

CHAPTER-7

DRILLING

Within the petroleum industry, the drilling of wells is of paramount importance: without a well there is no way to get oil and gas. The drilling phase of petroleum, then, becomes a subject worth considering in detail. Basically, the people directly involved in drilling are employed by operating companies, drilling contractors, and various service and supply companies.

7.1 The Companies

Operating companies are the financiers of the industry and are the principal users of the services provided by drilling contractors and service companies. An operating company, often called simply an operator, is a person or company who actually has the right to drill and produce petroleum that exist at a particular site. An operator can be a major company such as Exxon, Shell, Gulf Texaco, Mobil, BP to name but a few. Operating companies, both large and small, have found it more expeditious to utilize the men, equipment, and skills and experience of drilling contractors to perform the actual drilling of a well. The contract for making hole goes to a drilling contractor, but the operating company is usually the one that awards other contracts to the *service and supply companies*.

7.2 The Drilling Crew

Although the number of persons on a drilling crew varies from rig to rig, most crews working on land rigs consist of *toolpusher*, *a driller*, *derrickman*, and two or three *rotary helpers*. Sometimes the crew includes a motorman, a rig mechanic and a rig electrician. While not an actual member of the crew, the operating company usually has a *representative* on the site at all times. He is usually called the company man, although more formally he is called the company representative. As for personnel who work for the service and supply companies, their jobs vary according to the nature of the service they provide to the operator

and contractor. For example, mud companies-companies that supply the components for the drilling fluid- almost always have a *mud engineer* on duty at the rig. Also, *mud loggers* stay on the well site at all times and constantly monitors what is happening down hole as the well is drilled. At various stages of the drilling, *casing crews* are called in to run special pipe called “casing” into the hole. Since the casing has to be cemented in place, a *cementing service company* is usually called in to perform this task.

7.3 Rig Components

The main function of a rotary rig is to drill a hole, or as it is known in the industry, to *make hole*. Making hole with a rotary rig requires not only qualified personnel, but a lot of equipment as well. In order to learn about the components that it takes to make hole, it is convenient to divide them into four main systems: power, hoisting, rotating and circulating. Various components comprise the last three systems, but all require power to make them work.

7.3.1 Power System

Practically every rig uses internal combustion engines as its prime power source, or its prime mover. Most rig engines today are diesel. Diesel electric power is the dominant method used to drive most of the today’s rigs. Diesel engines, which on land rigs are usually located on ground level some distance away from the rig floor, drive large electric generators. The generators, in turn, produce electricity that is sent through cables to electric switch and control gear.

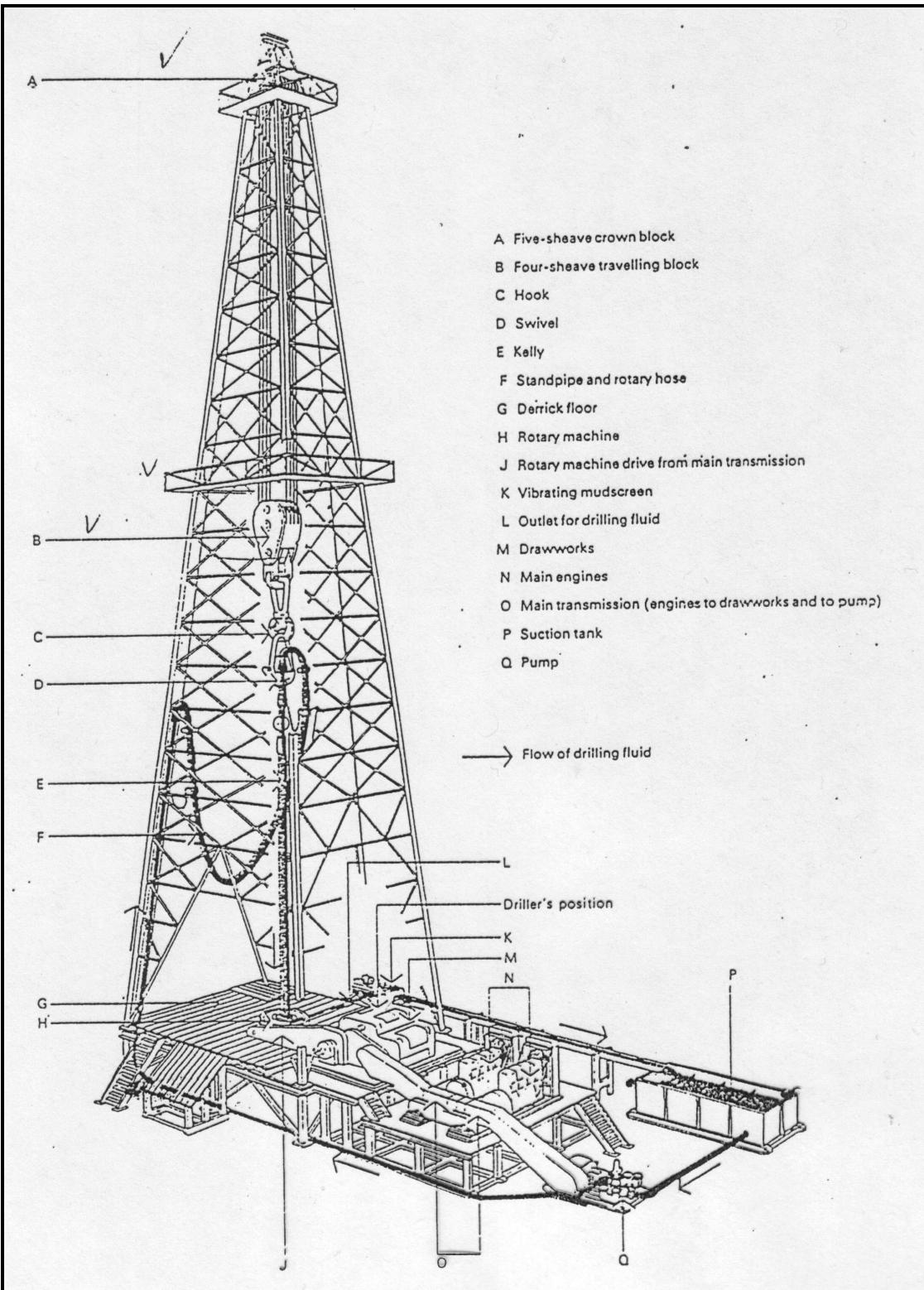


Figure 7-1 Rotary Drilling Rig

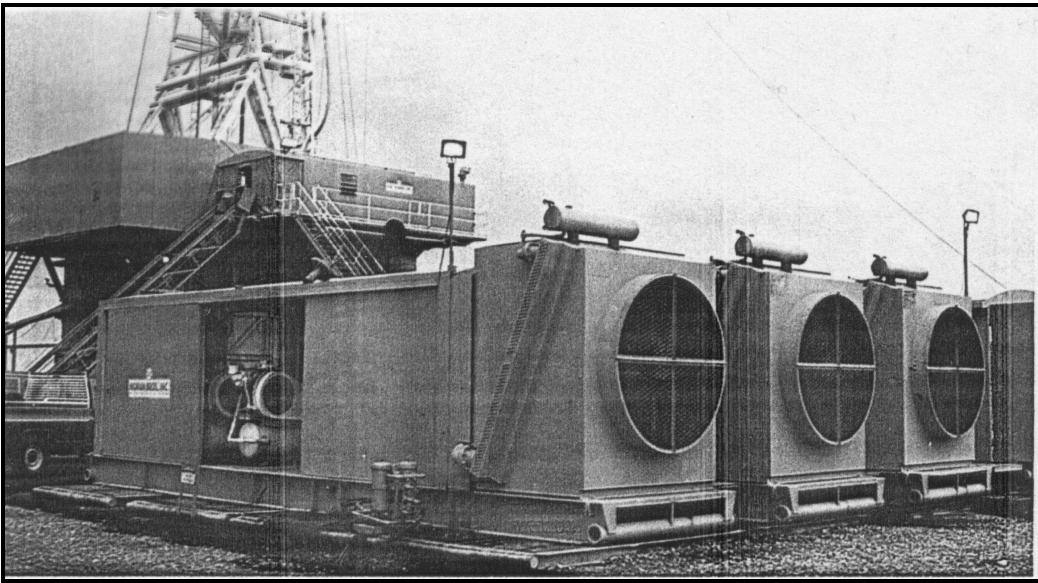


Figure 7-2 The Diesel Engines in use on this rig are located on the ground, some distance away from the rig.

7.3.2 Hoisting System

Regardless of whether the rig is mechanical or diesel-electric, its job is to make hole, and to do its job it must have a hoisting system. Basically the hoisting system is made up of the drawworks, a mast or derrick, the crown block, the traveling block and a wire rope.

The drawwork is a big, heavy piece of machinery. It consists of a revolving drum around which the wire rope called drilling line is spooled or wrapped. It also has a catshaft on which the catheads are mounted. Typically four catheads are mounted on the catshaft of the drawworks. Two different types of catheads are mounted on each end of the catshaft, which extends out from both sides of the drawworks. A friction cathead is a relatively small, spool-shaped device. A mechanical cathead can be employed to make up or break out the drill string when it is being put into the hole, or when a length of drill pipe is added as the hole deepens.

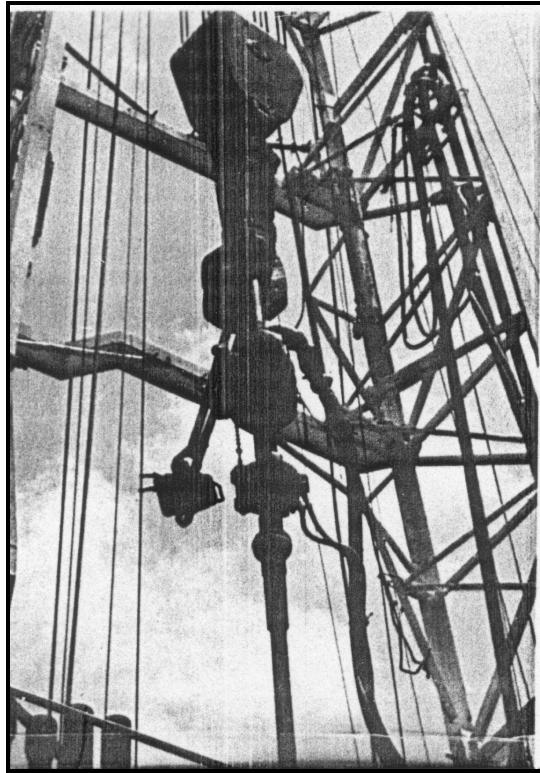


Figure 7-3 Hoisting System

A drilling line is made up of wire rope that generally ranges from $1\frac{1}{8}$ to $1\frac{1}{2}$ inches in diameter. Wire rope is similar to common fiber rope, but wire rope, as the name implies, is made out of steel wires and is a fairly complex device. For wire rope to be useful as the drilling line, it has to be strung up, for it arrives at the rig wrapped on a large supply reel. So, the first step in stringing up the drilling line is to take the end of the line off the supply reel and raise the end up to the very top of the mast or derrick where a large, multiple pulley is installed. This large set of pulleys is called the *crown block*. The pulleys are called *sheaves*. On the rig floor rests another very large set of pulleys or sheaves called the *traveling block*. The part of the drilling line running out of the drawworks up to the crown block is called the *fastline*-fast because it moves as the traveling block is raised or lowered in the derrick. The end of the line that runs from the crown block down to the wire rope supply reel is secured.

This part of the line is called deadline- dead because once it is secured, it does not move.

Mounted in the rig substructure is a device called a *deadline anchor*.

7.3.3 Circulating System:

A major function of the fluid-circulating system is to remove the rock cuttings from the hole as drilling progresses. The drilling fluid is most commonly a suspension of clay and other materials in water and is called ***drilling mud***. The drilling mud travels;

- from the steel tanks to the mud pump,
- from the pump through the high-pressure surface connections to the drillstring,
- through the drillstring to the bit,
- through the nozzles of the bit and up the annular space between the drillstring and hole to the surface, and;
- through the contaminant-removal equipment back to the suction tank.

The principal components of the rig circulating system include;

- mud pumps and mud pits,
- mud-mixing equipment, and
- contaminant-removal equipment.

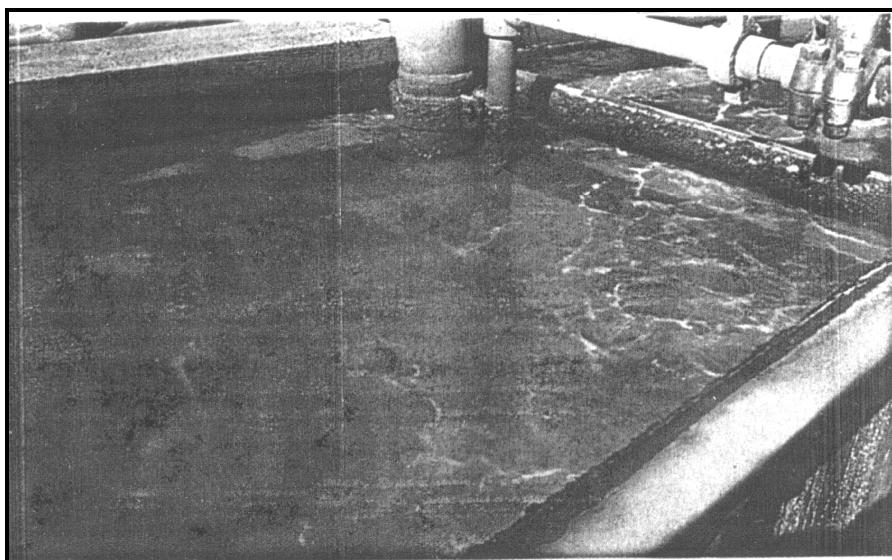


Figure 7-4 Drilling Fluid

With the exception of several experimental types, mud pumps always have used reciprocating positive-displacement pistons. Both two-cylinder (*duplex*) and three-cylinder (*triplex*) pumps are common. The duplex pumps generally are ***double-acting*** pumps that pump on both forward and backward piston strokes. The triplex pumps generally are ***single-acting*** pumps that pump only on forward piston strokes. Triplex pumps are lighter and more compact than duplex pumps, their output pressure pulsations are not as great, and they are cheaper to operate. For these reasons, the majority of new pumps being placed into operation are of the triplex design.

The advantages of the reciprocating positive-displacement pump are the;

- ability to move high-solids-content fluids laden with abrasives,
- ability to pump large particles,
- ease of operation and maintenance,
- reliability, and
- ability to operate over a wide range of pressures and flow rates by changing the diameters of the *pump liners* (compression cylinders) and pistons.

7.3.3.1 Components of the Circulating System.

The equipment in the circulating system consists of a large number of items. The mud pump takes in mud from the mud pits and sends it out a discharge line to a *standpipe*. The standpipe is a steel pipe mounted vertically on one leg of the mast or derrick. The mud is pumped up the standpipe and into a flexible, very strong, reinforced rubber hose called the *rotary hose* or *kelly hose*. The rotary hose is connected to the *swivel*. The mud enters the swivel the swivel: goes down the *kelly*, *drill pipe* and *drill collars* and exist at the *bit*. It then does a sharp *U-turn* and heads back up the hole in the annulus. The *annulus* is the space between the outside of the drill string and wall of the hole. Finally the mud leaves the hole

through a steel pipe called the mud return line and falls over a vibrating, screen like device called the *shale shaker*. *Agitators* installed on the mud pits help maintain a uniform mixture of liquids and solids in the mud. If any fine silt or sand is being drilled, then devices called *desilters* or *desanders* may be added. Another auxiliary in the mud system is a device called *degasser*. Sometimes small amounts of gas in a formation will enter the mud as it is being circulated down-hole.

The overall efficiency of a mud-circulating pump is the product of the mechanical efficiency and the volumetric efficiency. Mechanical efficiency usually is assumed to be 90% and is related to the efficiency of the prime mover itself and the linkage to the pump drive shaft. Volumetric efficiency of a pump whose suction is adequately charged can be as high as 100%. Most manufacturers tables rate pumps using a mechanical efficiency, E_m , of 90% and a volumetric efficiency, E_v , of 100%. Generally, two circulating pumps are installed on the rig.

For the large hole sizes used on the shallow portion of most wells, both pumps can be operated in parallel to deliver the large flow rates required. On the deeper portions of the well, only one pump is needed, and the second pump serves as a stand-by for use when pump maintenance is required.

7.3.4 Rotary System:

The rotary system includes all of the equipment used to achieve bit rotation. The main parts of the rotary system are the: swivel, kelly, rotary drive, rotary table, drill pipe and drill collars.

The *swivel* supports the weight of the drill string and permits rotation. The *bail* of the swivel is attached to the hook of the traveling block, and the *gooseneck* of the swivel provides a downward-pointing connection for the rotary hose. Swivels are rated according to their load capacities.

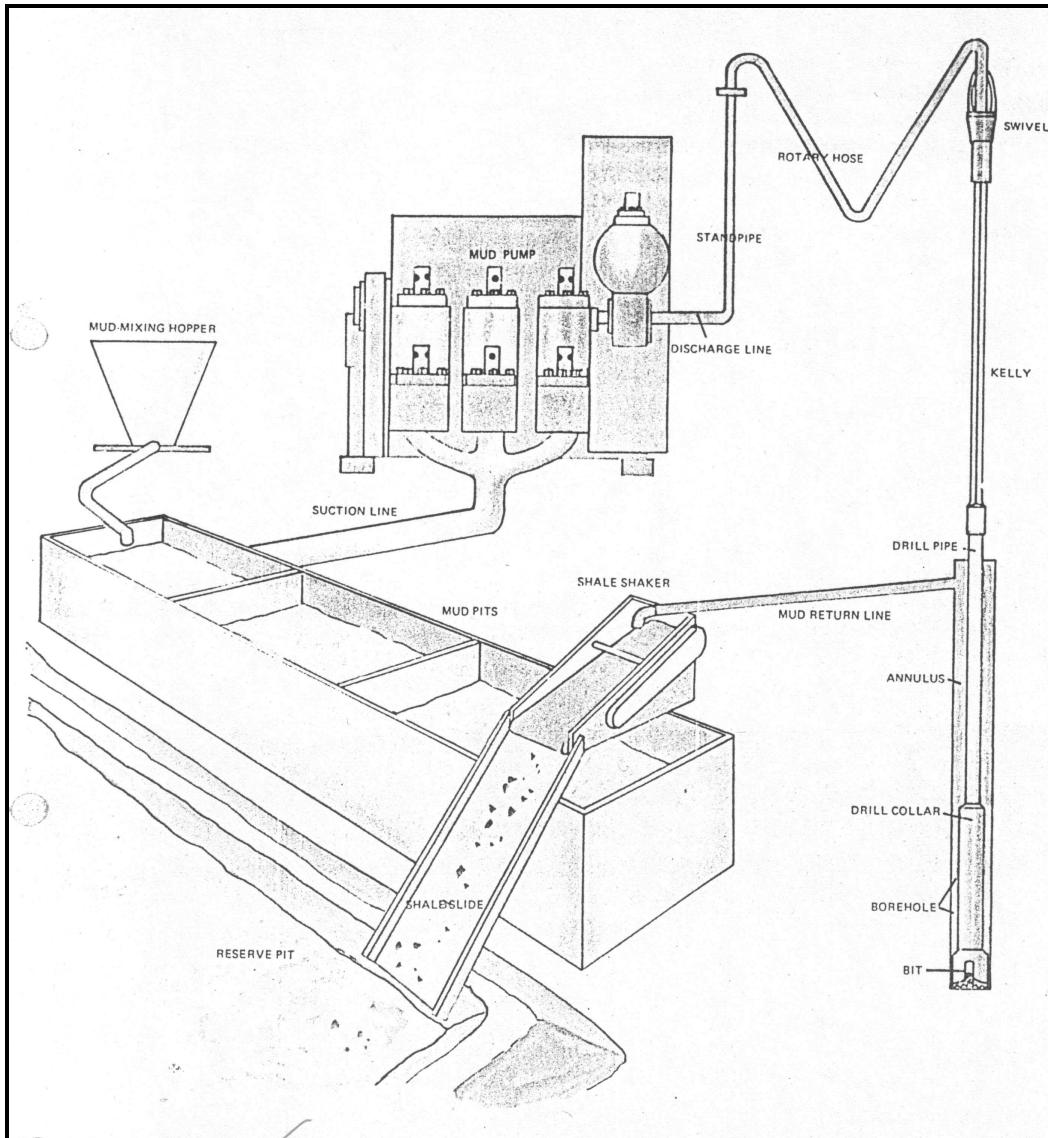


Figure 7-5 Components of the Circulating System

The **kelly** is the first section of pipe below the swivel. The outside cross section of the kelly is square or hexagonal to permit it to be gripped easily for turning. Torque is transmitted to the kelly through *kelly bushings*, which fit inside the master bushing of the *rotary table*. The kelly must be kept as straight as possible. A kelly saver sub is used between the kelly and the first joint of drill pipe.

The openings in the rotary table that accepts the kelly bushings must be large enough for passage of the largest bit to be run in the hole. The major portion of the drill string is composed of drill pipe. *API* has developed specifications for drill pipe. Drill pipe is specified by its outer diameter, weight per foot, steel grade and range length. Drill pipe is furnished in the following API length ranges.

Table 7-1 Ranges of Drill Pipes

Range	Length (ft)
1	18 to 22
2	27 to 30
3	38 to 45

Range-2 drill pipe is used most commonly. Since each joint of pipe has a unique length, the length of each joint must be measured carefully and recorded to allow a determination of total well depth during drilling operations. The drill pipe joints are fastened together in the drill string by means of *tool joints*. The *female* portion of the tool joint is called the *box* and the *male* portion is called the *pin*. The portion of the drill pipe to which the tool joint is attached has thicker walls than the rest of the drill pipe to provide for a stronger joint. This thicker portion of the pipe is called the *upset*.

The lower section of the rotary drill string is composed of *drill collars*. The drill collars are thick-walled heavy steel tubulars used to apply weight to the bit. The smaller clearance between the borehole and the drill collars helps to keep the hole straight. *Stabiliser subs* often are used in the drill collar string to assist in keeping the drill collars centralized.

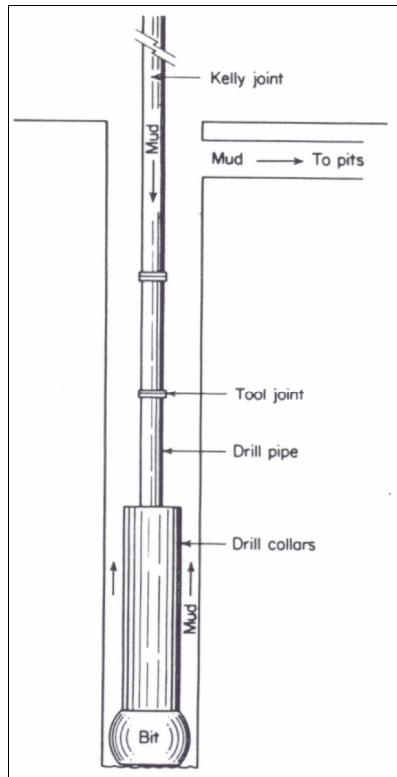


Figure 7-6 Schematic Diagram of Drill String Components and Bit.

7.4 Drilling Bits

The process of drilling a hole in the ground requires the use of drilling bits. Rotary drilling bits usually are classified according to their design as either *drag bits* or rolling cutter bits. All drag bits consist of fixed cutter blades that are integral with the body of the bit and rotate as a unit with the drill string. This type of bit includes bits with steel cutters, diamond bits and polycrystalline diamond (PCD) bits. An advantage of drag bits over rolling cutter bits is that they do not have any rolling parts, which require strong, clean bearing surfaces. Diamond bits perform best relative to other bit types in non-brittle formations that have a plastic mode of failure for the stress conditions present at the bottom of the hole. Diamond bits do not have cones; nor do they have teeth. The face or crown of the bit consists of many diamonds set in a tungsten carbide matrix. Since diamonds are so hard, diamond bits are sometimes used to efficiently drill rock formations that are quite hard. They are also used to

drill soft formations effectively. Since the mid-1970's a new family of drag bits has been made possible by the introduction of sintered polycrystalline diamond drill blank as a bit cutter element. The drill blank consist of a layer of synthetic. The bit shape or crown profile is also an important design feature of PCD bit. In addition to the double cone profiles used for diamond bits, single cone profiles of various tapers and flat-bottom profiles are used for PCD bits. The hydraulic cleaning action is usually achieved primarily by using jets for steel body PCD bits and by using watercourses for matrix body PCD bit. Roller cone bits have cone-shaped steel devices called cones that are free to turn as bit rotates. Most roller cone bits have three cones, although some have two and some have four. Bit manufacturers either cut teeth out of the cones or insert very hard tungsten carbide buttons into the cones.

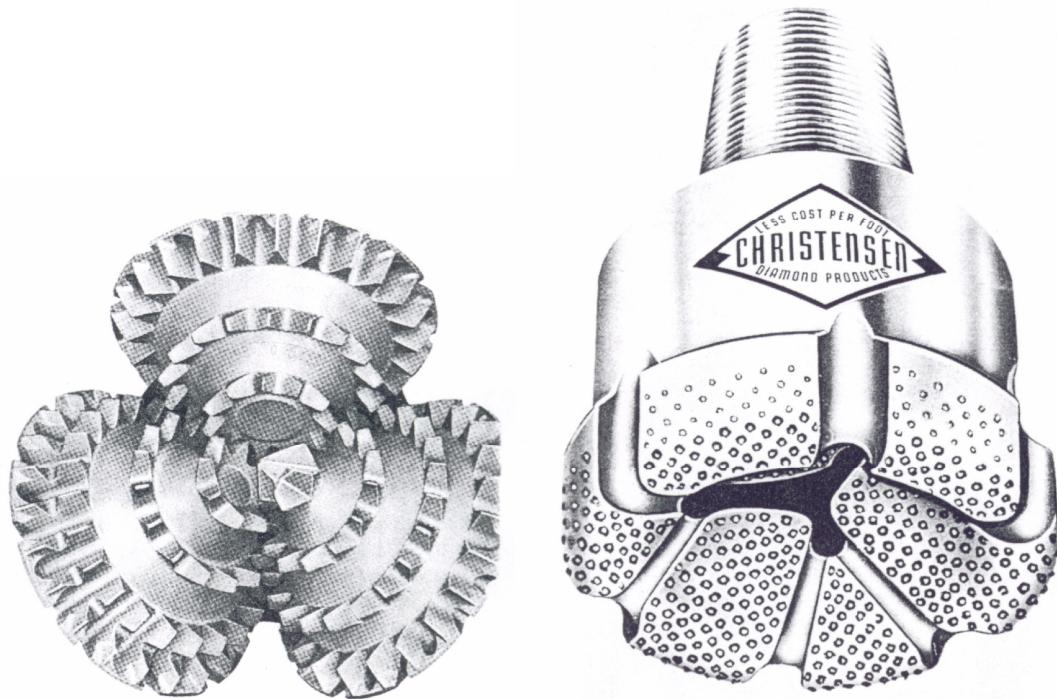


Figure 7-7 Three Cone Roller and Diamond Bit

The three-cone rolling cutter bit is by far the most common bit type currently used in rotary drilling operations. This general bit type is available with a large variety of tooth design

and bearing types and, thus, is suited for a wide variety of formation characteristics. The three cones rotate about their axis as the bit is rotated on bottom. The shape of the bit teeth also has a large effect on the drilling action- of a rolling cutter bit. Long, widely spaced, steel teeth are used for drilling soft formations. As the rock type gets harder, the tooth length and cone offset must be reduced to prevent tooth breakage; The drilling action of a bit with zero cone offset is essentially a crushing action. The smaller teeth also allow more room for the construction of stronger bearings. The metallurgy requirements of the bit teeth also depend on the formation characteristics. The two primary types used are (1) *milled tooth* cutters and (2) *tungsten carbide insert* cutters. The milled tooth cutters are manufactured by milling the teeth out of a steel cone while the tungsten carbide insert bits are manufactured by pressing a tungsten carbide cylinder into accurately machined holes in the cone. The milled tooth bits designed for soft formations usually are faced with a wear-resistant material, such as tungsten carbide, on one side of the tooth. The milled tooth bits designed to drill harder formations are usually case hardened by special processing and heat treating the cutter during manufacturing. The tungsten carbide teeth designed for drilling soft formations are long and have a chisel-shaped end. Rolling cutter bits with the most advanced bearing assembly are the *journal bearing* bits. In this type bit, the roller bearings are eliminated and the cone rotates in contact with the journal bearing pin. This type bearing has the advantage of greatly increasing the contact area through which the weight on the bit is transmitted to the cone.

7.5 Well Control System:

The well control system prevents the uncontrolled flow of formation fluids from the well-bore. When the bit penetrates a permeable formation that has a fluid pressure in excess of the hydrostatic pressure exerted by the drilling fluid, formation fluids will begin displacing the drilling fluid from the well. The flow of formation fluids into the well in the presence of

drilling fluid is called a ***kick***. The well control system permits :

- detecting the kick,
- closing the well at the surface,
- circulating the well under pressure to remove the formation fluids and increase the mud density,
- moving the drill string under pressure, and
- diverting flow away from rig personnel and equipment.

Failure of the well control system results in an uncontrolled flow of formation fluids and is called a ***blowout***. This is perhaps the worst disaster that can occur during drilling operations. Blowouts can cause loss of life, drilling equipment, the well, much of the oil and gas reserves in the underground reservoir, and damage to the environment near the well. Thus, the well control system is one of the more important systems on the rig. ***Annular preventers***, sometimes called bag-type preventers, stop flow from the well using a ring of synthetic rubber that contracts in the fluid passage. The rubber packing conforms to the shape of the pipe in the hole. Most annular preventers also will close an open hole if necessary. Annular preventers are available for working pressures of 2000, 5000 and 10000 psig. Both the ***ram*** and ***annular*** BOP's are closed hydraulically. In addition, the ram preventers have a screw-type locking device that can be used to close the preventer if the hydraulic system fails. The annular preventers are designed so that once the rubber element contacts the drill string, the well pressure helps hold the preventer closed.

7.6 Well-Monitoring System:

Safety and efficiency considerations require constant monitoring of the well to detect drilling problems quickly. Devices record or display parameters such as depth, penetration rate, hook load, rotary speed, rotary torque, pump rate, pump pressure, mud density, mud

temperature, mud salinity, gas content of mud, hazardous gas content of air, pit level and mud flow rate.

In addition to assisting the driller in detecting drilling problems, good historical records of various aspects of the drilling operation also can aid geological, engineering, and supervisory personnel. In some cases, a centralised well-monitoring system housed in a trailer is used. This unit provides detailed information about the formation being drilled and fluids being circulated to the surface in the mud as well as centralising the record keeping of drilling parameters. The *mud logger* carefully inspects rock cuttings taken from the shale shaker at regular intervals and maintains a log describing their appearance. Additional cuttings are labelled according to their depth and are saved for further study by the paleontologist. The identification of the microfossils present in the cuttings assists the geologist in correlating the formations being drilled. Gas samples removed from the mud are analysed by the mud logger using a gas chromatograph. This type of analysis often can detect the presence of a hydrocarbon reservoir. Recently, there have been significant advances in sub-surface well-monitoring and data-telemetry systems. These systems are especially useful in monitoring hole direction in non-vertical wells. One of the most promising techniques for data telemetry from sub-surface instrumentation in the drill string to the surface involves the use of a mud pulse that sends information to the surface by means of coded pressure pulses in the drilling fluid contained in the drill string.

7.7 Drilling Operations

7.7.1 Drilling a Well

Normal drilling operations are, after all, what the rig and crew is mainly hired to do. Simply stated, that which constitutes normal drilling operations is:
-keeping a sharp bit on bottom, drilling as efficiently as possible,

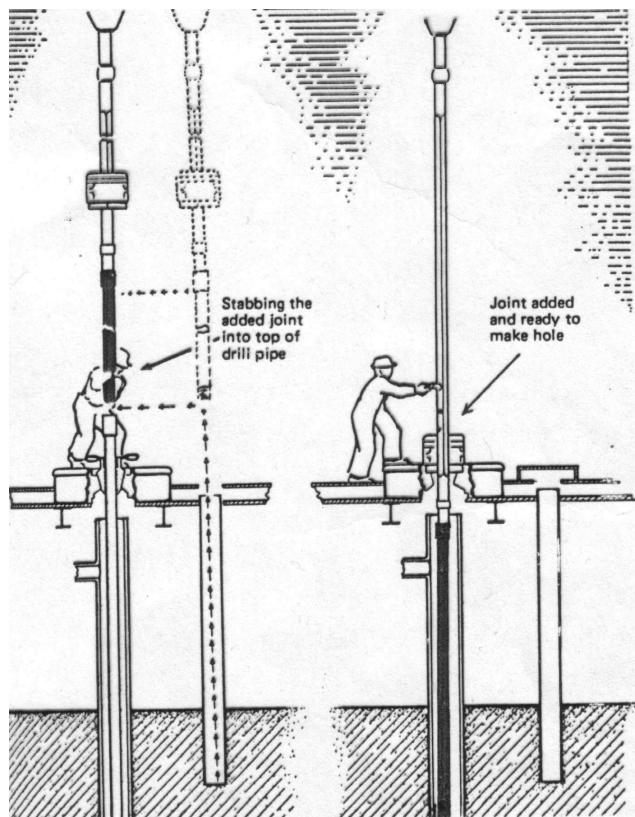
- adding a new joint of pipe as the hoe deepens,
- tripping the drill string out of the hole to put on a new bit and running it back to bottom, or making a round trip
- running and cementing the casing, large diameter steel pipe that is put into the hole at various predetermined intervals.

Assume that the crew is ready to begin drilling the first part of the hole. Remember that about 20 to 100 feet has already been started and lined with conductor pipe. The diameter of the conductor pipe varies (assume it is 20 inches). Therefore the first bit used will have to be smaller than 20 inches. Here a $17 \frac{1}{2}$ inch bit is chosen. This fairly large bit made up on the end of the first drill collar, and both bit and drill collar are lowered into the conductor hole.

Enough collars and drill pipe are made

up

Figure 7-8 The Mousehole



and lowered in until the bit almost to bottom. Then the kelly is picked up out of the hole where it has been waiting and is made up on the topmost joint of drill pipe sticking up out of

the rotary table. This joint of pipe is suspended in the rotary table by the slips. With the kelly made up, the pump is started to begin circulating drilling mud, and the kelly bushing is lowered to engage the master bushing in the rotary table. The driller actuates the rotary table, and rotation begins. Next, he gradually releases the drawworks brake, and the rotating bit touches bottom and begin making hole. Using an instrument called the weight indicator, the driller monitors the amount of weight put on the bit by the drill collars. Since the kelly is about 40 feet long, after 30 or so feet of hole is made, the driller stops the rotary, raises the kelly a little, and stops the mud pump. Then the crew prepares to make the first connection. They set the slips around the joint of pipe, and latch a big set of wrenches called tongs around the base of the kelly. A tong pulls line – a length of strong wire rope- runs from the end of the tongs over to the break out cathead on the drawworks. The driller engages the cathead, and it starts pulling on the line with tremendous force. The pulling force on the tongs breaks out, or loosens, the threaded joint between the kelly and drill pipe. Once the joint is loosened, the crew removes the tongs, and on a modern rig the driller engages the kelly spinner (an air-actuated device mounted permanently near the top of the kelly). The kelly spinner turns or spins the kelly so that it unscrews rapidly from the drill pipe. The crew moves the kelly over to the mouse hole, which is just a hole in the rig floor lined with pipe into which the joint of drill pipe is placed prior to its being made up in the string. The crew stabs the kelly into the box of the drill pipe, and the driller spins up the kelly. The crew grabs the tongs, latches them onto the kelly and pip and bucks up (tightens) the joint to final tightness. Next the driller uses the drawworks to raise the kelly and attached joint out of the mouse hole. The crew stabs the end of the new joint into the joint hanging in the rotary, and the two are connected together; that is, the joint is spun up and tongs are used to buck them up to final tightness. Finally, the driller lifts up the kelly and attached string a small amount, the crew removes the slips and drilling continues.