POLITECNICO DI TORINO

Department of Environment, Land and Infrastructure Engineering

Master of Science in Petroleum Engineering

Master of Science Thesis

Innovative Drilling and Completion Technologies

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November 2020

ABSTRACT

The oil and gas industry has developed fast in terms of drilling efficiency and cost savings in the 1990s. Some drilling milestones were quite notable at the end of the 20th century.

Although we are performing significant progress, the enlargement of the world economy has given rise to escalating demands for petroleum, giving the energy industry new challenges. For example, how can we advance technologies to benefit more oil and gas resources with lower drilling costs? How can we improve the efficiency of drilling tools and operation safety based on traditional drilling tools? These questions and challenges focus on drilling technologies and how to further improve the technology to better meet the energy demands of the world economy.

Advancements of drilling symbolize a breakthrough technology and a revolution in the oil and gas industry. They represent new achievements in drilling technology that have generated great contributions to the economic progress and development of oil and gas fields.

ACKNOWLEDGEMENTS

I would like to acknowledge everybody who played a significant role in my academic accomplishments. First, my mother, who always supported me with her love. Without your dedicated support, I could never have arrived at this level of achievement.

Secondly, my tutor, who has provided advice patiently during the thesis process. Thank you for your guidance.

Finally, I would like to thank to members of Petroleum Engineering Department of Politecnico di Torino for their help in this study.

DEDICATION

I dedicate my thesis to my family for nursing me with compassion and love and their committed support for success in my life.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF ABBREVIATIONS

API	American Petroleum Institute
BHA	bottomhole assembly
BOP	blowout preventer
BPA	by-pass actuator
BUR	build-up rate
DC	drill collar
DOR	drop-off rate
DST	drill stem test
DTU	double-tilt unit
DWOB	downhole weight on bit
ECD	electron capture detector
EIA	Energy Information Administration
ERD	extended-reach drilling
ERW	extended-reach well
ESP	electric submersible pump
ETL	Eni Turkmenistan Limited
EWL	electric wireline logging
FID	flame ionization detector
GBM	gas-based mud
GOR	gas-oil ratio
GR	gamma ray
GTF	gravity tool face
HP/HT	high-pressure/high-temperature
IADC	International Association of Drilling Contractors
ICD	inflow control device
KOP	kick-off point
LWD	logging while drilling
MD	measured depth
MODU	mobile offshore drilling unit
MPR	multiple propagation resistivity
MTF	magnetic tool face

MWD	measurement while drilling
OBM	oil-based mud
OD	outer diameter
PBU	pressure build-up
PCP	progressing cavity pump
PDC	polycrystalline diamond compact
PDM	positive displacement motor
POOH	pull out of hole
RCLS	rotary closed-loop drilling system
RF	recovery factor
RFT	repeat formation test
RIH	run in hole
RNT	reservoir navigation tool
ROP	rate of penetration
RPM	revolutions/rotations per minute
RSS	rotary steerable system
SCADA	supervisory control, alarm, and data acquisition
SPM	strokes per minute
SPP	standpipe pressure
TCD	thermal conductivity detector
TD	total depth
TVD	true vertical depth
UBHS	upper bearing housing stabilizer
VFD	variable frequency drive
WBM	water-based mud
WOB	weight on bit
WOC	wait on cement
WOH	weight on hook

1 INTRODUCTION

Over the past years, oil and gas industry has been in a downturn due to slump of oil prices. According to the most recent forecast from the US Energy Information Administration's (EIA) monthly Short-Term Energy Outlook, the prices are not expected to raise significantly in the next two years. This downturn impacted the revenues and profits of the energy companies. Oil and gas companies, which made huge profits, never cared to eliminate inefficiencies in the system years ago. Year by year the energy needs are rising, that forces energy companies to search new oil and gas fields in its turn development of this new reservoirs bears a huge expense because of unfavorable conditions at the deep. These conditions may create a different kind of problems during the drilling operations that may cause a losing of the well and even be dangerous for the crew. Due to the mentioned reasons, oil and gas companies started to invest and adopt innovative drilling and completion technologies. Innovative technologies used for drilling and completion have permitted the oil and gas industry to reach new sources of energy to meet the growing demand around the world and to seek cost cuts. Advances in technologies play an important role in meeting global energy demand because they enable the discovery of new resources, access to harsh locations and the development of challenged reservoirs that previously were not economically efficient to produce. These kind of drilling and completion technologies have facilitated the growth of production from unconventional oil and gas reservoirs in many parts of the world by using a combination of hydraulic fracturing and horizontal, extended reach drilling. New technologies have also helped to diminish the negative effects of energy production to the environment by allowing more oil and gas to be produced with fewer wells.

1.1 Organization of the Thesis

The fundamentals of drilling and well completion are covered in chapter 2. Innovative drilling and completion technologies are discussed in chapter 3 and chapter 4 respectively. The conclusions are summarized in chapter 5.

2 THE ROLE OF DRILLING AND COMPLETION

The assessment and development of hydrocarbon reserves are a complicated process demanding the relationship of different disciplines. Drilling and completion form pivotal roles in this activity as they oversee to form the path from the reservoir to the surface.

The exploration process for oil and gas can be divided into numerous consecutive activities, each cost more expensive and complicated than the previous and each leading to higher quality of data. Moreover, the acquired data is reviewed at the end of each activity, and the process adjusted or terminated as needed. The critical sections are [1]:

- Geological Appraisal
- Geophysical Prospecting
- Exploration Drilling
- Appraisal Drilling
- Development Drilling.

2.1 Geological Appraisal

The region's known geological data is analysed again. Establishments of government have an interest within the economic geology of available area and generally implement country's laws that maintain a database of all geological process within the area. The data that may have been acquired throughout exploration for a certain mineral resource is also existent to other earth scientists and geologists. As a result, easily accessible zones of the earth have been studied in greater detail.

The main purpose is to specify the type of rock where hydrocarbons can have accumulated. Those are known as sedimentary rocks and the series of existence of the rocks can be related to other series where hydrocarbons have already been confirmed. However, the patterns in accumulation are not reliable and although patterns in an area may be similar to those where hydrocarbons have been confirmed, minor assurance can be accommodated including the right structures to accumulate hydrocarbons and also present containing hydrocarbons.

A geological measurement of surface characteristics may be fulfilled to approve the geological forecast, or to catch additional details which may not be observed throughout the measurements in onshore. In offshore it can be conducted with shallow drilling [1].

2.2 Geophysical Prospecting

The implementation of the physics' basis to the analysis of subsurface geology is known as geophysical prospecting [2].

Geophysical prospecting improves the information that already known about the geology of formation. The target is to allocate the source rocks (rocks which were composed first and on which sedimentary basins may have afterwards composed) from the sedimentary rocks because hydrocarbons develop in sedimentary rocks. The sediments' thickness and the shape of structures among the sediments can be measured by geophysical techniques.

Geophysical surveys can be broken down into two wide groups: reconnaissance and detailed surveys. The purpose of the reconnaissance surveys is to summarize potential domain where there are thick sediments and the contingency of structural traps. Detailed surveys are used to determine the location of wells to examine certain structures [1].

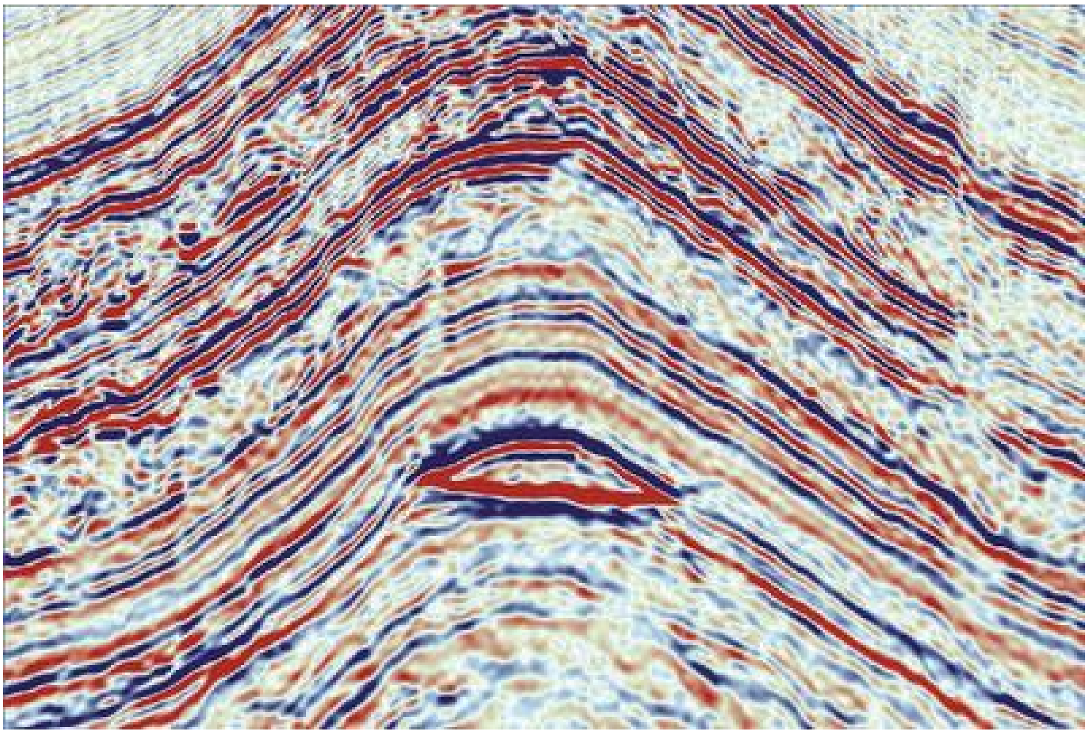

Figure 2.1: Typical seismic section [3]

The most used geophysical methods are magnetic, gravity and seismic surveys. The magnetic features of subsurface rocks produce the anomalies in the earth's magnetic field, and these anomalies are measured by magnetic surveys. Density of the rocks can also produce anomalies in the earth's gravitational field. These anomalies are measured by gravity surveys. Seismic surveys measure the time of sound waves which is travelled within the subsurface rocks. Reconnaissance methods include magnetic and gravity surveys. Seismic surveys can be grouped as detailed surveys [4].

After acquiring raw data from a seismic survey, it is manipulated electronically to get an output. It is called seismic section. The seismic section is interpreted for obtaining the depth and the rocks' type. This does not include fluid content information of the rock [1].

2.3 Exploration Well Drilling

Based on the interpretation of the geological and geophysical studies, energy companies decide to drill an exploration well. The location of the well is planned to intersect the features identified by the geophysical surveys. The cuttings from the well are evaluated by geologist at the well site to make a geological model of the area. As the well is drilled, wireline logs are run before the well is cased. These logs measure the natural radiation and electrical potential of the sediments as well as resistivity and sonic travel time. The wireline logs run depend on the geology of each section of the well; the layers containing oil and gas are logged in greater detail. The geological and the log information are used to determine if there are hydrocarbon bearing zones. If present, the nature and quantity of hydrocarbon, flow properties and pressure of the hydrocarbon bearing zone must be evaluated, as well as the depth at which the hydrocarbon exists, the thickness of the zone and the presence of an aquifer [1].

Formation evaluation is the term used to cover this activity, although the techniques used vary widely.

Routinely, a repeat formation test (RFT) is conducted. A tool is lowered inside the well and it is positioned against the side of the borehole. It can then measure the pore pressure (the pressure in the pores of the formation) at that depth and take a sample of the formation fluid. The tool is then released from the side of the borehole and repositioned to take another pressure reading. The pressures and depths can be correlated to examine the density of the fluid (and therefore the type of fluid) and the pore pressure profile within the formation. These results identify the zones that contain hydrocarbon but not the capacity nor the permeability of the formation. This is accomplished by flow tests termed drill stem tests (DST), (since the DP is used as a flow conduit during the test). These are advanced tests which allow sections of the formation to flow as though they were on production. The pressure at the bottom of the well, the flow rates at the surface and the composition of the fluids produced are measured during the test. These indicate the volume of hydrocarbon in the zone under test and the flow capacity or permeability of the zone. These tests may last 8 to 24 hours and the data (in exploration wells especially) is treated confidentially. These tests are very expensive, and when taken with the cost of drilling the well represent a massive investment [5].

The data from the exploration well (even if it was dry) are reviewed and suitable decision taken to drill appraisal wells.

2.4 Appraisal Well Drilling

Prior to the drilling of a development well, oil and gas companies usually drill appraisal wells. Appraisal wells are drilled only when a discovery is made, with the motive of assessing the size and viability of the reservoir [6]. If an exploration well has found economically interesting formations, appraisal wells are drilled in succession, in general, to the north, south, east and west of the location, ideally to intersect the contacts between the oil and water and the oil and gas (if they are present). The exact location of the wells cannot be planned (or there would be no need for appraisal) and the data from each well is reviewed and the location of the next appraisal well changed accordingly. Procedure of the logging and testing of appraisal wells is basically same with the exploration well [1].

2.5 Development Well Drilling

If the results of the appraisal wells are economically convenient, a development program for the field is put into operation. This program will specify the number and location of development wells to be drilled to fully cover the field and allow production and injection from or into the formations. The development wells may or may not include the exploration well and the appraisal wells. As the wells are drilled, they are logged and tested, the data augmenting the geological model of the formation and modifying the flow model of the reservoir.

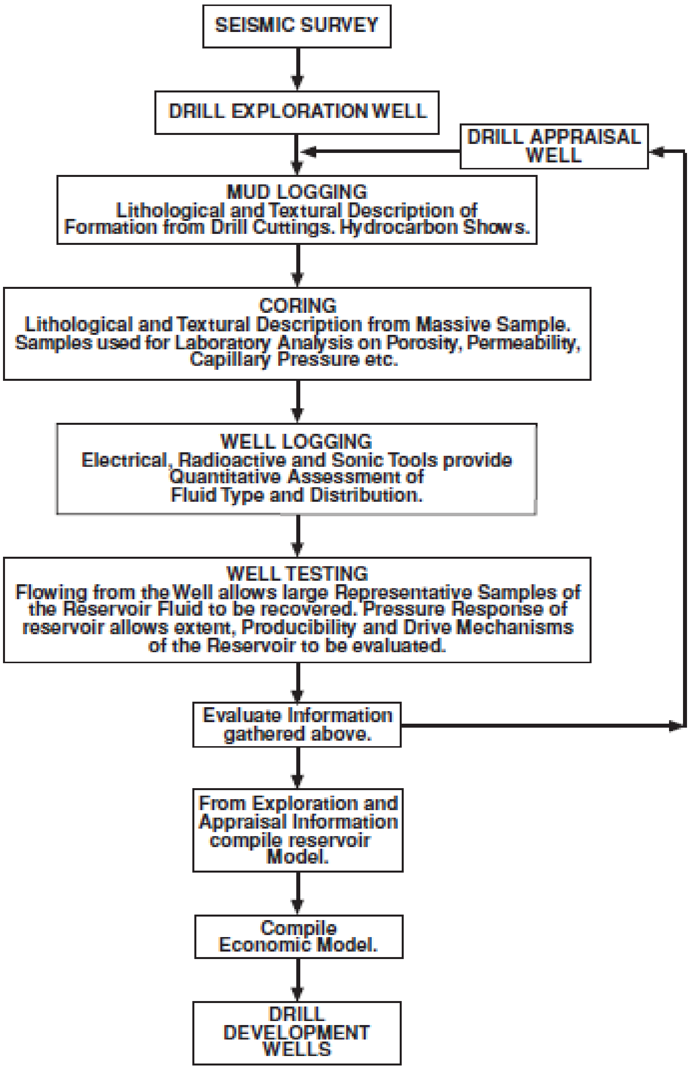

Figure 2.2: Role of the drilling in field development [7]

The number of development wells dictates the size of the platform required and the amount of ancillary equipment (water injection facilities, etc.). The estimate of the reservoir size and the program of development well drilling allows the determination of the production profile for the field. This is important from an engineering point of view since it schedules the work involved in bringing the reservoir into production and the remedial job, or workovers, expected during the life of the field. It is also a financial schedule for the field since it indicates the cash flow associated with the production from the field. Taken together with the exploration costs, an estimate of the overall profitability of the field can be made and also the requirements for finance (either borrowing money or producing profit to pay back loans) during the life of the field. As part of this, the reserves of the hydrocarbon must be calculated. These are not fixed figures, since the acquisition of data and re-evaluation of the reserves is related to the rate of drilling of the development wells and the data generated as the reservoir is produced [1].

2.6 Drilling Personnel

Drilling process requires diverse skills and involves many companies (**Figure 2.3**). The oil and gas company who manages the drilling and/or production operations is known as the operator. One company acts as operator on behalf of the other partners in joint ventures.

For drilling a well there are many different management strategies, but in virtually all cases the oil and gas company will employ a drilling contractor to actually drill the well. The contractor owns and maintains the drilling rig and employs and trains the personnel required to operate the rig. During the process of drilling the well certain specialized skills and equipment may be required including logging, surveying, etc. These are provided by service companies. Service companies develop and maintain special tools and staff. These service companies hire them out to the operator, generally on a day-rate basis.

The contracting strategies for drilling a well or wells range from day-rate contracts to turnkey contracts. The most common type of drilling contract is a day-rate contract. In the case of the day-rate contract the operator prepares a detailed well design and program of work for the drilling operation and the drilling contractor simply provides the drilling rig and personnel to drill the well. The contractor is paid a fixed sum of money for everyday that he spends drilling the well. All consumable items (e.g. drilling bits, cement), transport and support services are provided by the operator.

In the case of the turnkey contract the drilling contractor designs the well, contracts the transport and support services and purchases all of the consumables, and charges the oil and gas company a fixed sum of money for whole operation. The role of the operator in the case of a turnkey contract is to specify the drilling targets, the evaluation procedures and to establish the quality controls on the final well. In all cases the drilling contractor is responsible for maintaining the rig and the associated equipment.

The operator will generally have a representative on the rig (sometimes called the "company man") to ensure drilling operations go ahead as planned, make decisions affecting progress of the well, and organise supplies of equipment. S/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 wellsite geologist on the rig.

The drilling contractor will employ a toolpusher to be in overall charge of the rig. S/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. Because drilling continues 24 hours a day, there are generally 2 drilling crews. Every crew works under the direction of the driller. The crew usually consist of a derrickman (who also looks the pumps while drilling), 3 roughnecks (working on rig floor), an electrician, a mechanic, a crane operator and roustabouts (general labourers).

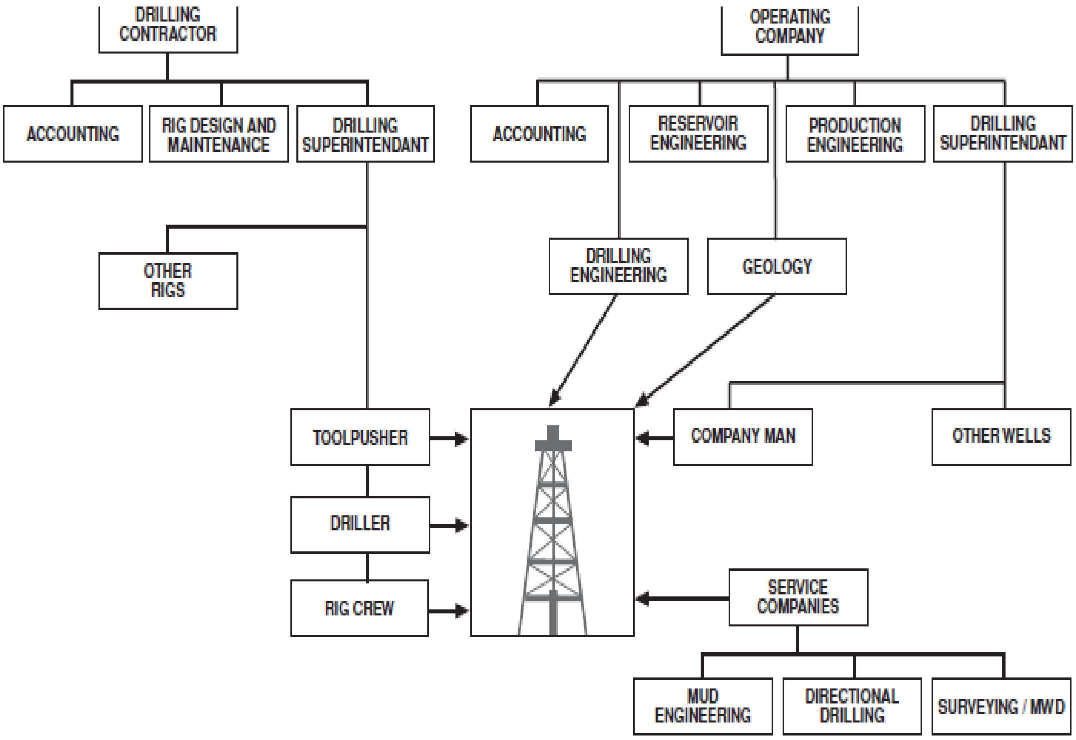

Figure 2.3: Personnel involved in drilling a well [7]

Service company employees are transported to the rig when they are 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, wireline field engineer) [7].

2.7 The Drilling Proposal and Drilling Program

Reservoir engineers, geophysicists and geologists prepare the proposal for drilling a well in the operating company and provide the information until the well will be designed and drilling program will be prepared. The proposal generally includes the following information:

- Objective of the well
- Depth (m/ft subsea), and location (longitude and latitude) of target
- Geological cross section
- Prediction of pore pressure profile

Drilling engineer prepares the drilling program. It generally includes the following information:

- Drilling rig to be used for the well
- Proposed location for the drilling rig
- Hole sizes and depths
- Casing sizes and depths
- Drilling fluid specification
- Directional drilling information
- Well control equipment and procedures
- Bits and hydraulics program

2.8 Rotary Drilling Equipment

The first planned oil well was drilled by Colonel Drake at Titusville, Pennsylvania USA in 1859. The well was shorter than 100 ft deep and produced about 50 bpd. To drill the first well it was used the cable-tool drilling method [8].

Cable-tool drilling (**Figure 2.4**) is a method of in which a hole is made by the repeated blows generated by lifting and dropping a heavy chisel bit on rocks or underground formations. The heavy (usually blunt) chisel bit is the “tool” and the cable could be made of something as simple as a manila rope or multiple steel strands [9].

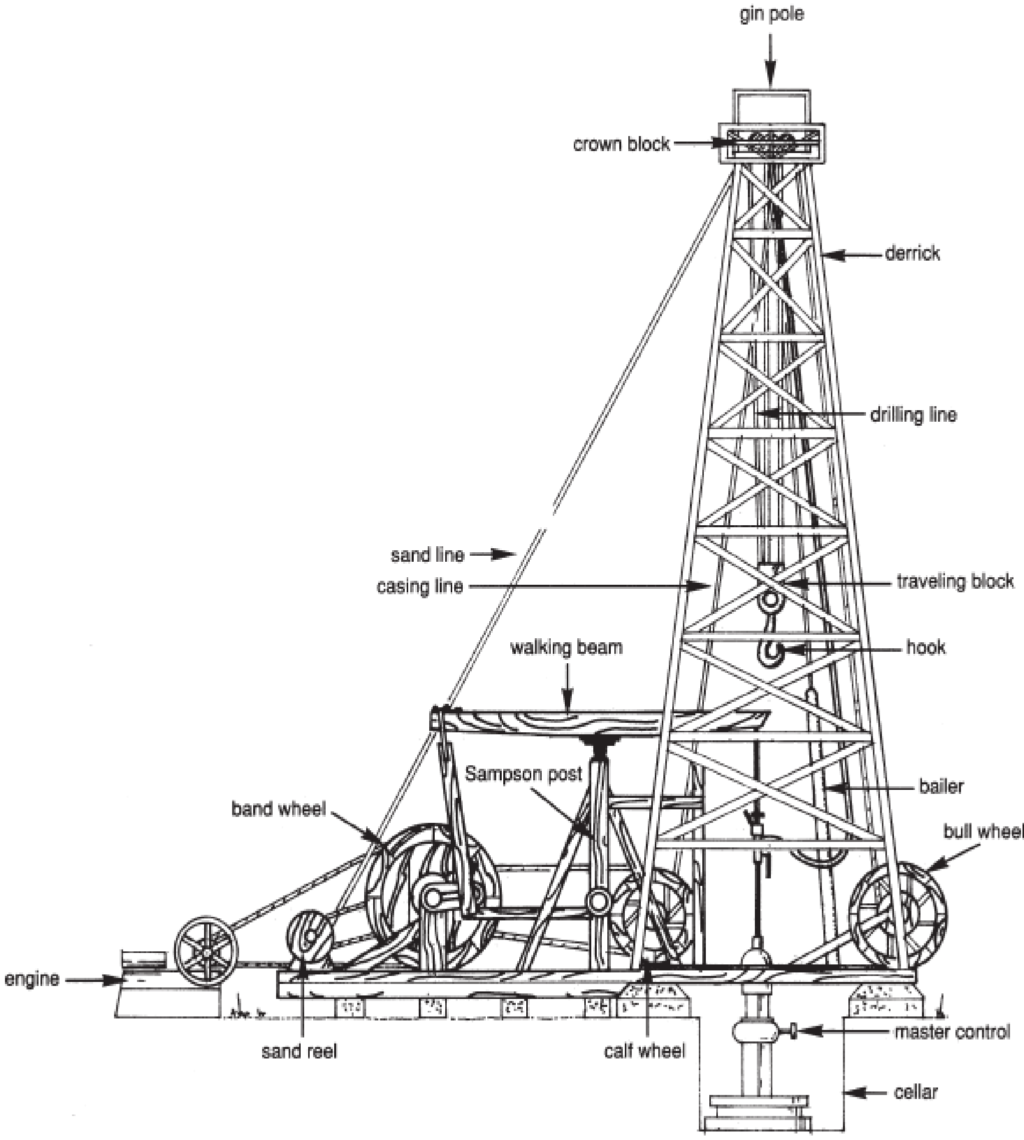

Figure 2.4: Cable-tool drilling rig [10]

In the 1890s the first rotary drilling rig (**Figure 2.5**) was introduced [7]. Rotary drilling is the method whereby the rock cutting tool (bit) is suspended on the end of hollow pipe; therefore, fluid can be easily and continuously circulated across the face of the drilling tool cleaning the drilling material from the face of the bit and carrying it to surface. Rotary drilling technique is a much more efficient than the cable-tool drilling technique. The cutting tool used in this technique is a complex tool (drill bit) which drills through the rock under the combined effect of axial load and rotation.

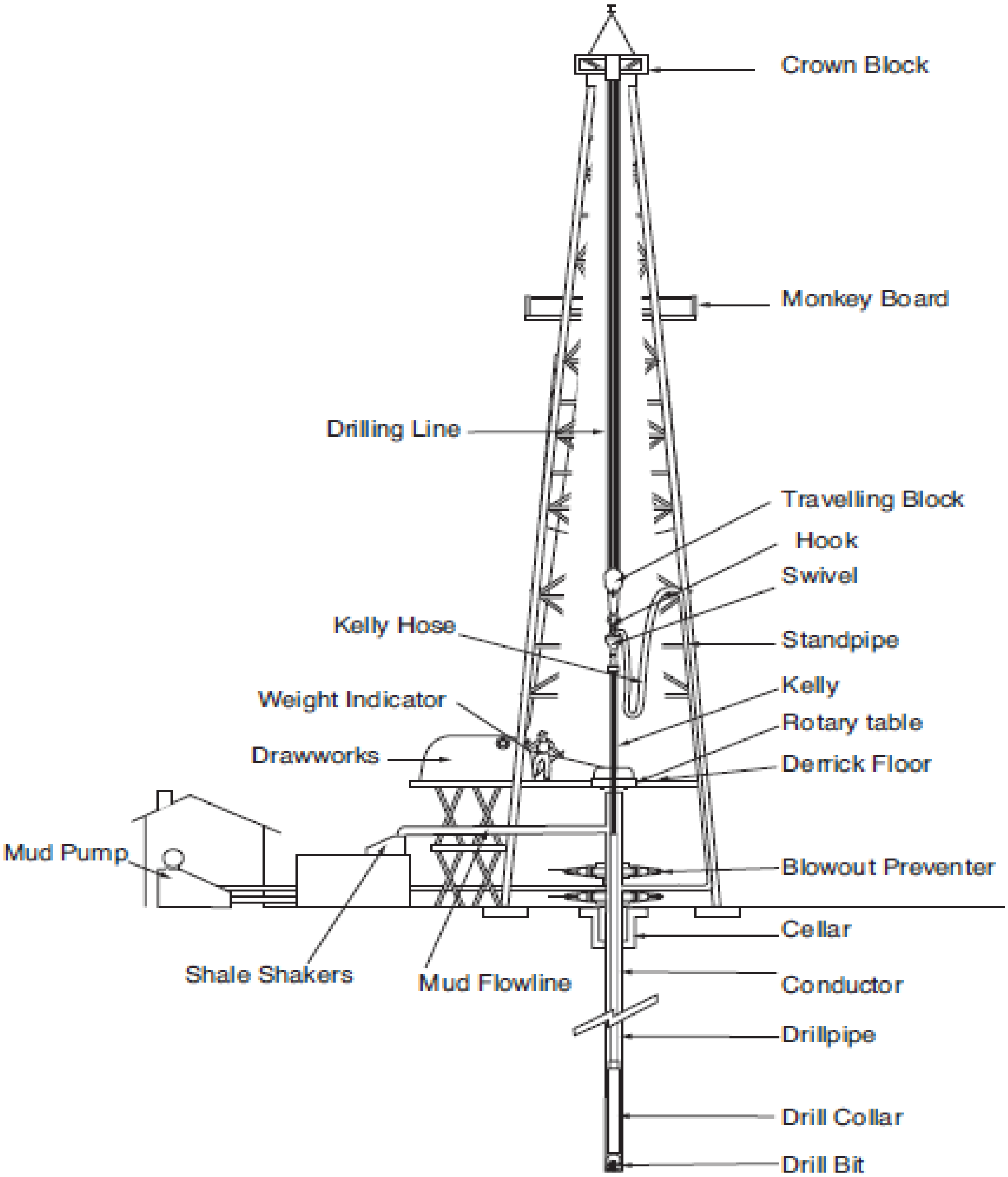

Figure 2.5: Rotary drilling rig [7]

2.8.1 Rotary Drilling Rig Components

The rotary drilling rig includes of a set of machinery and equipment located on the drilling well site. Extent of rig equipment depends on the type of the rig, but typically consists at least some of the items are listed below [7], [10], [11], [12] and shown in **Figure 2.6**.

1. ***Mud tanks (pits):*** A series of open tanks, usually made of steel plates, through which the drilling mud is cycled to allow sand and sediments to settle out.

Additives are mixed with the mud in the pit, and the fluid is temporarily stored there before being pumped back into the well. Mud tank compartments are also called shaker pits, settling pits, and suction pits, depending on their main purpose.

2. ***Shale shakers:*** A series of trays with sieves or screens that vibrate to remove cuttings from circulating fluid in rotary drilling operations. The size of the openings in the sieve is selected to match the size of the solids in the drilling fluid and the anticipated size of cuttings. Also called a shaker.

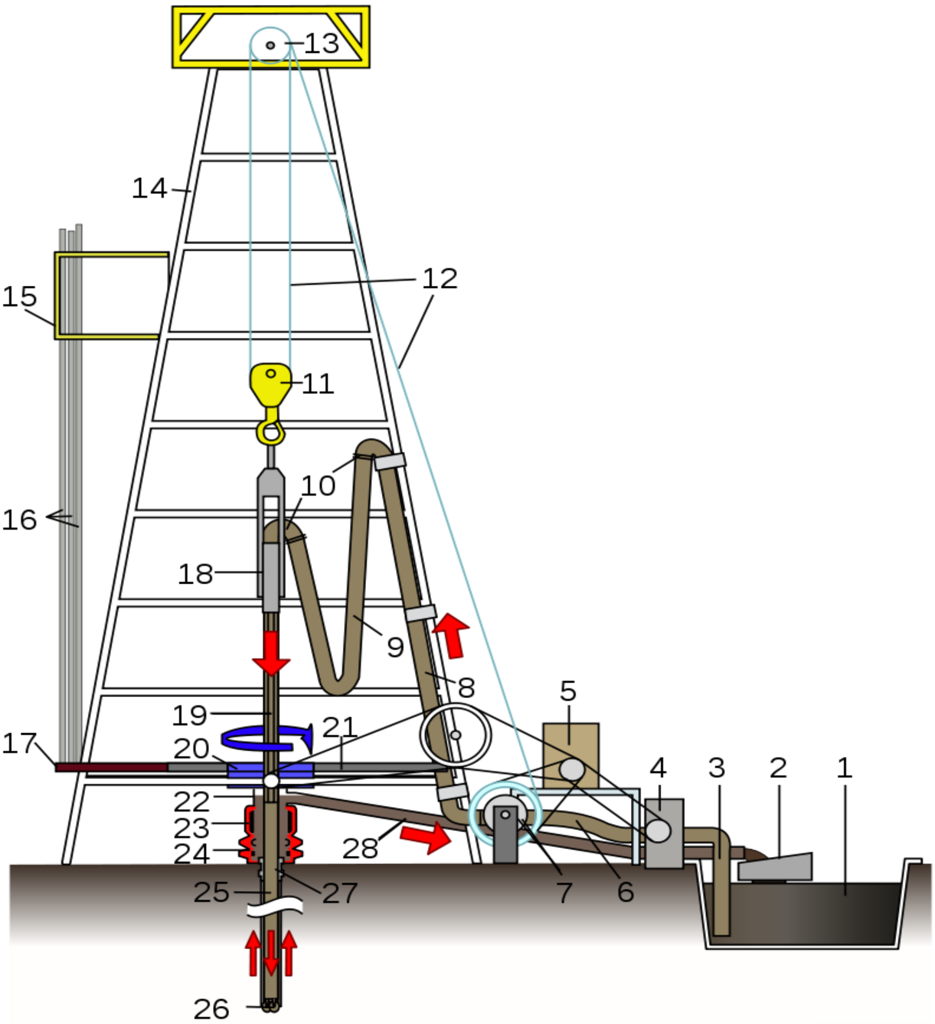

Figure 2.6: Simple diagram of a drilling rig

3. ***Suction line:*** A large-diameter pipe or hose used to draw drilling mud out of the mud tanks into the mud pumps or hogs. The drilling mud is often pumped through the suction line by a centrifugal pump in a process called supercharging.

4. ***Mud pump:*** A large reciprocating pump used to circulate the mud (drilling fluid) on a drilling rig.
5. ***Motor or power source:*** It provides constant voltage and frequency to all electrical components on the rig. Most drilling rigs generate 460 VAC, 60 Hz, 3 phase power or 380 VAC, 50 Hz, 3-phase power. Through transformers and other controls, a single power source can supply a variety of electrical power to accommodate the requirements of drilling rig components.
6. ***Vibrator hose:*** A hard rubber hose that transmits the drilling mud from the mud pump outlet to bottom of the standpipe on a drilling rig. It is similar in construction to the rotary hose. The vibrator hose is used to absorb fluid shocks and eliminate sharp angles (ells) in the line. API classifications include vibrator hoses with diameters of 3 and 3 1/2 in. (7.6 and 8.9 cm) and lengths of 10, 12, 15, 20, and 30 ft (3, 3.7, 4.6, 6.1, and 9.1 m). The hose has nipples with male threads on each end (rotary vibrator hose or shock hose).
7. ***Drawworks:*** The hoisting mechanism on a drilling rig. It is essentially a large winch that spools off or takes in the drilling line and thus raises or lowers the drill stem and bit.
8. ***Standpipe:*** A vertical pipe rising along the side of the derrick or mast. It joins the discharge line leading from the mud pump to the rotary hose and through which mud is pumped going into the hole.
9. ***Kelly hose:*** A large-diameter (3 to 5 in. inside diameter), high-pressure flexible line used to connect the standpipe to the swivel. This flexible piping arrangement permits the kelly (and, in turn, the drillstring and bit) to be raised or lowered while drilling fluid is pumped through the drillstring.
10. ***Gooseneck:*** An inverted U-shaped section of rigid piping normally used as a conduit for high-pressure drilling fluid. In particular, the term is applied to a structure that connects the top of a vertical standpipe running up the side of a derrick or mast to a flexible kelly hose that in turn is connected to another gooseneck between the flexible line and the swivel.
11. ***Traveling block:*** The set of sheaves that move up and down in the derrick. The wire rope threaded through them is threaded back to the stationary crown blocks located on the top of the derrick. This pulley system gives great mechanical

advantage to the action of the wire rope drilling line, enabling heavy loads (drillstring, casing and liners) to be lifted out of or lowered into the wellbore.

12. ***Drill line:*** The wire rope used to support the travelling block, swivel, kelly and drillstring. It is identified by the number of strands and the number of wires in each strand. It is a round-strand type usually wound in a right-regular lay. Also known as hoisting line.
13. ***Crown block:*** An assembly of sheaves or pulleys mounted on beams at the top of the derrick over which the drilling line is reeved.
14. Derrick: Vertical tower made of special structural steel that is assembled vertically and used as part of an offshore drilling rig hoisting system. On a jackup rig or floater, it remains vertically in place as wells are drilled.
15. ***Monkey board:*** The platform on which the derrickman works when handling stands of pipe.
16. ***Stand (of drillpipe):*** The connected joints of pipe racked in the derrick or mast when making a trip. On a rig, the usual stand is about 90 feet (about 27 meters) long (three lengths of drillpipe (DP) screwed together).
17. ***Setback:*** The drill floor area on a drilling rig adjacent to the V-door where the ends of DP or tubing stands rest as they are racked.
18. ***Swivel (or top drive for newer rigs):*** A device on a drilling rig that is hung from the rotary hook on the traveling block by a bail. The swivel allows the drillstring that is attached below it to rotate while being suspended from the derrick or mast. It consists of a heavy steel casting with a rotating ball in it. The mud line attaches to the swivel through the gooseneck. Drilling mud from the kelly hose flows through the swivel into the kelly. The swivel stem or body washpipe on the bottom of the swivel is connected to a swivel sub that connects to the kelly.

    Top drive: A device that turns the drillstring. It consists of one or more motors (electric or hydraulic) connected with appropriate gearing to a short section of pipe called a quill that in turn may be screwed into a saver sub or the drillstring itself. The top drive is suspended from the hook, so the rotary mechanism is free to travel up and down the derrick. This is radically different from the more conventional rotary table and kelly method of turning the drillstring because it enables drilling to be done with three joint stands instead of single joints of pipe.

It also enables the driller to quickly engage the pumps or the rotary while tripping pipe, which cannot be done easily with the kelly system. While not a panacea, modern top drives are a major improvement to drilling rig technology and are a large contributor to the ability to drill more difficult extended-reach wellbores. In addition, the top drive enables drillers to minimize both frequency and cost per incident of stuck pipe.

19. ***Kelly:*** A long square or hexagonal steel bar with a hole drilled through the middle for a fluid path. The kelly is used to transmit rotary motion from the rotary table or kelly bushing to the drillstring, while allowing the drillstring to be lowered or raised during rotation. The kelly goes through the kelly bushing, which is driven by the rotary table. The kelly bushing has an inside profile matching the kelly's outside profile (either square or hexagonal), but with slightly larger dimensions so that the kelly can freely move up and down inside.
20. ***Rotary table:*** The main component of the rotating machine which turns the drillstring. It has a beveled gear mechanism to create the rotation and an opening into which bushings are fitted.
21. ***Drill floor:*** An elevated steel platform supported by the substructure on a drilling rig on which the mast or derrick sits and drilling operations occur. The rotary table, drawworks, driller's console, and other equipment are located on the floor, and the well is in the center. On an offshore drilling rig, the drill floor is the work area surrounding the opening where the tools and drillstring are run into the ocean. Also known as derrick floor and rig floor.
22. ***Bell nipple:*** A funnel-shaped casing nipple run on top of a casing string. It has an expanded or belled top to guide drilling tools into the casing string and connects the aboveground casing head fittings to the casing. The bell nipple is threaded on one end to screw onto the casing. The inside diameter is equal to or larger than the blowout preventer bore. It has a side outlet connected to the mud return line to direct circulating drilling mud coming up the well to the shale shakers and also a fill up connection.
23. ***Annular type blowout preventer (BOP):*** A bladder-type closing device located on the top of a blowout preventer stack above the ram preventers that will close the well with a kelly, tubular, or wireline in the well or with an open wellbore.

The short cylindrical steel jacket of the preventer contains a reinforced oval-shaped elastomer such as nitrile rubber or a hard-rubber packing element that is squeezed with a hydraulically activated piston from the accumulators to seal the well to API specifications. The rubber seal's closing pressure can be eased to allow the DP to be removed under pressure (stripping).

24. ***Pipe rams (BOP):*** A closing element used on a blowout preventer stack. They are two steel blocks with rubber sealing surfaces. Inserts cut into the end of each ram fit around a specific size pipe in the well. Pipe rams can be thrown either manually or hydraulically. Variable pipe rams can fit around a range of pipe sizes.

    Blind rams (BOP): A closing element in a blowout preventer that uses two opposing steel plates with flat rubber surfaces that fit together to close and open the well. The elastomer that forms the sealing surface on the steel rams is often nitrile rubber. Because they have flat closing surfaces, they can be used only with no pipe in the well.
25. ***Drillstring:*** The string of DP with tool joints which transmits rotation and circulation to the drill bit. Sometimes used to include both drill collars (DCs) and DP.
26. ***Drill bit:*** The drilling cutting tool. A rotary bit, either fixed cutter (PDC, natural diamond, and fishtail) or roller cone (milled tooth and insert), is turned by the drillstring or downhole motor to chip and flake the rocks. The body is made of a hard steel ally with chrome, carbon, silicon, and cobalt and a high percentage of molybdenum and nickel. A polycrystalline diamond bit (**Figure 2.7**) is a drag bit with blanks of man-made polycrystalline diamonds. Natural diamond bits have diamonds imbedded into the matrix on the bottom and sides. A roller cone bit has one, two, or three (tricone) rotating cones on the bit bottom. Legs hold journals around which bearings rotate to allow the cone on each leg pin to turn. All rotary bits have nozzles or watercourses to allow drilling fluid to flow over or out of the bit face.
27. ***Wellhead:*** The permanent, uppermost portion of a well located just aboveground and used to maintain surface control. It is located between the uppermost surface casing and the tubing head connection. The wellhead is large, forged, or case

steel hardware with machined surfaces such as flange faces and ring grooves that seal the top of the well onto the surface casing or conductor pipe. It includes the casing heads and tubing head.

28. ***Flowline:*** The large-diameter metal pipe that connects the bell nipple under the rotary table to the possum belly at the mud tanks. The flowline is simply an inclined, gravity-flow conduit to direct mud coming out the top of the wellbore to the mud surface-treating equipment. When drilling certain highly reactive clays, the flowline may become plugged and require considerable effort by the rig crew to keep it open and flowing. In addition, the flowline is usually fitted with a crude paddle-type flow-measuring device commonly called a "flow show" that may give the driller the first indication that the well is flowing.

Figure 2.7: Polycrystalline diamond compact (PDC) bit

2.9 Drilling Rig Main Systems

There are many individual pieces of equipment on a rotary drilling rig. These individual pieces of equipment can however be grouped together into six sub-systems. These systems are [13]:

- Power System

- Hoisting System
- Fluid Circulating System
- Rotary System
- Well Control System
- 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. The equipment discussed below will be found on both land-based and offshore drilling rigs [7].

2.9.1 Power System

Most drilling rigs are required to operate in remote locations where a power supply is not available. They must therefore have a method of generating the electrical power which is used to operate the systems mentioned above. The electrical power generators are driven by diesel powered internal combustion engines (prime movers). Electricity is then supplied to electric motors connected to the drawworks, rotary table and mud pumps. The rig may have, depending on its size and capacity, up to 4 prime movers, delivering more than 3000 horsepower. Horsepower (HP) is an old, but still widely used, unit of power in the drilling industry. Older rigs used steam power and 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 drawworks and the mud pumps are the major users of power on the rig, although they are not generally working at the same time [7].

2.9.2 Hoisting System

The hoisting system is a large pulley system which is used to lower and raise equipment into and out of the well. In particular, the hoisting system is used to raise and lower the drillstring and casing into and out of the well. The components parts of the hoisting system are shown in **Figure 2.8**. The drawworks consists of a large revolving drum, around which a wire rope (drilling line) is spooled. The drum of the drawworks is connected to an electric motor and gearing system. 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 drilling line is threaded (reeved) over a set of sheaves in the top of the derrick, known as the crown block and down to another set of sheaves known as the travelling block. A large hook with a snap-shut locking device is suspended from the travelling block. This hook is used to suspend the drillstring. A set of clamps, known as the elevators, used when running, or pulling, the drillstring or casing into or out of the hole, are also connected to the travelling block [7].

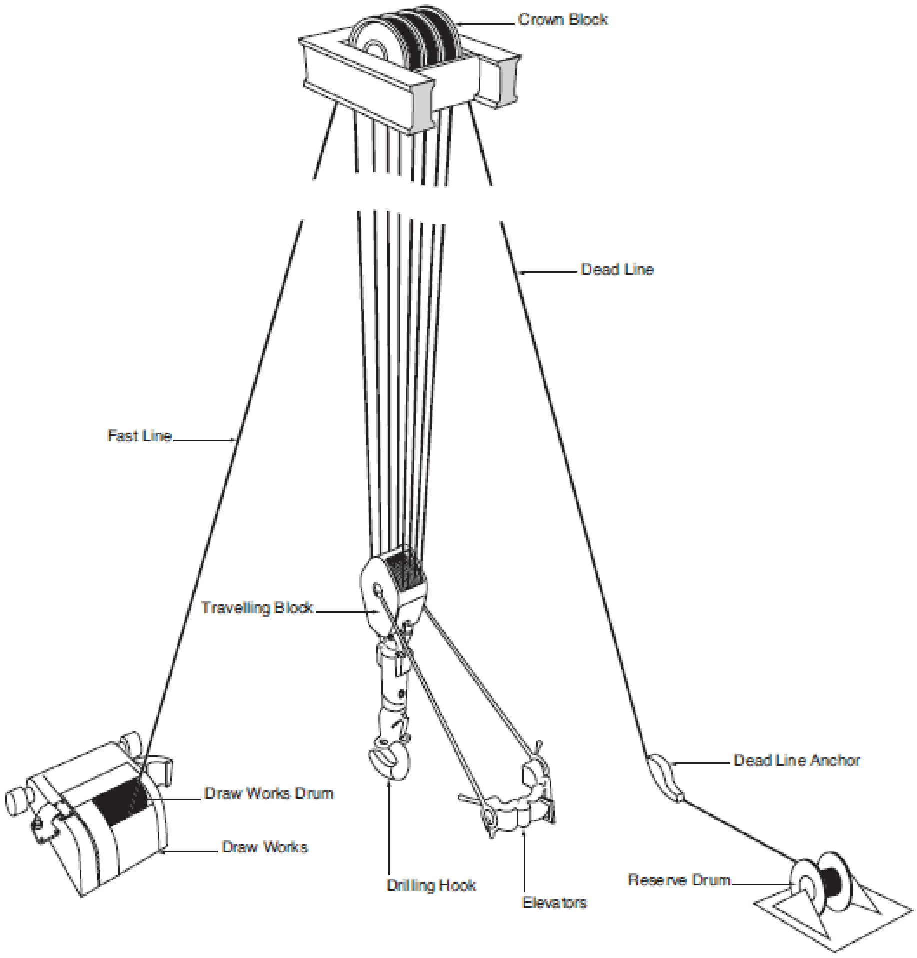

Figure 2.8: Schematic representation of rig hoisting system [7]

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. The tensile strength of the drilling line and the number of times it is reeved through the blocks will depend on the load which must be supported by the hoisting system [7].

2.9.3 Fluid Circulating System

The circulating system is used to circulate drilling fluid down through the drillstring and up the annulus, carrying the drilled cuttings from the face of the bit to surface [13]. The main components of the circulating system are shown in **Figure 2.9**.

Positive displacement type pumps are used (reciprocating pistons) to deliver the high volumes and high pressures required to circulate mud through the drillstring and up the annulus. There are two types of positive displacement pumps in common use:

- Duplex (2 cylinders) – double acting
- Triplex (3 cylinders) – single acting.

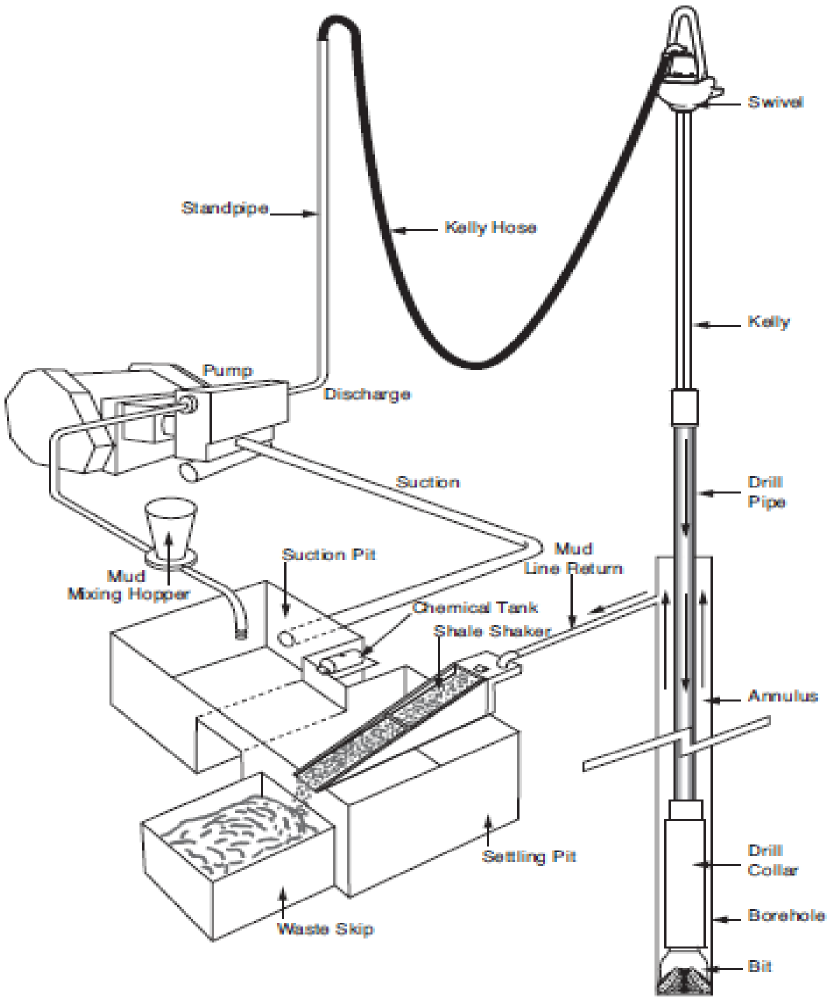

Figure 2.9: Schematic representation of fluid circulating system [14]

Triplex pumps are generally used in offshore rigs and duplex pumps on land rigs. Duplex pumps have two cylinders and are double-acting (i.e. pump on the up-stroke and the down-stroke). Triplex pumps have three cylinders and are single-acting (i.e. pump on the up-stroke only). Triplex pumps have the advantages of being lighter, give smoother discharge and have lower maintenance costs [7].

2.9.4 Rotary System

The rotary system is used to rotate the drillstring and therefore the drilling bit on the bottom of the hole. It includes all the equipment used to succeed bit rotation. A schematic diagram and nomenclature of the system is shown in **Figure 2.10**. The major parts of the rotary system are swivel, kelly, rotary drive, rotary table, DP and DCs.

2.9.5 Well Control System

The fundamental function of the well control system is to prevent the uncontrolled flow of formation fluids to the wellbore. When the drill bit penetrates a permeable formation, the pressure in the pore space of the formation may be higher than the hydrostatic pressure implemented by the drilling fluid column. Formation fluids will enter the wellbore and commence to displace drilling fluid from the borehole. Any influx of formation fluids such as oil, gas and water in the hole is known as a kick.

The well control system is designed to:

- Detect a kick
- Shut-in the well at surface
- Remove the influx which has entered into the well (circulation)
- Make the well safe.

Failure of the well control system results in an uncontrolled flow of formation fluids which is known as a blowout. Blowout is the worst tragedy that can happen during the drilling operations. It may lead loss of lives and equipment, damage to the environment near the well and the loss of hydrocarbon reserves.

Detecting a kick: There are many indications that a driller will become aware of when a kick has taken place. The first sign of a kick could be a sudden increase in the level of mud pits. Another indication may be mud flowing out of the well when the pumps are shut down. Devices such as pit level indicators and mud flowmeters which trigger off alarms to alert the rig crew that an influx has taken place are placed on all rigs. Regular pit drills are carried out to ensure that the driller and the rig crew can react as quickly as in the event of a kick [7].

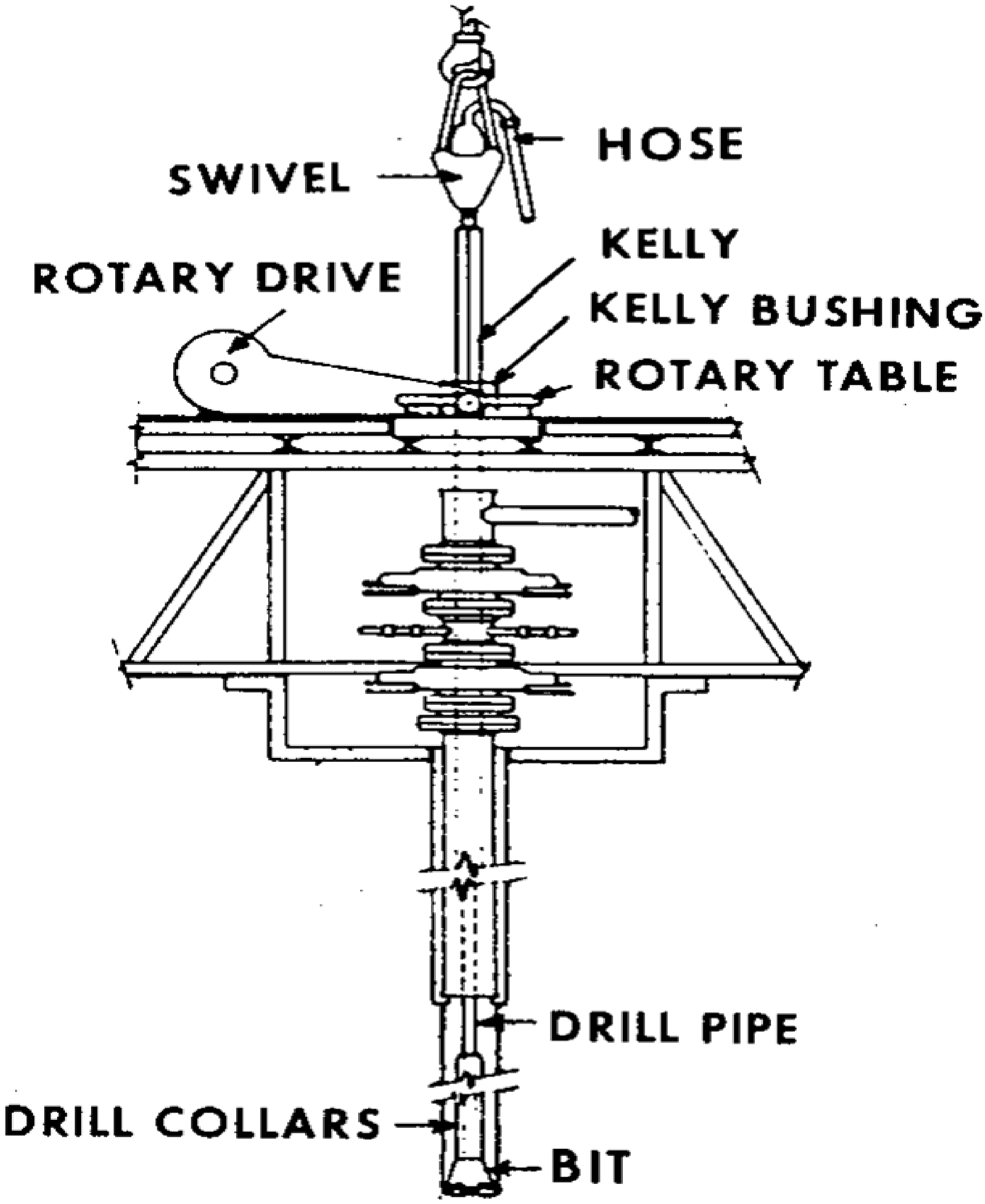

Figure 2.10: Schematic representation of the rotary system [15]

Shut-in the well: Blowout preventers (BOPs) must be nippled up to deal with any kick that may occur. BOPs are basically high pressure valves which seal off the top of the well. On land rigs or fixed platforms the BOP stack is located beneath the rig floor. In offshore rigs the BOP stack is nippled up on the sea bed. In both cases the valves are hydraulically operated from the rig floor.

There are two basic types of BOP:

- Annular type preventer (**Figure 2.11**)
- Ram type preventer (**Figure 2.12**)

The BOP stack includes both annular and ram type preventers (**Figure 2.13**).

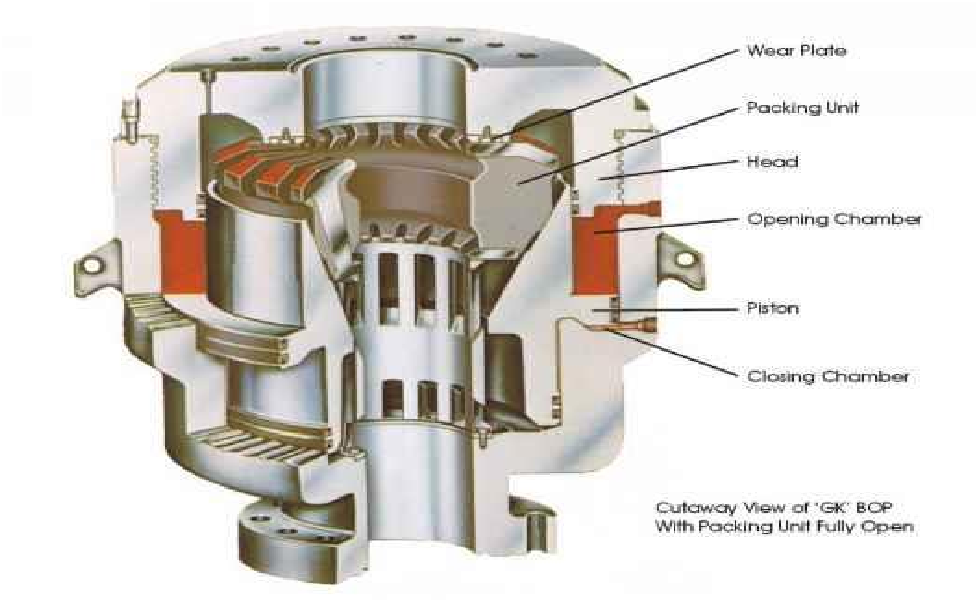

Figure 2.11: Annular preventer (Courtesy of Hydril)

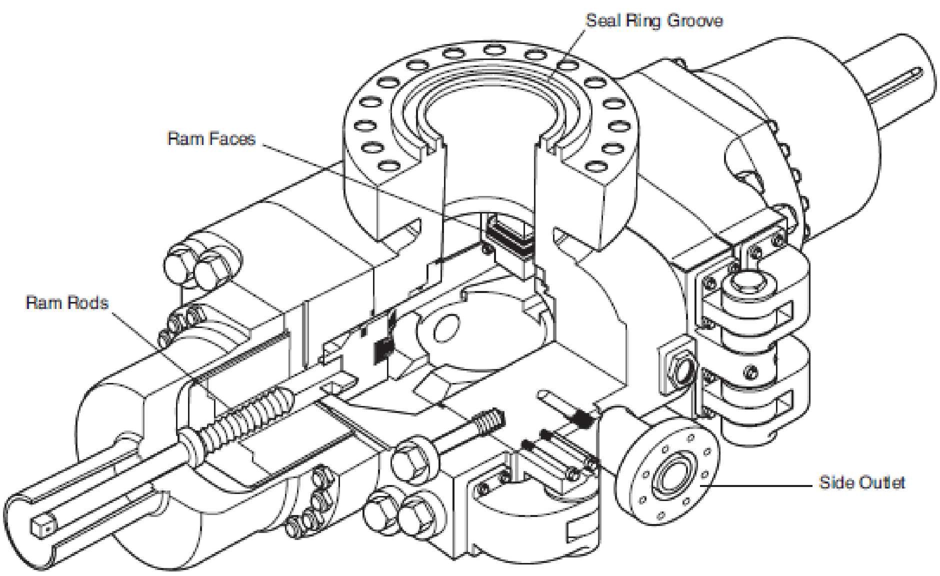

Figure 2.12: Ram type preventer (Courtesy of Hydril)

Circulating out a kick: High pressure circulating system is used to get rid of the formation fluids trapped in the annulus. A choke manifold with an adjustable choke is used to control flow rates during the circulation. Heavier mud must be pumped down through the DP to control the formation pressure and the fluids in the annulus circulated to the surface. As the kick starts moving up the hole, the choke opening is restricted to hold enough back pressure on the formation to prevent any further influx. The fluids are circulated out through the choke line, via the choke manifold out to a gas/mud separator and a flare stack. The well should be dead when the heavier mud has reached to the surface [7].

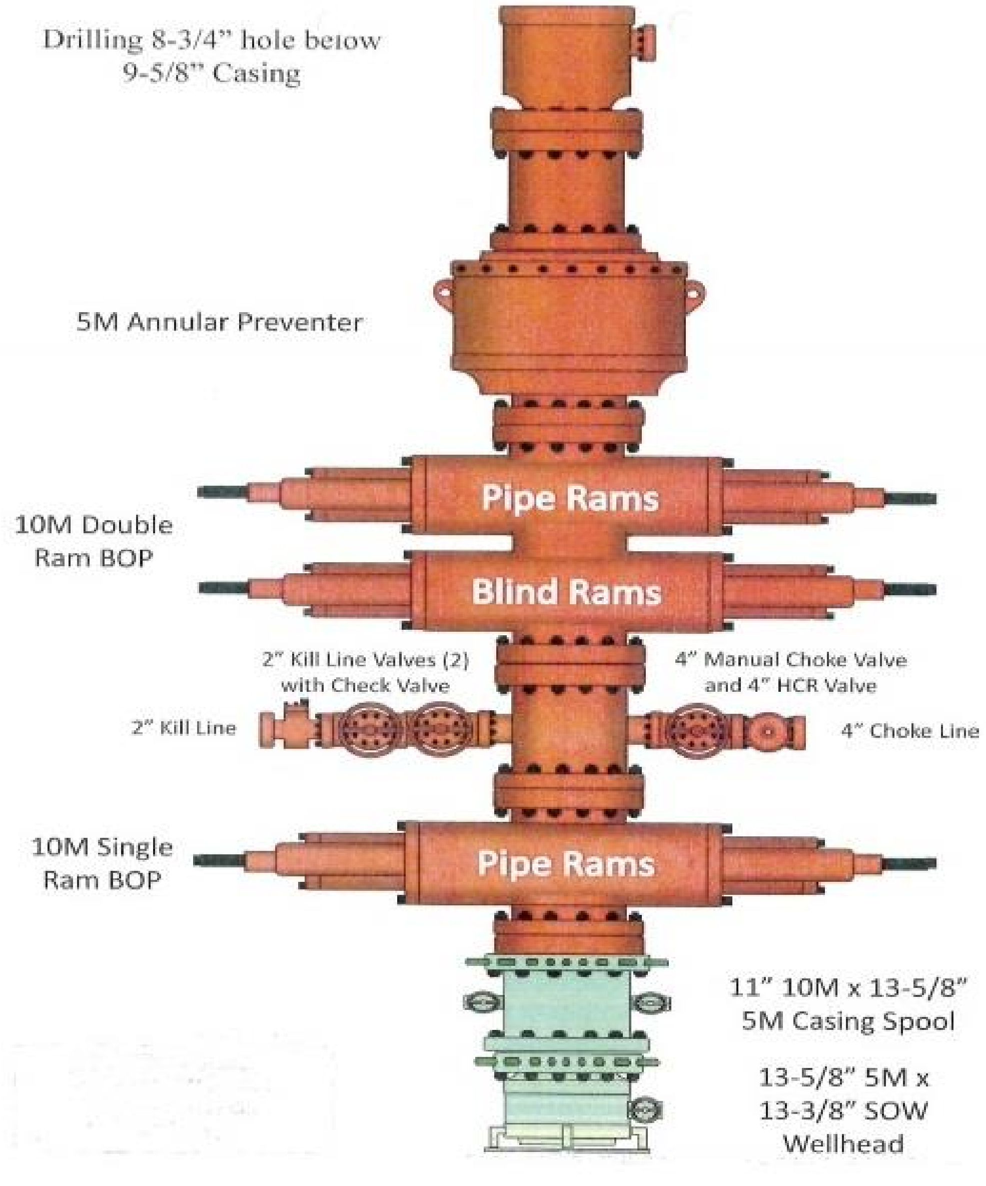

Figure 2.13: Schematic of BOP

2.9.6 Well Monitoring System

Safety requires constant monitoring of the drilling process. If problems are detected early, remedial action can be taken quickly, thereby avoiding major problems. The driller have to be aware of how drilling parameters are changing (e.g. WOH, RPM, pump rate, pump pressure, gas content of mud, etc.). For that reason, there are different gauges installed on the driller's console (**Figure 2.14**) where s/he can read them easily.
In addition to driller's control unit, another useful assistant in monitoring the well is mud logging.

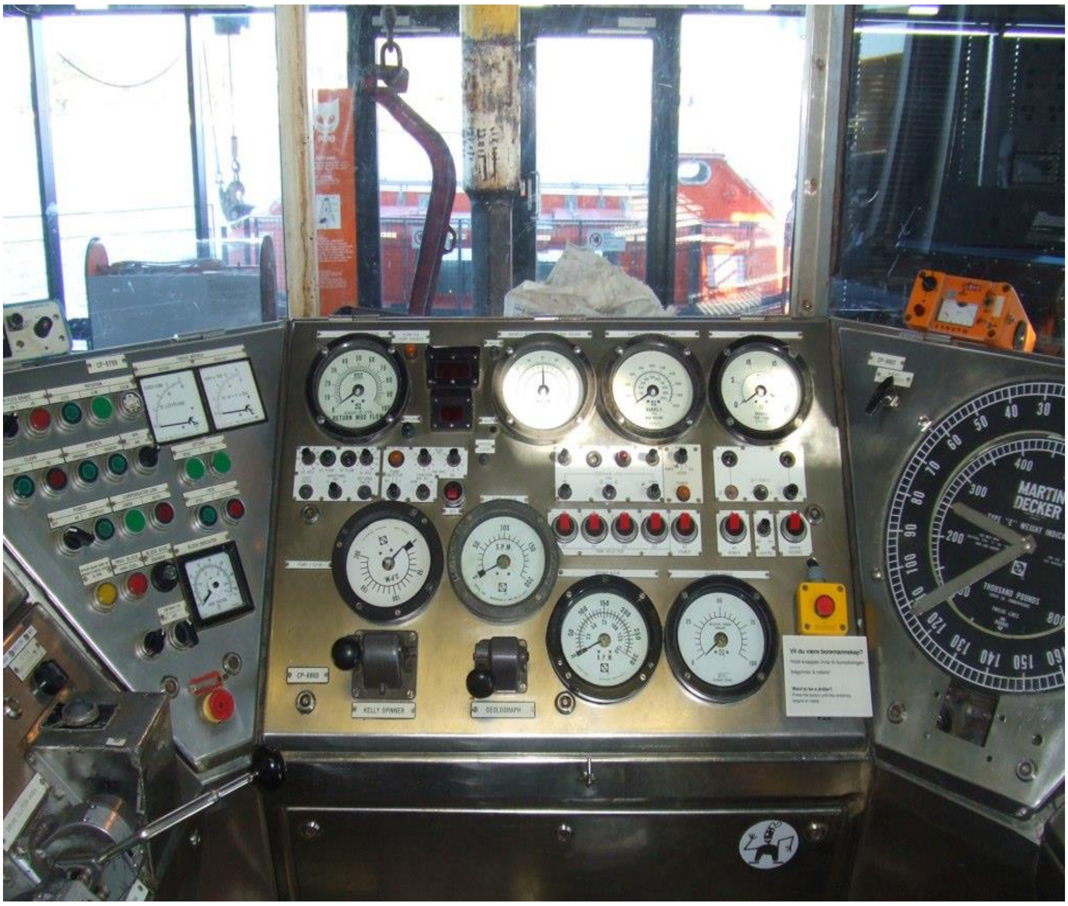

Figure 2.14: Driller's control unit

Mud logging is an essential part of the process that leads from the initial definition of a potential reservoir structure to optimised production of oil and/or gas. It adds a value to these process by capturing critical reservoir information which might otherwise be lost. The sources of this information include drilled cuttings and cores, liberated gas from the formations drilled and different physical parameters measured during the well site operations. The fundamental objective of mud logging is to assist in the efficient completion of exploration and development wells for oil and gas [16].

The mud logger (sometimes called surface logging specialist) carefully inspects rock cuttings taken from the shale shaker at regular intervals and maintains a log describing their appearance [13]. By calculating lag (or bottoms-up) 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 generally called master log and it is useful to the geologist in correlating ongoing drilling well with other offset wells [7]. The example of master log is shown in **Figure 2.15**.

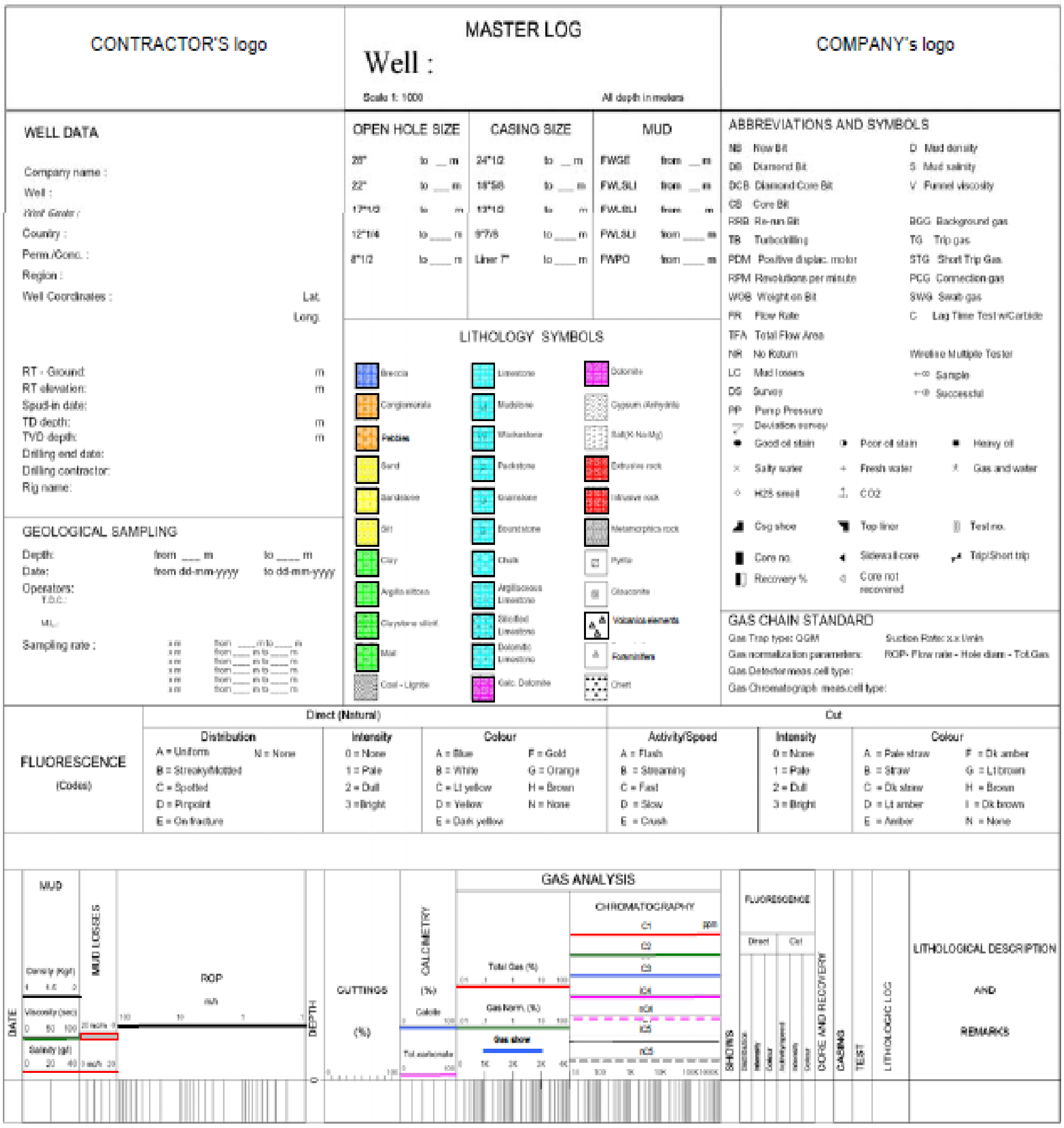

Figure 2.15: Example of master log [17]

Samples of gas removed with a sampling device called a gas trap (**Figure 2.16**) from the mud are analysed by the mud logger using a gas chromatograph. The typical gas chromatographs include [18]:

- Thermal Conductivity Detector (TCD): It is a detector system sensible to the thermal conductivity of the component in gas phase. It gives a signal proportional to the molecular mass of the vapours flowing through the detector.
- Electron Capture Detector (ECD): It is sensible to the presence of atoms with high mass and high electronegativity.
- Flame Ionization Detector (FID): It is sensible to the mole amount of carbon atoms.

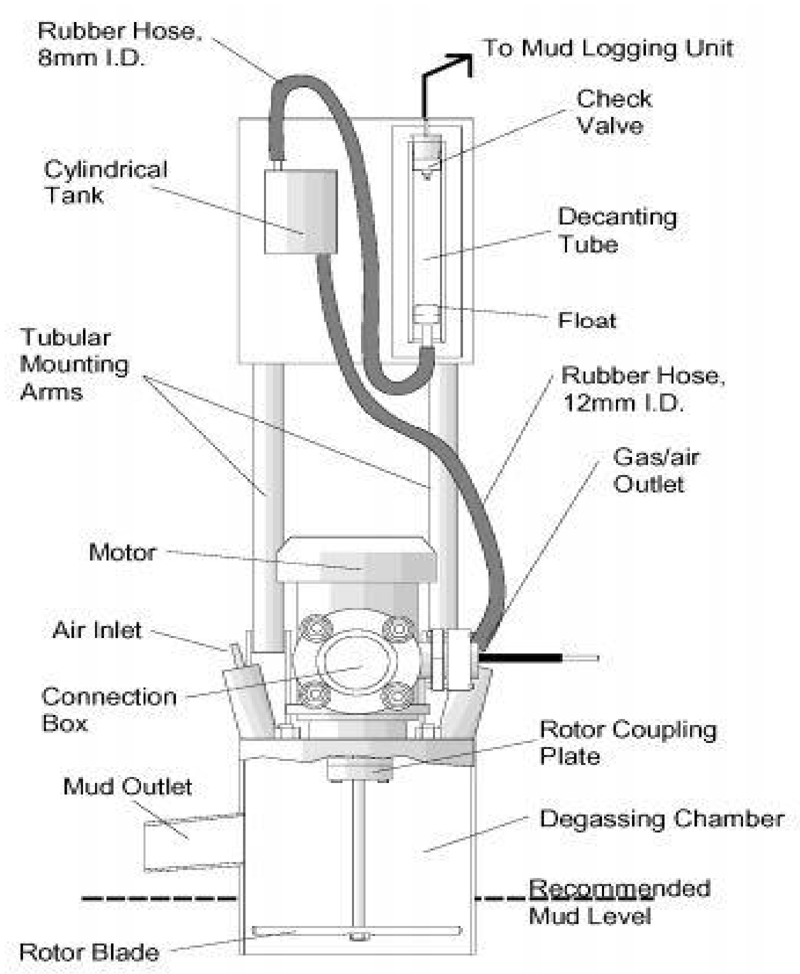

Figure 2.16: Schematic view of a gas trap [19]

Mud loggers also monitor the following geological and drilling parameters:

- Rate of penetration (ROP)

- Torque
- Rotations/revolutions per minute (RPM)
- Weight on hook (WOH)
- Weight on bit (WOB)
- Standpipe pressure (SPP)
- Casing pressure
- Mud pit levels
- Mud temperature
- Pump strokes
- Mud weight in/out
- Mud flow in/out.

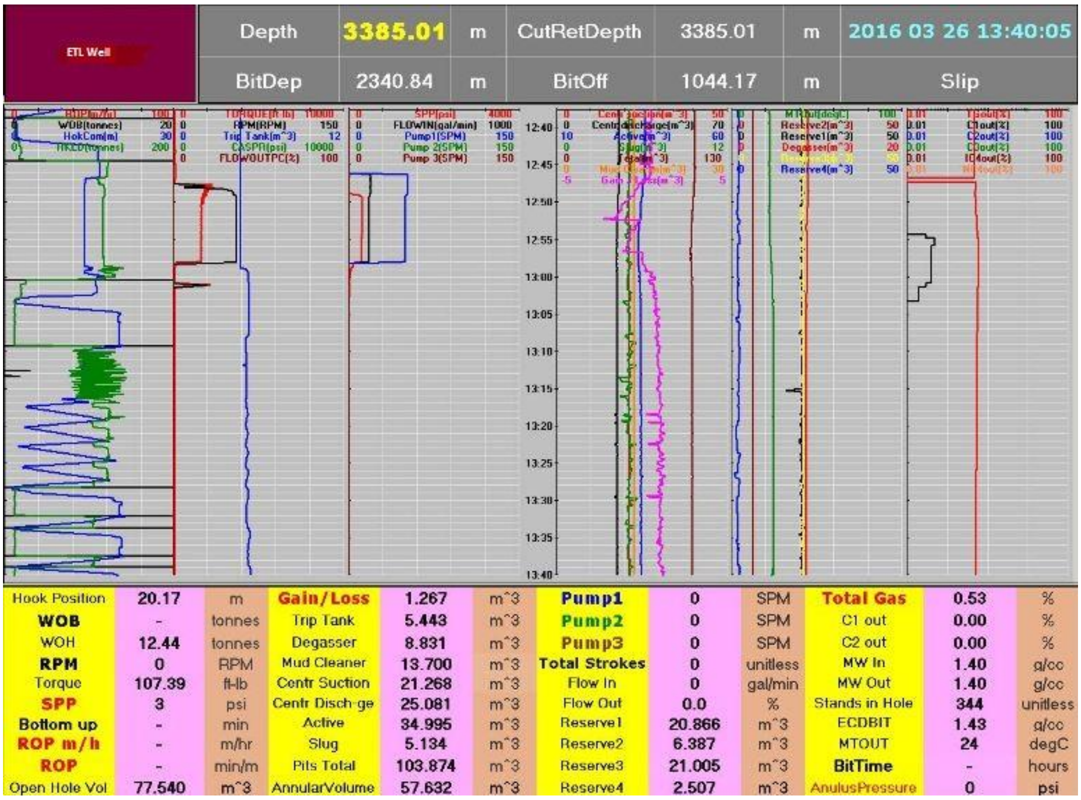

Figure 2.17: Example of a mud logging monitoring screen (Courtesy of ETL)

2.10 Offshore Drilling

About a quarter of the world's hydrocarbon is currently being produced from offshore. The same assumptions of rotary drilling used onshore are also used in offshore, but there are certain alterations of procedures and equipment which are mandatory to deal with a more hostile marine environment.

In many offshore fields (e.g. North Sea, Caspian Sea), exploration wells are drilled from a jack-up rig or a semisubmersible drilling platform (**Figure 2.18**). A jack-up drilling rigs are popular because they provide a very stable drilling platforms, since part of their structure is in firm contact with the bottom of the ocean. They can also drill in relatively deep water (the biggest can drill in waters about 350 feet or 107 meters deep). What is more, towboats can easily move a jack-up rigs from one location to another. A semisubmersible rigs are not bottom supported, but are designed to float (such rigs are commonly called “floaters”). Semisubmersibles can operate in water depths of up to 3500 feet or 1070 meters. In ultra-deep waters drillships (**Figure 2.19**) are used to drill the well. They have one or two drilling rigs mounted on the ship’s centre of gravity with DP racks located either forward or aft of each derrick. A drillship is not as stable as a jack-up rig or semisubmersible platform when drilling, but it has more storage volume and can move faster between drillsites [20]. There are also many different types of mobile offshore drilling units (MODUs) which are not mentioned above.

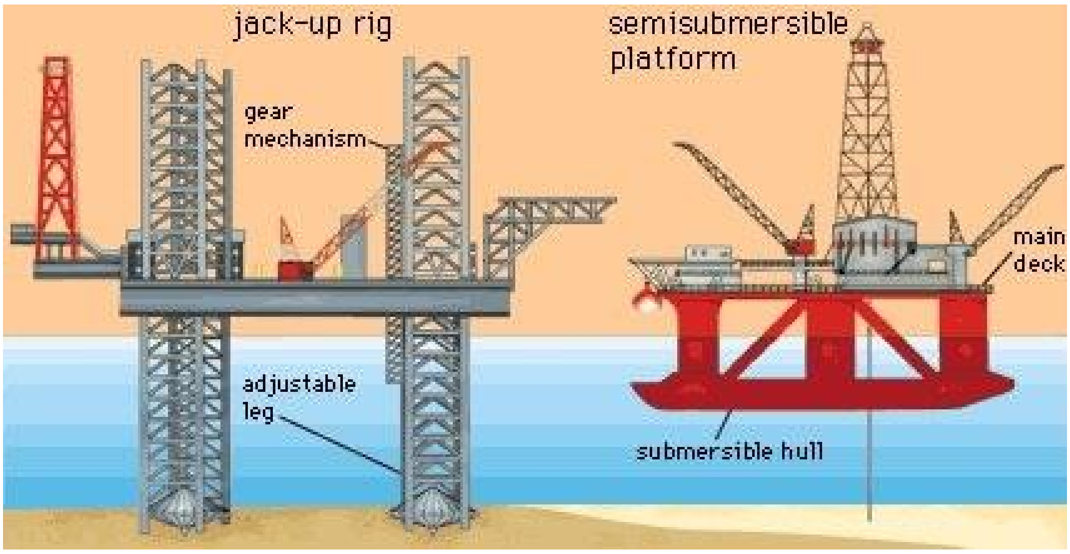

Figure 2.18: Jack-up and semisubmersible drilling rigs [20]

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). Since the daily cost of hiring an offshore rig is very high, operating companies are very anxious to reduce the drilling time and thus cut the cost of the well [7].

Figure 2.19: Drillship (Courtesy of Vantage Drilling International)

2.11 Drilling Fluids

Drilling fluid (or mud) is one of the most essential elements of any rotary drilling process. To ensure a safe and successful operation it is important to select suitable mud type and mud properties. Any problems where the drilling fluid does not meet its requirements can not only prove extremely costly in materials and time, but also threaten the successful completion of the well.
Drilling fluid is used in the drilling process to [13]:

- Clean the rock fragments from beneath the bit and carry them to the surface
- Exert sufficient hydrostatic pressure against subsurface formations to prevent formation fluids from flowing into the well
- Keep the newly drilled borehole open until steel casing can be cemented in the hole
- Cool and lubricate the rotating drillstring and bit.

In addition to serving these functions the drilling mud should not:

- Have properties detrimental to the use of planned formation evaluation techniques
- Cause any adverse effects upon the formation penetrated or cause any corrosion of the drilling equipment and subsurface tubulars.

The fundamental functions of drilling mud and the properties which are associated with achieving these functions are summarized in **Table 2.1**.

Function	Physical/chemical property
Transport cuttings from the wellbore	Yield point, apparent viscosity, velocity, gel strength
Prevent formation fluids flowing into the wellbore	Density
Maintain wellbore stability	Density, reactivity with clay
Cool and lubricate the bit	Density, velocity
Transmit hydraulic horsepower to bit	Velocity, density, viscosity

Table 2.1: Function and physical/chemical properties of drilling fluid [7]

The cost of the drilling fluid can be as high as 35% of the total cost of the well [21]. An operating company hires a service company to provide a drilling fluid specialist known as mud engineer on the rig to prepare, continuously monitor and treat the mud (if necessary).

Depending on the type of base fluid used as continuous phase, drilling fluids can be classified in three main categories [21]:

- Water-Based Muds (WBMs): It can be prepared with fresh water, sea water, various types of brines and salt saturated water within many different components can be added for obtaining the planned characteristics and performances.
- Oil-Based Muds (OBMs): It can have as continuous phase water-free oils, an oil (diesel, mineral or synthetic low toxicity oils) with emulsified water or brine (inverted emulsion systems) or water/brine in which an oil has been emulsified (direct emulsion systems). Also in this case many different chemicals are added to the system to get the desired properties.

- Gas-Based Muds (GBMs): The continuous phase is a gas (usually air, nitrogen or carbon dioxide) with additions of various quantities of water. If the water is present in low percentages, the system is defined as "mist". If the concentration of water is higher and foaming agents have been added to the system, one speaks about "foam" or "stiff foam". Finally, if the gas is added to the mud, the system is referred to as "aerated mud".

2.12 Casing

Casing is the primary structural component of a well. It is a tubular steel product used to line the wellbore (maintain borehole stability), prevent contamination of water sands, isolate water from producing formations, and control well pressures during drilling, production and workover operations. Casing provides locations for the installation of BOPs, wellhead equipment, production packers, and production tubing. The cost of casing is the main part of the overall well cost; therefore, the selection of casing size, grade, connectors and setting depth is a fundamental engineering and economic consideration. Since the well is normally drilled in sections, multiple concentric casing strings are usually ran in the well. An example of standard casing profile is shown in **Figure 2.20**. There are six basic types of casing strings. Each is discussed next [22].

Conductor pipe (casing): It is set above the surface casing, a first large diameter casing, called the conductor pipe or drive pipe (42", 30"), is usually set at about 20-50 meters with the purpose to protect the shallower weak, unconsolidated formations from caving in or collapsing or for avoiding any eventual stability problem to the drilling rig itself. The conductor pipe is usually driven into the ground without being cemented at all [21].

Surface casing: It is run to prevent caving of weak formations that are encountered at shallow depth. The surface casing should be set in competent rocks. This will ensure that formations at the casing shoe will not fracture at the high hydrostatic pressures which may be encountered later. The surface casing also serves to provide protection against shallow blowouts, hence BOPs are connected to the top of this string. The setting depth of this casing string is chosen so that troublesome formations, thief zones, water sands, shallow hydrocarbon zones and build-up sections of deviated wells may be protected [23].

Intermediate casing: This string provides blowout protection for deeper drilling and isolates troublesome formations that could impair well safety and hamper drilling operations. An intermediate casing string is commonly set when a well is likely to encounter an influx or loss of circulation in the open hole thus providing blowout protection by upgrading the strength of the well. The cement height is determined by the design requirement to seal off any hydrocarbon or flowing salt zones. The top of cement does not need to be inside the surface string [1].

Production casing: It is either run through the pay zone or set just above the pay zone (for an open hole completion or prior to running a liner). The main objective of this casing is to isolate the production interval from other formations (e.g. water bearing sands) and/or act as a conduit for the production tubing. Since it forms the conduit for the well completion, it should be thoroughly pressure tested before running the completion [7].

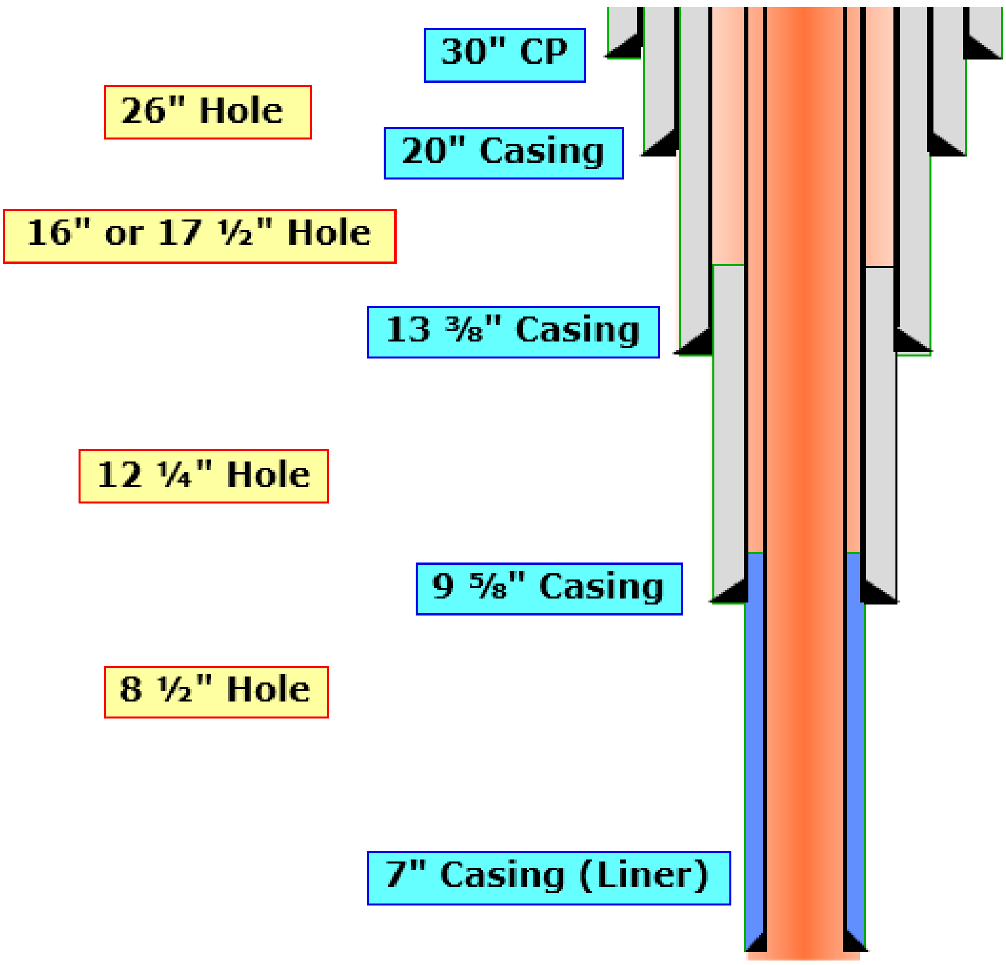

Figure 2.20: Standard casing profile [21]

Liner: It is a casing string that does not extend back to the wellhead, but instead it is hung from another casing string. Liners are used instead of full casing strings to reduce cost, improve hydraulic performance when drilling deeper, allow the use of larger tubing above the liner top, and not represent a tension limitation for a rig. It can be either an intermediate or a production string. Liners are typically cemented over their entire length [22].

Tieback string: It is a casing string that provides additional pressure integrity from the liner top to the wellhead. An intermediate tieback is used to isolate a casing string that cannot withstand possible pressure loads if drilling is continued (usually because of excessive wear or higher than anticipated pressures). Similarly, a production tieback isolates an intermediate string from production loads. Tiebacks can be uncemented or partially cemented [22].

2.13 Cementing

Cementing is the mixing and pumping of a cement slurry into a well generally by a service company. The cementing equipment used at the wellsite includes a cementing van that controls the operation, high-pressure and -volume truck- mounted diesel pumping units, bulk cement transport units and a cementing head on the well. Primary cementing (**Figure 2.21**) is done immediately after a casing or liner string is run in a well. It can be a single-stage cement job through the casing using top and bottom wiper plugs or a multistage cement job done in several steps to avoid fracturing the formation when cementing long casing strings.

Secondary cementing (Figure 2.22) is any cement job after primary cementing that is part of well servicing and workover or plug and abandonment. During a cementing job after the casing has been run, the hole is first reamed and wiped. Bulk cement is mixed with water and cement additives in a cement mixer and a mixing tub to make the slurry. A 10-50 bbl water spacer is often pumped down the casing first to separate the drilling mud and slurry and also to remove some of the mudcake. The slurry is then pumped by special cementing pumps through the cement placement line on the rig floor to the cementing head on the top of the casing and down the casing. Two cementing plugs are used during a cement job to separate the fluids. The bottom plug that separates drilling mud on the bottom from cement slurry on the top is first pumped down the well and seats on or bumps the float collar. It has a diaphragm that ruptures under pressure to open an orifice through the plug to allow the cement slurry to flow through.

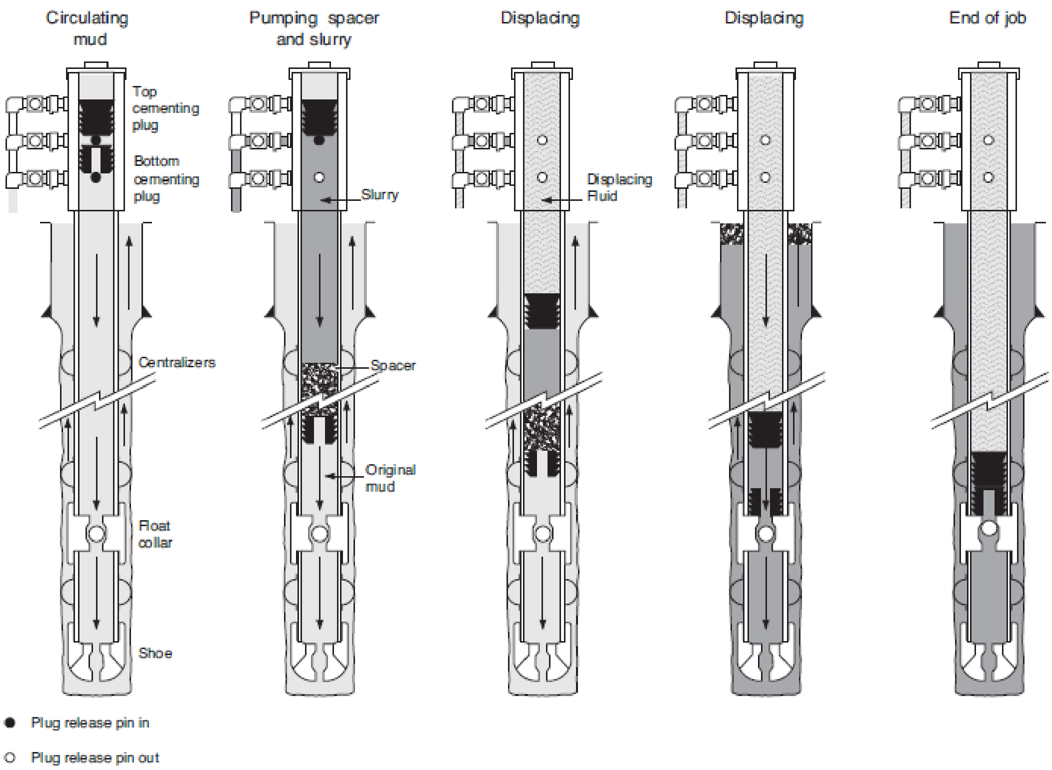

Figure 2.21: Primary cementing operations [7]

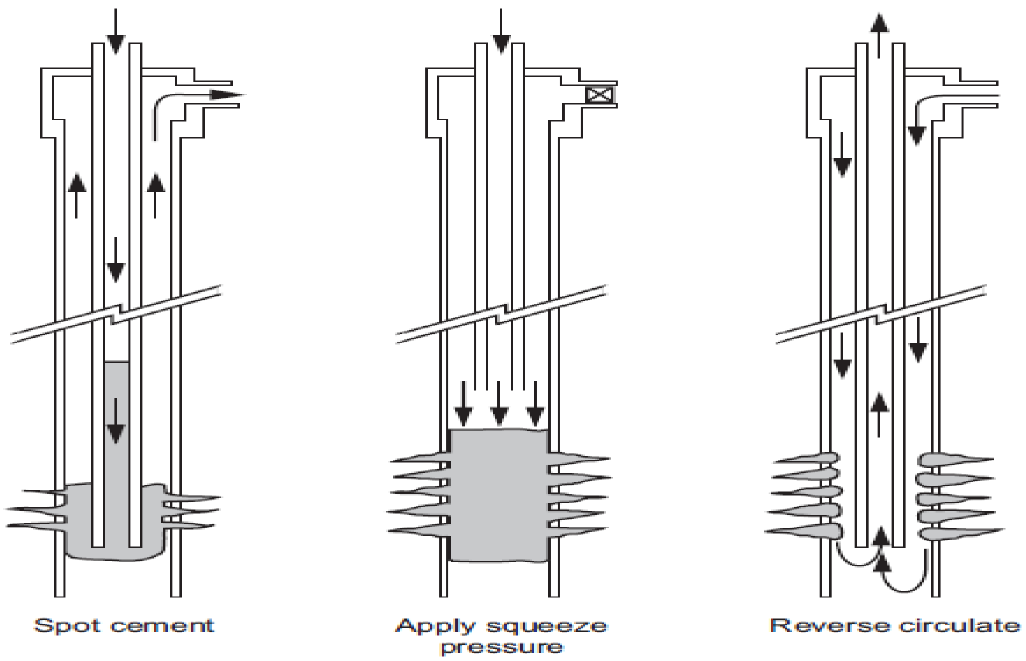

Figure 2.22: Example of secondary or squeeze cementing operation [7]

The displaced drilling mud that filled the casing comes up the well along the outside of the casing. The top plug that separates cement slurry from the displacement fluid (usually drilling mud) is then pumped down the well with a displacement fluid behind it until it bumps the bottom plug, forcing the cement slurry up the well behind the casing. The cement is then allowed to set during waiting on cement (WOC). The cementing plugs, guide shoe and cement on the bottom of the well are then drilled out [10].

2.14 Well Completion

The well completion is an upstream petroleum activity whose purpose is to furnish the well, once a well has been drilled and cased, with all of the equipment needed to extract the hydrocarbons to the surface, both in the case of natural flow and artificial lift. Completion has a permanent nature; therefore, planning parameters must be carefully assessed and possible solutions must undergo technical and economical optimisation [21]. The goals of a well completion are to:

- Connect the reservoirs to the surface
- Isolate the producing reservoir from other zones
- Provide a passage for well stimulation treatments
- Protect the integrity of the reservoir
- Provide a passage to measure the changes in flow rate and pressure needed to run a well test.

The wellbore provides the path from the surface to the reservoirs. The successful production and depletion of a reservoir depends on the successful completion and workover operations carried out to a well.
Different schemes are used to classify the well completions and some overlapping always occurs. The main types are as shown below.
Interface between wellbore and reservoir:

- Open hole
- Cased and uncemented
- Cased and cemented

Production method:

- Flow naturally

- Require artificial lift (**Figure 2.23**)

Stage of completion:

- Initial
- Recompletion
- Workover.

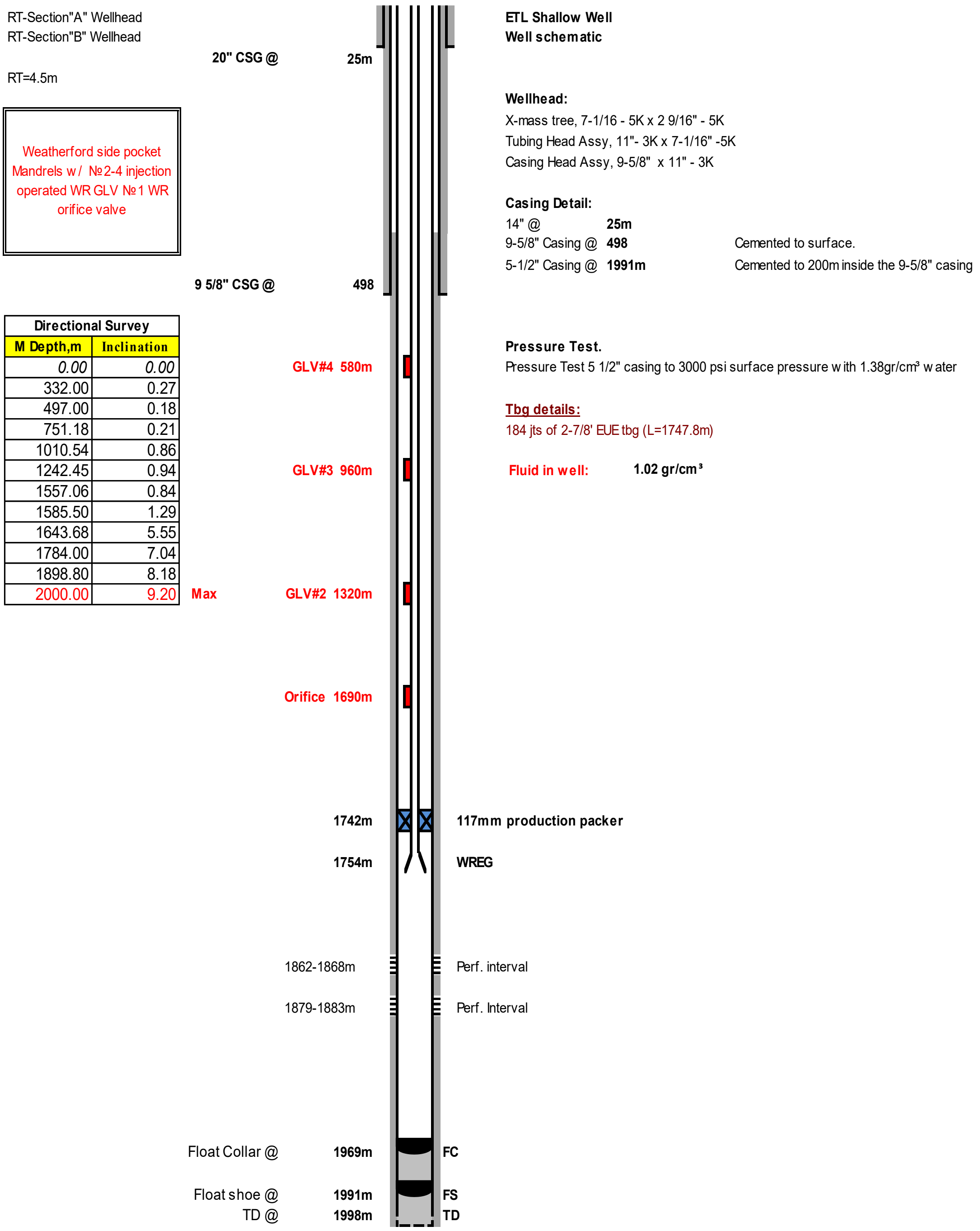

Figure 2.23: Typical gas lift completion (Courtesy of ETL)

3 INNOVATIVE DRILLING TECHNOLOGIES

The oil and gas industry has developed fast in terms of drilling efficiency and cost savings in the 1990s. Some drilling milestones were quite notable at the end of the 20th century.

Although we are performing significant progress, the enlargement of the world economy has given rise to escalating demands for petroleum, giving the energy industry new challenges. For example, how can we advance technologies to benefit more oil and gas resources with lower drilling costs? How can we improve the efficiency of drilling tools and operation safety on the basis of traditional drilling tools? These questions and challenges focus on drilling technologies and how to further improve the technology to better meet the energy demands of the world economy.

Advancements of drilling symbolize a breakthrough technologies and a revolution in the oil and gas industry. They represent new achievements in drilling technology that have generated great contributions to the economic progress and development of oil and gas fields.

3.1 Directional Drilling

When looking back to the oil and gas history, most wells were drilled straight down (vertically) into the oil and gas deposits. These wells were considered as vertical wells. Due to the bending of drillstring and formation effects, deviation always occurs in a wellbore. According to International Association of Drilling Contractors (IADC), the first directionally controlled boreholes were drilled from an onshore location to the oil and gas reservoirs underneath the Pacific Ocean in Huntington Beach, California, in 1930. There had been built jetties out into the ocean and built the drilling rig on the jetty. Because it was too expensive, the technique of drilling deviated wells was developed. Since that time many new techniques and innovative tools have been introduced to control the path of the wellbore.

Directional drilling is the process of directing the wellbore along some trajectory to a predetermined target [13]. An operating company usually hires a directional drilling and surveying service company to:

- Provide experts for planning a well

- Supply specific tools
- Provide wellsite assistance
- Measure the inclination and direction of the well while drilling continues.

3.1.1 Applications of Directional Drilling

There are many reasons for drilling directional wells. Some of the major applications of directional drilling are listed below and shown in **Figure 3.1**.

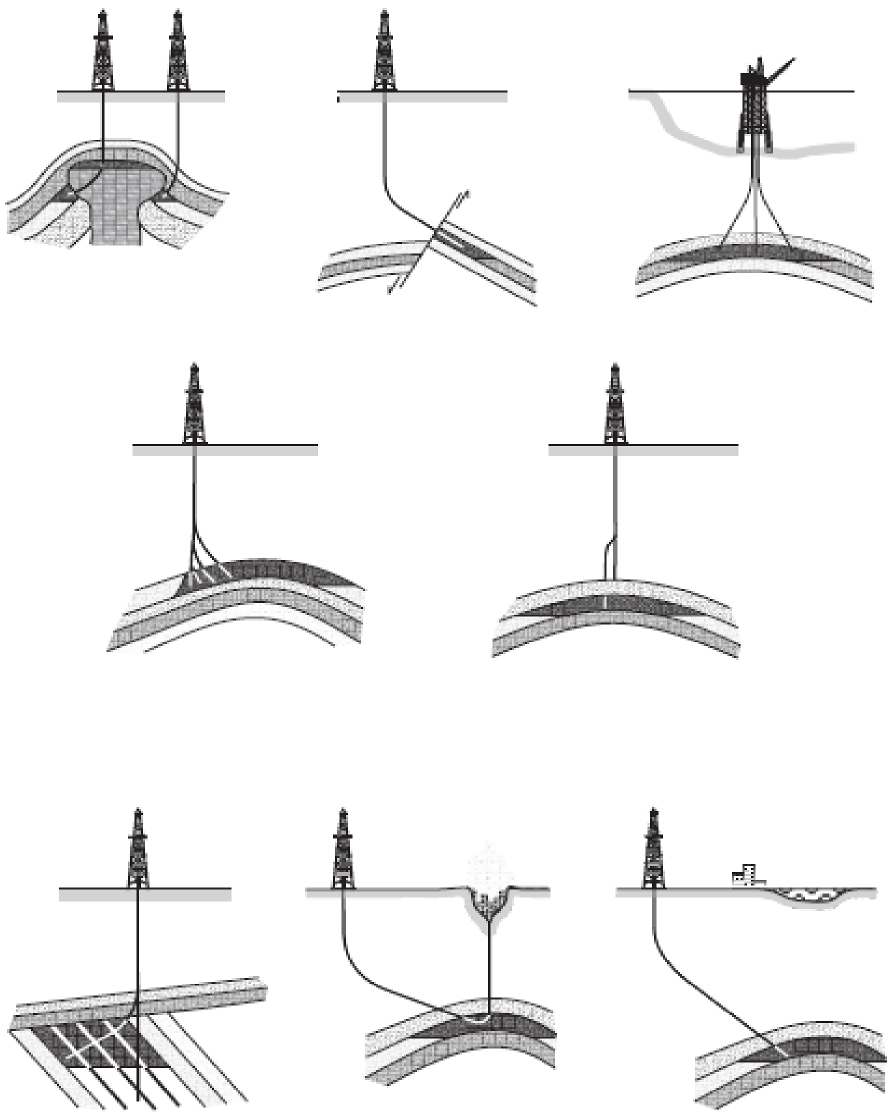

Figure 3.1: Applications of directional drilling [7]

Sidetracking and straight hole drilling: In many cases it is hard to control the angle of inclination of well and it might be mandatory to adjust the route of well for many acceptable reasons. For example, it may be crucial in the situation when plug back the well to drill another target or the drillstring becoming stuck to simply drill around the fish.

Fault drilling: It is sometimes difficult to drill a vertical well in a steeply dipping, inclined fault plane. The bit often deflects when passing through the fault plane and it will follow the fault plane. Well can be drilled on the up thrown or downthrown side of the fault and deflected into the producing formation to avoid the problem. The bit will cross the fault with enough angle where the direction of the bit cannot alter to follow the fault [24].

Drilling salt dome: Many hydrocarbon reservoirs are combined with the intrusion of salt domes. The reservoir lies directly under the flank of the salt dome in this type of trap. To prevent potential drilling problems such as moving salt, severe washouts and high pressure blocks of dolomite, a directional drilling method can be used to drill alongside the salt dome and then at an angle below the salt to enter the reservoir.

Inaccessible locations: There are situations when hydrocarbon reservoirs located under inaccessible places including cities (towns), shorelines, rivers, mountains and production facilities. When drilling equipment cannot be constructed directly above the producing formation, the wellbore can be drilled directionally. It permits to produce hydrocarbons from inaccessible reservoirs.

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. Mud or water are 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 must be precise and requires special tools [24].

Multi-well platform drilling: It is widely employed in offshore fields especially in the North Sea. The development of these fields is only economically feasible if it is possible to drill a large number of wells (up to 40 or 60) from one platform. The directional wells are designed to intercept a reservoir over a wide aerial extent. Many oilfields in the world (both onshore and offshore) would not be economically feasible if companies do not use for this technique [7].

3.1.2 Directional Well Planning

There are three basic configurations for a directional well [21] (**Figure 3.2**):

- Slant hole profile: In this configuration, the kick-off point (KOP) is placed at low depths. After the maximum angle of inclination has been reached during the build-up phase, the angle is maintained constant until the objective is attained. This is the classical profile of a directional well in which the objective consists of a single target or when an extended displacement is required. Also known as build and hold profile.
- S-shaped hole profile: The KOP is also placed at low depths in this case. After the maximum planned inclination has been reached, it is kept until the largest part of the displacement has been realized. This well profile is used in structures where different targets are present. It is also applied when there is necessity to hit the target vertically, but with a certain displacement from the surface location of the well. The KOP is placed near the surface, because trips are short and the build-up is much easily carried out in soft formations.
- J-shaped profile: It is preferred in special situations such as drilling close to faults, salt domes or in presence of particular geological requirements. The KOP is placed deep in the well and much closer to the objective. Once the maximum inclination has been obtained, the inclination angle is maintained constant till the target.

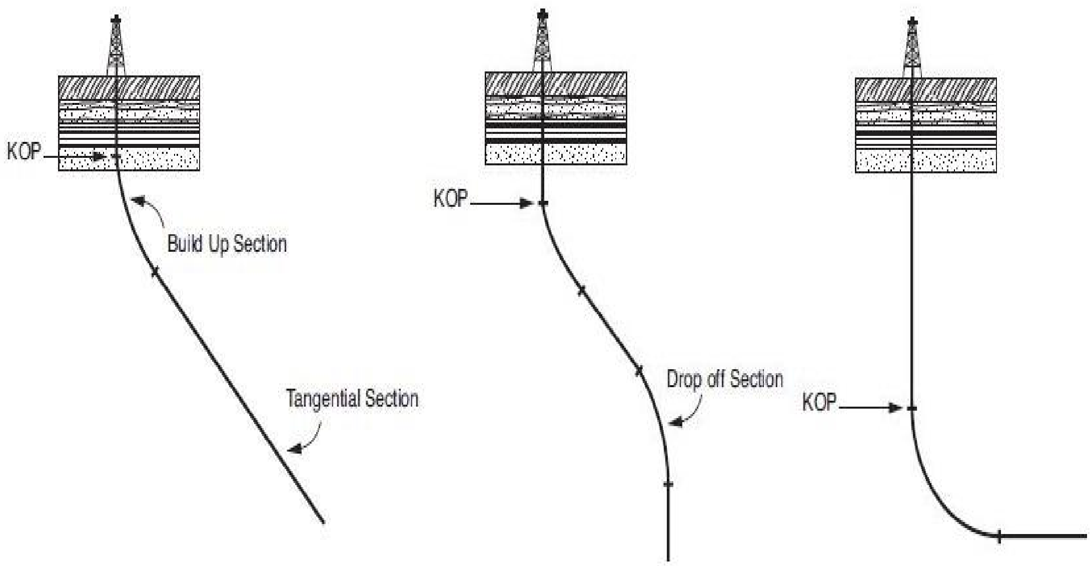

Figure 3.2: Standard well trajectories [7]

There are four specific parameters which have to be considered when planning the directional well. We need to combine these parameters to define the trajectory of the well and are:

- Kick-off Point (KOP): It is the depth in a vertical hole at which a deviated hole is started and the well is oriented in a particular direction in terms of North, South, East and West. Because it is generally difficult to kick off in deep formations, it is initiated in shallow and stable formations.
- Build-up Rate (BUR): It is the curvature of a build curve or rate of angle increase in a slant hole over a given distance. BUR is generally expressed in degrees per 100 ft (or per 30 m).
- Drop-off Rate (DOR): It is the angular decrease of the curvature in a slant hole and generally expressed degrees per 100 ft (or per 30 m).
- Tangent (or Drift) Angle of the well: It is the inclination (in degrees from the vertical) of the long straight section of the well after the buildup section of the well. The tangent angle will generally be between 10 and 60 degrees because it is difficult to control the trajectory of the well at angles below 10 degrees and it is difficult to run wireline tools into wells at angles of greater than 60 degrees [8].

A number of technical issues will have to be considered when planning a deviated well. These are:

- Location of target
- Size and shape of the target
- Rig location
- Subsurface obstacles (offset wells, geological structures, etc.).

In addition to the constraints given above, the following factors must be taken into account in the geometrical design of the well:

- Casing program
- Mud program
- Geological section.

3.1.3 Deviation Tools

There are many instruments (or tools) and techniques which can be used to alter the direction of a well in oil and gas industry. They are used to change the inclination and the azimuthal direction of the wellbore. Deviation tools work with two basic principles. The first one is the introduction of a bit tilt angle into the axis of the BHA just above the bit. The second principle is to introduce a sideforce to the bit (**Figure 3.3**). Applications of these two principles to the bit result in the bit drilling off at an angle to the ongoing trajectory.

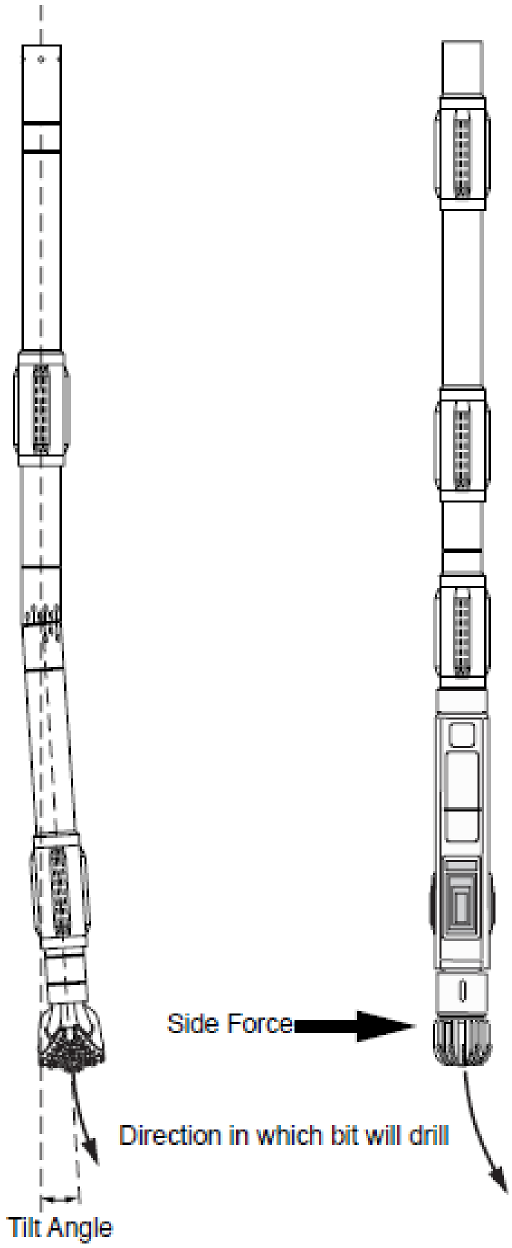

Figure 3.3: Bit tilt angle and sideforce [25]

The main tools currently used for this purpose are [25]:

- Bent Sub and Positive Displacement Motor
- Non-Rotating Steerable Drilling Systems
- Rotating Steering System
- Directional Bottom Hole Assemblies (BHA)
- Whipstocks

3.1.4 Bent Sub and Positive Displacement Motor

The most commonly used technique to change the well trajectory uses an equipment known as a bent sub and a positive displacement motor (**Figure 3.4**).

A bent sub (**Figure 3.5**) is a short pipe with threaded connections on either end which has almost the same diameter as the DCs. It is churned out in a way that the axis of the lower connection is slightly overhang (around 3 degrees) from the axis of the upper connection. When it is made up into the BHA, a bent sub introduces a tilt angle to the components of the BHA below it and to the axis of the drill bit.

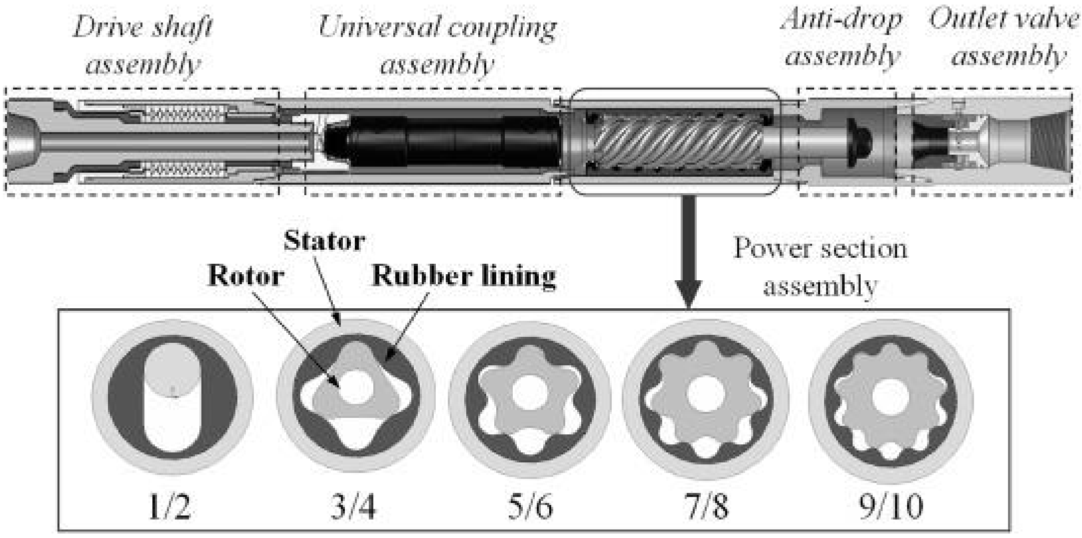

Figure 3.4: Bent sub and positive displacement motor [25]

However, when it is introduced into the BHA, the center of the drill bit is also overhang from the center of the drillstring above the bent sub. Therefore, it is not possible to rotate the bit by rotating the drillstring from surface. Even if it was possible to rotate, the effect of the tilt angle would be bypassed because there would not be preferential direction for the bit to drill in. For that reason, the bent sub must be used with a positive displacement motor (PDM) or a drilling turbine.

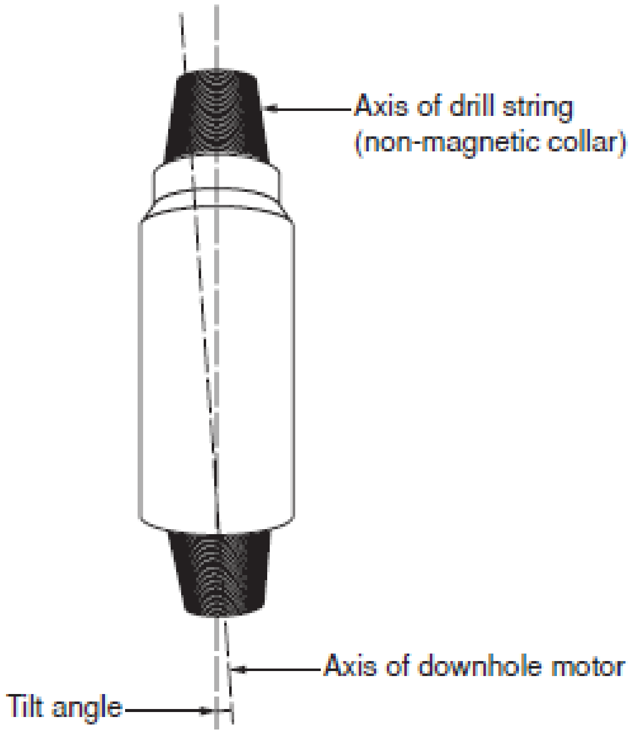

Figure 3.5: Directional drilling bent sub [25]

The PDM is frequently called a mud motor and is utilized in definitely a larger number of wells than the turbine. The mud motor is included in the BHA beneath the bent sub, between the bent sub and bit. When drilling mud is circulated through the drillstring and the inner shaft of the mud motor, which is located just above the drill bit, it rotates. As a consequence, the drill bit also rotates. It is not mandatory to rotate the whole drillstring from the surface if a mud motor is made up into the BHA. Because mud motors and turbines are very expensive parts of the BHA, they are not used when not drilling directionally.

A scribe line is marked on the inside of the bend of the bent sub. It indicates the direction in which the bit will drill. This direction is known as the toolface. A directional surveying tool (e.g. MWD tool) is usually run as a part of the BHA, simply on top of the bent sub in order to check the trajectory of the well periodically when the well is deviating.

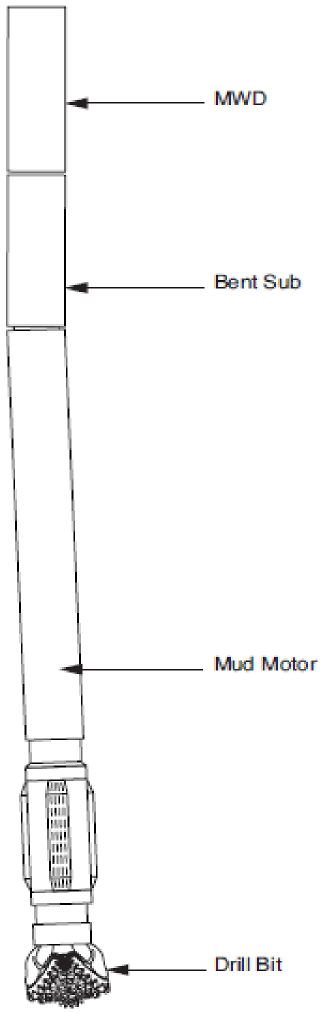

Figure 3.6: BHA with bent sub and PDM [7]

The bent sub and mud motor can be utilized in the build-up and drop-off part of the well since the bit pursue to drill in the direction of the tilt angle as long as the bent sub is within the BHA and the PDM is getting used to rotate the drill bit. This results in the main disadvantage of employing a bent sub and mud motor to alter the trajectory of the well.

In rotary drilling process, conventional BHA which is used to drill the vertical portion of the well must be POOH and BHA with bent sub and mud motor RIH before the trajectory can be altered. Therefore, the bent sub and PDM tools will be used to drill during a specific direction. Once the well is drilling within the needed direction (inclination and azimuth), the bent sub and mud motor should be pulled out and the conventional BHA re-run. POOH and RIH are time consuming operations depending on depth of the well.

3.1.5 Steerable Drilling Systems

A steerable drilling systems permit directional changes without tripping operation to change the BHA. According to [8], it includes a bit, a stabilized positive displacement steerable mud motor, a stabilizer and a directional surveying system that monitors and transmits the information to surface such as hole azimuth, inclination and toolface on a real time basis.

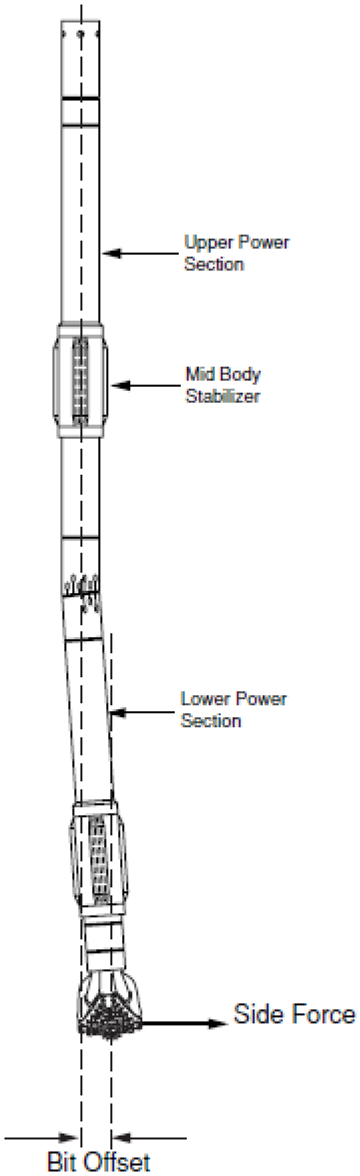

Figure 3.7: Steerable drilling system [25]

When the tilt angle is placed very close to the drill bit by using a navigation sub on regular mud motor, the capacity to change direction is increased. This tilt angle can be used to drill in a desired direction, in the same way as the tilt angle generated by a bent sub with the bit being rotated by the mud motor when circulating. Because the tilt angle is much closer to the drill bit compared with conventional bent sub assembly, it produces a much lower bit offset. It implies that the bit can also be rotated by rotating the complete drillstring at surface. Therefore, the steerable assembly can be used to drill in a desired direction by diverting the bent sub within the required direction and circulating the mud to rotate the bit or drilling a straight line by both rotating and circulating the drilling mud through the drillstring. As a consequence, the rotation of the drill bit created by the mud motor will be super-imposed on the rotation from surface. This does not mean that the effect of the tilt angle is eliminated by the rotation of the entire assembly.

When employing the navigation sub and mud motor to drill a directional part of the well, the expression "sliding or oriented" drilling is used to characterize the drilling activity. The expression “rotary” drilling is used to characterize the drilling activity when drilling in a straight line by rotation of the assembly. The directional tendencies of the system are mainly influenced by the navigation sub tilt angle, the size and distance between the PDM stabilizer and the principal stabilizer above the motor.

3.1.5.1 Applications of Steerable Drilling Systems

The steerable drilling systems are significantly valuable where changes within the direction of the hole are difficult to accomplish, wherever directional management is difficult to keep up in the tangent sections of the well or wherever frequent changes are also needed.

The steerable drilling systems are employed with combination of measurement while drilling (MWD) tools that contain petrophysical and directional sensors. These kind of MWD tools are generally named as logging while drilling (LWD) tools. The petrophysical sensors are employed to observe alterations within the properties of the formations including lithology, resistance and porosity while drilling. It permits to determine whether a change in direction is needed or not. The assembly is being used to trace desirable properties of formation and place the wellbore within the most desirable location from a reservoir engineering point of view. The expression “Geosteering” is usually used once the steerable drilling system is employed to drill a directional well with this approach.

3.1.5.2 Components of Steerable Drilling Systems

There are five main components in the steerable drilling system. These are [7]:

- Drill bit: Steerable systems are suitable with either tricone or PDC bits. In most situations, the PDC bit will be used since this eliminates frequent trips for changing the bit.
- Mud motor: The motor part of the system induces the drill bit to rotate when drilling fluid is circulated through the drillstring. It makes oriented drilling possible.
- Navigation sub: It converts a standard mud motor into a steerable motor by tilting the drill bit at a prearranged angle. The bit tilt angle and the location of the sub at a minimum distance from the bit permits both oriented and rotary drilling without enormous loads and wear on the bit and motor. The design of the navigation sub assures that the deflecting forces are mainly applied to the bit face (rather than the gauge) thereby maximizing cutting efficiency.
- Navigation stabilizers: It is required two specially designed stabilizers for the operation of the system and influence the directional performance of a steerable assembly. The motor stabilizer or Upper Bearing Housing Stabilizer (UBHS) is a fundamental portion of the navigation motor and it is slightly undergauge. The upper stabilizer which describes the third tangency point is also undergauge. It is alike to a string stabilizer. The size and spacing of the stabilizers also can be differed to fine-tune assembly reactions in both the adjusted and rotary modes.
- Survey system: A real time downhole survey system is needed to supply continuous directional information. An MWD system is often used for this purpose. An MWD tool can transmit fast and accurate data of the hole inclination, azimuth and the navigation sub toolface orientation. In some situations, a wireline steering tool is also used for this purpose.

3.1.5.3 Operation of a Steerable System

The steerable system able to drill directionally and also straight ahead as required. This allows the driller to manage the well's trajectory without time consuming tripping operations to modify the BHA. To control the hole throughout kick-offs or course corrections the system is directed employing MWD readings hence the bit can drill within the direction of the navigation sub's offset angle. When the drilling process is performed in this way, the system can be said drilling in the oriented or sliding (since the drillstring is not rotating) mode. The drill bit is driven by the downhole motor and the rotary table is locked in place, as it is when conventional motor drilling. As explained above, the system's two stabilizers and bit tend as the tangency points that define the curve to be drilled by the oriented assembly. The generated dogleg severity can be managed by varying the size and placement of the stabilizers by using a DTU with a distinct offset angle or by changing drilling with oriented and rotary intervals.

The steerable drilling system can also be employed to drill straight ahead by rotating drillstring. While the motor is running, the rotary table is generally rotated at 50-80 RPM. The system can be said drilling in the rotating mode when the drilling is fulfilled in this way. Oriented sections are minimized and the assembly is rotated as much as possible by careful well planning and BHA design. This maximizes ROP while maintaining the well on course. Survey readings from the MWD tool let efficient monitoring of directional data so the driller can keep the well's path close to the requested path. Slight deviations can be explored and then corrected with minor oriented drilling intervals before they become main problems.

3.1.6 Rotary Steering System

The rotary steering system explained here works on the basis of the application of a sideforce in a same way to the non-rotating systems expressed above. Nevertheless, it is also possible to rotate the drillstring even during directional drilling or as explained above when in the sliding mode in these systems. It is possible to rotate the drillstring all the time during the drilling. Rotating the string is desirable for several reasons. For example, it is easier to transport cuttings from the wellbore to surface when the drillstring is rotating. There is a tendency for the drilled cuttings to settle around the drill string when it is not rotating. As a result, string might become stuck.

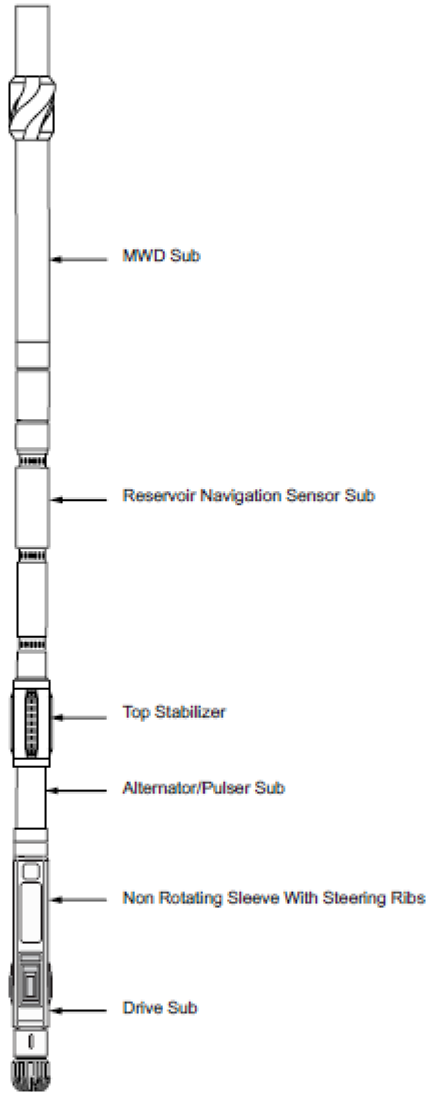

Figure 3.8: Rotary steering system (Courtesy of Baker Hughes a GE company)

There are many tools which have been developed to permit the drillstring to be rotated while drilling in the oriented mode. Baker Hughes a GE company AutoTrak™ RCLS [26], Schlumberger PowerDrive Orbit RSS [27] and Halliburton Geo-Pilot® RSS [28] are the most representatives of mainstream technologies amid the current rotary steering drilling technologies. One of these devices is detailed next.

The main elements of the rotary steering system that is described here (AutoTrak™ RCLS) are the downhole and surface systems.

3.1.6.1 Downhole System

The downhole system consists of [7]:

- The Non-Rotating Steerable Stabilizer
- The Electronics Probe
- The Reservoir Navigation or MWD Tool.

Non-Rotating Steerable Stabilizer

The steering unit included within a non-rotating sleeve controls the direction of the drill bit. A drive shaft rotates the drill bit thru the non-rotating sleeve. This sleeve is decoupled from the drive shaft and it is therefore not induced by drillstring rotation. This sleeve consists of three hydraulically operated ribs, the near bit inclinometer and control electronics. Pistons which are operated by high pressure hydraulic fluid apply controlled forces separately to each of the three steering ribs. The system exerts a special, managed hydraulic force to every steering rib and therefore the resulting force vector directs the tool throughout the specified trajectory at a programmed dogleg severity. This force vector is regulated by a combination of downhole electronic control and commands pulsed hydraulically from the surface [7].

The micro-processing system inside the AutoTrak™ RCLS calculates how much pressure has to be applied to each piston to get the desired toolface orientation. In determining the magnitude of the force applied to the steering ribs, the system also considers the dogleg limits for the current hole selection [7].

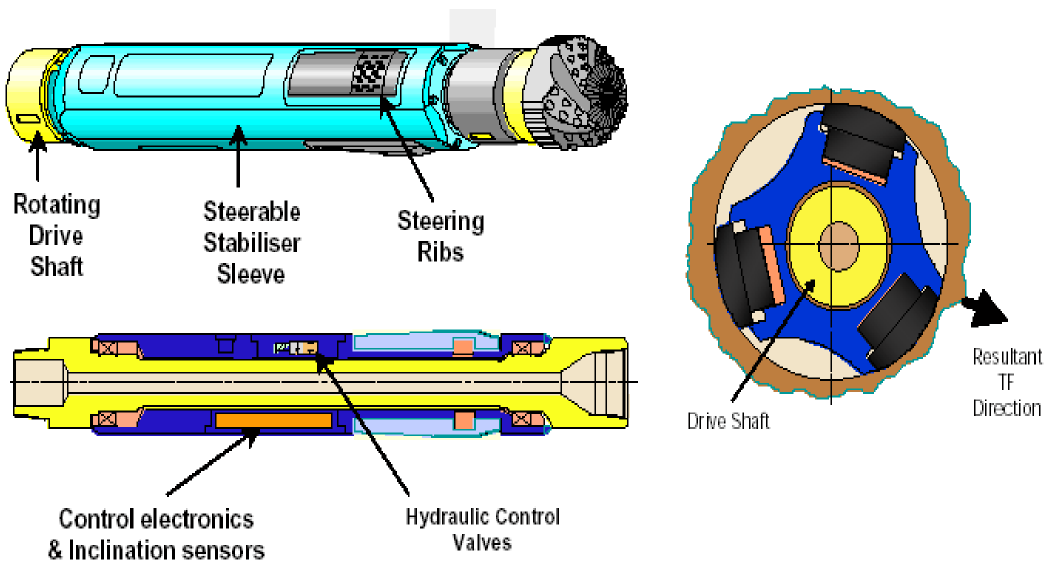

Figure 3.9: Non-rotating steerable stabilizer

According to the field tests, the sleeve has been seen to rotate around one revolution every half hour depending on the type of formation and ROP. To compensate, the system frequently monitors the relative position of the sleeve. Using these data, AutoTrak^{TM} RCLS automatically adjusts the force on each steering rib to supply a steady side force at the drill bit in the desired direction [7].

The Electronics Probe

The electronics probe manages the interface between all tool elements. It controls the exchange of data to and from the surface. This part also includes tool vibration and directional sensors. Azimuth measurements from the tri-axial magnetometer monitor and manage the steering unit in conjunction with the near drill bit inclinometer, providing early readings of tool inclination alterations. The vibration sensor helps assure that AutoTrak^{TM} RCLS is operated within specifications and at maximum efficiency [7].

Reservoir Navigation Tool (RNT)

The RNT sub with Multiple Propagation Resistivity (MPR) and Dual Azimuthal Gamma Ray (GR) sensors allows real-time geosteering within the reservoir. Using two frequencies and dual transmitters, the RNT provides four compensated resistivity measurements to determine R_t precisely under the different conditions. The system supplies deep-reading 400 kHz measurements and high vertical resolution 2 MHz readings. The 400 kHz readings can explore contrasting bed boundaries and fluid contacts up to 18 ft (5.5 m) from the tool while drilling horizontally. In a horizontal application, this enables drillers to estimate boundaries more than 250 ft (75 m) ahead of the drill bit. These two frequency readings and Dual Azimuthal GR measurement let AutoTrak operators to downlink course corrections to maintain the well in the zone of interest [7].

3.1.6.2 Surface System

AutoTrak's surface system has two major components [25]:

- Surface Computer System
- By-Pass Actuator (BPA).

Surface Computer System

The surface computer system encodes the downlink signals for transmission to the tool and decodes the MWD signals obtained from downhole. Additionally, it supplies standard directional and LWD outputs. The system consists of the central processor and an MWD decoding unit. Downlink communication with the AutoTrak^{TM} RCLS tool is controlled either by the computer or manually from the keypad. The downhole system is programmed by using the negative pulse telemetry generated in the surface BPA [25].

By-Pass Actuator

The BPA valve unit is designed to transmit commands to the downhole tool through negative mud pulse telemetry. Every valve unit is fully certified by Det Norske Veritas. The BPA is connected to the standpipe. It can divert a number of the mud flow to generate a series of negative pulses in the DP. The tool feels and decodes these as downlink instructions. Depending on the complexity of the downlink, an entire downlink command can take between 2 and 8.5 minutes. It sends a confirmation message back to the surface just after the AutoTrak^{TM} RCLS downhole tool receives the downlink information, then reconfigures itself for the task required. Automated operation of downlink can be fulfilled as drilling continues, permitting control of AutoTrak^{TM} RCLS without interrupting the progress of the well [25].

3.1.7 Directional Bottom Hole Assemblies (BHA)

A conventional BHA is generally used when drilling a vertical hole or the vertical sections of a directional well. It is also possible to drill the tangent parts of the well with the steerable assembly when using a steerable assembly in a deviated well.

The conventional BHA can be designed to result in an increase or decrease in the inclination of the wellbore. However, it is very challenging to estimate the rate at which the angle will increase or decrease with a conventional BHA. This technique is not common in drilling operations today.

The tendency of a conventional BHA to result in an increase or decrease in hole angle is a function of the flexibility of the BHA [7]. Because all parts of the drillstring are flexible to some degree, the BHA will bend when weight is exerted to the drill bit. It will introduce a tilt angle at the bit. The magnitude and orientation of the tilt angle will

depend on the WOB, the stiffness of the DCs and the number and position of the stabilizers in the BHA. This technique is also not widely used today.
Three different types of BHA have been used to control the hole deviation in the past. These are:

- Packed-hole assembly
- Pendulum assembly
- Fulcrum assembly

Packed-hole assembly: It is very stiff assembly, containing DCs and stabilizers properly spaced to reduce bending and maintain the bit on route. Packed-hole assembly is generally used in the tangential section of a deviated hole. It is very difficult to find a packed-hole assembly which will keep the tangent angle and direction.

Pendulum assembly: It makes use of the gravitational effects acting on the drill bit and lower section of the BHA to keep vertical hole or drop angle back to the vertical. This is performed by placing the first stabilizer approximately 30, 40 or 60 ft above the bit. The pendulum assembly is generally used as an angle reducing assembly on directional wells. Problems with this type of assembly occur in dipping formations and also when higher WOB are used which tend to deflect the bit, due to the lack of rigidity of the assembly, result in angle building [23].

Fulcrum assembly: The mechanism behind a fulcrum assembly is to put a reamer close to the drill bit and apply high WOB. When WOB is applied, the DCs above the reamer will act to bend against the low side of hole, making the reamer tend as a fulcrum forcing the drill bit upwards. The BUR depends on WOB, size of DCs, position of reamer and stabilization above the reamer.

3.1.8 Whipstocks

Whipstock is a tool used to kick-off a deviated hole. It is a steel casting that is around 20 ft (6 m) long is tapered or wedge shaped on the bottom, and has a concave groove on the inside. A ring or collar with a shear pin on the top of the whipstock is used to guide the drillstring and retrieve the whipstock. The bottom often has a chisel point to anchor it. The whipstock is run into the well on a special sub and oriented. In an uncased well, a small diameter gauge bit is deflected by the whipstock and used to drill a pilot hole or rathole out at an angle up to 4 degrees. In a cased hole, a casing whipstock is used. A window mill is unlatched from the whipstock and pushed ahead to mill a window in the casing. After drilling 10-20 ft (3-6 m) below the whipstock, the assembly is removed, the pilot hole is surveyed, and a regular or directional drillstring is run in the hole [10].

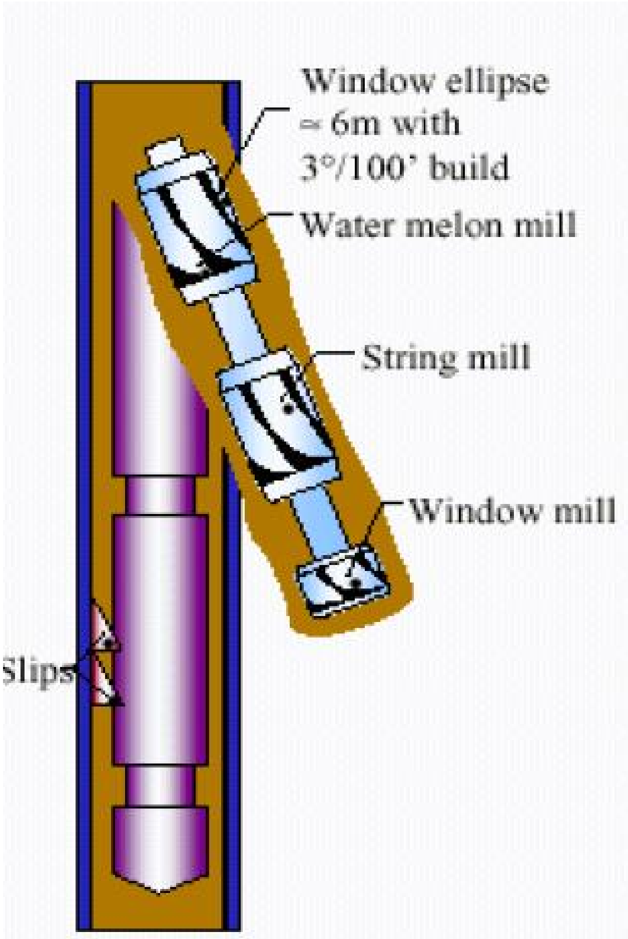

Figure 3.10: A whipstock [23]

3.2 Directional Surveying

When drilling a directional well, the actual trajectory of the well have to be frequently controlled to assure that it agrees with the planned trajectory. This can be done by surveying the position of the well at regular intervals. The surveys are taken at near intervals (30') in the critical sections of the well. They may be required every 120' while drilling the long tangential portion of the well. The surveying program is usually defined in the drilling program. A directional orientation tool must be run to get the well back on route if it is found that the well is not being drilled through its planned route. To recognize these kind of problems are significant for correcting them easily. Surveying keeps a critical role in deviated drilling.

The objectives of surveying in directional drilling are [29]:

- To monitor the actual path of well as drilling progresses to assure that the target will be achieved
- To steer deflection tools in the desired direction when correcting the well path
- To provide information that the being drilled well is not risky to intersect with nearby wells
- To identify the true vertical depths (TVDs) of the different formations that are encountered for permitting accurate geological mapping
- To assess the dogleg severity along the course of the hole
- To determine the precise bottomhole location of the well for monitoring reservoir performance and also for relief well drilling.

3.2.1 Photographic Surveying Tools

The oldest form of surveying tool used in the oil and gas industry was the acid bottle [29]. While taking a directional survey, the tool adjusted itself with the axis of the hole, but the surface of the acid remained level. The acid bottle was left in this position about a half hour for allowing the reaction to happen. The motion of the acid during RIH and POOH avoided any other lines being etched on the glass. This glass was checked out back at the surface and the inclination angle was determined. However, mentioned system did not determine the wellbore direction.

Since the 1930's the surveying tools have been employed in deviated wells. The basic tools include a device that measures the angle of inclination and N-S-E-W direction of the well. A photographic disc consisted of within the device is used to produce an image of the surveying instrument. When the device is retrieved back to the surface the disc is developed and also the results of survey recorded.

There are 3 ways of running and retrieving the photographic instrument [25]:

- It can be run and retrieved on wireline unit
- It can be dropped down the DP, then retrieved with an overshot by using wireline

- It can be put free down the DP and retrieved during a trip. When the instrument reaches bottom it sits within a baffle plate known as a Totco ring that holds the instrument in position.

3.2.1.1 Magnetic Single Shot

The magnetic single shot was first employed in the 1930's to measure the angle of inclination and direction of a well. It has 3 sections [7]:

- An angle unit including a magnetic compass and a device for the inclination measurement
- A camera
- A motion sensor unit or timing device.

The angle unit of the tool includes a magnetic compass and a plumb bob (**Figures 3.11**, **3.12** and **3.13**). While the tool is in the correct position (close to the drill bit), the magnetic compass is let for rotating till it puts in order itself with magnetic field of the Earth. The plumb bob holds on the vertically independent from how the instrument is deviated in the hole.

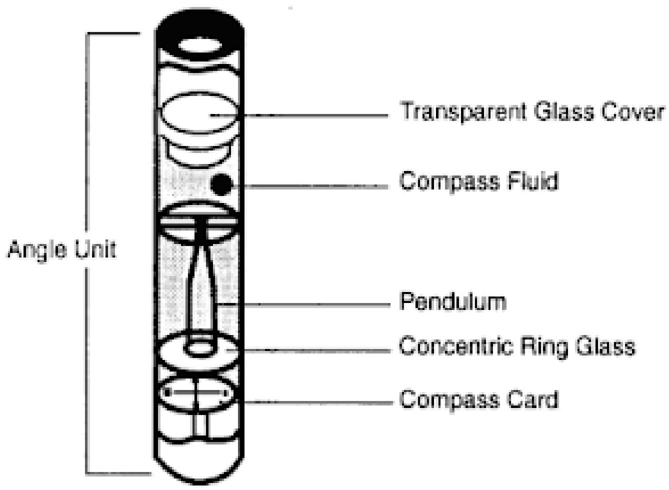

Figure 3.11: Angle unit of the tool [25]

The camera includes a photographic disc which is assembled in the tool in a lightproof loading device, a group of bulbs to illuminate the angle unit when required, and a battery unit which supplies energy to the light bulbs [7].

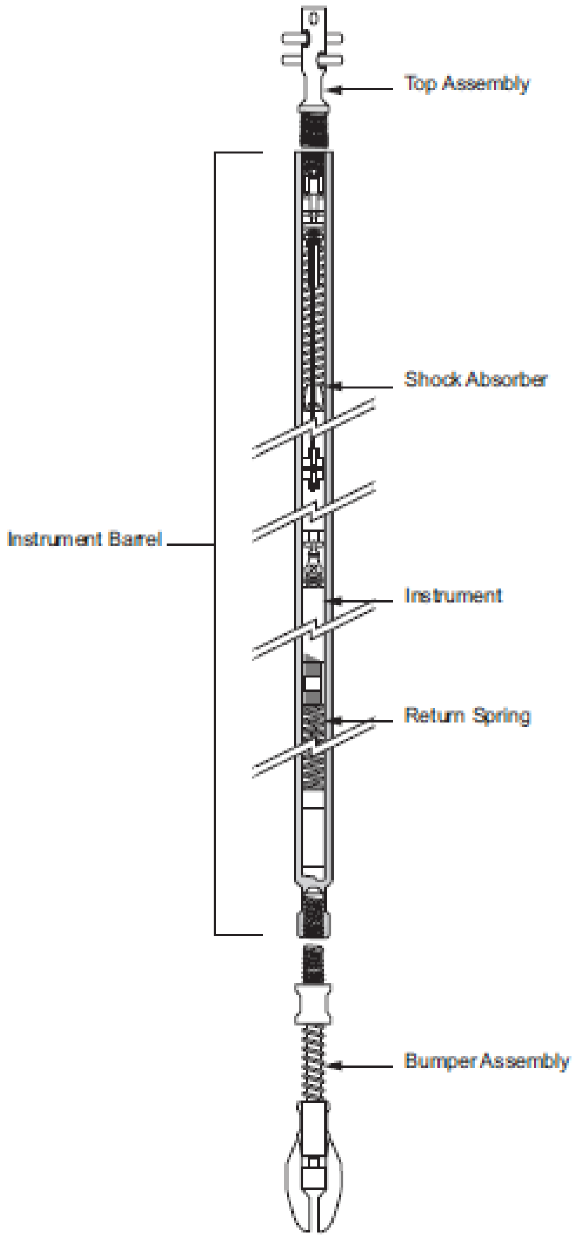

Figure 3.12: Main components of magnetic single shot device [25]

The timing device is employed to run the light bulbs when the instrument is in the correct position. The surveyor must estimate the required time to lower the instrument into desired position and set the timer accordingly. Modern instruments use a motion sensor unit, because sometimes it is not possible to guess the time required for the instrument to reach the bit. When the instrument stops to move, the motion sensor unit will illuminate the light bulbs. A photograph image of the plumb bob is superimposed on the compass card once the bulbs are lightened (**Figure 3.14**) [7].

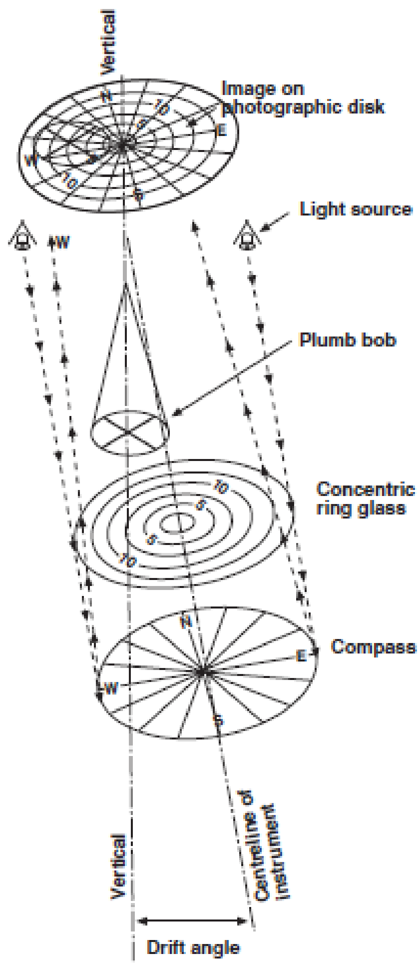

Figure 3.13: Diagrammatic view of magnetic single shot device [29]

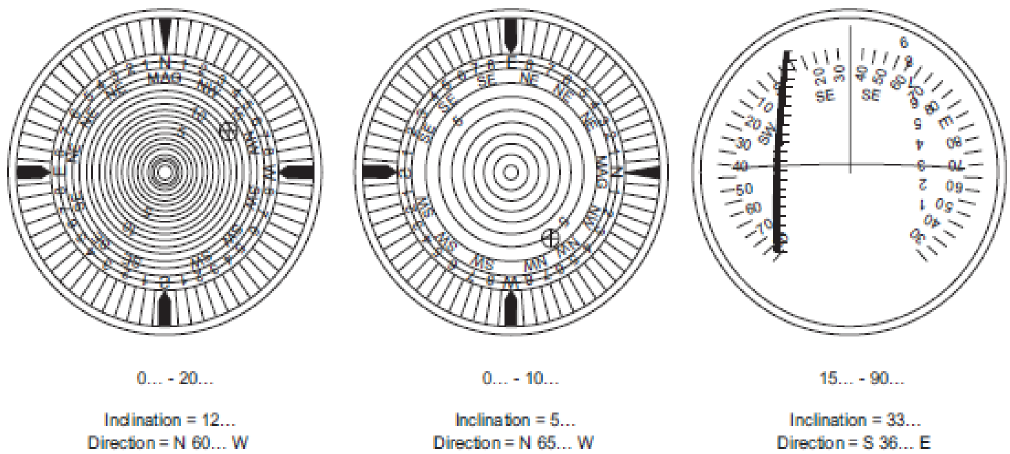

Figure 3.14: Examples of compass displays [29]

3.2.1.2 Magnetic Multi-shot

It is effective to know the overall trajectory in a single survey run just before the running casing. It is usually performed by a multi-shot device (**Figure 3.15**) which takes a series of images. The working principle of a magnetic multi-shot is the same as a magnetic single shot, but a multi-shot includes a special camera unit.

The magnetic multi-shot can be lowered into the non-magnetic collar by wireline or dropped free. Since the compass must stay among the non-magnetic collar to operate accurately, the multi-shot survey is performed as the pipe is tripped out of the hole. The directional surveyor must supervise the depth at which the pre-set timer takes a picture. The shots only with known depth will be recorded. Once the multi-shot is retrieved, the film is developed and the survey results read [25].

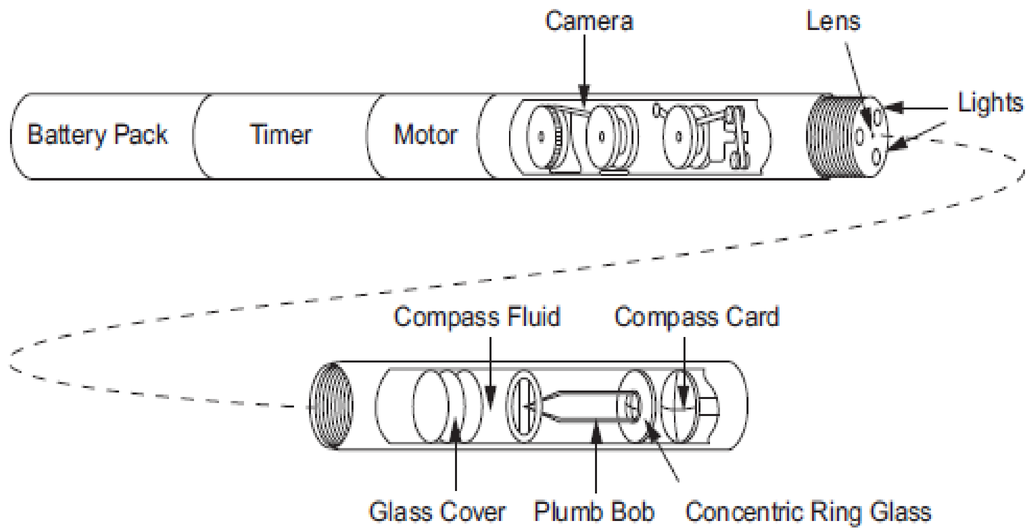

Figure 3.15: Magnetic multi-shot instrument [25]

If the magnetic compass is close to a magnetized steel, the readings from a compass will be erroneous. Drillstring and casing are run through the magnetic field of the Earth; therefore, both of them will be magnetized. As a result, the magnetic surveying tools cannot be used. This issue can be eliminated by using non-magnetic DCs in the BHA in the case of drillstring. These DCs are made up of Monel and the Earth's magnetic field is not affected by their presence. Therefore, the direction of the well can be obtained accurately. Depending on the magnetic latitude and hole direction, the number of DCs will be decided. More non-magnetic DCs must be used in the zones where the magnetic field lines are steeply dipping (**Figure 3.16**). This surveying method cannot be used in cased holes since casing also becomes magnetized.

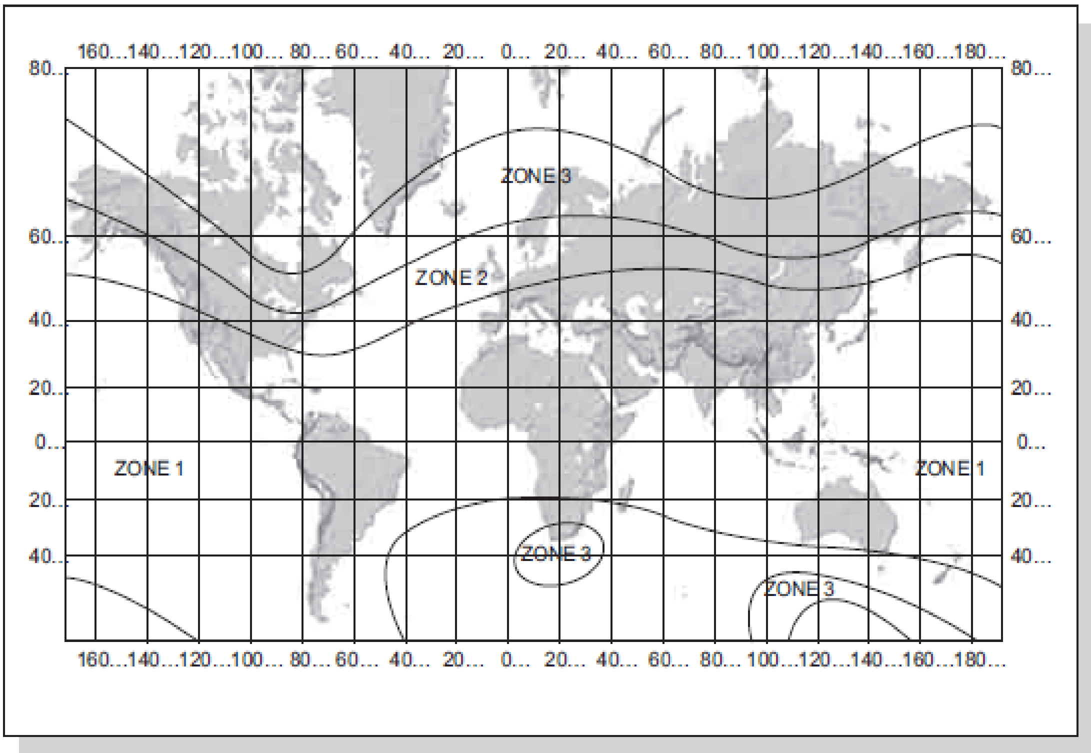

Figure 3.16: Effect of well position on the number of DCs [7]

3.2.1.3 Gyro Single Shot

Surveys which rely on compass readings can be unreliable. Different method of evaluating the direction of the well must be used in the cased hole and open hole where offset wells are cased. The well's inclination can be evaluated in the same way as in the magnetic tools. By using a gyroscopic compass, the magnetic effects can be eliminated.

A gyroscope is a wheel which turns around one axis, but is also free to rotate about one or both of the other axes, because it is fitted on gimbals. The inertia of the spinning wheel tends to stay its axis pointing in one direction [25]. A gyroscope is rotated by an electric motor roughly at 40,000 rpm in a gyro single shot instrument. The gyro is set up with the direction of true north on surface. Although there are forces which might tend to deviate the axis from the direction, the tool axis should continue to point in the direction of true north as the tool is in downhole. A compass card is mounted to and lined up with the axis of the gyroscope. This treats as a reference direction. When the tool has landed in the necessary position in the DCs, procedure is carried out which is also valid for the magnetic single shot. Because the compass card is connected to the gyroscope axis, it records true north direction. Therefore, it is not required to correct for magnetic declination. Since gyroscopes are sensitive to vibration, it must be run and retrieved with wireline unit. Gyro single shots are generally employed to orient deflecting tools near casing.

3.2.1.4 Multi-shot

Once a casing string has been run, the precise trajectory of the borehole is usually measured by a gyro multi-shot survey. It is run by wireline unit and the surveys are taken while RIH. This diminishes the errors induced by gyro drift which becomes important over time. Gyro drift does not increase uniformly with time. A series of drift checks are performed to correct the survey results for the effect of gyro drift both running in and pulling out of the hole. A number of images are taken at the same point in stationary condition for a few minutes. The raw survey data can be corrected by drawing up a drift correction chart.

3.2.2 Steering Tools

Orienting deflecting tools using the techniques mentioned above are time consuming. In addition to that, the deflecting tools might not provide the expected dogleg under practical conditions; therefore, the next survey may show some surprising results. A kind of telemetry surveying technique can remove this uncertainty. This type of tools are designed specifically to orientate deflecting tools and monitor the well's proceed during a correction run. They are known as steering tools in oil and gas industry. A steering tool measures direction and inclination of the well during drilling process. These tools can only be employed when a PDM is being used to fulfill the correction run.

The downhole element of the steering tool is known as a probe that continuously measures direction of hole and the toolface position. This information is sent through the wireline to a surface unit which provides a quantitative read-out and might also provide a circular dial indicating the orientation of the toolface in accordance with the high side of the hole. This is special value for the directional drilling engineer since s/he can recognize how the toolface is altering due to the reactive torque or geological effects as the well is being drilled. The steering tool will give the new heading immediately if the toolface must be altered by rotating the pipe. This saves a lot of time. The directional drilling field engineer can employ the steering tool to do build or drop, turn to right or left depending on the orientation of the toolface which is shown on the surface dial. The steering tool permits the directional drilling engineer to figure out exactly what is going on downhole.

An orienting sub with an adjustable key is mounted above the bent sub. The key is compiled with the scribe line of the bent sub. A non-magnetic DC is attached on top of the orienting sub. Once the BHA is RIH, a circulating head with a wireline pack off is placed on top of drillstring. The steering tool with a muleshoe stinger on the tip of it is brought down on a single conductor wireline till it connects the key in the orienting sub, hence coordinating the probe with the toolface.

The probe keeps in this position when pumps operate the downhole motor and drilling progresses. The probe continuously monitors the route of the hole and orientation of toolface as drilling proceeds. It must be pulled out when a pipe connection (a new joint of pipe) is made up. After connection the probe is RIH again on the wireline and drilling continues as before. To prevent the time wasted in the probe tripping, connections are only made at every 3 joints (the circulating head is installed on a stand of DP).

A little alteration to the regular steering tool is to run a side-entry sub. This enables the wireline to pass through the DP into the annulus at some point beneath the rotary table. The aim of this alteration is to permit pipe joints to be connected without pulling the probe. However, care must be taken when making connections since the wireline must pass through openings in the DP slips. This operation must be performed carefully, because wireline must pass through openings in the slips of DP. A free point indicator cannot be run if the DP becomes stuck at some point below the side entry sub.

The advantages of using a steering tool as opposition to a photographic tool for surveying and orienting may be summarized as follows [7]:

- It saves rig time due to sending results to surface more quickly, fewer attempts needed to get orientation correct and permits a correction run to be finished in shortest possible time

- It has better directional supervision of well path because of continuous monitoring
- It can monitor the orientation of deflection tool while drilling.

The major disadvantage is that due to the wireline, steering tools can be used only with a mud motor in conventional rotary drilling. Specialists worked to advance a steering tool which did not depend on wireline. Therefore, the MWD tools were developed and used for this aim.

3.3 Measurement While Drilling (MWD)

MWD systems (**Figure 3.17**) enable the driller to gather and send data from bottom to the surface without preventing normal drilling operations. This data consists of directional deviation, information related to the petrophysical properties of the formations and drilling data including WOB, torque and RPM. The data is collected and transmitted to surface by the sensors and transmission devices which is made up in a non-magnetic DC in the BHA. It is known as a MWD tool. The data is sent through the mud column in the drillstring to the surface. The signal is decoded and introduced to the driller in a suitable format at surface. The transmission system which is known as mud pulse telemetry does not include any wireline operations.

To take a directional survey by conventional wireline techniques might consume 1-2 hours. In contrast, an MWD system takes less than 4 minutes. MWD operations are expensive compared with wireline surveying methods. An operator can save rig time which is generally more important in terms of cost.

Service companies developed more sophisticated tools which is also able to provide geological data such as GR and resistivity logs. The latter tools are usually known as LWD tools. The transmission system can be enhanced by adding more sensors; therefore, MWD tools are becoming more complicated. Developments have been done over the past years and MWD tools are becoming a conventional tools for drilling activities in these days.

3.3.1 MWD Systems

MWD systems have certain basic similarities [7].

- A downhole system which includes a power source, sensors, transmitter and control system
- A telemetry channel (mud column) through which pulses are sent to surface
- A surface system which detects pulses, decodes the signal and presents results (numerical display, geological log, etc.).

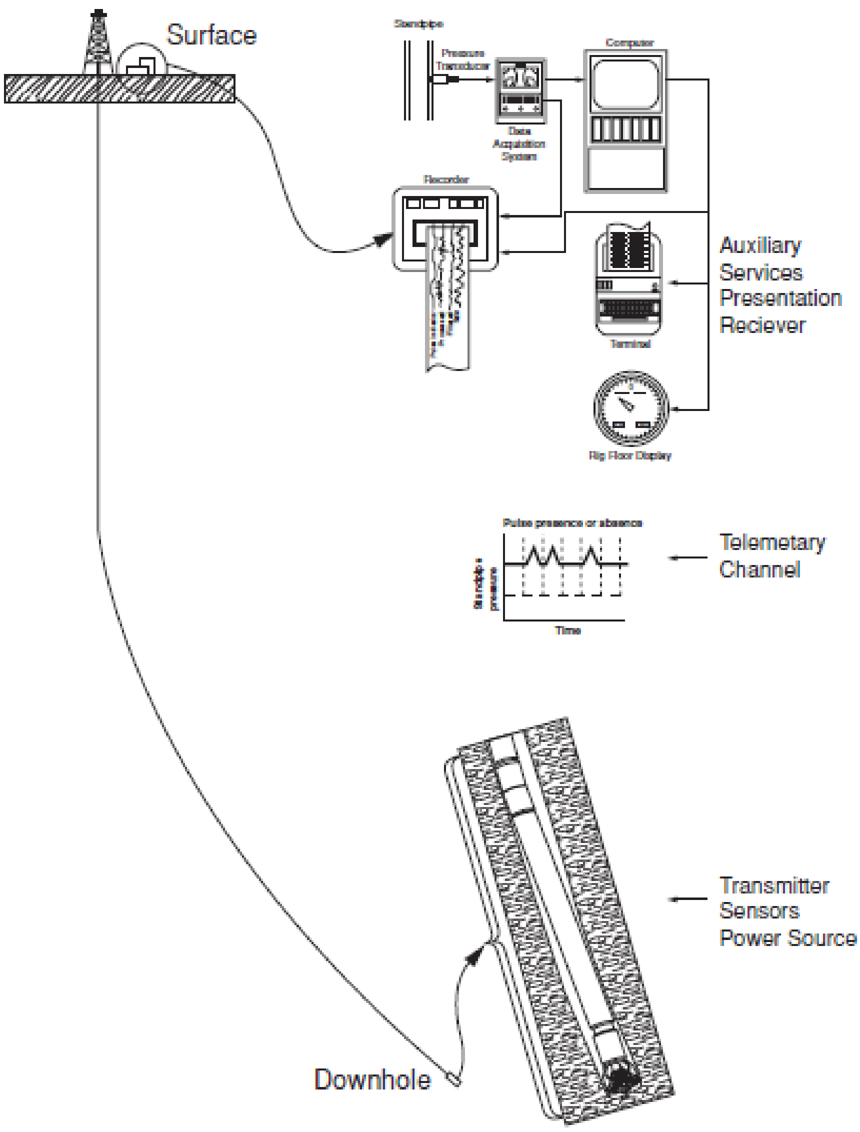

Figure 3.17: MWD system [25]

The transmission method is the main difference among the available three MWD systems. These systems encode the data to be transmitted into a binary code and send them up to the surface as a series of pressure pulses inside of the drillstring. The way in which the pressure pulses are generated is the only difference between the MWD systems (**Figure 3.18**).

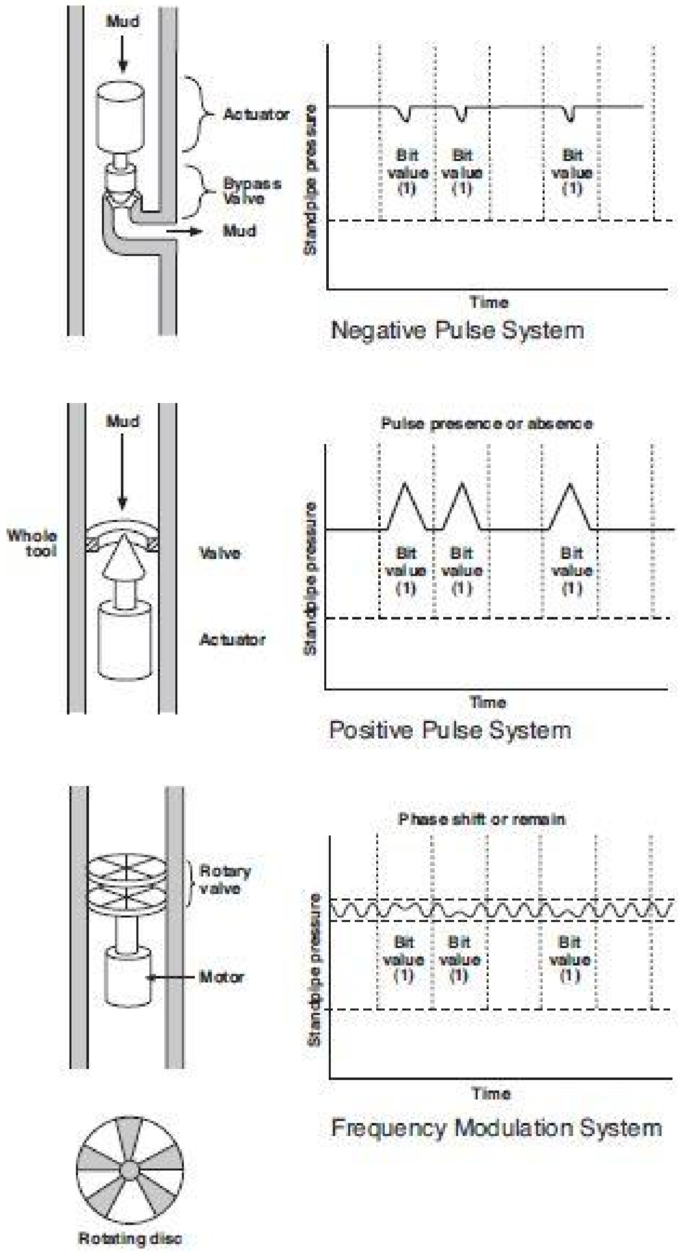

Figure 3.18: Mud pulse telemetry systems [25]

Negative mud pulse telemetry: Drilling mud have to be circulating inside the drillstring in all MWD systems. A valve located in the MWD tool opens and permits a small amount of drilling fluid to escape from the drillstring into the annulus in the negative mud pulse system. The opening and closing of the valve generates a little reduction in SPP (50-100 psi) which can be identified by a transducer on surface [25].

Positive mud pulse: In this system a valve inside the MWD tool partially closes and generating a temporary increment in SPP [25].

Frequency modulation (mud siren): A standing wave is set up in the mud column by a rotating slotted disc in this system. The phase of this continuous wave can be reversed. The data is transmitted as a series of phase shifts [25].

Tool sizes	13/4” OD-91/2” OD
Maximum temperature	150 ºC
Maximum pressure	20,000 psi
Power sources	Lithium batteries (up to 800 hours op. time) / turbine
Pressure drop	13-300 psi @ 1000 gpm
Telemetry type	Positive pulse / negative pulse / siren / electro-magnetic / downhole recording
Sensors	Directional (MTF / GTF) Petrophysical (GR / resistivity / neutron) Drilling (vibration / DWOB / torque / temperature / annular pressure)

Table 3.1: MWD tool specifications [25]

Many tools also can record downhole data for later retrieval at surface. It permits the operating company to gather huge amount of data. As a result, companies eliminate expensive electric wireline logging operations.

3.3.1.1 Power Sources

All needed power to operate the MWD tool must be generated downhole, because there is no wireline connection to surface. Therefore, a battery pack or a turbine-alternator must be made up into the MWD tool. The turbine has been the standard technique to generate power in the frequency modulation and positive pulse tools. Batteries have been used in the negative pulse system because of less power requirements. Batteries can be also replaced with turbines in negative pulse systems when more sensors being added and higher data rates required.

Turbines have many advantages compared with batteries (**Table 3.2**). However, turbines tend to failure mechanically. Filter screens are used to prohibit debris in the drilling fluid from damaging the turbine.

Power source	Advantages	Disadvantages
Batteries (Li)	Compact	Temperature limit (150 ºC) Time limit (100 to 800 hours)
Turbine	Higher power output Batteries Unlimited operating time	Filters required

Table 3.2: Advantages and disadvantages of MWD power systems [7]

3.3.2 Directional Tools

For calculation of inclination, azimuth and toolface, it is used the same sensors in all MWD systems. These directional sensors include 3 orthogonal magnetometers and 3 orthogonal accelerometers.

An accelerometer measures the part of Earth's gravitational field throughout the axis that is oriented. It works as per principle of "force-balance". A test mass is postponed from a quartz hinge which limits any action through one axis only (**Figure 3.19**). Because gravity is acting along that axis, the mass is prone to move. Therefore, its central position is protected by an opposing electromagnetic force. The larger the gravitational force, the larger the pick-up current needed to oppose it. The decline of voltage over a resistor in the pick-up circuit is measured. It has direct relationship with gravitational component. The reading on each accelerometer will be completely different according to orientation of the BHA. The angle of inclination and toolface can be calculated from those three components.

A magnetometer measures the part of Earth's magnetic field along one axis. When a wire is covered with a smooth iron core (**Figure 3.20**) and put in a magnetic field, the current stimulated in the pick-up circuit will vary depending on the angle at which the toroid is placed. Thus, the size of current is related to the course of the coil with respect to the course of magnetic field. The voltage is metered across a resistor in the pick-up circuit of the magnetometer. Then the readings of voltage in every magnetometer can be used for calculating the azimuth [25].

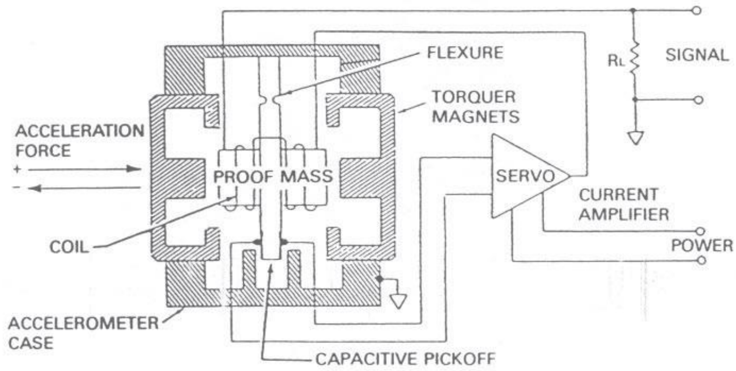

Figure 3.19: Accelerometer [7]

Accelerometer readings can be also used for calculating azimuth. Inclination, toolface and azimuth will all be wrong if the readings of accelerometer is incorrect. Because we are trusting the response of magnetometers only to the magnetic field of Earth, any other magnetic effects related to drillstring must be isolated. Sufficient number of non-magnetic DCs must be made up below and above the sensors to prevent any such interference.

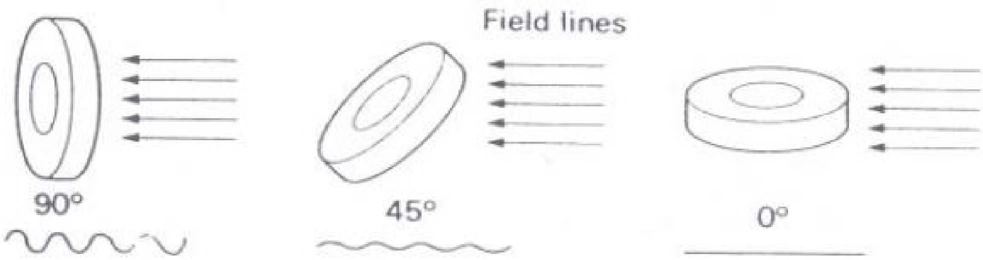

Figure 3.20: Magnetometer [7]

3.3.3 <u>GR Tools</u>

GRs are generally emitted by radioactive isotopes of K, Th and U in the formation. These elements present mainly in shales. Therefore, the GR log is a good indicator of shale. Significant engineering applications of GR log from an MWD system are summarized in **Table 3.3**. The GR logs are usually used together with MWD directional tool.

Generic application	Specific application
Geological	Immediate indication of change in lithology Picking formation tops, coring points Indication of shaliness Differentiate between cuttings and cavings Correlation with offset wells
Engineering	Casing point selection Identification of troublesome formations Identification of drilling problems Running checklog prior to EWL

Table 3.3: Applications of MWD

The GR sensor must be made up as close as possible below the directional sensors; therefore, lithology change can be known immediately.

Sensors which are used to identify GRs must be powerful and efficient. Although it detects small amount of rays, the most powerful sensor is the Geiger-Muller tube. The Scintillation counter is more sensitive one, but it is less robust. Scintillation counter is the most popular type and also the most employed one by service companies.

The comparison of GR and resistivity logs from an MWD tool with those obtained from wireline logging is useful (**Figure 3.21**). When making comparisons, many points must be taken into account:

- The logging velocities are different (MWD at 10-100 ft/hr and wireline at 1800 ft/hr). Therefore, resolution of the two logs will be affected.
- Hole conditions might be different since the MWD log was performed.
- MWD log is fulfilled through a DC. Thus, the attenuation of GRs will be higher.
- Central position of sensors could be different, particularly in high angled holes.

GR and directional sensors are well determined for MWD use. Many sensors are being established; therefore, the term Logging While Drilling (LWD) is employed to characterize the tools today.

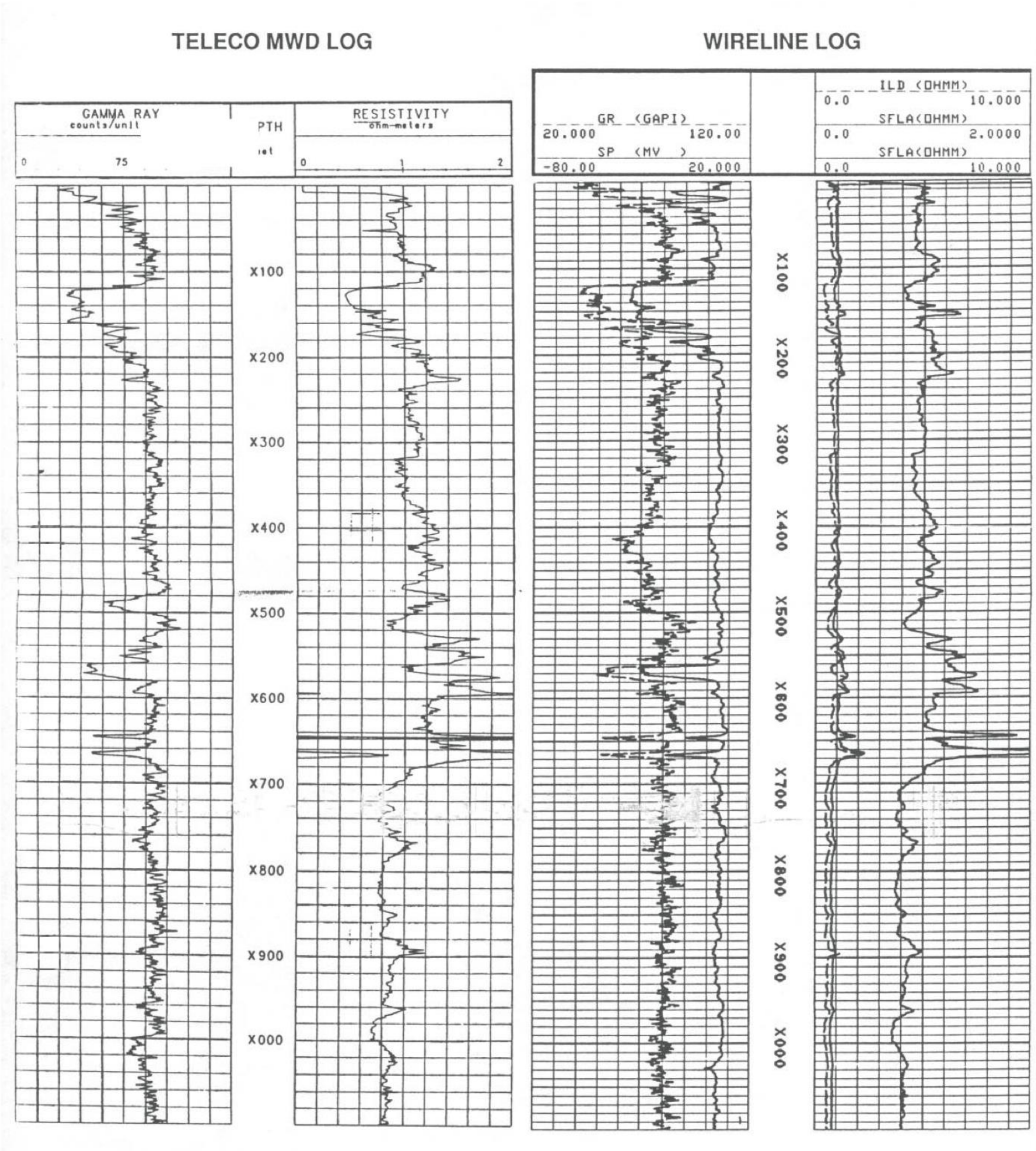

Figure 3.21: Comparison of MWD and wireline log [30]

3.3.4 Transmission and control systems

There is broad alteration within the design of the electronic packages. They are being continuously improved. The voltages of every detector must be read and stored in the memory till the tool is prepared to transmit. Coordination of the acquisition, storage and transmission of this data must be done by the control system. Because there is no electrical on/off switch controlling the system from the surface, the tool have to react to physical alterations such as detecting an increment in pump pressure. Once transmission is started the data is sent to surface through the column of mud as a series of pulses.

It is the presence or absence of a pulse that carries the data in many systems and the time interval between pulses in other systems. Even though these pulses move at around 4000 ft/sec, several pulses may be mandatory to transmit one number. The control system happens a critical factor with more sensors and more data to transmit (e.g. important GR signals could be lost while the tool is sending the directional data). There is also the problem of gathering huge amounts of data and it cannot transmit quickly enough. Transmission velocities of up to 0.8 bps are applicable. Survey data words generally include 10 bits and formation data words include of 11 bits. Common MWD data update rates are given in **Table 3.4**.

Variable	Update time (sec.)	
	@ 3 bps	@ 6 bps
Gravity toolface	10.8	5.4
Phase shift resistivity	28.9	14.4
Attenuation resistivity	28.9	14.4
GR	28.9	14.4
Downhole WOB	43.3	21.7
Downhole torque	43.3	21.7
Continuous direction	86.7	43.3
Continuous inclination	86.7	43.3
Shocks/sec.	86.7	43.3

Table 3.4: MWD data update rates [30]

3.3.5 Surface system

All MWD systems have a pressure transducer which is connected to the standpipe manifold. This transducer must be sensitive enough to observe small pressure changes (50-100 psi) occurring for only ±/≤ 1 sec. The series of pulses must then be decoded and processed to give the required information.

The simplest surface system is positive pulse. It has a microprocessor contained in the downhole tool; therefore, only numerical values of toolface and azimuth inclination require be carried to surface. A basic binary code is employed a pulse detected within a certain time period = 1, no pulse detected = 0. After that the binary number is transformed to a decimal number for the final result. The equipment necessary to perform this can easily be set up in the dog house. Only the raw data is sent to the surface in which case more advanced equipment is required (computers, electronic filters, etc.) in other systems. This equipment is generally housed in a special cabin or in the mudlogging unit. Because the cabin could be located far away, the survey results are relayed to a rig floor display unit where the driller can see them. Formation evaluation logs need plotting facilities that are also housed in the cabin [30].

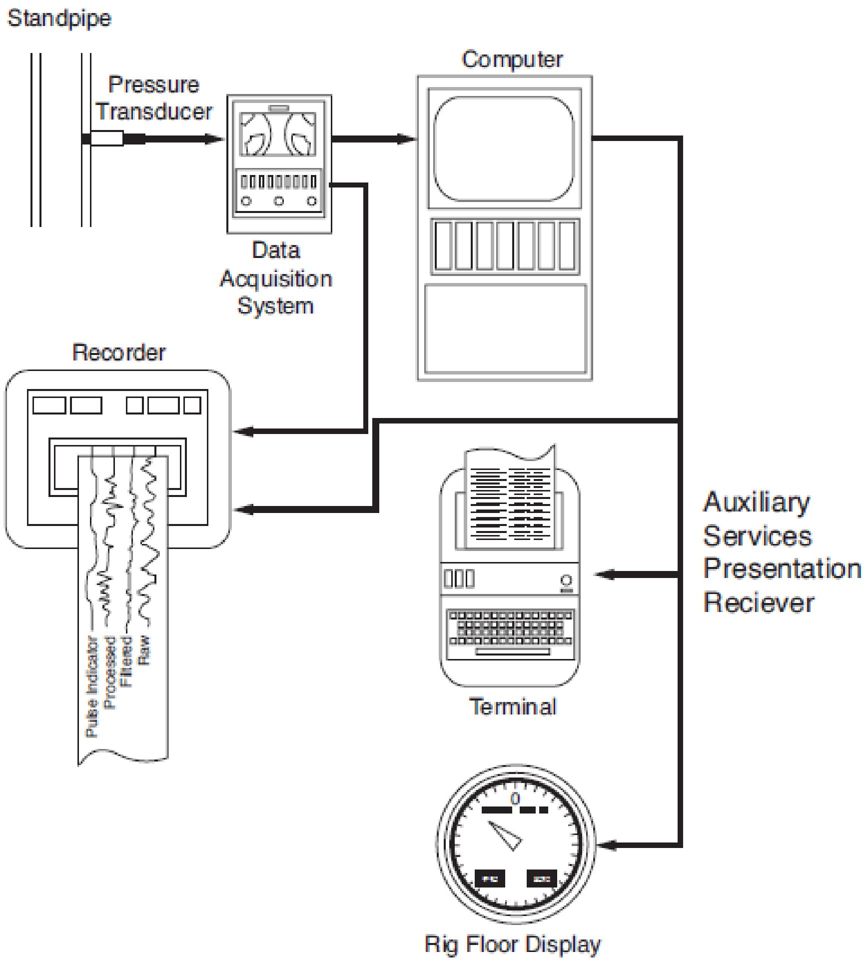

Figure 3.22: Surface processing and reporting system [25]

3.4 Extended-Reach Drilling (ERD)

An extended-reach well (ERW) is a well in which the ratio of the measured depth (MD) vs. the TVD is at least 2:1 [31].

Although ERD is technically challenging and expensive, it adds value to drilling operations. The main advantages of using ERD to reach reserves are based on the reduction of high capital cost items. It makes possible to lessen expensive subsea equipment and pipelines, by using satellite field development, by developing near-shore fields from onshore, and by diminishing the environmental impact. For offshore drilling, a considerable reduction in subsea equipment including fewer pipelines, has not only an influence on economics but also on environmental matter and even permitting. Year on year essential achievements are being made by energy companies. The driving force behind drilling such highly-cost and long wells is of course powerful economics. These tend to indicate that drilling and future intervention costs make sense. The possibility of encountering challenging drilling problems are generally much higher than the conventional wells.

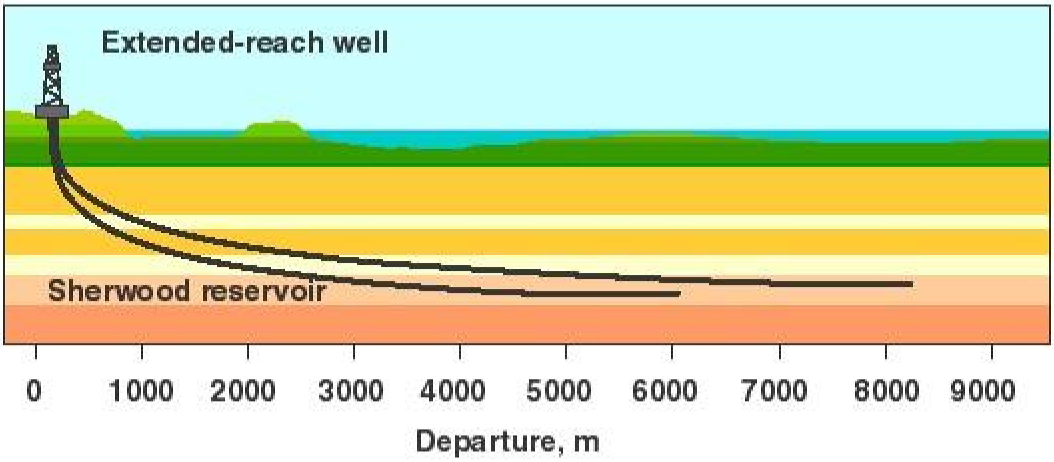

Figure 3.23: ERD (adapted from Schlumberger, 2020)

ERWs can be extremely long (MD) and relatively shallow vertically, as well as relatively short and very shallow vertically and everything in between. The extremely long reach wells are generally drilled to distant reservoirs to lower the infrastructure and operational footprint that would otherwise be required to enter the resource. The relatively short reach wells can be drilled to provide required reservoir contact length in very shallow reservoirs.

ERD permits companies to reach reservoirs that are great distances away from the drilling rig and this help to companies tap petroleum reservoirs under surface areas where a vertical well cannot be drilled including under developed or environmentally sensitive areas. In offshore, the use of ERD permits companies to reach accumulations far from offshore platforms, minimizing the number of platforms required to produce all the oil and gas.

Directional control, hole cleaning, drag and torque, and casing flotation play an elementary role with ERW. The sliding mode drilling results in several inefficiencies that are combined by extreme distances. The motor must be oriented and kept in a specific direction while drilling to pursue the desired path. This orientation is accomplished through a combination of rotating the drillstring several revolutions and working the pipe to turn it to the desired direction.

The selection of a drilling mud must balance variety of critical factors. The drilling mud must provide a stable wellbore for drilling long openhole intervals at high angles, maximize lubricity to diminish drag and torque, make appropriate rheology for sufficient cuttings transport, minimize the potential problems including lost circulation, differential sticking and minimize formation damage of hydrocarbon bearing zones. Pipe rotation is also critical factor in hole cleaning.

In ERW the main objective of the hole cleaning program is to improve drilling performance by preventing stuck pipe, avoiding tight hole on connections and trips, maximizing the footage drilled between wiper trips, eliminating backreaming trips before arriving the casing point and maximizing daily drilling progress [32].

4 INNOVATIVE COMPLETION TECHNOLOGIES

Generally, the main section of technological activities in production engineering have been related to the installation of the downhole completion equipment. The well completion string is a demanding element of the production system. It has to be designed efficiently, set up, and maintained to do it productive. Progressively, from higher reservoir pressures to more hostile development areas, the real capital expenses of all completion string have become a critical part of all well expense and hence worthy of greater technical consideration and optimization. The process of completion can be divided into many various important areas which need to be characterized including:

- The completion fluids must be recognized. In addition, it needs that the functionality of the completion fluid and the desired physical properties be specified.
- The well completion has to take into account and determine how the fluids will enter from the formation to the borehole i.e., whether in fact it is open hole or whether it is a cased hole which will require to be afterward perforated to permit a limited number of entrances for fluids to flow into the wellbore from the reservoir.
- The well completion string design must supply the needed control capacity to permit fluids to flow securely with minimal pressure loss to the surface. Moreover, however, it is important that the completion string can fulfill various additional functions which are related to monitoring, control, and safety, etc. As a rule, the well completion process must give to engineers the ability for reservoir management. The completion string must take into account what possibilities are present in the case of altering fluid production properties and how small servicing operations could be performed such as, substitution of valves, etc.

This chapter focuses on the innovative well completion technologies including intelligent well completion and artificial lift methods.

4.1 Intelligent Well Completion

In the late 1980s, the first intelligent well appeared and a downhole pressure and temperature meter was run in, thus achieving reading out data at the surface and real time monitoring of the downhole pressure and temperature of an oil well. After the 1990s, the intelligent well, which is able to control the downhole flow rate, appeared. Data of downhole temperature, pressure, and flow rate can be acquired at the surface using a hydraulic or electric control system. By 2004, there were more than 130 intelligent wells worldwide. In addition, more than 200 wells had downhole remote control devices by which downhole tools and gauges can be controlled remotely at the surface and more data of reservoir production parameters can be acquired.

The intelligent well completion system is a computerized automatic control system for controlling oil and gas production. It can be used for real-time monitoring and controlling the oil and gas production of production horizons in oil and gas wells or branch holes of a multibore well. It can measure and monitor downhole oil and gas production at the surface remotely, thus optimizing production rates of production horizons in accordance with theoretical calculation results and actual measurement data, enabling producing of production horizons in the optimum working state. Hence, the recovery factor of oil and gas reservoirs may be enhanced, the times of downhole operations may be decreased and the operating management of oilfield production may be optimized.

The intelligent well completion system includes the following subsystems: downhole information sensing system, downhole production control system, downhole data transmission system, and surface data acquisition, analysis and feedback control system. The downhole production control system includes various removable downhole tools and downhole sensors. These devices have good flexibility and can meet various requirements of well completion in accordance with oil reservoir production features. The intelligent well completion system consists mainly of the following components:

- Surface SCADA (supervisory control, alarm, and data acquisition) system interface
- Underwater control network
- Downhole control network

- Separate zone packers with bypass
- Removable, switchable and open degree adjustable downhole tools
- Downhole sensors of pressure, temperature, flow rate, water cut and density.

All of the downhole devices, including sensors and removable tools, are connected with the downhole control network. The system uses permanently installed cable for supplying power and provides bidirectional digital communication between the surface and the downhole sensors. The hydraulic or electromagnetic drive can be adopted. If the hydraulic drive is adopted, hydraulic power is supplied through a hydraulic line connected with the surface hydraulic power installation. If the electromagnetic drive is adopted, the electric driver is selectively indicated to provide mechanical power for various mechanical devices.

4.1.1 Functions of Intelligent Well Completion System

The intelligent well completion system has the following advantages and functions in reservoir management and behavior monitoring aspects:

- Multilayer reservoirs can be selectively produced, and the optimum working mode can be selected on the basis of the surveyed inflow and working environment parameter data of each layer in wells. The injection performance of the injection well and the production performance of the oil well can be improved, the choke of the high water cut layer or high gas-oil ratio (GOR) layer can be timely shut, more oil and gas can be produced from the reservoir and the recovery factor (RF) of the oilfield can be increased.
- Pressure build-up (PBU) and drop tests can be conducted with no need for well shut-in, and production rate, pressure, and temperature can be measured at any time. Material balance calculation of the reservoir can be conducted accurately. The reservoir performance can be kept informed. The oil and gas well management quality and efficiency can be enhanced by effectively analyzing and processing the flow parameter data of each layer.
- Downhole horizons can be treated with no need for downhole operations, thus decreasing times of downhole operations, decreasing production downtime,

decreasing production operation costs and enhancing the competitive power of oilfield production.

The hole structures of conventional and intelligent well completions are shown in **Figure 4.1**.

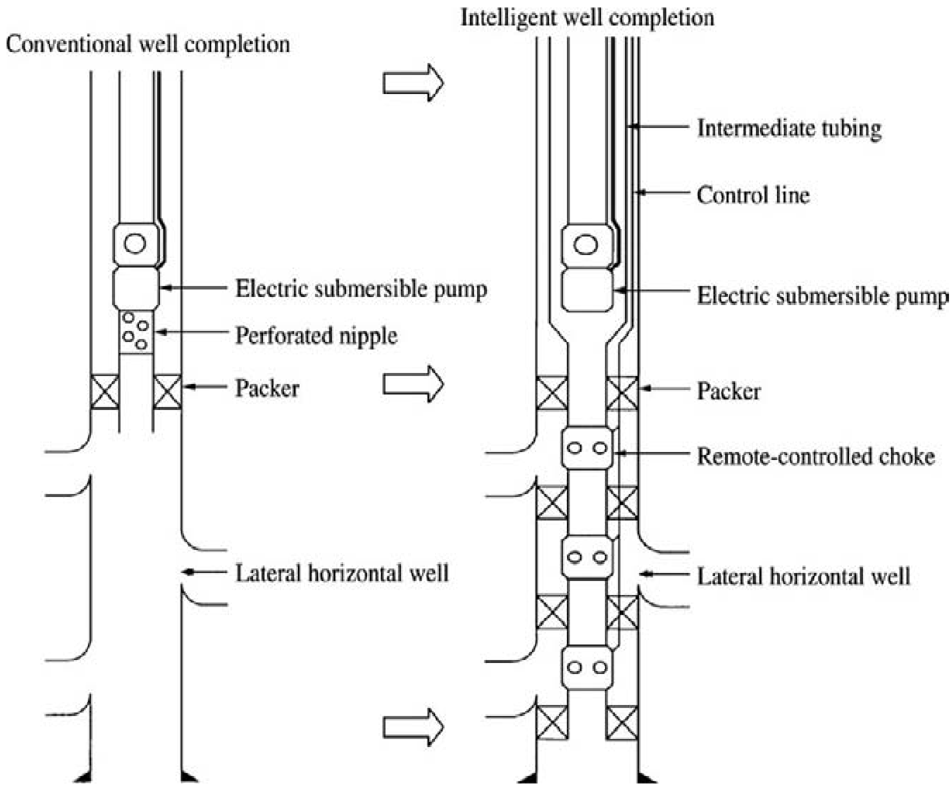

Figure 4.1: Hole structures of conventional and intelligent well completions [33]

By reason of the high investment of downhole completion devices, the intelligent well completion system is chiefly used for the subsea satellite wells, horizontal wells, ERWs in offshore deep water areas and the unattended oil wells, multilayer injection and production wells, and electric submersible pump wells in frontier areas at present. It is mostly used in oilfields with high productivity and downhole operation costs. The intelligent well completion system can achieve real-time production optimization of various production horizons, thus achieving a higher recovery factor and economic benefits. Presently, oilfields adopting the intelligent well completion system are located in the North Sea, Adriatic Sea, Gulf of Mexico, West Africa, Indonesia, and Venezuela. The intelligent well completion is a completion method with development prospects;

however, it is unsuitable for low-productivity wells, shallow wells and wells with a single series of strata due to diseconomy and no need.

4.1.2 Tools for Progress

The reliability of completion tools has improved substantially over the years. Recent statistics show that the newest generation of gauges using electrical dry-mate connectors has better than 98% survival after 48 months. For this reason, more operators now run downhole pressure and temperature sensors systematically on their new wells.

The same methodology used to boost the reliability of downhole monitoring systems has been applied to flow control valves. It involves specific focus on component qualification and testing, system integration, training and service delivery standards. This focus has led to smaller sensors with better metrology that consume less power. New telemetry allows many individual sensors to be run on one cable, acquiring data at high frequency, and soon systems will use wireless telemetry routinely. Both of these advances reduce the system cost significantly for downhole monitoring installations.

Similarly, the emergence of fiber-optic technology enables novel approaches. Distributed temperature sensing provides permanent and continuous temperature logging of wells all the way to the surface even under high-pressure/high-temperature (HP/HT) conditions that exceed standard-gauge capabilities. When combined with the right software and flowrate measurement at surface, it is possible to determine accurate flow profiles and even derive zonal back allocations.

More recently, inflow control devices (ICDs) have started gaining industry acceptance. These ICDs are integrated in the completion tubulars and allow control over the drawdown in each section of the well. In most cases, the reservoir is segmented with openhole packers with up to 15 segments per lateral. The use of ICDs to manage production by zone optimizes reservoir drainage, delays water or gas breakthrough and improves ultimate recovery.

The next-generation ICD will be monitored dynamically and controlled actively, allowing real-time adjustment of the choke settings as reservoir performance changes over time. This operation will not require intervention. These systems will include the actual downhole flow control hardware, the monitoring system and the logic to optimize well performance through a simple interface.

4.2 Artificial Lift Methods

Hydrocarbons will normally flow to the surface under natural flow when the discovery well is completed in a virgin reservoir. The fluid production resulting from reservoir development will normally lead to a reduction in the reservoir pressure, increase in the fraction of water being produced together with a corresponding decrease in the produced gas fraction. All these factors reduce, or may even stop, the flow of fluids from the well. The remedy is to include within the well completion some form of artificial lift. Artificial lift adds energy to the well fluid which, when added to the available energy provided “for free” by the reservoir itself, allows the well to flow at a (hopefully economic) production rate. It has been estimated that in 1994 there was a world inventory of more than 900,000 producing wells. Only 7% of these flowed naturally while the remaining 93% required some form of artificial lift. The average production per well was less than 70 bpd.

The most popular forms of artificial lift are illustrated in **Figure 4.2**. They are:

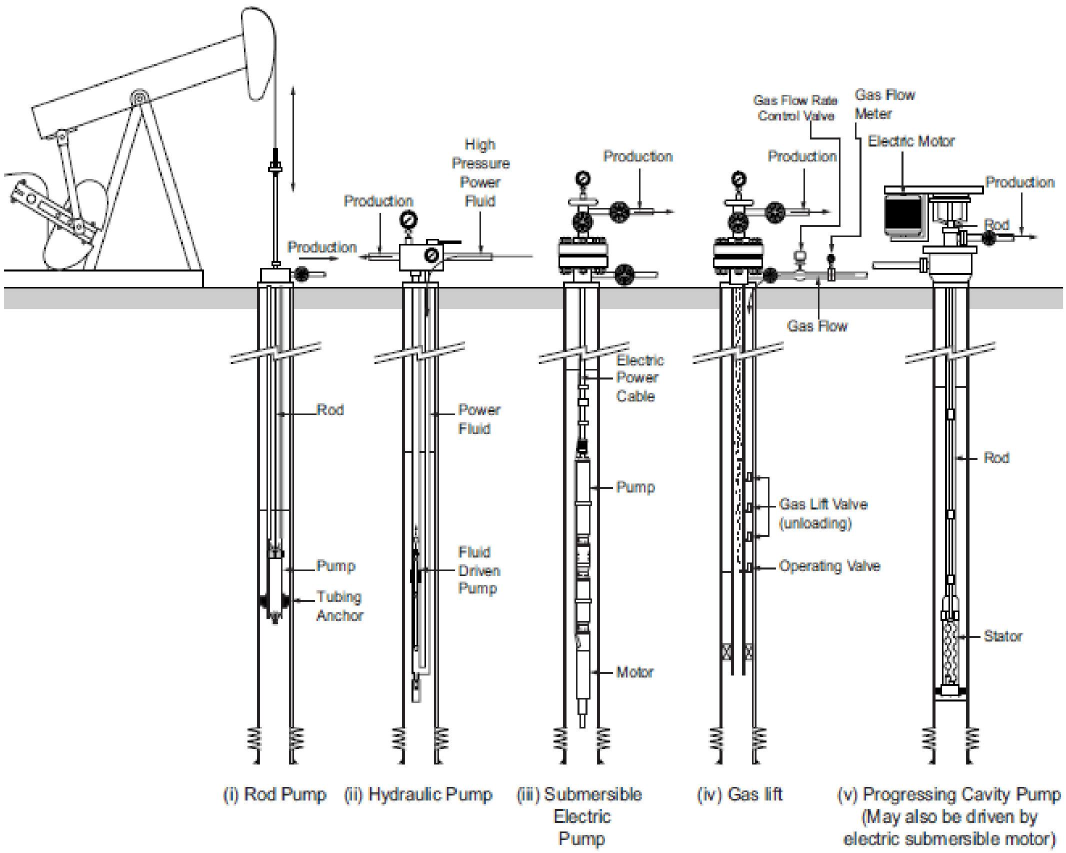

Figure 4.2: The most popular types of artificial lift [34]

(i) Rod pumps: A downhole plunger is moved up and down by a rod connected to an engine at the surface. The plunger movement displaces produced fluid into the tubing via a pump consisting of suitably arranged travelling and standing valves mounted in a pump barrel.

(ii) Hydraulic Pumps: They use a high pressure power fluid to:

  (a) Drive a downhole turbine pump or

  (b) Flow through a venturi or jet, creating a low pressure area which produces an increased drawdown and inflow from the reservoir.

(iii) Electric Submersible Pump (ESP): It employs a downhole centrifugal pump driven by a three phase, electric motor supplied with electric power via a cable run from the surface on the outside of the tubing.

(iv) Gas Lift: It involves the supply of high pressure gas to the casing/tubing annulus and its injection into the tubing deep in the well. The increased gas content of the produced fluid reduces the average flowing density of the fluids in the tubing, hence increasing the formation drawdown and the well inflow rate.

(v) Progressing Cavity Pump (PCP): It employs a helical, metal rotor rotating inside an elastomeric, double helical stator. The rotating action is supplied by downhole electric motor or by rotating rods.

In fact, nearly all the major classes of pumps are employed in the various forms of artificial lift (**Figure 4.3**).

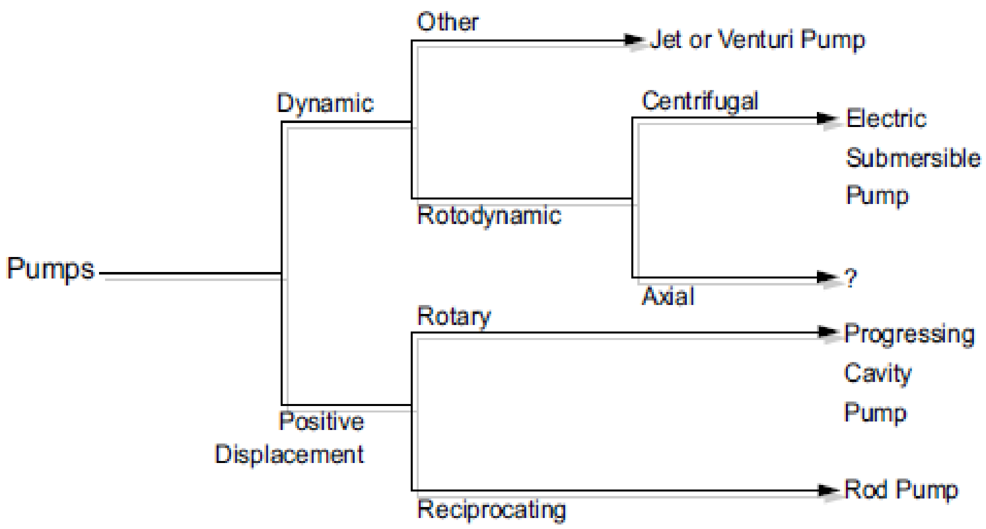

Figure 4.3: Pump classification

4.2.1 Rod Pumps

(Sucker) rod or beam pump was the first type of artificial lift to be introduced to the oilfield. It is also the most widely used in terms of the number of installations worldwide. In 1993, some 85% of the USA population of artificially lifted wells was produced by rod pumps and more than 70% of these produced less than 10 barrels of oil per day. The low cost, mechanical simplicity and the ease with which efficient operation can be achieved makes rod pumps suitable for such low volume operations.

Rod pumps can lift moderate volumes (1,000 bfpd) from shallow depths (7,000 ft) or small volumes (200 bfpd) from greater depths (14,000 ft). They are normally manufactured to standards set by the API. This means that, unlike other artificial lift methods, the equipment manufactured by the various supplies is fully interchangeable.

4.2.1.1 The Pumping Unit

The surface equipment for a rod pump is illustrated in **Figure 4.4**. The prime mover, normally an electric motor or gas engine, drives a speed reducing set of gears so that its fast rotation, of say 600 RPM, is reduced to as low as 20 strokes per minute (SPM) or less. The connection between the surface pumping unit and the downhole pump is the polished rod and the sucker rods. The polished rod moves up and down through a stuffing box mounted on top of the wellhead. This stuffing box seals against the polished rod and prevents surface leaks of the liquids and gases being produced by the well.

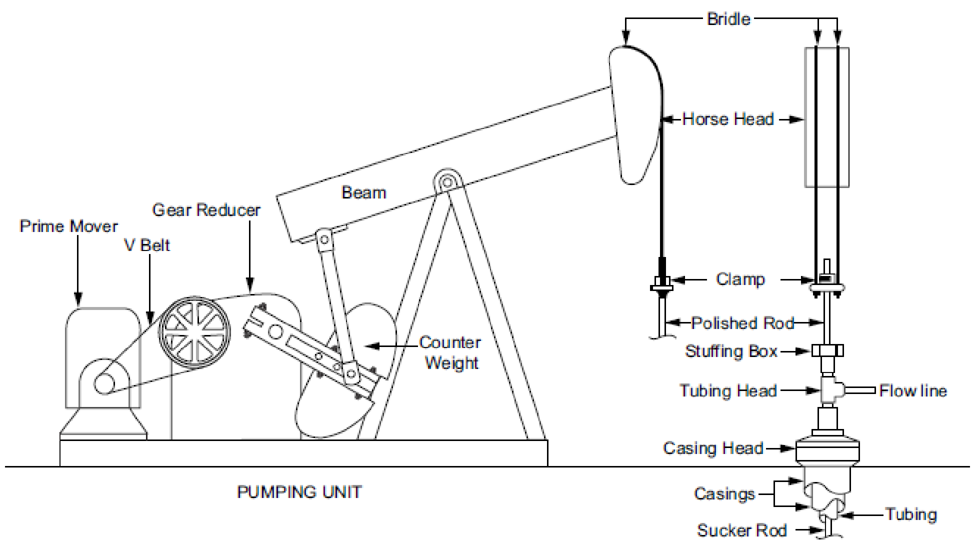

Figure 4.4: The surface equipment for a rod pump

4.2.1.2 The Sucker Rods

The sucker rods, typically 25 ft long, are circular steel rods with diameters between 0.5 in and 1.125 in, in increments of 0.125 in. A threaded male connection or pin is machined at each end of the rod. The two rods can be joined together by use of a double box coupling (**Figure 4.5**). Square flats are machined near the pins and at the center of the coupling to provide a grip for a wrench to allow the rods and couplings to be screwed together. The sucker rods are subjected to continuous fatigue when the pump is in operation. The weight of the rod string is one component of this fatigue load. It can be minimized by using a tapered sucker rod string. This involves installing lighter, smaller diameter rods lower down in the well where the load they have to support (weight of rods and fluid in the tubing string) is less than at the top of the well.

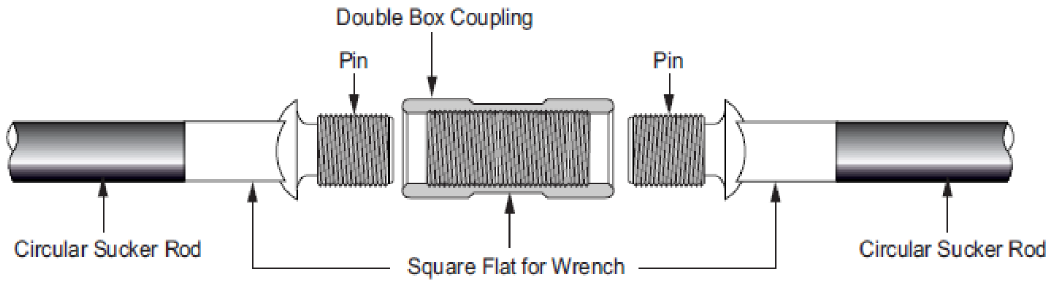

Figure 4.5: Sucker rods are joined together by a coupling [34]

4.2.1.3 The Pump

The pump is located near the perforations at the bottom of the string of sucker rods. The **Figure 4.6** shows that it consists of a hollow plunger with circular sealing rings mounted on the outside circumference moving inside a pump barrel which is either inserted into the tubing or is part of the tubing itself. A standing valve is mounted at the bottom of the pump barrel while the travelling valve is installed at the top of the plunger. The standing and travelling valves consist of a ball which seats (closes off) an opening.

The "up" and "down" movement of the pump barrel allows the fluid flow to open and shut these valves as shown in Figure 4.6. The left hand schematic shows the plunger status at the end of the "down" stroke. The upward rod movement reduces the pressure within the pump barrel and the upward flow of fluid from below the pump lifts the standing valve's ball off its seat. The pressure due to the fluid column above the plunger keeps the travelling valve ball on its seat. The situation is reversed during the "down" stroke, compression of fluid within the pump barrel forces it to flow through the hollow plunger and to lift the travelling valve off its seat while ensuring that the standing valve remains closed.

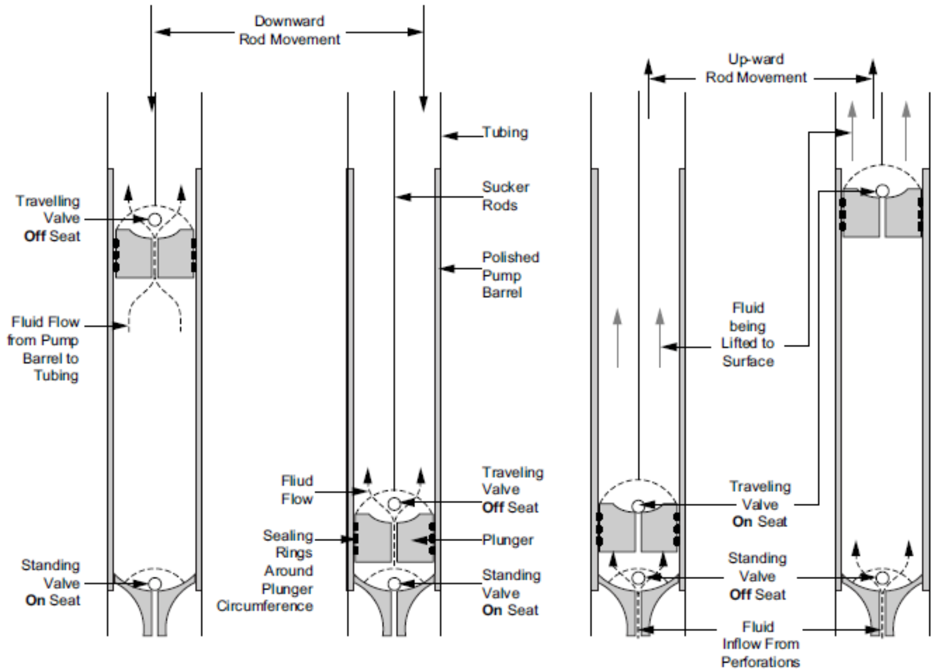

Figure 4.6: Operation of rod pump [34]

4.2.2 Hydraulic Pumps

Hydraulic pumps use a high pressure power fluid pumped from the surface (**Figure 4.7**) which:

- Drives a downhole, positive displacement pump. The **Figure 4.8** shows how the flow of power fluid through the upper engine unit is translated into a flow of high pressure produced fluid during both the "up" and "down" strokes.
- Powers a centrifugal or turbine pump.
- Creates a reduced pressure by passage through a venturi or nozzle where pressure energy is converted into velocity. This high velocity/low pressure flow of the power fluid commingles with the production flow in the throat of the pump. A diffuser then reduces the velocity, increasing the fluid pressure and allowing the combined fluids to flow to surface.

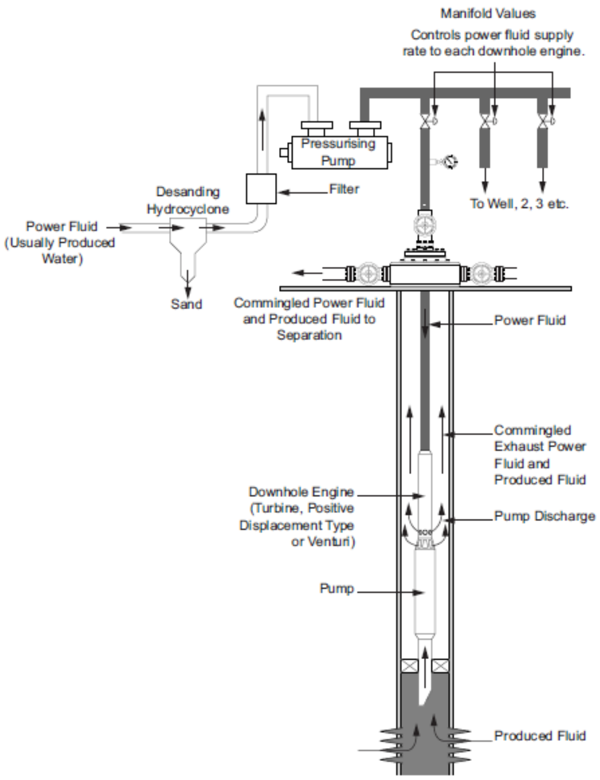

Figure 4.7: Principals of hydraulic lift operation. Turbine pump is illustrated [34]

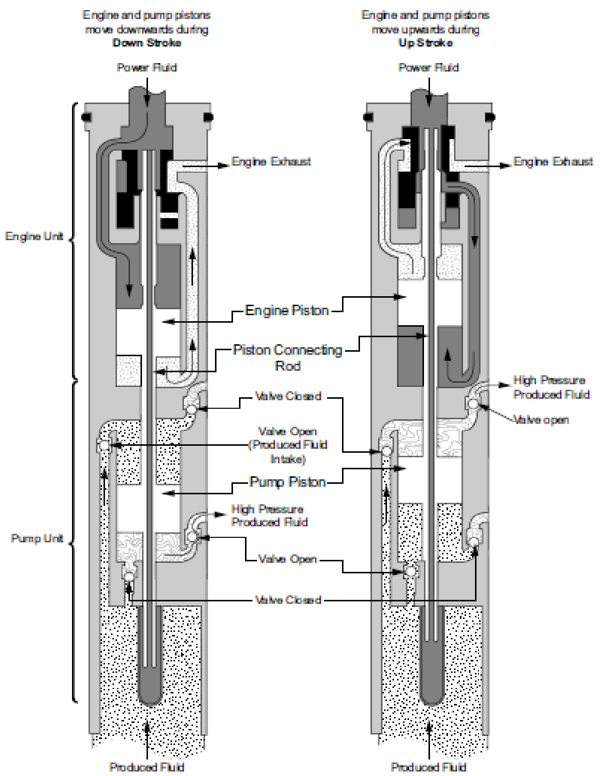

Figure 4.8: Operation of positive displacement hydraulic pump [34]

The power fluid consists of oil or production water (the large oil inventory in the surface power fluid system makes oil accounting difficult once high water cuts are being produced). The power fluid is supplied to the downhole equipment via a separate injection tubing. The majority of installations commingle the exhaust fluid with the production fluid [an “open system” **Figure 4.9** (a)]. If difficulties or high costs are encountered in preparing power fluid of the required quality from the production fluid, then a “closed system” may be installed in which the power fluid returns to the surface via a (third) separate tubing [**Figure 4.9** (b)]. This option is not available with a venturi pump. The completion design may also allow gas to be vented to surface via the casing/tubing annulus.

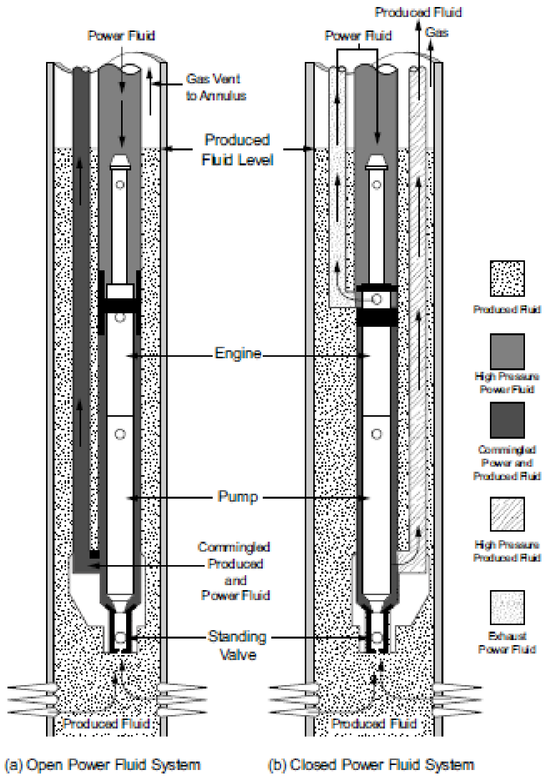

Figure 4.9: Types of hydraulic pump installation [34]

A typical power fluid supply pressure of between 1,500 and 4,000 psi. is provided by a pressurizing pump (**Figure 4.7**). This may be a reciprocating plunger (triplex) pump or a multi-stage centrifugal pump. This pressure determines the pressure increase achievable by the downhole (positive displacement or centrifugal) pump. The pump rate (and the rate at which power fluid has to be supplied) is determined by the diameter and speed of the downhole pump.

“Clean” power fluid is required to avoid erosion of the downhole pump components. The power fluid is often drawn from a settling tank where the larger solids are removed. It is then pumped via a desanding hydrocyclone and a guard filter before having its pressure raised to the operating pressure by the charge pump. The power fluid from the pressurizing pump may supply one or more wells (**Figure 4.7**).

4.2.3 Electric Submersible Pumps (ESPs)

ESPs are a versatile form of artificial lift with pumps ranging from 150 to 60,000 bfpd in operation. A typical low pressure well that is being artificially lifted using an ESP system is illustrated in **Figure 4.10**. The functions of the various components are summarized as follows:

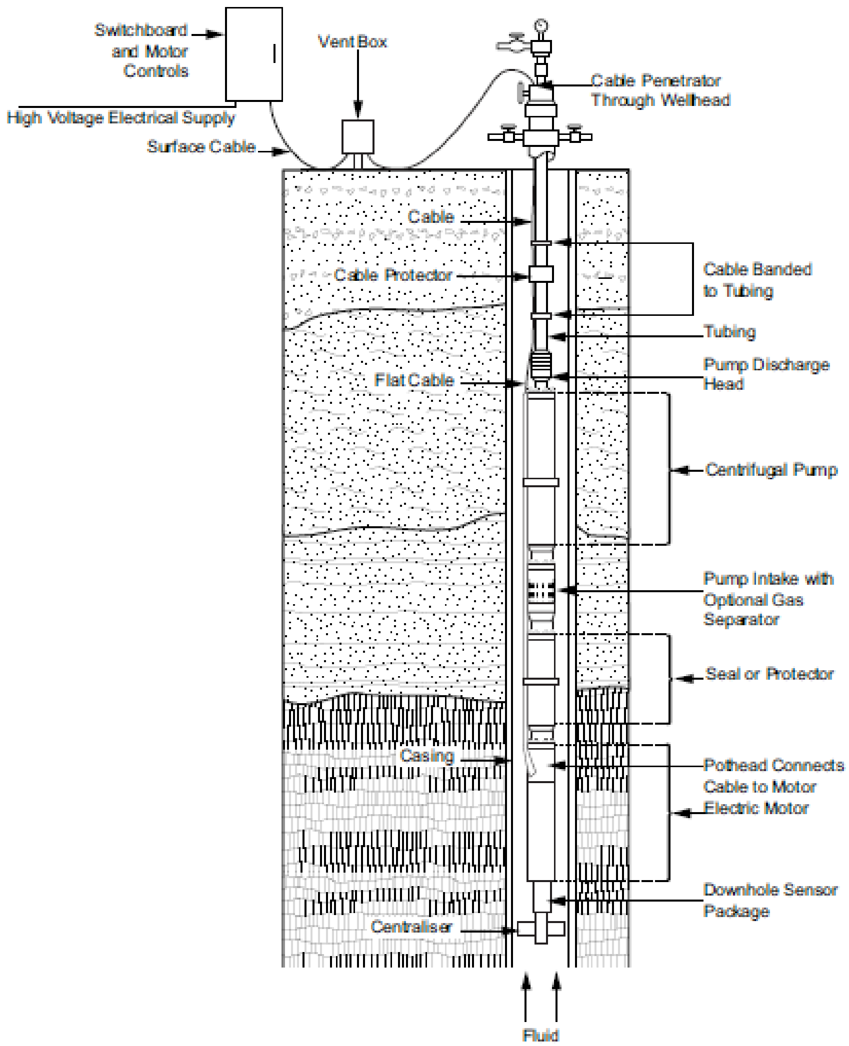

Figure 4.10: Artificial lift using an electric submersible centrifugal pump [34]

- Variable frequency drive (VFD): It allows the speed of the electric motor to be altered e.g. starting the pump using the “nameplate” design frequency of 50 Hz (Europe) or 60 Hz (North America) results in high instantaneous electric motor currents since the power developed by the pump is proportional to the frequency. These can be reduced by supplying the electric power at lower frequencies. It also allows the pump flow rate to be adjusted to the well inflow conditions since flow rate is also proportional to frequency.
  Practical experience shows that a 60 Hz motor can be operated between 35 Hz and 80 Hz. VFD installation increases the surface energy losses from some 3% to 5-15% of total power supplied.
- The vent box: It separates the surface cable from the downhole cable. This ensures that any gas, which travels up the downhole cable, does not reach the electrical switchgear.
- The downhole cable: It penetrates the wellhead. Downhole cable is banded to the tubing at regular intervals. Additional protection is supplied by cable protectors which are installed at critical points to prevent damage while the completion is being run into the hole. A “flat pack” cable shape is employed across the larger diameter completion components to minimize total width. The cable enters the electric motor housing at the pothead. It not only carries the electrical power supply for the motor (up to 750 HP motors are being routinely installed), but also carries the measurement signal from the downhole sensor package installed underneath the motor.
- The pump unit: It consists of a stacked series of rotating centrifugal impellers running on a central drive shaft inside a stack of stationary diffusers, i.e. it is essentially a series of small turbines. The pressure increase is proportional to the number of stages while the pump capacity (volume) increases as the diameter of the impeller increases. Rotation of the impeller accelerates the liquid to be pumped which is then discharged into the diffuser where this kinetic energy is transformed into potential energy i.e. a pressure increase. The impeller/diffuser pairs are arranged in series with the discharge of one unit being the suction of the next one. The number of pump stages (impeller/diffuser) pairs may range between 10 and more than 100, depending on the pressure increase required.

Abrasion resistance to produced solids is very dependent on the detailed design and materials selection employed during pump design.

However, ESPs with their rapidly rotating internals are not really compatible with large quantities of produced sand even when hardened, wear resistant materials are used. The option of using other forms of artificial lift such as gas lift and PCPs should be considered.

Standard pump impellers are very sensitive to gas fractions greater than 20% volume in the produced fluid. Alternatively, changes in pump design such as altering the design of the impeller from pure radial flow to mixed (i.e. a combination of both radial and axial) flow can double the gas/fluid ratio to 40% volume.

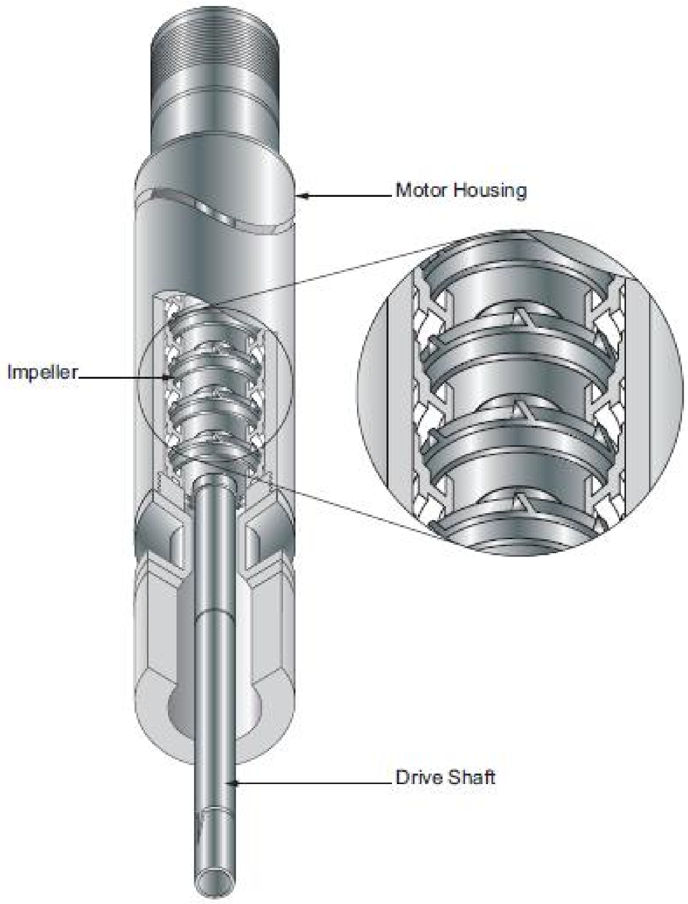

Figure 4.11: Cutaway schematic drawing of ESP [34]

A tapered pump design using mixed flow impellers in the lower pressure stages (with the higher gas volume fractions) and radial flow impellers in the upper stages can prove to be effective.

- The pump intake: It may include a rotary gas separator if gas fractions higher than 20%. This consists of a centrifugal device, which separates the lower density, gaseous phase from the denser liquid phase. The latter is concentrated at the center of the device and enters the pump suction while the lighter, gas phase is directed towards the casing/tubing annulus where gas is vented/gathered at surface.

  A reduction in casing/tubing annulus pressure increases the maximum achievable drawdown at the formation face. A single rotary gas separator can increase the ESP's gas handling capabilities up to 80% volume. Two separators, arranged in tandem, are even more efficient, increasing the pumpable gas fraction to > 90% volume. However, the addition of extra equipment always comes with the cost of greater operational problems e.g. produced formation solids can damage the rotary separator, scale formation can unbalance rapidly rotating equipment. Some operators will not use them due to these problems which have resulted in rotary separators having a poor reputation for reliability.
- The protector or seal unit: It connects the drive shaft of the electric motor to the pump or gas separator shaft. It also performs as:
  (a) An isolation barrier between the clean motor oil and the well fluids
  (b) An expansion buffer for the motor oil when it reaches operating temperature
  (c) Equalizes internal motor pressure with the well annular pressure and
  (d) Absorbs any thrust generated by the pump.
- The electric motor: It is powered by three phase alternating current supplied by the cable connected to the motor at the pothead. They are available in sizes between 15 and 900 HP in the manufacturer's catalogue. Two or even three motors may be placed in series if high pump power requirements exist.

  The motor is filled with oil which insulates the electrical winding. [Ingress of reservoir fluids (water) is a common cause of motor failure]. A second, less obvious cause of failure is power surges/voltage spikes/harmonics on the power supply. These are more prevalent when the power is generated locally rather than supplied by the (electrical) utility grid.

When the motor is switched off the head of fluid present in the tubing will reverse the flow direction through the pump as it flows back into the reservoir. This will cause the motor to spin backwards. Trying to restart the motor while it is rotating backwards will lead to the motor burning out very quickly. This can be avoided by:

(a) Installing a check valve in the tubing to prevent fluid backflow (however this results in a "wet string" when the tubing/ESP is recovered)

(b) Electronically preventing motor restart for a specified time after it has been shut down or

(c) Using a sensor to detect backspin and preventing motor restart (see the next section on downhole sensors).

- A downhole sensor package: It may be mounted underneath the motor. Measurements can include:

  (a) Pump suction and discharge pressures and temperatures

  (b) Fluid intake temperature

  (c) Electric motor temperature

  (d) Vibration

  (e) Current leakage.

A downhole flow meter and/or phase cut can be added to the above and all the above data transmitted to surface via the power cable. The above can be combined with measurement of the power supply frequency and surface current/voltage as well as wellhead temperature, pressure and surface flow rate so as to be able to present a complete picture of well performance. The data can be:

(a) Stored at the well site and downloaded to a (hand held) data log at regular intervals for later analysis

(b) Used to trigger on-site alarms which shut the ESP unit down e.g. if the pump suction pressure falls below a preset value indicating that the fluid level in the well is reducing and the well is being "pumped off"

(c) Transmitted continuously to the operations office where more sophisticated monitoring analysis can be carried out

(d) Replace non-routine well surveillance operations e.g. the sensors may be sufficiently accurate to obviate the need for running memory gauges into the well when preforming flowing bottomhole pressure surveys, build up tests or reservoir pressure monitoring.

The **Figure 4.10** is for a low pressure well since a packer had not been installed in the well, i.e. the well will probably not flow without artificial lift. Inclusion of a packer in the completion design, as is often required by the regulatory authorities in live and many offshore wells, precludes venting the gas to the surface via the casing/tubing annulus unless a dual packer arrangement is employed with a safety valve installed on at least the main production tubing and (possibly) on the gas vent line as well.

4.2.4 Progressing Cavity Pumps (PCPs)

Progressing Cavity (or Moyno) Pumps are becoming increasingly popular for the production of viscous crude oils. A typical completion is illustrated in **Figure 4.12** where a prime mover (in this case an electric motor) is shown rotating a sucker rod string and driving the PCP.

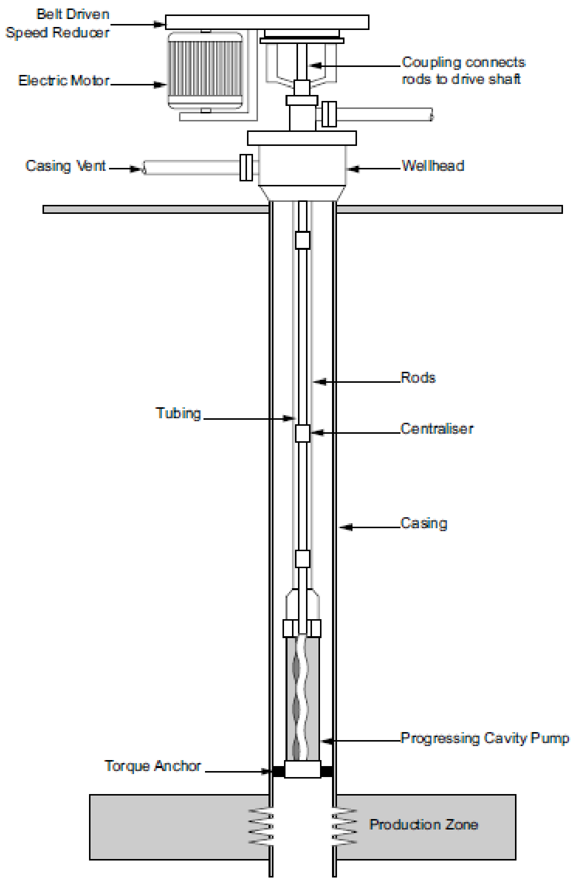

Figure 4.12: A well completed with artificial lift using a PCP [34]

4.2.4.1 Progressing Cavity (or Moyno) Pump Principle

Figure 4.13 illustrates the main components of a PCP. A steel shaft rotor of diameter has been formed into a helix [**Figure 4.13** (a)]. The rotor is rotated inside an elastomeric pump body or stator, which has been molded in the form of a double helix with a pitch of the same diameter and exactly twice the length of the pitch given to the rotor [**Figure 4.13** (b)]. **Figure 4.13** (c) shows that, when assembled, the center line of the rotor and the stator are slightly offset, creating a series if fluid filled cavities along the length of the pump. **Figure 4.14** is a perspective view of **Figure 4.13** (c), which helps explain how the interference fit between the rotor and stator creates two chains of spiral (fluid filled) cavities.

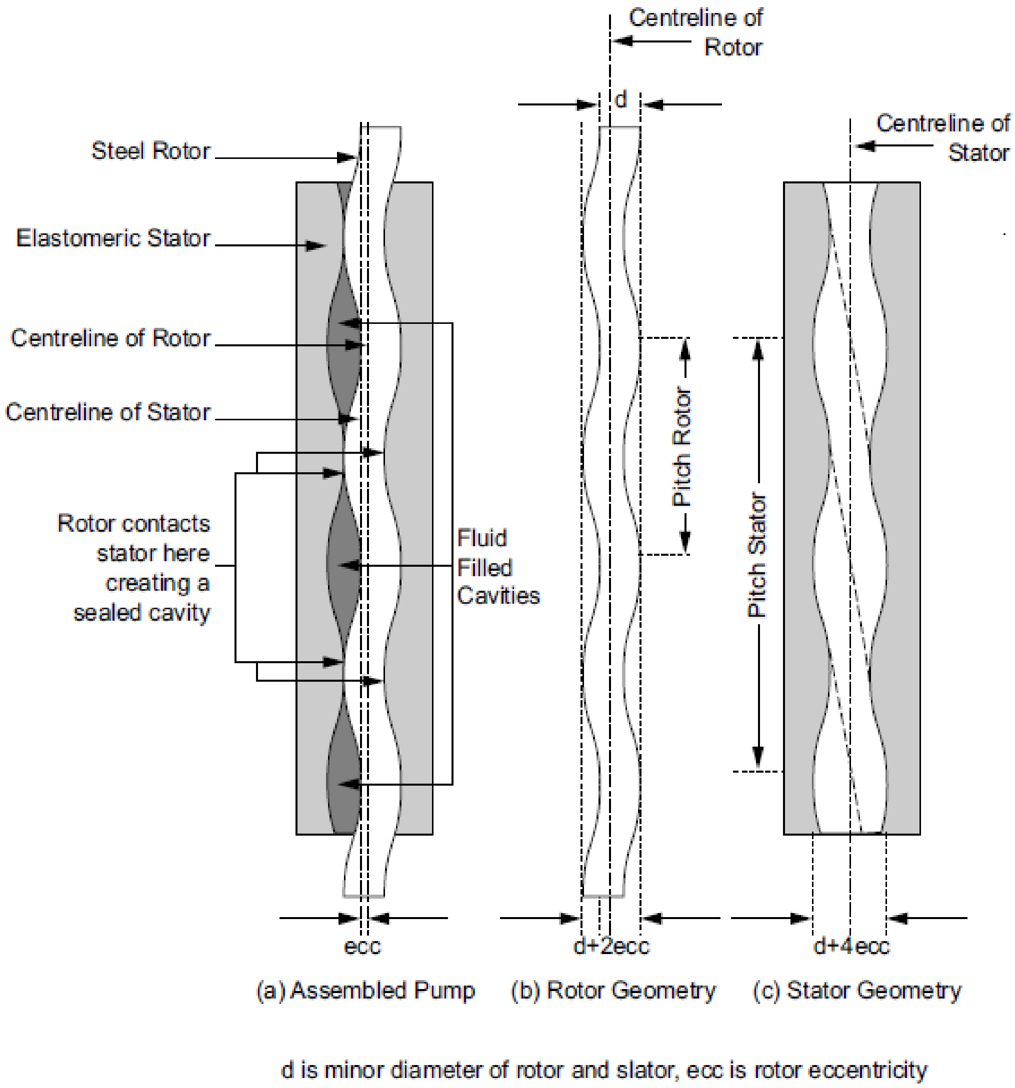

Figure 4.13: Cross section PCP and its components [34]

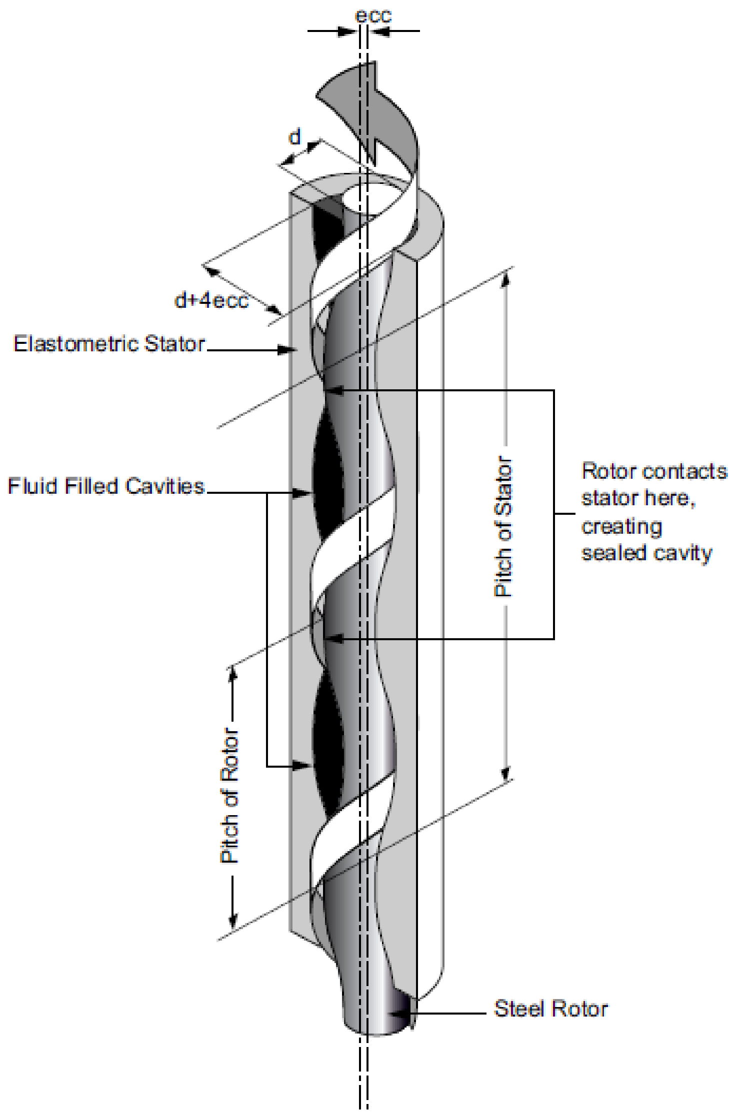

Figure 4.14: Perspective view of operating PCP [34]

The rotor within the stator operates as a pump. This causes the fluid, trapped in the sealed cavities, to progress along the length of the pump from the suction to the pump discharge. These cavities change neither size nor shape during this progression. **Figure 4.15** shows how, as one cavity diminishes, the next one increases at exactly the same rate; giving a constant, non-pulsating flow. It acts as a positive displacement pump. The pressure increase that can be achieved by the pump depends on the number of “seal-lines” formed along the pump body by the rotor and stator. Typically, this is found to be 300-200 kPa pressure increase per stage. It is found that fluid will “slip” backwards if a greater pressure increase is demanded from the pump. This can be avoided by increasing the number of pump stages. Wear of the stator of rotor will decrease this value since the maximum pressure increase depends on this interference fit. However, the construction of the stator body from an elastomer makes this pump design relatively tolerant to produced solids, particularly since they are often used to pump viscous oils which provides a lubrication film to protect the rotor and stator from wear.

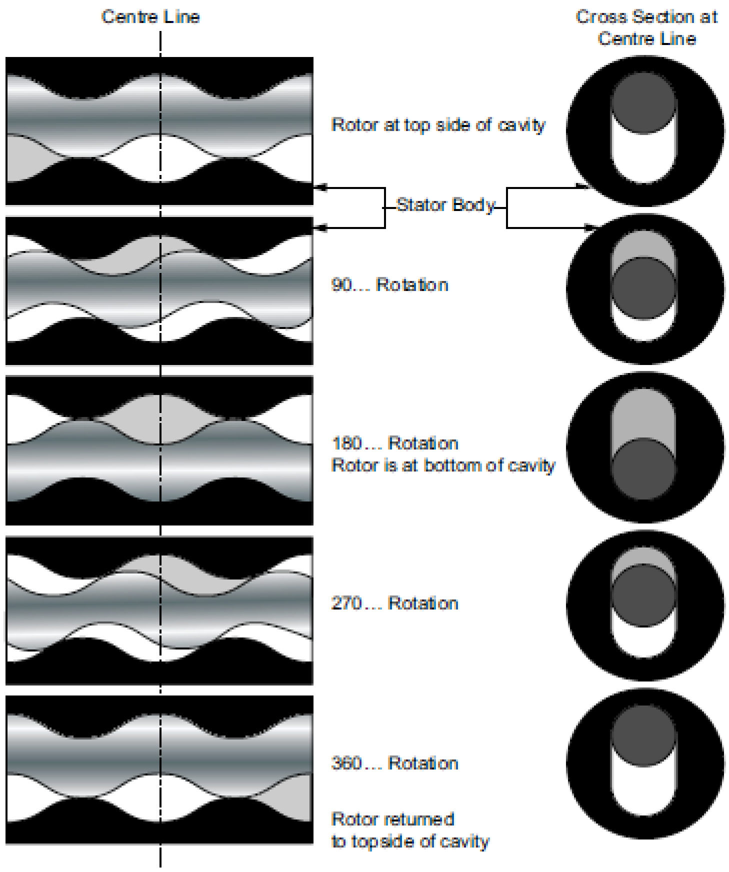

Figure 4.15: Operating principle of PCP [34]

4.2.4.2 PCP Power Supply

Traditionally, PCPs have been powered by an electric motor and gearbox mounted above the wellhead and turning a string of sucker rods connected to the PCP pump, i.e. the rods are rotated rather than reciprocated (**Figure 4.12**). On rod pumps, this string of sucker rods is susceptible to failure, especially in crooked or deviated wells or when formation sand is being produced. There is a similar tendency to a higher frequency of tubing failures since the rods are rotating inside the tubing. Installation of centralizers on the sucker rod string can mitigate this problem. This rod/tubing frictional contact, even when reduced by centralizing the sucker rod string, leads to a large loss of starting torque as well as wastage of power when the pump is operating.

Further, the tubing must be pulled and then rerun when the pump unit requires repair. This can normally be done by a light workover hoist since the wells are not normally capable of natural flow.

5 CONCLUSIONS

Generally, the main section of technological activities in production engineering have been related to the installation of the downhole completion equipment. The well completion string is a demanding element of the production system. It has to be designed efficiently, set up, and maintained to do it productive. Progressively, from higher reservoir pressures to more hostile development areas, the real capital expenses of all completion string have become a critical part of all well expense and hence worthy of greater technical consideration and optimization. The process of completion can be divided into many various important areas which need to be characterized including:

- The completion fluids must be recognized, and it needs that the functionality of the completion fluid and the desired physical properties be specified.
- The well completion has to take into account and determine how the fluids will enter from the formation to the borehole i.e., whether in fact it is open hole or whether a cased hole which will require to be afterward perforated to permit a limited number of entrances for fluids to flow into the well from the reservoir.
- The well completion string design must supply the needed control capacity to permit fluids to flow securely with minimal pressure loss to the surface. Moreover, however, it is important that the completion string can fulfill various additional functions which are related to monitoring, control, and safety, etc. As a rule, the well completion must give the ability for reservoir management. The completion string must take into account what possibilities are present in the case of altering fluid production properties and how small servicing operations could be performed such as, substitution of valves, etc.

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