually the last full string of pipe set in a well. This casing string is run to isolate producing formations and provide for selective production in multi-zone production areas. The production casing should form a sealed connection between the reservoir and wellhead, and protect the production equipment against pollution from outside, and making possible to control the well, when the production assembly is retrieved from workover. It may also be exposed to injection pressures from fracture jobs, gas lift, or the injection of inhibitor oil. A good primary cement job is very critical for this casing. Commonly production casing has gas-tight connections, its outside diameter ranges from 9 5/8 to 5 inch.

**Liner.** A liner is a string of casing that does not reach the surface but is suspended from the bottom of the previous larger casing by a device known as a liner hanger. The liner hanger consists of a collar which has hydraulically or mechanically set slips which, when activated, grip the inside of the previous string of casing. These slips support the weight of the liner and therefore the liner does not have to extend back up to the wellhead. Commonly the liner lap is a few hundred feet into the previous casing to enable a good cement seal. The major advantage of a liner is the cost of the string is reduced as well as running and cementing times. A liner can be used either as an intermediate casing or as a production casing. In deeper well, liner is used to reduce the tensional loading where there are limitations to the rig strength and wellhead tensional loads. Liner may also be used as a patch over existing casing for repairing damaged casing or for extra protection against corrosion.

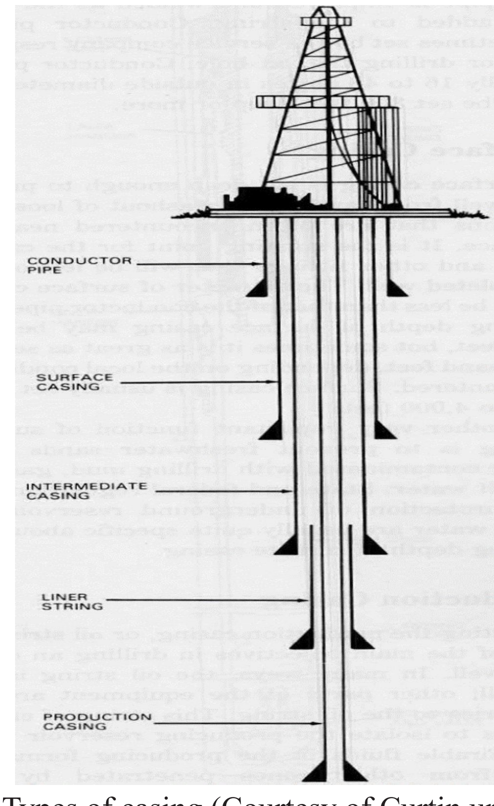


Fig 64: Types of casing (Courtesy of Curtin university)

## Casing Classification

Casing joints are manufactured in a wide variety of sizes, weights and material grades and a number of different types of connection are available. American Petroleum Institute (API) has developed standards for casing and other tubular goods that have been accepted internationally by the petroleum-producing industry. Casing is generally classified, in manufacturer's catalogues and handbooks, in terms of its size (outside diameter), steel grade, unit weight, connection type and length range. API has adopted a casing "grade" designation to define the strength of casing steels. This designation consists of a grade letter followed by a number, which designates the minimum yield strength of the steel in thousands of psi. The letter serves to indicate roughly the type of steel and is selected arbitrarily to provide a unique designation for each grade of casing. The letter designation is also used to distinguish between various tensile-strength requirements or different heat-treatment methods used on casing with the same minimum yield strength. There are many proprietary steel grades that do not conform to all API specification but are widely used in the industry. The more usually encountered API grades of casing are as follows:

H-40 A low grade casing of minimum yield strength of 40,000 psi suitable only for surface casing and light duty

J-55 A good quality steel casing with minimum yield strength of 55,000 psi and ultimate tensile strength of 75,000 psi. This has been more frequent encountered in oilfields than almost any other grade. However, it is now largely being superseded by the next grade.

K-55 A fairly high quality steel with minimum yield strength of 55,000 psi but with an ultimate tensile strength of 95,000 psi.

C-75 A steel of controlled strength and hardness, with a minimum yield strength of 75,000 psi. The steel is designed for use in moderately corrosive conditions. It will usually require special order and is more expensive than others.

N-80 A high quality steel, with minimum yield strength of 80,000 psi. This is the industry standard for medium deep, moderately high pressure service, and it is widespread use. It is hard alloy steel, and is not suitable for some conditions of corrosive service, when the "C" grade may be preferred.

L-80 Differs from N-80 casing only in the guaranteed hardness of the steel. It is therefore suitable for slightly sour environments, where the hardness of standard N-80 casing might cause a problem with embrittlement.

C-95 Similar in metallurgy and heat treatment to the C-75 grade, it is suitable for fairly deep, high pressure service in moderately corrosive conditions.

P-110 A very high strength steel for deep well, high pressure conditions. Although a standard API grade, it is likely to be a special order and extremely expensive.

V-150 Only used for the deepest wells and extremely high pressure conditions.

For each casing size there are a range of casing weights available. The nominal weight is based on the theoretical calculated weight per foot for a 20 feet length of threaded and coupled casing joint. The weight of the casing is a representation of the wall thickness of the pipe. Although there are strict tolerances on the dimensions of casing, set out by the API, the actual ID of the casing will vary slightly in the manufacturing process. For this reason, the drift diameter of casing is quoted in the specifications for all casing. The drift diameter refers to the guaranteed minimum ID of the casing. This may be important when deciding whether certain drilling or completion tools will be able to pass through the casing.

Individual joints of casing are connected together by a threaded connection. These connections are variously classified as: API; premium; gastight; and metal-to-metal seal. In the case of API connections, the casing joints are threaded externally at either end and each joint is connected to the next joint by a coupling which is threaded internally. Couplings are short pieces of casing used to connect the individual joints. They are normally made of the same grade of steel as the casing. The connection must be leak proof but can have a higher or lower physical strength than the main body of the casing joint. A coupling is already installed on one end of each joint when the casing is delivered to the rig. The API has specifications for four types of couplings, namely short round threads and couplings (CSG), long round threads and couplings (LCSG), buttress threads and couplings (BCSG), and extremeline threads (XCSG). The CSG and LCSG have the same basic thread design. The threads have a rounded shape, with eight threads per inch. These threads are generally referred to as API 8-round. The only difference between the two is that the LCSG has a longer thread run-out, which offers more strength for the connection. Buttress (BCSG) threads are more square, with five threads per inch. They are also longer couplings, with corresponding longer thread run-out. The extremeline couplings are different from the other three connectors in that they are integral connectors, meaning the coupling has both box and pin ends. In addition to API connections, various manufacturers have developed and patented their own connections, e.g. Hydril, VAM). These connections are designed to contain high pressure gas and are often called gastight, premium and metal-to-metal seal connections. These connections are termed metal-to-metal seal because they have a specific surface machined into both the pin and box of the connection which are brought together and subjected to stress when the connection is made up.

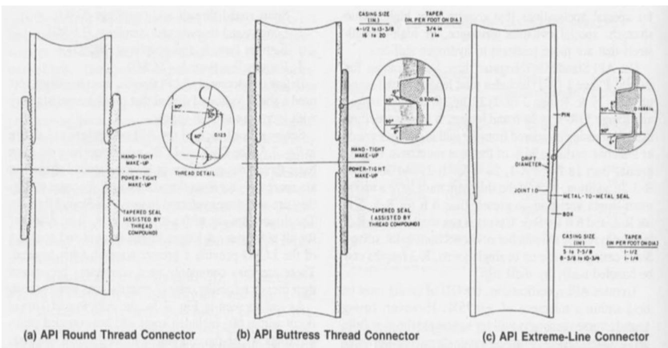


Fig 65: Thread connections (Bourgoyne et al. 1986)

The API standard recognizes three length ranges for casing. Range 1 (R1) includes joint lengths from 16 to 25 feet. Range 2 (R2) covers the 25 to 34 feet range, and Range 3 (R3) the 34 to 48 feet range. Casing is run most often in R3 lengths to reduce the number of connections in the string. Because casing is made up in single joints, R3 lengths can be handled easily by most rigs. Use of a consistent range of casing lengths in a string is desirable to facilitate casing-running operations.

## Casing Design

The selection of the number of casing strings and their respective setting depths generally is based on a consideration of pore pressure gradients and fracture gradients of the formations to be penetrated. Other factors - such as the protection of fresh water aquifers, the presence of vugular lost-circulation zones, depleted low-pressure zones, salt beds that tend to flow plastically and to close the borehole, and government regulations – also can affect casing setting depth requirements. In general, the casing setting depths calculation starts at the bottom of the well with the minimum required hole seize. After determination of the hole seize to drill and applying the corresponding mud weight, a kick is assumed and it is calculated where, when the kick is circulated out, the pressure of the kick would fracture the formation. This is the highest depth the previous casing could be set to handle the assumed kick. Having the setting depth of the previous casing, the proper corresponding hole size is determined. From here on, the same procedure is applied to find the next casing setting depth and so on until the depth of the surface casing is reached. The formations to be drilled themselves are also influencing the casing setting depths determinations. It is often required to seal off a porous formation before drilling deeper, or to isolate various sensitive formations like salt. As common practice a casing is normally set into a competent shale formation. Once the length and outside diameter of casing string is established, the weight, grade, and couplings used in each string can be determined. In general, each casing string is designed to withstand the most severe loading conditions anticipated during casing placement and the life of the well. The casing design is usually based on an assumed loading condition. The assumed design load must be severe enough that there is a very low probability of a more severe situation actually occurring and causing casing failure. The loading conditions that are always considered are burst, collapse, and tension. When appropriate, other loading conditions, e.g. bending or buckling, must also be considered as well as the effects of casing wear and corrosion should be included in the design criteria. These effects tend to reduce the casing thickness and greatly increase the stresses where they occur. Most classic design methods never permitted a material to be loaded beyond its design rating, which could be based on a material's yield strength or failure strength. A safety factor is the margin of safety between an applied load and the design rating. A design factor is the minimum safety factor allowed for a particular load; thus, it limits the load that can be safely applied. Design factors are usually based on experience and account for uncertainties in the loads and in the strength or resistance of a tubular. The loads to which the casing will be exposed during the life of the well will depend on the operations to be conducted: whilst running the casing; drilling the subsequent hole section; and during the producing life of the well. Since the operations conducted inside any particular string, e.g. surface casing will differ from those inside the other string, e.g. production casing the load scenarios and consequent loads will be specific to a particular string. The definition of the operational scenarios to be considered is one of the most important steps in the casing design process and they will therefore generally be established as a company policy.

# CEMENTING

## Introduction

Cement is used in the drilling operation to protect and support the casing, prevent the movement of fluid through the annular space outside the casing, stop the movement of the fluid into the annular or fractured formations, support for the well bore wall in conjunction with the casing to prevent the collapse of formations, and close an abandoned portion of the well. Cementing an oil or gas well comprises the displacement of cement slurry down the drill string, tubing or casing to a predefined section of the annulus of the well. Subsequently, cement slurry becomes hardened that exhibits favorable strength characteristics. The two principal functions of the cementing process are to restrict fluid movement between the formations and to bond and support the casing. It is essential to achieve a good bond between cement and casing and between cement and formation. In addition, cement also aids in protecting the casing from corrosive fluids in the formations, protecting the casing from shock loads in deeper drilling, preventing shattering when perforating, sealing off zones of lost circulation or thief zones, and preventing blowouts by quickly forming a seal.

## Cement

Almost all drilling cements are made of Portland cement, a mixture of burning a blend of limestone and clay. This name comes from the solid mixture resembling the rocks quarried on the Isle of Portland, off the coast of England. Cement is made of limestone (or other materials high in calcium carbonate content), clay or shale, some iron and aluminum oxides if they are not present in sufficient quantity in the clay or shale. These dry materials are finely ground and mixed thoroughly in the correct proportions. This raw mixture is then fed into the rotary kiln that is fired to temperatures of 2,600 to 3,000 °F. These temperatures cause certain chemical reactions to occur between the ingredients of the raw mixture with the resulting material called clinker. After it cools, the clinker is pulverized and blended with a small amount of gypsum (1.5 to 3.0 percent by weight) to control the setting time of the finished cement. The clinker is ground to form the product "Portland Cement" that we use in almost all drilling cements. The principle compounds resulting from the burning process are Tricalcium Silicate (C3S), Dicalcium Silicate (C2S), Tricalcium Aluminate (C3A), and Tetracalcium Aluminoferrite(C4AF). The hydration reaction is exothermic and generates a considerable quantity of heat. Portland cements are usually manufactured to meet certain chemical and physical standards that depend upon their application. In some cases, additional or corrective components must be added to produce the optimum compositions. Examples of such additives are sand, siliceous loams, pozzolans, diatomaceous earth (DE), iron pyrites, and alumina. These materials are in an anhydrous form. When water is added, they convert to their hydrous form, which is then called a "cement slurry".

The American Petroleum Institute (API) has established a classification system for the various types of cements, which must meet specified chemical and physical requirements. API has defined eight standard classes for oil well cements designated Class A to Class H. Each of these cement powders have different properties when mixed with water. The difference in properties produced by the cement powders is caused by the differences in the distribution of the four principle compounds which are used to make cement powder. The chemical and physical requirements for the various types and classes are given in API Spec. 10A. The majority of oil well cements are Class G and Class H.

**Class A:** Intended depth range for usage: surface to 6,000 feet, when special properties are not required, available in ordinary type only. The primary use in well cementing is for surface pipe, or other applications of low temperatures and pressure.

**Class B:** Intended depth range for usage: surface to 6,000 feet, when conditions require moderate to high sulfate-resistance, available as moderate and high sulfate-resistance types. Class B is similar to Class A, but it contains less C3A and is generally ground more coarsely. This causes longer thickening times and slower strength development than Class A.

**Class C:** Intended depth range for usage: surface to 6,000 feet, when condition require high early strength, available in ordinary, moderate and high sulfate-resistance types. Through iron modification, all are produced free of C3A which is the cement constituent attacked by the sulfate ion and whose absence renders cement highly sulfate resistance.

**Class D:** Intended depth range for usage: 6,000 to 10,000 feet, at moderately high temperatures and pressures conditions, available in moderate and high sulfate-resistance types. This cement is classified as one of the manufactured slow-set cements and is no longer generally available. Class D cement has been replaced by Class G and Class H cements for most applications.

**Class E:** Intended depth range for usage: 10,000 to 14,000 feet, at high temperature and pressure conditions, available in moderate and high sulfate-resistance types. This cement is also classified as one of the manufactured slow-set cements and is not generally available. Lignosulfonate retarders are commonly used in the manufacture of Class E cements. Class E cement has been replaced by Class G and Class H cements.

**Class F:** Intended depth range for usage: 10,000 to 16,000 feet, at extremely high temperature and pressure conditions, available in moderate and high sulfate-resistance types. This cement is also classified as one of the manufactured slow-set cements and lignosulfonate retarders are used in its manufacture. Class F cement was used primarily in overseas markets but it has been largely replaced by Class G and Class H cements.

**Class G:** Intended as basic cement in the depth range: surface to 8,000 feet, when used with accelerators and retarders covers wide range of temperatures and pressures, no other additions than calcium sulfate, water or both are to be blended with the clinker, available in moderate and high sulfate-resistance types. When modified with additives, this cement can be used for most well applications both shallow and deep. This cement is manufactured under stringent requirements for chemical content and physical performance tests.

**Class H:** Intended as basic cement in the depth range: surface to 8,000 feet, when used with accelerators and retarders covers wide range of temperatures and pressures, no other additions than calcium sulfate, water or both are to be blended with the clinker, available in moderate sulfate-resistance type only. When modified with additives, this cement can also be used for most well applications both shallow and deep.

The majority of oil well cements are Class G and Class H. Class G and Class H cements are both manufactured to the same chemical and physical requirements. The only difference is in the grind. Class H is ground more coarsely than Class G and, therefore, requires less mixing water, resulting in a higher slurry density. The purpose of the development of these two classes of cement was to provide basic (neat) cements without additives, which would not vary in composition among manufacturers. They would be standard products that could be interchanged in various slurries.

Nonstandard cements are often used for special applications and do not fall into any specific API classification. Some of these cements are dry blends of API cements and additives for well applications in primary or remedial cementing operations. Some of these cements that are commonly used are

**Pozzolan-Portland Cements.** Pozzolanic materials are often dry blended with Portland cements to produce "lightweight" (low-density) slurries for well cementing applications. Pozzolanic materials include any natural or industrial siliceous or silica-aluminous material, which, though not cementitious in itself, will combine with lime in the presence of water at ambient temperatures to produce strength-developing insoluble compounds similar to those formed from hydration of Portland cement. Pozmix cement is formed by mixing Portland cement with ground volcanic ash and 2 percent bentonite. This is a very lightweight but durable cement. It is less expensive than most other types of cement and due to its light weight is often used for shallow well casing cementation operations.

**Gypsum Cements.** Gypsum cement is a blended cement composed of API Class A, C, G, or H cement and the hemihydrate form of gypsum. In practice, the term "gypsum cements" normally indicates blends containing 20 percent or more gypsum. Gypsum cements are commonly used in low-temperature applications for primary casing or remedial cementing work. This combination is particularly useful in shallow wells to minimize fallback after placement. The unique properties of gypsum cement are its capacity to set rapidly, its high early strength, and its positive expansion. A limitation of gypsum cements is that they are not stable in contact with external water sources, including corrosive formation waters.

**Microfine Cements.** Microfine cements are composed of very finely ground sulfate-resisting Portland cements, Portland cement blends with ground granulated blast-furnace slag, and alkali-activated ground granulated blast-furnace slag. The blends of Portland cement and ground granulated blast furnace slag cement are equivalent to a finely ground pozzolanic cement, resulting in a faster hydration reaction. Applications for such cements are in consolidation of unsound formations and in repairing casing leaks in squeeze operations, particularly "tight" leaks that are inaccessible to conventional cement slurries because of their penetrability.

**Expanding Cements.** Expansive cements are available for the primary purpose of improving the bond of cement to pipe and formation. If expansion is properly restrained, its magnitude will be reduced and a pre-stress will develop. Expansion can also be used to compensate for the effects of shrinkage in normal Portland cement.

**Latex Cement.** Latex cement, is actually a blend of API Class A, G, or H with latex. In general, a latex emulsion contains only 50 percent latex by weight of solids and is usually stabilized by an emulsifying surface-active agent. Latexes impart elasticity to the set cement and improve the bonding strength and filtration control of the cement slurry. Latex in powdered form can be dry-blended with the cement before it is transported to the wellsite and is not susceptible to freezing.

**Resin or Plastic Cements.** Resin and plastic cements are specialty materials used for selectively plugging open holes, squeezing perforations, and cementing waste disposal wells, especially in highly aggressive, acidic environments. They are usually mixtures of water, liquid resins, and a catalyst blended with an API Class A, B, G, or H cement. A unique property of these cements is their capability to be squeezed under applied pressure into a permeable zone to form a seal within the formation. These specialty cements are used in wells in relatively small volumes.

## Cement Slurry

The water which is used to make up the cement slurry is known as the mixwater. The amounts of mixwater used to make up the cement slurry are based on need to have a slurry that is easily pumped, need to hydrate all of the cement powder so that a high quality hardened cement is produced, and need to ensure that all of the free water is used to hydrate the cement powder and that no free water is present in the hardened cement. The amount of mixwater is carefully controlled to meet the specific temperature and pressure conditions which will be experienced during the cement job. If too much mixwater is used the cement will not set into a strong, impermeable cement barrier. The properties of a specific cement slurry will depend on the particular reason for using the cement, however, there are fundamental properties which must be considered when designing any cement slurry.

**Slurry Density.** The density of the cement slurry must be high enough to prevent the higher-pressured formations from flowing into the well during cementing operations, yet not so high as to cause fracture of the weaker formations. It is generally the case that cement slurries generally have a much higher density than the drilling fluids which are being used to drill the well. The density can be altered by changing the amount of mixwater or using additives to the cement slurry.
Thickening Time. The length of time the cement slurry is pumpable is also called “thickening time”. The slurry should have sufficient thickening time to allow it to be mixed, pumped into the casing, and displaced by drilling fluid until it is in the required place. It also allows enough time for any delays and interruptions in the cementing operation. Wellbore conditions have a significant effect on thickening time. An increase in temperature, pressure or fluid loss will each reduce the thickening time and these conditions will be simulated when the cement slurry is being formulated and tested in the laboratory before the operation is performed.

**Compressive Strength.** To hold the casing in place, enable support capability of the surface wellhead equipment and withstand the differential pressures across the cement-formation interface, the compressive strength of the set and hardened cement has to be high enough. As general practice, 500 psi of compressive strength has to be developed by the hardening cement before any other downhole operation commences. The time it takes the cement to reach this minimum compressive strength is often referenced as “wait on cement” (WOC). The development of compressive strength is a function of several variables, such as: temperature; pressure; amount of mixwater added; and elapsed time since mixing.

**Water Loss.** The slurry setting process is the result of the cement powder being hydrated by the mixwater. If water is lost from the cement slurry before it reaches its intended position in the annulus its pumpability will decrease and water sensitive formations may be adversely affected. The amount of water loss that can be tolerated depends on the type of cement job and the cement slurry formulation. The amount of fluid loss from a particular slurry should be determined from laboratory tests.

To better fit the individual well requirements, the properties of the cement slurry and hardened cement have to be adjusted. Therefore, certain cement additives are mixed into the slurry. The additives can be used according to their functionality such as to vary the slurry density, change the compressive strength, accelerate or retard the setting time, control filtration and fluid loss, and reduce slurry viscosity. Additives may be delivered to the rig in granular or liquid form and may be blended with the cement powder or added to the mixwater before the slurry is mixed.

**Density Control.** In most cases, the density of the cement slurry obtained by mixing cement with the normal amount of water will be too great for the formation fracture strength, and it will be desirable to lower the slurry density. Consequently, lightweight additives (also known as extenders) are used to reduce the weight of the slurry. Any material with a specific gravity lower than that of the cement will act as an extender. Bentonite is the most common type of additive used to lower slurry density. The bentonite material absorbs water, and therefore allows more mixwater to be added. Bentonite will also however reduce compressive strength and sulphate resistance. A number of pozzolanic materials are available for use in producing lightweight cement slurries. These can be either natural or artificial and include fly ash, diatomaceous earth, microsilica, and granulated blast-furnace slag. Microspheres are used when slurry densities from 8.5 to 11 ppg are required. They are hollow spheres obtained as a byproduct from power generating plants or are specifically formulated. It is possible to make slurries ranging in density from 4 to 18 ppg using foamed cement. Foamed cement is a mixture of cement slurry, foaming agents, and a gas, usually nitrogen. Weighting agents or heavyweight additives are used to increase slurry density for control of highly pressured wells. The main requirements for weighting agents are that the specific gravity is greater than the cement, the particle size distribution is consistent, they have a low water requirement, they are chemically inert in the cement slurry. Hematite is the most commonly used weighting agent. The high specific gravity of hematite can be used to raise slurry densities to 22 ppg. Hematite significantly reduces the pumpability of slurries and therefore friction reducing additives may be required when using hematite. Barite can be used to attain slurry densities of up to 18 ppg. The water requirements for barite are considerably higher than for hematite. The large amount of water required decreases the compressive strength of the cement and dilutes the other chemical additives.

**Setting-Time Control.** The cement must set and develop sufficient strength to support the casing and seal off fluid movement behind the casing before drilling or completion activities can be resumed. Most operators wait on cement to reach a minimum compressive strength of 500 psi before resuming drilling operations. When cementing shallow, low-temperature wells, it may be necessary to accelerate the cement hydration so that the waiting period after cementing is minimized. The commonly used cement accelerators are calcium chloride, sodium chloride, the hemihydrate form of gypsum, and sodium silicate. Cement setting time also is a function of the cement composition, fineness, and water content. In deep wells the higher temperatures will reduce the cement slurry's thickening time. Retarders are used to prolong the thickening time and avoid the risk of the cement setting in the casing prematurely. The bottom hole temperature is the critical factor which influences slurry setting times and therefore for determining the need for retarders. Deflocculants used as drilling fluids additives tend to delay the setting of cement, thus they are applied as retarders. These materials also are called thinners or dispersants. Common retarders are lignosulfonates, modified cellulose, organic acids, organic materials and borax. Calcium lignosulfonate, one of the common mud deflocculants, has been found to be very effective as a cement retarder at very low concentrations. Two cellulose polymers are used in well-cementing applications. They are hydroxyethyl cellulose (HEC) and carboxymethyl hydroxyethyl cellulose (CMHEC). Inorganic compounds, commonly used as cement retarders, are borax and other borates such as boric acid. Borates are commonly used as a retarder aid for high-temperature retarders at the bottom hole circulating temperature of 300°F and greater. Water containing salt concentrations of greater than 20 percent by weight of water has a retarding effect on cement. Saturated salt cements are also dispersed, and salt reduces the effectiveness of fluid-loss additives.

## Cementing Operations

Cementing operations can be divided into two broad categories: primary cementing and remedial cementing. The objective of primary cementing is to provide zonal isolation. Most primary cement jobs are performed by pumping the slurry down the casing and up the annulus; however, modified techniques can be used for special situations. These techniques are cementing through pipe and casing (normal displacement technique), stage cementing (for wells with critical fracture gradients), inner-string cementing through tubing (for large-diameter pipe), outside or annulus cementing through tubing (for surface pipe or large casing), reverse-circulation cementing (for critical formations), delayed-set cementing (for critical formations and to improve placement), and multiple-string cementing (for small-diameter tubing). Remedial cementing is usually done to correct problems associated with the primary cement job. The need for remedial cementing to restore a well's operation indicates that primary operational planning and execution were ineffective, resulting in costly repair operations.

In order to carry out a conventional primary cement job some special equipment must be included in the casing string as it is run. At the bottom of the casing string a guide shoe, a rounded nose to guide the casing past any ledges or other irregularities in the hole, is mounted and a float collar 1 to 3 joints above. A float collar acts as a seat for the cement plugs used in the pumping and displacement of the cement slurry and also contains a non-return valve so that the cement slurry cannot flow back up the casing. Sometimes the guide shoe also has a non-return valve as an extra precaution. It is essential that the non-return valves are effective in holding back the cement slurry. Centralizers are hinged metal ribs which are installed on the casing string as it is run. Their function is to keep the casing away from the borehole so that there is some annular clearance around the entire circumference of the casing. Centralizers are particularly required in deviated wells where the casing tends to lie on the low side of the hole. The spacing of centralizers will vary depending on the requirements of each cement job. In critical zones, and in highly deviated parts of the well, they are closely spaced, while on other parts of the casing string they may not be necessary at all. Wipers/scratchers are devices run on the outside of the casing to remove mud cake and break up gelled mud. They are sometimes used through the production zone. Once the casing string is run to the bottom, a cementing head is attached to the top joint of well casing. The cementing head provides the connection between the discharge line from the cement unit and the top of the casing. This piece of equipment is designed to hold the cement plugs used in the conventional primary cement job. It allows cementing plugs to be released ahead of and behind the cement slurry in order to isolate the cement slurry from wellbore fluids ahead of the cement and from displacing fluids pumped behind the slurry. The bottom plug has a shallow top, is made of rubber diaphragm, and has a hollow core. It is used ahead of the cement slurry to prevent cement/drilling fluid contamination and to clean the casing wall of filter cake. When the bottom plug reaches the float collar, it stops; pressure builds up, which quickly ruptures the plug's diaphragm and allows the slurry to continue flowing through it. The top plug has a deep cup on its top and has a solid, molded rubber core. It is dropped after the cement slurry has been pumped, to prevent contamination with the displacement fluid. The top plug also signals the end of displacement by forming a seal on top of the bottom plug, causing a pressure increase. Before the cement is pumped, a spacer may be pumped into the casing. A spacer is a volume of fluid injected ahead of the cement but behind the drilling fluid. It is a fluid of controlled viscosity, density and gel strength used to form a buffer between the cement and drilling fluid and can also enhance the removal of gelled drilling fluid, allowing a better cement bond. Mud is normally used to displace the cement slurry. The cement pumps or the rig pumps may be used for the displacement. It is recommended that the cement slurry is displaced at as high a rate as possible. High rate displacement will aid efficient mud displacement. It is highly unlikely that it will be possible to achieve turbulence in the cement slurry since it is so viscous and has such a high density. However, it may be possible to generate turbulence in the spacer and this will result in a more efficient displacement of the mud. The pumping rate should be slowed down as the top plug approaches the float collar and the plug should be gently bumped into the bottom plug.

The casing is often pressure tested at this point in the operation. The pressure is then bled off slowly to ensure that the float valves, in the float collar and/or casing shoe, are holding. Throughout the cement job the mud returns from the annulus should be monitored to ensure that the formation has not been broken down. If formation breakdown does occur then mud returns would slow down or stop during the displacement operation.

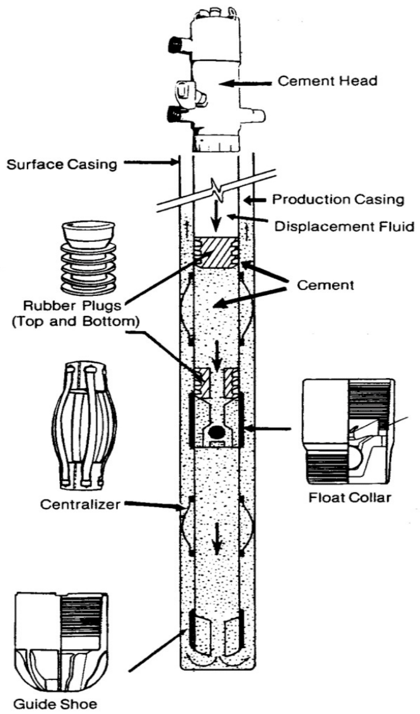


Fig 66: Accessories for cementing operations (Courtesy World Oil's Cementing Handbook)

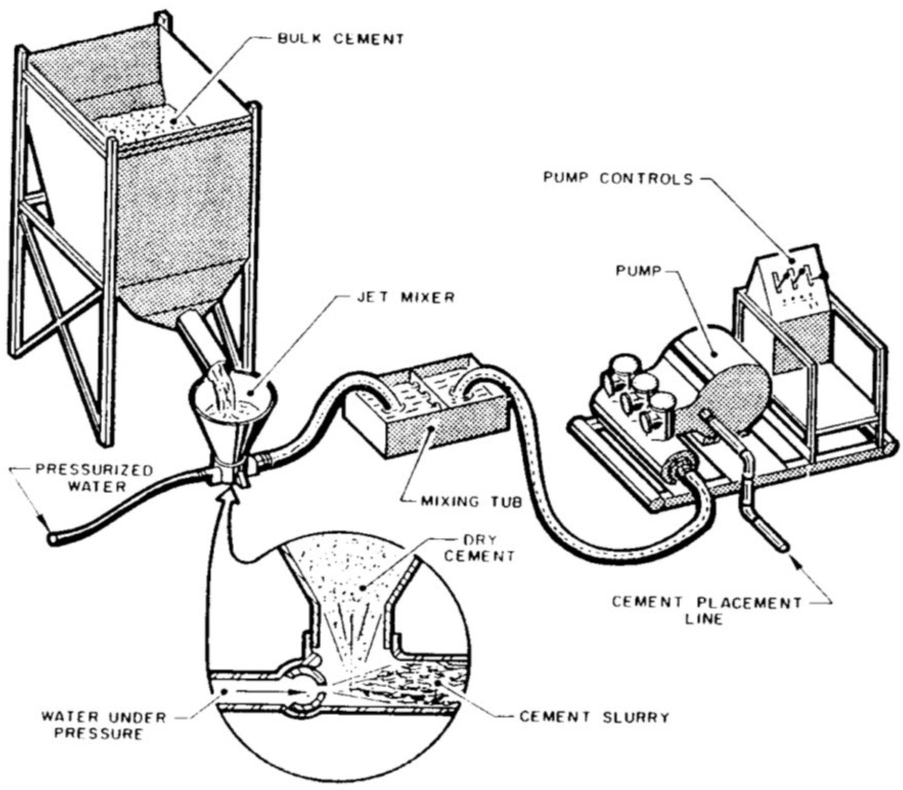


Fig 67: Cementing unit (Courtesy of Baker Hughes INTEQ)

Multistage cementing is one of the procedures developed to permit using a cement column height in the annulus that normally would cause the fracture of one or more subsurface formations. It also can be used to reduce the potential for gas flow after cementing. The first stage of the cementing operation is conducted in the conventional manner. The second stage of the operation involves the use of a special tool known as a stage collar, which is made up into the casing string at a pre-determined position. The ports in the stage collar are initially sealed off by the inner sleeve. This sleeve is held in place by retaining pins. After the first stage is complete a special dart is released form surface which lands in the inner sleeve of the stage collar. When a pressure of 1,000 – 1,500 psi is applied to the casing above the dart, and therefore to the dart, the retaining pins on the inner sleeve are sheared and the sleeve moves down, uncovering the ports in the outer mandrel. Circulation is established through the stage collar before the second stage slurry is pumped. The second stage cement then is pumped through this side port and into the annulus above the set first stage cement. If necessary, more than one stage collar can be run on the casing so that various sections of the annulus can be cemented.

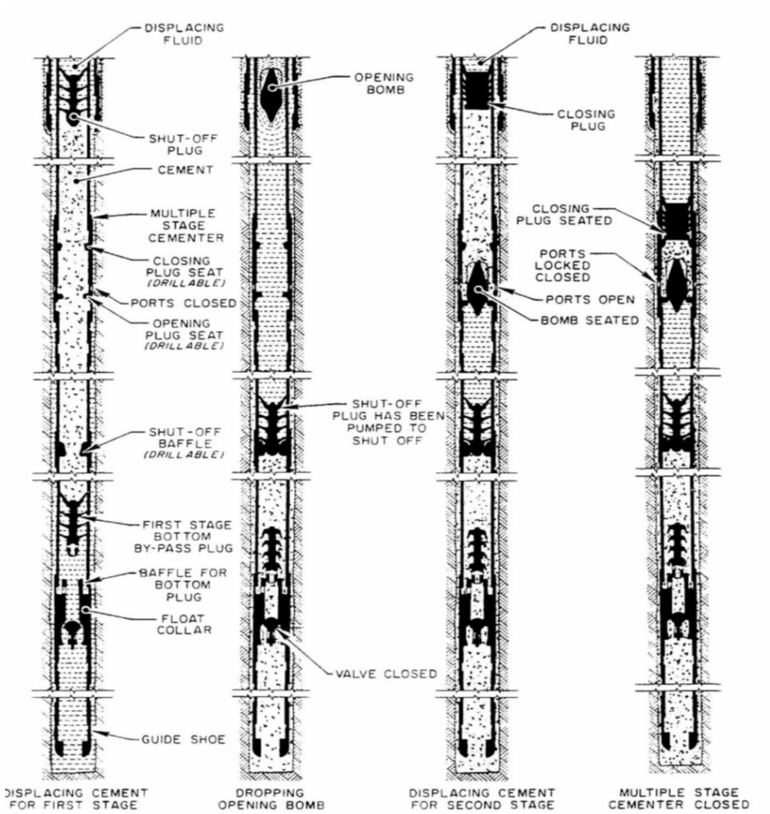


Fig 68: Multistage cementing (Courtesy World Oil's Cementing Handbook)

For large diameter casing, such as conductors and surface casing, conventional cementing techniques result in the long cementing time and the large amount of cement left in the shoe joint of large-diameter casing. An alternative technique, known as a stinger cement job, is to cement the casing through a tubing or drill pipe string, known as a cement stinger, rather than through the casing itself. A special sealing adapter, which can seal in the seal bore of the seal float shoe, is attached to the cement stinger. Once the casing has been run, the cementing string with the seal adapter attached, is run and stabbed into the float shoe. Drilling mud is then circulated around the system to ensure that the stinger and annulus are clear of any debris. The cement slurry is then pumped with liquid spacers ahead and behind the cement slurry. No plugs are used in this type of cementing operation since the diameter of the stinger is generally so small that contamination of the cement is unlikely if a large enough liquid spacer is used. The cement slurry is generally under-displaced so that when the seal adapter on the stinger is pulled from the shoe the excess cement falls down on top of the shoe.

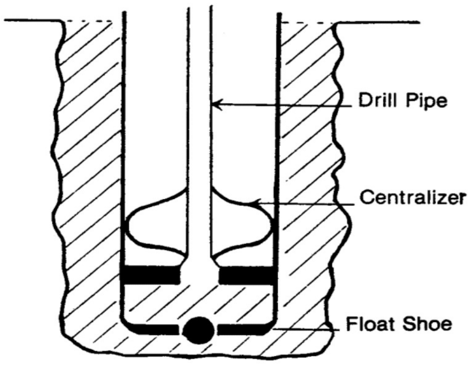


Fig 69: Large diameter casing cementing (Courtesy World Oil's Cementing Handbook)

Liners are run on drill pipe and therefore the conventional cementing techniques cannot be used for cementing a liner. Special equipment must be used for cementing these liners. The liner is attached to the drill pipe using a special liner-setting tool. The liner-setting tool then is actuated so that the liner is attached mechanically to and supported by the casing without hydraulically sealing the passage between the liner and the casing. The cement is pumped down the drill pipe and separated from the displacing fluid by a latch-down plug. This latch-down plug actuates a special wiper plug in the liner setting tool after the top of the cement column reaches the liner. When the wiper plug reaches the float collar, a pressure increase at the surface signifies the end of the cement displacement. The drill string then must be released from the liner-setting tool and withdrawn before the cement hardens.

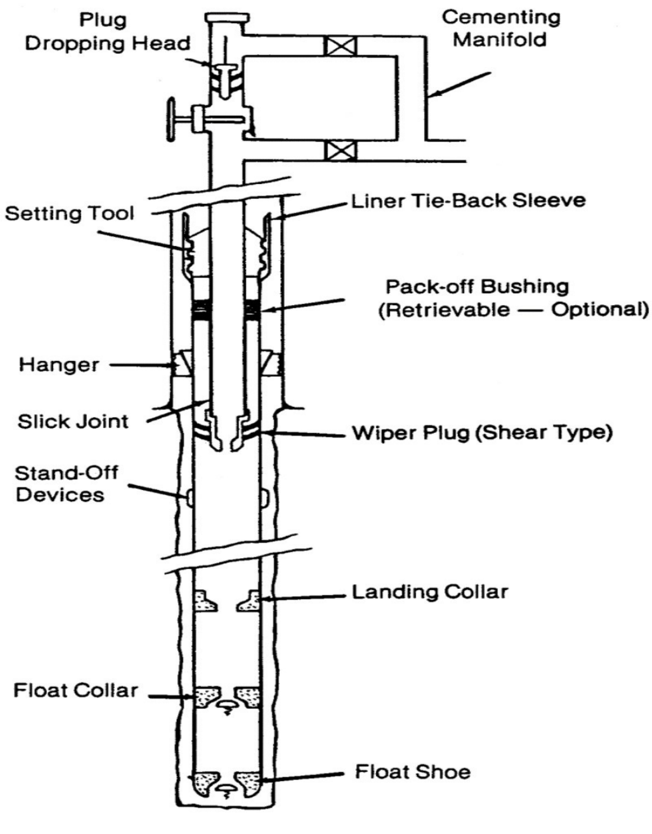


Fig 70: Liner cementing (Courtesy World Oil's Cementing Handbook)

Remedial cementing requires as much technical, engineering, and operational experience, as primary cementing but is often done when wellbore conditions are unknown or out of control, and when wasted rig time and escalating costs force poor decisions and high risk. Squeeze cementing is a "correction" process that is usually only necessary to correct a problem in the wellbore. Squeeze cementing is the process by which hydraulic pressure is used to force cement slurry through holes in the casing and into the annulus and/or the formation. A cement slurry is prepared and pumped down a wellbore to the problem area or squeeze target. The area is isolated, and pressure is applied from the surface to effectively force the slurry into all voids. The slurry is designed specifically to fill the type of void in the wellbore, whether it is a small crack or micro-annuli, casing split or large vug, formation rock or another kind of cavity. Thus, the slurry design and rate of dehydration or fluid loss designed into the slurry is critical, and a poor design may not provide a complete fill and seal of the voids. Squeeze cementing can be divided into two classifications depending on the way the cement is placed, high pressure squeeze and low pressure squeeze. In a high pressure squeeze the formation is initially fractured by a solid free breakdown fluid. After the formation is broken down a slurry of cement is spotted adjacent to the formation, and then pumped into the zone at a slow rate. The injection pressure should gradually build up as the cement fills up the fractured zone. After the cement has been squeezed the pressure is released to check for back flow. A low pressure squeeze is any squeeze application conducted below the fracturing pressure. This method can be applied whenever clean wellbore fluids can be injected into a formation, such as permeable sand, lost circulation interval, fractured limestone, vugs, or voids. Filtrate from the cement slurry is easily displaced at low pressures, and the dehydrated cement is deposited in the void. Whole cement slurries will not invade most formations unless a fracture is readily open or is created during the squeeze process. Only a small volume of cement is required for a low pressure squeeze.

At some stage during the life of a well a cement plug may have to be placed in the wellbore. A cement plug is designed to fill a length of casing or open hole to prevent vertical fluid movement. As such, a competent plug must provide a hydraulic and mechanical seal. Some of the varied reasons for performing plugging operations are abandoning depleted zones, seal off lost circulation zones, providing a kick off point for directional drilling, e.g. side- tracking around fish, isolating a zone for formation testing, and abandoning an entire well. Each plugging operation presents a common problem in that a relatively small volume of plugging material, usually a cement slurry, is placed in a large volume of wellbore fluid. Wellbore fluids can contaminate the cement, and even after a reasonable wait on cement time, the result is a weak, diluted, nonuniform or unset plug. For the plug cementing operations, a balanced plug technique, that requires pumping a preflush and a spacer behind the cement, is most often carried out. When the height of the spacer inside the tubing is equal to the height of the preflush, the cement plug is placed balanced. Preflush, cement slurry and spacer fluid are pumped down the drill pipe and displaced with mud. The displacement continues until the level of cement inside and outside the drill pipe is the same (hence balanced). If the levels are not the same then a U-tube effect will take pace. The drill pipe can then be retrieved leaving the plug in place.

# DIRECTIONAL DRILLING

## Introduction

Directional drilling can generally be defined as the art and science of directing a wellbore along a pre-determined trajectory to intersect a designated subsurface target. In the early days of land drilling most wells were drilled vertically, straight down into the reservoir. Although these wells were considered to be vertical, they rarely were. Some deviation in a wellbore would occur, due to formation effects and bending of the drill string. A well that was not vertical was at first considered having disadvantages, e.g. more footage than necessary had to be drilled in order to reach the producing zone, crooked shape of the wellbore increased the wear on the drill string making a failure more likely. Directional drilling had a strong start offshore and in other areas where it was difficult or expensive to build a surface location. Directional techniques allowed drilling multiple wells from one location, thus eliminating construction of an expensive structure for each well. Offshore developments led to a big expansion in the use of directional drilling. These and similar procedures firmly established directional drilling, and it has developed into a reliable, efficient drilling procedure with widespread usage. The continuing need to reduce drilling costs provided the incentive to produce new tools and techniques to improve efficiency. Directional drilling has now become an essential element in oilfield development, both onshore and offshore. Despite the advances made in drilling technology, there is still a great need for personnel with the proper training and experience to use the technology to its maximum benefit.

## Applications of Directional Drilling

Some typical applications of directionally controlled drilling are as follow:

**Multiple wells from one surface location.** Drilling multiple wells directionally from one surface location is a common, important application of directional drilling. Multi-well drilling sites include offshore platforms, man-made islands and peninsulas, and platform and earthen locations in swamps, jungles, drilling pads, and other isolated areas. Many productive formations do not contain sufficient volumes of oil and gas to justify the costs of building individual platforms or single-well locations in order to drill vertical wells. The more cost effective procedure of drilling multiple wells from a single location often allows economically development and production. This allows production of oil and gas that would not otherwise be produced. The bottom hole locations of these wells are carefully spaced for optimum recovery. Where the environment is concerned, roads and production facilities may not be allowed for each surface location with a vertical well. As oil companies become more environmentally conscious, it may be politically advantageous to develop fields from drilling pads in sensitive areas.

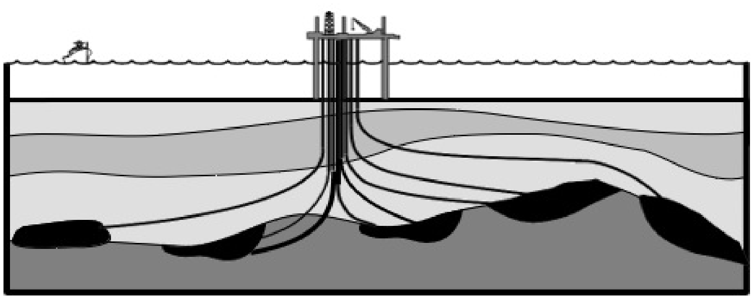

Fig 71: Multiple wells from one surface location (Courtesy of Baker Hughes INTEQ)

**Inaccessible surface locations.** Inaccessible surface locations inhibit development by the drilling of individual vertical wells for various reasons, e.g. river, lake, mountain range, parks, residential and industrial areas. In such case the well may be directionally drilled into the target from a rig site some distance away from the point vertically above the required point of entry into the reservoir. In the case where a reservoir lies offshore but quite close to land, the most economical way to exploit the reservoir may be to drill directional wells from a land rig on the coast.

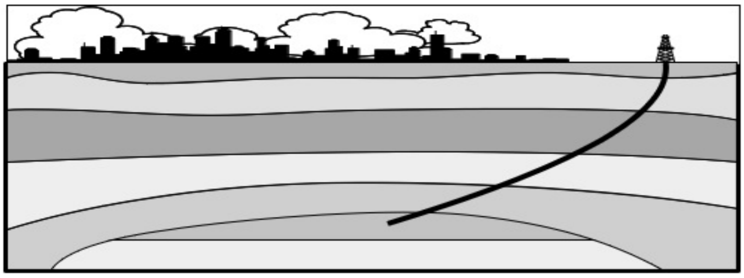

Fig 72: Inaccessible surface locations (Courtesy of Baker Hughes INTEQ)

**Geological problems.** It is sometimes difficult to drill a vertical well in a steeply dipping, inclined fault plane. Often, the bit will deflect when passing through the fault plane, and sometimes the bit will follow the fault plane. To avoid the problem, the well can be drilled on the upthrown or downthrown side of the fault and deflected into the producing formation. The bit will cross the fault at enough of an angle where the direction of the bit cannot change to follow the fault. If a well is drilled across a fault the casing can be damaged by fault slippage. The potential for damaging the casing can be minimized by drilling parallel to a fault and then changing the direction of the well to cross the fault into the target. Petroleum reservoirs are sometimes associated with salt dome structures. Salt domes, called diapirs, often form hydrocarbon traps overlying reservoir rocks. In this form of traps the reservoir is located directly beneath the flank of the salt dome. Part of the salt dome may be directly above the reservoir, so that a vertical well would have to penetrate the salt formation before reaching the target. Drilling through a salt section introduces certain drilling problems such as large washouts, lost circulation, and corrosion. Instead of drilling through the salt, the well is drilled at one side of the dome and is then deviated around and underneath the overhanging cap to reach the reservoir.

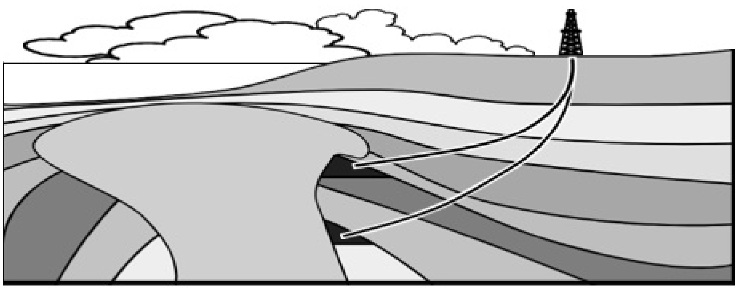

Fig 73: Geological problems (Courtesy of Baker Hughes INTEQ)

**Sidetracking.** Sidetracking is one of the primary uses for directional drilling. Sidetracking is an operation which deflects the borehole by starting a new hole at any point above the bottom of the old hole. During the drilling of a well, an obstruction (or fish) may become stuck at the bottom of the hole. This may be the result of a drill string failure or an intentional back-off where the lower part of the string is left in the hole. A cement plug is placed on top of the fish and is allowed to set firmly. This forms a good foundation from which the new section of hole can be kicked off. Once the sidetrack has been drilled around the obstruction, the hole is continued down to the target. Geological and reservoir information obtained during drilling may suggest a more promising or productive area near the wellbore. It is common in this case to plug back, sidetrack, and drill directionally into the new target.

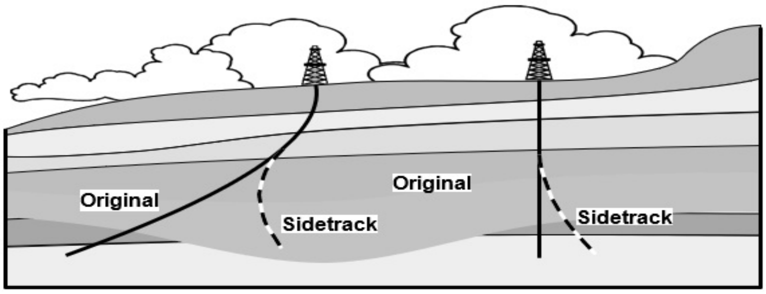


Fig 74: Sidetracking (Courtesy of Baker Hughes INTEQ)

**Controlling straight wells.** In some areas of the world, deviation from vertical is caused by the natural formation tendencies. It should be noted that sometimes targets are unduly restricted. Controlling the inclination of a well costs significantly more than letting it deviates. To keep vertical wells on target, directional techniques have to be used. Pendulum assemblies are used to keep the inclination as low as possible though with limited success at lower inclinations. If the inclination is already too great to hit a previously specified target, pendulum assemblies, and sometimes downhole motors are used to bring the hole back within range of the target.

**Relief wells.** A highly specialized application for directional drilling is the relief well. If a well blows out and is no longer accessible from the surface, then a relief well is drilled to intersect the uncontrolled well near the bottom. High density drilling fluid is then pumped through the relief well and into the uncontrolled well. Since it is sometimes required that the relief well intersect the uncontrolled well, the directional drilling has to be extremely precise and requires special tools.

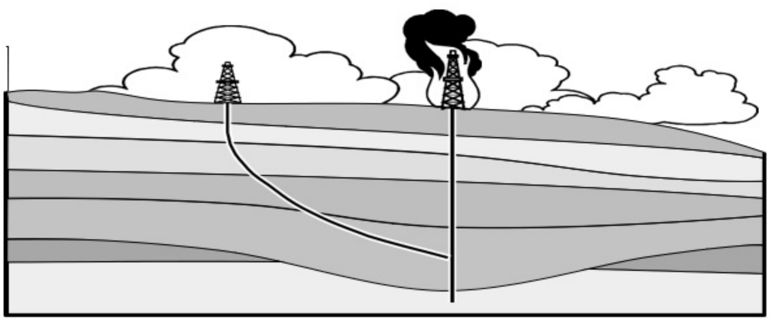

Fig 75: Relief well (Courtesy of Baker Hughes INTEQ)

**Horizontal wells.** Horizontal drilling is another special application of directional drilling and is used to increase the productivity of various formations. One of the first applications for horizontal drilling was in vertically fractured reservoirs. In fractured reservoirs, a significant quantity of the production comes from fractures. A horizontal well has a much greater chance of encountering fracture system. The horizontal well is optimally placed in the thin oil zones with water or gas coning problems. The oil can then be produced at high rates with much less pressure drawdown because of the amount of formation exposed to the wellbore. At higher drawdown pressures, sand production is a common problem, especially the production of unconsolidated and fine grained sand. Sand control placement, e.g. screens and gravel packing limit sand entry into the wellbore and in some cases reduce production rates. Horizontal wells can produce oil with less pressure drawdown thus eliminates the need for screens and gravel packing and allows higher production rates. Horizontal wells are used to increase productivity from low permeability reservoirs by increasing the amount of formation exposed to the wellbore, additionally hydraulic fractures can be placed along the wellbore to increase production and reduce the number of vertical wells required to drain the reservoir. There are a number of wells drilled that are considered to be horizontal by some individuals but not others. One definition requires a horizontal wellbore to have an inclination greater than 86° and only portions of the wellbore greater than 86° constitutes the horizontal wellbore length. Another definition states that any portion of a wellbore after the well reaches 80° is considered as part of the horizontal length even if the inclination falls below 80°.

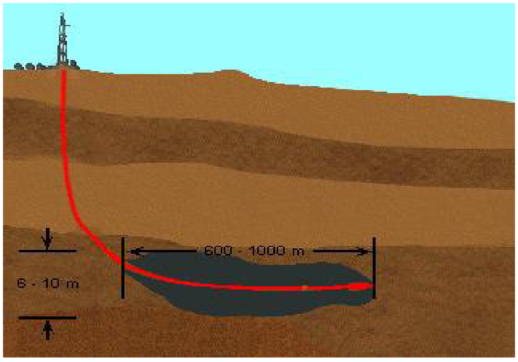


Fig 76: Horizontal well (courtesy of Schlumberger)

**Multilateral wells.** Multilaterals are additional wells drilled from a parent wellbore. Multilaterals can be as simple as an open hole sidetrack or it can be more complicated with a junction that is cased and has pressure isolation and reentry capabilities. Initially, the multilateral technology was associated with horizontal drilling. From the build curves, open-hole side tracks were drilled. These laterals gave good production results, creating industry's interest in this technology. Multilaterals can be drilled from existing wells or drilled as a new well using special multilateral equipment. The complexity of the multilaterals drilled depends on the integrity of the formation, the prevention of water or gas coning, the requirements to isolate the main wellbore from the laterals, the requirement to reenter each lateral and the requirements to isolate production from the laterals. Multilaterals can be used offshore where the number of slots are limited or where production can be incrementally increased with less capital costs.

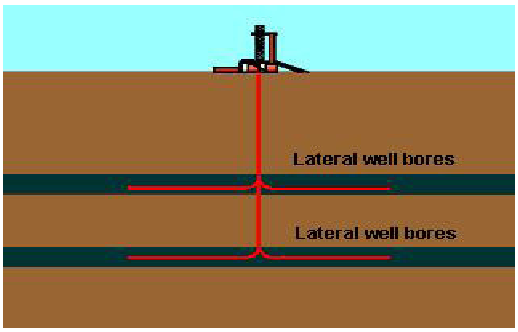


Fig 77: Multilateral well (courtesy of Schlumberger)

## Well Trajectory Types

There are basically four types of well trajectories established for practical realizations.
A. Build-and-hold trajectory,
B. Build-and-hold-and-drop (S) trajectory,
C. Build-and-partial drop-and hold (modified S) trajectory,
D. Continuous build trajectory.

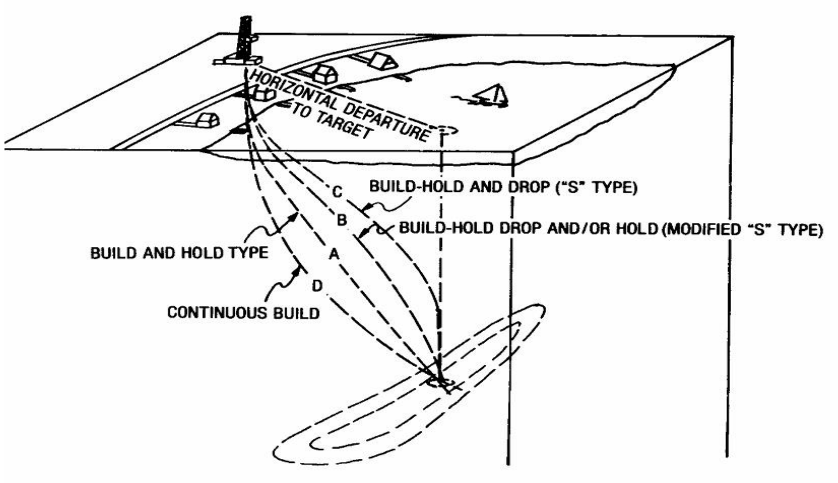


Fig 78: Major types of well trajectories (Bourgoyne et al. 1986)

At type A trajectory, the well is kicked off at a specified depth, inclination is build up until a certain amount (end of build) and kept until the target is reached. The build and hold profile is the most common well trajectory and is the most simple trajectory to achieve when drilling. This type of profile is often applied when a large horizontal displacement is required at relatively shallow target depths. Since there are no major changes in inclination or azimuth after the build-up section is completed, there are fewer directional problems with this profile.

At type B trajectory, the well is kicked off at a specified depth, inclination is build up until a certain amount (end of build) and kept until the drop down point is reached. From the drop down point until the end of drop point the inclination is reduced to zero degrees and the well is continued until the target is hit vertically. Here an extra torque and drag are expected due to the additional bend. This type of trajectory is sometime required by reservoir engineers and production technologists in exploration and appraisal wells since it is easier to assess the potential productivity of exploration wells, or the efficiency of stimulation treatments when the productive interval is entered vertically, at right angles to the bedding planes of the formation. This type of profile is used when the target is deep but the horizontal displacement is relatively small. It also has applications when completing a well that intersects multiple producing zones. The S-shaped well is more complex but is required to ensure that the well penetrates the target formation vertically.

At type C trajectory, the well is kicked off at a specified depth, inclination is build up until a certain amount (end of build) and kept until the drop down point. From the drop down point until the end of drop point the inclination is reduced but differently to type B trajectories, not to zero degrees. Then the inclination is kept until the target is intercepted. The applications and characteristics of this well type are somewhat similar to the ones of type B.

At type D trajectories, the well is kicked off at a specified depth and inclination is build up continuously until the target is reached. This type of trajectory is preferred for an inclination angle of between 30 to 40 degrees since within these values, close control over the trajectory-progress is convenient. This type of trajectory is usually used for either pre-planned short deviations or for plugging back and deviating a straight hole that has been drilled. Deviation is accomplished in the same manner as the type A and B trajectories except this type of well is usually not protected by casing until total depth is reached. Type D trajectory is usually used for exploratory purposes or when a single wellhead must be used for economy or surface location considerations. Protective casing is usually not set through the deviated section of the hole in this type of pattern.

## Planning Directional Well

The trajectory of a directional well must be carefully planned so that the most efficient trajectory is used to drill between the rig and the target location. The first step of planning a directional well is to identify where the target (targets) are located in respect to the rig location. When planning, and subsequently drilling the well, the position of all points along the well path and therefore the trajectory of the well must be considered in three dimensions. This means that the position of all points on the trajectory must be expressed with respect to a three dimensional reference system. The common method of fixing the position of a point on the Earth's surface is to give its latitude and longitude. A line of latitude runs parallel to the equator, and is denoted by a number of degrees (0-90°) North or South of the equator. A line of longitude is perpendicular to the equator and passes through the North and South poles and is denoted by a number of degrees (0-180°) East or West of Greenwich. However, for the purposes of planning a directional well, it is more convenient if the curved surface of the Earth is projected onto a flat surface on which maps can be drawn. One such system is known as the Universal Transverse of Mercator (UTM). This is basically a projection of the section of the Earth's surface that contains the area of interest. For the purposes of planning and monitoring, all measurements must be tied back to a common reference point. For drilling, the origin of the trajectory is taken from the rotary table. Thus the location of the target in UTM or latitude/longitude coordinates, has to be re-calculated into "Northing" and "Easting" in respect to the rotary table. The three dimensional system that is generally used to define the position of a particular point along the well path is:

- The vertical depth of the point below a particular reference point
- The horizontal distance traversed from the rotary table in a Northerly direction
- The distance traversed from the rotary table in an Easterly direction

The datum systems which are most widely used are mean sea level (MSL) and derrick floor elevation (DFE). The depths of the formations to be penetrated are generally referenced, by the geologists and reservoir engineers, to MSL since DFE will not be known until the drilling rig is in place. The elevation of the derrick floor above the MSL will be measured when the drilling rig is placed over the drilling location. In most drilling operations the derrick floor elevation is used as the working depth reference since it is relatively simple, for the driller for instance, to measure depths relative to this point. Depths measured from these references are often called depths below derrick floor (BDF) or below rotary table (BRT). The top of the kelly bushing is also used as a datum for depth measurement. In this case the depths are referred to as depths below rotary kelly bushing (RKB). The depth of the target, which can be referenced to mean sea level (MSL) has to be referenced to the derrick floor as well. The depth of any point in the well path can be expressed in terms of the Measured Depth (MD) and the True Vertical Depth (TVD) of the point below the reference datum.

The measured depth is the depth of a point from the surface reference point, measured along the trajectory of the borehole. Whereas the true vertical depth is the vertical depth of the point below the reference point. The MD will therefore always be greater than the TVD in a deviated well. Since there is no direct way of measuring the true vertical depth, it must be calculated from the information gathered when surveying the well. Note that the derrick floor elevation is specific to a particular rig and when an old well has to be re-entered or sidetracks drilled, the survey of the old well is referenced to the derrick floor elevation of the rig it was drilled with which can be different from the one use later on.

The majority of today's directional well planning is performed on computers. Computers are fast and can incorporate both changes in build and drop rates and changes in direction. All directional drilling service companies offer this service; therefore, a final well plan would be generated by a computer. When planning a directional well a number of technical constraints and issues will have to be considered, e.g. target(s), rig location, adjacent wells, geological sections, etc. The location of the target is chosen by the geologists and/or the reservoir engineers. The target location will be specified in terms of a geographical co-ordinate system such as longitude and latitude or a grid co-ordinate system such as the UTM system. The grid reference system, in which the co-ordinates are expressed in terms of feet (or meters) north and east of a local or national reference point, is particularly useful when planning the directional well path, since the displacement of all points on the well path can be easily calculated. The depth of the target is generally expressed by the geologist in terms of true vertical depth, TVD below a national reference datum such as Mean Sea Level. The difference between this national reference point and the drilling reference datum, i.e. the rotary table, must be computed so that the driller can translate the computed TVD of the borehole below the rotary table elevation, into depth below mean sea level, and therefore proximity to the target. The size and shape of the target is also chosen by geologist and/or reservoir engineer. The target area will be dictated by the shape of the geological structure and the presence of geological features, such as faults. In general, the smaller the target area, the more directional control is required, and so the more expensive the well will be. The target area should therefore be as large as the geologist or the reservoir engineer can allow. The position of the rig must be considered in relation to the target and the geological formations to be drilled, e.g. salt domes, faults etc. If possible the rig will be placed directly above the target location. When developing a field from a fixed platform the location of the platform will be optimized so that the directionally drilled wells can reach the full extent of the reservoir. Drilling close to an existing well can be very dangerous, particularly if the existing well is on production. This is especially true just below the seabed on offshore platforms, where the wells are very closely spaced. The proposed well trajectory must be designed so that it avoids all other wells in the vicinity. It is essential that the possible errors in determination of the existing and proposed wells are considered when the trajectory of the new well is designed. The trajectory of the well will be designed so that the most difficult parts of the well are drilled through competent formations, minimizing problems whilst drilling the well. It is very common to initiate the kick off just below the surface casing. In highly deviated wells the buildup section of the well may also be cased off before drilling the long, tangent section of the well. The trajectory of the well will therefore be designed so that these operations correspond to the casing setting depths which have been selected for many other reasons.

There are several specific parameters which must be considered when planning one of the trajectories. These parameters combine to define the trajectory of the well.

**Kick off point (KOP).** The kick off point is the along hole measured depth at which a change in inclination of the well is initiated and the well is orientation in a particular direction (in terms of North, South, East and West). In general, the most distant targets have the shallowest KOPs in order to reduce the inclination of the tangent section of the well. The kick off point may be selected based on hole conditions and target constraints. In selecting the KOP the hardness of the formation is important. Hard formations may give a poor response to the deflecting tool, so that the kick off may take a long time. It is important to avoid very soft, very hard, abrasive, or laminated formations. The KOP should be selected in medium-soft or medium drillability, massive formations when possible. Many times it is desirable to case the build curve to minimize the possibility of a keyseat; therefore, the kick off point may be based on casing seats. It may be desirable to drill some troublesome formations such as lost circulation or sloughing before kicking the well off. The kick off should also be initiated in formations which are stable and not likely to cause drilling problems, such as unconsolidated clays. It is generally easier to kick off a well the shallow formations than in deep formations. A deep kick off point has certain disadvantages such as formation will probably be harder and less responsive to deflection, more tripping time is needed to change out BHAs during side tracking, and build-up rate is more difficult to control.

**Buildup rate (BUR) and drop off rate (DOR).** The buildup rate and drop off rate (in degrees of inclination) are the rates at which the well deviates from the vertical (usually measured in degrees per 100 ft drilled). The buildup rate is chosen on the basis of drilling experience in the location and the tools available, but rates between 1 degree and 3 degrees per 100ft of hole drilled are most common in conventional wells. Since the buildup and drop off rates are constant, these sections of the well, by definition, form the arc of a circle. The build rate can be chosen to minimize fatigue in drill pipe, minimize keyseat possibility, or help to minimize torque and drag. If drilling a horizontal well, the build rate may be selected based on steerability of the bottom hole assembly. The buildup rate is often termed the dogleg severity. Generally, the buildup rate is chosen trying to keep below the endurance limit of the drill string in order to minimize the possibility of fatigue damage. The higher in the hole the kick off point, the lower the dogleg severity needs to be in order to minimize fatigue in the drill string through the build section.

**Tangent (or Drift) Angle.** The tangent angle (or drift angle) is the inclination (in degrees from the vertical) of the long straight section of the well after the buildup section of the well. This section of the well is termed the tangent section because it forms a tangent to the arc formed by the buildup section of the well. The tangent angle will generally be between 15 and 60 degrees since it is difficult to control the trajectory of the well at angles below 15 degrees and it is difficult to run wireline tools into wells at angles of greater than 60 degrees. In addition, high inclination angles can result in excessive torque and drag on the drill string and present hole cleaning, logging, casing, cementing and production problems. The hold inclination can be chosen based on any number of concerns. At low inclinations, it may be difficult to maintain the direction of the wellbore. Bit walk is greater at low inclinations because the direction can change significantly with small changes in dogleg severity.

**Horizontal Projection.** On many well plans, horizontal projection is just a straight line drawn from the slot to the target. On multi-well platforms however, it is sometimes necessary to start the well in a different direction to avoid other wells. Once clear of these, the well is turned to aim at the target. The path of the drilled well is plotted on the horizontal projection by plotting total North/South coordinates (Northings) versus total East/West coordinates (Eastings). These coordinates are calculated from surveys. To eliminate the risk of collisions directly beneath the platform, the proposed well path is compared to existing and other proposed wells. The distances between the other wells and the proposal are calculated at frequent intervals in critical sections.

**Dog-leg Severity.** Changes in hole curvature are often referred to as dog-legs. The severity of a dog-leg is determined by the average changes in angle and/or direction of the distance this change occurs. For example, if there is a 5 degree change in angle (no direction change) over 100 feet of hole, the dog-leg severity is 5 degrees per 100 feet. The severity of the dog-legs must be controlled to prevent fatigue failure of the drill string, key seating, difficulty in logging and surveying below the bend, production problems, inferior cementing caused by non-centralized casing and easing coupling failure due to excessive flexure. Early detection of dog-legs is very important. Until a dog-leg reaches some threshold value, no drill stem fatigue damage occurs. This threshold value is called Critical Dog-leg. The critical dog-leg is dependent upon the dimensions (size) and metallurgy of the drill pipe and drill pipe tension (pull) in the dog-leg. In the event a severe dog-leg appears in the hole above the expected total depth, then an important decision must be made before further drilling. A dog-leg can be smoothed to some extent by string reaming, but a severe dog-leg should be wiped out and resurveyed or side tracked to be sure the severe dog-leg has been eliminated.

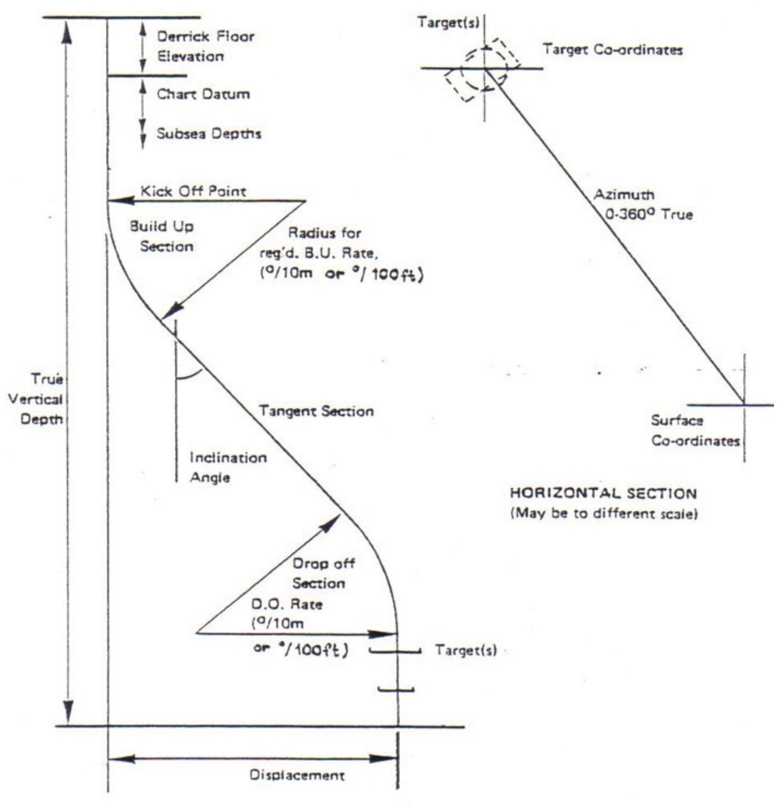


Fig 79: Well planning parameters

## Deflection Tools and Techniques

There are a number of tools and techniques which can be used to change the direction in which a bit will drill. These tools and techniques can be used to change the inclination or the azimuthal direction of the wellbore or both.

**Whipstock.** The whipstock method to deviate a bit is the oldest technique and, if properly used, the most reliable one. It is an old directional drilling tool which is used today primarily to sidetrack out of casing. The whipstock is a steel wedge with a chisel shaped point at the bottom, which is run in the hole and set at the KOP. The purpose of the wedge is to apply a sideforce and deflect the bit in the required direction. This chisel shape prevents the whipstock from turning when drilling begins. Once it is installed down hole, it guides the bit or the mill against the casing or the open hole wall to drill in the desired direction. The whipstock causes a significant change in hole direction and angle in a very short interval. The whipstock's biggest advantage is that it provides a controlled hole curvature at the onset, while distributing the side force over the length of the whipstock body. Whipstocks can also be run at any depth in any kind of rock although they are best suited for use in very hard rock where other deflecting techniques are generally ineffective. The main disadvantage of the whipstock is the necessity to drill the pilot hole and then trip out to change the smaller bit to one of the wellbore diameter. The other disadvantage is that it produces a sudden sharp deflection or in other words a severe dogleg which may give rise to subsequent problems with the hole.

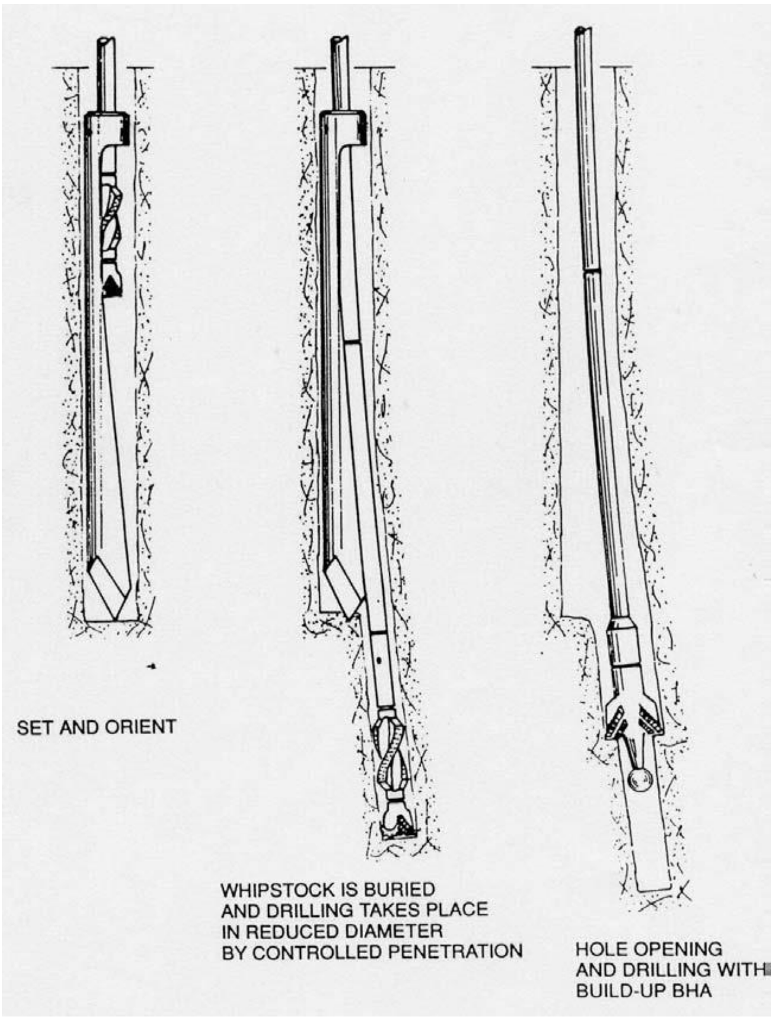


Fig 80: Whipstock (Courtesy of Maersk)

**Jetting bit.** Hydraulic deflection method of changing the trajectory of a wellbore requires the use of a jetting bit to wash away the formation. Drilling fluid is pumped through a large jet that is oriented in the direction of the desired trajectory change. Jetting is a technique best suited to soft-medium formation in which the compressive strength is relatively low and hydraulic power can be used to wash away a pocket of the formation to initiate deflection. To deflect a well using the jet method, the assembly is run to the bottom of the hole, and the large jet is oriented in the desired direction. The pump is started, and the formation below and adjacent to the bit is eroded. The assembly is gently spudded to force the bit into the eroded pocket. After several feet of jetting, the bit is set on bottom and drilling commences. Anywhere from 10 to 100 feet of hole can be drilled before jetting again. The amount of hole drilled will depend upon the deflection desired. The actual design of the jetting process is a function of hole size, pump capacity, expected formation hardness, and the desired bit cleaning efficiency while drilling. The amount of inclination produced is also related to the type of bottom hole assembly used with the jetting bits.

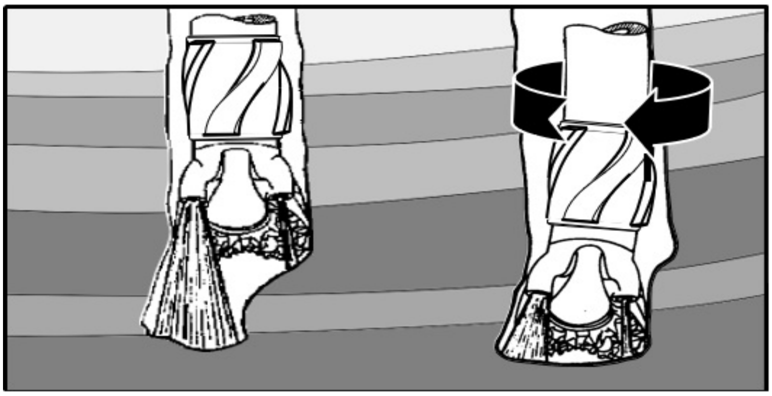

Fig 81: Jetting bit (Courtesy of Baker Hughes INTEQ)

**Bent sub and hydraulic motors.** The most commonly used technique for changing the trajectory of the wellbore uses a piece of equipment known as a "bent sub" and downhole hydraulic motor. A bent sub is a short length of pipe with a diameter which is approximately the same as the drill collars and with threaded connections on either end. It is manufactured in such a way that the axis of the lower connection is slightly offset (less than 3 degrees) from the axis of the upper connection. When made up into the bottom hole assemblies (BHA) it introduces a "tilt angle" to the elements of the BHA below it and therefore to the axis of the drill bit. Adjustable bent subs are similar to fixed angle bent subs, except the bend angle is adjustable while drilling. This saves tripping time to replace the fixed-angle bent sub when a different size of sub is needed. The bent sub must therefore be used in conjunction with a downhole hydraulic motor. The downhole hydraulic motors are driven by the flow of drilling mud down the drilling string, thus eliminating the need for rotating the drill pipe. Two types of the downhole hydraulic motors are turbine motor and positive displacement motor (PDM). The turbine motor consists of bladed rotors and stators mounted at right angles to fluid flow. The rotors are attached to the drive shaft, while the stators are attached to the outer case. The stators direct the flow of drilling fluid onto the rotor blades, forcing the drive shaft to rotate. Each rotor-stator pair is called a stage; a typical turbine motor may have 75-250 stages. A positive displacement motor (PDM) is a downhole hydraulic motor that uses the reverse Moineau pump principle to drive the bit without rotating the entire drill string. The motor can be powered using drilling mud, air or gas. It is constructed in a different way than the turbine motor, but use the same principles as with the rotor and stator. The PDM has a sinusoidal-shaped rotor fitted inside the stator, an elongated, rubber-lined cavity. The rotor has one or more lobes and is located inside a stator that has one more lobe than the rotor. Common motors use one rotor and two lobes for high torque. Increasing the number of lobes increases speed and reduces torque for a given size. When drilling fluid is pumped through the motor it is forced under pressure into cavities between rotor and stator.

The design of the motor is such that the rotor is forced to turn clockwise. This rotation is transferred via the drive shaft to the bit. One popular motor variation is the bent-housing motor, which has a bend constructed near the lower end. A universal joint transmits power through the bent section. This serves as a primary deflection tool for deviating. The mud motor is made up into the BHA of the drill string below the bent sub, between the bent sub and drill bit. A scribe line is marked on the inside of the bend of the bent sub, and this indicates the direction in which the bit will drill. A directional surveying tool is generally run as part of the BHA, just above the bent sub so that the trajectory of the well can be checked. periodically as the well is deviating.

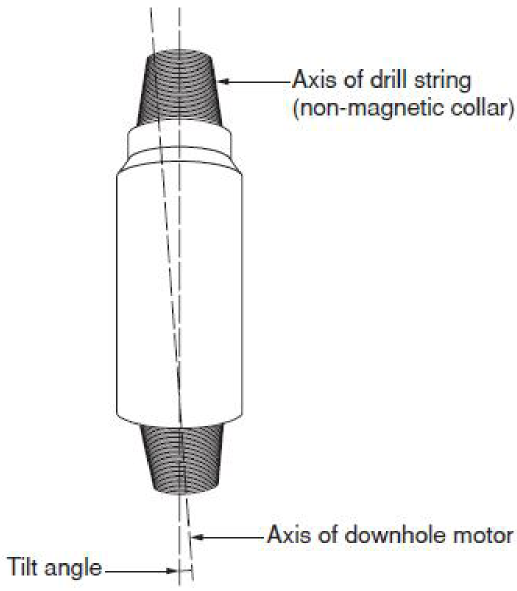


Fig 82: Bent sub (Courtesy of Heriot Watt)

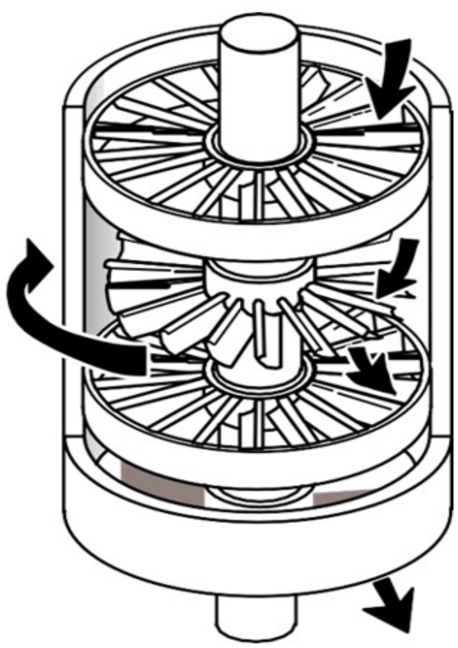

Fig 83: Turbine type motor (Courtesy of Baker Hughes INTEQ)

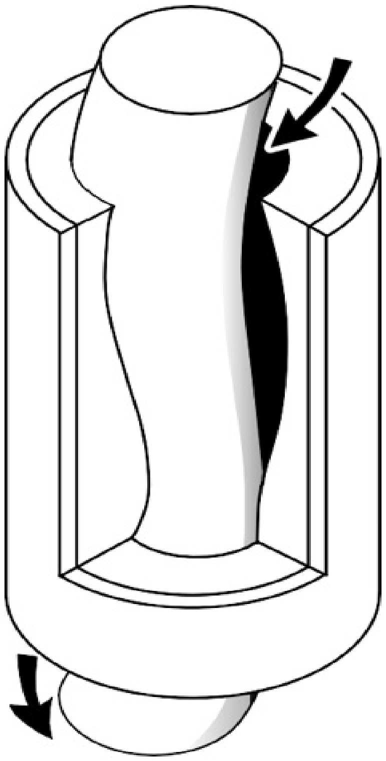

Fig 84: Positive displacement type motor (Courtesy of Baker Hughes INTEQ)

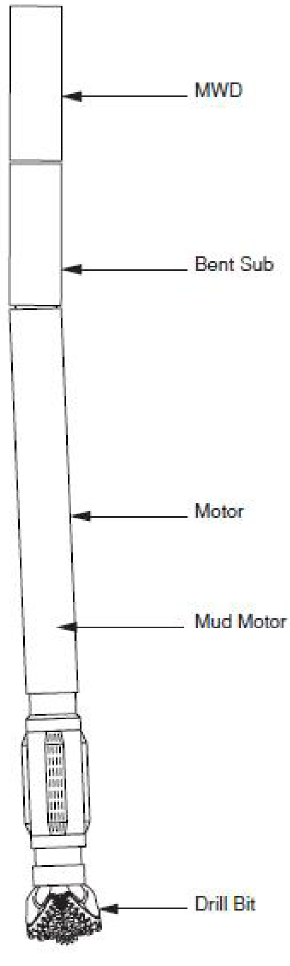


Fig 85: Bent sub and hydraulic motor (Courtesy of Heriot Watt)

**Steerable drilling system.** The increased application of downhole motors as deflection tools has led to the concept of having an adjustable component with the bottom hole assembly that is capable of altering the well path without having to pull out of the hole in order to change the bottom hole assembly. Such a steerable drilling system is comprised of a bit, a steerable motor, survey tools, and stabilizing unit(s). A real time downhole survey system is required to provide continuous directional information. A measurement while drilling, MWD system is typically used for this purpose. An MWD tool will produce fast, accurate data of the hole inclination, azimuth, and the navigation sub tool face orientation. A steerable drilling system allows directional changes (azimuth and/or inclination) of the well to be performed without tripping to change the BHA, hence its name. The capability to change direction at will is made possible by placing the tilt angle very close to the bit, using a navigation sub on a standard PDM. This tilt angle can be used to drill in a specific direction, in the same way as the tilt angle generated by a bent sub with the drill bit being rotated by the mud motor when circulating. However, since the tilt angle is much closer to the bit than a conventional bent sub assembly, it produces a much lower bit offset and this means that the drill bit can also be rotated by rotating the entire string at surface (in the same way as when using a conventional assembly). Hence the steerable assembly can be used to drill in a specific direction by orienting the bent sub in the required direction and simply circulating the fluid to rotate the bit (as in the bent sub assembly) or to drill in a straight line by both rotating and circulating fluid through the drill string. When using the navigation sub and mud motor to drill a deviated section of hole (such as build up or drop off section of hole) the term "oriented or sliding" drilling is used to describe the drilling operation. When drilling in a straight hole, by rotation of the assembly, the term "rotary" drilling is used to describe the drilling operation. The directional tendencies of the system are principally affected by the navigation sub tilt angle and the size and distance between the PDM stabilizer and the first stabilizer above the motor. The steerable drilling systems are particularly valuable where: changes in the direction of the borehole are difficult to achieve; where directional control is difficult to maintain in the tangent sections of the well (such as in formations with dipping beds) or where frequent changes may be required. The steerable systems are used in conjunction with MWD tools which contain petrophysical and directional sensors. These types of MWD tools are often called Logging Whilst Drilling, LWD tools. The petrophysical sensors are used to detect changes in the properties of the formations (lithology, resistivity or porosity) whilst drilling and therefore determine if a change in direction is required. Effectively the assembly is being used to track desirable formation properties and place the wellbore in the most desirable location from a reservoir engineering perspective. The term "Geosteering" is often used when the steerable system is used to drill a directional well in this way.

## Wellbore Survey

In both straight and deviated holes the position of the wellbore beneath the surface must be determined as the well is being drilled. When drilling a directional well, the actual trajectory of the well must be regularly checked to ensure that it is in agreement with the planned trajectory. This requires the use of surveying instruments that are able to measure the hole inclination and direction at various depths along the course of the well. These surveys will be taken at very close intervals (30 feet) in the critical sections, e.g. in the buildup section of the well. Whilst drilling the long tangential section of the well, surveys may only be required every 100 feet. If it is found that the well is not being drilled along its planned course, a directional orientation tool must be run to bring the well back on course. In general, the earlier such problems are recognized the easier they are to be corrected. Surveying therefore plays a vital role in directional drilling. The position of the wellbore relative to the surface location can be calculated from the cumulative survey results.

Surveying instruments. Surveying tools have been used in directional wells since the 1930's. The most simple tools consist of an instrument that measures the inclination and N-S-E-W direction of the well. A photographic disc contained within the instrument is used to produce an image of the surveying instrument. When the instrument is brought back to surface the disc is developed and the survey results recorded. There are two types of survey instruments: magnetic and gyroscopic. The magnetic instrument works on the principle related to earth's magnetic field. The instrument reading can be influenced by factors that affect the magnetic field. Magnetic survey instruments use a magnetic compass which points to magnetic north. In most cases, magnetic north is not the same as true geographical north, the North Pole. Therefore, the magnetic surveys have to be adjusted for the difference between the magnetic north and true geographical north. It is also important that any local magnetic field in the drill string is not allowed to distort the compass reading. The steel drill collars or drilling bit may become magnetized, creating "poles" especially near connections. To isolate the magnetic compass from possible distortion, the instrument must be contained within a non-magnetic environment. The instrument barrel and the drill collar within which it is measuring the survey angles must be made of non-magnetic materials. Magnetic instruments can be further broken into two categories: compass-based and electronic based. The compass units use various types of compasses to determine the direction of the well. The inclination and direction at the survey point are recorded on photographic film. Therefore, a compass-based instrument contains a compass and a camera. The electronic-based instruments obtain the hole direction from flux gate magnetometers and the hole inclination using accelerometers. The magnetometers measure the x, y and z components of the earth's magnetic field and the vectorial sum of these components will determine the direction. The earth's gravity component is measured by a three axis accelerometer to determine inclination. The magnetic instruments are used for single-shot and multi-shot surveys. As the name suggests, the single-shot unit takes one picture at the survey point. The unit is retrieved from the wellbore and the film developed to determine the direction and inclination of the hole. The multi-shot instrument operates in the same manner as the single-shot except it is capable of taking more than one survey per run. For the compass unit, a reel of film records numerous surveys at different depths. With an electronic unit, the surveys are stored in memory. Gyroscopic instruments use a spinning gyro to determine the direction of the well. The gyro is used where magnetic survey instruments cannot be used such as in cased hole and in areas where magnetic interference is encountered. The gyroscope consists of a spinning wheel mounted on a horizontal axis and driven by an electric motor at speeds up to 40,000 rpm. The direction in which the gyro is spinning is maintained by its own inertia, and so can be used as a reference for measuring azimuth. The gyroscope may also drift away from its set direction while it is being run in the hole. When the instrument is recovered therefore, its alignment must be checked, and a correction applied to the readings obtained from the survey.

The direction angles obtained by magnetic tools must be corrected for true north and the gyroscope corrected for drift since the magnetic north does not coincides with the true north. During the critical kick-off stage in the drilling of a directional well it is necessary to survey the well at close intervals. It is to have an instrument that can be run in the bottom hole assembly to survey the well continuously while it is being drilled with a downhole motor. The surveying tool is generally called "steering tool", since it provides the directional driller with the necessary information to steer the bit in the correct direction. A steering tool is a wireline telemetry surveying instrument which measures inclination and direction while drilling is in progress. The downhole component of the steering tool is called a probe which continuously measures hole direction and the position of the tool face. This data is sent via the wireline to a surface unit which gives a numerical read-out and may also give a circular dial showing the orientation of the tool face with respect to the high side of the hole. This is of particular value to the directional driller because he can see how the tool face is changing as the well is being drilled. If the tool face must be changed by rotating the pipe the steering tool will give the new heading instantaneously. This makes the orienting procedure very much simpler and saves a lot of time. The directional driller can use the steering tool to make the well build or drop, turn to left or right depending on the orientation of the tool face shown on the surface dial. The steering tool allows the directional driller to see exactly what is happening downhole.

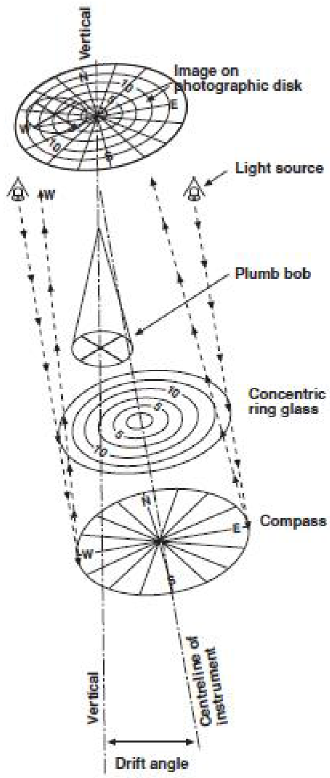


Fig 86: Magnetic single shot instrument (Courtesy of Heriot Watt)

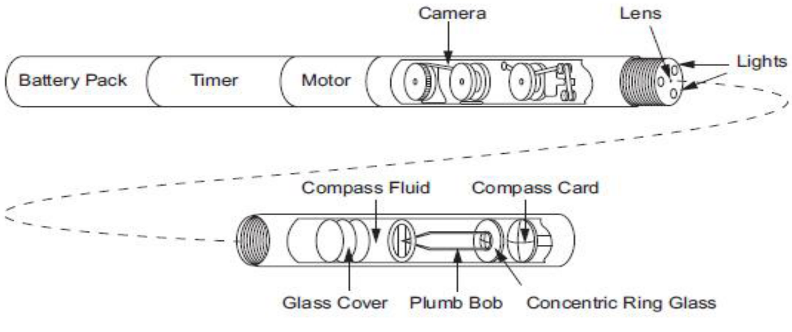


Fig 87: Magnetic multi shot instrument (Courtesy of Heriot Watt)

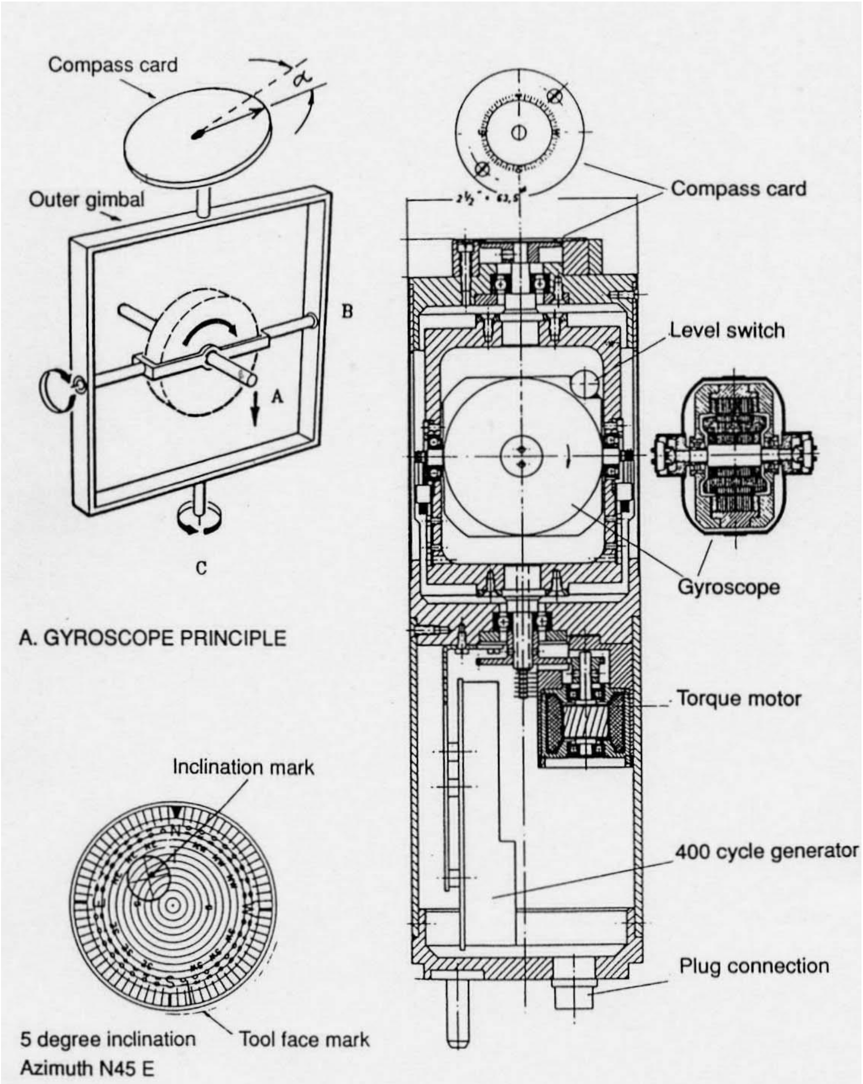


Fig 88: Gyroscopic instrument (Courtesy of Maersk)

**Measurement While Drilling** - MWD systems allow the driller to gather and transmit information from the bottom of the hole back to the surface without interrupting normal drilling operations. The systems have been primarily designed and utilized as a means of improving the efficiency of the drilling operations by minimizing lost time due to time consuming activities such as borehole surveying and wireline logging as well as obtaining drilling parameters, e.g. weight on bit, downhole torque. The information is gathered and transmitted to surface by the relevant sensors and transmission equipment which is housed in a non-magnetic drill collar in the bottom hole assembly. The data is transmitted through the mud column in the drill string, to surface. At surface the signal is decoded and presented to the driller in an appropriate format. The transmission system is known as mud pulse telemetry and does not involve any wireline operations. Since there is no wireline connection to surface all the power required to operate the MWD tool must be generated downhole. This means that either a battery pack or a turbine-alternator must be installed as part of the MWD tool. All MWD systems have certain basic similarities namely, a downhole system which consists of a power source, sensors, transmitter and control system, a telemetry channel (mud column) through which pulses are sent to surface, and a surface system which detects pulses, decodes the signal and presents results. The systems encode the data to be transmitted into a binary code and transmitting this data as a series of pressure pulses up the inside of the drill string. Tools also include the ability to record downhole data for later retrieval at surface. Because the amount of data measured by while drilling techniques can be large, mostly not all measurements are continuously transferred to the rig. Data that are not transferred are commonly stored and retrieved at the following trip.

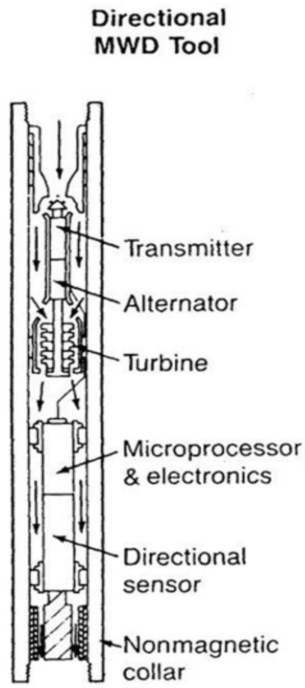


Fig 89: Simplified diagram of MWD tool (Carden et al. 2007)

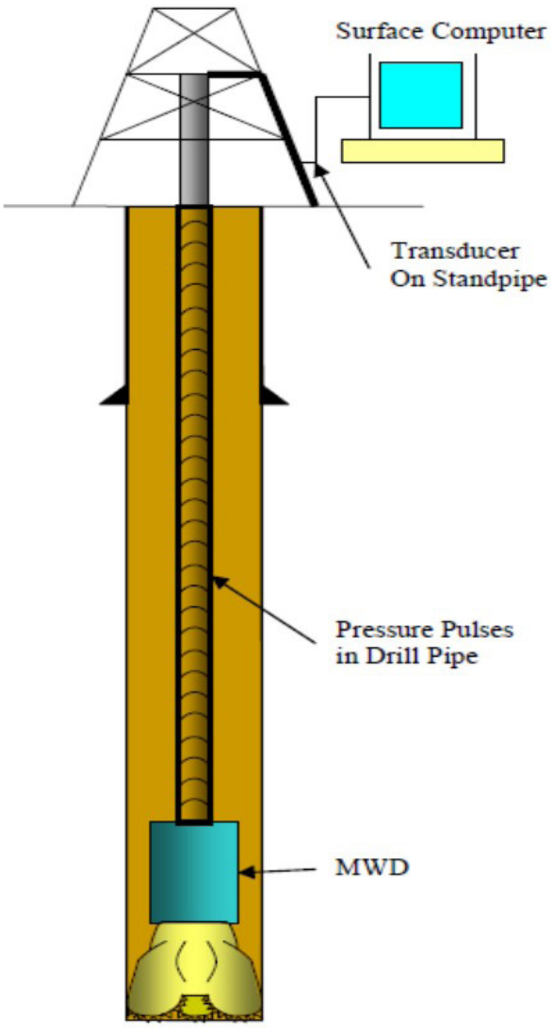


Fig 90: Schematic of MWD transmission system (Carden et al. 2007)

# WELL CONTROL

## Introduction

The function of well control can be conveniently sub-divided into two main categories, namely primary well control and secondary well control. Primary well control is the maintenance of sufficient hydrostatic head of fluid in the wellbore to balance the pressure exerted by the fluids in the formation being drilled. However, it should be noted that balancing formation pressure is a theoretical minimum requirement; good drilling practice dictates that a sufficient excess of hydrostatic head over formation pressure, be maintained at all times to allow for contingencies. This excess head is generally referred to as trip margin or overbalanced. If for any reason the effective head in the wellbore should fall below formation pressure, an influx of formation fluid (kick) into the wellbore would occur. If this situation occurs the blowout preventers (BOPs) must be closed as quickly as possible to prevent or reduce the loss of mud from the well. The purpose of secondary well control is to rectify the situation by either allowing the invading fluid to vent harmlessly at the surface, or closing the well in. i.e. providing a surface pressure to restore the balance between pressures inside and outside the wellbore. This secondary well control prevents any further influx of formation fluid and allows any one of a variety of kick removal methods to be applied thus restoring a sufficient hydrostatic head of fluid in the wellbore. This re-establishes the preferred situation of primary well control.

A comprehensive study of all available information on the area to be drilled is invaluable when selecting a well plan which will minimize the drilling hazards without affecting the goal. This is equally important whether the goal is a producing well or an exploratory hole. Unfortunately on wildcat locations little or no information may be available from offset wells, thus the amount of pre-spud information could be limited. On development and production work the experience gained from previous nearby wells can be of great assistance. Determination of formation pressure is estimated by a number of methods. These methods rely on establishing the normal trend of measured shale properties with depth and subsequently identifying any departures from the normal trend which could indicate overpressure zones. Formation Pressure is the pressure of the fluid contained in the pore spaces of sediments or other rocks. It is also called Pore Pressure. Normal hydrostatic formation pressure depends on the weight of the column of water saturating the pore spaces of the sediments. The density of this formation water varies depending on its salinity, depth and area. An average density is assumed to be 0.465 psi/ft. A hydrostatic formation pressure implies a connection between the pore spaces of the rock and surface or atmosphere. Abnormal Formation Pressures are pressures which for various reasons are caused by pressure gradients substantially higher than normal. i.e. having a gradient higher than 0.465 psi/ft that is exerted on the exposed annular formations. Subnormal Formation Pressures are those which have a fluid pressure gradient that is less than 0.465 psi/ft. The primary means of controlling the flow of formation fluid into the well bore is the drilling fluid.

Formations are subjected to varying forces of compressive and tensile stresses. These are conditions which exist before drilling. When drilling, an induced fracture can occur if the forces or the pressure exerted by the mud on the walls of the drilled hole exceed the strength of the rock. When drilling into a permeable zone with a mud density that exerts less pressure than the fluid pressure within that zone, the pressure unbalance or differential pressure will result in a kick. Detection of formation pressure changes before the well goes underbalanced is therefore an essential step in maintaining primary control of the well. Constant monitoring of the mud density being pumped and of the mud returning from the well must be made. A significant increase in the rate of penetration is often indicative of a change in the formations being drilled. These new formations could have the potential to cause kicks. A more gradual change in the rate of penetration could signify that an abnormal pressure zone is being drilled.

When a drilling break is recorded the depth drilled should be kept to a minimum. Drilling breaks should be flow checked. Drilling with a fluid that has been unintentionally diluted may result in mud exerting less pressure than the fluid pressure within that zone. This may occur as formations being drilled can release gas into the mud, as the gas is moved up the well bore, it will expand causing a reduction in the mud weight as it gets to the surface. Overall the reduction of the bottom hole pressure is generally slight.

When pulling the drill string, bottomhole pressure can be reduced below formation pressure, allowing an influx of formation fluids in to the wellbore. The pressure reduction is caused by friction between the mud, the string that is being pulled and the walls of the hole. When pulling the string there must be a flow of mud past the bit to compensate for the steel being pulled. Any restriction to a free flow of fluid past the bit will cause a reduction to bottomhole pressure. A safety overbalance or trip margin is normally applied to the mud to compensate for swabbing. Constant monitoring to ensure that; a) the well takes the correct amount of mud, b) the correct replacement of mud when tripping out and, c) the correct displacement when tripping in. It is essential that mud volumes be monitored using a trip tank. If the hole fails to take the correct amount of mud, this can be detected at the trip tank. A trip sheet is used to record the volume of mud put into or displaced from the well. Trip sheets should be maintained whenever tripping takes place. It may be necessary prior to tripping to have the mud reconditioned. Circulate the hole clean. Observe for any tight spots when pulling. If there is any likely hood of swabbing then each stand should be circulated out until above the potential swab zone. When pulling the drill string from the well, a volume of steel is being removed. If the hole is not filled up with mud to compensate for this, a reduction in bottomhole pressure will occur. If this reduction exceeds the safety overbalance, a kick may occur. The hole must be kept full when tripping, using a trip tank to monitor that it takes the correct amount. If the mud level in the well drops, a reduction in bottomhole pressure will occur. If this reduction exceeds the hydrostatic safety overbalance a kick can occur.

## Kick

A kick is the unwanted influx of formation fluids into the wellbore. For a kick to occur, formation pressure must exceed hydrostatic pressure. If a kick starts to occur whilst drilling, the influx fluids will follow the path into the annulus. The results of a kick include lost operation time, hazardous operation with high pressure and gas, and possible equipment losses during attempts to regain control of the well. If recognized and controlled in time, the kick can be handled and removed from the well safely. If the kick is allowed to continue, it may no longer be able to be controlled. This is said to be a blowout or uncontrolled kick. Since a kick may happen at any time, we must be able to recognize, identify and react to all kick warning signs. These signs indicate either that the conditions for a kick exist or that the well may be kicking. It makes sense that all possible means should be used to prevent kicks. The rate that the fluids flow into the well will be governed by some of the following factors:

- The type of influx fluid: Gas; Oil; Water
- The permeability and porosity of the exposed formations
- The length of exposed formations
- The differential pressure: the pressure difference between formation pressure and mud hydrostatic pressure.

Delays in responding to kick detection will result in large volume kicks. High annular pressures and, in the worst case scenario, a blowout could occur with possible fatalities due to fire or poisonous gas hazards, pollution and other environmental problems. Early kick detection is imperative. When a kick is detected the well should be closed in immediately. A large gas kick will result in a high annular pressure initially at shut-in and during the subsequent kill operation. There is the additional hazard of venting the very large volumes of gas at surface.

Two essential pieces of instrumentation on the rig are pit level indicators and flow rate indicators. Mud pit level indicators were originally a piece of string with a nut tied to the end of it. The derrick-man could notice any changes in level by adjusting the nut to sit on top of the mud. This method is still used by the derrickman but is backed up by air/electric/ultrasonic monitors. These monitors register volumes, losses and gains at the driller's console. Return flow lines are now fitted with paddle type or strain gauge type sensors to measure flow. Air/electronic signals are sent to a dial at the driller's console. Variations of flow can be noticed as either a percentage of flow or barrel per minute scale. Floating rigs generate surge in the flow line which makes the system difficult to read, but electronic dampers do help to reduce surge and steady the gauge. Computers are now becoming more popular to analyze important data.

A reduced circulating rate is used in conventional well kill operations. A slow circulating rate pressure is recorded for each pump. The pump is typically run at 30 strokes per minute and the pump pressure is recorded. The pump is then run at 40 strokes per minute and the pump pressure is also recorded. This reduced circulating pressure is reestablished whenever anything in the circulating system is changed. i.e. mud weight change, mud pump liner change, bit nozzle change, and drilling approximately 500 feet interval. Factors to be considered in selecting a slow pump speed to kill a well will be size and nature of the kick, surface pressures, pressure safety tolerance, and condition of the hole. When a kick is being circulated from a well bore, the choke operator is manipulating the choke device from the choke panel and maintaining a predetermined bottom hole pressure. A slow pump rate makes choke control easier. It gives the operator more time to react to any potential problem. It will minimize pressures in the well bore. Other considerations are:

• Displacement rates should not exceed the rate that weight material can be mixed.
• Displacement rates should not exceed the handling capabilities of the surface equipment.
• A pump rate should be selected that will reduce or minimize interruptions during the kill operation.

The total pressure acting on the wellbore is affected by pipe movement upwards or downwards. When tripping out swab pressure is created, reducing the pressure on the wellbore. Swabbing occurs because the fluid in the well does not drop as fast as the string is being pulled. This creates a suction force and reduces the pressure below the string. This force can be compared to a plunger in a syringe, with formation fluid being pulled into the wellbore. When lowering the string too fast, surge pressure is created because the fluid does not have a chance to get out of the way. Since liquids do not compress to any appreciable degree, pressure throughout the well can increase and cause leak-off or fracture. Both surge and swab pressures are affected by the rate of pipe movement, clearances between pipe and hole and fluid properties. While it is often impossible to avoid these pressures, they can be minimized by slowing the tripping speed.

## Kill Methods

The objective of a kill method is to circulate out the influx fluids and displace the well to a suitable kill mud without allowing further influx fluids into the well bore. This should be done with the minimum damage to the well bore. The kill mud that is circulated is normally a mud that will balance formation pressure. Safety factors can be added after the kill operation.

**Driller's Method.** The Driller's method is a technique used for circulating formation fluids out of well with or without killing the well. It is often used to remove kicks swabbed in during a trip out of the hole. Driller's method is simple and straightforward. In certain case, however, the Driller's method may cause somewhat higher casing pressures than do other techniques and requires more time to kill the well. It is ideally suited for tripping applications. Once back to bottom the annular fluid column is circulated and the influx removed. It is also used where no weighting material is needed or available. In addition, it is used to remove gas kicks where high migration rates can cause shut in problems. It may also be used where personnel and/or equipment resources are limited. However, it is not often used on wells where lost circulation is anticipated or expected. This operation is split into two stages. During the first stage, the influx is circulated out using the mud that exists in the well. Once the influx is out of the well and it is shut-in. The second stage is displacing the well to kill mud. The advantage of this method is that it involves the least waiting time. The operation can be started quickly. It is less complicated, particularly in high angle hole sections.

**Wait & Weight Method.** The Wait and Weight method is a compromise of the various advantages and disadvantages inherent in the different constant bottom hole pressure methods. The wait and weight method kills the kick in the shortest time and keeps the wellbore and surface pressures lower than any other method. It requires good mixing facilities for weighting the fluid, full crews, and additional supervisory help. All are available on most marine rigs and on deep or geo-pressured land operations. For some companies this is the preferred method for killing a well. In the wait and weight method, the well is shut in after a kick. The stabilized pressures and kick size are recorded. The fluid weight is increased before starting to circulate, thus the name, wait and weight. Then the fluid is circulated through the well, maintaining the correct weight and pressures while killing the well. When the well is shut-in a kill mud will be determined. This is a single operation that will displace the well to kill mud as the influx is being circulated out.

**Concurrent Method.** The Concurrent method, which involves weighting up fluid while in the process of circulating out the kick, has also been called the circulate and weight method or slow weight-up method. It is a primary constant bottom hole pressure well killing method. To execute the concurrent method some bookkeeping and calculations are required while in the process of circulating out the kick because there may be several different fluid weights in the string at irregular intervals. Because some of the calculations must be done on the fly, operational personnel have often opted for either the driller's or the wait and weight method, dismissing the concurrent method as too complicated.

Should a well flow with the bit off bottom, the first action will be to shut the well in using the appropriate procedure. The influx is probably due to swabbing when the string was being pulled or the hole was not being filled up. The influx will generally be below the bit. When the well is shut-in initially, surface pressures and pit gain will be recorded. If the recorded shut-in drill pipe pressure and the shut-in casing pressure are the same, this will indicate that the influx is below the bit. The main reason for stripping is to get the bit below the influx, so that the influx can be circulated out of the well. The drill pipe that is to be stripped through the closed preventer will have a non-return type safety valve fitted. As the pipe is being lowered into the closed well, the choke operator will maintain a surface pressure by bleeding off a volume of mud that will correspond to the volume of steel being stripped in, this being the closed end displacement of the pipe. Stripping will take time and will place high levels of stress on the BOP equipment as the pipe is lowered through the closed preventer.

**Volumetric Method.** The Volumetric method can be described as a means of providing for controlled expansion of gas during migration. It can be used from the time the well is shut in after a kick until a circulating method can be implemented and can be used to bring a gas kick to the surface without using a pump. As with other constant bottom hole pressure methods, the volumetric method is based on the principles of the gas law. It trades pressure for volume at the appropriate time to maintain a bottom hole pressure that is equal to, or slightly higher than, the kicking formation pressure without exceeding the formation fracture pressure. The volumetric method is not intended to kill the kick, but rather it is a method of controlling the downhole and surface pressures until killing procedures can be started. In cases of a swabbed in kick, it can be used to bring the influx to surface. And, providing no additional influx allowed in, volumetric techniques can be used to replace the gas with fluid to bring the well back into hydrostatic pressure control. The primary concern is that migrating gas can cause pressure increases at the surface, downhole and throughout the well that could in turn cause surface equipment or casing failure, or formation break-down with resulting lost returns and possibly an underground blowout. The volumetric method reduces these high pressures by a systematic bleeding of fluid to allow expansion of gas.

**Lubricate and Bleed Method.** The Lubricate and Bleed method is often a continuation of the volumetric method, and is used once kick fluid reaches the wellhead. It is also used if perforations or circulating ports in the tubing are plugged, tubing is sanded up or plugged, circulation is not feasible or high well pressures start to reach rated wellhead pressure ratings. In the lubricate and bleed method, fluid is pumped into the well and allowed to fall down into the annulus. Sufficient time must be allowed for the fluid to begin to increase the annular hydrostatic pressure. Since hydrostatic pressure was added to well, backpressure may be taken or bled off equal to the gain of hydrostatic. To begin lubricate and bleed, fluid must be pumped into well. This fluid must be carefully measured. From the number of pump strokes or from a measure of volume pumped, length of fluid when in the wellbore can be calculated. Once length is known, the gain in hydrostatic pressure created by it can be determined. This value will be bled off on surface.

**Bullheading Method.** Bullheading, also called deadheading, is a common way to kill a well in workover in some areas. This technique works when there are no obstructions in the tubing and injection into the formation can be achieved without exceeding any pressure limitations. In bullheading, the well fluids are pumped back into the reservoir, displacing the tubing or casing with a sufficient quantity of kill fluid. Bullheading is applicable in some drilling circumstances, mainly if hydrogen sulfide kick is taken. It may be preferable to pump it away, back into the formation, instead of bringing it to the surface. Another bullheading technique, used mainly in drilling requires pumping into the annulus and not allowing returns through the drill pipe. As mentioned, this does have applications such as sour gas, and kick sizes too large to bring to surface or where surface equipment cannot withstand the anticipated maximum pressure which could be placed on it. It should be remembered that the decision to bullhead in drilling must be made before hand, as part of the shut in procedure. If there is delay before the decision is made to use this technique, gas may migrate up, and decrease the chances of forcing the kick back into the formation that produced it. Pumping this way which is pressuring up the wellbore, can result in formation fracture at the shoe or other weak points in the system.

## Shallow Gas

Shallow gas is produced from the burial of organic material degrading in buried sediments. A study of blowouts worldwide shows that the largest and most single cause of all blowouts occurred as a result of encountering shallow gas. Probably the most common occurrence for a shallow gas kick would be when drilling to set suface casing. Shallow gas kicks can result from any or a combination of the following:

- Drilling into a gas-bearing sand with insufficient mud weight.
- Swabbing gas into the well bore when tripping. If it is necessary, circulate out of the well to avoid swabbing.
- Not keeping the hole full can lead to a loss of hydrostatics. Good practices should prevent this from occurring.
- Any reduction in hydrostatics, such as a loss of circulation. Penetration rates should be controlled to prevent overloading the annulus with cuttings.
- Gas cutting of the mud or any gas influx will reduce hydrostatics.

When a gas starts to enter into the well bore, mud will be displaced at surface from the well and hydrostatics will be reducing. This reduction in hydrostatics will increase the gas inflow rates. As the gas inflow accelerates, more & more mud is being displaced until the remaining mud is blown from the well.

## Blowout Preventer System (BOPs)

The blowout preventer (BOP) system is actually a unique set of very large hydraulic valves. The BOP stack may be built in a variety of configurations. The stack usually comprises of annular preventer, ram preventers, and drilling spool. The most important consideration of how the stack is organized is what appears to be the greatest hazard that may be encountered. To cover all possible scenarios and handle different kick situations, different BOPs are collectively attached to the wellhead. From the viewpoint of well control, the purpose of the BOP stack is to close in the well when a kick occurs and still allow the greatest flexibility for subsequent operations. If this is kept in mind, many possible stack configurations are satisfactory. Critical concerns of well control operations are some inherent limits such as pressure, heat, space, economics, etc., in the design or operation of the stack.


Fig 91: Blowout preventer stack

**Annular Preventers.** Commonly known as bag type preventers or spherical preventers. As their name implies they are designed to seal off the annulus, but can be used to completely seal off an open hole. One special feature is that the annular preventer will allow for stripping procedures. Normal operating pressures are in the range of 600 - 1,500 psi. Certain models obtain assistance in sealing from well pressures. The main advantage of annular preventers is that they can seal around any sizes and shapes of pipe. Spiral drill collars often require higher closing pressure to get an effective seal.

Fig 92: Annular preventer (courtesy of Hydrilpressurecontrol)

**Ram Preventers.** Rams come in many sizes and pressure ratings. There are many types of custom built or specialty rams designed for particular applications. Rams range from simple manual one-ram sets to multiple-ram set bodies. Simple rams may consist of a polished rod that closes by turning handles on either side to screw the ram inward and around the pipe. Complex multiple sets of rams may be housed in a single body remotely operated by hydraulic pressure.

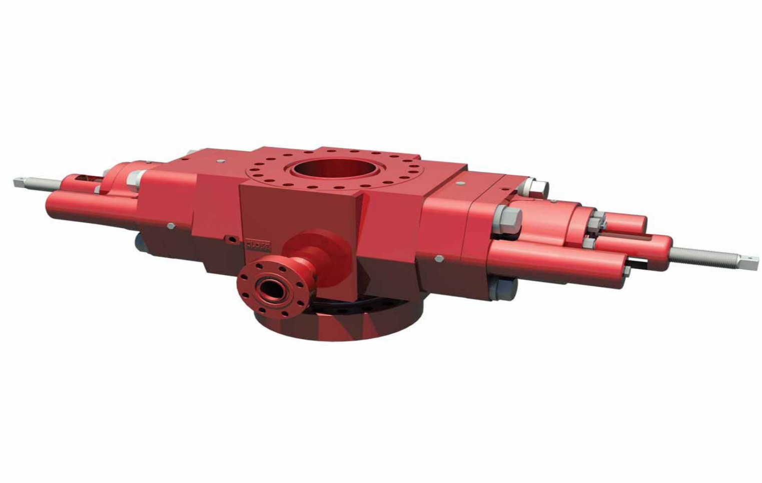

Fig 93: Ram preventer (Courtesy of Schlumberger)

**Pipe Rams.** Pipe rams are designed to seal around a specific size of pipe body (not tool joints) i.e. 5” rams for 5” drill pipe. Closure on open hole is not recommended as the rubber packing element will be extruded and possibly damaged. Reciprocating the pipe will also wear the element. Pipe rams are considered more suitable for high pressure use. They are easier to service and are installed below annular preventer. They can be locked in the closed position and are designed to support the weight of the drill string when hung off. Rams normal operating pressure 1,500 psi. During most kill operations the uppermost pipe rams are used to seal off the annulus. Choke and kill lines are therefore always found below top rams.

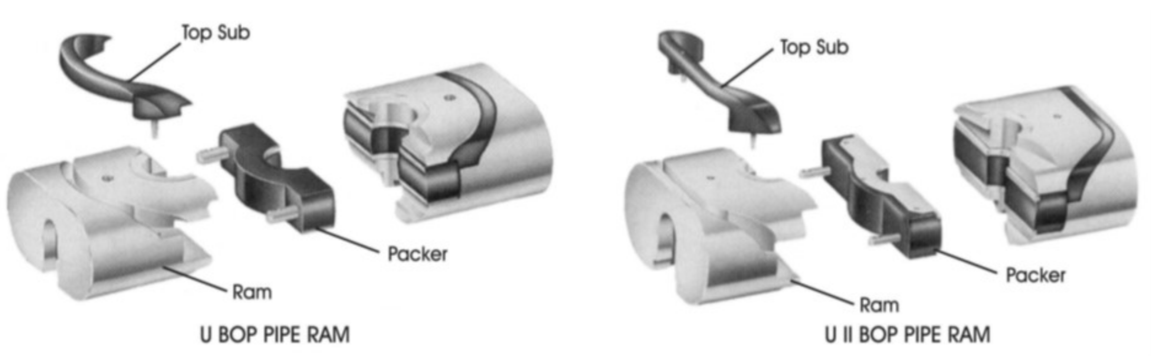


Fig 94: Pipe rams (Courtesy of Weatherford)

**Blind and Shear Rams.** Blind rams are designed to seal the well if no pipe is in the hole. They have flat edges, so will not cut through the pipe if accidentally closed. Shear rams are a type of blind ram. Their function is cut the pipe and then seal off the wellbore. Because this action will cause the drill string to drop, the tool joint of the pipe should be set on a lower set of pipe rams.


Fig 95: Blind rams

**Variable Bore Rams.** Variable bore rams are designed to seal on a variety of pipe body sizes, they have a front packing element similar to that of an annular preventer.


Fig 96: Variable bore rams

**Shear Blind Rams.** Shearing blind rams shear the pipe in the hole, then bend the lower section of sheared pipe, allowing the rams to close and seal. They can be used as blind rams during normal operations. The operating pressure required to shear pipe is 3,000 psi and the maximum size of pipe that can be sheared is 5½” outside diameter. Shearing blind rams will shear pipe numerous times without damage to the cutting edge. The ram incorporates a single piece body with an integrated cutting edge.

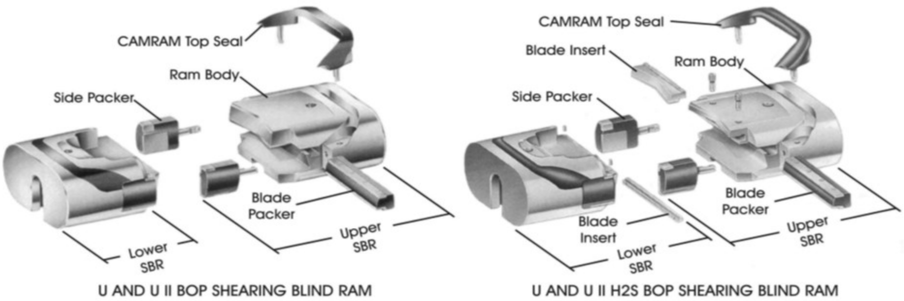


Fig 97: Shearing blind rams (Courtesy of Weatherford)

**Drilling Spool.** A drilling spool is a connector placed within the BOP stack, to which are attached the choke and kill lines. They must have pressure ratings equal to the stack and a bore that will allow the largest diameter equipment to be lowered into the well. Like all other stack equipment the spool should be studded, flanged or a clamp on type connection. Certain rams have integral choke and kill line connections and, therefore, no spool is required.

Fig 98: Drilling spool

**Diverters.** Diverters are used to direct flow to a safe distance from the rig. A diverter system consists of an annular type preventer, a large diameter vent line or lines and vent line valves. A diverter is not designed to shut-in or halt flow, but rather permits routing of the flow to a safe distance away from the rig. At this stage of drilling, if the well is completely shut-in uncontrolled flow around the outside of the shallow casing could result. The rate of pressure of the diverter and vent lines is not of prime importance. Rather they are sized to permit diversion of well fluids minimizing wellbore back pressure. Vent lines usually vary from 4 inch to 12 inch. Vent line valves should be fully opening and designed to automatically open whenever the diverter is closed. In addition, regular checks for plugging with drill cuttings or other debris are recommended. Shallow wells that are blowing out usually bleed down or bridge off quite soon.

Fig 99: Diverter

The purpose of an accumulator system is to provide opening and closing power to the BOPs. The system is hydraulic and is designed to close the BOPs quickly and to be able to maintain closing pressure. The closing pressure can be adjusted according to the operation requirements.

Fig 100: Accumulators and BOP control system

Chokes serve under severe conditions during a well kill operation. They must maintain the proper amount of back pressure on the wellbore to control formation pressure as mud is pumped into the well through the drill pipe or kill line. Chokes are susceptible to erosion and plugging. For these reasons, multiple chokes are always made available. Choke manifolds must perform the rugged task of controlling the release of high pressure wellbore fluids during the kill process. At high working pressures, it is desirable to use more than two chokes. Adjustable chokes allow the quick changes in choke opening sizes which are required during the kill process. The orifice size is changed by turning a hand wheel on the choke itself. A right-hand thread operates a hard steel tungsten carbide needle valve inside of the choke. A remotely operated choke allows personnel to monitor casing pressure, drill pipe pressure, and pump strokes while operating the choke. Several different types of remote chokes are available.

Fig 101: Choke manifold

**Mud Gas Separator** (Poor Boy Degasser). The height and diameter of an atmospheric separator are critical dimensions which affect the volume of gas and fluid the separator can efficiently handle. As the mud and gas mixture enters the separator, the operating pressure is atmospheric plus pressure due to friction in the gas vent line. The vertical distance for the inlet to the static fluid level allows time for additional gas break-out and provides an allowance for the fluid to rise somewhat during the operation to overcome friction loss in the mud outlet lines. The separator inlet should have at least the same inside diameter as the largest line from the choke manifold which is usually 4 inch. An 8 inch minimum inside diameter gas outlet is usually recommended to allow a large volume of low pressure gas to be released from the separator with minimum restriction. Care should be taken to ensure minimum back pressure in the vent line. This line is recommended to minimize frictional losses.

Fig 102: Mud gas separator

## Safety Valves

The Gray inside BOP is a heavy-duty drop check valve with a conical plug to reduce the cutting action of the mud on the valve seat, ensuring positive closure whenever required. Installed in the drill string, it protects the rotary swivel, rotary hose, standpipe, and mud pumps from drill pipe kicks. It may be used along with high-pressure pumps to maintain well control by preventing high-pressure backflow. A special release tool allows the valve to be held open to permit stabbing into position against a backflow of fluid. This optional release tool can be installed on the float valve and the entire assembly kept ready on the rig floor for quick installation at the first signs of serious backflow when drill pipe is pulled from the well. Standard inside BOP units are designed for service pressures up to 10,000 psi, but all sizes may be supplied on special order for higher service pressures. Size requirements are based on the box and pin thread, and size of casing or drill pipe. O-rings normally supplied are limited to use at well temperatures below $+250^{O}F$, but other compositions are available to use at extremely high or low temperatures. Special metallurgical requirements may be met for extremely low temperatures or corrosive environments.

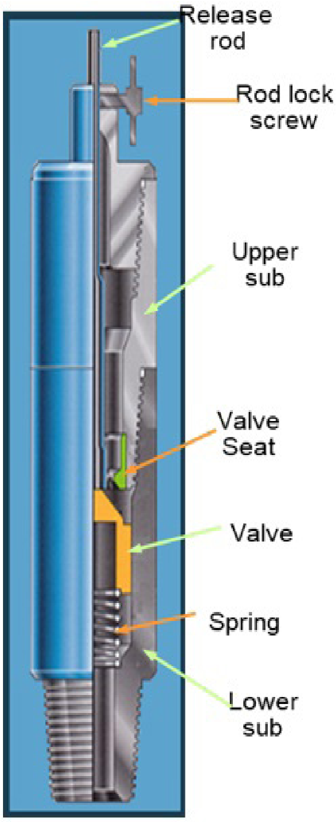


Fig 103: Inside BOP valve (Courtesy of Petroleum Training Services)

Kelly cock is a manually operated ball valve used to close the bore of the drill string to flow. The Kelly cock valves facilitate well control and prevent mud spillage. They are attached above and below the Kelly to close the bore to upward flow from the wellbore, or downward flow during a connection.

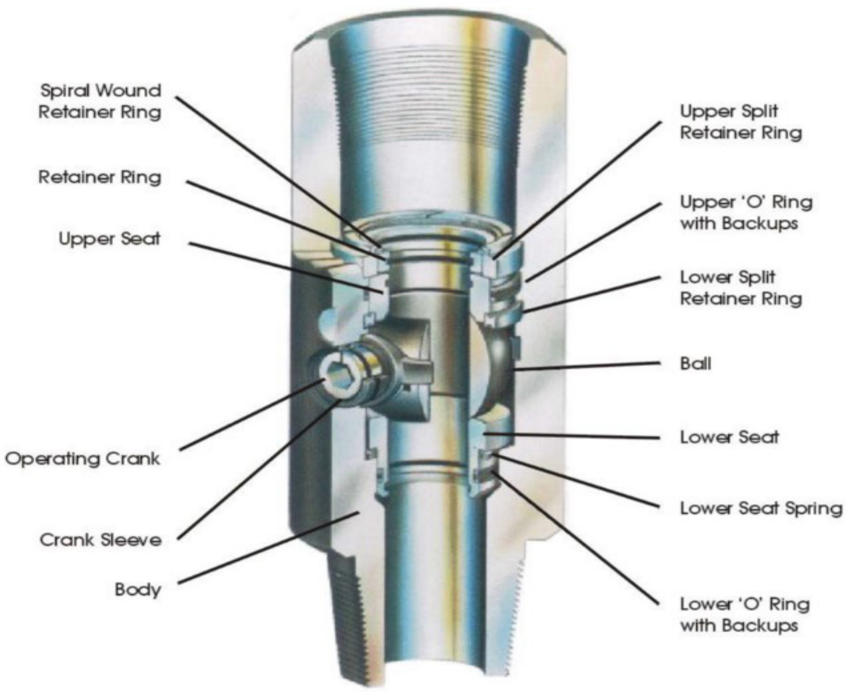


Fig 104: Kelly cock valve (Courtesy of Petroleum Training Services)

Dart valve is a drop-in check valve for the drill string. The check valve remains at surface until needed and is retrievable by wire line. It provides the driller with a means to control the drill pipe pressure when required. The check valve prevents upward flow through the drill pipe, but also allows fluid to be pumped downward to circulate the well. Only the landing sub is installed as the drill string is run. When control is needed, the valve is pumped down the string where it latches automatically in the landing sub. The check valve sits in the landing sleeve, latching positively. The sleeve has recessed areas into which the check valve packer seals. The valve seals pressure up to 10,000 psi yet is lightweight and easily handled. The valve can be retrieved by tripping the pipe out of the hole or by wireline.

Fig 105: Dart valve (Courtesy of Petroleum Training Services)

Drill pipe float valves are normally installed directly above the drill bit. In the simplest terms they are non-return valves. They enable circulation down the drill string only and provide instantaneous shut-off from the annulus whenever the pumps are turned off. While drilling their main function is to prevent backflow while making connections. They also provide fluid flow control at the bottom of the drill string during tripping or when shut-in. Two common types are the spring loaded float valves and the flapper type float valve. The flapper type valve incorporates a built-in latch which allows tripping the drill string into the hole with the valve in the open position, thus eliminating the need to fill the pipe. This also has the effect of reducing surge pressure. The latch is automatically released by initial circulation of mud. As soon as circulation is stopped the valve closes. Some flapper valves are vented to permit the reading of pressures during shut in conditions. The spring loaded float valve has similar functions as mentioned above. Some variations are ported with a small hole drilled through the center of the valve, enabling drill pipe pressure to be recorded during shut-in conditions. The main disadvantages when running float valves are summarized by higher surge pressures, inability to read drill pipe pressure or reverse circulate, and having to stop to fill the pipe.

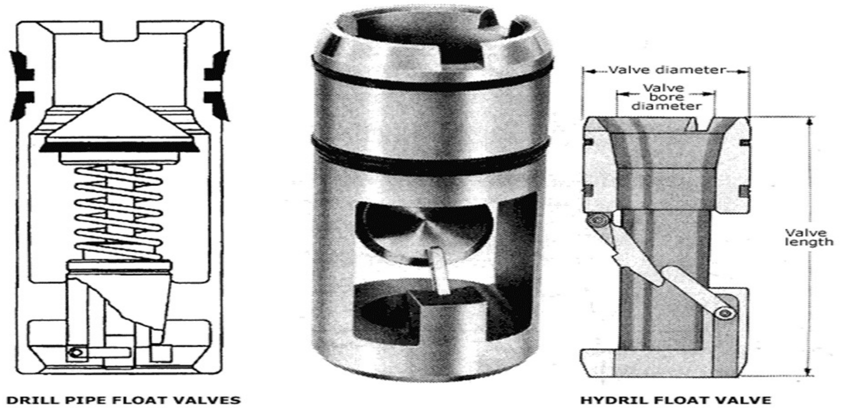


Fig 106: Float valves (Courtesy of Petroleum Training Services)

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