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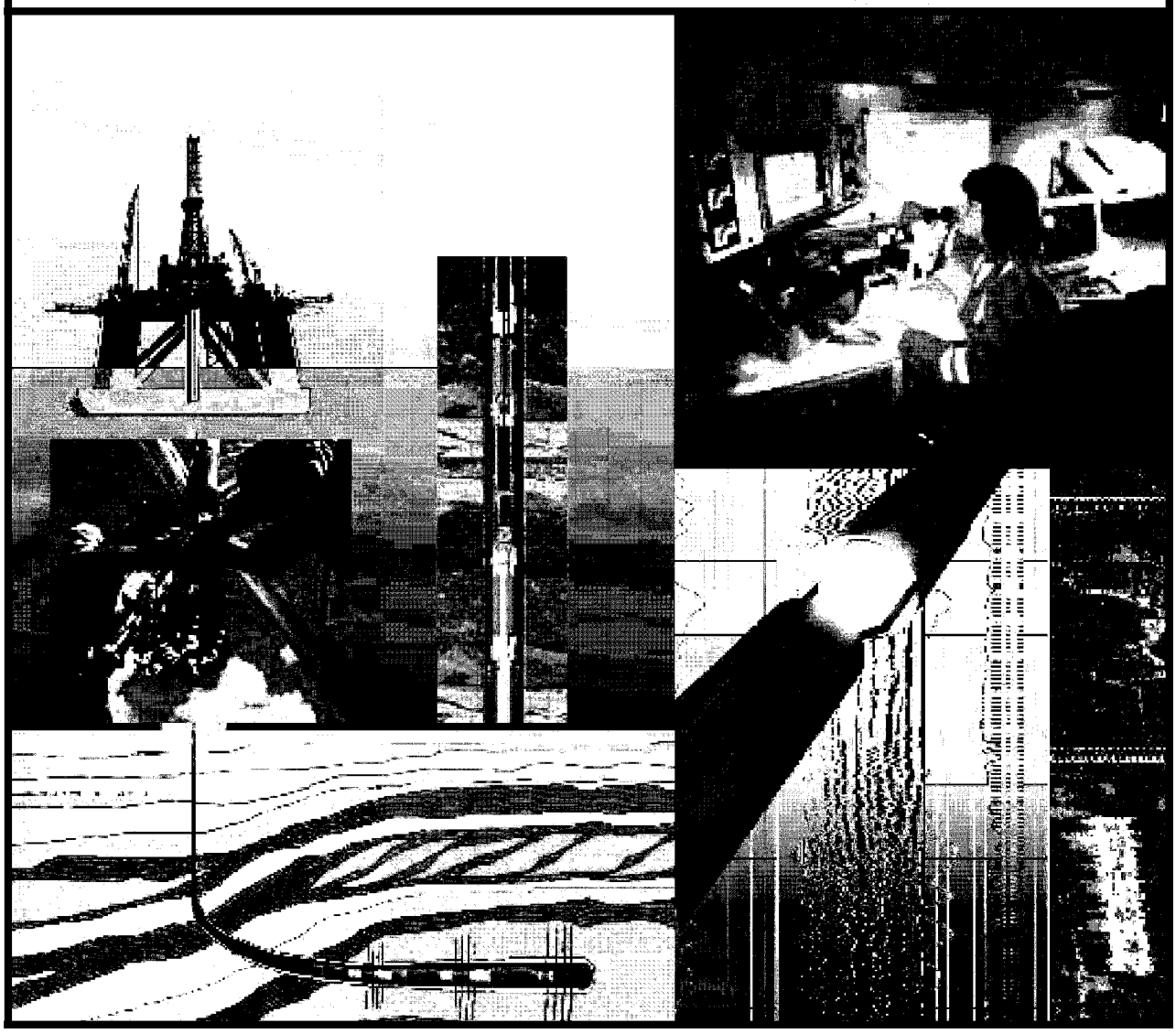
Surface Data Logging Core Fundamentals

Sperry-Sun Drilling Services
Houston, Texas



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Surface Data Logging Core Fundamentals

Sperry-Sun Drilling Services Course 236

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Chapter 1 Rigs, Rig Components and Rig Personnel

A drilling rig is a complex system consisting of people and equipment who must work safely under extreme conditions. Work locations could be from the Arctic Circle and North Sea to the swamps of Louisiana or the deserts of the Middle East. Rigs can range from a truck mounted work-over rig to a large ocean going drill ship. Rigs are primarily divided into two major categories: land and marine. It is important to be cognizant of each type of rig so that as a logging engineer you will be able to competently participate in the safe and hopefully productive completion of the well. The drilling rig and personnel perform very special functions at different times. Land rigs and their component parts will be discussed first since they are the easiest to study. This will be followed by a discussion of marine rigs. After learning about the rigs, we will discuss the duties of the crews who operate the rigs and the process of drilling.

In the United States, the customary unit of measure of rig production is the foot. In Canada and many parts of the world, the meter is used in place of the foot (i.e., a meter equals about 3.3 feet). The foot is a convenient unit by which to measure the product of a drilling operation and pay the contractor who drilled or "made the hole." It is a fact of life in the drilling industry, however, that the cost per foot of making hole varies directly in relation to the depth to which the foot of hole is drilled. The deeper the hole, the more costly each additional foot drilled.

Most rigs are owned by an individual or a firm known as a drilling contractor. The majority of leases, or wells, are owned by companies engaged in finding, producing, or refining petroleum. These companies are often called operators, or operating companies. Representing the operator is the company man or drilling foreman. The operator hires or contracts the drilling contractor to drill the well. In most cases, drilling contracts are drawn on a day work basis, which means that payment is made for each day the rig is used, plus certain extras. Both the operator and the contractor are interested in such details as the time required for completing the job; the safety of the equipment, property, and personnel throughout the operation; and the ability of both the men and the equipment to do acceptable work.

1.1 Land Rigs

Land rigs are generally either wheel mounted portables or a component system which must be moved by trucks and cranes. The drilling floor generally sits on top of a steel substructure that could be 30 feet high or more. A drilling mast (derrick) is attached and raised above the floor. In general, the deeper wells need a larger, taller rig. The mast must be capable of supporting the vertical load and weight of

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the stacked drill pipe. It must also withstand wind loads of 100 to 130 miles per hour. Shallow wells and wells being completed or repaired will probably use a portable rig. This rig can be driven to the wellsite, and raised up hydraulically with guide wires in place. When the well is completed, the mast is hydraulically lowered and the rig is driven away.

1.2 Offshore Rigs

1.2.1 Marine Rigs

One of the hazards of offshore drilling is the hostile environment. The effects of water depths, storms, wave action and uncertain exploratory data all greatly increase the financial risks. The exploratory wells must be drilled and a reserve potential established that can justify these costs. These exploratory wells seek to establish new reservoir locations and sizes. Once drilled and evaluated, the exploratory well is most often plugged and abandoned. This results in the use of marine rigs for offshore drilling. The development wells are usually drilled from fixed platforms specially designed to exploit the reserves of the reservoir. The platform is also used for production facilities after all drilling operations are complete.

The environment also determines which type of marine rig will be used. Each rig has advantages and disadvantages when used in different water depths and weather conditions. The type of marine rig also can depend on problems involved in getting the rig on location and keeping it stationed in the desired position. The choices include the jack-up rig, semi-submersible rig, the submersible rig, the drill ship the platform rig, the inland barge rig, and the tension leg platform.

1.2.2 Jack-Up Rigs

The jack-up rig has replaced the submersible rig as a fixed drilling platform. It is less costly to build and can operate in up to 600 feet of water. It is ideal for soft ocean sediments found in river deltas.

The jack-up rig consists of a watertight hull and three or more mobile legs. The legs are raised up to allow the vessel to be towed to a location. Then the legs are carefully jacked down until each rests on the seabed. The hull is then jacked up on the legs until it is above the predicted height of storm waves. This height depends on the area and the season. In the Gulf of Mexico it varies from 25 to 35 feet, and in the North Sea up to about 95 feet for the worst storm conditions to be expected.

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Because the jackup also sits on the seabed, it does not have heave problems. It can have vessel motion problems during bad weather if jacked to the top of the legs. This eliminates the need for most motion compensation equipment and special mooring and anchoring equipment.

Disadvantages include its difficulty in towing, especially in rough seas; the legs must be removed during long moves.

1.2.3 Semi-Submersible Rigs

The semi-submersible rig evolved from the older submersible rigs. It provides a relatively stable drilling platform. It can operate under more severe weather and sea conditions and in water depths of from 600 to 4,000 feet.

The semisubmersible rig contains a normal working deck plus columns and pontoons under the deck. These pontoons are ballasted to a water depth that causes the upper deck to remain high above the water.

Older semi-submersibles are kept on location by means of anchors and chains; some of the newer ones are kept on location by means of thrusters.

The pontoons can be re-floated to change locations. They can be towed easily or even self-propelled to the new location.

1.2.4 Drillships

The drillship is a mobile drilling platform used for exploratory drilling. It is self-propelled and can carry larger loads of drilling supplies. This makes them more mobile and self-supporting in remote ocean areas. A drillship is capable of drilling in waters of up to 9,000 feet. It also offers advantages of faster travel times, is self-propelled, and can use dynamic positioning systems.

The disadvantages of drillships include high salaries for the ship's crew who are not directly involved in the drilling operations. Also, the drillship is greatly affected by wave motion (heave) and drifting. This requires a motion compensation system, a marine riser system, and/or a mooring and anchoring system or thrusters for dynamic positioning.

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1.2.5 Platform Rigs

If the exploration drilling program is successful in finding a commercial reservoir, a development program must be planned. All facilities needed to drill, produce, store and transport the hydrocarbons must be designed, fabricated and installed on the site.

All fixed platforms must be able to withstand the environmental forces of its region. This can include wind, waves, currents, ice, earthquakes and soil conditions.

A platform generally consists of four to eight piles or legs resting or driven into the sea bed. The working area must be high enough above the water level to be safe from the waves of the worst storm.

All crew quarters and operating areas are made up of modules which are raised into position by cranes or derrick barges.

Drilling slots on the platform are arranged in a grid system. The actual drilling rig will be skidded from slot to slot for each well. The individual wells will be drilled at an angle to allow for efficient production of the reservoir. A fixed drive pipe extends from a subsea template to the substructure of the platform. The blowout preventer (BOP) stack is connected to the fixed drive pipe for each well slot as it is drilled. Because of its location, the stack is easier to install, repair or change sizes.

1.2.6 Inland Barge Rigs

The inland barge rig is the oldest form of marine rig. It consists of two hulls which are connected by legs. The upper hull is air tight and provides the buoyancy necessary to float the rig to each site. The rig is positioned over the site and the lower hull is flooded. This causes the rig to sink until it rests on the water floor. After drilling the well, the rig is re-floated and moved to a new location, though they are not easy to move. The inland barge rig is limited to working in relatively shallow water, less than 50 feet normally.

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1.2.7 Tension Leg Platforms (TLP)

The Tension Leg Platform is one of the newest types of rigs available. It is a combination of a semi-submersible rig and a platform rig. It is used strictly for production drilling. Normally, some of the wells in the field have already been drilled, and then the TLP is positioned over the pre-drilled wells and the production lines run to the existing wellheads. They are set up with drilling equipment in the event other wells need to be drilled, or any existing wells must be worked over. Current technology allows TLPs to work in up to 5,000 feet of water.

1.2.8 Submersible Rigs

The new submersible rigs are based on the principal of the oldest type of marine rig. These rigs are outfitted with drilling, production, and storage facilities on board. Many are capable of having tankers come along side and off-load oil without the need of having to pipe the oil to a shore base. These rigs are capable of withstanding the rough seas and weather of the North Atlantic and North Sea. They can work in up to 1,500 feet of water.

1.3 Rig Components

A typical rig shown in Figure 1.1 shows the layout of the basic component parts. Use this layout as you read about each system on the rig. Not all rigs are arranged the same. Newer rigs use modular designs and space saving techniques. However, all rigs have five basic functional systems. These include:

- A **hoisting system** to raise and lower drill pipe, casing, and tubing.
- A **circulating system** to remove cuttings and maintain pressure in the well bore.
- A **rotating system** to turn the drill stem.
- A **power production** system to produce mechanical and electrical power.
- A **blowout prevention** system to seal off the well bore and control formation fluids.

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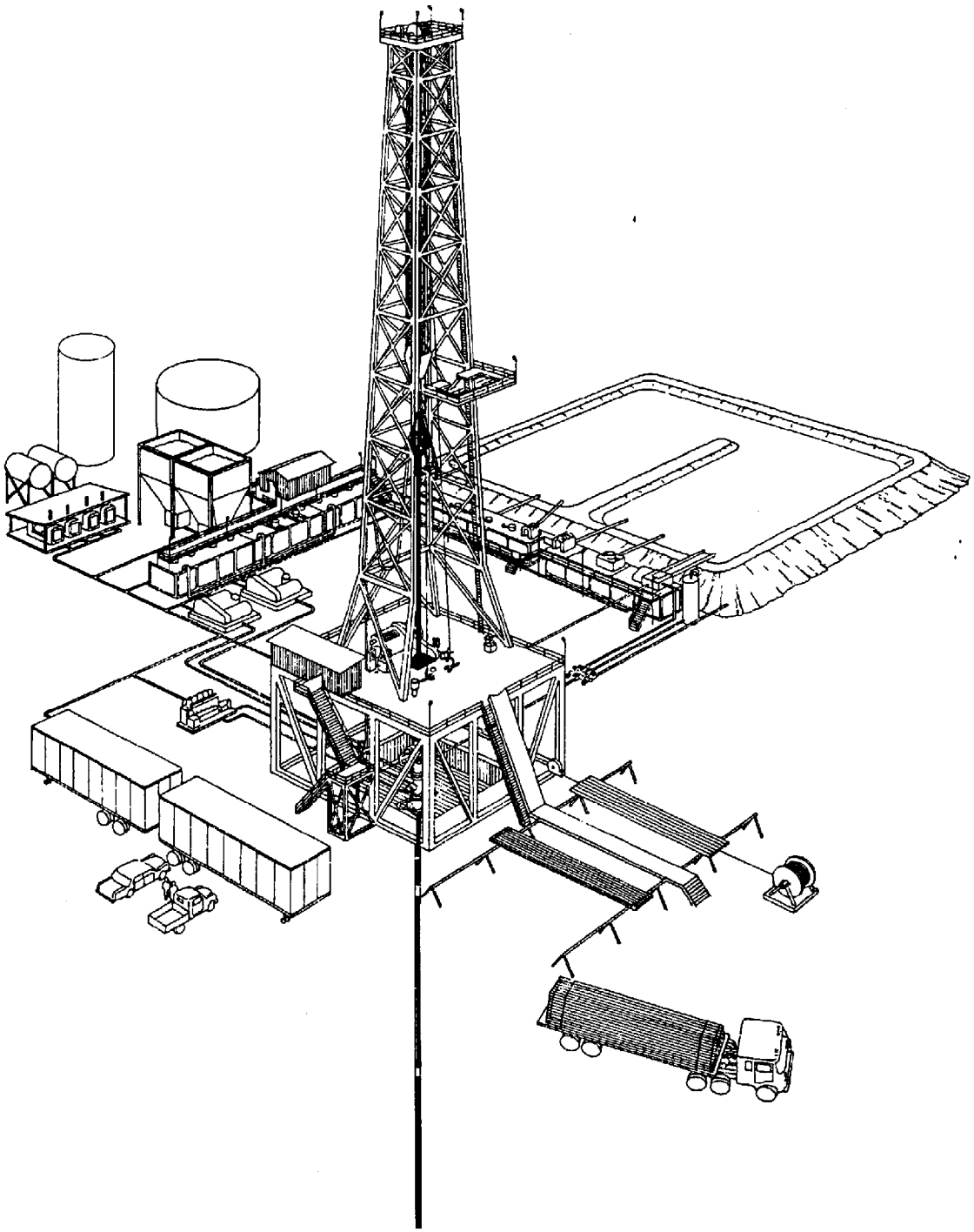

Figure 1.1 Typical Rig Layout

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1.3.1 Power Systems

On a diesel engine rig, the diesel engines are usually located at ground level some distance away from the rig floor. These engines drive large electric generators that in turn, produce electricity that is sent through cables to electric switches and control gears. From here, electricity goes through additional cables to electric motors that are attached directly to the equipment involved in drilling (i.e., draw works, mud pumps, and the rotary) See Figure 1.2.

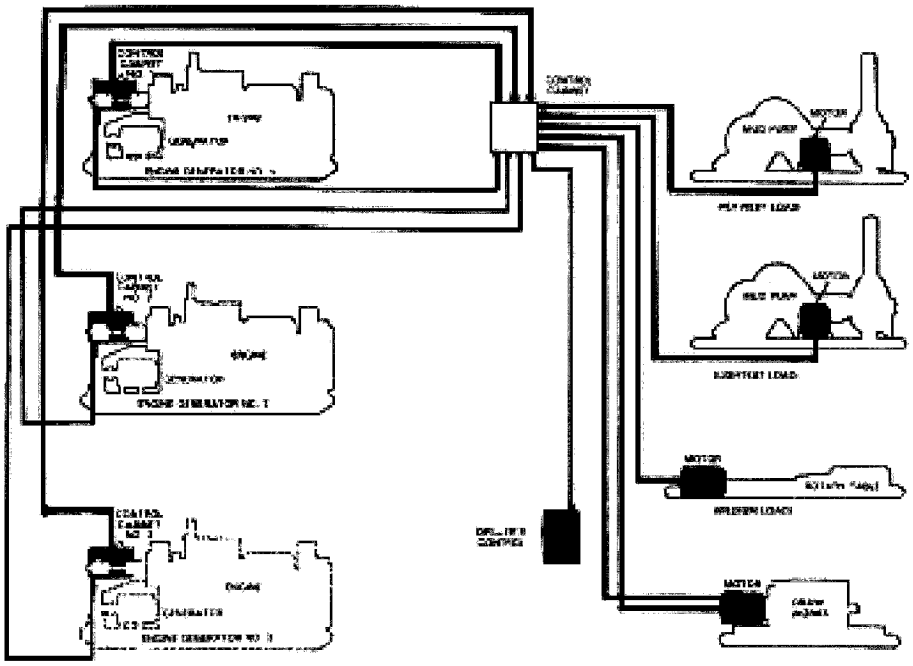

Figure 1.2 Diesel-electric System of Power Transmission of a Rotary Drilling Rig

The diesel-electric system has a number of advantages over the mechanical system. One of the primary advantages is the elimination of the heavy, fairly complicated compound and chain drive, thus eliminating the need for aligning the compound with the engines and draw works. Another advantage is that the engines can be placed away from the rig floor reducing engine noise for the crew.

The layout of a rig is far from standardized; the prime movers, draw works, pumps, and rotary can be arranged in any number of ways, depending on the preference of the drilling contractor. Each contractor has different ideas about layout and arranges the rig accordingly.

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The variations in layout take power demand into consideration. The hoisting system requires the heaviest power supply when drill pipe is being raised or casing being run. The second biggest user of power is the circulating system, though mud pumps may have their own power source or may be driven from an engine along with the rotary, which requires the least amount of power.

1.3.2 Derrick or Mast

One important consideration when starting a job is the derrick or mast to be used. A derrick or mast is the steel structure that supports many feet of drill pipe, often weighing more than 100 tons.

A standard derrick is a structure with four supporting legs resting on a square base. It can be assembled piece-by-piece each time a well is drilled. In contrast, the mast (Figure 1.3) is assembled once when it is manufactured. After manufacture, it remains a single unit each time a well is drilled. When a mast is raised and lowered, it looks something like the blade of a huge jackknife being opened and closed. As a result, masts are sometimes referred to as jackknife masts. For most offshore drilling rigs, the derrick is the standard.

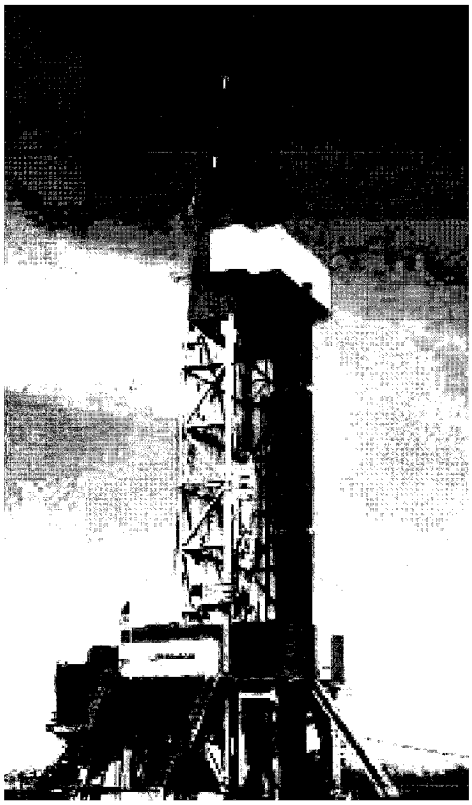

Figure 1.3 Modern Land Drilling Mast

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The mast or derrick is erected on a substructure which serves two main purposes:

- support the rig floor and provide space for equipment and workers, and
- provide space under the rig floor for special BOP valves.

The substructure supports not only the rotary table, but also the full load of the drill string when the string is suspended in the hole by the slips. It also supports a string of casing when casing is being run in the hole by an arrangement of slips resting on the rotary. The rig floor also holds the draw works, driller's control panel, doghouse, and other related equipment.

Derricks and masts are rated according to the vertical load they can carry and the wind velocity they can withstand from the side. Derrick load-bearing capacity figures can vary from 250,000 to 1,500,000 pounds. A typical mast or derrick can withstand winds of about 100 to 150 miles per hour with the racks full of pipe and without the need for external bracing.

Another consideration in the design of the derrick is height. The derrick and its substructure support the weight of the drill string at all times, whether the drill string is suspended from the crown block or resting in the rotary table. The height of a derrick does not affect its load-bearing capacity, but the length of the sections of drill string to be removed from the hole is limited by the height of the derrick. This is because the crown block must be sufficiently elevated above the rig floor to permit the withdrawal and temporary storage of the drill string when it is pulled from the well to change bits or for other reasons.

Drill pipe is pulled and racked in *stands* (Figure 1.4). A stand usually consists of three joints of pipe, each about 30 feet long. Such a stand, having a total length of some 90 feet, can be accommodated in a derrick that is 136 feet high or higher.

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Figure 1.4 Drill Collars and Drill Pipe Stands in the Derrick

1.3.3 Hoisting System

The *draw works*, sometimes called the *hoist*, is a heavy piece of machinery (Figure 1.5) that consists of a revolving drum around which wire cable, called the *drill line*, is spooled or wrapped. It also has a cat-shaft, a kind of axle that crosses through the draw works, that has a revolving drum (called a cat-head) on either end. Several other shafts, clutches, and a chain-and-gear drive facilitates speed and direction changes.

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Figure 1.5 Draw works and Driller's Console on a Rotary Drilling Rig

The origin of the term *draw works* is not known, but probably is related to the fact that part of the function of the draw works is to draw pipe out of the hole. The two main purposes of the draw works are:

- to lift pipe out of the hole, and
- to lower pipe back into the hole.

Wire rope or cable is, reeled or spooled, on a drum in the hoist. When the draw works is engaged, the drum turns and, depending on the direction it turns, either reels in the drill line to raise the traveling block or lets out the line to lower it. Since the drill string is attached to the block by the elevators, the string is thus raised or lowered.

One of the outstanding features of the hoist is a brake system, which enables the driller to easily control a load of thousands of pounds of drill pipe or casing. On most rigs there are at least two brake systems. One brake is mechanical and can bring the entire load to a full stop. The other brake is hydraulic or electric, and can control the speed of the descent of a loaded traveling block, although it is not capable of bringing it to a complete halt.

An integral part of the draw works is a transmission system of speed changes. The transmission system (Figure 1.6) gives the driller leverage in hoisting the pipe. The drum of the hoist can have a minimum of four, and often as many as eight speeds.

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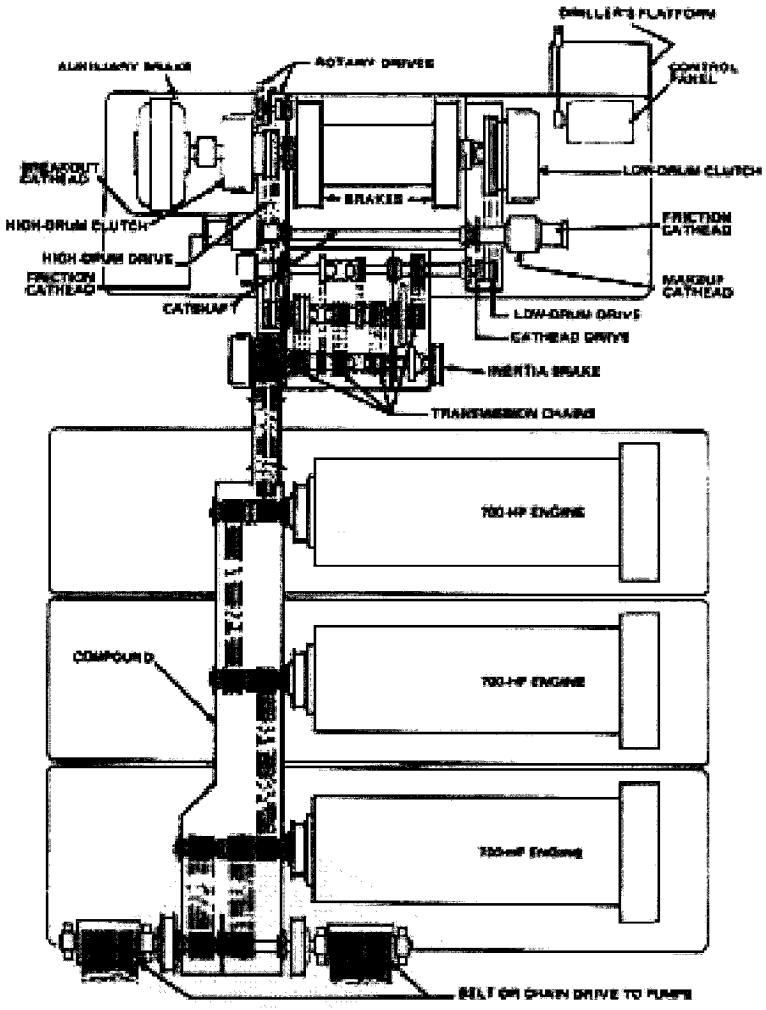

Figure 1.6 Draw Works Transmission

Another feature of the draw works is the cat-shaft with its two special cat-heads. The makeup (spinning) cat-head on the driller's side of the draw works is used to spin up and tighten the drill pipe joints. The other, located opposite the driller's position on the draw works, is the break-out cat-head (Figure 1.7). It is used to loosen the drill pipe when the pipe is withdrawn from the hole. Attached to each cat-head is a spool around which fiber rope (cat-line) can be wrapped and used to lift and move relatively light loads on the rig floor such as drill pipe from the catwalk. On most rigs an air hoist is used for handling light loads. Cat-heads are essential to operations on a rotary rig, but they can be deadly if not used with care and common sense.

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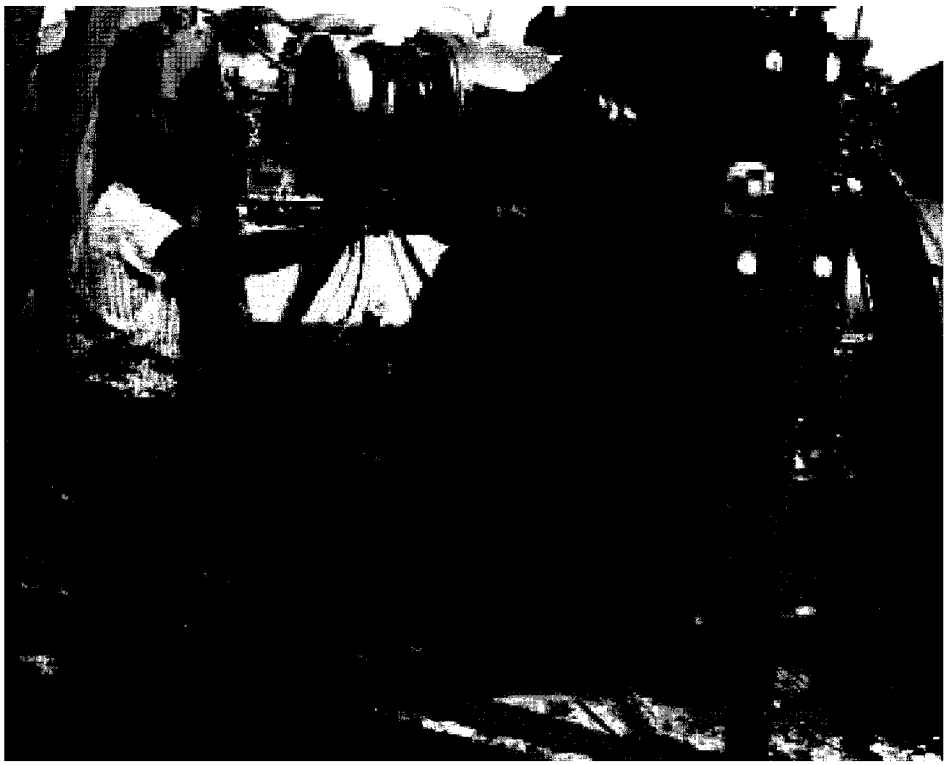

Figure 1.7 Cat-Head

1.3.4 Blocks and Drilling Line

The *traveling block, crown block*, and *drilling line* (Figure 1.8) are the three components whose function is to support the load of drill pipe in the derrick as it is lowered into or pulled from the hole. During drilling operations, this load consists of the hook, swivel, kelly, drill pipe, drill collars, and a bit attached to the bottom of the drill collars. During cementing operations, a string of special pipe called *casing* (often heavier than the drill pipe and drill collars) has to be lowered into the hole and cemented.

As is true of almost every part of the rotary rig, the blocks and drill line must be very strong to be able to bear such heavy loads. Friction must also be eliminated in the blocks while still maintaining the desired strength. Thus, well made bearings and proper lubrication of these bearing by the crew are very important.

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Drill line is usually made of wire rope that generally ranges from $1^1/_2$ inches to $1^3/_4$ inches in diameter. Wire rope is similar to common fiber rope, but wire rope, as the name implies, is made of steel wires and is a fairly complex material. As wire rope manufacturers like to emphasize, a wire rope is in itself a machine in the sense that it requires lubrication. This is because the constant movement of strands within the wire rope rub against one another as the rope flexes over sheaves in the blocks.

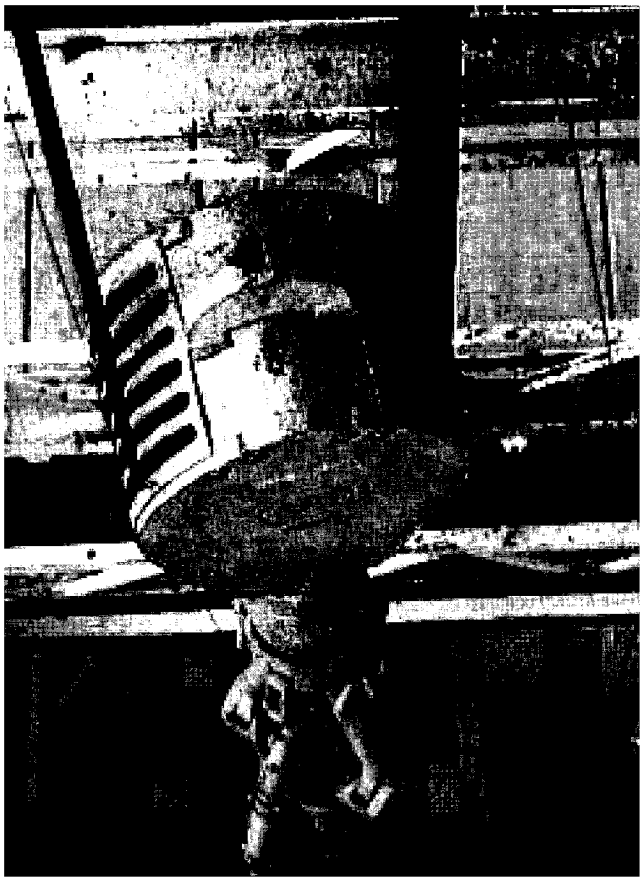

Figure 1.8 Traveling Block, Hook and Kelly

Although wire rope looks very much like cable, it is specially designed for the heavy loads encountered on the rig. To achieve the greatest economy from the use of wire on a drilling rig, the line selected should be in accord with both the load requirements and the design of the sheaves in the traveling block and crown block through which the line must travel. The line should be frequently inspected to ensure that it is in good condition. The drill line should be moved periodically (*slipped* is the field term) so that it wears evenly as it is used. Cut-off procedures should take into account the amount of usage or work done by the wire rope. Wire rope wear is determined by the weight, distance, and movement of wire rope travel over a given point (ton-miles).

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For wire line to be used in drilling operations, it has to first be strung up (Figure 1.9) because it is shipped to the rig wrapped on a large supply spool. The first step in stringing up the drill line is to take the end of the line off the supply reel and raise it to the very top of the derrick, where a large, multiple pulley is installed. The large set of pulleys is called the crown block. The pulleys are called *sheaves* (pronounced "shivs").

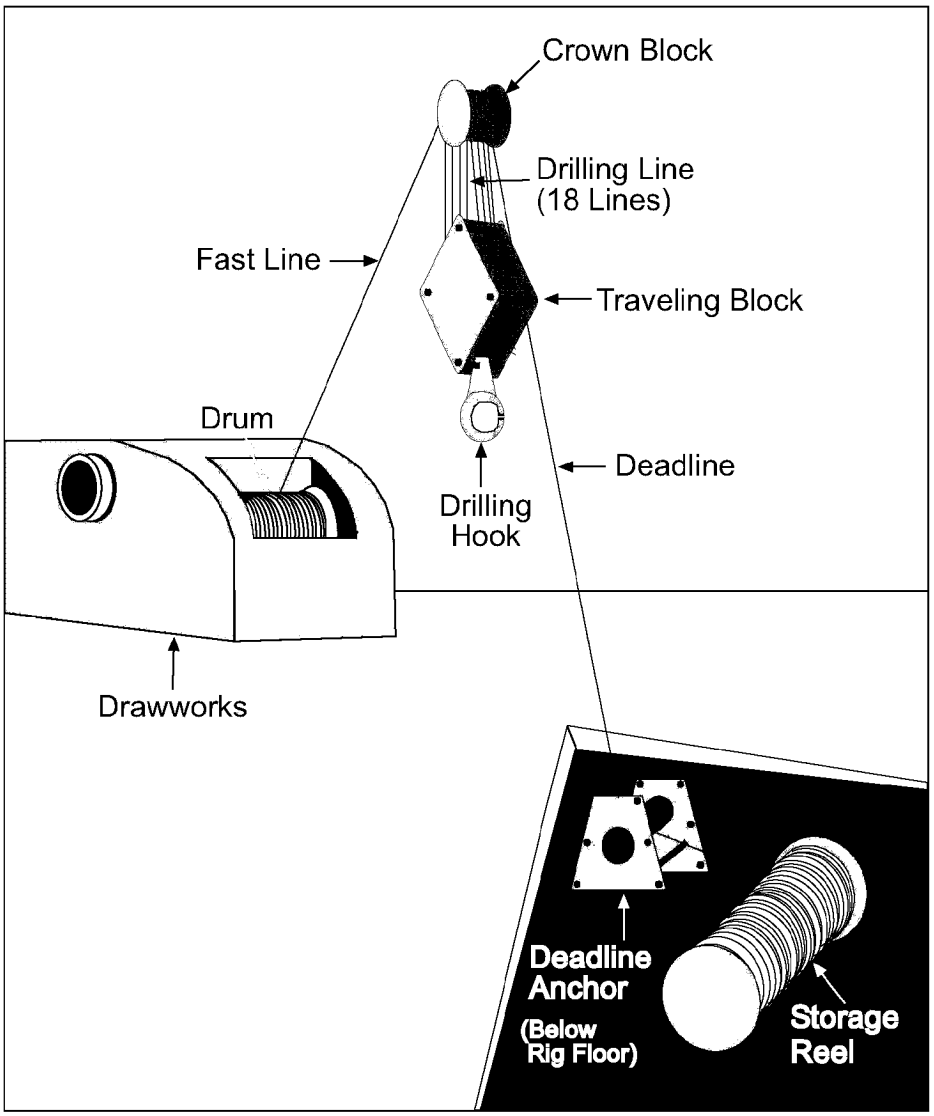

Figure 1.9 A Rotary Drilling Rig Hoisting System

The drill line is threaded over a crown block sheave and lowered down to the rig floor. On the rig floor rests (temporarily) another very large set of pulleys or sheaves called the traveling block. The end of the line is threaded through one of

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the traveling block sheaves and is raised again up to the crown block. There, the line is threaded over a sheave in the crown block, lowered back down, and threaded through the traveling block. This is done a number of times until the correct number of lines has been strung up.

The number of lines is only one of course; but since the drill line is threaded through the crown block and traveling block several times, it has a multiplied effect. The number of lines strung depends on the weight to be supported. The more weight to be supported, the more lines that are needed and vice versa.

Once the last line has been strung over the crown block sheaves, the end of the line is lowered down to the rig floor and attached to the drum on the draw works. Several wraps of line are then taken around the draw works drum. The part of the drill line running out of the draw works up to the crown block is called the *fastline*; "fast" because it moves as the traveling block is raised or lowered on the derrick. The end of the line that runs from the crown block down to the supply reel is then secured. This part of the line is called the *deadline*; "dead" because, once it is secured, it does not move. Mounted on the rig substructure is a device called a deadline anchor. The deadline is firmly clamped to the anchor. Now the traveling block can be raised off the rig floor and into the derrick by taking up line with the draw works. To lower the traveling block, line is let out of the draw works drum.

Crown blocks and traveling blocks usually look smaller than they actually are because of the distance from which they are seen. The sheaves around which the drill line passes are often 5 feet or more in diameter, and the pins upon which the sheaves rotate may be 1 foot or so in diameter. The number of sheaves needed on the crown block is always one more than the number required in the traveling block. For example, a ten line string requires six sheaves in the crown block and five in the traveling block. The extra sheave in the crown block is needed for threading the deadline.

Attachments to the traveling block include a spring to act as a shock absorber and a large hook to which the equipment suspended on the drill string is attached. The hook on the traveling block can be attached to a cylindrical steel bar called a *bail* that supports the swivel. In addition to this bail for the swivel are two other bails, which are used to connect the elevators to the hook. Elevators are a set of clamps that are latched onto the drill pipe to allow the driller to raise or lower the drill string out of or into the hole. The driller lowers the traveling block and the elevators down to a point where the drill crew can latch the elevators onto the drill pipe.

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1.3.5 Rotating Equipment

The rotating equipment consists (from top to bottom) of the swivel, the kelly, the rotary table, the drill string and the bit. The drill string is the assembly of equipment between the swivel and the bit, including the kelly, drill pipe and drill collars (Figure 1.10). The term *drill string* simply refers to the drill pipe and drill collars, however in the oil field, drill string often means the whole works.

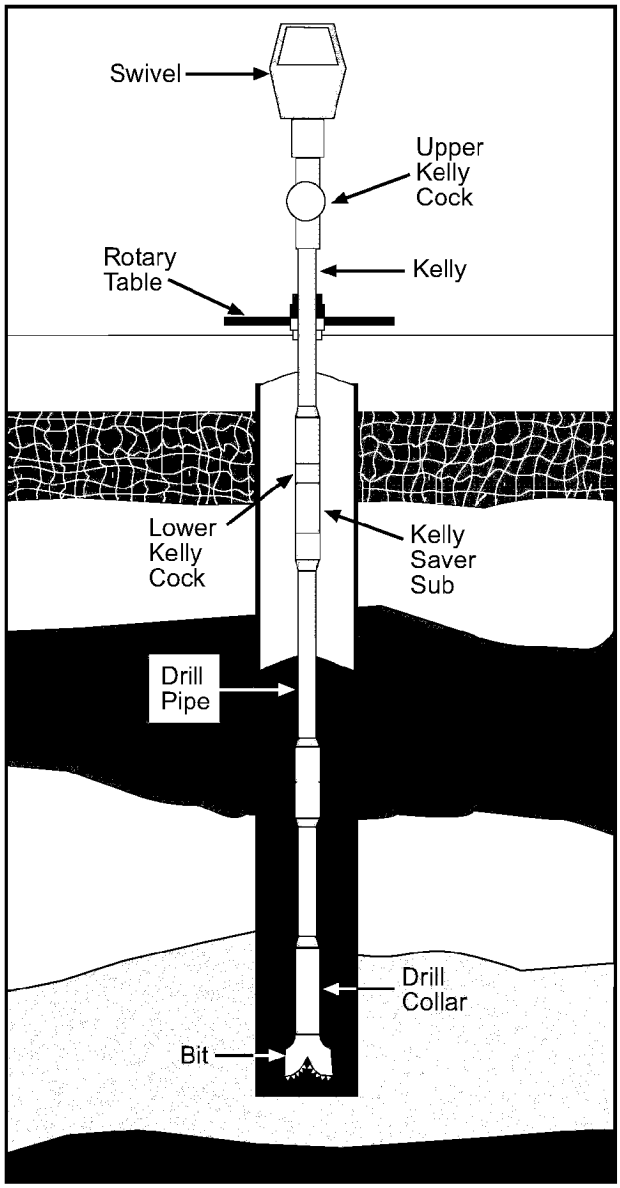

Figure 1.10 The Drill String

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Swivel. The *swivel* is attached to the traveling block by a large bail (Figure 1.11). This remarkable mechanical device has three main functions:

- support the weight of the drill string,
- allow the drill string to rotate; and
- provide a pressure-tight seal and passageway for the drilling fluid to be pumped down the inside of the drill string.

The drilling fluid is under extreme pressure sometimes exceeding 4,500 pounds per square inch (psi). The fluid comes in through the gooseneck, a curved pipe that connects the swivel to a hose (kelly hose) carrying the drilling fluid from the mud pumps. The fluid then passes through the wash pipe, a vertical tube in the center of the swivel body, and into the kelly and drill string.

Figure 1.11 The Swivel, Attached to the Upper End of the Kelly

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Kelly and Rotary Table. The *kelly* is a 3-, 4-, or 6-sided length of pipe, about 50 feet long, that is the upper part of the drill string. It serves as a passageway for the drilling fluid on its way into the hole and transmits the rotary movement to the drill pipe and bit.

An upper kelly cock (Figure 1.12) is a special valve that can often be recognized as a bulge on the upper part of the kelly. The kelly cock can be closed to shut off well pressure coming up from inside the drill string. Most kelly cocks require a special wrench to operate the closing valve.

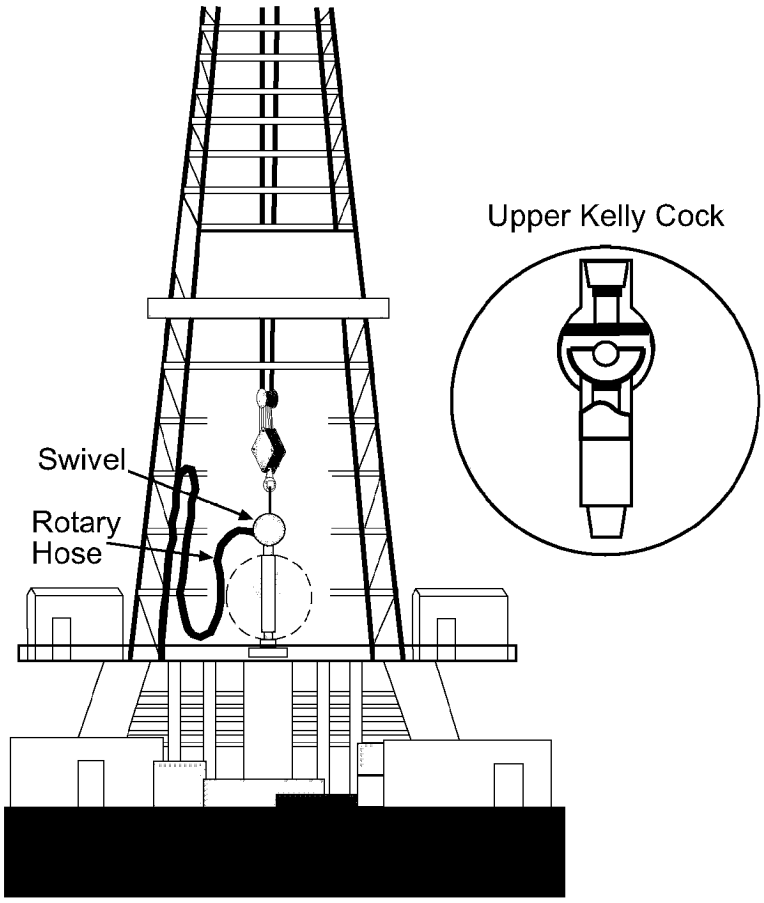

Figure 1.12 Upper Kelly Cock

A lower kelly cock (also called a drill pipe safety valve or a drill string valve) is usually made up between the lower end of the kelly and the top joint of drill pipe. When the kelly is pulled up high above the rotary table, as it usually is when a joint of pipe is being added to the drill string (i.e., when a connection is being made), the upper kelly cock cannot be easily reached should it be necessary to close in the drill string. However, the lower kelly cock is readily accessible when the kelly is raised.

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The kelly's upper end is connected to the swivel, and its lower end is connected to the drill pipe. The drill pipe screws into a device called a *kelly saver sub*, or a saver sub. The sub is a short, connecting fitting that screws into the bottom of the kelly. The bottom threads on the sub are temporarily joined with threads on the top of each length of drill pipe that is added to the string. The sub saves wear on the threads of the kelly. When the threads of the sub become worn, the sub is replaced and rethreaded.

The kelly fits into a corresponding square or hexagonal opening in a device called a *kelly bushing*, or drive bushing (Figure 1.13). The kelly bushing fits into a part of the rotary table called the master or *rotary bushing*. As the rotary bushing rotates, the kelly rotates, and as the kelly rotates so do the drill string and bit.

Figure 1.13 The Rotary Table and Kelly Drive Bushing

Rotary drilling derives its name from the rotary table. The rotary table is powered by the compound or by its own electric motor. The rotary table also accommodates the *slips*, a tapered device lined with strong teeth-like gripping elements that hold the drill pipe suspended in the hole when the kelly is disconnected.

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Top Drive System. The top drive system is replacing the kelly and rotary table on many rigs. This one piece of equipment replaces both the kelly and rotary table. It has another advantage in that it can rotate the drill string while pulling it upwards. Another advantage is that it requires fewer personnel to operate when making a connection.

The mud flow through the top drive is basically the same as with the older rotary system. See Figure 1.14 and Figure 1.15.

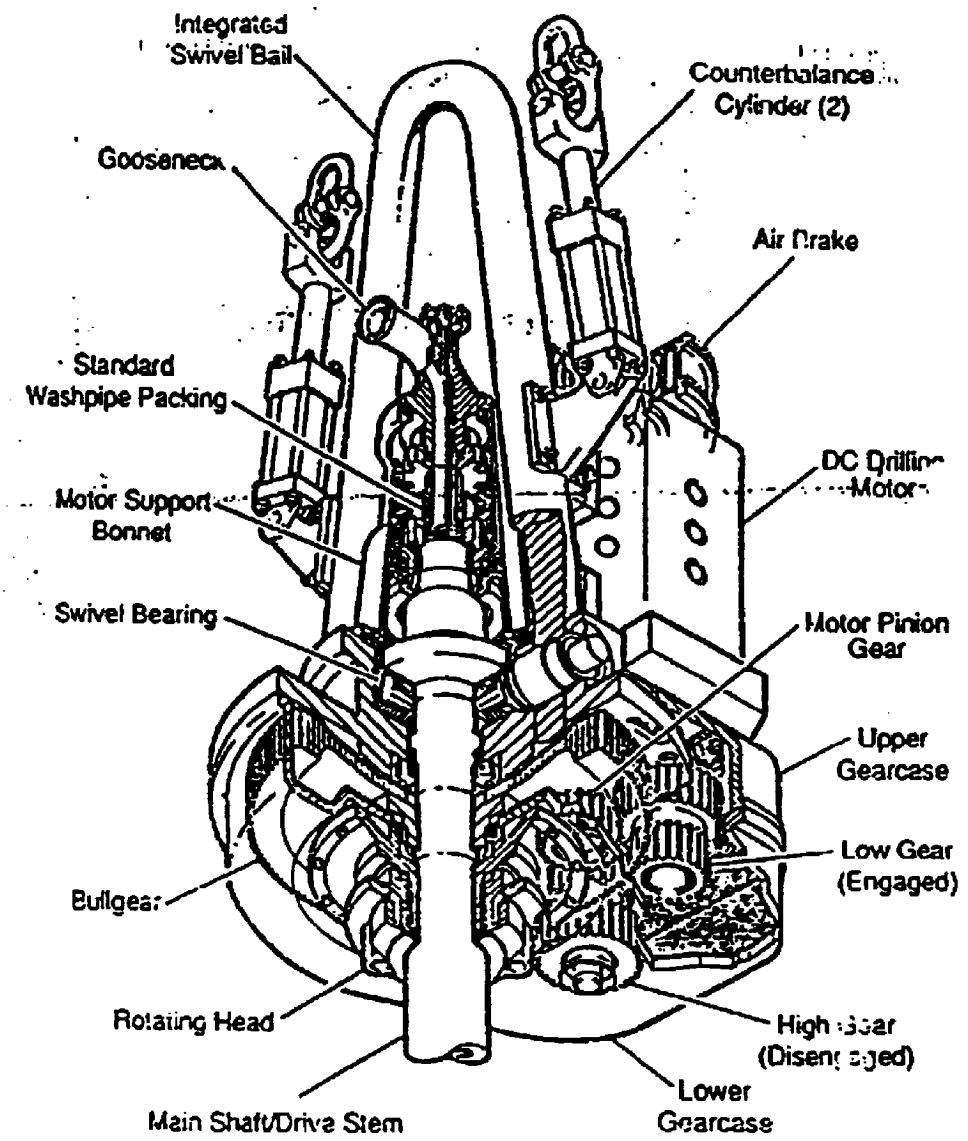

Figure 1.14 Top Drive Motor and Swivel Housing Assembly

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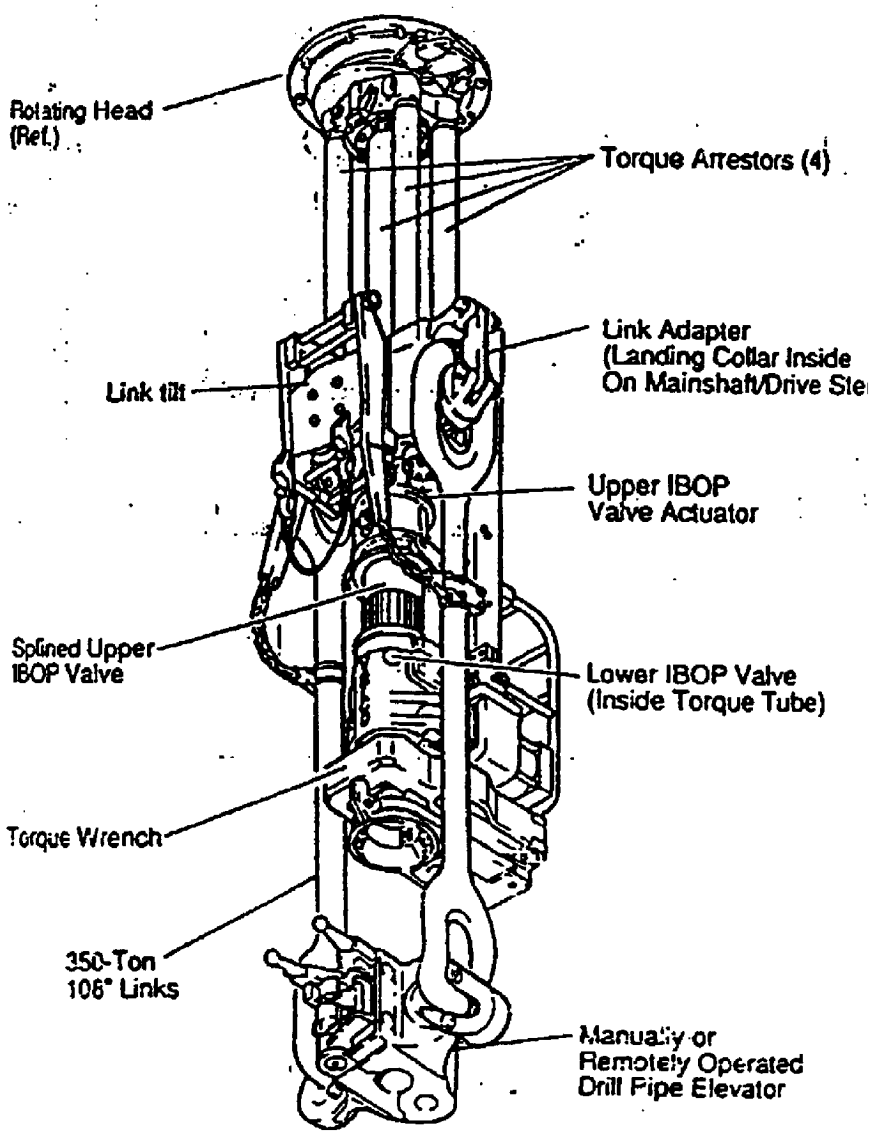

Figure 1.15 Top Drive Pipehandler Assembly

Drill String. The drill string (Figure 1.16) is made up of the drill pipe and special, heavy-walled pipe called *drill collars*. Each length of drill pipe is about 30 feet long and is called a *joint* of pipe. Each end of each joint is threaded. The end of the joint with the interior threads is known as the *box*, and the end of the joint with the exterior threads is called the *pin*. When pipe is made up, the pin is stabbed into the box and the connection tightened. The threaded ends of the pipe are called *tool joints* and are actually separate parts that are welded onto the ends of the drill pipe by the manufacturer who cuts the threads to industry specifications.

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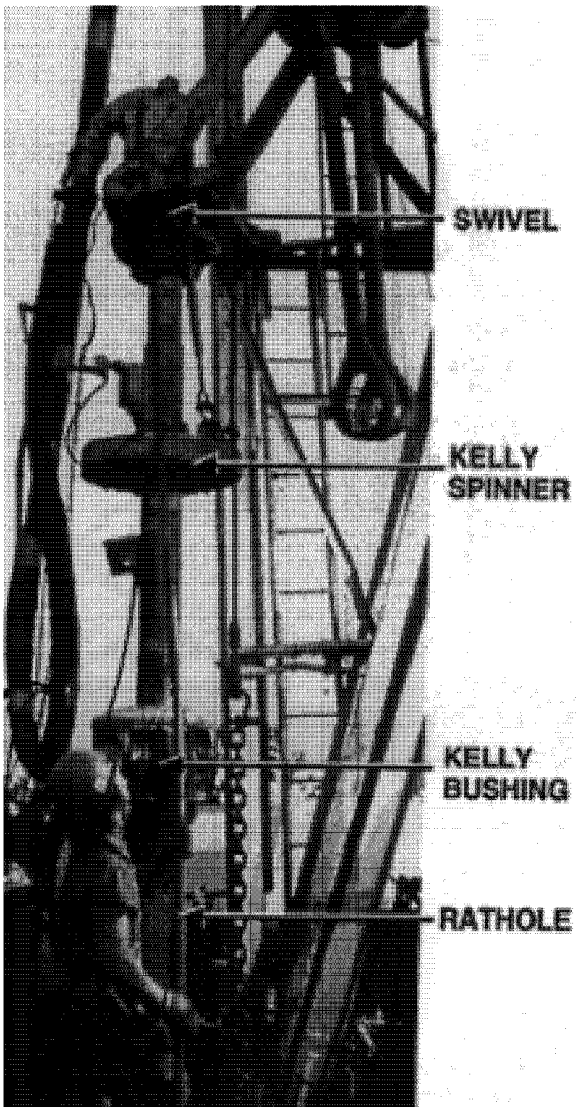

Figure 1.16 Kelly, Kelly Drive Bushing, and Drill Pipe in the Derrick

Drill collars, like drill pipe, are steel tubes through which mud is pumped. Drill collars are heavier than drill pipe and are used on the bottom of the drill string to put weight on the bit. This weight presses down on the bit to make it drill. Drill collars are about 30 feet long and, unlike the drill pipe that has tool joints welded on, they have the boxes and pins cut into them (Figure 1.17).

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Figure 1.17 Drill Collar (right) and Drill Pipe (left)

Bits. Three main types of bits have been developed through the years for efficient drilling. *Roller cone* or *rock bits* have cone-shaped steel devices called cones that turn freely as the bit rotates. Most 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. The teeth are responsible for actually cutting or gouging out the formation as the bit is rotated. All bits have passages drilled through them to permit drilling fluid to exit. Most bits have nozzles that direct a high-velocity stream or jet of drilling fluid to the sides and bottom of each cone so that rock cuttings are swept out of the way as the bit drills. Figure 1.18 show two examples of roller cone bits.

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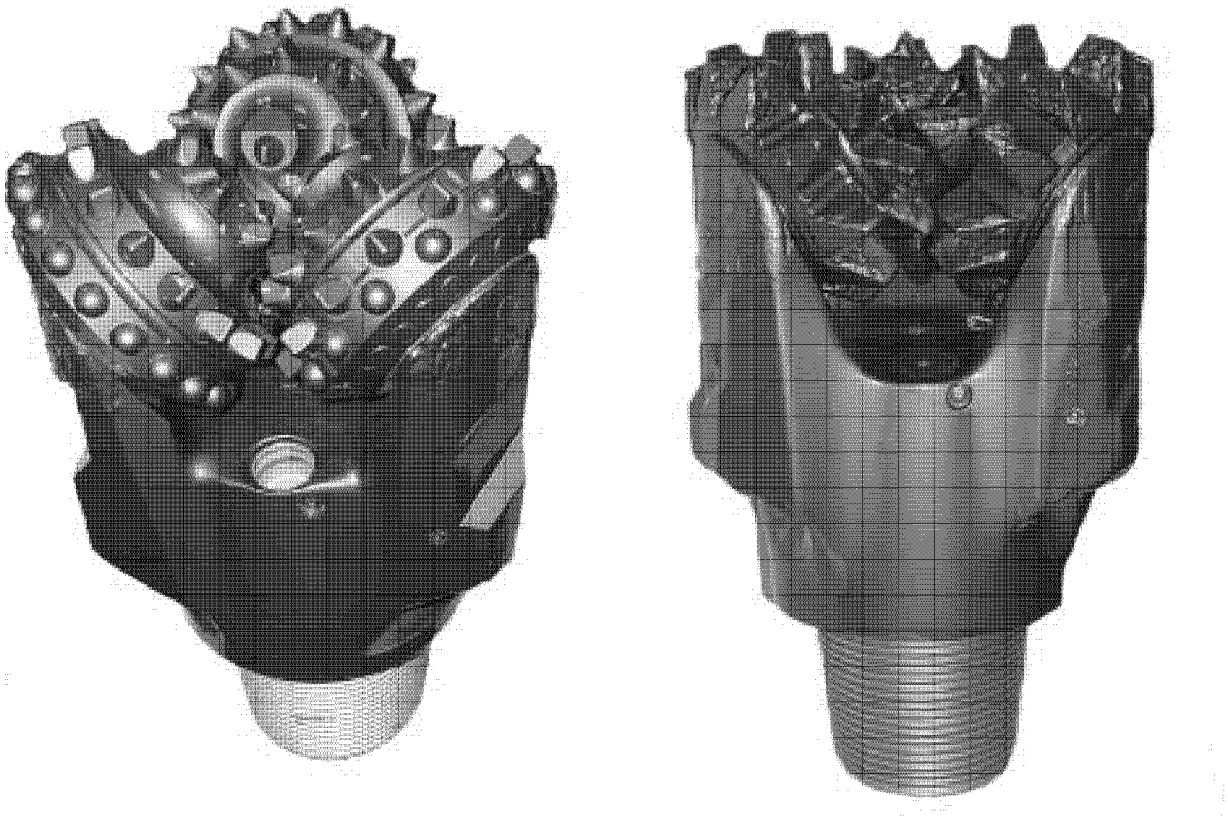

Figure 1.18 Roller Cone Bottom Bit (Left) and Rock Bit (Right)

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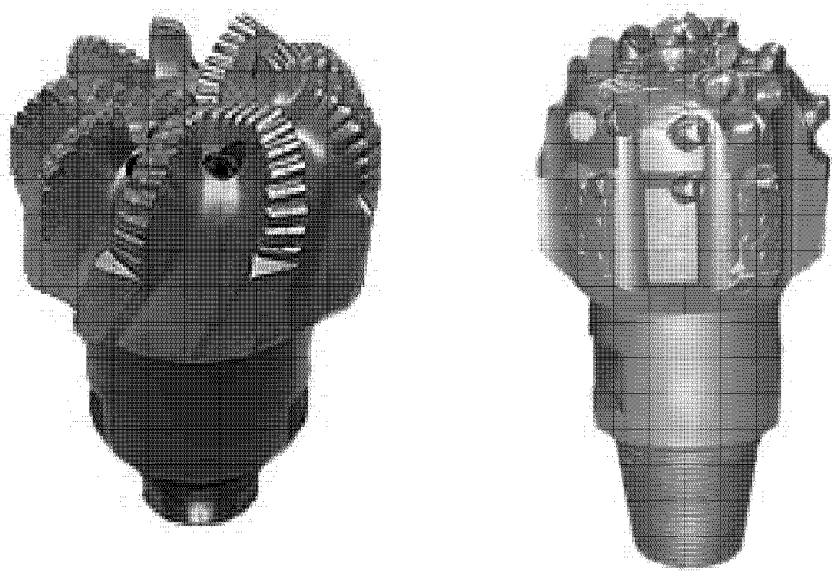

Figure 1.19 PDC Bits

Polycrystalline Diamond Compact (PDC) bits do not have cones; they have tungsten carbide teeth (Figure 1.19). *Diamond bits* do not have cones, nor do they have teeth. Instead, several hundred diamonds are embedded into the bottom and sides of the bit. Because diamonds are hard, diamond bits are especially suited for drilling hard formations, but they can also be very effective on soft formations. Figure 1.20 shows a cross-section of a diamond bit.

Finally, Figure 1.21 shows an example of a *core bit*.

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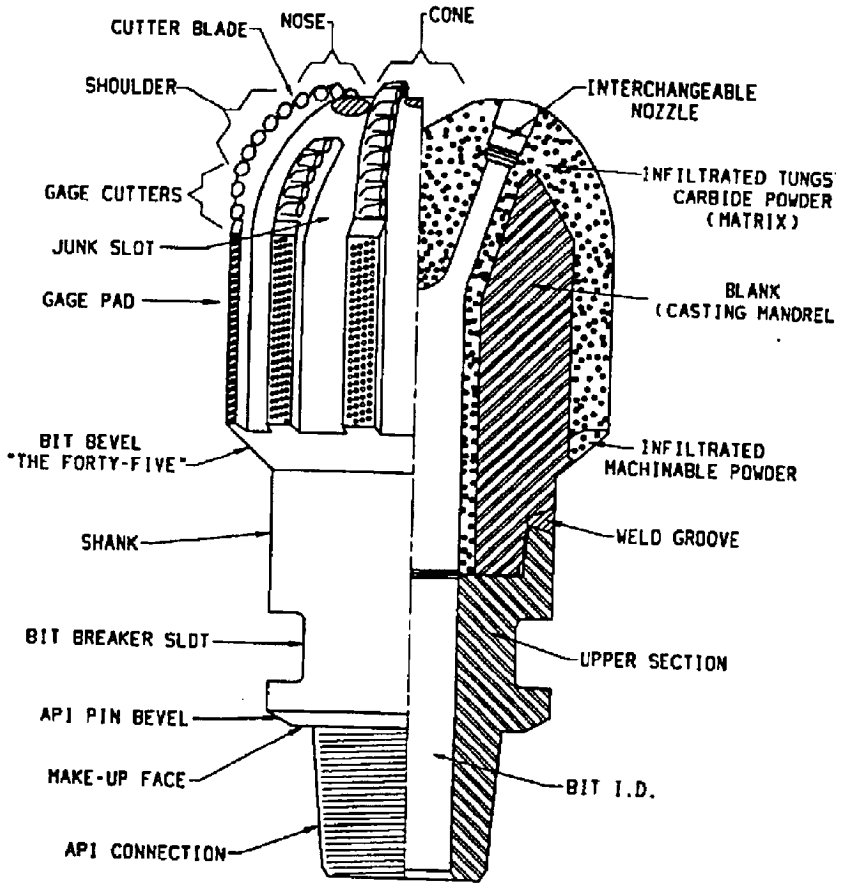

Figure 1.20 Polycrystalline Diamond Compact Bit and Diamond Bit

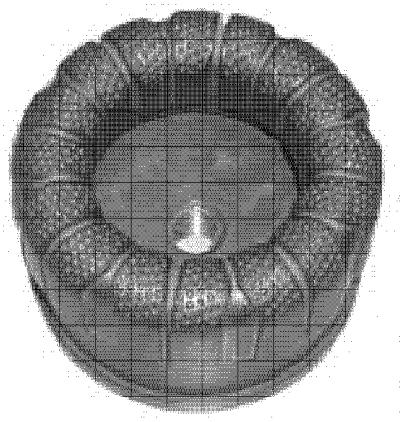

Figure 1.21 Core Bit

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1.3.6 Circulating Systems

Rotary drilling has two important features:

- a drill string rotates to turn the bit, and
- drilling fluid is circulated or pumped down the drill string, out through the bit, and back up the annulus to the surface (Figure 1.22).

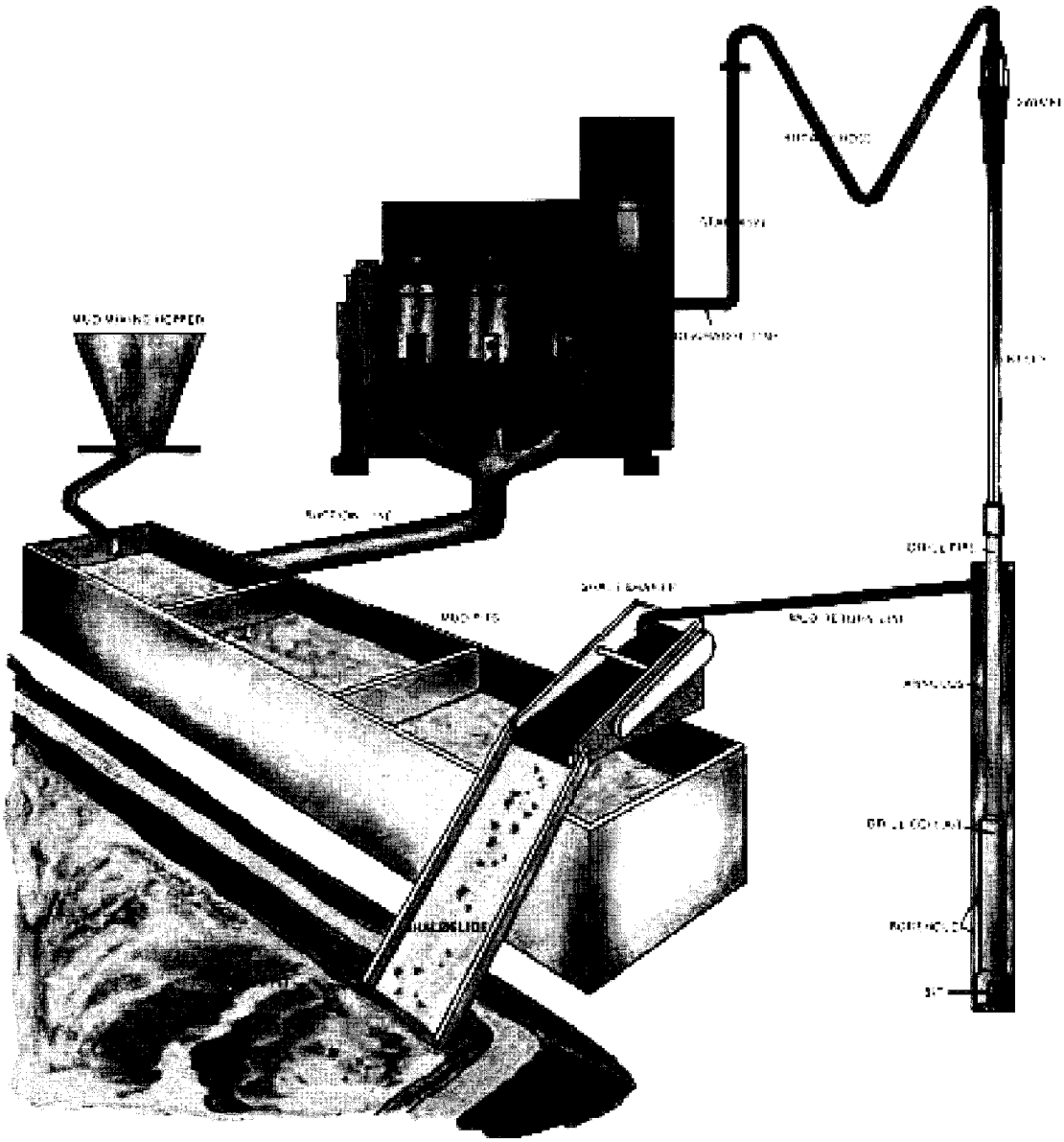

Figure 1.22 Systems for Fluid Circulation and Mud Treatment on a Rotary Drilling Rig

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Drilling fluid may be either liquid or gas. A liquid such as water is a fluid that cannot be compressed. A gas on the other hand, such as air or natural gas, CAN be compressed. The main purposes of circulation are:

- transport cuttings to the surface,
- clean the bottom of the hole,
- cool and lubricate the bit and drill string,
- support the walls of the wellbore, and
- prevent formation fluids from entering the well.

Other purposes of circulation are to make it possible to detect gas, oil, or water that may enter the drilling fluid from a formation being drilled; to get information necessary for evaluating producing zones (from cuttings, cores, or electric logs); and to transmit hydraulic power to the bit. In addition, drilling fluid is sometimes used to drive a mud motor that has been placed at the bottom of the drill string. In this case, the drilling fluid provides power to the motor so that the bit turns without engaging the rotary table. Compressed air used in air drilling, can also power a hammer drill, a downhole device that combines rotary motion with a pounding action.

Drilling Fluid. The circulation fluid is usually a liquid, but can also be air or gas. If the circulating, or drilling fluid is a liquid, it is made up mostly of water, although occasionally oil is the major component. Both types of drilling fluids are called *muds*, or *drilling muds*, because that is what they appear to be. However, some drilling muds are more than just muds. Special chemical additives and weighting materials may be mixed in to achieve a purpose or the greatest efficiency. Special clays are used to give body to the mud, and *barite* (a heavy mineral) is added to increase the density of the mud. Chemicals are used to control the thickness or viscosity of the mud, and to improve the ability of the solid particles in the mud to deposit a layer, or cake, on the wall of the hole.

In perhaps 1% of all wells drilled, compressed air or natural gas is used as the circulating fluid instead of mud. Conditions are usually such that air drilling, although a very efficient drilling method, cannot be used. Circulating with a liquid is less efficient but offers the advantages of hydraulic lift (such as its ability to lift cuttings made by the bit), counterbalance formation pressure as depth increases, and so on.

Mud Pits and Pumps. Mud is mixed in mud pits (sometimes called mud tanks) with the help of a mud hopper into which most of the dry ingredients for the mud is poured. These tanks contain agitators (paddle-like projections) that mix the mud. The mud is mixed with either oil or water, depending on the mud properties needed.

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The mud pump (Figure 1.23) is the primary component of any fluid circulating system. Pumps are either powered by electric motors attached directly to them, or driven by the compound. The pumps for rotary drilling rigs are capable of moving large volumes of fluid at very high pressures. When circulating with air or gas, the pump is replaced by compressors and mud pits are not required.

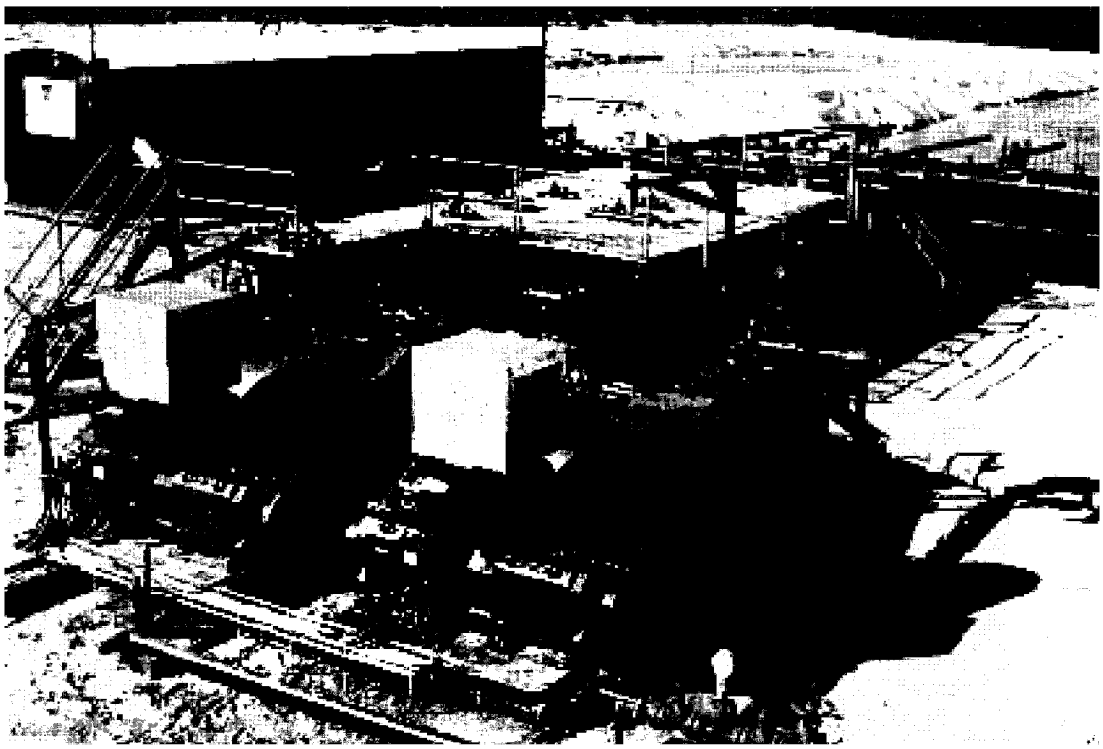

Figure 1.23 Triplex Mud Pump

Functions of Drilling Fluids

Fluid in the circulating system of a rotary drilling rig transports bit cuttings to the surface, cleans the bottom of the hole, cools the bit, and lubricates the drill string, supports the walls of the wellbore, and prevents entry of formation fluids into the well.

Transporting Cuttings to the Surface. Liquid, air or gas in circulation moves rock chips, sand, or shale particles out of a well as it moves up the annulus. For a liquid, the annular velocity, or speed, is usually from 100 to 300 feet-per-minute (ft/min) in order to keep the hole clean. Circulation of 3,000 ft/min is considered ample velocity in the annulus for cleaning with gas or air. The solids in mud are separated at the surface by screening, settling, centrifugal action, chemical flocculation, or a combination of methods. Solids brought up by air or gas in air drilling are blown as dust or fine chips to a waste pit.

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The viscosity of a drilling fluid is its resistance to flow. A Marsh funnel is generally used to measure viscosity on a rig. The timed rate of flow obtained usually correlates with true viscosity. Funnel viscosity may be from 30 to 40 seconds-per-quart (s/qt) for low solids muds, from 40 to 50 for high solids muds, and above 50 s/ft for high-density muds. Regardless of whether or not the mud is weighted, viscosity is needed to clean the hole adequately.

Mud must have the proper viscosity and gel strength to lift cuttings and to keep them in suspension both during circulation and during the time circulation is stopped. Gel strength is the ability of a mud to keep cuttings from slowly settling when the mud is not in motion. It can be observed from the way the mud flows and stiffens in ditches and pits. When circulation is begun again after having been stopped, the mud should again liquefy.

Cleaning the Bottom of the Hole. A bit must have a clean surface on which to work when making hole, whether it is crushing or shearing the formation. If chips or cuttings are not swept away as they are cut, the bit bogs down, and eventually the drill string cannot turn. For the bit to regrind loose chips in the bottom of the hole is effort wasted, reducing the power available for making hole. The usual method for cleaning the hole is by circulation of fluids through jet nozzles in the bit. High-velocity streams of fluid blast the bottom of the hole, creating a turbulence that moves the chips from the face of the formation as fast as they are formed (Figure 1.24). In drilling with air or gas, the pressure and volume applied to bring the cuttings to the surface are normally more than enough to clean the bottom of the hole.

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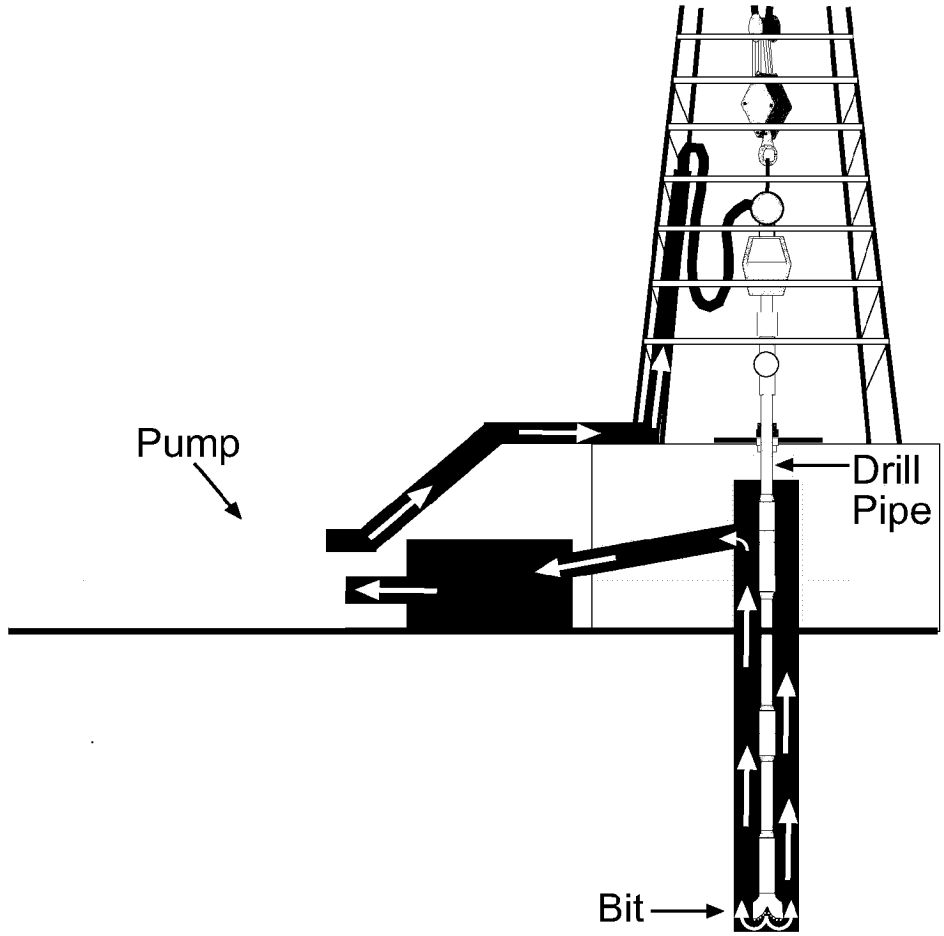

Figure 1.24 Cleaning the Bottom of the Hole

At the surface, the cuttings must be separated and removed so that the fluid pumped back to the bit is clean. In addition, the system should be designed so that a large volume of liquid under high pressure can reach the bit. The proper combination of pump, drill string, nozzles, and hole diameter makes it possible for 50% to 60% of the fluid pressure generated by the pumps to reach the bit nozzles and clean the bottom of the hole.

Cooling the Bit and Lubricating the Drill String. The bit is forced against the bottom of the hole quite heavily at times. For example, weight on an $8^1/_2$-inch bit sometimes exceeds 60,000 pounds (about the weight of a railroad freight car). A larger diameter bit may require twice that amount. The bit may be rotated at a speed of 50 to 200 revolutions-per-minute (rpm). This combination of weight and speed creates heat due to friction in the bit bearings and abrasion of the formation against the teeth or blades.

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Unless a bit is well cooled, it overheats and quickly wears out. Fluid circulated around the parts of the bit removes the heat (Figure 1.25 and Figure 1.26). Oily substances in the drilling fluid can reduce friction in the bit bearings and act as a lubricant between the drill string and the walls of the hole. Oil-emulsion muds and oil muds are especially helpful in this way. Air or gas circulation is very efficient for cooling because air or gas expands as it leaves the bit nozzles and produces a cooling effect. For this reason, and because air contains no significant foreign material, wear on the bit bearing is much less with air circulation than with mud circulation.

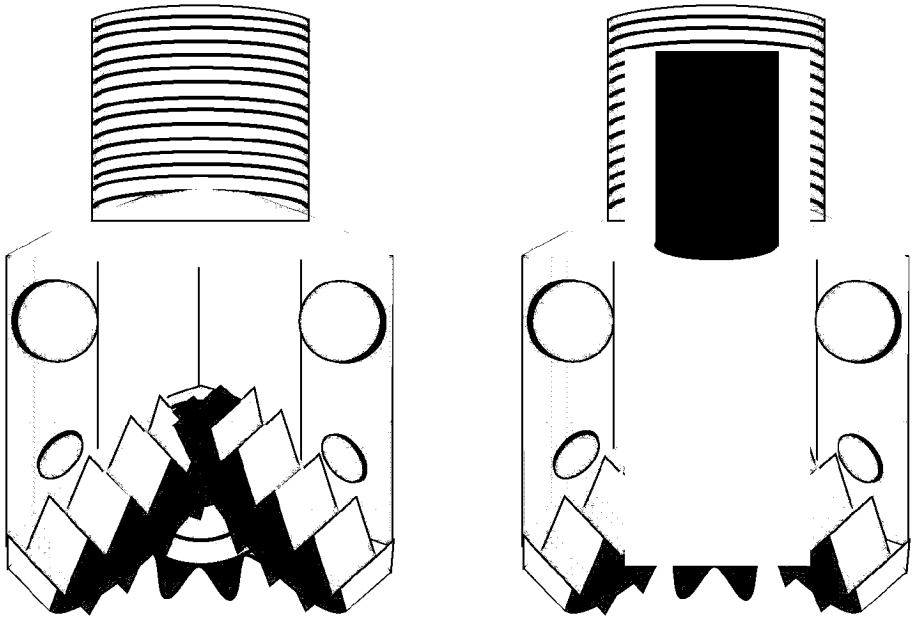

Figure 1.25 Watercourses in a Roller Cone Bit

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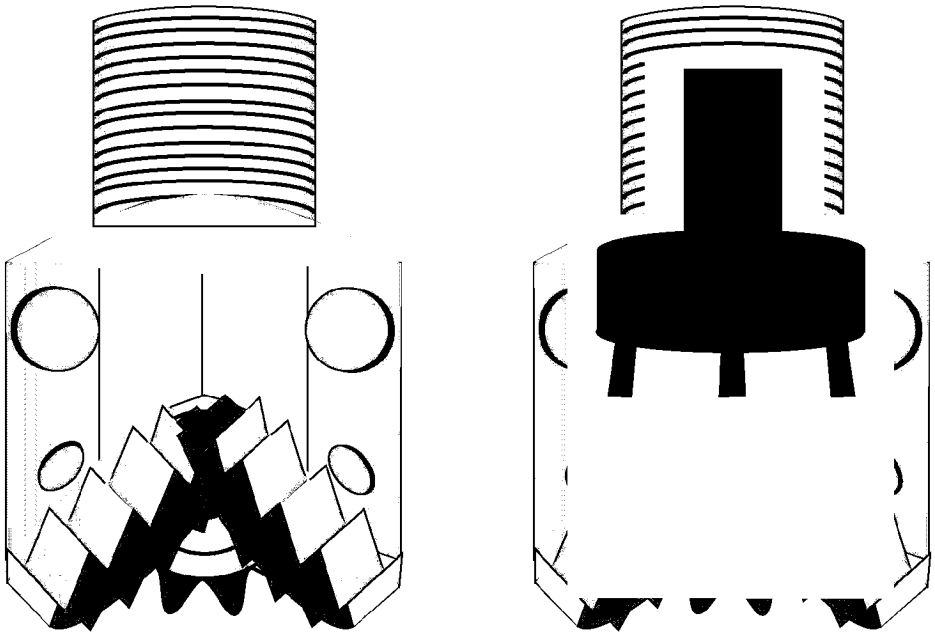

Figure 1.26 Jet Nozzles in a Roller Cone Bit

Supporting the Walls of the Well. A drilling fluid with the proper characteristics can support a formation that might otherwise cave in. This type of drilling fluid, or mud, plasters the walls of a well like mortar. Furthermore, the hydrostatic pressure created by the weight of the fluid column in the hole pushes against the plastered wall to support unconsolidated or loose formations that might fall or slough into the hole (Figure 1.27). Hard rock formations have little tendency to slough and can therefore be drilled with air, gas or water instead of mud.

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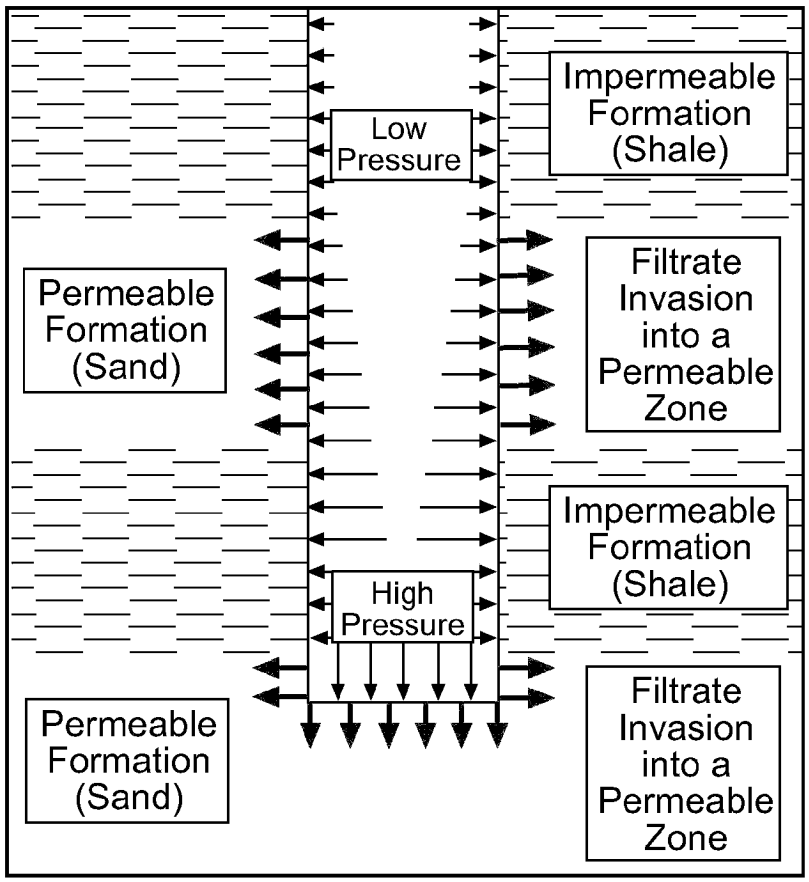

Figure 1.27 Hydrostatic Pressure on the Sides and Bottom of the Hole

Hydrostatic pressure is the force exerted on adjacent bodies by a liquid that is standing still. In a well, the hydrostatic pressure of the drilling fluid is determined by the unit weight or density of the fluid and the height of the fluid column. An increase in the hydrostatic pressure at any depth can be obtained by increasing the density of the fluid, usually accomplished with mud by adding barite. Barite is a mineral that is 4.2 times as dense as water.

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The weight of drilling mud is measured by means of a mud balance. *Mud weight* is commonly expressed in terms of pounds-per-gallon (ppg) or pounds-per-cubic foot (pcf or lb/ft^3). A 10.0 ppg mud exerts about 0.5 psi per foot of depth. Hydrostatic pressure (psi) can be calculated using either of the following equations:

- True Vertical Depth (ft) × mud weight (ppg) × 0.052, or
- True Vertical Depth (ft) × mud weight (pcf) × 0.00695.

Filter cake, (Figure 1.28) the plaster-like coating formed from mud solids on the walls of a well, has the ability to seal the wellbore and prevent the loss of whole fluid. The force of the hydrostatic pressure squeezes the liquid part of the mud (the filtrate) into the permeable zones (such as sand), and the solid material is left behind as a filter cake.

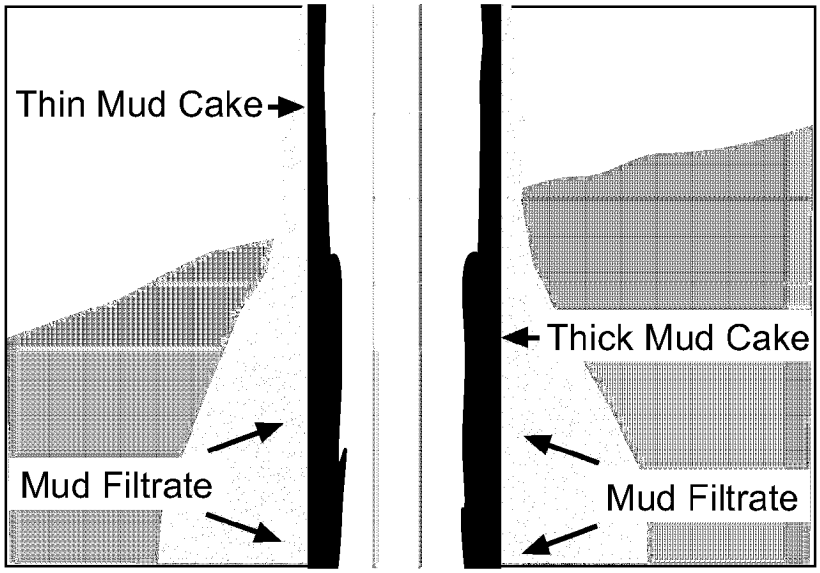

Figure 1.28 Filter Cake

This filtration slows to a very low rate when a good filter cake has been formed on the walls of the well. A good filter cake is thin, slick, and impermeable. Finely grounded clays or other substances are added to drilling mud to improve its wall-building quality, its ability to form a filter cake. Using a filter press to measure the amount of filtrate that passes through a filter paper at 100 psi helps to indicate the wall-building quality of that mud.

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Certain difficulties may arise if the fluid loss of a mud becomes excessive. First, the filter cake may become thick enough to reduce the diameter of the hole, causing tight places in the hole that may stick the drill string. Second, muds with a high fluid loss may in some instances cause sloughing and caving of a shale formation. Third, filtrate entering the productive zone may reduce the rate of oil flow after completion.

Preventing Entry of Formation Fluids into the Well. The pressures of gas, oil, or water in formations penetrated by the bit may exceed the hydrostatic pressure of the fluid column in a well. If this happens, formation fluid will enter the well (take a *kick*). To kill a kick, the blowout preventers (BOPs) are closed to hold back-pressure on the column at the surface. Then, heavier mud is circulated down the wellbore in order to produce additional hydrostatic pressure at the bottom of the hole to overcome the formation pressure.

Water or mud produces sufficient hydrostatic head to overcome formation pressures usually encountered. The addition of weighting material to mud in a well can make a mud dense enough to hold back almost any formation pressure. When formation pressures are expected to be high, a high mud weight is needed, so the pits and other equipment should be arranged to handle the heavier mud. A mud weight of 16 to 18 ppg is considered heavy.

1.3.7 Blowout Prevention Systems

The final major rig system is the blowout prevention system consisting of a blowout preventer stack, a choke manifold system, connecting choke and kill lines and valves, a mud/gas separator and a accumulator unit. The system works in harmony with the rotating and circulating systems to help control the formation pressures and allow safe drilling operations. See Figure 1.29, and Figure 1.30.

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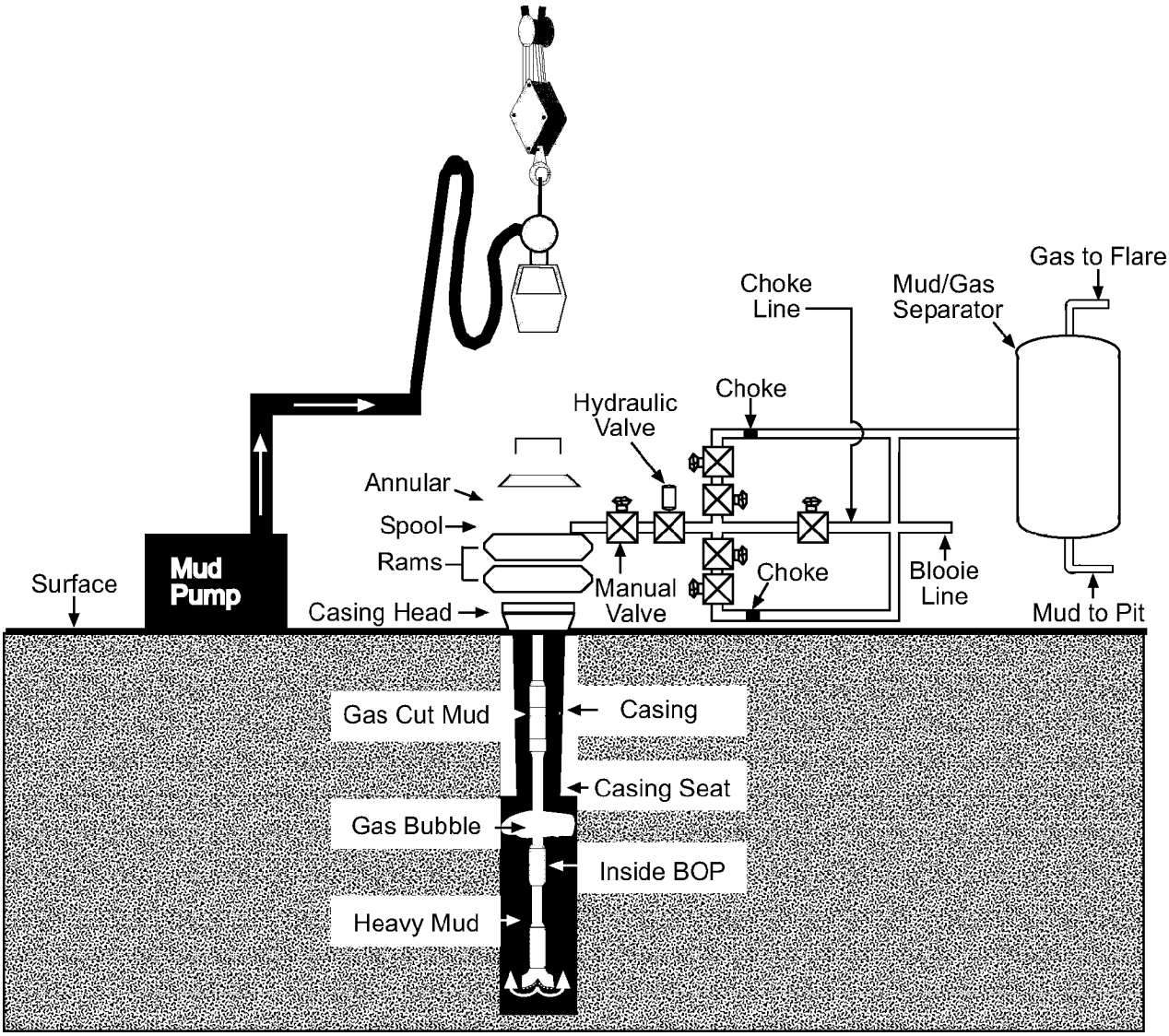

Figure 1.29 Surface Pressure Control System

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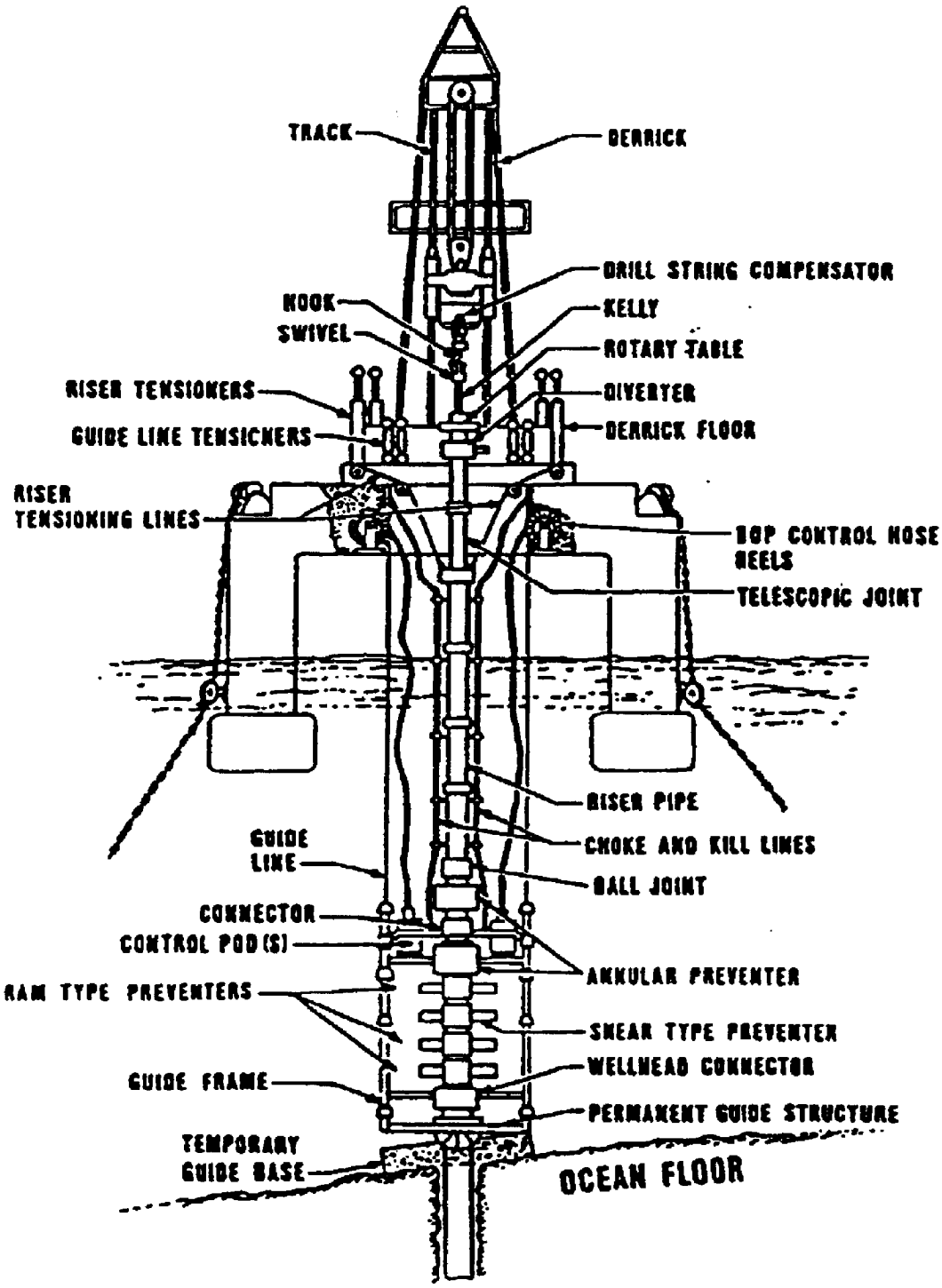

Figure 1.30 Subsea Pressure Control System

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The system is operated by hydraulic pressure that is supplied by the *accumulator* unit. This "accumulator" stores nitrogen gas and hydraulic fluid under pressure in storage bottles. A manifold system routs the fluid to the open and close ports of each blowout preventer and hydraulic valve in the stack. A panel on the drill floor contains operating controls to open and close each part of the stack. A separate system operates the hydraulic chokes and valves on the choke manifold.

The preventer stack is located on the substructure below the rig floor or on the wellhead on the sea floor. The stack is flanged and bolted to the casing head. The casing, casing head, and all parts of the preventer stack should be able to withstand anticipated well pressures of up to 15,000 psi or higher.

During normal drilling, the mud is pumped into the well bore via the drill string. The mud is weighted with materials that can be used to exert a hydrostatic pressure. For each foot of true vertical depth, a given pressure can be calculated. The mud weight is balanced to provide a slightly greater pressure than the formation pressure being drilled. When the formation pressure increases and exceeds the hydrostatic pressure of the mud, a "kick" can occur. This kick is usually a gas bubble that enters the well bore and rises to the surface. The "kick" must be controlled or a *blowout* can occur. This is when the formation fluids blow the drilling mud out of the well and oil, gas and/or water flow freely. This is the most dangerous condition you can encounter on a rig. The blowout prevention system is the final line of defense to control this. Pressure control equipment is designed to allow the driller to control the gas and avoid a "blowout."

1.3.8 Special Rig Components for Semisubmersible or Drillship Rigs

A mobile floating rig such as the semisubmersible or drillship is constantly being subjected to vertical and horizontal motions due to wind, waves and currents. The rig must be equipped with a system that automatically compensates for these forces. A marine riser system provides for a flexible path for drilling fluids between the drill floor and the wellbore below the sea floor. It also provides a passageway for the drill string and casing down to the BOP stack sitting on the sea floor.

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Riser System

The drilling riser system consists of a BOP stack hydraulic connection, lower ball joint, flexible choke and kill lines, riser pipe and connectors, telescopic (slip) joints, diverter system, and a riser tensioner system. Some systems include another annular BOP between the hydraulic connector and the lower ball joint. This preventer can be used to allow replacement of the rubber elements on the other annular BOP in the preventer stack.

The ball joints allow for up to 10 degrees of deviation from the vertical. The telescoping joint at the top of the marine riser has the ability to extend up to 45 feet and still maintain a pressure seal. It compensates for the vertical movement and minor horizontal movement of the drilling rig. The inner barrel is attached to a bell nipple on the rig floor. The outer barrel is attached to the riser tensioner system.

The riser tensioners support a major portion of the weight of the marine riser system plus the drilling mud it contains. The wave action causes the floating drilling platform to constantly rise and fall. This system must sometimes cycle up to 6,000 times in one 24-hour period. The tensioner cylinders operate on compressed air and hydraulic fluid to maintain a steady pull on the marine riser.

Drill String Compensation

The entire drilling rig will heave vertically due to the wave action. The rising deck would pull the entire drill string upward, raising the bit off bottom. As the wave crest passes, the deck would sink rapidly. The rigid drill string would drop and jar the bit on the bottom of the borehole. Also, the proper amount of weight on bit could not be maintained. Drilling would be impossible and unsafe.

The drill string compensation system consists of large cylinders and an air pressure vessel. The cylinders and pistons are placed between the traveling block and the hook suspended in the mast. They are generally capable of stroking 18 feet which is adequate for even high waves. The heave of the drilling rig raises and lowers the fixed portion of the compensator but the relative position of the drill string will remain constant.

BOP Stacks

As with all drilling rigs, the offshore rigs are equipped with BOP stacks. The mobile rigs will have the stack mounted on the sea floor below the marine riser. Drilling platforms and jack-up rigs will have the BOP stack located in the substructure below the rig floor.

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The subsea blowout preventers must not only control high pressure formation fluids. They must also be able to close the top of the borehole at the sea floor; disconnect, hang off or cut the drill pipe; and disconnect and reconnect the marine riser system to the wellhead.

Modern rigs use single stacks consisting of two annulars and four ram-type BOPs in one stack. The total stack may have an $18^3/_4$-inch bore and 10,000 psi or higher working pressure. One ram will contain shear/blind ram blocks for cutting the drill string in case of emergency.

The redundancy found in the design of the BOP stack is also found in the control system. The pressurized fluids are located on the BOP stacks in accumulator bottles. They can rapidly close a BOP when directed by the driller's or toolpusher's console. Electric panels are used in both locations and control the equipment either through electro-hydraulic or hydraulic lines. Again, all parts of the system have an alternate or redundant part in case of failure in the primary system. The total system must be tested and inspected often, and all drillers must be skilled at operating the system.

1.3.9 Rig Personnel

Whatever job you perform for Sperry-Sun, you will need to know how the drilling process is managed, supervised and completed. Who is in charge? Who can authorize the stopping of drilling? Who can authorize you to visit the rig floor?

The chain of command is usually filled with personnel of varying degrees of experience. Those at the top have generally had experience in all phases of rig operations. Those with the least experience are usually found performing specific duties requiring limited training.

Crew Members

The chain of command includes managers not located at the rigsite and supervisors who may spend full or part time at the rigsite. The process of drilling a well begins with the decisions of the operating company. They decide where a well will be drilled, obtain the necessary leases, provide the finances required, and finally contract a drilling contractor to actually drill the well.

The drilling bid proposal will contain many important specifications. These will usually include the starting date, depth to be drilled, formations to be penetrated, hole sizes, casing sizes, drilling mud program, logging program, casing program, cementing, testing and well completion. The operating company is represented on the rigsite by a company representative.

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Company Representative. The *company representative* is employed by the operating company, and is responsible for all phases of drilling the well and for all needed equipment and services such as casing, drilling mud, logging and cementing. Upon arrival at a rigsite, contact the company representative first.

Toolpusher. The *toolpusher* is in charge of the drilling rig and crews needed in the drilling operations. He is generally an expert in drilling operations and equipment, and is the main liaison between the drilling contractor and the operating company.

Driller. The next highest level of authority on the rig is the *driller*, who is the working supervisor for the shift. The driller operates the controls on the drill floor. He raises and lowers the drill string, sets the speed and penetration rates, operates the mud pumps and operates the BOP stack if needed.

Derrickman. The next man in line under the driller is the *derrickman*. He is experienced enough to assist or relieve the driller. During a trip out of the hole, he will work atop the derrick racking the stands of drill pipe. At other times, he may be servicing the mud and mud equipment.

Roughnecks. The *roughnecks* are the workers who make up and break out the joints of pipe. They work on the floor and keep a steady supply of drill pipe to connect to the drill string. The roughnecks also help maintain other equipment on the rig floor. The roughnecks report to the driller.

Crane Operator. The *crane operator* is in charge of the loading and unloading of boats. The pipe rack area is also under the crane operator's responsibility, as are the roustabout crews. The crane operator reports directly to the toolpusher.

Roustabouts. The *roustabouts* are the workers who help load and unload equipment for the crane operator. They also clean, repair and maintain the rig and its systems. They report to the crane operator.

Subsea Engineer. The *subsea engineer* is responsible for maintaining the subsea BOP system. This includes the wellhead connection, the BOP stack, control system, marine riser system, and the motion compensation equipment.

Barge Engineer. A floating platform and drillship will have a *barge engineer* assigned, who is responsible for the stability and ballast of the vessel. The barge engineer must be notified before any heavy equipment is moved or loaded on the rig. He must keep the rotary table in the correct position to drill the hole.

Specialty Crewmen. Some skills are needed on the rig full time. These specialty skills include a motorman, rig mechanic, rig welder, and rig electrician.

Service Specialists. The operator will contract special service companies for certain needs. These service crews include well loggers, mud suppliers, analysis and treatment, cementing, casing, wireline operations and others, who are usually only present on the rig part time.

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Chapter 2 Drilling Process

Drilling for oil and gas seems, on the surface, to be a relatively simple process of drilling a subsurface hole (wellbore) until it penetrates an oil- or gas-bearing formation. However, in reality, drilling for oil or gas is a highly sophisticated process requiring an effective organization; a vast knowledge base, large amounts of capital, expensive equipment and machines, and dedicated, highly trained and committed personnel. In order to begin to understand the process, it is important to become familiar with a number of generalizations that can be made about drilling an oil or gas well. These include a brief description of a simplified cross-section of an oil or gas well, an introduction to the basic methods of drilling a well, the three stages of drilling a typical well, and the completion of a drill stem which actually produces the wellbore.

2.1 Tripping In Hole

The following steps must be taken **before** tripping in hole.

1. The bit is made up. There is a bitsub usually attached to the bit before the rest of BHA is assembled.
2. Depending on the type of the drilling operation, a specific collar or mud motor is added to the bit.
3. The rest of BHA including stabilizers, jars, subs, MWD subs, heavyweight drill pipes and regular drill pipes are added to the bottom hole assembly.
4. The kelly and swivel are attached, and drilling begins.
5. Joints of drill pipe are moved to the mouse hole and then are added to the drill string.

2.2 Drilling

A typical well is usually drilled in three stages. After the hole is begun at the surface or “spudded-in,” the first stage of the well is drilled. This is called the “surface hole.” Then the second stage of the hole is drilled. This section is called the “intermediate hole.” Next, the final stage of the hole is drilled. This section is called the “production hole.” A well will vary in the number of stages required for its completion depending on its location and the conditions encountered downhole. For example, some wells do not require an intermediate hole. A brief description of each stage follows.

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2.2.1 Stage 1: The Surface Hole

The surface hole is a relatively large diameter wellbore that is located immediately below the surface. Surface holes are usually drilled more rapidly as the formations are generally soft. On completion of the surface hole, casing is run into the wellbore and cemented. This brings the surface hole under complete control and allows drilling to continue.

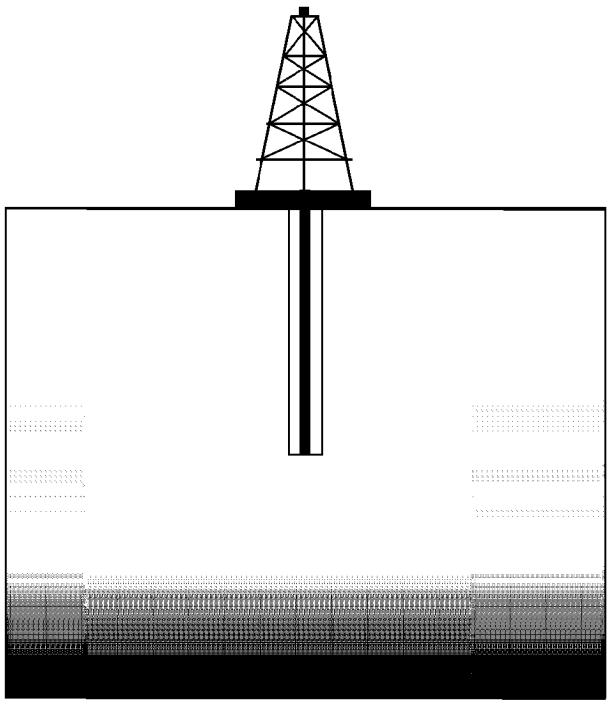

Figure 2.1 Surface Hole

2.1.1 Stage 2: The Intermediate Hole

A smaller diameter intermediate hole is then drilled. Casing is run into the wellbore and cemented. This brings the intermediate hole under complete control and allows drilling to continue. Several intermediate casing strings may be required for deep, high pressure wells. However, an intermediate casing string is not always required, such as when loss of circulation is not anticipated in shallower formations, or when it is necessary to seal off older producing zones.

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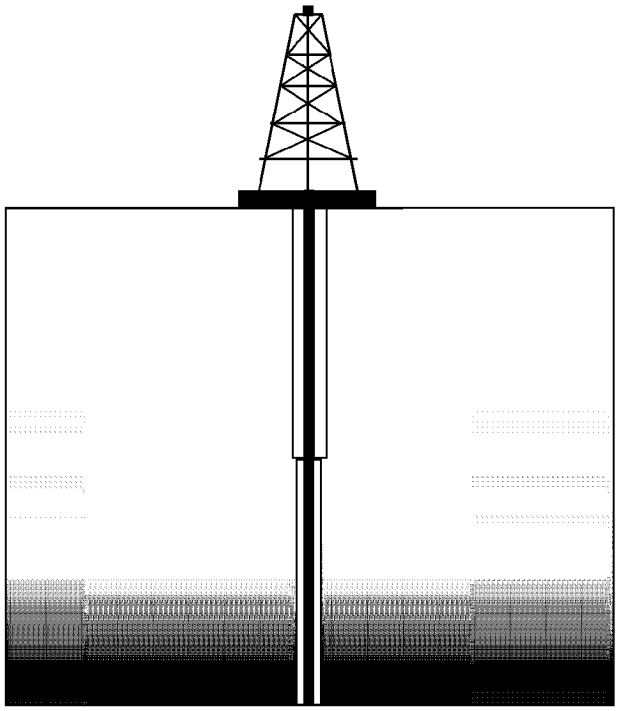

Figure 2.2 Intermediate Hole

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2.2.1 Stage 3: The Production Hole

Smaller in diameter, the production hole is then drilled to the target formation. Tests are then conducted to determine if hydrocarbon presence is sufficient to justify the expense of running and cementing production casing into the hole. If the hole is "dry," it is plugged and abandoned.

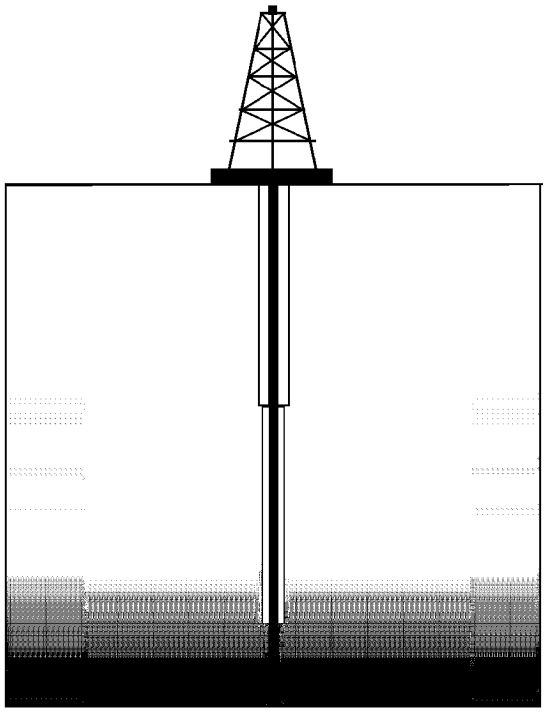

Figure 2.3 Production Hole

2.4 Drilling Methods

A well is generally drilled using one of two methods: straight hole drilling, or directional drilling, or a combination of both methods.

2.4.1 Straight Hole Drilling

In straight hole drilling, an attempt is made to drill a wellbore to the target formation as vertically straight as possible, with a minimum amount of deviation.

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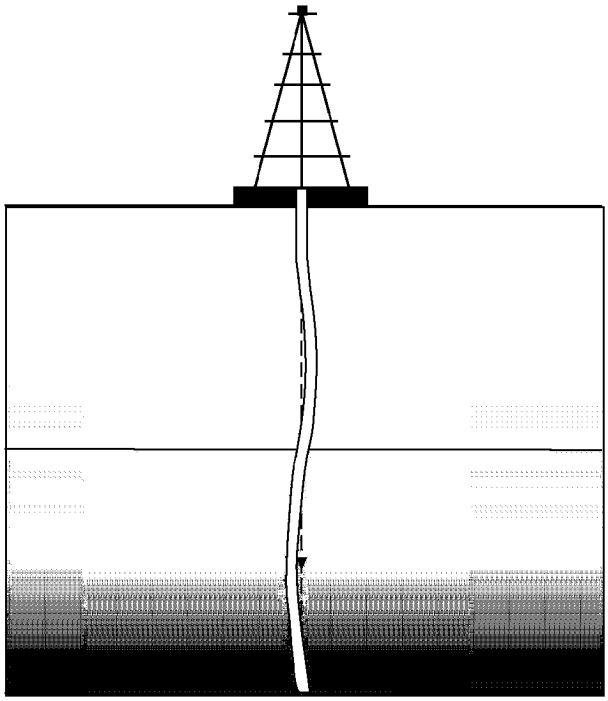

Figure 2.4 Straight Hole Drilling

2.4.1 Directional Drilling

In directional drilling, a deliberate attempt is made to change, deviate or change the direction of the wellbore as drilling operations proceed.

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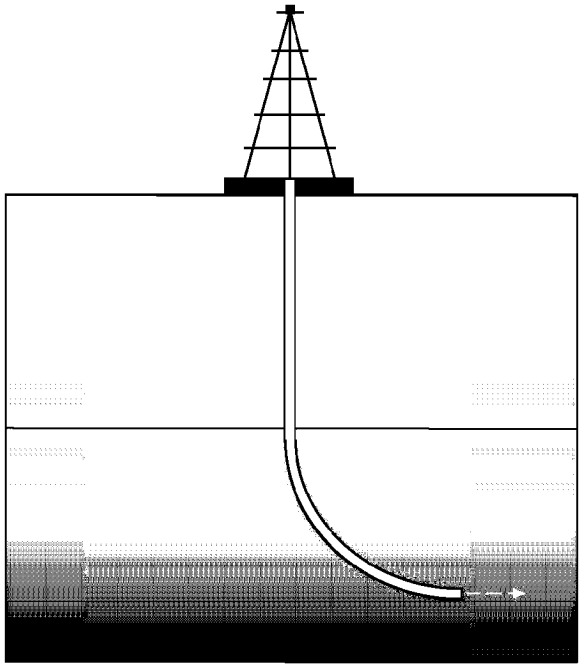

Figure 2.5 Direction Drilling

2.6 Wellbore Control

In order to deal with varying downhole pressure conditions, two basic circulation fluids are used: a routine "mud" system using a water- or oil-based drilling fluid, or a special air-based drilling procedure.

2.6.1 Routine "Mud" System

Most rotary drilling operations use a drilling fluid consisting of water or oil, with bulk and chemical additives to control downhole wellbore conditions. About 92% of wells use a mud system.

2.6.2 Air Drilling

In a small number of wells, downhole formation pressure is not a problem. Compressed air is used instead of a routine drilling fluid. Penetration rates

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improve, but it requires special care in handling the compressed air. Only about 8% of all wells drilled use compressed air.

2.7 Circulating

Depending on the stage of drilling operation, circulation of mud can occur either as drilling is ongoing or once drilling stops. Mud is circulated for the following reasons:

- lubricate the bottom hole assembly (BHA),
- clean the hole from cuttings and other materials,
- cool the bit,
- stabilize the hole,
- remove formation gas, shale gas, etc. from the mud,
- increase/decrease mud weight and condition the mud, and
- condition the hole for tripping out or wireline logging, running casing, etc.

2.8 Tripping Out Hole

After the hole is conditioned (such as casing, changing the bit, changing the mud motor, changing any part of BHA, or running wireline), all of the BHA and drill pipes have to be removed from the hole and stacked against the derrick or mast.

Depending on the size of the rig and length of the mast, drillpipe stands of 2 or 3 joints are removed from the hole and stacked. During this operation, the following must be done:

- fill the hole with mud as the pipes are being removed from the drill stem.
- monitor any increase or decrease in the mud volume removed from the hole or added to the hole.
- if there is any extra drag (friction to the wall) which is not normal, start circulation and clean that section of hole,
- if there is any discrepancy in the depth, measure and record all of the stands to verify the correct depth.

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2.9 Wireline Logging

Most wells are logged by wireline systems. There are usually two kinds of wire line logs: open hole logs and cased hole logs.

2.9.1 Open Hole Logs

Open hole logging is done immediately after the BHA is removed from the hole. There may be one, two, or more runs of wireline logging. In normal and most common operations, a resistivity tool, gamma, and one or more porosity tools (such as neutron, density, or sonic) are used. In exploratory wells, more sophisticated wireline tools are used.

2.9.2 Cased Hole Logs

Cased hole logging is done after casing is set. This requires tools whose signals can penetrate through casing and into the formation. Examples of cased hole logs are cement bond logs, gamma logs for correlation, casing integrity test logs, etc.

2.10 Setting Casing

As the drilling of an oil or gas well progresses, it becomes necessary to line the walls of the hole with heavy steel pipe called casing. Casing, together with cement around it, performs the following functions:

- prevents caving of the hole,
- prevents contamination of freshwater in the upper sand zones,
- excludes water from the oil or gas producing formations,
- confines production to the wellbore,
- provides a means for controlling pressure,
- facilitates installation of subsurface equipment required if artificial lift becomes necessary in producing the well,
- facilitates the use of acidizing, zone fracturing, etc.

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2.10.1 Properties

Casing is classified according to six properties:

1. outside diameter (OD)
2. wall thickness
3. material grade
4. type of joint
5. length range, and
6. unit weight

Liners is the same as casing but in an abbreviated oil string extending from the bottom of the hole upwards to a point approximately 100-200 feet above the lower end of the production string, where it is suspended from a liner hanger and sealed off.

2.10.2 Classifications

There are five different classifications of casing in relation to the stages of drilling:

1. **Drive pipe or conductor casing**

   The first string to be run or placed in the hole is usually the drive pipe or conductor pipe (casing). The normal depth range is from 100 to 300 feet in soft rock area such as South Louisiana or most offshore environments. The pipe is hammered into the ground with a large diesel hammer. Hard rock areas require that a large diameter, shallow hole be drilled before running and cementing the pipe.

   The primary purpose of this string of pipe is to provide a fluid conduit from the bit to the surface. Very shallow formations also tend to wash out severely. In addition, most shallow formations exhibit some type of lost circulation problem that must be minimized.

   An additional purpose of this string of pipe is to minimize hole caving problems. Gravel beds and unconsolidated rock will continue to fall into the wellbore if not stabilized with conductor casing.

2. **Structural casing**

   Occasionally, drilling conditions require an additional string of casing below the conductor casing. Typical depths range from 600 to 1000 feet. The purpose of structural casing is basically the same as for conductor casing.

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3. **Surface casing**

   Surface casing is run from the surface to below the last fresh water sand. This casing provides the means for attaching the BOP, in addition to protecting the fresh water zones.

4. **Intermediate casing**

   The primary applications of intermediate casing involves abnormally high or subnormal formation pressure. As higher mud weights are required to control these pressures, the shallower weak formations must be protected to prevent lost circulation or stuck pipe.

   Occasionally, intermediate pipe is used to isolate zones that cause hole problems such as heaving, and sloughing shales or salt zones.

   Drilling liners are used for the same purpose as intermediate casing.

5. **Production casing**

   Production casing is often called the oil string. This casing can be set at a depth slightly above, midway through, or below the pay zone. The casing serves the following purposes:

   - isolates the producing zone from other formations,
   - provides a work shaft of a known diameter to the pay zone,
   - protects the production tubing equipment, etc.

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2.10.3 Components

Casing is composed of the following sections:

1. **Casing-cementing heads**

   Casing heads provide a connection from cementing and rig pump lines to casing.

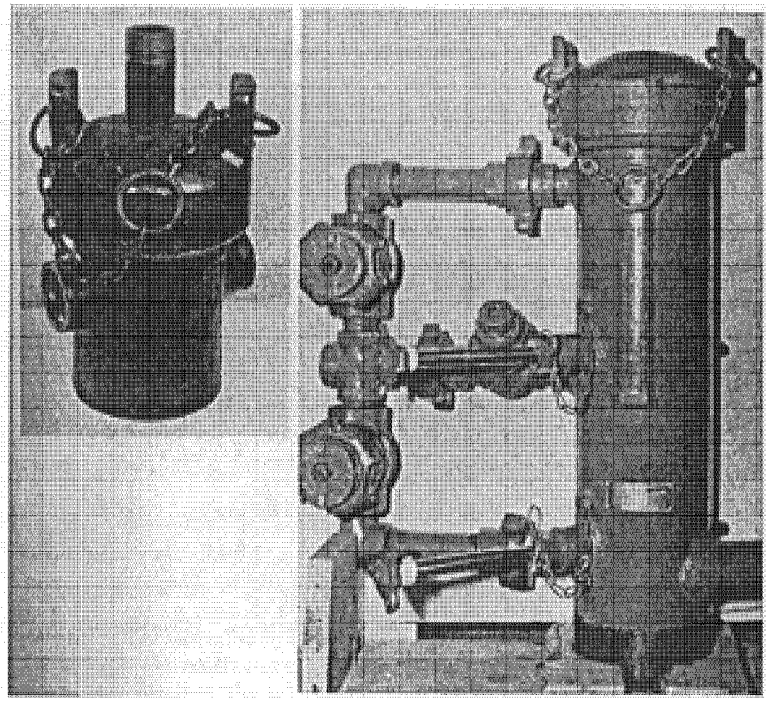

Figure 2.6 Typical Casing-Cementing Heads

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2. Guide and float shoes

There are two kinds of shoes: plain guide shoes, and the combination float and guide shoe.

The plain guide shoe is run on the bottom joint of casing and is only intended to guide the casing past any sidewall irregularities.

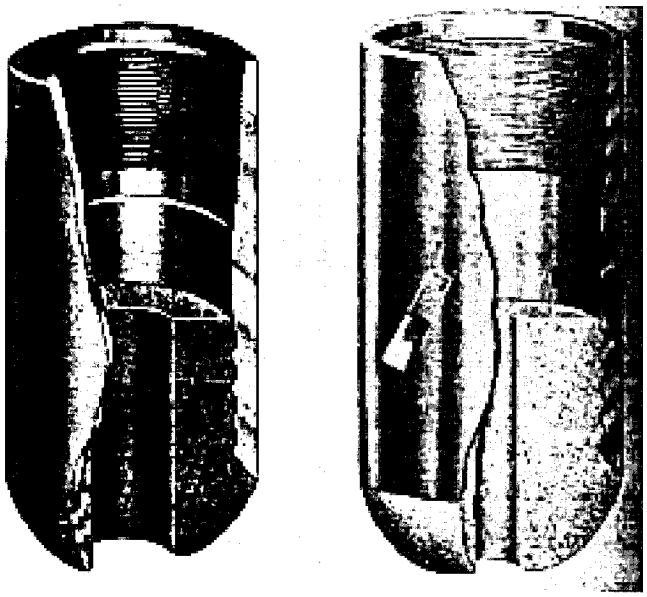

Figure 2.7 Bottom and Side-Discharge Guide Shoes

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The combination float and guide shoe includes a back pressure valve as an integral part of the equipment and a side discharge. The back pressure valve is composed of drillable materials such as cement and plastics.

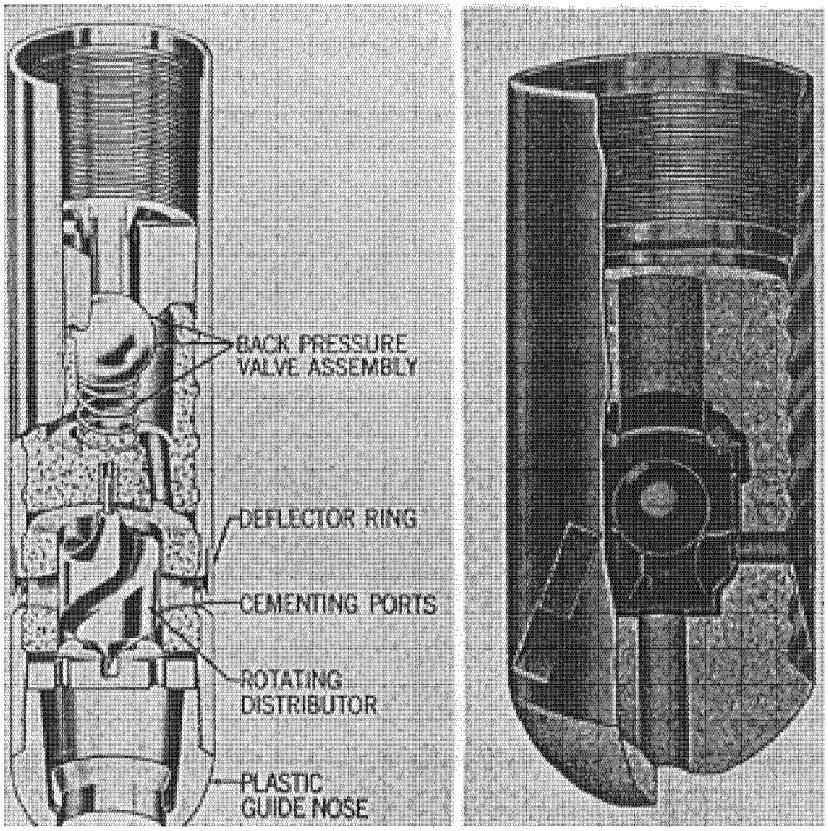

Figure 2.8 Side-Outlet Combination Float and Guide Shoes

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3. Float collars

The float collar is set at one or more joints above the combination float and guide shoe, and contains a back pressure valve similar to that of the float shoe.

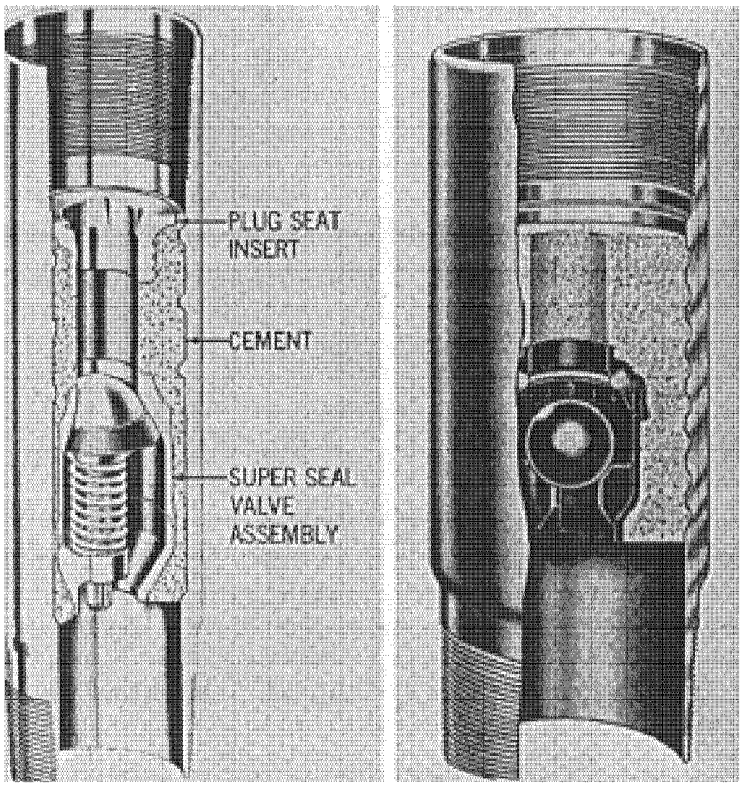

Figure 2.9 Float Collars

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4. Stage collars

Stage collars are used to cement a long section of casing in two or more stages.

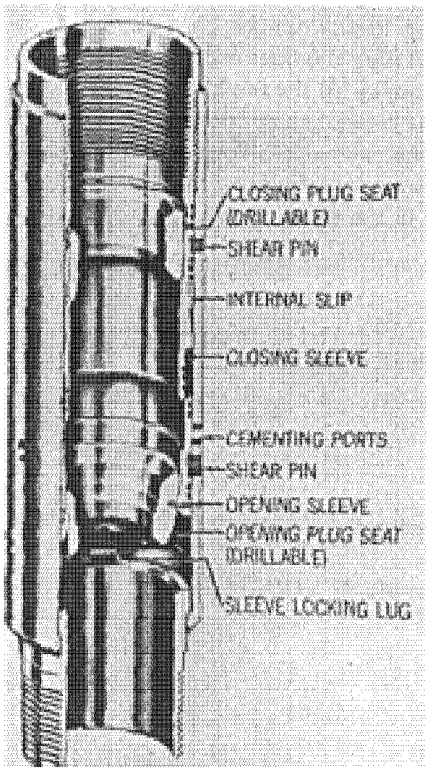

Figure 2.10 Stage-Cementing Collar

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5. Wiper plugs

Wiper plugs are made of molded rubber and cast aluminum or plastic, and are designed for the following reasons:

- wipe the casing free of mud,
- separate mud from cement inside the casing

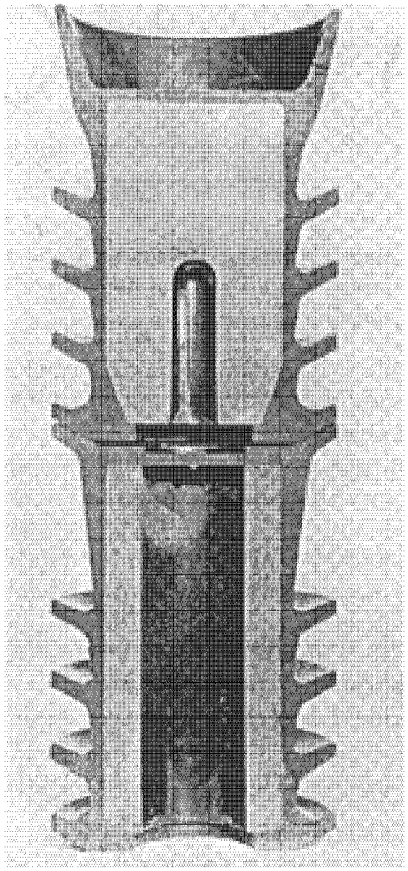

Figure 2.11 Bottom and Top Wiper Plugs

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6. Casing centralizers

Casing centralizers are used for the following:

- center the casing in the wellbore,
- permit equal hydrostatic pressure in the annulus, thereby preventing differential pressure sticking,
- prevent casing from key seating, and
- assist in wall cake removal and breaking up cement channeling

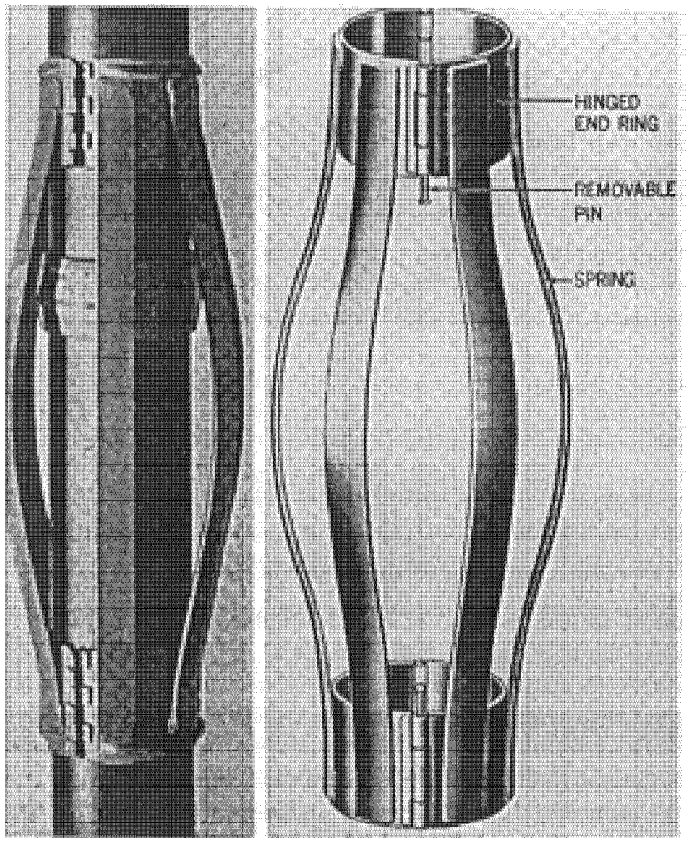

Figure 2.12 Casing Centralizers

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7. **Scratcher**

   A scratcher is a mechanical wall cleaning device. Its purpose is to remove all wall cake from the wellbore in an area before and during the cementing operation. This allows good bonding of the cement to the formation and prevents contamination and channeling during placement.

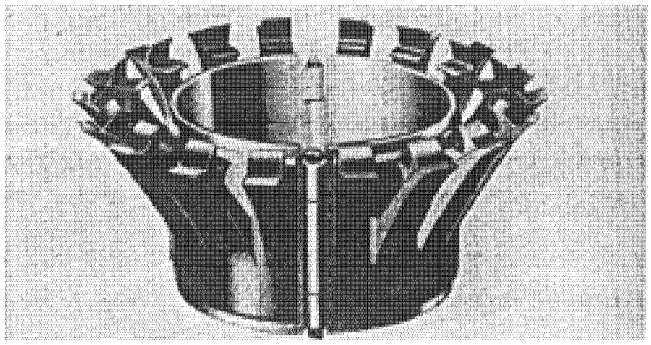

Figure 2.13 Scratcher

2.14 Cementing

After casing is set at a certain depth (usually a few feet above TD), a cementing crew arrives. In most offshore wells, a cementing crew is present on location at all times for safety reasons.

At this time, all of the necessary equipment, such as flow lines, valves, pressure monitor gauges, etc., are installed, and cement is pumped into and around the casing through the casing shoe. Generally, cement does the following:

- prevents escape of oil and gas from one strata to another,
- prevents intrusion of water into oil or gas zones, and
- prevents pollution of freshwater sands by oil, gas, and/or saltwater

In each country or state, there is a regulatory body empowered by the legislature to require casing and cementing to be done in such a manner as to prevent the above mentioned cases. There are also rules established to minimize quantities of cement placed around the surface, intermediate, or production casings.

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2.15 Leak Off Test

If drilling is to continue after casing is set, it must be determined how much pressure can fracture the formation at the casing shoe since it is the shallowest, unprotected formation. By this measurement, drilling can continue until the mud weight (equivalent mud weight AND fracture pressure equivalent mud weight) can be calculated. As the depth of drilling increases, mud weight must be increased. The maximum mud weight that can safely be used without fracturing the formation at the shoe is calculated as follows:

1. After cement in the casing is drilled out, the casing shoe is drilled out.
2. About 5 to 10 feet of new formation below the casing shoe is drilled.
3. The hole will be circulated until all of the cuttings from the new formation is out of the hole, and the hole (and inside casing) is very clean and free from shale, sand, and cuttings.
4. Special wellhead plugs and packers are set.
5. A mud with a known and pre-determined weight is pumped down the hole through the drill pipe.
6. Pressure is applied and monitored very carefully and accurately.
7. Pressure is increased slowly and steadily until the formation at or below the shoe fractures open and fluid can flow into the formation.
8. At the moment of formation fracture, the pressure is measured accurately.
9. Leak off test pressure is calculated using this pressure. Fracture pressure or fracture pressure equivalent mud weight is the combination of pressure equivalent mud weight applied and the mud weight equivalent of the hydrostatic head.

2.16 Running Cement Bond Log

Cement bond logs are used to evaluate the quality of the cement-to-casing bond around cemented casing.

A cement bond log records the amplitude in millivolts of the first half-cycle of the signal at a receiver located 3 feet from the transmitter. This amplitude is maximum in unsupported pipe, and minimum in well casing. It is a function of casing size and thickness, cement-strengthened thickness, degree of cement bonding, and tool centering.

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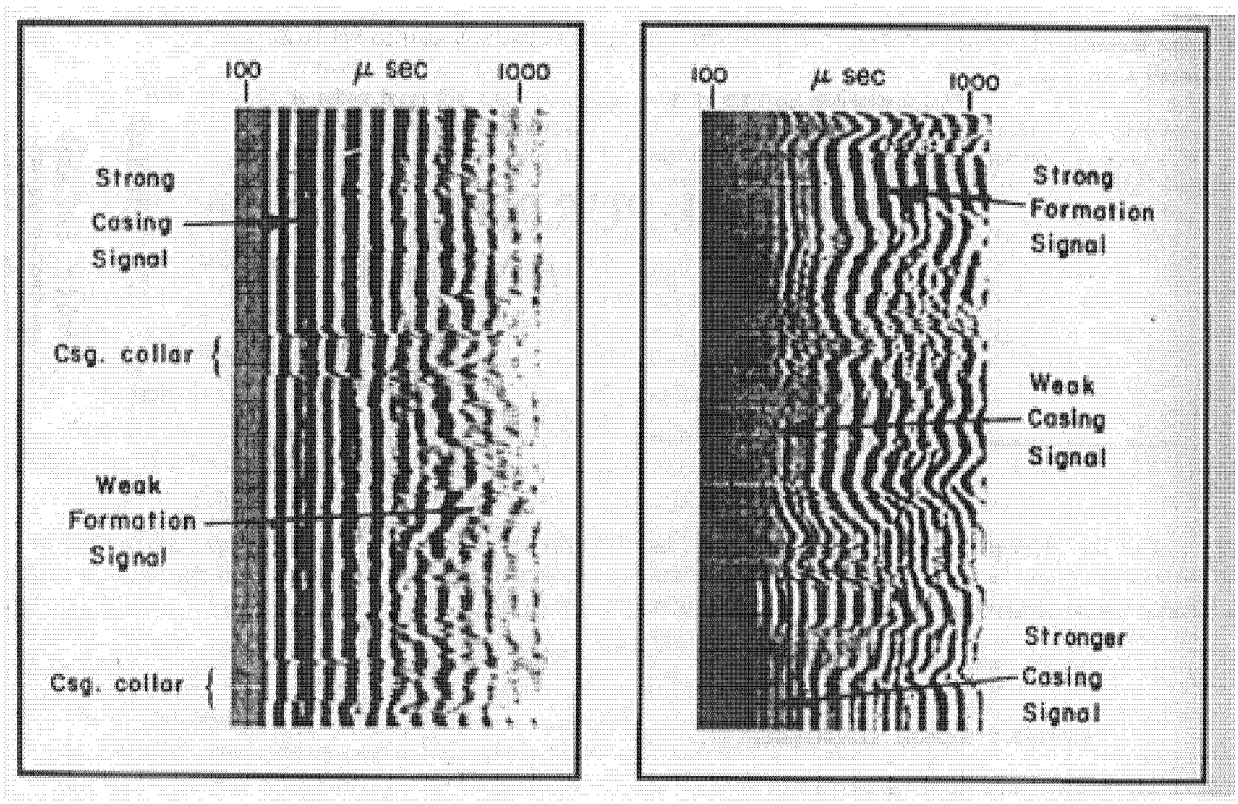

Figure 2.17 Cement Bond Logs

2.18 Completion of the Well

After a well has been drilled, tested and evaluated, the well is completed and prepared for production of oil and/or gas. The well must be converted from a well being drilled to a production well. The BOP stack will be replaced with a production wellhead, the rig will be removed, and a series of decisions are then made as to how the well should be completed. The type and method of completion is determined by the well, its reservoir characteristics, and its economic potential.

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2.18.1 Economic Considerations

The bottom line of any well is its profitability, as economic decisions play a decisive role in completion practices. If return is expected to be high over a long period, then the well justifies a considerable expenditure or investment. This would be reflected in many ways, including the quality of the tools and equipment used.

2.18.2 A Typical Well Completion

A typical completion consists of three components:

- A wellhead assembly or specialized surface equipment that seals and controls the wellbore
- A casing and tubing arrangement that provides improved control over the wellbore from the surface to the producing zone
- The bottom hole or producing zone completion for improved control over the producing zone.

2.18.3 Wellhead

A production wellhead is an assembly of specialized equipment that is located at the surface of a drilled wellbore, which seals the casing and tubing previously run into the well, permitting a controlled flow of produced fluids. This assembly of valves is commonly referred to as a "Christmas Tree". The wellhead is installed during drilling operations and modified as required if the well is to be produced. The wellhead consists of three basic components:

1. **The casing head**

   The casing head is a steel fitting (wellhead casing flange) that is connected to the top of the surface casing string at the wellhead. It supports the casing string until cemented into place.

2. **The tubing head**

   The tubing head is similar to the casing head but is smaller, and sits atop the casing head where it supports the tubing string.

3. **The "christmas tree"**

   The "christmas tree" is an assembly of fittings, valves, and chokes that control the rate of oil and gas flow from the well. It usually contains a pump and gauge(s) and may contain a BOP.

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As indicated, a well completion will vary depending on the well and reservoir characteristics, as well as its economic potential. A variety of completion methods and procedures have been developed. Basically, completions can be divided into two categories: single zone and multiple zone. However, regardless of the type, the production casing or "oil string" must be set, the tubing arrangement determined, packers must be properly placed, and a decision must be made about the type of bottom hole completion that will be used on the well. A review of the basic variations follow.

2.18.4 Packer Placement

A packer is a device that seals or closes off the annulus between the tubing string and the casing string. This confines production to the tubing string. There are two basic packer arrangements: a single packer and a double or straddle-packer arrangement.

Open Casing Arrangement

In some single zone producing wells, a packer is not used. This type of well is called an open casing arrangement, where the casing is used as a production fluid flow line. There is no production tubing placed in the well.

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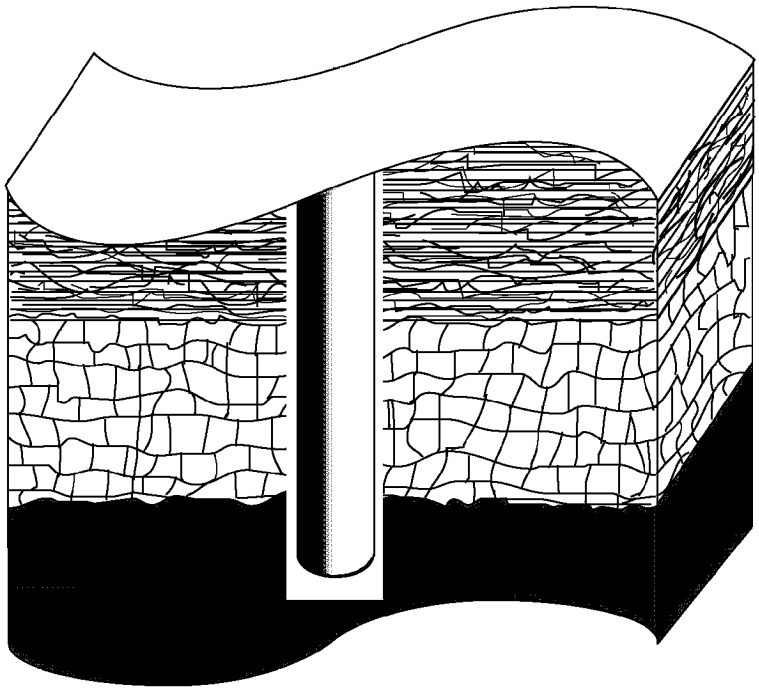

Figure 2.15 Open Casing Arrangement

Single Packer Arrangement

In most single zone producing wells, a single packer is placed above the producing zone in order to seal off the producing zone from the casing annulus above. This type of arrangement isolates the producing zone and increases production efficiency.

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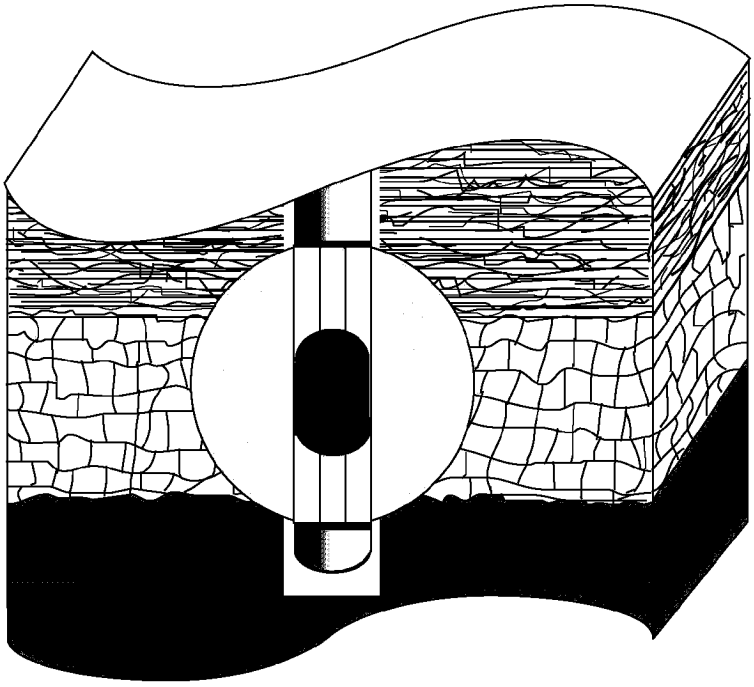

Figure 2.16 Single Packer Arrangement

Straddle-Packer Arrangement

In multi-zone completions, a straddle-packer arrangement is used in each producing zone above the one at the bottom of the well. The two packers located above and below the producing zones isolate the zone and allow production from additional zones within the wellbore. A straddle-packer arrangement may also be used in a single zone completion if the producing zone is to be raised to a higher level within the formation.

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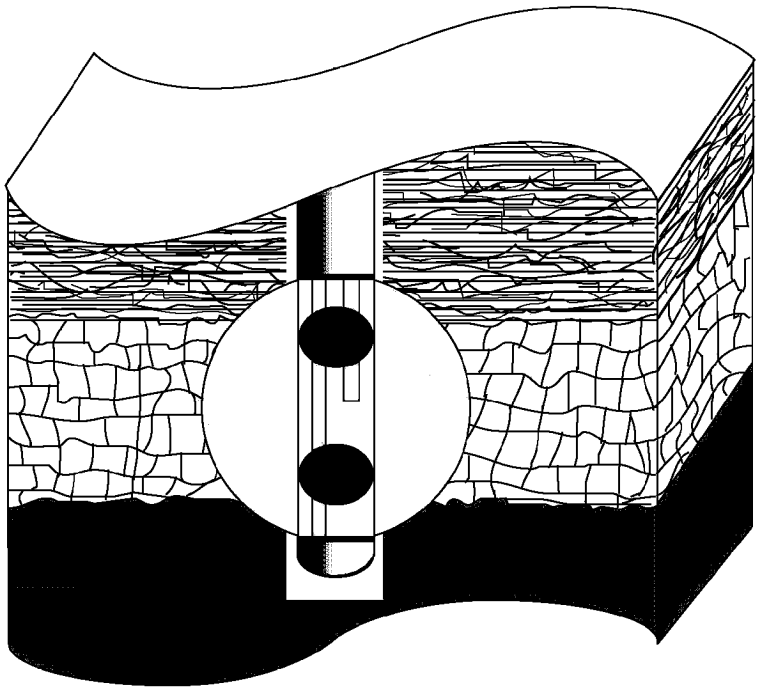

Figure 2.17 Straddle-Packer Arrangement

Bottom Hole Completions

The bottom of the wellbore may be completed in a number of different ways, depending on the producing formation. There are three basic bottom hole completions methods:

1. **Open hole completion**

   An open hole completion is one in which casing is set just above the target formation, leaving the bottom of the wellbore open. This type of completion is limited in use. Today, it is generally restricted to limestone reservoirs. Its major advantage is that the well completion costs are minimal, allowing recovery from marginal reservoirs.

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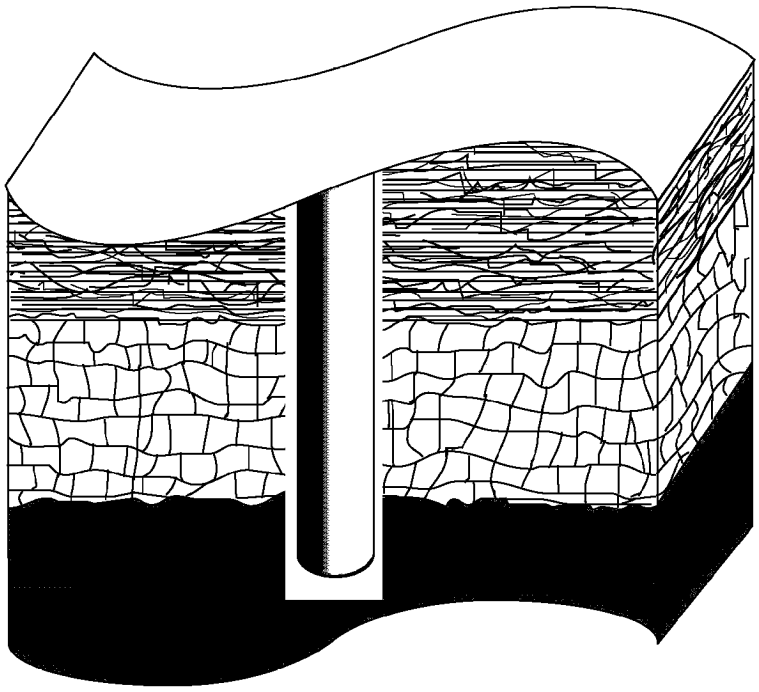

Figure 2.18 Open Hole Completion

2. **Open hole with liner completion**

   An open hole with liner completion is one in which a liner or screen-like cylinder is placed at the bottom of the wellbore. This type of completion is usually used in loose or unconsolidated formations where sloughing may occur in the bottom of the wellbore. The liner is used in a number of variations such as gravel-packed or cemented liner completion.

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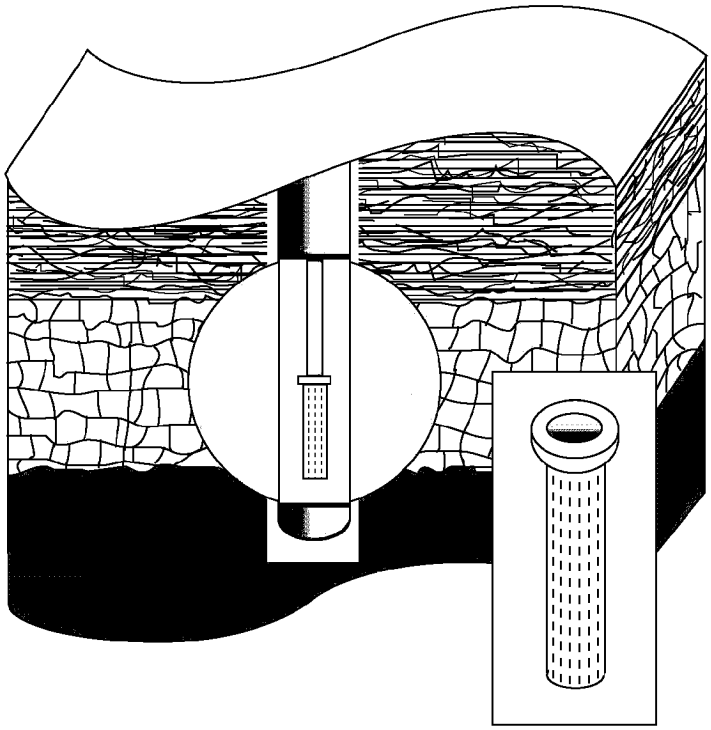

Figure 2.19 Open Hole with Liner Completion

3. **Perforated completion**

The perforated casing completion is one in which the producing zone is sealed off by a "packer" that is placed around the tubing just above the producing zone in a single zone completion, and just above and below the producing zone in a multi-zone completion. This type of completion is the most common in use as it is economical, versatile and can be relatively easily worked over when needed.

The most common completion method is the perforated casing completion, and the least used method is the open hole completion.

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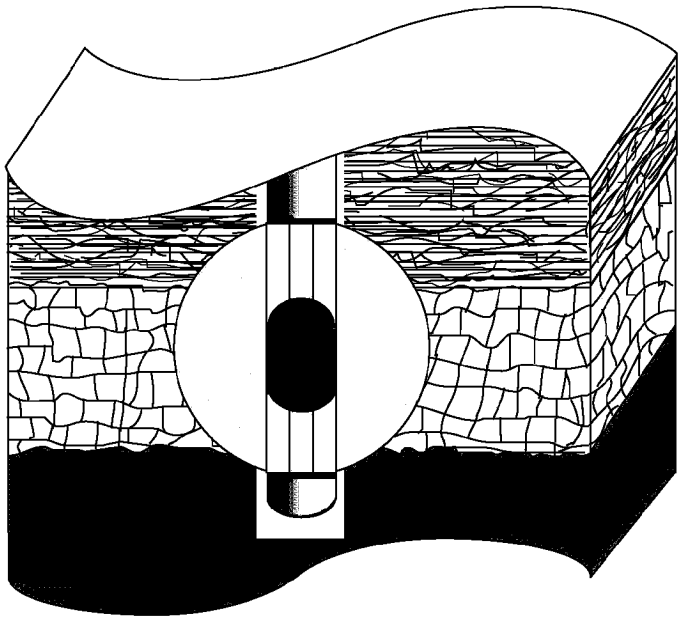

Figure 2.20 Perforated Casing Completion

2.2.1 Zones

Most wells are single zone completions. That is, only one producing formation is being tapped at one time. About 10% of the producing wells are multi-zone completions, meaning that two or more producing formations are being tapped in a single wellbore. In some instances, a completion may be tubingless and the formation fluids are produced directly through the casing.

Single Zone

The most common method of well completion is the single zone tubed completion, where only one producing formation is tapped at a time. The producing zone is usually located at the bottom of the wellbore. The casing is set and production tubing is run into the well. A packer is usually set just above the producing zone to seal off the zone from the rest of the wellbore. The cased well is then normally perforated with a shaped charge.

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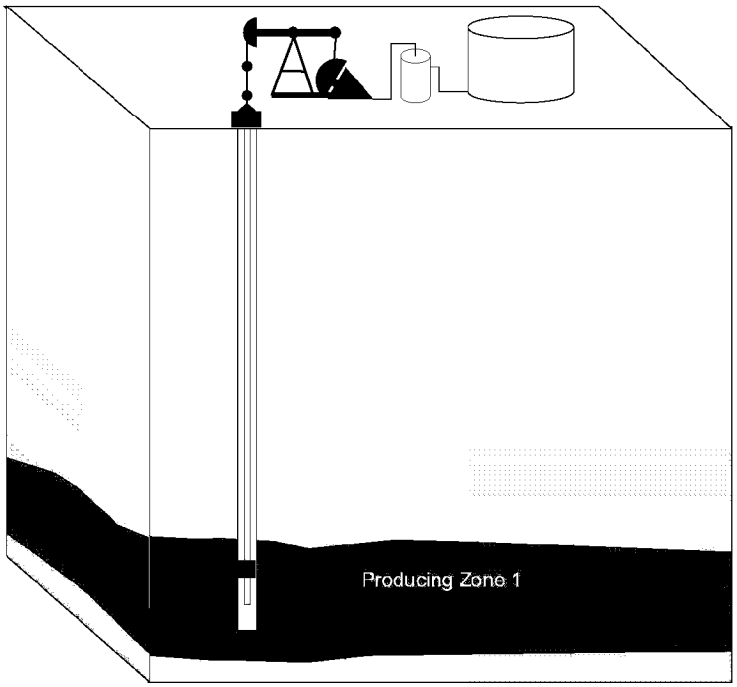

Figure 2.21 Single Zone

Double Zone

When two producing formations or zones are tapped from a single wellbore at the same time, it is called a "dual" completion. The use of this procedure requires careful planning and execution. Although limited in use, its primary advantage is that two zones can be recovered from a well economically. About 9 out of 10 multi-zone completions are dual or "parallel string" completions, as two strings of production tubing of different lengths are run into the casing. In a typical dual completion, the lower completion will use a single packer arrangement to isolate the lower producing zone while the higher producing zone will use a straddle-packer arrangement to isolate the other producing zone.

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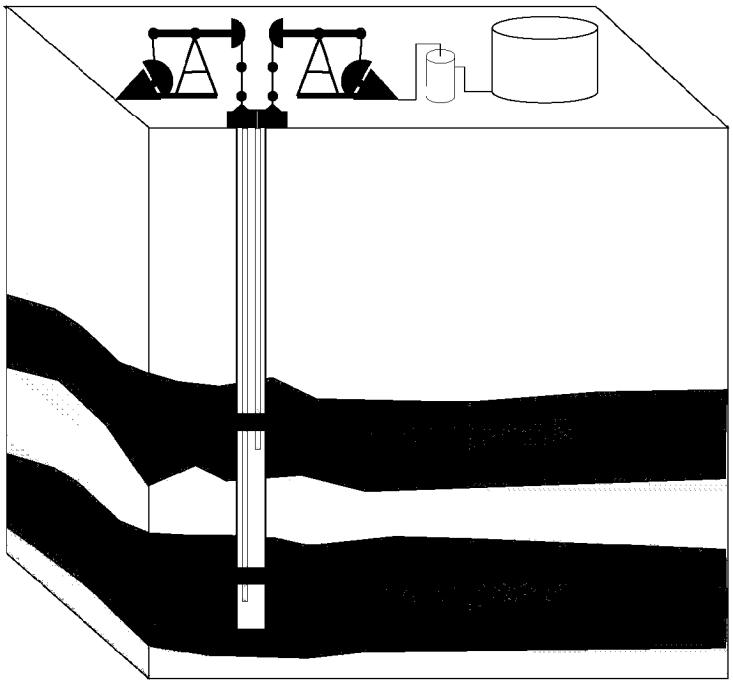

Figure 2.22 Double Zone

Triple Zone

When three producing formations or zones are tapped from a single wellbore at the same time, it is called a “triple” completion. As more zones are tapped within a single wellbore, it requires additional careful planning and execution. Its primary advantage is also the fact that multiple producing zones may now make the well economical to produce. About 1 in every 10 multi-zone completions are triple completions. The tubing and packer arrangements are similar to the dual completion except that an additional tubing string and straddle-packer arrangement are employed in the third producing zone.

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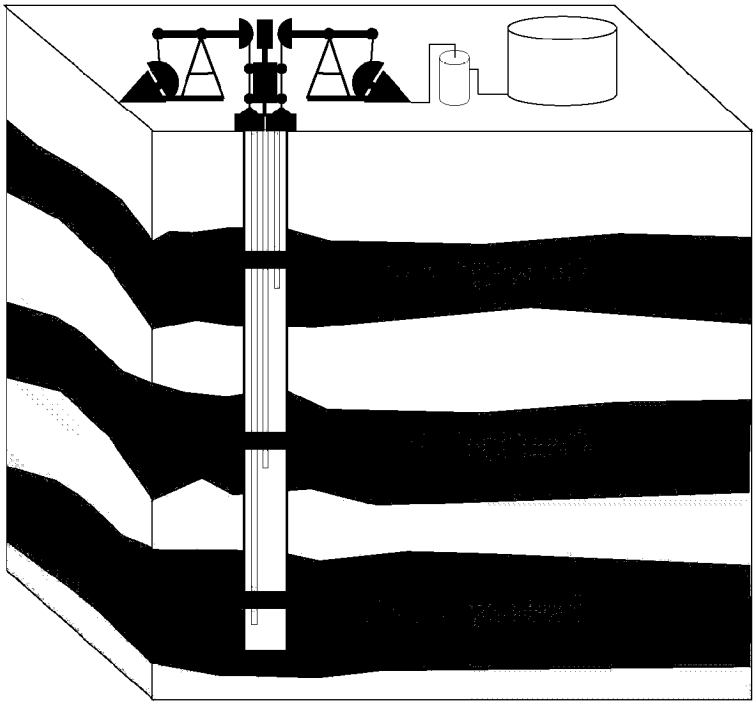

Figure 2.23 Triple Zone

When four zones are tapped from a single wellbore at the same time, it is called a "quadruple" completion. Although rare, as many as six zones have been produced from a single wellbore.

Tubingless Completion

If a well is expected to be a low-return, low-volume, or short-lived producer and it is anticipated that the well will have minimum sand and water problems and require relatively simple stimulation treatments, then a tubingless, miniaturized completion may be considered.

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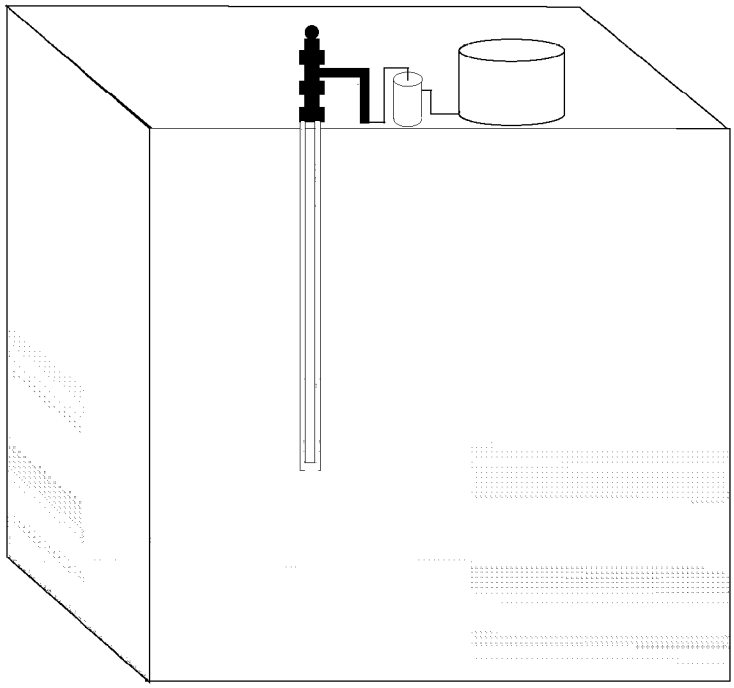

Figure 2.24 Tubingless Completion

Tubingless completions may be single or multi-zone completions.

In a typical tubingless completion, one or more strings of small diameter (2 ½ or 3 ½ inches) production casing is run into the well, cemented and then perforated.

2.2.5 Basic Perforation Methods

Typically, this type of completion reduces initial investment in the well, as well as servicing and workover costs later.

In a multiple zone tubingless completion, two strings are run into the well simultaneously, using dual slips and elevators. Multiple tubingless completions are only used where marginal oil or gas sands would not otherwise allow sufficient quantities to be produced economically.

In a typical completion, after a well has been prepared for production by executing the completion design, the final procedure required to "bring in" the well is to perforate the producing zone. Perforating the producing zone is the process of piercing the casing (or inner wall) and the cement sheath in a cased hole that separates the producing zone(s) formation fluid from access to the

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completed wellbore. The primary purpose of perforating a well is to establish a direct link between the wellbore and the producing formation. The piercing of the wellbore is accomplished by using a perforation gun assembly, which fires a shaped charge or a bullet. The created holes in the casing and cement sheath allow formation fluids to enter the wellbore where it will either move up the production tubing to the surface by the natural force (pressure) contained in the producing formation, or with artificial lift assistance. Perforation is also used for improving the injection of fracturing or acidizing fluids into a formation or to introduce additional cement into the wellbore.

In order to carry out a successful perforation, a number of factors are considered, including casing size, type of cement, cementing procedure, type of formation, formation fluid, hydrostatic pressure, as well as the well temperature and zone or zones to be perforated.

The well is perforated by the use of a perforation tool string which usually includes the following:

- weights to ensure a straight line
- perforation assembly consisting of:
  - blasting cap(s) which initiates detonation
  - detonating cord that transmits the explosive charge
  - explosive devices (charges) that actually perforate the well
  - possibly a casing collar locator (CCL), a gamma tool, an orienting device, a magnetic positioner, etc.

The explosive charges used are one of the following:

- shaped charged (called a jet perforation)
- bullet (called a bullet perforation)

Shaped Charge (Jet) Perforation

A shaped charge (called a jet perforation) uses a jet of high velocity gas to perforate the casing, cement sheath and formation. A jet perforation device (called a carrier gun) containing a number of capsule charges is lowered into the wellbore to a predetermined depth and fired electronically. The charge penetrates the casing, cement sheath and formation. Shaped charge perforations usually minimize casing and cement damage but does leave some debris in the formation. It is particularly effective in highly compressed producing formations and is the most common method in use.

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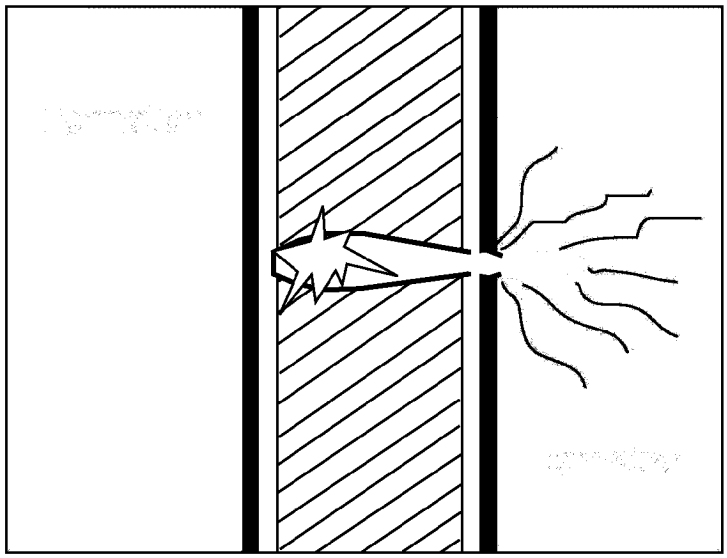

Figure 2.25 Shaped Charge Perforation

Bullet Perforation

When perforating a well with bullets, a bullet perforating gun (also in the shape of an elongated tube) is lowered into the wellbore to a predetermined depth and fired electronically. The bullets then penetrate the casing, cement sheath and formation in similar fashion to shaped charges. This type of perforation causes little damage to the cement sheath and provides a perforation with little or no debris. It is particularly effective in low to moderately compressed producing formations.

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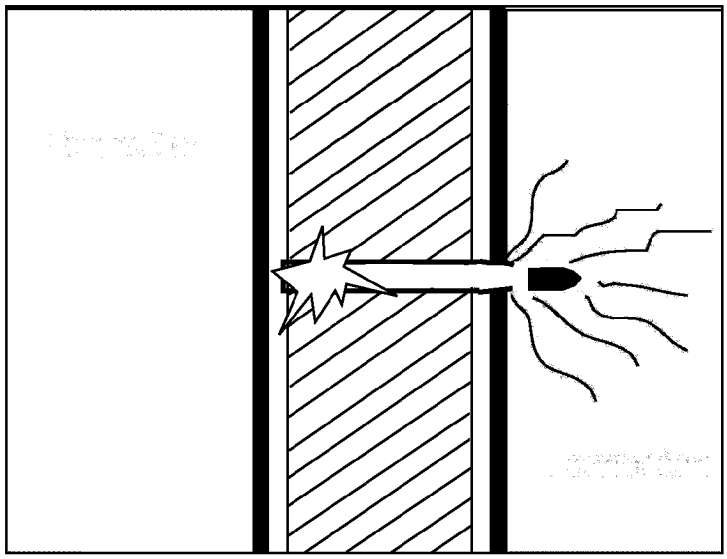

Figure 2.26 Bullet Perforation

2.2.7 Perforation Process

Well perforations are carried out by specialized well service or wireline companies. The selected company usually follows a set of standardized procedures that include:

1. **Preplanning**

   After receiving a perforation request, the job is planned. This includes evaluating the conditions (zones, type of perforation required, temperature, pressure, etc.) under which the perforation is to be made. A determination is then made as to the most appropriate method of perforating the well and a perforation plan is prepared.

2. **Arrival**

   The required gun (tool) is selected and prepared at the district support shop. The perforation service crew and truck are then dispatched to the well. Upon arrival at the site, the requirements are verified. A safety check is made for any possible safety hazards. A safety plan is then prepared and a meeting is held with the crew.

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3. **Rigging-up**

   The perforation and supporting equipment are unloaded from the truck. The appropriate wellhead assembly is installed for raising and lowering the perforation assembly and controlling any wellhead pressures. The truck instrumentation system is then made operational.

4. **Perforation**

   The perforation assembly or tool string is assembled. This usually includes a set of weights, a perforation gun assembly consisting of a blasting cap, a detonating cord and a set of shaped charges. It may also include a casing collar locator, a gamma tool, an orienting device, etc. The assembly is then lowered into the wellbore to the assigned depth and the gun is fired electronically from the surface.

5. **Rig-down**

   The assembly is then removed from the wellbore, the perforating crew reassembles their equipment, makes a safety check of the area, and returns to their district service center.

Desired Results

A successful perforation:

provides a smooth, clean opening through the casing, cement sheath and into the producing formation, leaving a minimum amount of debris.

produces a maximum penetration which will result in a maximum flow rate with the minimum number of perforations.

2.2.8 Well Completion

General Well Testing. Represents a series of tests conducted initially to determine a well's potential productivity and at periodic intervals during the life of the well to verify the results.

Well Logging Services. Represents a wide range of additional testing and logging procedures that are available to monitor a well. These procedures are conducted by special "well logging" companies.

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Additional Wireline Services. Are a wide range of additional operations performed by "wireline companies" other than logging, such as perforating a well, tubing and casing caliper services, etc. The term *wireline* is used because a wire line is used to lower and raise a tool from the wellbore.

All of these important services are performed as needed throughout the producing or economic life of a well.

Well Testing

Once the well is perforated, it is carefully tested to determine potential productivity. This is called "productivity testing." Although the well probably had a DST (Drill Stem Test) performed on it earlier, the final production testing is completed to verify the earlier predictions. There are three basic production tests performed: the Potential Test, the Bottom Hole Pressure Test, the Productivity Test.

These tests are conducted using in-place surface equipment, a wireline service, or a special sled-mounted testing unit.

Potential Test. The *potential test* or *production test*, measures the amount of oil and/or gas that a specific well is capable of producing in a given 24-hour period. The test is performed on all new wells and then repeated at certain intervals during the producing life of the well. The produced oil and gas can be measured by the available standard equipment at the lease tank battery or by the use of a special test unit. This test is the most frequently conducted well test. The method of testing is usually specified by state law or regulation.

Bottom-Hole Pressure Test. The *bottom hole pressure (BHP) test* measures the pressure in the producing reservoir formation. In this test, a special pressure gauge is lowered into the well by means of a wireline. The gauge records the pressure at the selected depth and is removed from the well. There are a number of variations of this test, including a *flowing bottom hole pressure test* (taken when the well is flowing), a *shut-in bottom hole pressure test* (taken when the well is shut in for a specific length of time), etc. These tests are performed at scheduled intervals, providing important information about formation pressure changes. This information determines if there is a need (initially or later) for the installation of artificial lift equipment.

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Productivity Test. The *productivity test* determines the effects of different flow rates on the pressure within a reservoir. This is the most widely used method of determining well capacity without actually doing anything potentially damaging to the well. The procedure first measures the "closed-in bottom-hole pressure". Then the well is opened and produced at several rates. At each rate, the flowing bottom-hole pressure is measured. The obtained information is then interpreted by an engineer who can provide an estimate of the maximum flow that can be expected from the well. Productivity tests usually provide the basis for regulating gas wells.

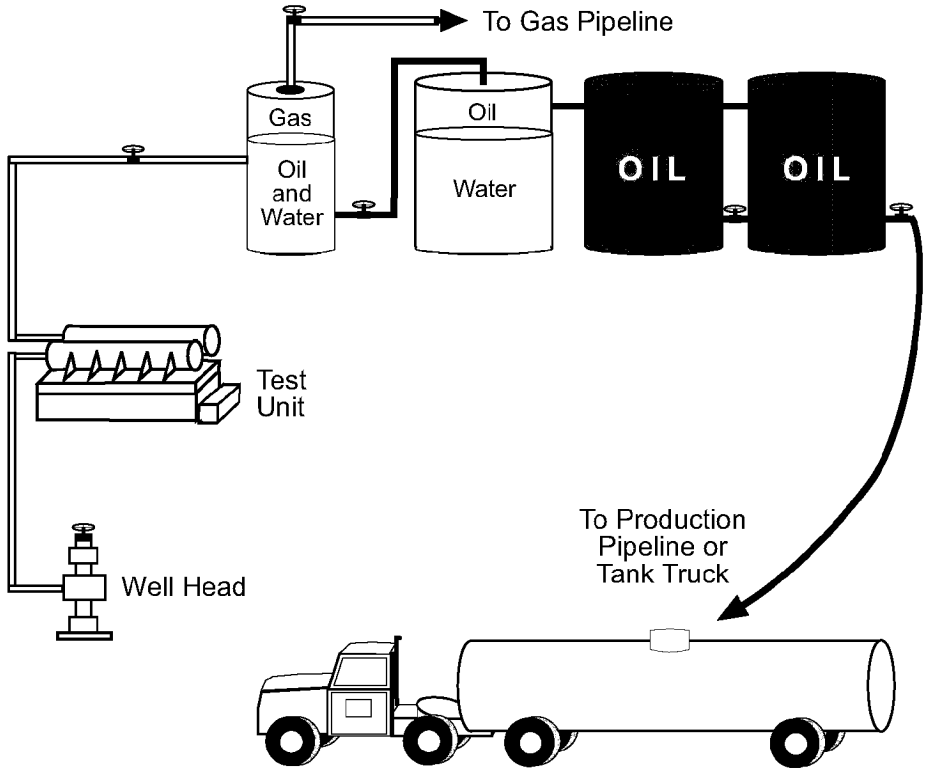

Figure 2.27 Productivity Test

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Typical Measurements Taken on a Producing Well

Testing and evaluating a well is a continuous process throughout its producing life. Tests vary considerably as to frequency, point of measurement, climatic considerations, etc. Below is an illustration showing the points throughout the producing and treating system that are regularly monitored.

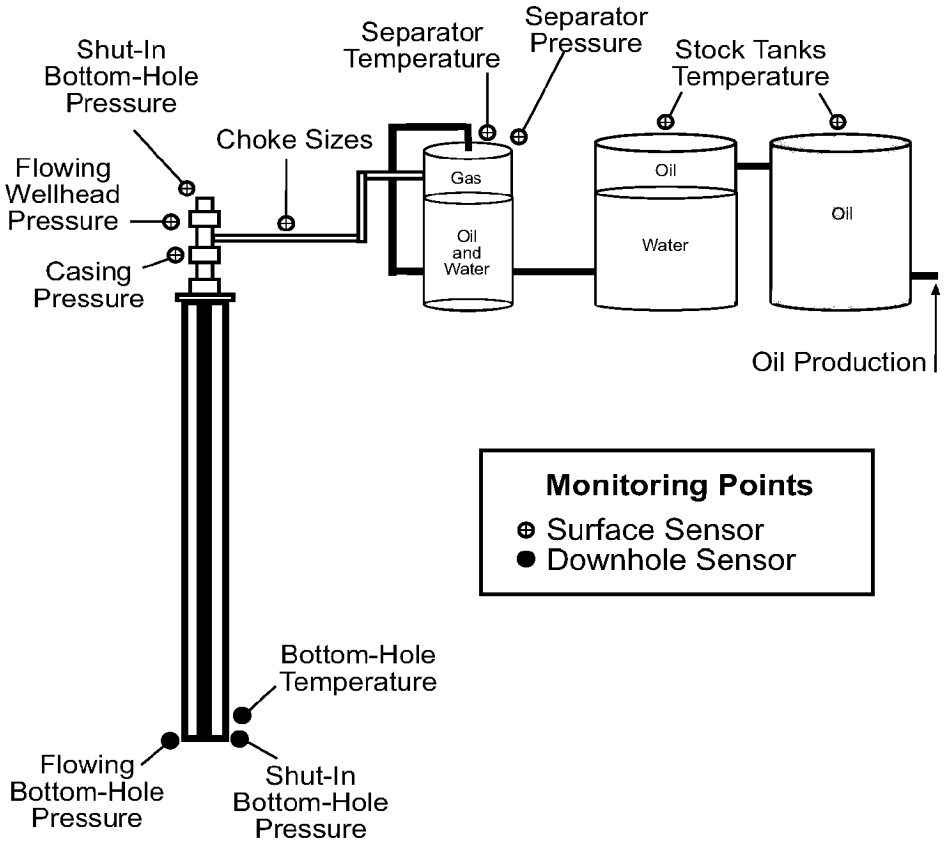

Figure 2.28 Typical Measurements Taken on a Producing Well

1. **Oil Production**

   The amount of oil produced from a well, expressed in barrels (bbls).

2. **Gas Production**

   The amount of gas produced from a well, expressed in cubit feet (CF).

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3. **GOR: Gas/Oil Ratio**

   The number of cubic feet of natural gas produced with a barrel of oil. A high GOR is an indication that the reservoir pressure is being depleted rapidly. This is an extremely undesirable situation.

4. **WOR: Water/Oil Ratio**

   The measure of the percentage of the total amount of water being produced with each barrel of oil. A high WOR may indicate a water breakthrough to the wellbore, often resulting in a dramatic decrease in oil production and profitability.

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Chapter 3 Hydraulics, Mud Data, and Mud Systems

Hydraulics as applied in the oil field is a combination of known facts and observed relationships. The known facts are those that can be measured accurately, such as drill pipe OD (outer diameter), casing ID (inner diameter), and mud weight. While the mud weight can be accurately measured, the flow behavior of the mud cannot and therefore, is an observed or empirical factor in hydraulic measurements. Other observed factors include such things as hole size and hole shape, and can only be "within range" at best. Most hydraulic calculations are the "within range" type because the behavior of the drilling mud under pressured flow is not completely understood.

There are two accepted methods by which to calculate oil field hydraulics. The older method is the *Bingham Plastic method*. In recent years, the Bingham Plastic method has been replaced by the *Power Law method* when dealing with water-based muds. It is generally accepted that Power Law is more accurate than Bingham Plastic, except in the case of oil-based muds. Both methods will be explained later in this chapter.

3.1 Bingham Plastics

The Bingham Plastic flow model was the method used for years to calculate pressure losses in the circulating system. While not as accurate as the Power Law model with water-base drilling fluids, it is the most accurate with oil-bases drilling muds. Therefore, it is necessary to know both systems.

Rheology in the Bingham model is basically concerned with plastic viscosity (PV) and yield point (YP). These two numbers can usually be obtained from the mud engineer's report. The plastic viscosity is calculated by subtracting the 300 rpm reading of a rheometer from the 600 rpm reading. The yield point is calculated by subtracting the PV from the 300 rpm

number.

Example:

600 rpm = 97
300 rpm =59

$$\begin{aligned} PV &= 600 \text{ rpm} - 300 \text{ rpm} \\ &= 97 - 59 \\ &= 38 \end{aligned}$$

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$$YP = 300\ \text{rpm} - PV$$
$$= 59 - 38$$
$$= 21$$

Determining well bore hydraulics requires that pressure drops from the drill string and annulus be calculated. This section provides the formulas and methods for determining drill string and annular hydraulics. The hydraulics of the drill bit will be discussed later.

3.1.1 Drill String (Bingham Plastics Model)

The following equations are an approximate solution to the Bingham model used in INSITE. Calculate the pressure drop for each hydraulic drill string section. A hydraulic section is defined as a length of drill string with a consistent ID, such as the drill pipe.

1. Calculate average velocity (V ft/min, Q gpm, D_p in)

$$V = \frac{24.51Q}{D_p^2}$$

2. Calculate the pipe pressure drop for Laminar flow or smooth flow (P_L psi, PV cp, L ft, V ft/min, D_p in, YP lb/100ft^2)

$$P_L = \frac{PV \times L \times V}{90000 D_p^2} + \frac{YP \times L}{225 D_p}$$

3. Calculate the apparent viscosity (P_L psi, ρ ppg, PV cp, YP lb/100ft^2, D_p in)

$$\mu = \frac{90000 \times P_L \times D_p^2}{L \times V}$$

4. Calculate the Reynolds number (Re, D_p in, V ft/min, ρ ppg, PV cp)

$$Re = \frac{15.47 \times D_p \times V \times \rho_f}{\mu}$$

5. If the Reynolds number is less than or equal to the critical Reynolds number (typically about 2000), then the flow is laminar.

$$Re \leq 2000$$
$$P = P_L$$

If the Reynolds number is greater than the critical Reynolds number, then the flow is turbulent.

$$Re > 2000$$
$$P = P_T$$

The following additional calculations will be required to calculate the turbulent pressure drop.

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6. Calculate the Fanning friction factor (f).

$$f = \frac{0.079}{Re^{0.25}}$$

7. Calculate the pipe pressure drop for Turbulent flow (P_L psi, PV cp, L ft, V ft/min, D_p in, YP lb/100ft^2)

$$P = P_T = \frac{f \times L \times \rho_f \times V^2}{92903 D_p}$$

8. Calculate critical velocity (V_c ft/min, ρ ppg, PV cp, YP lb/100ft^2, D_p in)

$$V_c = \frac{64.8PV + 64.8\sqrt{PV^2 + 12.34D_p^2 \times YP \times \rho_f}}{\rho_f \times D_p}$$

These calculations must be performed for each drill string hydraulic section.

Example - Bingham Pipe Flow

Depth	=	10,000 feet
Bit diameter	=	12.25 inches
Drill pipe OD	=	5 inches
Drill pipe ID	=	4.276 inches
Drill collars OD	=	8 inches
Drill collars ID	=	3 inches
Drill collar length	=	500 feet
Mud weight	=	12.4 ppg
PV	=	31 cp
YP	=	11 lb/100 ft^2
Pump output	=	400 gpm

For the drill pipe

1. Calculate average velocity (V ft/min, Q gpm, D_p in)

$$V = \frac{24.51 \times Q}{D_p^2}$$

$$= \frac{24.51 \times 400}{4.276^2}$$

$$= 536.2 \text{ ft/min}$$

2. Calculate the pipe pressure drop for Laminar flow or smooth flow (P_L psi, PV cp, L ft, V ft/min, D_p in, YP lb/100ft^2)

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$$P_L = \frac{PV \times L \times V}{90000D_p^2} + \frac{YP \times L}{225D_p}$$

$$= \frac{31 \times 9500 \times 536.2}{90000 \times 4.276^2} + \frac{11 \times 9500}{225 \times 4.276}$$

$$= 204.6$$

3. Calculate the apparent viscosity μ (P_L psi, D_p in, V ft/min)

$$\mu = \frac{90000 \times P_L \times D_p^{\ 2}}{L \times V}$$

$$= \frac{90000 \times 204.6 \times 4.276^2}{9500 \times 536.2}$$

$$= 66.08$$

4. Calculate the Reynolds number (Re, D_p in, V ft/min, ρ ppg, μ cp)

$$Re = \frac{15.47 \times D_p \times V \times \rho_f}{\mu}$$

$$= \frac{15.47 \times 4.276 \times 536.2 \times 12.4}{66.08}$$

$$= 6655$$

5. If the Reynolds number is less than or equal to the critical Reynolds number (typically about 2000), then the flow is laminar.

   $Re \leq 2000$

   $P = P_L$

   If the Reynolds number is greater than the critical Reynolds number, then the flow is turbulent.

   $Re >$

   $P = P_T$

   The following additional calculations will be required to calculate the turbulent pressure drop.

6. Calculate the Fanning friction factor (f).

$$f = \frac{0.079}{Re^{0.25}}$$

$$= \frac{0.079}{6655^{0.25}}$$

$$= 0.00875$$

7. Calculate the pipe pressure drop for Turbulent flow (P_L psi, PV cp, L ft, V ft/min, D_p in, YP lb/100ft^2)

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$$P_T = \frac{f \times L \times \rho_f \times V^2}{92903 D_p}$$

$$= \frac{0.00875 \times 9500 \times 12.4 \times 536.2^2}{92903 \times 4.276}$$

$$= 746 \text{ psi}$$

Note: INSITE calculates the turbulent pressure drop as 741 psi

8. Calculate critical velocity (V_c ft/min, ρ ppg, PV cp, YP lb/100ft^2, D_p in)

$$V_c = \frac{64.8PV + 64.8\sqrt{PV^2 + 12.34D_p^2 \times YP \times \rho_f}}{\rho_f \times D_p}$$

$$= \frac{64.8 \times 31 + 64.8\sqrt{31^2 + 12.34 \times 4.276^2 \times 11 \times 12.4}}{12.4 \times 4.276}$$

$$= 256 \text{ ft/min}$$

Note: INSITE calculates the critical velocity as 184 ft/min.

These calculations must be performed for each drill string hydraulic section.

3.1.2 Annulus (Bingham Plastic Model)

Determine the type of flow that is occurring in each hydraulic section of the annulus. A hydraulic section is defined as a length of annulus with a consistent OD and ID, such as the open hole and the drill collars. To determine the flow type:

1. Calculate average velocity (V ft/min, Q gpm, D_h in, D_p in)

$$V = \frac{24.51Q}{D_h^2 - D_p^2}$$

2. Calculate the pipe pressure drop for Laminar flow or smooth flow (P_L psi, PV cp, L ft, V ft/min, D_p in, YP lb/100ft^2)

$$P_L = \frac{PV \times L \times V}{60000(D_h^2 - D_p^2)} + \frac{YP \times L}{200(D_h - D_p)}$$

3. Calculate the apparent viscosity (P_L psi, ρ ppg, PV cp, YP lb/100ft^2, D_p in)

$$\mu = \frac{60000 \times P_L \times (D_h - D_p)^2}{L \times V}$$

4. Calculate the Reynolds number (Re, D_p in, V ft/min, ρ ppg, PV cp)

$$Re = \frac{15.47 \times (D_h - D_p) \times V \times \rho_f}{\mu}$$

5. If the Reynolds number is less than or equal to the critical Reynolds number (typically about 2000), then the flow is laminar.

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$Re \leq 2000$

$P = P_L$

If the Reynolds Number is greater than the critical Reynolds number, then the flow is turbulent.

$Re > 2000$

$P = P_T$

The following additional calculations will be required to calculate the turbulent pressure drop.

6. Calculate the Fanning friction factor (f).

$$f = \frac{0.079}{Re^{0.25}}$$

7. Calculate the pipe pressure drop for Turbulent flow (P_L psi, PV cp, L ft, V ft/min, D_p in, YP lb/100ft^2)

$$P = P_T = \frac{f \times L \times \rho_f \times V^2}{92903(D_h - D_p)}$$

8. Calculate critical velocity (V_c ft/min, ρ_f ppg, PV cp, YP lb/100ft^2, D_h in, D_p in)

$$V_c = \frac{64.8PV + 64.8\sqrt{PV^2 + 9.27(D_h - D_p)^2 \times YP \times \rho_f}}{\rho_f \times (D_h - D_p)}$$

These calculations must be performed for each annular hydraulic section.

The main reason for determining the pressure drop in the annulus is so the equivalent circulating density (ECD) can be calculated. ECD is the combined pressure being exerted hydrostatically by the mud and the mud pump when the system is circulating. The annular pressure drop is the pressure being exerted on the annulus by the mud pump to overcome friction. To determine the ECD:

1. Calculate the pressure drop in the annulus
2. Calculate ECD

$$ECD = \rho_f + \frac{P}{0.052 \times L}$$

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Example - Bingham Annular Flow

Depth	=	10,000 feet
Bit diameter	=	12.25 inches
Drill pipe	=	5 inches OD
Drill collars	=	8 inches OD
Drill collar length	=	500 feet
Mud weight	=	12.4 ppg
PV	=	31 cp
YP	=	11 lb/100 ft^2
Pump output	=	400 gpm

For the open hole/drill pipe

1. Calculate average velocity (V ft/min, Q gpm, D_p in)

$$V = \frac{24.51Q}{D_h^2 - D_p^2}$$

$$= \frac{24.51 \times 400}{12.25^2 - 5^2}$$

$$= 78.4 \text{ ft/min}$$

2. Calculate the pipe pressure drop for Laminar flow or smooth flow (P_L psi, PV cp, L ft, V ft/min, D_p in, YP lb/100ft^2)

$$P_L = \frac{PV \times L \times V}{60000(D_h^2 - D_p^2)} + \frac{YP \times L}{200(D_h - D_p)}$$

$$= \frac{31 \times 9500 \times 78.4}{60000 \times (12.25^2 - 5^2)} + \frac{11 \times 9500}{225 \times (12.25 - 5)}$$

$$= 67.1 \text{ psi}$$

3. Calculate the apparent viscosity (P_L psi, D_p in, V ft/min)

$$\mu = \frac{60000 \times P_L \times (D_h - D_p)^2}{L \times V}$$

$$= \frac{60000 \times 67.1 \times (12.25 - 5)^2}{9500 \times 78.4}$$

$$= 284.2$$

4. Calculate the Reynolds number (Re, D_p in, V ft/min, ρ ppg, μ cp)

$$Re = \frac{15.47 \times (D_h - D_p) \times V \times \rho_f}{\mu}$$

$$= \frac{15.47 \times (12.25 - 5) \times 78.4 \times 12.4}{284.2}$$

$$= 384$$

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5. If the Reynolds number is less than or equal to the critical Reynolds number (typically about 2000), then the flow is laminar.

   $Re \leq 2000$

   $384 \leq 2000$

   $P = P_L = 67$ psi

   Note: INSITE calculates the laminar pressure drop as 67 psi

6. Calculate critical velocity (V_c ft/min, ρ_f ppg, PV cp, YP lb/100ft^2, D_p in)

$$V_c = \frac{64.8PV + 64.8\sqrt{PV^2 + 9.27(D_h - D_p)^2 \times YP \times \rho_f}}{\rho_f \times (D_h - D_p)}$$

$$= \frac{64.8 \times 31 + 64.8\sqrt{31^2 + 9.27(12.25 - 5)^2 \times 11 \times 12.4}}{12.4 \times (12.25 - 5)}$$

$$= 209 \text{ ft/min}$$

   Note: INSITE calculates the critical velocity as 199 psi

These calculations must be performed for each annular hydraulic section.

3.1.3 Slip Velocity

An annular hydraulics review would not be complete without a discussion of slip velocity. The rate at which cuttings fall back toward bottom is called slip velocity.

To determine the slip velocity of cuttings:

1. Determine the type of flow using the same method as for the annulus flow, see page 3-5.
2. If the flow is laminar use the following:
   a. Calculate the apparent viscosity μ (P_L psi, D_h in, D_p in, L ft, V ft/min):

$$\mu = \frac{P_L \times 60000 \times (D_h - D_p)}{L \times V}$$

   b. Calculate the slip velocity (V_s ft/min, D_c in, ρ_c ppg, ρ_f ppg, μ)

$$V_s = 175 \times D_c \left[\frac{(\rho_c - \rho_f)^2}{\mu \times \rho_f}\right]^{0.33}$$

3. If the flow is turbulent use the following:
   a. Calculate the slip velocity

$$C_D = 1.5$$

$$V_s = 113.4 \times \sqrt{\frac{D_c \times (\rho_c - \rho_f)}{D_c \times \rho_f}}$$

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Example - Slip Velocity

Depth	=	10,000 feet
Bit diameter	=	12.25 inches
Drill pipe	=	5 inches OD
Drill collars	=	8 inches OD
Drill collar length	=	500 feet
Mud weight	=	12.4 ppg
PV	=	31 cp
YP	=	11 lb/100 ft^2
Pump output	=	400 gpm
Cuttings density	=	21 ppg
Cuttings diameter	=	0.2 inches

Slip Velocity around the drill collars

1. Determine the type of flow.
2. For turbulent flow use the following:
   a. Calculate the slip velocity

$$C_D = 1.5$$

$$V_s = 113.4 \times \sqrt{\frac{D_c \times (\rho_c - \rho_f)}{C_D \times \rho_f}}$$

$$= 113.4 \times \sqrt{\frac{0.2 \times (21 - 12.4)}{1.5 \times 12.4}}$$

$$= 34 \text{ ft/min}$$

Slip Velocity around the drill pipe

1. Determine the type of flow (using the same method as for the annulus)
2. For laminar flow use the following:
   a. Calculate the apparent viscosity μ:

$$\mu = \frac{60000 \times P_L \times (D_h - D_p)^2}{L \times V}$$

$$= \frac{60000 \times 67.1 \times (12.25 - 5)^2}{9500 \times 78.4}$$

$$= 284.2$$

   b. Calculate the slip velocity

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$$V_s = 175 \times D_c \left[\frac{(\rho_c - \rho_f)^2}{\mu \times \rho_f} \right]^{0.33}$$

$$= 175 \times 0.2 \left[\frac{(21 - 12.4)^2}{284.2 \times 12.4} \right]^{0.33}$$

$$= 10 \text{ ft/min}$$

The Bingham Plastic flow model is more accurate for oil-based muds than the Power Law flow model. Determining pressure drops is necessary before the ECD can be calculated, if lost circulation is to be prevented. Knowing what the ECD is becomes more and more critical the closer the mud weight comes to the fracture strength of the open hole. To insure that the hole is being cleaned at the proper rate, the annular velocity should be at least twice that of the slip velocity.

3.2 Power Law Model

The Power Law flow model is the most accurate method to use with water-based muds. The same kind of calculations are required as in the Bingham Plastic model. The difference is in the formula values.

The *n* and *k* factors are used to replace the PV and YP values in the formulas. The rheology of the Power Law model is different from that of the Bingham Plastic model because it allows for a more plastic or pseudo-fluid behavior. A water-based drilling fluid under pressure and high temperature behaves more like plastic than water. The Power Law flow model is adjusted for this and therefore, produces more accurate information.

To determine the n and k factors, the 300 rpm and 600 rpm rheometer readings are required. These can also be calculated from PV and YP.

$$n = 3.32 \log \frac{600 \text{ rpm}}{300 \text{ rpm}}$$

$$K = \frac{300 \text{ rpm}}{511^n}$$

3.2.1 Drill String (Power Law Model)

The following equations are the Power Law equations used in INSITE. They are presented for information only.

1. Calculate average velocity (V ft/min, Q gpm, D_p in)

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$$V = \frac{24.51Q}{D_p^2}$$

2. Calculate the pipe pressure drop for Laminar flow or smooth flow (P_L psi, K, L ft, V ft/min, D_p in, n)

$$P_L = \frac{L \times K}{300D_p}\left[\frac{1.6V}{D_p} \times \frac{(3n+1)}{4n}\right]^n$$

3. Calculate the critical Reynolds number (n)

$$Re_c = 3470 - 1370n$$

4. Calculate the apparent viscosity (P_L psi, ρ ppg, PV cp, YP lb/100ft^2, D_p in)

$$\mu = \frac{90000 \times P_L \times D_p^2}{L \times V}$$

5. Calculate the Reynolds number (Re, D_p in, V ft/min, ρ ppg, PV cp)

$$Re = \frac{15.47 \times D_p \times V \times \rho_f}{\mu}$$

6. If the Reynolds number is less than or equal to the critical Reynolds number, then the flow is laminar.

$$Re \leq 2100$$
$$P = P_L$$

If the Reynolds number is greater than the critical Reynolds number, then the flow is turbulent.

$$Re > 2100$$
$$P = P_T$$

The following additional calculations will be required to calculate the turbulent pressure drop.

7. Calculate the Fanning friction factor (f).

$$f = \frac{0.079}{Re^{0.25}}$$

8. Calculate the pipe pressure drop for Turbulent flow (P_L psi, PV cp, L ft, V ft/min, D_p in, YP lb/100ft^2)

$$P = P_T = \frac{f \times L \times \rho_f \times V^2}{92903D_p}$$

9. Calculate critical velocity (V_c ft/min, ρ ppg, PV cp, YP lb/100ft^2, D_p in)

$$V_c = \frac{64.8PV + 64.8\sqrt{PV^2 + 12.34D_p^2 \times YP \times \rho_f}}{\rho_f \times D_p}$$

These calculations must be performed for each drill string hydraulic section.

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To determine the pressure drops in the drill string:

Step #1:

Calculate the average velocity the same as for the Bingham Model.

Step #2:

Calculate the critical velocity.

Formula: $$V_C = \frac{[5.82 \times 10^4 \times k]^{\frac{1}{2-n}}}{W} \frac{[(1.6)}{d} \frac{(3n+1)]^{\frac{n}{2-n}}}{4n}$$

Step #3:

Determine flow type.

a. $V \leq V_C$ = Laminar flow

b. $V > V_C$ = Turbulent flow

Step #4:

Determine the pressure drop.

a. Laminar flow

Formula: $$P_d = \frac{[(1.6V)}{D} \frac{(3n+1)]^n}{4n} \times \frac{K \times L}{300D}$$

b. Turbulent flow

Formula: $$P_d = \frac{7.7 \times 10^{-5} \times W^{0.8} \times PO^{1.8} \times PV^{0.2}}{D^{4.8}}$$

3.2.2 Annulus: (Power Law Model)

Annular pressure drops are calculated for the purpose of determining the ECD of the circulating system. The procedure is the same as that of the drill string, except for different formulas. The formulas for n, k, and v are the same to determine the ECD in the annulus:

Step #1:

Calculate V.

Step #2:

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Calculate V_C.

Formula: $$V_C = \frac{(38780K)^{\frac{1}{2-n}}}{W} \times \left[\frac{(2.4)}{d_h - d_p} \cdot \frac{(2n+1)^{\frac{n}{2-n}}}{3n} \right]$$

Step #3:

Determine type of flow.

Step #4:

Calculate pressure drop (laminar).

Formula: $$P_d = \frac{[(2.4V)}{d_h - d_p} \cdot \frac{(2n+1)]^n}{3n} \times \frac{K \times L}{300(d_h - d_p)}$$

Step #5:

Repeat Steps 1 through 4 until all of the hydraulic sections are done.

Step #6:

Calculate the ECD.

Formula: $$ECD = W + \frac{P_d}{0.052 \times L}$$

The determination of well bore hydraulics is an important part of oilfield hydraulic calculations. Pressures generated by circulating the drilling fluid affect the stability of the well bore. If too much pressure is generated, the possibility of loss circulation becomes great. Loss of returns can lead to a number of other problems like hole collapse, stuck pipe and kicks.

Power Law slip velocity is generally less than Bingham Plastic slip velocity. It is also much more complex to calculate. If slip velocity is calculated using Bingham Plastic formulas, adequate hole cleaning will be maintained.

To calculate slip velocity using Power Law:

Step #1:

Determine mud viscosity.

Formula: $$\mu = \frac{[(2.4V)(2n+1)]^n}{d_h - d_p \quad 3n} \times 200 \times K \times (d_h - d_p)$$

Step #2:

Determine slip velocity.

Formula: $$S_V = \frac{175 \times Dc \times (Wc - W)^{0.667}}{w^{0.333} \times \mu^{0.333}}$$

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The Power Law method should always be used in determining the hydraulic characteristics of water-based drilling fluids. It is a more complex system of calculations than the Bingham Plastic model, and therefore requires a deeper understanding.

3.3 Swab/Surge Pressure

Swab pressure is the negative pressure produced by pipe movement upward. Surge pressure is the positive pressure generated by pipe movement downward. These pressures must be checked on trip and casing runs to insure that a formation is neither swabbed in or broken down by excessive pressures.

To determine the nature of the pressures being generated, the speed of the pipe must be known. Using a watch, time the stand or casing joint. Then determine the maximum velocity of the pipe.

3.3.1 Plugged Pipe

Formulas:

$$V_A = \frac{(0.45 + d_p^2)}{d_h^2 - d_p^2} \cdot \frac{(T_p)}{P_L}$$

$$V_n = 1.5\ (V_A)$$

3.3.2 Open Pipe

Formulas:

$$V_A = [0.45 + \frac{(d_p^2 - d_i^2)]}{d_h^2 - d_p^2 + d_i^2} \cdot \frac{(T_p)}{P_L}$$

V_n	=	1.5 (V_A)
d_h	=	diameter of hole (inches)
d_p	=	diameter of pipe (inches)
d_i	=	inside diameter of pipe (inches)
T_p	=	travel time of joint or stand (minutes)
P_L	=	length of joint or stand (feet)
V_A	=	average pipe velocity (ft/min)
V_n	=	maximum pipe velocity (ft/min)

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Step #1:

Calculate swab/surge pressure.

Formula: $$= \left[\frac{(2.4Vn)}{d_h - d_p}\frac{(2n+1)}{3n}\right]^n \times \frac{K \times L}{300 \times (d_h - d_p)}$$

Step #2:

Calculate hydrostatic pressure.

Swab

Formula: $H_A = H - S_w$

Surge

Formula: $H_A = H + S_u$

A	=	Static bottom hole hydrostatic pressure
H_A	=	Bottom hole hydrostatic during pipe movement
S_w	=	Swab pressure
S_u	=	Surge pressure

If the hydrostatic pressure is either less than formation pressure or greater than fracture pressure, the speed of the pipe must be reduced to ensure the safety of the well.

3.4 Bit Hydraulics

With the introduction of drill bits with fluid jets, the determination of the hydraulic characteristics of the bit became important. Time can be saved by proper utilization of the hydraulic horsepower of the mud pump at the bit. Two methods are being used in the field. The first method requires that the pump pressure used to force the mud through the fluid jets be held to 65% of the available pressure. To adjust the system, either the flow rate or the jet sizes must be manipulated to produce the 65% at the bit. The accepted way is to change the jets. This system is called the *hydraulic horsepower method.*

The other system requires the utilization of 48% of the available mud pump pressure at the bit. This method optimizes the impact force of the mud on the formation at the bit, and is called the *impact force method.*

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The recommended percentages cannot always be used because of limitations such as lost circulation material, pump size, and pipe size; yet the closest approximation of these percentages should be attempted.

The use of either method is primarily determined by the mud pump size, annular velocity requirements and the possibility of lost circulation. The impact force method allows the use of larger jets or slower pump rates than does the hydraulic horsepower method.

To calculate the needed factors for either method requires that the hydraulic characteristics of the previous bit be determined first.

Step #1:

Calculate the jet area.

Formula: $A_N = .00076699\ (J_1{}^2 + J_2{}^2 + J_3{}^2)$

Step #2:

Calculate the jet velocity.

Formula: $JV = \frac{0.32083(OP)}{A_N}$

Step #3:

Calculate the pressure drops.

Formulas: $P_{db1} = \frac{OP^2 W}{12031(A_N^2)} \times 9025$

$D_{dxbl} = D_{ds} - P_{db}$

Step #4:

Calculate the hydraulic horsepower at the pump.

Formula: $HHP_S = \frac{PP \times OP}{1714}$

Step #5:

Calculate the hydraulic horsepower at the bit.

Formula: $HHP_b = \frac{Pdb \times OP}{1714}$

Step #6:

Calculate the % of HHP at the bit.

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Formula: % = $\frac{HHPb}{HHPs} \times 100$

Step #7:

Calculate the impact force.

Formula: I.F. = $\sqrt{Pd_d \times W} \times (0.0173)(OP)$

After determining these numbers, the choice of systems must be made. If HHP optimization is desired, then the constant .35 must be used. Impact force requires the use of .52. The maximum allowable pump pressure must be determined (this is usually done by asking the toolpusher). The maximum and minimum flow rates must also be decided. Usually, the maximum is the output at which critical flow around the pipe occurs, and the minimum is least at which proper hole cleaning can be maintained. The steps in optimization are:

Step #1:

Calculate the maximum pump output.

Formula: OP_m = $\frac{((0.52 or 0.35)\dot{P}m)^{0.538}}{Pd_{xb1}} \times OP$

Step #2:

Calculate the pressure drop excluding the bit.

Formula: Pd_{xb2} = $\frac{(OPm)^{1.86}}{OP} \times Pd_{xb1}$

Step #3:

Calculate the pressure drop through the bit.

Formula: Pd_b = $Pm - Pd_{xb}$

Step #4:

Calculate the jet area.

Formula: A_N = $\frac{0.32(OPm)}{\sqrt{\frac{Pd_{b2}}{W} \times 1120}}$

Step #5:

Calculate the jet size in 32's.

Formula: J s = $\sqrt{\frac{A_N}{(0.00076699)(3)}}$

Step #6:

Calculate the jet velocity.

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Formula: $JV = \frac{(0.32)(OPm)}{A_N}$

Step #7:

Calculate the impact force.

Formula: $I.F. = \frac{(JV)(W)}{1932} \times OPm$

Step #8:

Calculate the hydraulic horsepower at the bit.

Formula: $HHP_b = \frac{(Pdb)}{1714} \times OPm$

A_N	=	area in inches ^{2} of jets
OP	=	pump output (gpm)
W	=	mud weight (ppg)
J_1	=	size of jet #1 in 32's
J_2	=	size of jet #2 in 32's
J_3	=	size of jet #3 in 32's
Pd_{bl}	=	pressure drop at the bit of the previous bit (psi)
Pd_{xb1}	=	pressure drop excluding the previous bit (psi)
JV	=	Jet velocity (ft/sec)
IF	=	Impact force
HHP_s	=	hydraulic horsepower available at the surface
HHP_b	=	hydraulic horsepower at the bit
OP_m	=	maximum pump output (pgm)
Pd_{xb2}	=	pressure drop excluding the bit (psi)
Pd_{b2}	=	pressure drop at the bit (psi)
P_m	=	maximum allowable pump pressure (psi)
P_s	=	pump pressure of the previous bit (psi)
P_p	=	pump pressure (psi)

By following these steps, a bit hydraulics program can be obtained.

The use of either system on a continuing basis by the operator will decrease the time required to drill the well to total depth. One important thing to remember is the effect a change in mud weight will have on the utilization percentage at the bit. A reduction in mud weight reduces the percentage, while an increase will occur with an increase in mud weight. If an increase is expected during the life of the bit, then the jet sizes should be increased slightly. A rule of thumb is for one 32 for each .5 ppg increase.

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To develop a hydraulics program for a well requires a little time and effort on our part as surface data loggers. While not all operators use the information developed, those that do are always appreciative of your efforts. It is to your benefit to learn the methods and techniques described above.

3.5 Mud Data

The following is a brief explanation of the mud data in PC-2000 mud record:

3.5.1 Density

Any accepted terminology that indicates the weight per unit volume of a drilling fluid that may be used to determine the hydrostatic pressure exerted by that fluid. It is measured in four basic ways, as follows: pounds per gallon (ppg), pounds per cubic foot (CF), specific gravity (SP), and gradient psi per 1000 feet of depth.

The effects of density are as follows: hydrostatic pressure, pressure differential on the formation, and therefore, the drilling rate, hydraulics, circulating pressure, lifting capacity and hole cleaning, flow patterns (laminar or turbulent), and stability of pressured formations.

3.5.2 Rheology

To understand rheology, you must first understand viscosity. Viscosity is a measure of the internal resistance of a fluid to flow; the greater the viscosity, the greater the resistance. For drilling operations, viscosity of mud must be controlled and a standard means of measuring viscosity is provided. Hole size, hole condition, pumping rate, drilling rate, cuttings size, caving, presence or absence of shale separators, mud weight, design of the pit system, and gel characteristics of the mud are factors influencing the specification of the viscosity of any mud.

Fluid phases of drilling fluids are water, oil, synthetic fluids, and air. The viscosity of water varies somewhat with temperature and with the concentration of various substances that may be dissolved in the water. Oils of varied viscosities may be used in drilling fluids, and the viscosity of each individual oil varies further with temperature and pressure. In a liquid mud, the volume percent of solids for a given mud weight depends upon the specific gravity of the solids. With regard to particle shape, the viscosity of a slurry will be the lowest when the solid particles in it are spherical.

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The two most common instruments used in the oil field for determining mud viscosity are the marsh funnel and a variable speed rheometer.

On a rig, when you hear the viscosity called out, that viscosity is determined using the marsh funnel. The viscosity is the measured times it takes for one quart of mud to gravity feed through a hole of a specific diameter. As a rule of thumb, the viscosity determined by the marsh funnel should be three to four times the mud weight. This is strictly a generalization and does not apply in every case.

The variable speed rheometer relates viscosity to shear rate and shear stress. The two speeds or shear rates most commonly used are the 600 rpm and the 300 rpm. The shear stress is the dial reading given by the rheometer at a given shear rate. 600 is the shear stress reading at 600 rpm. Similarly, 300 is the shear stress reading at 300 rpm.

Shear rate and shear stress, along with viscosity, describe flow patterns of the drilling fluid. Flow behavior of oil field muds is generally classified as either Newtonian, Bingham Plastic or Power Law. Newtonian fluids are characterized by constant viscosity, independent of shear rate. Water, glycerin, and diesel are examples of Newtonian fluids.

Virtually all drilling fluids that contain clay flow in a quasi-Bingham Plastic manner.

The following equations describe the flow behavior of drilling fluids:

Newtonian	T	$=$	$\mu(-\gamma)$
Bingham Plastic	T	$=$	$Y + (PV)(-\gamma)$
Power Law	T	$=$	$K(-\gamma)^n$

Where:

T	$=$	shear stress ($lb_f/100\ ft^2$)
μ	$=$	viscosity (centipoise)
γ	$=$	shear rate (sec^{-1})
PV	$=$	plastic viscosity (centipoise)
Y	$=$	yield point ($lb_f/100\ ft^2$)
n	$=$	slope of shear stress versus shear rate (straight line on log paper)
K	$=$	intercept of shear stress versus shear rate (straight line on log paper)

Similarly, PV is the slope of the straight line portion of the stress-strain curve, and YP is the intercept value of zero shear.

$$n = 3.32\log\frac{(\theta 600)}{\theta 300}$$

is referred to as the flow behavior index,

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$$K = \frac{\theta 300}{(511)n}$$

and is referred to as the consistency index.

$$PV = \theta 600 - \theta 300$$

$$YP = \theta 300 - PV$$

The plastic viscosity is governed by the viscosity of the base fluid and the size, shape and number of particles composing the mud. The yield point is controlled by the interparticle forces. The flow profile of the annulus is described by *n* and ranges from one to approaching zero. *K* describes the pumpability of the fluid.

When drilling, the most important rheological property is the yield point. This is because changes in the yield point are the most readily noticed. A high yield point shows the mud is thick; a low yield point shows the mud is thin. Also, changes in the yield point can drastically change the hole's hydraulics; most noticeably the ECD and the slip velocity. Changes in the PV usually indicate a change in the fluid's solids content. Changes in *n* are only indicative of alterations in the laminar annular flow profile. Alterations in the circulating system pressure losses are indicated by *K*. The higher the *K* value, the higher the system pressure losses.

The hydraulics of a water-based mud conform best to those defined by the Power Law equations. The hydraulics of an oil-based mud conform best to those defined by the Bingham Plastic equations. For the most accurate results, use the Power Law equations with water-based muds, and Bingham Plastic equations with oil-based muds.

Funnel viscosity

Funnel viscosity is a routine field measurement of drilling fluid viscosity made with a marsh funnel. This measures the timed rate of flow in seconds per quart. The values obtained are called "apparent" viscosity.

Plastic Viscosity

Plastic viscosity is the part of the flow resistance in a mud caused primarily by the friction between the suspended particles and by the viscosity of the continuous liquid phase. For practical purposes, plastic viscosity depends on the concentration of solids present and the size and shape of these solid particles.

Yield Point

Yield point is a measurement under flowing conditions of the forces in mud which cause gel structure to develop when the mud is at rest. These forces exist between the

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solid particles, and are the result of positive and negative electrical charges located on or near the surface of each particle. When the mud is at rest, the solid particles tend to arrange themselves in such a manner that these attractive/repulsive forces are best satisfied.

Gel Strength

Gel strength is a rheological property of a drilling fluid at rest. Drilling mud has gel strength when a force is required to start moving the mud. Gel strength arises mainly from attraction between particles and from friction between solids in suspension or between the solids and the liquid around them. Gels can be progressive, in that gel strength may increase continuously for a long period of time, while other muds may reach a near-maximum gel strength in a brief period of time. These latter muds are said to have "flat" gels. A mud with "fragile" gels is one having *low* flat gels. An increase in gel observed over several days in a well may indicate that the mud is thickening too much during trips. The mud should therefore be treated, or perhaps high temperature shear tests should be run to get further evidence.

The effects of rheology (flow properties) on drilling fluid includes: circulating pressure, hydraulics, lifting capacity and hole cleaning, flow patterns (laminar or turbulent), flow profile in laminar flow (flat or peaked), suspension of cuttings, suspension of lost circulation material, suspension of weight material, and release of cuttings for settling in the surface system.

pH

The degree of acidity on the alkalinity of drilling mud is indicated by the hydrogen-ion concentration which is commonly expressed in terms of pH. A perfectly neutral solution has a pH of 7.0. Alkalinity solutions have pH readings ranging from just above 7 (slight alkalinity) to 14 (strong alkalinity), while acid solutions range from just below 7 (slight acidity) to less than 1 (strong acidity).

The pH measurement aids in determining the need for chemical control of mud, as well as indicating the presence of contaminates such as cement or gypsum.

There are two common methods for determining this value. The pHydroin dispenser provides a series of paper indicator strips that determine pH from 1 to 14. Changes in color over the range of each indicator should be sufficient to allow the operator to read within .5 pH units. The other method is a pH meter which can measure pH to within .1 pH units.

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Filtration

The filtration properties of drilling muds allow the solid components of the mud to form a thin, low permeability filter cake. The lower the permeability the thinner the filter cake, and the lower the volume of filtrate from muds of comparable solids concentration. This property is dependent upon the amount and physical state of the colloidal material in the mud. It has been shown repeatedly in the field that when mud of sufficient colloidal content is used, drilling difficulties are minimized. In contrast, mud low in colloids and high inert solids, deposit a thick filter cake on the walls of the hole. A thick filter cake restricts the passage of tools and allows an excessive amount of filtrate to pass into the formation, thus providing a potential cause of caving. Lack of proper walling properties may result in further trouble such as difficulty in running casing or creating a swabbing effect, which may cause the formation to cave or swab reservoir contents into the hole. The high pressure high temperature method of determining filtration property is used to simulate down hole conditions.

Alkalinity

The dictionary defines alkalinity as water-soluble chemicals that can neutralize acids. There are three tests for alkalinity: Pm, Pf, and Mf.

Pf and Mf tests the alkalinity of the filtrate. Pf is the amount in milliliters of N50 sulfuric acid required to reduce the pH of one ml of filtrate to 8.3 Mf is equal to the Pf and ml of N50 sulfuric acid required to reduce the pH from 8.3 to 4.3.

These tests can be used to determine any contaminates present in the mud.

Chloride Content

It is desirable to know the salt content of muds to account for certain aspects of their performance. Filtration, suspension, viscosity and gel properties are adversely affected by salt unless the mud is specifically designed to withstand salt contamination. Salt content checks made at regular intervals may be useful in identifying salt sections or filtration of salt water into the mud system. Salt content in a sample is expressed in parts per million chloride (ppm Cl). Multiply ppm Cl by 1.65 for ppm NaCl.

Calcium

It may be desirable to determine the presence and quantity of calcium ion in a drilling mud. Calcium ions may be added to the system by drilling cement, anhydrite or gypsum, or by the addition of hard make-up water and treating chemicals containing calcium, etc.

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Retort

Knowledge of the liquid and solids content of drilling mud is essential for good control of the mud properties. Such information will often explain poor performance of the mud and indicate whether the mud should be conditioned by the addition of water or whether treatment with chemical thinner or the removal of a contaminant is required. Similarly, proper maintenance of an oil emulsion mud depends upon knowledge of the oil content. Oil and water content can be analyzed by distilling a measured volume of mud and condensing and measuring the liquid fraction.

3.6 Mud Systems

3.6.1 Oil Base and Synthetic Mud Systems

An oil mud is defined as a mud that has oil as its continuous phase, and an all-oil filtrate. The terms *oil base mud* and *invert emulsion* are sometimes used to distinguish between types of oil muds. Oil base mud traditionally refers to muds with 1 - 5% water by volume, while invert emulsion implies an oil mud with more than 5% water by volume.

The purpose of this section is to discuss advantages and disadvantages of oil muds, so no further effort will be made to differentiate between oil mud types, and comments will apply to oil muds in general. The following are general advantages of oil muds:

- Protection of production horizons.
- The ability to drill water soluble formations (i.e., salt)
- The ability to drill shales which would swell or hydrate and disperse or slough in water muds.
- The recovery of native state core samples (that is, no problems due to filtration invasion).
- The prevention and relief of stuck pipe.
- Longer bit runs than with water-based muds of the same weight.
- No chemical changes at higher temperature (which cause viscosity and gel problems in water-based muds), making oil muds excellent for drilling deep, hot holes.
- Long-term stability and nonconductive for use as packer fluids.

The greatest disadvantages of oil muds are their high cost, both in purchase price and maintenance costs.

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3.6.2 Fresh Water Mud Systems

Fresh water muds are systems composed of relatively fresh water as opposed to salty water. The term *fresh water* should not be construed to mean that muds of this type contain no dissolved salts. Fresh water muds often contain dissolved salts that are incorporated into the mud as contaminants during the drilling operation or were in the water source of the drill water. The term *fresh water* means that the muds are designed to function best in the absence of soluble salts, and that soluble salts are not purposely added to the mud.

Offshore, it is often impractical to use fresh water due to limited storage facilities, cost of boats to haul water, lack of adequate fresh water supply, or any combination thereof. Therefore, sea water is used. As defined above, sea water muds are also considered as fresh water muds despite the fact that sea water contains small amounts of various inhibitive chemicals.

Spud Mud

A spud mud is a low cost, easy to maintain system requiring a minimal amount of differing chemicals on hand. The drawbacks are heat sensitivity, lack of filtration control, and necessity of using large amounts of water.

Low Solids Mud

This is another relatively inexpensive system. It differs from a spud mud in that polymers (starches) are used for filtration control, and either inorganic phosphates or organic thinners are used to control viscosity, if it becomes so excessive that water cannot control it.

Phosphates lose their thinning ability with a temperature in excess of 130°F or when chlorides exceed 5000 ppm. As bottom hole temperatures increase and weight material is added, the viscosity becomes more difficult to maintain. It is usually advisable to convert to a system that provides greater rheological control prior to exceeding a mud weight of 11.0 ppg.

Lignite System

A lignite system uses lignite as its primary thinner and primary filtration control agent. A spud mud is converted (broken over) to a lignite system simply by adding lignite. Lignite is one of the most inexpensive thinners on the market. It is also one of the least effective. Lignite is a fine filtration control chemical, but cannot effectively control the rheology of muds in excess of 10.0 ppg. Lignite also does not function well with a hardness in excess of 400 ppm.

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Lignite Surfactant System

This is one of the most expensive mud systems available, but it is also one of the best. It is essentially a lignite mud with the addition of a surfactant (surface active agent). Although lignite begins to suffer from thermal degradation at 450°F, lignite surfactant muds have been used in holes with bottom hole temperature in excess of 450°F with no problems.

Lignite surfactant mud is somewhat pH sensitive. It also requires fresh water. It has limited tolerance to salt, gypsum and cement. To maintain good rheological properties in high temperature, high mud weight holes, the clay (gel) content of the mud must be kept low (5-8 ppb).

Lignosulfonate System

A lignosulfonate mud is essentially a spud mud with lignosulfonate added to control viscosity and the filtration rate. It is an extremely versatile mud although somewhat more expensive than a lignite mud. It is not especially affected by gypsum, salt, or cement. It also has good tolerance to an excessive clay content and works well in both low and high pH ranges.

While lignosulfonate is one of the best thinners available, it is at best an average filtration control agent. For best results, lignosulfonate should be used in conjunction with another filtration control substance. Lignosulfonate begins breaking down at 375°F.

Lignite Lignosulfonate System

The best of both worlds is a lignite lignosulfonate mud system. Lignosulfonate is an efficient thinner in small quantities, and lignite is an efficient filtration control agent in small quantities. This is the most versatile system available. It is good in shallow, deep, hot or cool holes. It is not pH sensitive. It is good in water-sensitive shales, but can be improved with the addition of other filtration control chemicals. It has good tolerance to an excessive clay content. Lignite lignosulfonate mud systems have successfully drilled wells with bottom hole temperatures over 400°F.

While gypsum, salt and cement have little effect on the thinning ability of a lignite lignosulfonate mud, they do affect the filtration rate.

Both lignosulfonate and lignite lignosulfonate systems do little to prevent hole erosion in the upper part of the hole. All of the previous systems listed do little, if anything, to protect productive zones, and some have even been known to make producible zones unproducible.

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One way to reduce the possibility of doing damage to productive zones is to use a mud system that is more congruent to the productive zone. This is the same type of logic that goes into the selection of workover fluids when a well is perforated for productive purposes.

3.6.3 Inhibited Mud Systems

Water-based muds that repress the hydration (swelling due to water wetting) and subsequent dispersion of clay into the mud are called inhibited muds.

Conventional water-based muds are basically suspensions of clay in water. The optimum clay content of most water muds is confined to rather closely fixed limits. The addition of small amounts of clay often results in dramatic changes in the physical properties of a water mud. Many formations contain clay. Drilling fluids are, therefore, subject to the intrusion of additional clay during the drilling operation. Since optimum clay concentrations are usually present in freshly prepared muds, additional clay incorporated into the mud from formations drilled is often detrimental to mud properties.

The effect of drilled solids (clays) on inhibited muds is minimized due to the electrolyte (inhibiting ion) content of the fluid. The term *inhibited mud*, therefore, is actually descriptive of the condition of the clay present in the mud. The ability of clay to subdivide into numerous interacting particles is, in other words, suppressed or inhibited in an inhibited drilling fluid.

There are three major electrolytes used as inhibitors: potassium, calcium and chlorides. There are essentially six types of muds presently being used that are broadly classified as inhibited muds: lime muds, low-lime muds, gyp muds, K-plus muds, saturated salt water muds, and seawater muds.

Seawater muds are defined as either *fresh water* or *inhibited* depending on their ultimate purpose. If the main reason for using seawater is because of its inhibiting qualities, then it must be classified as an inhibited system.

In general, inhibited muds are more expensive than conventional mud, but have the following advantages over conventional mud.

- Can tolerate a higher concentration of clays than conventional water muds before developing high viscosity.
- Common mud contaminants, such as cement, anhydrite or salt do not usually affect inhibited muds as drastically as conventional water muds.
- Can usually be weighted to a higher mud weight before developing excessive viscosity.
- Exhibit less gelling tendency (referring to the ratio between the 10-second and 10- minute gels) often associated with conventional water muds.

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Lime Mud System

In addition to the desirable properties typically associated with inhibited muds, lime muds have several unique advantages. The very high alkalinity (pH) of lime muds provides protection of the drill string against corrosion. The corrosion rates of most metals is significantly reduced in environments having a pH of 11 or above. The high alkalinity of lime muds also suppresses biological activity in such muds. Biodegradable materials, such a starch, can be added to lime muds without biocide treatment.

The primary limitation of lime muds is that they tend to solidify with bottom hole temperatures in excess of 250°F. It should also be noted that phosphate-treated muds are often more difficult to convert to lime muds due to the buffering effect of the phosphate (phosphates are often used in conventional water muds to combat cement contamination).

Low Lime Mud System

In order to avoid the problem of high temperature solidification encountered with lime muds, the low-lime mud was developed. The low-lime mud is formulated with less alkaline material than the conventional lime mud, which results in increased temperature stability. Low-lime muds have been successfully used at bottom hole temperatures as high as 350°F.

Since the total alkali (pH control materials) in low-lime muds is reduced, the mud alkalinity must be monitored closely to avoid depletion of alkali, and subsequent development of high viscosity and gel (10-second and 10-minute.)

Gyp Mud System

Gyp muds are similar to lime muds in that both systems use calcium as their inhibiting ion. However, the source of the ion is gypsum (which is anhydrite) in gyp muds as opposed to lime in lime muds. Gyp muds show the following contrasts to lime muds:

- Gyp muds function at lower alkalinities than lime muds.
- Gyp muds contain more soluble calcium than lime muds, and are therefore, more inhibitive.
- Gyp muds are more resistant to contamination than lime muds.
- Because gyp muds contain more soluble calcium, only a lignosulfonate can be used as a thinner.
- Gyp muds have been successfully used at temperatures over 350°F.
- Gyp muds are more pH sensitive than lime muds and must be maintained in a narrow pH range.

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Seawater Mud System

The primary advantage of seawater muds offshore is the utilization of a convenient source of water. Seawater muds used as inhibited muds are extremely pH sensitive. They offer several inhibitive ions, but frankly, do a poor job.

Saturated Salt Water Mud System

Although saturated salt muds are adequate for many applications, they have several deficiencies. Most of the thinners presently used are virtually useless in concentrated salt environments. Lignosulfonate has been used in saturated salt muds, but a high pH is required to produce any thinning or filtration control. Because salt muds usually rely on starch for filtration control, the stability of the system is often tied to the stability of the starch used in it. Saturated salt muds containing starch generally begin to deteriorate at 250°F, but can be formulated for usage up to 300°F. Starches are not effective in salt water environments in the presence of soluble calcium, however. Saturated salt water muds exhibit a limited tolerance to a build up of a clay concentration.

K-Plus Mud System

The K-Plus mud system is the best inhibited mud system because it uses both potassium and chloride as inhibitors (potassium is better than calcium as an inhibitor). The primary disadvantage of the K-Plus system is its cost. It often costs more than oil muds and has almost the same environmental impact as oil muds.

K-Plus systems are also limited to a number of specialty products designed to work in a potassium and chloride environment.

The following is a list of the primary inhibitor(s) in each of the previously mentioned systems:

- Lime and low-lime — lime (CaOH)
- Gyp — gypsum ($CaSO_4$)
- Seawater and saturated saltwater — Salt (NaCl)
- K-Plus — Potassium Chloride (KCl)

3.6.4 Water-Based Emulsion Systems

An emulsion is formed when one liquid is dispersed as small droplets into another liquid, and the dispersed liquid is incapable of causing the second liquid to be a variation of itself. A good example of this is an oil and vinegar salad dressing. You can blend them, but the ingredients will still be oil and vinegar. Usually oil and

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vinegar separate when allowed to sit. The same is true in an emulsion; there is no separation. The chemical that keeps the two liquids from separating is called an emulsifier, since it creates the emulsion.

In an emulsion, the liquid being dispersed into the second liquid is known as the discontinuous phase of the system. The liquid that is used in the greatest amount is the continuous phase. If you made your oil and vinegar dressing with 60% oil and 40% vinegar, then the vinegar would be the discontinuous phase, and oil would be the continuous phase.

There are two types of emulsion systems used in drilling fluids: oil in water and water in oil. The oil in water emulsion has water as its continuous phase. The water in oil emulsion has oil as its continuous phase. The reason for needing to know which phase is continuous is because addition of the continuous phase will probably be needed to thin the system. This is the basic reason you add water to water muds and oil to oil muds.

Every water-based system can be converted to a water-based emulsion system simply by adding oil to that system. In many instances, the chemicals that compose the system will act as an emulsifier, so no extra chemicals will be needed. The only drawback is that adding oil can cause an undesired increase in viscosity and may necesitate the need for more thinners.

Some of the advantages of water-based emulsions are:

- Reduction of pipe torque
- Reduction in pipe drag
- Increased penetration rate
- Increased bit life
- Reduction of bit balling
- Alleviation of differential sticking
- Better filtration control
- Better protection of production zones

The only major disadvantage of a water-based emulsion system is that oil will tend to coat the drilled cuttings and require a cuttings box or some other form of disposal system for cuttings due to environmental impact.

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3.7 Mud Contaminants

Materials that enter the drilling fluid system and alter its properties in an undesirable manner are called contaminants. The following lists include contaminants commonly encountered:

Water-Based Muds

1. Shales
2. Soluble salts (including cement)
3. Acid gasses (H_2S and CO_2)

Oil-Based Muds

1. Green cement
2. Saltwater
3. Acid gasses

These contaminants are for the most part naturally occurring in either rock formations or formation fluids and gasses. Experience in an area or research of the area can generally aid an engineer in choosing a mud system that will be tolerant to these types of contaminants.

3.7.1 Water-Based Mud Contaminants

By far, the most important contaminant on the list is shale. As shales are drilled, they tend to disperse in the drilling fluid and increase its solids content. The mud thickens as a result and steps must be taken to counteract this effect. High solids slow the drilling rate and increase the ECD. The latter increases the likelihood of losing circulation and so on. Furthermore, shales occur in quantity in almost every well that is drilled.

Soluble salts act on some of the solids in the mud in a manner that causes the mud to thicken and the filtrate to increase. Expensive chemical treatment and rig time are usually required to get the mud back in proper condition. Hole instability and stuck pipe also sometimes occur in the process. *Green* or unset cement produces effects similar to those of a soluble salt.

Acid gasses are serious contaminants. In addition to their effects on mud conditions, they may also be the source of sudden and severe corrosive attack on the drilling tools.

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3.7.2 Oil-Based Mud Contaminants

Oil muds are a completely different ball game from water muds. Cement slurries are contaminants in oil muds because oil muds thicken in water-wet solids. The same is basically true with salt water, except that salt water causes the solids in the mud rather than supplying its own source of solids.

Acid gasses attack the alkalinities in oil mud and cause the emulsion to break down. They may also cause sudden and severe corrosion on the drilling tools.

3.7.3 Charts

The following tables show the effects of some common contaminants on various mud types.

Table 3.1 Water-Based Mud (Lignite Lignosulfonate)

	Anhydrite	Salt water	Cement	Soda Ash or Bicarb	CO_2	CaCl	Solids	H_2S
Weight	n/c	⇓	n/c	n/c	⇓	⇓	⇑	⇓
Viscosity	↑	↑	↑	↑	↑	↑	↑	↑
PV	n/c	⇑	⇑	n/c	⇑	⇑	↑	⇓[a]
YP	↑	↑	↑	↑	↑	↑	⇑	↑
Gels	↑	↑	↑	↑	↑	↑	↑	↑
Filtrate	↑	↑	↑	↑	↑	↑	⇓	↑
pH	⇓	↓	↑	⇑	⇑	↓	n/c	↓
Pf	⇓	↓	↑	⇑	⇑	⇑	n/c	↓
Mf	⇓	↓	↑	⇑	n/c	⇑	n/c	↓
Pm	⇓	↓	↑	⇓	⇓	⇓	n/c	↓
Hardness	↑	⇑	↑	↓	n/c	↑	n/c	↓
Chlorides	n/c	↑	n/c	n/c	n/c	↑	n/c	n/c
Solids	n/c	n/c	n/c	n/c	n/c	n/c	↑	n/c
Elec Stab	↑	⇑	n/c	n/c	n/c	n/c	n/c	n/c

a. The effect on these properties will vary dependent upon the extent of contamination.

Symbols: n/c = no change, ↑ = increase, ↓ = decrease, ⇑ = if anything, increase, ⇓ = if anything, decrease

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Table 3.2 Water-Based Mud (Inhibited)

	Anhydrite	Salt water	Cement	Soda Ash or Bicarb	CO_2	CaCl	Solids	H_2S
Weight	n/c	⇓	n/c	n/c	⇓	⇑	⇑	⇓
Viscosity	n/c	⇓	n/c	⇑ ↑ [a]	⇑ ↑ [a]	⇑	↑	↑
PV	⇑	⇓	⇑	n/c [a]	n/c	⇑	↑	n/c
YP	n/c	⇓	n/c	↑ [a]	↑ [a]	n/c	⇑	↑
Gels	⇑	⇓	n/c	↑ [a]	↑ [a]	n/c	⇑	↑
Filtrate	n/c	↑	⇑ [b]	⇑ ↑ [a]	⇑ ↑ [a]	⇑ [a]	⇑	↑
pH	⇓	↓	⇑ [b]	n/c	⇓	n/c	n/c	↓
Pf	⇓	↓	⇑ [b]	n/c	⇓	n/c	n/c	↓
Mf	⇓	↓	⇑ [b]	n/c	⇓	n/c	n/c	↓
Pm	⇓	↓	⇑ [b]	n/c	⇓	n/c	n/c	↓
Hardness	⇑ ↑ [b]	n/c	⇑ [b]	↓	↓	⇑ [b]	n/c	↓
Chlorides	n/c	⇓ ↑ [a]	n/c	n/c	n/c	⇑ [a]	n/c	n/c
Solids	n/c	⇓	⇑	n/c	n/c	⇑	↑	n/c
Elec Stab	⇑ [b]	⇑	⇓	n/c	n/c	n/c	n/c	↑

a. The effect on an NaCl or KCl mud would be slight but would be more severe in a lime or gyp mud.

b. The effect on a lime or gyp mud would be slight but would be more severe in an NaCl or KCl mud.

Symbols: n/c = no change, ↑ = increase, ↓ = decrease, ⇑ = if anything, increase, ⇓ = if anything, decrease

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Table 3.3 Oil-Based Mud

	Anhydrite	Salt water	Cement	Soda Ash or Bicarb	CO_2	CaCl	Solids	H_2S
Weight	n/c	⇓	n/c	n/c	n/c	⇓	⇑	n/c
Viscosity	⇑	⇑	n/c	n/c	⇑	⇑	⇑	⇑
PV	⇑	⇑	n/c	n/c	⇑	⇑	⇑	⇑
YP	n/c	⇑	n/c	n/c	⇑	⇑	⇑	⇑
Gels	n/c	⇑	n/c	n/c	⇑	⇑	⇑	⇑
‘	n/c	⇑	n/c		⇑	⇑	⇑	⇑
pH[a]	⇓	⇓	⇑		⇓	⇓	⇑	⇓
Pf[b]	⇓	⇓	⇑		⇓	⇓	n/c	⇓
Mf[b]	⇓	⇓	⇑		⇓	⇓	n/c	⇓
Pm[b]	⇓	⇓	⇑		⇓	⇓	n/c	⇓
Hardness[b]	↑	⇑	⇑	⇓	⇓	⇑	n/c	⇓
Chlorides[b]	n/c	⇑	n/c	n/c	n/c	⇑	n/c	n/c
Solids	n/c	n/c	n/c	n/c	n/c	n/c	↑	n/c
Elec Stab	⇓	⇓	⇓	n/c	⇓	⇓	n/c	⇓

a. Water phase

Symbols: n/c = no change, ↑ = increase, ↓ = decrease, ⇑ = if anything, increase, ⇓ = if anything, decrease

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Chapter 4 Basic Surface Data Logging

The present day business of drilling for oil and/or gas employs and depends upon the application of diverse fields of knowledge, practices, and techniques. Before a well is either completed, suspended, or abandoned, many specialized practices will be applied, and vast quantities of information and data will be complied, assimilated, and acted upon by highly trained specialists applying the best of their skills. Momentous and expensive decisions will be made.

A geological or engineering appraisal of a well is almost always relative; that is, the physical characteristics exhibited by a given well bore are usually judged on the basis of their comparison with known facts or the known performance of similar properties elsewhere. Years of use have established certain accepted standards as a basis for comparison of the various parameters involved in surface data logging.

Surface data logging is commonly thought of as a technology of "watching" the drilling mud. This results in early or immediate information about the drilled formation and a systematic by-depth catalog and analysis of drilled samples of information in whatever phase (solid, liquid, or gas) they appear. With the addition of supplemental surface sensors and the ability to interphase with certain downhole real-time tools, *watching* a well has progressed to an even more advanced stage. In brief, surface data logging helps the operator to know what is going on downhole as soon and as scientifically as possible.

The purpose of this manual is to furnish the surface data logging engineer with a guide to common interpretation of collected data and presentation of results. An additional purpose is to expedite the training of the engineer by giving him or her a compilation of experience as a basis on which to arrive at sound solutions to new problems as they arise.

For complete information on any specific instrument or process, refer to the manual for that instrument or process. Also, for exact procedures the surface data logger should consult his supervisor and/or the oil company representative.

4.1 History

Geologists and engineers did not enter the oil exploration picture until about 1910, considerably after the start of rotary drilling in 1900. The early crude methods of cuttings-ditch-inspection were not really satisfactory, and other methods were sought by early operators. The inspection of coarse samples of formation clinging to the bit when it was brought to the surface led to evolution of crude methods of obtaining cores with rotary tools, and later the modern core barrel was invented in

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the early 1920's. With this reasonably successful coring apparatus available, a trend toward continuous coring developed to alleviate the possibly of passing up a potential producing zone. This practice was time consuming and very expensive. In the 1930's, electric logging came into general use and reduced the amount of coring done. However, electric logging does not furnish knowledge of the formation until after a considerable section of hole has already been drilled.

It is at this point that the need for immediate bottom-hole information while drilling is fulfilled. The procedures of surface data logging had its beginning in 1938 with work done by John T. Hayward, Chief Engineer, Barnsdall Oil Company, and Vice-President, Barnsdall Research Corporation. Baroid, now Sperry-Sun Surface Logging Systems, as a commercial Well Logging Service, entered the field in 1939, being the first such service available.

Because of the fact that all information obtained by surface data logging is of a relative and abstract nature, the need for accuracy of this information is paramount. The awareness of this need in association with additional development and improvement of all phases of oil finding techniques has motivated Sperry-Sun Surface Logging Systems, from it inception, to strive toward the most diagnostic and accurate results possible in the development of its equipment and processes.

4.2 Application

Surface data logging in principle does not supersede human intuition, nor does it interfere with the drilling processes. The results of surface data logging are available immediately. The use of this exploratory tool is widespread throughout the world. Very briefly, this tool consists of mud and cuttings analysis, engineering techniques, and the technique of continuous collecting and analyzing data. Analysis reveals physical characteristics of the subsurface strata immediately as it becomes available at the surface, and based on interpretation of this information, exercise of control of certain phases of the drilling operation is obtained. Also, when plotted in graph form, this data produces a graphical representation of the physical properties of the penetrated strata.

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The surface data logging unit is the surface data logging engineer's laboratory in which he analyzes information relative to the strata being drilled. The instruments and equipment of the surface data logging unit are the tools with which he compiles the information on which to base his evaluation of the characteristics of the penetrated strata and recommendations pertaining to this information. See Figure 4.1.

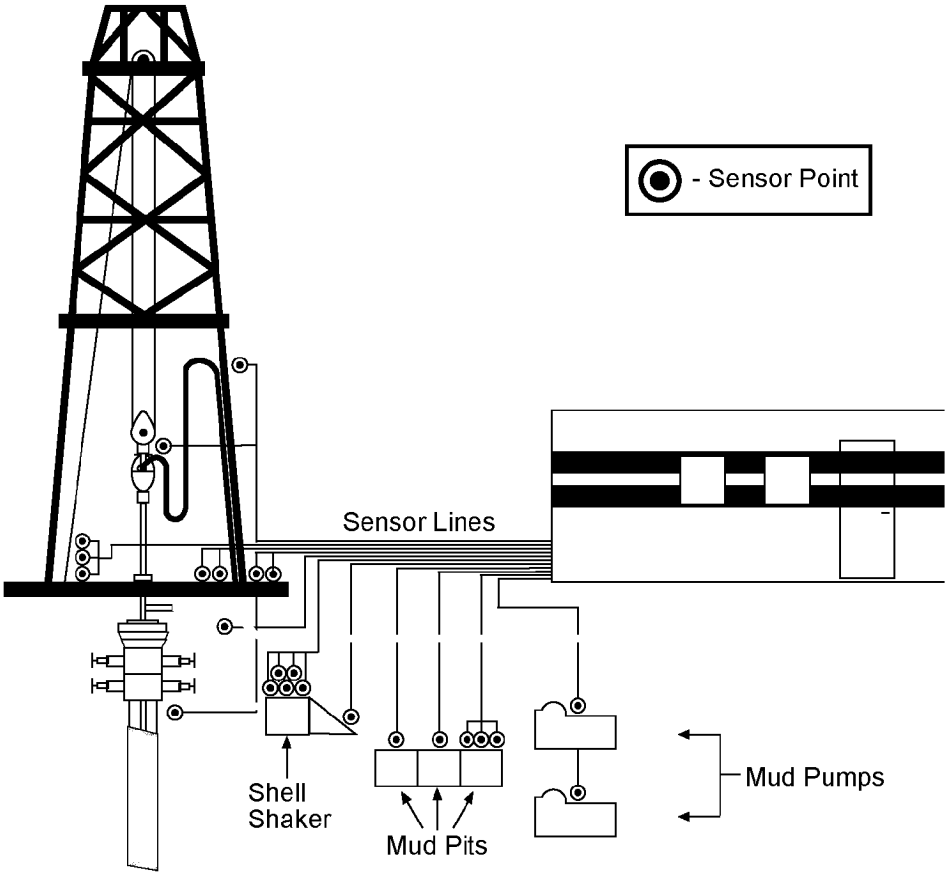

Figure 4.1 Interrelationship of the Drilling Rig and Surface Data Logging Sensors

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The Sperry-Sun surface data logging unit provides the operator with a log obtained from drilling mud analysis instruments and surface drilling sensors. This log may furnish the following information:

- A measure of the total hydrocarbon gases from the drilling mud.
- A parts per millio (PPM) analysis of hydrocarbons released into the drilling mud with accompanying ratio plots analysis of hydrocarbons in the mud.
- An estimate of liquid hydrocarbons in the drill cuttings.
- Lithologic percentages and descriptions of the drill cuttings.
- Surface sensor data, such as weight on bit (WOB), rotary speed, torque, etc.
- Trip data, such as hook load and hole fill volumes.

The core analysis equipment provides measures of porosity, permeability, oil and water saturation, and ratio of measured gas volume to bulk volume of the core. This last measure permits quick evaluation of formation potential to avoid operations delay.

Surface data logging has particular application in the following cases:

1. **Wildcat wells.** These are generally in areas where detailed subsurface information is lacking.
2. **Field development or outpost wells.** These are in areas where lensing sands and folding or faulting leads to difficult correlation.
3. **Wells in high-pressure formations.** Here gas indications want of impending kicks, thus aiding in controlling high pressure zones.
4. **Areas of difficult electric log interpretations.** These wells are characterized by limestone or carbonate rocks and muds having high saline content and sands containing fresh or brackish waters.
5. **Wells encountering extensive testing, coring and DST.** Tests can be conducted immediately through information on drill rate and returns analysis. A description of this process is as follows:

    a. Drilling proceeds without interruption until a significant increase in drill rate indicates a possible reservoir has been encountered.
    b. Two to four feet of formation are drilled.
    c. Drilling is then stopped until the mud returns can be pumped to the surface.
    d. If analysis of the drilling mud and drilled cuttings indicates oil and/or gas, a core might be taken.
    e. If not, then normal drilling is resumed until another drilling break is encountered.

Thus, coring of non-productive formations is reduced to a minimum.

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4.3 The Place of the Surface Data Logging Engineer

Sperry-Sun Drilling Services, as a service company, neither drills, produces nor markets oil or gas, but depending upon the continued search for oil and/or gas by operating and producing companies, provides commodities and services necessary to their operations which are either impractical or uneconomical for them to provide for themselves.This is a practical and economical approach to well monitoring. In this area, Sperry-Sun has proven to be a professional.

As a service company, Sperry-Sun and its employees become the employees of the operating company for the purpose of locating hydrocarbons. It is in this capacity that the engineers assigned to the job become endowed with the same obligations and responsibilities as those affiliated with that company on a permanent basis.

In this situation a logging crew must work very closely with the company personnel. Operating company personnel will be the final judge in important and irrevocable decisions, but their decisions must be based on the results of the logger's efforts.

Obviously, communication plays a vital role in the logging job. It is not only what he knows, but how he conveys what he knows which renders his decisions useful to the company being served. Whatever the means of communication, the customer must be able to say, "I know exactly what has been said, and I am clear on the matter." Thus, sound decisions and accurate communication defines success on the job.

The logging engineer, equipped with his own experience, knowledge and sense of logic and the data at his disposal, becomes the eyes of the oil company customer.

Realize that it is not important to Sperry-Sun whether a logged well is a successful producer or not, but what is important is that the customer be able to say upon completion of the well that the bore was comprehensively evaluated and that no possibility of production was missed.

Sperry-Sun's success depends on the customer's success, and the more efficiently and economically the customer is able to drill his well, the more wells he will be able to drill, which in turn means more jobs for Sperry-Sun.

The surface data logging engineer both contributes to, and is dependent upon the success of Sperry-Sun. Without his knowledgeable and careful decision making, Sperry-Sun cannot function. To obtain the business objective, he must continue to sell himself and the company; public relations is important as his personal contact with the customer puts him in a position to create good customer relations.

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Of course, all company personnel with whom the logger comes in contact with will appreciate a man who makes their jobs easier and more successful. Much of Sperry-Sun's repeat business is because the oil company personnel on one location liked the attitude of one or more of the surface data loggers, and will even request a particular crew to do another job, which is a nice compliment. Aside from the personal satisfaction of knowing he has done a job well, one of the greatest attributes a surface data logger can have is being in demand by the people for whom he works.

Professional status means taking a job seriously, having a constructive attitude toward the work by being methodical in performance, and maintaining an agreeable disposition. By incorporating these attitudes, there is no limit to the success a logger can achieve while in the service of a company on the job.

4.4 Surface Data Logging Theory (The Basics)

While drilling, mud is continuously being pumped down through the drill pipe to the bottom of the hole, out through the bit, up through the annulus (around the drill pipe) to the surface, out the flow line, over the shale shaker into the mud pit, through the mud pump, up the standpipe, through the kelly hose and swivel, down the kelly, and back into the drill pipe. During the circulation, the drill bit continuously cuts off small particles of formation, or *cuttings*, which are carried up and out of the hole by the mud and are caught and strained out of the mud at the shale shaker. It is at the shale shakers that access to the drilled formation information is gained. Basically, surface data logging is made practical by the use of the returning mud stream as a medium for communication with the bottom of the hole. The theory is that the drilled formation is carried to the surface partly in pieces of formation and deposited on the shale shaker in the chronological order that it was drilled, and partly in gases released into the mud. Surface data logging is a matter of extracting the information that is delivered by the returning mud for restoration of the in-place characteristics of the formation upon which a model is formulated and the well control decisions derived from this.

Before being broken up by the bit and carried to the surface by the mud, the formation remains under formation pressure, however great or small that may be. Historically, the drilling mud exerts a pressure (on the formation being drilled) considerably greater than that which the formation exerts on the mud. Thus, there was thought to be considerable flushing (replacement of hydrocarbon liquids and gases by the drilling mud) of the formation ahead of the bit by the mud filtrate.

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The factors which affect the amount of oil and gas remaining in the formation after being flushed to some extent, and which in turn affect the amount of oil and gas entrained in the drilling mud are:

- Depth
- Rate of penetration
- Hole size
- Volume of drilling fluid being circulated
- Physical properties of the formation
- Properties of the drilling mud

Balanced drilling is a name given to the use of mud weights which will result in the drilling mud column exerting almost the same, or a very little amount more hydrostatic pressure on the formation fluids and gases than the formation fluids exert back on the mud column. *Overbalanced* drilling is the case of too much mud weight resulting in more pressure exerted by the mud column than the formation exerts back. Balancing of pressures results in greatly improved drilling rates and formation evaluation. *Underbalanced* mud weights can result in a potential *kick* or even a *blowout*, which will be discussed later.

As the cuttings travel up the annulus to the surface, they undergo a pressure reduction, resulting in a release of formation fluids from the cuttings. Also, the jetting action of mud going through the bit causes a reduction in the hydrocarbon content of the cuttings.

Therefore, by analyzing the cuttings, drilling mud, and drilling parameters for hydrocarbon-associated phenomenon, we can develop a great deal of information and understanding concerning physical properties of a well from surface to final depth. The following discussion describes the techniques of measuring, recording and interpreting available data.

To perform the basic well logging function the following equipment is needed:

- Rig pump stroke counter
- Depth measuring device
- Gas detection equipment (total gas and chromatograph)
- Continuous multichannel recorder
- Geological examination devices and reagents

Here, the methods of applying available data to produce a *mud log* are discussed in detail. The mud log is the graphical presentation and final interpretation of gathered data. It is the prime reason for our presence on a drilling rig. Cursory mention only is made as to the principles of equipment operation as this aspect is covered in the latter part of this section. The mud log is our final product and how we present the data reflects directly on the logging crew and Sperry-Sun logging systems.

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4.4.1 Drilling Breaks

A *drilling break* is a term used to describe a departure of the Rate of Penetration (ROP) from a normal trend. As drilling progresses the average ROP tends to decrease with depth. This is due to rocks becoming harder as overlaying formations bear down on them. This compressive force causes sediments to become more dense and thus harder to drill (also called drillability) which results in the establishment of a gradual reduction of the ROP with increasing depth. This gradual reduction is expressed as the normal trend of penetration rates versus depth. However, as different formations exhibit differing drillabilities, the normal trend can shift to the right or left of the baseline upon entering a change in lithology (or rock type).

Consider the case of drilling through a shale cap rock into a limestone reservoir. Shale tends to drill faster than the more dense limestone. Therefore, it is quite probable that a reverse drilling break will occur (i.e., a significant reduction in ROP is observed). Conversely, if we drilled into a sand section from a shale, the drilling rate would tend to increase, resulting in a drilling break. The amount of change in ROP which may constitute a drilling break (and set by the operating company) could be in the range of 50% to 100%.

A drilling break is the first indicator of a formation change and is an important flag! It may signal the top of a potential reservoir or the point at which to cut a core.

Instructions must be sought by the logger from the operating company representatives as to their specific procedure for dealing with a drilling break. However, a typical requirement might read as follows:

1. Inform the driller and have him “pick-up” and check for flow.
2. Advise the company representative.
3. Assuming that the well is static, circulate the well out.
4. Just before the drilling break samples begin to arrive on the surface, start collecting additional samples so that an accurate background condition can be established.
5. Continue to collect additional samples until the break has been completely circulated out.
6. Complete the analysis of the samples and advise the company representatives of the results.
7. Await instructions; at this stage it may be decided to continue drilling or make arrangements to log the zone.

The most important thing is that the break be identified quickly. For example, if a core is to be cut, a minimum amount of the formation should be drilled so that a maximum amount of rock be available for examination. Actual drilling rates would tend to determine the relative depth penetrated during the break, but in any

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event, it would not be expected that more than 1 to 3 feet would be cut. If in any doubt, request the driller to pick up and circulate, then contact the company representative.

4.4.2 Lag Application

It is obvious that at the instant a drilled sample is delivered to the shale shaker that the bit has penetrated some distance deeper into the hole from the time when that sample was cut loose from the formation, so that sample at the surface will be from a depth shallower than that at which the bit is currently drilling. For example, if it takes an hour for a sample to reach the surface from the bottom of a 6,000-foot hole, and the bit is drilling at a rate of 100 feet per hour, the well depth will be 6,100 feet when the samples from the 6,000-foot depth are just reaching the surface.

This critical interval of time is called *lag* and is measured in terms of the mud pump cycles or in time. This lag applies to all down hole information except penetration rates. This lag always exists and, theoretically, changes continuously as the hole deepens. Likewise, the length of the lag time is dependent on anything that changes the hole volume, such as hole washout or channeling of the mud flow in the annulus.

It is necessary to always know the lag and apply it continuously to returning samples in locating accurately the depth from which they came. Because of the factors present which cause the lag to change, the lag must be checked and rechecked frequently and regularly. A lag determination should be run at least once each 24 hours or once every 500 feet, whichever occurs first. When drilling an average size hole less than 10 inches in diameter, every 500 feet may be enough. If the hole is larger than 10 inches in diameter, the lag determination should be run at least every 250 feet.

4.4.3 Running the Lag

The lag can be determined by injecting a tracer in the mud in the drill pipe at the surface when the kelly is broken off and counting the number of strokes that the mud pumps have to make in the interval between injection and recovery at the shale shakers. From this total pump cycle the number of cycles required to pump the tracer down the pipe to the bit must be subtracted. This arithmetic result is called the *lag* for the particular tracer material that was used.

There are two main types of materials that are used today for determining the lag. They are Lost Circulation Material (LCM) and calcium carbide. This last material when placed in the drill pipe reacts with the water in the mud to form acetylene

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gas and is picked up by the gas detector and gas chromatograph. It is important to remember that calcium carbide only reacts with water, so it cannot be used with an oil-based mud. The calcium carbide method is the most convenient for determining the lag. The lag obtained in this manner is called *gas lag*. For logging operations, the gas lag is normally used. When a lag tracer is placed in the drill pipe, a stroke counter must be set to monitor the number of strokes required for the tracer to travel down the drill string and back up the annulus. When the lag tracer appears at the shale shaker or the carbide gas reading appears on the gas detector on its return to the surface, the total number of strokes is recorded. It is then necessary to subtract the calculated number of strokes down the drill string (down-pipe factor); the result is the lag. Calculate the number of barrels from the number of strokes and enter this adjustment in the computer.

Some helpful hints on actually carrying out this operation follow. Gas travels from the bit to the surface faster than the cuttings in the mud from the same depth. Therefore, it is necessary to add a correction factor to the LCM lag to arrive at the correct gas lag to be used. Usually it is safe to assume a 10% correction in a positive direction. In practical application for the drill pipe and pump sizes commonly used, the total circulating time from surface-to-surface for LCM without subtracting the down pipe factor will approximate the gas lag (Figure 4.2)

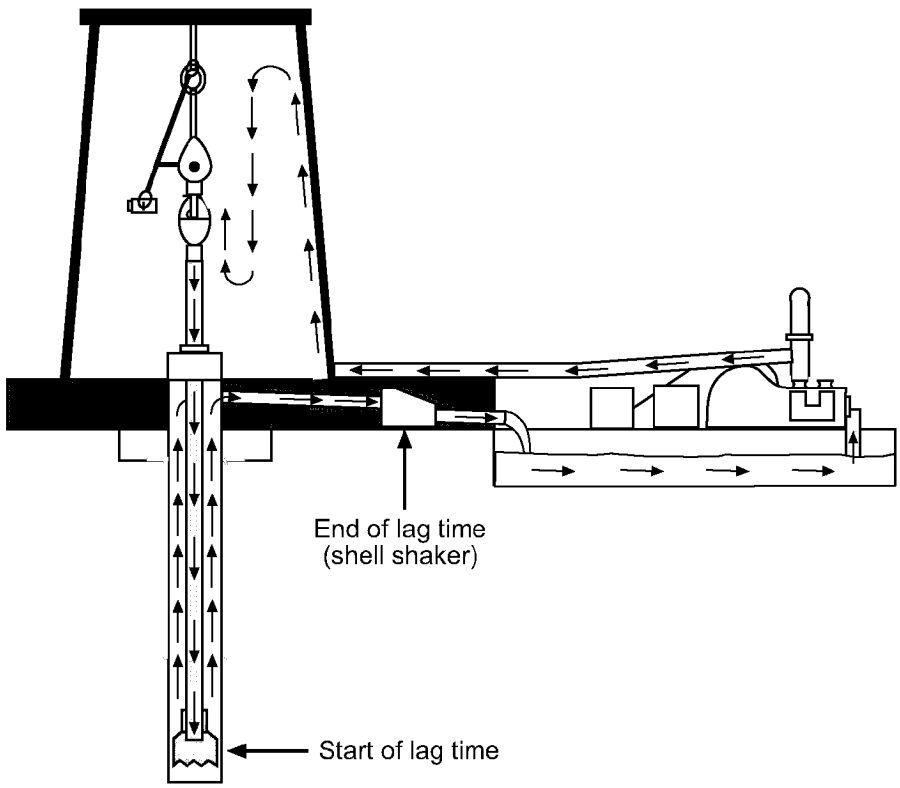

Figure 4.2 Running the Lag

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Determining the lag in terms of pump strokes has advantages over a lag determined on the basis of time. The reason is that when the pumps are stopped, the clocks continue to run, and a factor may be introduced which must be taken into account. Another factor is that the lag determined in terms of time is correct only for one pump speed or that particular speed at which the lag was run, whereas, the lag in pump cycles is accurate for any pump rate.

Another item to be aware of at this point is the reaction of calcium carbide with drilling mud forming acetylene which will be read on the gas detector as a gas peak. You will be able to distinguish this from a formation gas as it will show up on the gas chromatograph at approximately 73 seconds.

Important: A gas lag should not be run during or immediately following a drilling break or in a zone where there is reason to believe that a show of hydrocarbons might occur.

Another situation requiring special procedures is the usage of oil-based mud. Two possible procedures in this situation would be:

1. After obtaining permission to do so, put calcium carbide in the drill pipe during a connection when the drill pipe joint is open:

   a Displace enough fluid already in the pipe so that a space is provided for the lag material.

   b Pour water into the cleared space leaving some extra space for the lag material.

   c In this space add carbide in sufficient quantity (depending on depth, volume of the annulus, etc.) to give a distinct reaction on the gas detector which is monitoring the hydrocarbons in the returning mud flow.

2. If enough time is available, have the driller pump a small LCM pill during a connection and watch for their exit from the hole at the shaker and record the number of strokes or time for this interval.

The down-pipe factor we have alluded to above requires a volumetric calculation of pumped volume per stroke in terms of linear feet of drill pipe or the *down-pipe* factor. The factors influencing this calculation are pipe size, pump liner size, rod sizes, length of the pump's stroke and the length of the drill string. This pipe factor must be recalculated any time the size of the pump liners or drill string is changed.

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Hints and Precautions Concerning the Use of Lag Materials

1. Put the lag material in the drill string, not in a mouse hole.
2. Note that the amount of lag material used may have to increase as the depth increases.
3. Observe samples during drilling breaks as checks on lag calculation accuracy when the opportunity arises.
4. Observe connection gases when possible; do not use trip or short trip gases as a check.
5. Make sure the shale shaker has not been bypassed.
6. Be sure to record all pertinent data for future referral, as this can be critical in future discussions on the matter.

4.4.4 Calculating Down Pipe Volume

The down pipe factor is expressed in terms of volume (barrels of mud) or strokes (pump cycles). That is, for a known drill pipe length and inside diameter (ID), the capacity of the drill string in barrels can be calculated.

Given the following data we can determine the down pipe factor:

Hole depth = 11,000 feet
Drill string = 5 inches OD and 4.276 inches ID
Pump data = Triplex, single action: 6-inch liner
12-inch stroke
95% efficiency

1. First calculate the volume of the string with one of the following formulas:
   $ID^2 \times 0.00097$ = barrels per foot or
   $ID^2 \div 1029.4$ = barrels per foot
   $4.276^2 \times 0.00097 = .0177$ barrels per foot or
   $4.276^2 \div 1029.4 = .0177$ barrels per foot
2. Multiply the drill string capacity by the length of the drill string to obtain the total number of barrels.
   $.0177 \times 11{,}000 = 195.4$ barrels
3. To obtain the number of strokes for the down pipe factor you will have to calculate the pump output in barrels. The formula is as follows:
   bbl/stk = $.000243$ (liner ID^2) $\times$ L
   ID = liner size in inches
   L = stroke length of the pump

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Example: The output of a $6^1/_2$-inch × 11-inch PZ-11 triplex is:

bbl/stk = $.000243(6.5^2) \times 11 = .1129$ bbl/stk at 100% efficiency
Since the pumps are only 95% efficient multiply by .95
$.1129 \times .95 = .1073$ efficiency corrected barrels per stroke

To obtain the down pipe factor in strokes, divide the volume (in barrels) by the pump output:

$195.4 \div .1073 = 1821$ strokes

Note: This information can be found in the tables at the end of this chapter. However, these tables may not always be available so the logging engineer must be prepared to make volumetric calculations.

The previous calculations did not take into account the fact that the bottom hole assembly (drill collars and heavy weight drill pipe) normally has a smaller ID than the drill pipe.

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4.4.5 Calculating Bottoms Up Lag

An alternative to the tracer method of calculating the lag exists. This is calculating the annular volume by using either of the following two approaches:

1. Principles of volume
2. Capacity/displacement tables

Using similar data as for the previous example:

Hole depth =	11,000 feet
Drill pipe =	5 inches OD by 4.276 inches ID
Pump data =	.0997 barrels per stroke

In addition, we must consider the following data:

Hole size =	12.25 inches
Depth of last casing =	9,500 feet
Size of last casing =	13.375 inches OD by 12.347 inches ID (72 pounds per foot)
Size of drill collars =	8 inches OD by 3 inches ID (147.0 pounds per foot)
Length of drill collars =	500 feet

These specifications result in a pictorial representation of the well geometry as follows.

As noted, there are three distinct annular sections.

- Annular section 1 is formed by the drill pipe and casing
- Annular section 2 is formed by the drill pipe and open hole
- Annular section 3 is formed by the drill collars and open hole

The simplest method of arriving at a total annular volume is to calculate each section independently and the add up the results.

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Example: Using Principles of Volume

Capacity of the annulus in barrels per foot = (hole size or casing ID)^2 - (drill pipe outside diameter)^2 × 0.00097 or

(hole size or casing ID)^2 - (drill pipe outside diameter)^2 ÷ 1029.4

Annular section 1 = (casing ID^2 - drill pipe OD^2) × 0.00097

$(12.347^2 - 5^2) \times 0.00097 = .1236$ barrels per foot

next barrels per foot × section length = barrels

.1236 × 9500 = **1174** barrels

Annular section 2 = (hole size^2 - drill pipe OD^2) × 0.00097

$(12.25^2 - 5^2) \times 0.00097 = .1213$ barrels per foot

next barrels per foot × section length = barrels

.1213 × 1000 = **121.3** barrels

Annular section 3 = (hole size^2 - drill collar OD^2) × 0.00097

$(12.25^2 - 8^2) \times 0.00097 = .0835$ barrels per foot

next barrels per foot × section length = barrels

.0835 × 500 = **41.7** barrels

Adding up the sections we have: 1174 + 121.3 + 41.7 = 1337 barrels total annular volume

To convert this volume into pump strokes, divide the total annular volume by the pump output:

1337 barrels ÷ .0997 barrels per stroke = 13410 strokes

Divide the total strokes by the pump rate per minutes to obtain the bottoms up time.

13410 strokes ÷ 150 strokes per minute = 89.4 minutes

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Example: Using the Tables

Annular section 1 = capacity of the casing - (capacity + displacement of drill pipe) × length of the section

capacity of 13.375 (P-110) casing at 72 pounds per foot is .1479 barrels per foot
capacity of 5 inches × 4.276 inches Grade E drill pipe is .0177 barrels per foot
displacement of 5 inches × 4.276 inches Grade E drill pipe is .0070 barrels per foot

thus, .1479 - (.0177 + .0070) = .1232 barrels per foot
.1232 × 9500 (section length) = 1170 barrels

Annular section 2 = capacity of the hole - (capacity + displacement of drill pipe) × length of the section

capacity of a 12.25 hole is .1456 barrels per foot
capacity of 5 inches × 4.276 inches Grade E drill pipe is 0177 barrels per foot
displacement of 5 inches × 4.276 inches Grade E drill pipe is .0070 barrels per foot
thus, .1456 - (.0177 + .0070) = .1209 barrels per foot
.1209 × 1000 (section length) = 120.9 barrels

Annular section 3 = capacity of the hole - (capacity + displacement of drill collars) × length of the section

capacity of a 12.25 hole is .1456 barrels per foot
capacity of 8-inch × 3-inch drill collars is .0087 barrels per foot
displacement of 8-inch × 3-inch drill collars is .0535 barrels per foot
thus, .1456 - (.0087 + .0535) = .0834 barrels per foot
.0834 × 500 (section length) = 41.7 barrels

Adding up the sections we have: 1170 + 120.9 + 41.7 = 1332.6 barrels total annular volume.

To convert this volume into pump strokes, divide the total annular volume by the pump output:

1332.6 barrels ÷ .0997 barrels per stroke = 13366 strokes

Divide the total strokes by the pump rate per minute to obtain the bottoms up time.

13366 strokes ÷ 150 strokes per minute = 89.1 minutes

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When logging, note that the calculated lag will invariably be less than that obtained by using the tracer method. Reasons for this are:

- Lag tracer materials or cutting will tend to slip behind the velocity of the mud with respect to their relative densities and the particular mud's carrying capabilities.
- Enlargement of the hole, due to erosion by the mud, is not accounted for when making the lag calculation.
- Mud flows are sometimes turbulent which results in a tendency for the cuttings and tracer materials to rotate up the annulus rather than rising uniformly.

Due to the characteristics of drilling mud in laminar flow, the center annulus flow rate tends to be faster than that near the walls; thus, cuttings in the center annulus region tend to be moved over into the slower flow areas and subsequently are again moved back into the faster region. This is a similar effect to the previous paragraph although the rotational effects are much less harsh.

Cumulatively, these effects tend to delay the arrival of cutting samples at the surface. Conversely, gas samples tend to rise at the same or possibly at a slightly higher rate than the mud, particularly if the mud is relatively thin. As gas rises in the annulus, a reduction of hydrostatic pressure will be exerted on the samples resulting in an expansion of the gas in proportion to its volume and original pressure. Hole enlargement will, however, have a similar effect on gas samples as with heavier materials.

The net result is that gas samples tend to arrive at the surface sooner than cuttings. In any event a lag calculation is a good approximation but should be corrected or checked for accuracy, and corrected as necessary by noting the arrival of cuttings from a drill break or connection gas.

We have considered three circulation periods:

- Off bottom-to-surface
- Kelly-to-surface complete circulation
- Complete system circulation including the surface mud volume

For case number 3, the annular, drill string and surface volumes are added and then divided by the pump output to arrive at this value.

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Points to note are:

- Drill pipe, drill collars and casing sizes are often referred to by weight of the item under consideration. It is therefore necessary to refer to charts and tables for actual dimensions (see attached tables).

87.9 lb/ft drill collars	=	6-inch OD × 1.75-inch ID
or 19.5 lb/ft drill pipe	=	5-inch OD × 4.276-inch ID
or 36.0 lb/ft casing	=	9.625-inch OD × 8.921-inch ID

- Unless the hole is totally cased the actual lag will always be greater than the calculated. Therefore, use sample data or run a tracer lag to accurately set the lag value.

Details concerning pumps sizes are always available from the rig personnel (company representative or toolpusher).

As a well deepens, the pump liners are sometimes replaced by liners of a smaller diameter. Make a periodical check as to the liner size. This normally takes place when a new casing string is run.

Most drilling rigs are equipped with two mud pumps, whereas, most of the deep water semisubmersible rigs will have three mud pumps. One of these pumps are normally used to boost the riser during drilling operations. Ensure that the computer is properly configured as to which pumps are on the hole and which are on the riser.

When the rig pumps are stopped the mud column stops. Also, if drilling is suspended and the well circulated out, the flow of information that is collected at the shale shakers and new information is no longer being supplied at the bottom of the hole. After the expiration of the lag, the bottom of the mud column will have reached the surface. Without the lag as an indexing tool, all the mud and cuttings analysis would apply to formation only at unknown depths and, as logic would dictate, this information is almost useless without knowing at what depth the analysis pertains to. Therefore, with the lag calculation it is known exactly to what depths these analysis apply.

In conclusion, the annulus represents a continuous column of surface data logging information moving up and out of the hole which is transferred to the computer by the logging engineer as part of the daily routine.

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4.4.6 Background Gas

Under normal drilling conditions, it is quite common for a relatively small amount of gas to be continuously in evidence. This *background gas* can originate from a previously drilled section, which contained a show and bled a small amount of gas into the mud. Normally, gas can be contained in the formation being drilled of very low proportions (i.e., shales often contain gas due to their extremely low porosity and permeable characteristics). Background gas is often methane only, with little or no heavy gases. However, continuously high levels of background gas often indicate that the well is being drilled very close to balance and may indicate that a higher mud weight is required.

4.4.7 Connection Gas

Also, when the bit is raised off bottom is gas due to *swabbing*, even short distances such as those encountered when making a connection, and due to the lowering of the hydrostatic pressure from the loss of ECD (equivalent circulating density) when the mud pumps are shut down for a connection or check for flow. Therefore, this connection gas is a helpful guide towards determining how near the hydrostatic pressure is to a balanced condition.

Connection gas can be identified by the occurrence of gas peaks observed on the recorders. These peaks on the recorder trace will be separated by the time between each connection and will arrive on the surface near lagged depth of the connection depth. When connection gases are evident, a similar phenomenon may be observed when the drill string is pulled off bottom and the pumps are shut down. This method can also be used to simulate a connection gas peak to help in determining a balanced condition. As with background gas and trip gas, connection gas is a strong indicator of a balanced drilling condition.

4.4.8 Trip Gas

It is normal for an increase in the gas readings to occur after a trip has been made. This occurrence is commonly referred to as *trip gas*.

To understand the presence of trip gas, it is necessary to visualize what happens as the bit is pulled out of the hole, for it is during this operation that gas which is subsequently labeled “trip gas” gains entry into the mud system. Not only does the bit have the largest diameter of all tools in the hole, it also is at the extreme lower end of the drill string. In the process of coming out of the hole, the bit is being pulled through a mud filled cylinder of a diameter of only slightly greater than the bit itself. As the bit is pulled through this cylinder formed by the hole wall, a swabbing action on the formation takes place. The drilling fluid is, therefore,

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forced to rush pass the bit to its underside, and there is a momentary reduction in hydrostatic pressure immediately adjacent to and below the bit as it is travelling upward. As the bit travels up the hole past sections containing gas, those of sufficient pressure will bleed into the adjacent mud column when the hydrostatic pressure is reduced by the swabbing action of the bit. Once this gas has entered, it is entrained by the mud and remains static in the mud until the trip is completed. When the trip is completed and the bit is near bottom and circulation resumes, this gas interval is pumped to the surface where the gas is detected as trip gas.

After a trip has been made and drilling is resumed, a period of time equal to the lag must transpire before any cuttings or gas shows from the formation drilled after the trip will appear at the surface. Trip gas is recognized as that increase in mud gas which often appears on the gas detector sometime between the time drilling is resumed and the time the first sample from a newly drilled formation is at the surface. Usually trip gas will appear toward the end of this period, just before the first newly drilled sample is due.

Further recognition of trip gas is the rapid buildup to a gas peak and the rapid decrease almost immediately after the peak. The buildup of the trip gas reading should be watched carefully on the gas detector and recorder along with the pit volume. The reason is that if the gas continues to increase for an abnormally long time, and does not start dropping off when it should, or if the pit volume continues to show an abnormal increase, a kick may be imminent and the driller should be advised immediately. The gas reading should have returned to practically its normal level by the time the new formation is due at the surface. The gas detector and recorder should be watched for the highest reading obtained during this interval and its maximum value should be recorded on the data sheet and on the log as trip gas.

The fact that trip gas most often appears at the end of the lag period, indicates that it is from near the bottom of the hole, may be accounted for by at least two reasons. First, at the time a trip is started, the bottom section of the hole will have been only recently drilled and exposed to the mud column; therefore, wall building and invasion forces of the mud have been at work for only a short time when the trip is made. The hole wall here, near the bottom, will not be nearly as well sealed against gas entry as the sections further up the hole, because the bottom section has not been thoroughly invaded by the mud filtrate; the gases will not have been driven back as far from the hole wall as in shallower zones. Gases will have only a short distance to travel to re-enter the hole. Secondly, the mechanical forces which result in the accumulation of trip gas may be expected to be greatest where the hole is nearest to gauge. What is meant here is the hole is closer to the diameter of the bit than shallower sections of the hole, thus having a greater swabbing effect on the formation.

It is important to remember that if the hole was not completely circulated out prior to the trip, the trip gas will usually be accompanying the returns of the formation that were drilled prior to the trip. There is always the possibility that the gas is not

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trip gas but rather a legitimate show which was drilled just prior to making the trip and is coincidental with the appearance of the trip gas. The gas reading should be watched closely to see whether it persists as a legitimate show might. The cuttings and other available data should be carefully scrutinized with the object of ascertaining definitely whether the gas reading is due to trip gas or show gas.

This trip gas may often be turned to the logger's advantage, by starting the stroke counters exactly when circulation is broken after a trip and comparing the number of strokes required to bring the trip gas to the surface. By comparing these strokes to the strokes for bottoms up, a good approximation of the depth of the zone from which the gas is coming may be made. (*Circulation is broken* is an expression for the time when mud first starts flowing in the flow line.) It may be found that this is a zone of special interest previously logged, or a zone which may have been drilled before the logging job started. The information may have considerable value to the customer at times.

Trip gas will sometimes recirculate once, and may even recirculate several times. Recirculation of trip gas will not usually be observed, and when it is, it will be less than $^1/_3$ of the original reading and evident by a smoothing out of the gas peak. The recorder will show this as regularly spaced peaks becoming smoother in the gas curve. The time interval between peaks is the total circulation time and not the bottoms up lag time.

If a float is run in the drill string, then there will be air trapped in the drill pipe while tripping in the hole. When this air is circulated out, after a trip, what is observed is an air bubble at the surface. This air bubble is directly proportional to the volume of air trapped and is evident by anything from a slight aerated appearance to even "belching" over the bell nipple.

4.4.9 Logging After a Trip

The making of a trip for a new bit can create a weak spot in the continuity of the log. Care and attention should be exercised to minimize this weakness. When a trip is made, if circulation is stopped before all the samples are lagged from the hole and the pipe is pulled immediately out, then the continuity of the drilled samples and gas is lost. On a deep well this may account for an interval of considerable footage. The weakness in continuity comes about when the possibility arises that a potentially productive zone has been drilled somewhere within this now unlogged interval. If this occurs, and no precautions were taken to circulate all the formation out, then it means that the show will not be discovered until after the trip has been completed, circulation resumed, and possibly new formation drilled. By then, at best, the appearance of the show may be coincidental with the trip gas, and in this case, the show will be distorted.

One means of eliminating this danger is to have the driller pick the bit off bottom and circulate out all the samples before starting the trip out of the hole. Some

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companies mandate that this be done before each trip, even though it is costly in terms of rig time. The surface data logger should inform the company representative of the type of formations he suspects may be in the hole. One method to gain this knowledge of what may remain in the hole is to study the rate of penetration. If there is a change of penetration rate from the normal trend, this indicates that a change in formation is possible. Another method, if a downhole MWD tool is present, is to study what information has been pulsed to the surface from the MWD tool. Be sure that the company representative is made aware of any type formation that may be left in the hole if he does not circulate out completely.

In many areas of high pressure gas sands, the making of a trip without prior circulating out actually constitutes a safety hazard. In some areas all possible precautions are taken to prevent the well from blowing out and since the danger is greatest when a trip is being made, a precautionary step toward reducing this hazard is the practice of always circulating out all samples before a trip is made. In some areas of high gas readings some customers mandate that the rig is to circulate until the mud reading is below a certain value before starting out of the hole. In any case, even in the absence of such requirements, if there is reason to believe that a hazardous condition exists, the surface data logger should make his data and reasons for his belief available to the company representative and work closely with him.

It is easy to see that by the time the samples that were left in the hole during the trip have been circulated out, they have become disrupted and displaced in sequence. The logger should start logging as soon as the pumps are started and returns are at the flow line. The sample interval that remained in the hole should be logged as though the trip has not occurred. However, the logger should recognize that the data obtained is not quite as reliable as it might otherwise have been. To communicate this fact, the interval involved is defined on the data sheet and the log along with the abbreviation “LAT” (logged after trip). This will clearly indicate to the customer the condition under which the interval was logged.

4.4.10 Logging While Coring

In general, as coring ROPs are slow, oil companies will require more frequent samples in case the whole core is not recovered.

When coring is in progress, the cutting (which will be smaller than normal) should be examined carefully just as in normal drilling. This will help locate cores in cases of incomplete core recovery. For instance, in a 10-foot section of cored hole, perhaps only 5 feet of core is recovered. The question is, “Which 5 feet (top, middle, or bottom) of the 10-foot section, were recovered?” Obviously, the core itself should be the basis of the lithological description when it is available.

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Therefore, a complete description of the cores and the footage recovered should always be kept.

Particular effort should be applied to making a good sample collection of cuttings as this is the only permanent proof to the oil company of what was actually drilled.

Sidewall coring

Sidewall coring is a supplementary coring method used in zones where core recovery by conventional methods was small or where cores were not obtained while drilling.

A sidewall coring device, a CST (chronological sample taker) tool, is lowered into the hole on a wireline cable and a sample of the formation is taken at the desired depth. This is done by discharging a hollow "bullet" into, and pulling it out of the wall of the hole. Usually there are thirty bullets per gun. More than one gun can be run each time.

Sidewall cores taken with CSTs are small ($1 \times 2^1/_2$ inches) and in some cases the recovered material consists largely of mud cake. Sidewall coring is usually unsuccessful in very hard rocks. Nevertheless, cores of this type provide a means of examining the rock in portions of the hole in which information may be extremely scanty. Sidewall cores are sometimes taken with the intention of evaluating the porosity, permeability and saturation characteristics of the rock. However, because some compaction occurs as the bullet enters the formation, the results are inevitably less reliable than those from conventional cores.

4.4.11 Logging When Air or Foam Drilling

In order to have the proper equipment for logging with air or foam drilling, all or part of an air drilling kit is required in addition to the normal logging equipment.

In air drilling, if the returns from the bottom are dry or relatively dry, an air filter is rigged up on the flow (blooie) line from the bell nipple. Installation of this filter near the end of the flowline should reduce the chances of pulling moisture into the gas detector. The filter consists of a funnel shaped steel unit with a cover arranged to take 18.5 cm felt backed up with a screen so that a moderate pressure on the flowline can be accommodated without closing off the outlet to the gas detector. This filter will remove dust from the gas stream before it enters the standard gas trap hose going to the logging unit. A $^1/_4$-inch NPT × OXY fitting is provided on the cover of the filter unit for connecting this hose. The funnel-shaped steel unit should be screwed into a 2-inch nipple and collar on the top side of the flowline. The shape of this unit is such that dust can fall back into the flowline in case it

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builds up on the filter medium. It is also recommended that a 2-inch gate valve be placed between the filter and the flowline if difficulty is experienced in the normal hook-up, and to facilitate filter cleaning or changing during drilling operations.

If the cuttings and dust coming from the well are moist or accompanied with foam or slugs of water, it will be necessary to run the air from the flowline through a water trap and then to the logging unit. Most of the equipment required for this installation will normally be available on the rig or in local hardware stores. The hole in the bottom of the drums allows water and foam to be discharged without getting into the gas detector line. A pressure relief hole may be provided about half-way up the barrel and covered with a thin plastic flap in case the bottom hole gets closed off. Since there will be a continuous leak from this drum, it should be installed at a safe distance from the rig to minimize the fire hazard in case of a gas show. This hazard should be pointed out to the rig personnel so they will not have open flames around the drum. A valve may be installed in a $^1/_2$-inch line from the blooie line so that the leak can be stopped if it becomes dangerous. This valve should be in an accessible position in case of fire. Because of the high flow rates used in air drilling, this drum will not add an appreciable lag time to a show.

Eight sample boxes 12 inches in length are normally included in the kit. These will generally collect samples from a 10-foot interval before becoming filled. The box affords a collection of samples in the order they were drilled from the bottom to the top of the vertical box.

In some areas it has been found that air-drilled cuttings were so small that it was necessary to have a higher than normal magnification for observing them under a microscope. For this reason, a 4X viewing objective, pointed tweezers, and a high-powered microscope lamp have been included in the kit, as well as a 30-mesh sieve for better separation of the cuttings. Though the cuttings are badly pulverized, the standard method of examining the cuttings should be sufficient.

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Chapter 5 Well Problems

The loss of well control is often a subtle and unnoticed event until it has suddenly become a threat to life, property and environment. Today, wells are being drilled at faster penetration rates, with lower mud weights, and deeper than ever before. Your ability to recognize the warning signs of kicks and potential blowouts, and to assist with the execution of correct and safe well control practices is important. Your life, as well as the success of the operation in which you are involved, may depend upon your knowledge of well control technology.

5.1 Washout of the Drill String

A washout is a hole through the drill pipe or drill collars, usually at a tool joint. Once seepage starts through such a leak, it takes only a matter of a few moments for a sizeable hole to develop. Besides the damage to the drill pipe or drill collars from the presence of the hole itself, the hazard of twisting off the pipe occurs rapidly as the hole develops. Early detection of these leaks is, therefore, critical.

When a hole has been washed out in the pipe the drilling mud will jet out through it with such force that a back pressure against the rig mud pumps will be seen. This decrease in pressure will usually cause the pumps to run a little faster. As in the case of lost circulation or a pending kick, a washout should be indicated in the logging unit by a gradual increase in the pump rate with a gradual loss in pump pressure.

The driller should immediately be notified of any unexplained increase in the pump rate or decrease in the pump pressure. Conclusive proof of a washout in the drill pipe may be verified by placing lag material (calcium carbide) in the drill pipe and watching for its return on the gas detector. If the lag returns in an abnormally short time, a washout is almost certain. The approximate depth of the washout can be determined by the lag.

Hints and Precautions

1. An increase, normally a gradual steady increase in the pump rate or a decrease in pump pressure may be indicative of lost circulation, a pending kick, or a washout of the drill pipe.
2. Check for a decrease (lost circulation), an increase (kick) or no change (washout) in the pit volume.
3. Look carefully at the records on the recorder of the pump rate, pump pressure and pit levels.

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4. A lag may be run for more positive identification of a washout in the drill pipe. However, the additional circulation required will enlarge the hole and weaken the drill pipe further if there is a washout. Running such a lag should only be suggested to the company representative as an option and should not be initiated by the logging crew.

5.2 Lost Circulation

Lost circulation refers to drilling mud absorbed into the exposed subsurface formation. The extent of lost circulation, or the amount of mud lost, can vary from only a slight amount to the complete loss of the mud from the hole. It is a common, serious, and expensive problem that can occur at any depth, in any type and age of rock.

From the sensors and instruments in the logging unit, it is possible to gain a great deal of information that is helpful in preventing or controlling loss of circulation of the mud. The instrument and sensors primarily involved in detecting these hazards are the pitwatcher, the stroke counters and the strip chart recorders.

The pit watcher is the logging sensor used for indicating the level of mud in the mud pits. Combined with the strip chart recording of the pit level, the pitwatcher indicates the rate of change in the mud level. It is this rate of change that is most indicative of the occurrence or extent of lost circulation. For the best and most rapid detection of loss circulation, the pitwatcher should be rigged up in the suction pit.

An excessive drop in the level of mud in the pits, while drilling is under way, indicates that mud is being lost from the circulating system. It may be lost to a porous zone being drilled at the time or to a zone up the hole that may be gradually taking mud or the mud is being deliberately dumped by the drill crew.

Loss of circulation should not be confused with loss of make-up water or filtrate into the formation. The latter is a normal continuous result of the wall-building property of drilling mud. As drilling is in progress on any well, there is a normal decrease of the mud volume in the pits due to the increase of depth, wall building and filtrate loss, and surface evaporation. So long as this fluid is not replaced, there will be a normal, continuous, steady decrease in the mud pit level. Since the pit level is being recorded, this normal rate of decrease will be apparent at a glance.

Lost circulation will be manifested by an abrupt decrease in the pit level which is apparent on the chart recorder. The degree of abruptness will depend on the extent to which mud is being lost. Complete loss of returns will result in the entire contents of the pits being pumped away in a matter of a few minutes if undetected.

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Serious cases of lost circulation will usually be accompanied by an increase in the pump rate. The speed of the mud pumps increase because pumps are required to lift less mud out of the hole and doing less work, they will run faster on the same power input. Another indication of lost circulation is an increase in the hook load reading. This is due to the loss of buoyancy of the mud on the drill string.

The logger should keep a continuous watch on the mud pit volume and the rate of change on the chart recorder. The cause of any abnormal increase or decrease in the pit volume should be immediately determined.

5.2.1 Formation Susceptible to Lost Returns

Cavernous formations with limestone reefs tend to have openings which vary from pin size to tunnel size. Upon drilling into a void of this kind, the drilling rate will increase drastically followed by a loss of mud which can be severe enough to allow a blowout from shallower zones or it may cause caving because of the reduced hydrostatic pressure. If the voids are small enough to be bridged by lost circulation material (LCM) and the rock matrix is strong enough to withstand the pressure surges present in the drilling operation, then this type of lost circulation can be cured by a judicious application of LCM. If the void cannot be sealed, the alternative in the Gulf Coast area is to drill without returns. After drilling through the lost circulation zone, casing should then be set. In the Gulf Coast, this type of lost circulation is present around the Florida coast in the shallower formations.

Extremely permeable, shallow formations, like uncompressed gravel and sand. This type of lost circulation is found at shallow depths, which are usually subnormally to normally pressured. In order to take whole mud, the openings between the solid particles in the formation must be somewhat larger than the solid particles in the mud. To cure lost circulation in this situation, first cut the mud weight as much as possible. Various soft plugging agents can be added to the mud to help cut the loss. A thick bentonite slurry fluffed with lime is often successful in this situation.

Formations containing natural fractures. A natural fracture can be defined loosely as the interface between two layers of rock which have little if any chemical bond between them. The fractures are held together either by the overburden pressure or by tectonic stresses. When critical pressures are reached, such fractures may open and take mud. As more mud is pumped into the fracture, the fracture may widen causing the formation to take mud at even lower pump pressures.

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The most effective approach to this problem is to maintain minimum mud weight, and to avoid pressure surges by moving the pipe, and to maintain the mud properties so as to keep the ECD as low as possible. Cutting down on the pump pressure may also help. Lost circulation may help prevent mud loss in a low density and low solids mud. In high solids mud, the increase in ECD resulting from the LCM may do more harm than good.

Formations that are easily fractured. Mud losses to formations that are fractured mechanically by excessive mud pressures are often a problem in the Gulf Coast, while drilling with a weighted mud. To avoid excess pressures, it is necessary to keep the mud weight as low as possible, keep the mud as thin as possible, raise and lower the drill string slowly, start the mud pumps slowly, etc. The best cure for this type of lost circulation is to wait for a period of 6-12 hours and allow the formation to "heal." Sometimes LCM pumped into the formation to help seal it off before allowing it to heal will aggravate the problem by propping open the fracture.

5.2.2 Combating Lost Circulation

A wide variety of lost circulation materials have been used to combat lost circulation over the years. Anything bulky and available at a tolerable price has been tried at one time or another. Lost circulation material can be divided into fibers, flakes, granules and mixtures.

A general purpose LCM could be characterized by the following criteria:

- It should contain high-strength granules with a definite size distribution.
- It should form a seal at both high and low differential pressures.
- It should be equally effective in sealing unconsolidated formations and fractures or vugs in hard formations.

A mixture of fibers, flakes and granules was formulated which met all of the above requirements. The product evolved as Kwik-Seal. The optimum concentration for sealing under the most severe conditions is 30 to 40 lb/bbl. This formulation is good for low weight, low solids muds. Wall-Nut (ground walnut hulls) is best for high weight, high solids muds.

High filtrate squeezes can be used to combat lost circulation in either high pressure or normally pressured drilling areas. This method involves the use of a special slurry which is pumped into the thief zone under pressure and held under squeeze pressure for several hours before trying to circulate. This type of squeeze for lost circulation depends upon tightly packed and substantially dehydrated solids to effect the required seal. The volume of slurry used may be 50 to 200 barrels, depending on the volume of uncased hole in the well. The LCM should be mostly granular (walnut hulls) when drilling with heavy mud, and mostly fibers and flakes (cotton seed hulls and mica) when drilling with low density mud.

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Gunk squeezes are mixtures and formulas that are pumpable at the surface and develop shear strength when pumped into place downhole. Some of the phases which have been used to describe these plugs are somewhat standardized. The plug is said to develop a "rubbery gel" or "putty-like consistency" and breathes as different pressures are imposed on natural and induced fractures in the formation. As many successes as failures have been experienced using gunk squeezes for curing lost circulation.

5.2.3 Locating the Loss Zone

There are several methods available for locating a loss zone. In practice, these tools are used very rarely. They are described here to familiarize the logging engineer with these methods.

1. **Radioactive tracers:** First a gamma ray log is run, then a slug of radioactive material is spotted above the suspected loss zone and squeezed into the formation. A second gamma ray log is run where the depth of the loss will be identified by a sudden increase in radioactivity. This method is very accurate, but it is expensive and mud has to be pumped into the formation intentionally.
2. **Temperature survey:** A temperature survey is run to establish the temperature gradient for the hole. Mud is then pumped into the hole, and a second temperature survey is then run. The zone of loss is identified by a sudden change in the difference between the two surveys.
3. **Hot wire survey:** An instrument containing a wire whose resistance varies with temperature is spotted in the hole and the resistance measured. Mud is then pumped into the hole. If the tool is below the zone of loss, the resistance will not change. If the tool is above the zone of loss, the wire will cool and the resistance will change. The drawback to this method is that a large volume of mud can be pumped away while making a careful determination of the depth of loss.

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5.3 Restriction in the Drill String

A restriction is anything that might impede the normal flow of mud through the drill string. This restriction may take place at any point in the mud flow system. The restriction could be anything from a pump problem to the hole packing off in the annulus around the drill string. Early detection and warning of a restriction should be taken seriously and the driller notified immediately.

When a restriction occurs, the mud logger will see an increase in the pump pressure with a corresponding decrease in the pump rate. If the restriction is not on the surface, then the problem is either inside the drill string or in the annulus of the hole. One thing that can be done is a "What if..." hydraulics scenario; this compares the actual versus calculated pump pressure. If there is a big difference between the two values, then the logger should do another "What if..." hydraulics scenario but with one less jet than is actually in the bit. The logger may have to back out more than one jet to get the two values to agree.

If the restriction is in the annulus, the logger will normally, but not always, see an increase in the surface torque in the drill string. This is called "packing off." This is the most serious cause of a restriction and something must be done immediately to correct the problem.

Hints and Precautions

1. A decrease in the pump rate with a corresponding increase in the pump pressure may indicative a drill string restriction or the hole packing off.
2. Look carefully at the records of the pump rate, pump pressure, and torque to know which problem is occurring.

5.4 Well Kick

A *kick* may be defined as a condition which exists when the formation pressure exceeds the hydrostatic pressure exerted by the drilling fluid, thus allowing an influx of formation fluids into the wellbore.

A *blowout* is an uncontrolled influx of formation fluids into the wellbore. A kick is not a blowout, but if it is improperly handled, it can become a blowout.

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When the formation pressure is less than the hydrostatic pressure of the mud, plus any pressure losses and imposed pressures, this is known as an *overbalance*. When the formation pressure exceeds the total pressure exerted by the mud column, friction losses and imposed pressures, then this condition is known as an *underbalanced*.

There are a number of factors which determine the severity of a kick: permeability, sand, and underbalanced drilling being a few of them.

In order to allow fluid to flow from a formation into the wellbore, there must be sufficient formation permeability and porosity for this to occur. *Permeability* is a term used to describe the ability of a fluid to move through the rock, and *porosity* is a term used to measure the amount of space in the rock that contains fluid.

Sand, generally speaking, has a greater potential for causing a kick than does shale because:

- the volume of the rock occupied by fluid (porosity) is greater than in shale, and
- the ability of the fluid to move through the rock (permeability) is easier than it is for shale.

The third factor controlling kick severity is the amount of underbalance. The greater the amount of underbalanced, the easier it is for formation fluids to flow from the formation into the wellbore.

5.4.1 Failure to Keep the Hole Full

Failure to fill the hole during a trip is a common cause of a kick. As pipe is removed from the well, the fluid level in the wellbore falls because the drill pipe has displaced a certain amount of mud. With pipe no longer in the hole, mud itself must fill the void which has been created by removing the pipe. If no additional mud is pumped into the well, the volume of fluid in the wellbore remains constant, but because of the void created by removing the pipe, the fluid level in the hole drops. If the fluid level drops enough to decrease the hydrostatic head of the mud to a point where the formation pressure exceeds the mud hydrostatic pressure, an influx of formation fluids into the wellbore will occur.

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5.4.2 Swabbing

Swab pressures are created by pulling the drill string from the hole. The swab pressure acts like a negative hydrostatic pressure, causing reduced bottom hole pressures. If the bottom hole pressure becomes less than the formation pressure, an influx of formation fluids (i.e., a kick) can occur. There are a number of factors upon which swab pressures depend. Some of these are:

- the speed at which the drill pipe is pulled from the hole,
- mud flow properties, especially the yield point and gel strength,
- hole geometry, and
- balled-up equipment (bit, drill collars, stabilizers).

Hole swabbing is easy to recognize. First, the hook load indicator may show more drill string weight than what the string actually weighs. Although drag may depend on a number of factors, it is an immediate tip-off that potential hole swabbing can be taking place. Hole swabbing can be detected by watching the fluid level as pipe is pulled from the hole. If the fluid level does not fall enough or if the fluid seems to be following the pipe as the pipe is pulled, swabbing is taking place. Again some remedial action must be taken immediately. Swab pressures can become severe enough that a bottom hole pressure reduction of several hundred psi may occur. This is very common in a gumbo formation and happens because some of the drilling assembly acts like a piston, which impedes the flow of mud required to fill the void created as the pipe is pulled.

It is common practice to pull up into casing and then put the rig in "high-high gear" and get the pipe out of the hole in a hurry. Swab pressures are exerted at every point in the open hole below the bit. In an area where hole washout is severe, the ID of the casing may be less than the ID of the open hole. If this is true, the potential for hole swabbing is just as great or greater once the bit reaches the casing, as it was when the bit was still in open hole. This may not always be the case, but caution should be exercised in hole surveillance.

5.4.3 Lost Circulation

Lost circulation can be another cause of a kick. If lost returns occur, the fluid level in the hole begins to fall. The length of the fluid column in the hole decreases, causing the hydrostatic pressure of the mud in the hole to decrease. If the hydrostatic pressure of the mud decreases to the point where it becomes less than the formation pressure, a potential kick situation exists. If the lost circulation problem goes undetected, a large amount of fluid influx can occur usually at the bottom of the wellbore or the casing shoe.

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5.4.4 Gas Cut Mud

Gas cut mud can cause a kick, although it does not happen very often. The source of gas in the mud is usually from the drilled formation itself. In the oil field, this phenomenon is variously referred to as *drill gas*, *cuttings gas*, or *core volume*.

Most gas expansion takes place near the surface of the well. If a large diameter hole is being drilled at a high rate of penetration, the amount of gas cut by the bit itself can be considerable. Expansion of the gas occurs as the gas nears the surface, so the hydrostatic head of the mud is reduced. If the hydrostatic head is reduced to a value lower than the formation pressure, a kick can occur. However, the hydrostatic head reduction at the hole bottom by gas cut mud is generally not a significant value. The main concern when dealing with gas cut mud should be to make certain that the surface equipment is adequate to keep gas cut mud from being pumped back down the hole. An operational *degasser* is a necessity when dealing with gas cut mud.

5.4.5 Insufficient Mud Density

Although most blowouts or kicks occur while drill pipe is being tripped, insufficient mud density is the second most common cause of kicks. About 41% of all blowouts occur while drilling ahead, which implies that the mud density in use at the time was not sufficient to control the formation pressure. In the Gulf Coast area, most wells are drilled with higher than a 9.0 ppg mud weight. The normal formation pressure in the Gulf Coast area is assumed to be 9.0 ppg. If 9.0 ppg or greater mud density is insufficient to control formation pressure, then abnormal formation pressures exist. Insufficient mud density and abnormal formation pressures often go hand-in-hand with one another.

There are a number of techniques available to aid in the detection of abnormal pressure. Among those which may provide prior information that abnormal pressure exists are:

- paleontology,
- offset well logs, and analysis of offset well histories,
- temperature changes,
- gas readings,
- formation resistivity,
- cuttings appearance, and
- hole conditions

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Each of the above may be an indication that abnormal pressure exists, but there are also a number of techniques available to determine what the magnitude of the abnormal pressure actually is. Among these are:

- "D" exponent
- resistivity

Because abnormal pressures and insufficient mud weights often go hand-in-hand, it would seem that a solution to this problem would be to drill with high mud weights. However, high mud weights may exceed the fracture gradient, causing stuck pipe, and lower the rate of penetration. The best practice is probably to maintain enough mud weight to keep a slight overbalance, and set additional casing when the mud weight nears the fracture gradient in the weakest part of the open hole.

5.5 Kick Warning Signals

There are a number of indicators that warn of an impending kick. Remember that the earlier a kick is detected, the more easily the control of the well can be maintained. Early detection can keep a relatively minor problem from becoming a major catastrophe. It is the responsibility of each individual crew member to be aware of, and on the lookout for any indicators of abnormal hole conditions which may be noticed. Since most of the downhole information is inferred from what happens to the drilling mud, most of the kick warnings also involve the drilling mud.

5.5.1 Flow Rate Increase

The most obvious indicator of a kicking well is an increase in the rate at which mud is returning from the well while pumping mud in at a constant rate. Since mud enters and leaves the well at the same rate under normal conditions, an increase in return mud flow means that the formation fluid is aiding in the return mud flow. The increase in return flow rate may be noticed on a recorder, by visual inspection at the bell nipple or shaker, or by the most obvious sign of all, the kelly bushings being "floated" up from the rotary table.

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5.5.2 Pit Volume Increase

If fluid is leaving the well faster than it is being pumped into the well, there will be an increased volume of mud in the pits. For this to be an early indicator, changes made and additions to the surface mud system must be accounted for. Good communications are a necessity. Often times, adding a mud treatment to the surface mud systems causes a pit level increase which can cause panic at other parts of the rig because no one was told beforehand that the mud was being treated. By the same token, the level in the pits could be rising due to a kick while everyone is attributing the level increase to mud treatment. Anything done to the mud system at the surface should be made known to those people on the rig who monitor the remote pit level indicators.

5.5.3 Well Flowing with the Pumps Off

When the rig pumps are not pumping mud into the hole, there should be no mud returning from the well. It usually takes a few seconds for flow to stop after the pumps have been shut down. A continued flow returning from the well after the pumps have been stopped is a very good kick indicator. If the mud in the drill pipe is heavier than the mud in the annulus, the well will flow until the hydrostatic pressure in the drill pipe and the annulus equalize. Slugging is easy to differentiate from a kick because a kick generally flows faster while a slug in the drill pipe causes a decreasing flow as the drill pipe and annulus hydrostatic pressures equalize.

5.5.4 Pump Pressure Decrease and Pump Stroke Increase

A change in pump pressure may be a kick warning signal. When formation fluid first enters the wellbore, the mud may become flocculated (thick), causing an increase in pump pressure due to the increased mud thickness. This rise in pump pressure is momentary and may go entirely unnoticed in a normal drilling situation.

As an influx fluid enters the wellbore, the fluid column in the annulus becomes lighter. This makes the mud in the drill pipe fall. The pump stroke rate will increase and the pump pressure will drop due to the falling mud in the drill pipe.

Pump pressure changes can be caused by several different things. Among these are plugged pump suction, aerated mud at the pump suction, pump component failure, washouts in the drill string, washed out bit nozzles, lost circulation, and others. Pump pressure decrease is not necessarily a kick indicator, but it is still a good procedure to check for a kick if a pump pressure decrease is observed.

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5.5.5 Improper Hole Fill on Trips

As was previously mentioned, a predetermined number of pump strokes or barrels of mud is required to fill the hole on trips. If the hole takes less than the calculated amount of mud to fill, it is a fair assumption that formation fluid or gas has entered the wellbore. Although some influx has entered the wellbore, the well may not flow because not enough has gotten into the annulus to lighten the hydrostatic head of the mud in the annulus to a level below that of the formation pressure. However, corrective action should be undertaken immediately if the hole takes less than the calculated amount of mud on trips.

5.5.6 String Weight Change

A drill string weighs less when it is immersed in mud than it does in air because the mud provides a buoyant effect on the drill string. Heavy mud exerts more buoyant force on a string of pipe than light mud does. Formation fluid influx lightens the mud column and results in decreased buoyancy acting on the drill string.

5.5.7 Drilling Breaks

It was stated previously that a rock must have sufficient permeability and porosity for a kick to occur. Increasing porosity will result in drilling rate increases because more of the rock itself is occupied by fluid and less space is occupied by the actual rock matrix itself. An abrupt change in the rate of penetration usually signals a formation change (as in going from a shale into a sand). Sand has a greater kick potential than does shale, so it warrants stopping the pumps 3 to 5 feet into the sand and checking the well for flow. A gradual increase in the rate of penetration is not a drilling break, but it is an abnormal pressure detection and may warrant checking if it persists.

5.5.8 Changes in Mud Gas

As a well is being drilled, gas often enters the returning mud stream because gas is present in the formation is actually being chipped loose by the bit. The gas trapped in the pore spaces of the drilled rock expands as it travels up the annulus. This gas can be detected at the surface with a gas detector. If the amount of gas in the mud is high enough, a mud weight reduction at the flowline is observable due to the gas bubbles present in the mud, and the mud is said to be *gas cut*.

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Gas may also become entrapped in the mud as a result of the swab pressures created by pipe movement while making trips and connections. If the number of pump strokes to circulate bottoms up are known, connection gases and trip gases can be determined by counting the pump strokes since the last trip or connection, and noting any increases or decreases in the gas level at the time that the gas is due at the surface. Connection and trip gases must be evaluated by the amount of change from previous readings rather than by the reading themselves. If the trip or connection gases keep increasing with each trip or connection, there is a good chance that the formation pressure is increasing. However, increased connection or trip gases may also be caused by deteriorating mud flow properties or balled up equipment. These two factors must be considered when evaluating connection gases or trip gases.

Background gas is gas encountered while actually drilling the well. If a gas bearing formation is being drilled, gas will manifest itself at the surface. High gas readings do not automatically mean that an increase in mud weight is required, but simply that a gas bearing formation has been drilled. Of course gas may enter the wellbore from the formation as a result of underbalance. In this case, the amount of gas entering the mud may not be sufficient to cause a kick because the volume of gas entering the mud stream is low (low rock permeability). However, if a zone of higher permeability is later drilled, a kick may occur. As a result, it often becomes necessary to determine whether the gas has been caused by core volume cutting or bleed-in from the formation. A common way of determining whether gas in the mud is caused by core volume cutting or formation gas influx is to circulate the cuttings from the wellbore. If the gas readings fall back to a low value (they will generally not reach "zero" even if the hole is clean), the gas is probably a result of core volume cutting. If relatively high gas reading persists, the gas may be the result of bleed-in from the formation and an increase in mud weight may be necessary to correct this situation.

Gas cutting increases are a truer warning sign of impending abnormal pressure than they are of an impending kick. Caution must be used in evaluating gas readings, however; because of the variety of sources which may cause gas reading to change.

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5.6 Stuck Pipe

One problem which has plagued every oil and gas operator at one time or another is that the drill string becomes stuck and cannot be raised, lowered or rotated. Besides lost rig time, the expense of special tools and technical services, and special mud conditioning makes stuck pipe an expensive and annoying inconvenience. Another reason to avoid stuck pipe is that the stability of the uncased hole may deteriorate in the time required to free the pipe and get back to drilling. Because of the expense and problems associated with stuck pipe, it is desirable to avoid stuck pipe and to expedite getting it loose when it does happen. Therefore, it is a significant concern of the drilling operation.

5.6.1 Causes of Stuck Pipe

Key Seating

This problem is usually present in a directional hole, especially if the direction or angle of the hole has changed, causing a *dog leg* in the hole. This can also occur in a straight hole that has deviated drastically from the vertical and corrective measures are taken causing a dog leg. If a dog leg exists, the drill pipe which is always in tension, tends to wear into the wall of the hole where the drill pipe is rotating against it. This phenomenon is illustrated in Figure 5.1 and Figure 5.2. It is called *key seating* because the hole in cross section looks like a keyhole.

Figure 5.1 Illustrating Key-Seating Effect on a Crooked Hole

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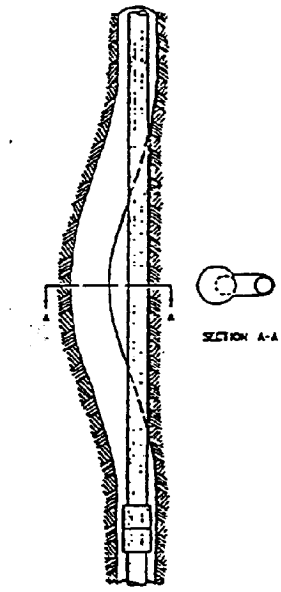

Figure 5.2 Position of Pipe After Key-Seating

The parts of a drilling string which are most likely to become stuck are the parts with the largest diameter. This would be the drill collars, stabilizers, tool joints or even possibly the drill bit. Figure 5.3 shows an example of a drill collar which is stuck in a key seat.

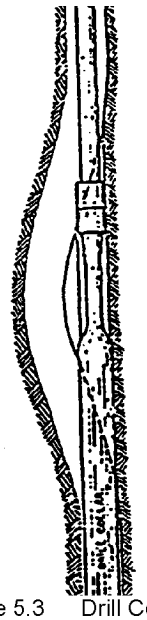

Figure 5.3 Drill Collar Stuck in a Key-Seat

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One preventive measure which can be taken if a key seat is known to exist is to insert in the drill string a hole opener which will open up the small diameter portion of the hole. This will prevent the possibility of sticking the drill string in this key seat while pulling out or going in the hole.

The possible remedies for this sort of sticking problem are to try spotting fluid, while jarring on it with a good set of jars, downward movement, or backing off and washing over. It is recommended to try spotting fluid at least twice before giving up on this method.

Particles in the Hole

Solid particles such as bit cones, rock fragments that cave into the annulus, or pipe rubbers which are too large to pass freely between the drill string and the annulus can cause stuck pipe.

Sometimes a good driller can avoid getting stuck by skillfully manipulating the drill string by judicious hoisting, rotating or lowering the drill string, and by starting and stopping the mud pump to dislodge any small particles present. Massive caving into the hole may be more than skillful handling of the drill string can overcome.

Two specific subsurface conditions from which massive caving often results is pressure underbalance and tectonically stressed and brittle shale.

Pressure underbalance is the condition that exists when the hydrostatic head of the mud column is lower than the pressure on the pore fluids in the formation. Quantities of large shale coming across the shale shaker are an indication of this phenomenon as well as fill on bottom after connections and trips.

Formations that are tectonically stressed and brittle, are generally quite old geologically, and are subjected to stresses associated with the formation of mountains. The shale beds often dip steeply from horizontal, are highly fractured, and contain layers of expanding shales interwoven with brittle, non-expanding shales. Massive caving results when these shales absorb water, causing enough expansion to force masses of shale cuttings to disengage from the walls of the hole. Unequal swelling of the expanding and non-expanding shales cause brittle layers to break off and fall into the hole. An additional source of cuttings in the hole that may stick the pipe are *ledges* that may form while drilling, as illustrated in Figure 5.4. When strings of rocks, unaffected by water lie between beds that are water soluble or water dispersible, washouts occur in the latter beds leaving a ledge without support from above or below. A blow from the drill pipe can break off part of the ledge as illustrated in Figure 5.5.

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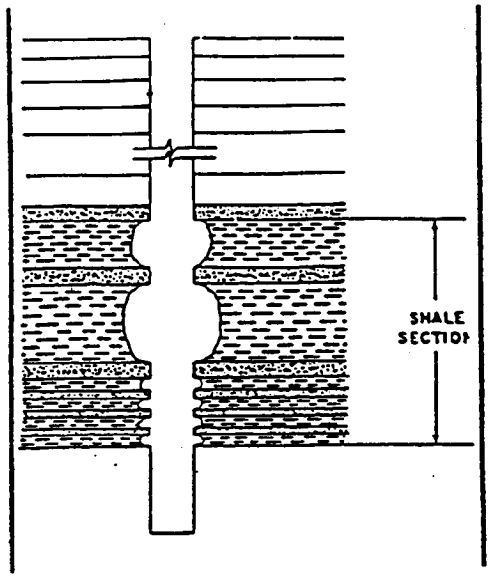

Figure 5.4 Ledges Trapping Cuttings

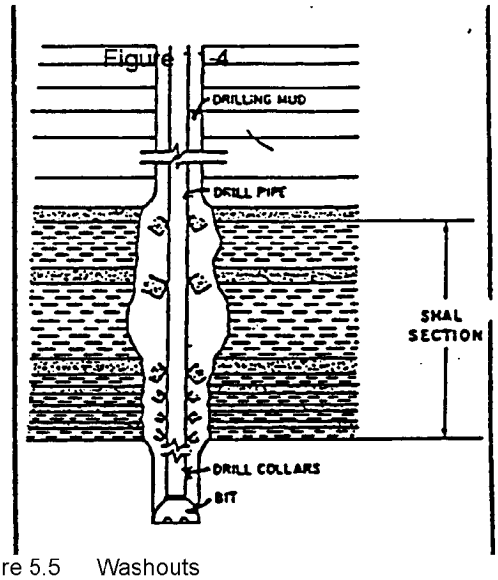

Figure 5.5 Washouts

These cuttings can be a serious threat, even though they may be few in number. The cuttings are not easily worked to the bottom of the hole where they can be redrilled because of their large size. Ledges are best avoided by preventing washouts because washout sections can also accumulate large quantities of cuttings, which can be swabbed into the hole or otherwise be disturbed and cause stuck pipe.

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Stuck pipe caused by caving can be controlled to a significant degree by using a shale-inhibiting-type mud of sufficient weight.

Undergauge Hole

An undergauge hole is a hole which becomes smaller than the bit used to drill it. This problem may be caused by one or more of the following natural causes:

- **Weight of the overburden:** Undergauge hole caused by the weight of the overburden may occur in a shale that is plastic or easily deformed upon being stressed. This shale will have a high water content and probably a high smectite (expandable clay) content as well. Shale of this kind are encountered often at shallow depths in geologically young formations. When a shale of this kind is drilled with a mud weight of 9.0 ppg, then the overburden pressure will be greater than the hydrostatic pressure of the mud and the hole will close.
- **Undergauge hole from abnormal pore pressure:** When a shale that is abnormally pressured is drilled without enough mud weight to counterbalance the pore pressure, then the pore fluids will expand and the shale will extrude into the hole.
- **Cohesion between cuttings and the wall of the hole:** Adhesion of drill solids to the bit and bottom hole assembly has been observed for many years. Since the force of adhesion between drill cuttings and the bottom hole assembly, and the force of cohesion between clay particles depends in large part on the water content of the clay in the cuttings, the two phenomena are probably related. The clay in the mud and drill cuttings attach themselves to the clay in the formation causing a build-up on the sides of the hole, causing an undergauge hole.

The best way to prevent stuck pipe because of undergauge hole is good mud chemistry and mud weight.

Differential Pressure Sticking

Differential sticking is sticking of the pipe against a permeable formation as the result of the pressure of the mud in the hole exceeding the pore fluid pressure. Figure 5.6 is a diagram of what happens when pipe becomes differential stuck or *wall stuck*. If mud circulates, but the pipe will neither rotate nor move up or down, and the mud weight is significantly higher than the pore pressure of the shallowest permeable zone then the chances are good that the pipe is differentially stuck.

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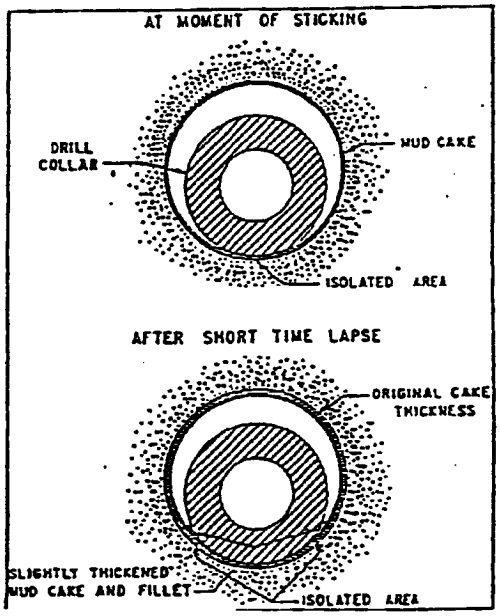

Figure 5.6 Stuck Drill Pipe

Stuck drill pipe results when it becomes motionless against a permeable bed. After cake build-up, hole pressure presses the pipe against the hole wall.

Figure 5.7 shows how spotting fluid affects mud filter cake and helps free stuck pipe.

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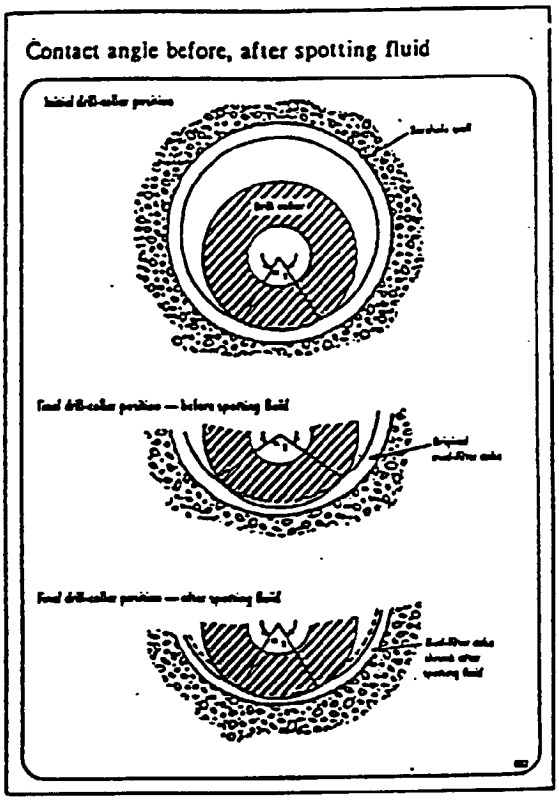

Figure 5.7 Contact Angle Before and After Spotting Fluid

Differential sticking can be avoided by using the lowest mud weight possible, maintaining a low filtration rate, by using some sort of lubricant in a water-based mud, and not letting the drill string stand motionless for any extended period of time.

The most often used technique to free differentially stuck pipe is spotting an oil mud. Differentially stuck pipe is usually freed when a properly formulated oil mud of equal or slightly greater density than the drilling mud in use is spotted in the stuck zone. The best results are achieved when the spot is allowed to soak (to break up the wall cake) for 12 to 18 hours. It is sometimes helpful at this point to locate the free point, back the free pipe from the stuck pipe with a string shot, and pull the free pipe out of the hole. Then go back into the hole with a good set of fishing jars, screw back into the stuck pipe and work the pipe until it becomes free. Try using spotting fluid at least twice before giving up. The only other alternatives at this point is washing over the fish or side tracking the hole.

Differential sticking can intensify with progression in wall cake thickness, so it is important that proper remedial action be taken immediately. It has been proven in laboratory tests that rotating the drill string is more effective to break the mud seal than working the pipe vertically.

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Free Point Depth from Pipe Stretch Procedure

The estimated depth of the free point can be determined by using the following procedure:

1. Pick up more than the weight of the drill string.
2. Mark a reference point on the pipe.
3. Record the hook load in pounds.
4. Pull additional 40,000 to 60,000 pounds on the drill string.
5. Mark another reference on the pipe and measure the distance between point 1 and point 2.
6. Use the following formula to obtain the estimated free point.

Formula: $$L = \frac{735 \times 10^3 (We)}{F}$$

Where:
- L = length of free pipe (feet)
- e = distance in inches between the two reference points and is the stretch of the pipe
- F = the difference in hook load between the initial and final reading, or force required to obtain "e"
- W = weight of the pipe (lb/ft)

5.7 Other Hole Problems

There are two more common types of hole problems that occur in drilling a well. *Sloughing shale* and *dog legs* will be discussed in this section.

Sloughing shale occurs in most wells sometimes during the drilling operation. It can occur for a variety of reasons and therefore must be approached with care and study.

The occurrence of dog legs is another common problem that can lead to other problems of a more serious nature such as key seating and parted drill strings.

5.7.1 Sloughing Shale

Hole sloughing is generally a problem associated with shale. Each drilling area of the world has specific names for the sloughing shale zones in that area. This simply means that it is common for shale to slough into the hole and when the problem occurs repeatedly, operators begin to plan drilling programs to combat the shale problems.

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Shales, in general, have a strong affinity for water and when water is absorbed by shale, the stability of the shale section is reduced. This does not mean that the shale will necessarily slough or cause trouble. Some other causes are: a high percentage of high yielding clays such as sodium montmorillonite, steeply dipping shale beds, pressure shale section (where the pore pressure exceeds the hydrostatic pressure), and turbulent flow in the annulus which promotes erosion.

Almost any shale absorbs some water if it is available. When the water is absorbed, the yield strength of the shale is reduced and the shale generally expands in a direction perpendicular to its bedding plane. The amount of water a shale absorbs depends on its hydration state and composition. Shales containing sodium montmorillonite are likely to expand more than those containing a clay such as kaolinite. However, it has been shown that all shales tend to absorb some water.

Some shales absorb water faster than others and in certain drilling situations may cause trouble very quickly; others absorb water slowly and several days may elapse before any sloughing occurs. Because most shale expansion is in a direction perpendicular to the bedding plane, horizontal shale beds are not likely to slough as a result of this expansion. In fact, an increase in bed dip, increases the probability that a given shale will slough when exposed to water.

A common practice is to reduce water loss when sloughing shale becomes a problem or when drilling through known sloughing shale zones. Based on the discussion concerning the effect of water on shale, this practice sounds reasonable. However, most wetting of shales occurs by the absorption of water into the shale, not by a filter process associated with permeability.

The actual magnitude of the hydrational stress or pressure that forces water into the shale may be on the order of a magnitude of 50,000 psi. Actually, it is determined from the ratio of the aqueous vapor pressure of shale to the aqueous vapor pressure of water. This simply means that if water is present, it will wet the shale even if the measured API water loss is reduced to zero.

One argument for reducing filtration rate has been that shales had interbedded sand stringers or fractures which are invaded by filtrate and the shale is permitted more contact with the water. If the filtration takes place because of the sand or fractures in the shale the argument about greater contact with water would be true. However, the shale would be wet in either case and the surface wetting in the vicinity of the borehole is the most detrimental.

Methods to prevent shale sloughing and hole enlargement have been studied almost since the beginning of rotary drilling. The concept of controlling water loss to stop sloughing was introduced in the 1920's. Lime muds were introduced for this and other purposes in the 1930's. Special calcium-type muds were introduced in the 1950's to inhibit shales and prevent hydration. Oil-based muds already used for the purpose of absorption by shales changed to include salt in the water phase

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during the 1960's. Current practices include potassium chloride-polymer muds which are claimed to prevent clay swelling by absorption and encapsulation.

The question might be asked, "why do certain practices endure if they are not beneficial?" First, it should be remembered that any practice may appear successful at times because formations are not homogenous. Second, the operator feels he must do something even if it is not successful. Consider water loss control, many papers and talks were given on the beneficial effects of drilling with a low water loss to prevent shale sloughing. It would be impossible to determine the specific effects of this practice at the time; however, it is suspected that the control of water loss helped improve filter cake qualities, and many times increased lifting capacity of the muds, which reduced problems of bridges in the hole and pipe sticking. This of course, made the practice worthwhile at the time, even if the diagnosed effect was not correct. Caliper logs helped show that hole enlargement could not be correlated with the API water loss.

The first breakthrough in controlling shale sloughing came with the oil-based muds when the water phase of these muds was saturated with salt. The use of calcium chloride in the water phase of oil-based muds was first introduced by Mondshine in 1966. He showed that water could be pulled into the shale from oil-based muds if no calcium chloride was used, and that water could be pulled out of the shale if an excess amount of calcium chloride was used. The desired result was to ensure no movement of water into or out of the shale. To do this required a balance between the vapor pressure of the water phase in the oil and the vapor pressure of the water of hydration in the shale.

This discussion has been concerned primarily with methods to prevent expansion of the shales. Another cause of sloughing is where the pore pressure in the shale exceeds the hydrostatic pressure of the mud. At times, the operator may drill without excessive shale problems even if the hydrostatic pressure is less than the pore pressure of the shale. If the dip of the shale beds is low, say less than 5 degrees, some underbalance of the hydrostatic pressure can be tolerated because the primary direction of the shale expansion is perpendicular to the bedding plane. If water can be prevented from entering the shale, as discussed above, then the yield strength of the shale may be high enough to prevent excessive sloughing even though the hydrostatic pressure is less than the pore pressure.

In general, the method used to prevent sloughing in pressured shales is to maintain a mud weight that is equal to or greater than the pore pressure of the shale. An alternative option is to simply permit some sloughing as drilling progresses.

Whether high annular velocities cause hole erosion and if so, to what degree is the next question. If the annular flow pattern is laminar, the fluid velocity would probably have no effect on hole erosion. If the flow pattern is turbulent, the fluid velocity would probably substantially affect hole erosion. Thus, in high angle fractured shale zones that have a history of severe sloughing, it is suggested that the mud be thick enough to remove cuttings instead of using thin fluids at high annular velocities that would create turbulent flow patterns. In all probability, the

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hole will slough in either case; a turbulent flow pattern would simply accelerate the problem and once enlargement begins, the thin fluid would not clean the hole.

One method of combating shale problems is to clean the hole by raising the lifting capacity of the mud. Lifting capacity can be increased by flocculating clays, adding more bentonite or by using polymers. A frequent problem encountered is that the operator wants to increase lifting capacity and at the same time control water loss. Any flocculation of the clays to thicken the mud will increase the water loss. The addition of bentonite will increase lifting capacity, however, unless a thinner is also added, the mud is very likely to flocculate.

If a thinner is added, the lifting capacity is reduced and the shale problem continues. Polymers can be added for thickening, however, cost has to be considered. A very important point to remember is that if the hole is not being cleaned, absolutely nothing can be gained by adding a thinner to lower water loss. If the filtration rate must be reduced in this case, use a filtration control agent such as starch.

One other problem that may arise if thickening the mud for hole cleaning is the possibility of losing circulation. If lost circulation problems are associated with hole cleaning problems a compromise may be necessary. Thicken 25 to 50 barrels of mud by one of the methods mentioned; the amount of thickening will depend on the specific problem. However, a yield point of 60 to 100 should be achieved. Pump this batch of thick mud with the thinner mud. The thick mud should clean the hole with a minimum effect on the total annular pressure.

5.7.2 Dog Legs

Dog legs are sudden changes in hole angle or direction. They have been a major potential problem since the beginning of the drilling business. In the pioneer days, when it was possible to determine that a rapid change in angle had occurred their solution was to automatically pull back and start over.

Modern surveying techniques indicate that no hole is perfectly vertical. Any hole has a tendency to spiral. In fact, some holes surveyed made three complete circles in 100 feet. Spiraling is reduced as the deviation from vertical increases. The maximum spiraling occurs at angles of less than 3 degrees from vertical. At angles greater than 5 degrees from vertical, the hole may move in a wide arc, but spiraling is almost nonexistent.

Dog legs are a major factor in many of our more severe drilling problems. Dog legging should be suspected when the following problems are encountered: unable to run electric logs on wireline, unable to run casing, key seating, excessive casing wear, excessive wear on drill pipe and drill collars, excessive drag, and fatigue failures of drill pipe and drill collars.

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The major problem facing the drilling industry was to define a severe dog leg within the industry's ability to survey dog legs. Arthur Lubinski made the first effort to define a severe dog leg in his paper entitled, "Maximum Permissible Dog Legs in Rotary Boreholes," published in 1961. Lubinski recognized that severe dog legs created major drilling problems and proposed that a dog leg was too severe if any one of the following conditions existed:

- the stress reversals, when rotating in the dog leg, were sufficient to fatigue the drill pipe
- the thrust force on the drill pipe tool joint in the dog leg was sufficient to cause the tool joint to dig into the formation and cause a key seat or produce casing wear
- the stress reversals, when rotating in the dog leg, were sufficient to fatigue the drill collars

Lubinski concluded that these conditions should be avoided and each section of the hole should be evaluated in view of the limiting conditions in order to determine the maximum permissible dog leg at any given depth.

The final limiting condition, according to Lubinski, is drill collar fatigue. Lubinski studied various conditions for different collar sizes, and made calculations of the abrupt dog leg angles to which the connections would be subjected to produce fatigue failure. It was concluded that the critical angle is a function of collar-to-hole clearance, the amount of tension or compression which the collars are subjected to in the dog leg, and increasing/decreasing hole inclination. Obviously, a much larger change in angle can be tolerated at total depth, whereas, only very small changes can be tolerated at the surface in very deep holes. Based on experience, it was assumed that a 2,000 pound or less thrust force would never create a drilling problem. Conversely, it is obvious from Lubinski's work that reduced collar-to-wall clearance resists dog legging.

In an effort to apply Lubinski's work, the API Mid-Continent Study Committee on Straight Hole Drilling, published in 1963, a study of 1094 dog legs in the Gulf Coast, Mid-Continent and West Coast areas. Elaborate efforts were made to associate problems with dog legs and their severity. Dog legs up to 25 degrees per 100 feet were reported.

The committee's study substantiated the minimum limitation of 1 to $1^1/_2$ degrees per 100 feet. This minimum limit should be re-evaluated when drilling ultra-deep holes or horizontal holes. Further, the study substantiated the limitations with regard to drill collar fatigue. Essentially, the committee suggested that the bottom of the hole equal to the length of the collar string should be limited by collar fatigue (i.e., $3^1/_2$ degrees per 100 feet for $6^1/_2$-inch collars) at the bottom and limited to $1^1/_2$ degrees per 100 feet over the remainder of the hole.

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Two other significant conclusions were reached in these papers. First, Lubinski concluded that dog leg severity was *independent of* the weight on the bit. That is, drilling with more weight on bit would not result in sharper dog legs; conversely, drilling with reduced bit weight or "fanning bottom" is detrimental to the drill string since reduced bit weight results in increased string tension which increases the potential for casing wear, pipe fatigue, collar fatigue, and key seating.

Since dog leg severity is primarily a function of clearance, the only practical method available to reduce dog leg severity is to reduce the collar-to-wall clearance or pack the hole and to increase stiffness by decreasing hole size (a last resort). Packed hole assemblies include all forms of reamers, integral blade stabilizers, spiral drill collars, and rotating stabilizers at almost any spacing combination.

There have been numerous successful reports from all over the world including South America, the Gulf Coast, Mid-Continent, Rocky Mountains, and Canada, and under every conceivable drilling condition. In all the information reviewed no dog leg severity greater than $3^1/_2$ degrees per 100 feet was reported while using square drill collars regardless of drilling conditions.

Other practices used to cope with severe dog legs include:

- increasing the frequency of drill collar inspections
- using non-hardband drill pipe through the dog leg to avoid excessive casing wear
- reducing rotary speed while drilling through a dog leg to reduce the number of stress reversals
- minimizing off-bottom rotation to reduce unnecessary stress reversals with maximum tensile stress
- using packed hole assemblies to reduce dog leg severity
- keeping the kick-off point in a directional well as deep as practical
- using heavier casing through working dog legs
- using string reamers to reduce dog leg severity and prevent key sets.

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Appendix A Displacement of Single-Acting Triplex Mud Pumps

Liner Size	Stroke Length[a]								
	7	$7^1/_2$	8	$8^1/_2$	9	$9^1/_2$	10	11	12
3	.643[0153]	.689[.0164]	.734[.0175]	.780[.0186]	.826[.0197]	.849[.0202]	.918[.0219]	1.01[.0240]	1.10[.0262]
$3^1/_4$	.754[.0180]	.808[.0192]	.862[.0205]	.915[.0218]	.969[.0231]	.997[.0237]	1.08[.0257]	1.19[.0283]	1.29[.0262]
$3^1/_2$	.874[.0208]	.937[.0223]	1.00[.0238]	1.06[.0252]	1.12[.0267]	1.16[.0276]	1.25[.0298]	1.37[.0326]	1.50[.0357]
$3^3/_4$	1.00[.0238]	1.08[.0257]	1.15[.0274]	1.22[.0290]	1.29[.0307]	1.33[.0317]	1.43[.0340]	1.58[.0376]	1.72[.0410]
4	1.14[.0271]	1.22[.0290]	1.31[.0312]	1.39[.0331]	1.47[.0350]	1.51[.0359]	1.63[.0388]	1.80[.0429]	1.96[.0467]
$4^1/_4$	1.29[.0307]	1.38[.0329]	1.47[.0350]	1.57[.0374]	1.66[.0395]	1.70[.0405]	1.84[.0438]	2.03[.0483]	2.21[.0526]
$4^1/_2$	1.45[.0345]	1.56[.0371]	1.65[.0393]	1.76[.0419]	1.86[.0443]	1.91[.0455]	2.07[.0493]	2.27[.0540]	2.48[.0590]
$4^3/_4$	1.61[.0383]	1.73[.0412]	1.84[.0438]	1.96[.0467]	2.07[.0493]	2.13[.0507]	2.30[.0548]	2.53[.0602]	2.76[.0657]
5	1.79[.0426]	1.91[.0455]	2.04[.0486]	2.17[.0517]	2.30[.0548]	2.36[.0562]	2.55[.0607]	2.81[.0669]	3.06[.0729]
$5^1/_4$	1.97[.0469]	2.11[.0502]	2.25[.0536]	2.39[.0569]	2.53[.0602]	2.60[.0619]	2.81[.0669]	3.09[.0736]	3.37[.0802]
$5^1/_2$	2.16[.0514]	2.31[.0550]	2.47[.0588]	2.62[.0624]	2.78[.0662]	2.85[.0679]	3.09[.0736]	3.39[.0807]	3.70[.0881]
$5^3/_4$	2.36[.0562]	2.53[.0602]	2.70[.0643]	2.87[.0683]	3.03[.0721]	3.12[.0743]	3.37[.0802]	3.71[.0883]	4.05[.0964]
6	2.57[.0612]	2.75[.0655]	2.94[.0700]	3.12[.0743]	3.30[.0786]	3.40[.0810]	3.67[.0874]	4.04[.0962]	4.41[.1050]
$6^1/_4$	2.79[.0657]	2.99[.0712]	3.19[.0760]	3.39[.0807]	3.59[.0855]	3.69[.0879]	3.98[.0948]	4.38[.1043]	4.78[.1138]
$6^1/_2$	3.02[.0719]	3.23[.0769]	3.45[.0821]	3.66[.0871]	3.88[.0923]	3.99[.0950]	4.31[.1026]	4.74[.1129]	5.17[.1231]
$6^3/_4$	3.25[.0774]	3.49[.0831]	3.72[.0886]	3.95[.0941]	4.18[.0995]	4.30[.1024]	4.65[.1107]	5.11[.1217]	5.58[.1329]
7	3.50[.0833]	3.75[.0893]	4.00[.0952]	4.25[.1012]	4.50[.1071]	4.62[.1100]	5.00[.1190]	5.50[.1340]	6.00[.1429]
$7^1/_4$	3.75[.0893]	4.02[.0957]	4.29[.1021]	4.56[.1086]	4.83[.1150]	5.09[.1212]	5.36[.1276]	5.90[.1405]	6.43[.1531]
$7^1/_2$	4.02[.0957]	4.30[.1024]	4.59[.1093]	4.88[.1162]	5.16[.1229]	5.45[.1298]	5.74[.1367]	6.31[.1502]	6.89[.1640]
$7^3/_4$	4.29[.1021]	4.60[.1095]	4.90[.1167]	5.21[.1240]	5.51[.1312]	5.82[.1386]	6.13[.1460]	6.74[.1605]	7.35[.1750]
8	4.57[.1088]	4.90[.1167]	5.22[.1243]	5.55[.1321]	5.88[.1400]	6.20[.1476]	6.53[.1555]	7.18[.1709]	7.83[.1864]

a. See Figure A.1 for calculation formula.

Note 1: Liner sizes and stroke length in inches.

Note 2: Displacement expressed in gallons [barrels] per stroke at 100% volumetric efficiency.

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The output in barrels per stroke of a single-acting triplex pump is as follows:

Output = .000243 × (liner ID^2) × stroke length (inches)

Example: The output of a 6" × 12" triplex pump is:

Output = .000243 × (6^2) × 12
= .000243 × 36 × 12
= .1050 bbl/stk

Figure A.1 Output of a Single-Acting Triplex Pump

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Appendix B Hole Capacity Table

Hole Size (In.)	Capacity[a] (bbl/ft)	Hole Size (In.)	Capacity[a] (bbl/ft)	Hole Size (In.)	Capacity[a] (bbl/ft)
$2^1/_2$	.0061	7	.0476	$11^7/_8$	.1370
$2^5/_8$	.0067	$7^1/_8$	.0493	12	.1399
$2^3/_4$	.0073	$7^1/_4$	.0511	$12^1/_8$	.1428
$2^7/_8$	.0080	$7^5/_8$	.0565	$12^1/_4$	.1458
3	.0087	$7^3/_4$	.0583	$12^3/_8$	.1488
$3^1/_8$	.0095	$7^7/_8$	.0602	$12^1/_2$	.1518
$3^1/_4$	.0103	8	.0622	$12^5/_8$	.1548
$3^3/_8$	.0107	$8^1/_8$	.0641	$12^3/_4$	.1579
$3^1/_2$	.0119	$8^1/_4$	.0661	$12^7/_8$	.1610
$3^5/_8$	.0128	$8^3/_8$	.0673	13	.1642
$3^3/_4$	.0137	$8^1/_2$	.0702	$13^1/_8$	.1673
$3^7/_8$	.0146	$8^5/_8$	.0723	$13^1/_4$	.1705
4	.0155	$8^3/_4$	.0744	$13^3/_8$	.1738
$4^1/_8$	.0165	9	.0787	$13^1/_2$	.1770
$4^1/_4$	.0175	$9^1/_8$	.0809	$13^5/_8$	.1803
$4^3/_8$	.0186	$9^1/_4$	.0831	$13^3/_4$	.1837
$4^1/_2$	.0197	$9^3/_8$	.0854	$13^7/_8$	.1870
$4^5/_8$	.0208	$9^1/_2$	.0877	14	.1904
$4^3/_4$	.0219	$9^5/_8$	.0900	$14^1/_8$	.1938
$4^7/_8$	.0231	$9^3/_4$	.0923	$14^1/_4$	.1973
5	.0243	$9^7/_8$	.0947	$14^3/_8$	.2007
$5^1/_8$	.0255	10	.0971	$14^1/_2$	.2042
$5^1/_4$	.0268	$10^1/_8$	.0996	$14^5/_8$	.2078
$5^3/_8$	.0281	$10^1/_4$	.1021	$14^3/_4$	.2113
$5^1/_2$	.0268	$10^3/_8$	.1046	$14^7/_8$	.2149
$5^5/_8$	.0307	$10^1/_2$	.1071	15	.2186
$5^3/_4$	.0321	$10^5/_8$	.1097	$15^1/_8$	.2222
$5^7/_8$	.0335	$10^3/_4$	.1123	$15^1/_4$	.2259
6	.0350	$10^7/_8$	.1149	$15^3/_8$	.2296
$6^1/_8$	.0364	11	.1175	$15^1/_2$	.2334
$6^1/_4$	.0379	$11^1/_8$	.1202	$15^5/_8$	.2372
$6^3/_8$	.0395	$11^1/_4$	.1229	$15^3/_4$	.2410
$6^1/_2$	.0410	$11^3/_8$	.1257	$15^7/_8$	.2448
$6^5/_8$	.0426	$11^1/_2$	.1285	16	.2487
$6^3/_4$	.0443	$11^5/_8$	.1313	$16^1/_8$	.2526
$6^7/_8$	.0459	$11^3/_4$	.1341	$16^1/_4$	.2565

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Hole Size (In.)	Capacity[a] (bbl/ft)	Hole Size (In.)	Capacity[a] (bbl/ft)	Hole Size (In.)	Capacity[a] (bbl/ft)
$16^3/_8$	.2605	$21^1/_8$	.4335	$25^7/_8$	.6504
$16^1/_2$	.2645	$21^1/_4$	.4386	26	.6567
$16^5/_8$	.2685	$21^3/_8$	.4438	$26^1/_8$	.6630
$16^3/_4$	.2725	$21^1/_2$	.4490	$26^1/_4$	.6694
$16^7/_8$	.2766	$21^5/_8$	.4543	$26^3/_8$	.6757
17	.2807	$21^3/_4$	.4595	$26^1/_2$	.6822
$17^1/_8$	.2849	$21^7/_8$	.4648	$26^5/_8$	.6886
$17^1/_4$	.2890	22	.4702	$26^3/_4$	.6951
$17^3/_8$	.2933	$22^1/_8$	.4755	$26^7/_8$	.7016
$17^1/_2$	.2975	$22^1/_4$	.4809	27	.7082
$17^5/_8$	.3018	$22^3/_8$	.4863	$27^1/_8$	.7147
$17^3/_4$	.3061	$22^1/_2$	.4918	$27^1/_4$	.7213
$17^7/_8$	.3072	$22^5/_8$	.4973	$27^3/_8$	.7280
18	.3147	$22^3/_4$	.5028	$27^1/_2$	.7346
$18^1/_8$	.3191	$22^7/_8$	.5083	$27^5/_8$	.7413
$18^1/_4$	.3235	23	.5139	$27^3/_4$	.7480
$18^3/_8$	.3280	$23^1/_8$	.5195	$27^7/_8$	.7548
$18^1/_2$	.3325	$23^1/_4$	.5251	28	.7616
$18^5/_8$	.3370	$23^3/_8$	.5308	$28^1/_8$	.7684
$18^3/_4$	.3415	$23^1/_2$	.5365	$28^1/_4$	.7752
$18^7/_8$	.3461	$23^5/_8$	.5422	$28^3/_8$	.7821
19	.3507	$23^3/_4$	.5479	$28^1/_2$	.7890
$19^1/_8$	.3553	$23^7/_8$	.5537	$28^5/_8$	.7960
$19^1/_4$	.3507	24	.5595	$28^3/_4$	.8029
$19^3/_8$	.3647	$24^1/_8$	.5654	$28^7/_8$	.8099
$19^1/_2$	.3694	$24^1/_4$	.5712	29	.8169
$19^5/_8$	.3741	$24^3/_8$	.5771	$29^1/_8$	.8240
$19^3/_4$	.3789	$24^1/_2$	.5831	$29^1/_4$	.8311
$19^7/_8$	.3837	$24^5/_8$	.5890	$29^3/_8$	.8382
20	.3886	$24^3/_4$	.5950	$29^1/_2$	.8454
$20^1/_8$	.3934	$24^7/_8$	.6011	$29^5/_8$	.8525
$20^1/_4$	.3983	25	.6071	$29^3/_4$	.8597
$20^3/_8$	.4033	$25^1/_8$	.6132	$29^7/_8$	.8670
$20^1/_2$	.4082	$25^1/_4$	.6193	30	.8743
$20^5/_8$	.4132	$25^3/_8$	.6230	$30^1/_8$	.8816
$20^3/_4$	.4182	$25^1/_2$	.6317	$30^1/_4$	.8889
$20^7/_8$	.4233	$25^5/_8$	.6379	$30^3/_8$	.8963
21	.4284	$25^3/_4$	.6441	$30^1/_2$	.9036

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Hole Size (In.)	Capacity[a] (bbl/ft)	Hole Size (In.)	Capacity[a] (bbl/ft)	Hole Size (In.)	Capacity[a] (bbl/ft)
$30^5/_8$	.9111	$30^7/_8$	.9260	$31^1/_8$	.9411
$30^3/_4$	.9185	31	.9355	$31^1/_4$	.9486

a. See Figure B.1 for calculation formula.

The hole capacity in barrels per foot is as follows:

Capacity = Hole Diameter^2 × .0009714

Example: Capacity of a $17^1/_2$-inch hole is:
Capacity = 17.52 × .0009714
= 306.25 × .0009714
= .2975 bbl/ft

Figure B.1 Hole Capacity Calculation

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Appendix C Casing Data

Outside Diameter (in)	Nominal Weight With Coupling (lb/ft)	Grade	Wall Thickness (in)	Inside Diameter (in)	Drift Diameter (in)	Outside Diameter of Coupling (in)	Burst Strength (psi)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)
$4^1/_2$	9.50	F-25	0.205	4.090	3.965	5.000	1,990	.0162	.0034
	9.50	H-40	0.205	4.090	3.965	5.000	1,990	.0162	.0034
	9.50	J-55	0.205	4.090	3.965	5.000	4.380	.0162	.0034
	10.50	J-55	0.224	4.052	3.927	5.000	4,790	.0159	.0037
	11.60	J-55	0.250	4.000	3.875	5.000	5,350	.0155	.0041
	9.50	K-55	0.205	4.090	3.965	5.000	4,380	.0162	.0034
	10.50	K-55	0.224	4.052	3.927	5.000	4,790	.0159	.0037
	11.60	K-55	0.250	4.000	3.875	5.000	5,350	.0155	.0041
	11.60	C-75	0.250	4.000	3.875	5.000	7,290	.0155	.0041
	13.50	C-75	0.290	3.920	3.795	5.000	8,460	.0149	.0047
	11.60	L-80	0.250	4.000	3.875	5.000	7,780	.0155	.0041
	13.50	L-80	0.290	3.920	3.795	5.000	9,020	.0149	.0047
	11.60	N-80	0.250	4.000	3.875	5.000	7,780	.0155	.0041
	13.50	N-80	0.290	3.920	3.795	5.000	9,020	.0149	.0047
	11.60	C-90	0.250	4.000	3.875	5.000	8,750	.0155	.0041
	13.50	C-90	0.290	3.920	3.795	5.000	10,150	.0149	.0047
	11.60	C-95	0.250	4.000	3.875	5.000	9,240	.0155	.0041
	13.50	C-95	0.290	3.920	3.795	5.000	10,710	.0149	.0047
	11.60	P-110	0.250	4.000	3.875	5.000	10,690	.0155	.0041
	13.50	P-110	0.290	3.920	3.795	5.000	12,410	.0149	.0047
	15.10	P-110	0.337	3.826	3.701	5.000	14,420	.0142	.0055
	15.10	V-150	0.337	3.826	3.701	5.000	19.660	.0142	.0055
5	11.50	F-25	0.220	4.560	4.435	5.563	1,930	.0202	.0041
	11.50	J-55	0.220	4.560	4.435	5.563	4,240	.0202	.0041
	13.00	J-55	0.253	4.494	4.369	5.563	4,870	.0196	.0047
	15.00	J-55	0.296	4.408	4.283	5.563	5,700	.0189	.0054

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Outside Diameter (in)	Nominal Weight With Coupling (lb/ft)	Grade	Wall Thickness (in)	Inside Diameter (in)	Drift Diameter (in)	Outside Diameter of Coupling (in)	Burst Strength (psi)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)
5 (cont.)	11.50	K-55	0.220	4.560	4.435	5.563	4,280	.0202	.0041
	13.00	K-55	0.253	4.494	4.369	5.563	4,870	.0196	.0047
	15.00	K-55	0.296	4.408	4.283	5.563	5,700	.0189	.0054
	15.00	C-75	0.296	4.408	4.283	5.563	7,770	.0189	.0054
	18.00	C-75	0.362	4.276	4.151	5.563	9,600	.0178	.0065
	20.30	C-75	0.408	4.184	4.059	5.563	10,710	.0170	.0073
	21.40	C-75	0.437	4.126	4.001	5.563	-----	.0165	.0077
	23.20	C-75	0.478	4.044	3.919	5.563	15,890	.0159	.0084
	24.10	C-75	0.500	4.000	3.875	5.563	13,130	.0155	.0087
	15.00	L-80	0.296	4.408	4.283	5.563	8,290	.0189	.0054
	18.00	L-80	0.362	4.276	4.151	5.563	10,140	.0178	.0065
	21.40	L-80	0.437	4.126	4.001	5.563	11,420	.0165	.0077
	23.20	L-80	0.478	4.044	3.919	5.563	12,520	.0159	.0084
	24.10	L-80	0.500	4.000	.875	5.563	------	.0155	.0087
	15.00	N-80	0.296	4.408	4.283	5.563	8,290	.0189	.0054
	18.00	N-80	0.362	4.276	4.151	5.563	10,140	.0178	.0065
	21.40	N-80	0.408	4.184	4.059	5.563	11,420	.0170	.0072
	23.20	N-80	0.478	4.044	3.919	5.563	12,550	.0159	.0084
	24.10	N-80	0.500	4.000	3.875	5.563	14,000	.0155	.0087
	15.00	C-90	0.296	4.408	4.283	5.563	9,320	.0189	.0054
	18.00	C-90	0.362	4.276	4.151	5.563	11,400	.0178	.0065
	21.40	C-90	0.437	4.126	4.001	5.563	-----	.0165	.0077
	23.20	C-90	0.478	4.044	3.919	5.563	15,060	.0159	.0084
	24.10	C-90	0.500	4.000	3.875	5.563	15,750	.0155	.0087
	15.00	C-95	0.296	4.408	4.283	5.563	9.840	.0189	.0054
	18.00	C-95	0.362	4.276	4.151	5.563	12,040	.0178	.0065
	20.30	C-95	0.408	4.184	4.059	5.563	13,560	.0170	.0072
	21.40	C-95	0.437	4.126	4.001	5.563	-----	.0165	.0077
5 (cont.)	23.20	C-95	0.478	4.044	3.919	5.563	15,890	.0159	.0084
	24.10	C-95	0.500	4.000	3.875	5.563	16,630	.0155	.0087
	15.00	P-110	0.296	4.408	4.283	5.563	11,400	.0189	.0054
	18.00	P-110	0.362	4.276	4.151	5.563	13,940	.0178	.0065
	20.30	P-110	0.408	4.184	4.059	5.563	15,710	.0170	.0072
	21.40	P-110	0.437	4.126	4.001	5.563	-----	.0165	.0077

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Outside Diameter (in)	Nominal Weight With Coupling (lb/ft)	Grade	Wall Thickness (in)	Inside Diameter (in)	Drift Diameter (in)	Outside Diameter of Coupling (in)	Burst Strength (psi)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)
	23.20	P-110	0.478	4.044	3.919	5.563	18,400	.0159	.0084
	24.10	P-110	0.500	4.000	3.875	5.563	19,250	.0155	.0087
	15.00	V-150	0.296	4.408	4.283	5.563	15,540	.0189	.0054
	18.00	V-150	0.362	4.276	4.151	5.563	19,000	.0178	.0065
	20.30	V-150	0.408	4.156	4.031	5.563	20,280	.0168	.0075
	24.20	V-150	0.500	4.000	3.875	5.563	20,280	.0155	.0087
$5^1/_4$	16.00 [b]	---	0.300	4.650	4.525	6.050	-----	.0210	.0058
$5^1/_2$	13.00	F-25	0.228	5.044	4.919	6.050	1,810	.0247	.0047
	14.00	H-40	0.244	5.012	4.887	6.050	3,110	.0244	.0050
	14.00	J-55	0.244	5.012	4.887	6.050	4,270	.0244	.0050
	15.50	J-55	0.275	4.950	4.825	6.050	4,810	.0238	.0056
	17.00	J-55	0.304	4.892	4.767	6.050	5,320	.0232	.0061
	14.00	K-55	0.244	5.012	4.887	6.050	4,270	.0244	.0050
	15.50	K-55	0.275	4.950	4.825	6.050	4,810	.0238	.0056
	17.00	K-55	0.304	4.892	4.767	6.050	5,320	.0232	.0061
	17.00	C-75	0.304	4.892	4.767	6.050	7,250	.0232	.0061
	20.00	C-75	0.361	4.778	4.653	6.050	8,610	.0222	.0072
	23.00	C-75	0.415	4.670	4.545	6.050	9,900	.0212	.0082
	26.00	C-75	0.476	4.548	4.423	6.050	11,360	.0201	.0093
	17.00	L-80	0.304	4.892	4.767	6.050	7,740	.0232	.0061
	20.00	L-80	0.361	4.778	4.653	6.050	9,190	.0222	.0072
	23.00	L-80	0.415	4.670	4.545	6.050	10,560	.0212	.0082
	17.00	N-80	0.304	4.892	4.767	6.050	7,740	.0232	.0061
	20.00	N-80	0.361	4.778	4.653	6.050	9,190	.0222	.0072
	23.00	N-80	0.415	4.670	4.545	6.050	10,560	.0212	.0082
	26.00	N-80	0.476	4.548	4.423	6.050	12,120	.0201	.0093
	17.00	C-90	0.304	4.892	4.767	6.050	8,710	.0232	.0061
	20.00	C-90	0.361	4.778	4.653	6.050	10,340	.0222	.0072
	23.00	C-90	0.415	4.670	4.545	6.050	11,880	.0212	.0082
	26.00	C-90	0.476	4.548	4.423	6.050	13,630	.0201	.0093
	35.00	C-90	0.650	4.200	4.075	6.050		.0171	.0122

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Outside Diameter (in)	Nominal Weight With Coupling (lb/ft)	Grade	Wall Thickness (in)	Inside Diameter (in)	Drift Diameter (in)	Outside Diameter of Coupling (in)	Burst Strength (psi)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)
	17.00	C-95	0.304	4.892	4.767	6.050	9,190	.0232	.0061
	20.00	C-95	0.361	4.778	4.653	6.050	10,910	.0222	.0072
	23.00	C-95	0.415	4.670	4.545	6.050	12,540	.0212	.0082
	26.00	C-95	0.476	4.548	4.423	6.050	14,390	.0201	.0093
	17.00	P-110	0.304	4.892	4.767	6.050	10,640	.0232	.0061
	20.00	P-110	0.361	4.778	4.653	6.050	12,640	.0222	.0072
	23.00	P-110	0.415	4.670	4.545	6.050	14,520	.0212	.0092
	26.00	P-110	0.476	4.548	4.423	6.050	16,660	.0201	.0093
	20.00	V-150	0.361	4.778	4.653	6.050	17,230	.0222	.0072
	23.00	V-150	0.415	4.670	4.545	6.050	18,520	.0212	.0092
	26.00	V-150	0.476	4.548	4.423	6.050	22,720	.0201	.0093
$5^{9}/_{16}$	15.00 [b]	---	0.258	5.047	4.922	6.625	-----	.0247	.0053
6	15.00	F-25	0.238	5.524	5.399	6.625	1,740	.0296	.0053
	18.00	H-40	0.288	5.424	5.299	6.625	3,360	.0286	.0064
	18.00	J-55	0.288	5.424	5.299	6.625	4,620	.0286	.0064
	18.00	N-80	0.288	5.424	5.299	6.625	6,720	.0286	.0064
	20.00	N-80	0.324	5.352	5.227	6.625	7,560	.0278	.0071
	23.00	N-80	0.380	5.240	5.115	6.625	8,870	.0267	.0083
	23.00	P-110	0.380	5.240	5.115	6.625	12,190	.0267	.0083
	26.00	P-110	0.434	5.132	5.007	6.625	13,920	.0256	.0094
$6^{5}/_{8}$	17.00	F-25	0.245	6.135	6.101	7.390	1,620	.0366	.0061
	20.00	H-40	0.288	6.049	5.924	7.390	3,040	.0355	.0071
	20.00	J-55	0.288	6.049	5.924	7.390	4,180	.0355	.0071
	24.00	J-55	0.352	5.921	5.796	7.390	5,110	.0341	.0086
	20.00	K-55	0.288	6.049	5.924	7.390	4,180	.0355	.0071
	24.00	K-55	0.352	5.921	5.796	7.390	5,110	.0341	.0086
	24.00	C-75	0.352	5.921	5.796	7.390	6,970	.0341	.0086
	28.00	C-75	0.417	5.791	5.666	7.390	8,260	.0326	.0101
	32.00	C-75	0.475	5.675	5.550	7.390	9,410	.0313	.0114

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Outside Diameter (in)	Nominal Weight With Coupling (lb/ft)	Grade	Wall Thickness (in)	Inside Diameter (in)	Drift Diameter (in)	Outside Diameter of Coupling (in)	Burst Strength (psi)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)
	24.00	L-80	0.352	5.921	5.796	7.390	7,440	.0341	.0086
	28.00	L-80	0.417	5.791	5.666	7.390	8,810	.0326	.0101
	32.00	L-80	0.475	5.675	5.550	7.390	10,040	.0313	.0114
	24.00	N-80	0.352	5.921	5.796	7.390	7,440	.0341	.0086
	28.00	N-80	0.417	5.791	5.666	7.390	8,810	.0326	.0101
	32.00	N-80	0.475	5.675	5.550	7.390	10,040	.0313	.0114
	24.00	C-90	0.352	5.921	5.796	7.390	8,370	.0341	.0086
	28.00	C-90	0.417	5.791	5.666	7.390	9,910	.0326	.0101
	32.00	C-90	0.475	5.675	5.550	7.390	11,290	.0313	.0114
	24.00	C-95	0.352	5.921	5.796	7.390	8,830	.0341	.0086
	28.00	C-95	0.417	5.791	5.666	7.390	10,460	.0326	.0101
	32.00	C-95	0.475	5.675	5.550	7.390	11,920	.0313	.0114
	24.00	P-110	0.352	5.921	5.796	7.390	7.390	.0341	.0086
	28.00	P-110	0.417	5.791	5.666	7.390	12,120	.0326	.0101
	32.00	P-110	0.475	5.675	5.550	7.390	13,800	.0313	.0114
7	17.00	F-25	0.231	6.538	6.413	7.656	1,440	.0415	.0061
	17.00	H-40	0.231	6.538	6.413	7.656	2,310	.0415	.0061
	20.00	H-40	0.272	6.456	6.331	7.656	2,720	.0405	.0071
	20.00	J-55	0.272	6.456	6.331	7.656	3,720	.0405	.0071
	23.00	J-55	0.317	6.366	6.241	7.656	4,360	.0394	.0082
	26.00	J-55	0.362	6.276	6.151	7.656	4,980	.0383	.0093
	20.00	K-55	0.272	6.456	6.331	7.656	3,720	.0405	.0071
	23.00	K-55	0.317	6.366	6.241	7.656	4,360	.0394	.0082
	26.00	K-55	0.362	6.276	6.151	7.656	4,980	.0383	.0093
	23.00	C-75	0.317	6.366	6.241	7.656	5,940	.0394	.0082
	26.00	C-75	0.362	6.276	6.151	7.656	6,790	.0383	.0093
	29.00	C-75	0.408	6.184	6.059	7.656	7,650	.0371	.0105
	32.00	C-75	0.453	6.094	5.969	7.656	8,490	.0361	.0115
	35.00	C-75	0.498	6.004	5.879	7.656	9,340	.0350	.0126
	38.00	C-75	0.540	5.920	5.795	7.656	10,120	.0340	.0136
	23.00	L-80	0.317	6.366	6.241	7.656	6,340	.0394	.0082

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Outside Diameter (in)	Nominal Weight With Coupling (lb/ft)	Grade	Wall Thickness (in)	Inside Diameter (in)	Drift Diameter (in)	Outside Diameter of Coupling (in)	Burst Strength (psi)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)
	26.00	L-80	0.362	6.276	6.151	7.656	7,240	.0383	.0093
	29.00	L-80	0.408	6.184	6.059	7.656	8,160	.0371	.0105
	32.00	L-80	0.453	6.094	5.969	7.656	9,060	.0361	.0115
	35.00	L-80	0.498	6.004	5.879	7.656	9,960	.0350	.0126
	38.00	L-80	0.540	5.920	5.795	7.656	10,800	.0340	.0136
	23.00	N-80	0.317	6.366	6.241	7.656	6,340	.0394	.0082
	26.00	N-80	0.362	6.276	6.151	7.656	7,240	.0383	.0093
	29.00	N-80	0.408	6.184	6.059	7.656	8,160	.0371	.0105
	32.00	N-80	0.453	6.094	5.969	7.656	9,060	.0361	.0115
	35.00	N-80	0.498	6.004	5.879	7.656	9,960	.0350	.0126
	38.00	N-80	0.540	5.920	5.795	7.656	10,800	.0340	.0136
	23.00	C-90	0.317	6.366	6.241	7.656	7,130	.0394	.0082
	26.00	C-90	0.362	6.276	6.151	7.656	8,150	.0383	.0093
	29.00	C-90	0.408	6.184	6.059	7.656	9,180	.0371	.0105
	32.00	C-90	0.453	6.094	5.969	7.656	10,190	.0361	.0115
	35.00	C-90	0.498	6.004	5.879	7.656	11,200	.0350	.0126
	38.00	C-90	0.540	5.920	5.795	7.656	12,150	.0340	.0136
	23.00	C-95	0.317	6.366	6.241	7.656	7,530	.0394	.0082
	26.00	C-95	0.362	6.276	6.151	7.656	8,600	.0383	.0093
	29.00	C-95	0.408	6.184	6.059	7.656	9,690	.0371	.0105
	32.00	C-95	0.453	6.094	5.969	7.656	10,760	.0361	.0115
	35.00	C-95	0.498	6.004	5.879	7.656	11,830	.0350	.0126
	38.00	C-95	0.540	5.920	5.795	7.656	12,820	.0340	.0136
	26.00	P-110	0.362	6.276	6.151	7.656	9,960	.0383	.0093
	29.00	P-110	0.408	6.184	6.059	7.656	11,220	.0371	.0105
	32.00	P-110	0.453	6.094	5.969	7.656	12,460	.0361	.0115
	35.00	P-110	0.498	6.004	5.879	7.656	13,700	.0350	.0126
	38.00	P-110	0.540	5.920	5.795	7.656	14,850	.0340	.0136
	29.00	V-150	0.408	6.184	6.059	7.656	15,300	.0371	.0105
	32.00	V-150	0.453	6.094	5.969	7.656	16,990	.0361	.0115
	35.00	V-150	0.498	6.004	5.879	7.656	17,320	.0350	.0126
	38.00	V-150	0.540	5.920	5.795	7.656	17,320	.0340	.0136
$7^5/_8$	20.00	F-25	0.250	7.125	7.000	8.500	1,430	.0493	.0072

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Outside Diameter (in)	Nominal Weight With Coupling (lb/ft)	Grade	Wall Thickness (in)	Inside Diameter (in)	Drift Diameter (in)	Outside Diameter of Coupling (in)	Burst Strength (psi)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)
	24.00	H-40	0.300	7.025	6.900	8.500	2,750	.0479	.0085
	26.40	J-55	0.328	6.969	6.844	8.500	4,140	.0472	.0093
	26.40	K-55	0.328	6.969	6.844	8.500	4,140	.0472	.0093
	26.40	C-75	0.328	6.969	6.844	8.500	5,650	.0472	.0093
	29.70	C-75	0.375	6.875	6.750	8.500	6,450	.0459	.0106
	33.70	C-75	0.430	6.765	6.640	8.500	7,400	.0445	.0120
	39.00	C-75	0.500	6.625	6.500	8.500	8,610	.0426	.0138
	42.80	C-75	0.562	6.501	6.376	8.500	9,670	.0411	.0154
	45.30	C-75	0.595	6.435	6.310	8.500	10,240	.0402	.0163
	47.10	C-75	0.625	6.375	6.250	8.500	10,760	.0395	.0170
	26.40	L-80	0.328	6.969	6.844	8.500	6,020	.0472	.0093
	29.70	L-80	0.375	6.875	6.750	8.500	6,890	.0459	.0106
	33.70	L-80	0.430	6.765	6.640	8.500	7,900	.0445	.0120
	39.00	L-80	0.500	6.625	6.500	8.500	9,180	.0426	.0138
	42.80	L-80	0.562	6.501	6.376	8.500	10,320	.0411	.0154
	45.30	L-80	0.595	6.435	6.310	8.500	10.920	.0402	.0163
	47.10	L-80	0.625	6.375	6.250	8.500	11,480	.0395	.0170
	26.40	N-80	0.328	6.969	6.844	8.500	6,020	.0472	.0093
	29.70	N-80	0.375	6.875	6.750	8.500	6,890	.0459	.0106
	33.70	N-80	0.430	6.765	6.640	8.500	7,900	.0445	.0120
	39.00	N-80	0.500	6.625	6.500	8.500	9,180	.0426	.0138
	42.80	N-80	0.562	6.501	6.376	8.500	10,320	.0411	.0154
	45.30	N-80	0.595	6.435	6.310	8.500	10.920	.0402	.0163
	47.10	N-80	0.625	6.375	6.250	8.500	11,480	.0395	.0170
	26.40	C-90	0.328	6.969	6.844	8.500	6,780	.0472	.0093
	29.70	C-90	0.375	6.875	6.750	8.500	7,750	.0459	.0106
	33.70	C-90	0.430	6.765	6.640	8.500	8,880	.0445	.0120
	39.00	C-90	0.500	6.625	6.500	8.500	10,330	.0426	.0138
	42.80	C-90	0.562	6.501	6.376	8.500	11,610	.0411	.0154
	45.30	C-90	0.595	6.435	6.310	8.500	12,290	.0402	.0163
	47.10	C-90	0.625	6.375	6.250	8.500	12,910	.0395	.0170
	26.40	C-95	0.328	6.969	6.844	8.500	7,150	.0472	.0093
	29.70	C-95	0.375	6.875	6.750	8.500	8,180	.0459	.0106

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Outside Diameter (in)	Nominal Weight With Coupling (lb/ft)	Grade	Wall Thickness (in)	Inside Diameter (in)	Drift Diameter (in)	Outside Diameter of Coupling (in)	Burst Strength (psi)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)
	33.70	C-95	0.430	6.765	6.640	8.500	9,380	.0445	.0120
	39.00	C-95	0.500	6.625	6.500	8.500	10,900	.0426	.0138
	42.80	C-95	0.562	6.501	6.376	8.500	12,250	.0411	.0154
	45.30	C-95	0.595	6.435	6.310	8.500	12,970	.0402	.0163
	47.10	C-95	0.625	6.375	6.250	8.500	13,630	.0395	.0170
	29.70	P-110	0.375	6.875	6.750	8.500	9,470	.0459	.0106
	33.70	P-110	0.430	6.765	6.640	8.500	10,860	.0445	.0120
	39.00	P-110	0.500	6.625	6.500	8.500	12,620	.0426	.0138
	42.80	P-110	0.562	6.501	6.376	8.500	14,190	.0411	.0154
	45.30	P-110	0.595	6.435	6.310	8.500	15,020	.0402	.0163
	47.10	P-110	0.625	6.375	6.250	8.500	15,780	.0395	.0170
	33.70	V-150	0.430	6.765	6.640	8.500	14,800	.0445	.0120
	39.00	V-150	0.500	6.625	6.500	8.500	17,310	.0426	.0138
	45.30	V-150	0.595	6.435	6.310	8.500	19,680	.0402	.0163
$7^3/_4$	46.10 [b]	Q-125	0.595	6.560	6.500	8.500	16,790	.0418	.0165
8	16.00 [b]	---	0.186	7.628	7.503	-----	-----	.0565	.0056
	20.00 [b]	---	0.236	7.528	7.403	-----	-----	.0550	.0071
	23.09 [b]	---	0.280	7.440	7.315	-----	-----	.0538	.0084
	26.00 [b]	---	0.307	7.386	7.261	-----	-----	.0530	.0092
$8^1/_8$	28.00 [b]	---	0.320	7.485	7.360	-----	-----	.0544	.0097
	32.00 [b]	---	0.370	7.385	7.260	-----	-----	.0530	.0111
	35.50 [b]	---	0.420	7.285	7.160	-----	-----	.0516	.0126
	36.00 [b]	---	0.420	7.285	7.160	-----	-----	.0516	.0126
	39.50 [b]	---	0.470	7.185	7.060	-----	-----	.0501	.0140
	40.00 [b]	---	0.470	7.185	7.060	-----	-----	.0501	.0140
	42.00 [b]	---	0.500	7.125	7.000	-----	-----	.0493	.0148
$8^5/_8$	24.00	F-25	0.264	8.097	7.972	9.625	1,340	.0637	.0086
	28.00	H-40	0.304	8.017	7.892	9.625	2,470	.0624	.0098
	32.00	H-40	0.352	7.921	7.796	9.625	2,860	.0609	.0113
	24.00	J-55	0.264	8.097	7.972	9.625	2,950	.0637	.0086
	32.00	J-55	0.352	7.921	7.796	9.625	3,930	.0609	.0113
	36.00	J-55	0.400	7.825	7.700	9.625	4,460	.0595	.0128

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Outside Diameter (in)	Nominal Weight With Coupling (lb/ft)	Grade	Wall Thickness (in)	Inside Diameter (in)	Drift Diameter (in)	Outside Diameter of Coupling (in)	Burst Strength (psi)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)
	24.00	K-55	0.264	8.097	7.972	9.625	2,950	.0637	.0086
	32.00	K-55	0.352	7.921	7.796	9.625	3,930	.0609	.0113
	36.00	K-55	0.400	7.825	7.700	9.625	4,460	.0595	.0128
	36.00	C-75	0.400	7.825	7.700	9.625	6,090	.0595	.0128
	40.00	C-75	0.450	7.725	7.600	9.625	6,850	.0580	.0143
	44.00	C-75	0.500	7.625	7.500	9.625	7,610	.0565	.0158
	49.00	C-75	0.557	7.511	7.386	9.625	8,480	.0548	.0175
	36.00	L-80	0.400	7.825	7.700	9.625	6,090	.0595	.0128
	40.00	L-80	0.450	7.725	7.600	9.625	6,850	.0580	.0143
	44.00	L-80	0.500	7.625	7.500	9.625	7,610	.0565	.0158
	49.00	L-80	0.557	7.511	7.386	9.625	8,480	.0548	.0175
	36.00	N-80	0.400	7.825	7.700	9.625	6,490	.0595	.0128
	40.00	N-80	0.450	7.725	7.600	9.625	7,300	.0580	.0143
	44.00	N-80	0.500	7.625	7.500	9.625	8,120	.0565	.0158
	49.00	N-80	0.557	7.511	7.386	9.625	9,040	.0548	.0175
	36.00	C-90	0.400	7.825	7.700	9.625	7,300	.0595	.0128
	40.00	C-90	0.450	7.725	7.600	9.625	8,220	.0580	.0143
	44.00	C-90	0.500	7.625	7.500	9.625	9,130	.0565	.0158
	49.00	C-90	0.557	7.511	7.386	9.625	10,170	.0548	.0175
	36.00	C-95	0.400	7.825	7.700	9.625	7,710	.0595	.0128
	40.00	C-95	0.450	7.725	7.600	9.625	8,670	.0580	.0143
	44.00	C-95	0.500	7.625	7.500	9.625	9,640	.0565	.0158
	49.00	C-95	0.557	7.511	7.386	9.625	10,740	.0548	.0175
	40.00	P-110	0.450	7.725	7.600	9.625	10,040	.0580	.0143
	44.00	P-110	0.500	7.625	7.500	9.625	11,160	.0565	.0158
	49.00	P-110	0.557	7.511	7.386	9.625	12,430	.0548	.0175
	44.00	V-150	0.500	7.625	7.500	9.625	15,220	.0565	.0158
	49.00	V-150	0.557	7.511	7.386	9.625	16,950	.0548	.0175
$8^3/_4$	49.70 [b]	---	0.557	7.636	7.500	9.625	-----	.0566	.0177
9 [b]	19.00	---	0.196	8.608	8.483	10.000	-----	.0720	.0067
	34.00	---	0.355	8.290	8.165	10.000	-----	.0668	.0119
	38.00	---	0.402	8.196	8.071	10.000	-----	.0653	.0134

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Outside Diameter (in)	Nominal Weight With Coupling (lb/ft)	Grade	Wall Thickness (in)	Inside Diameter (in)	Drift Diameter (in)	Outside Diameter of Coupling (in)	Burst Strength (psi)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)
	40.00	---	0.425	8.150	8.025	10.000	-----	.0645	.0142
	41.20	---	0.425	8.150	8.025	10.000	-----	.0645	.0142
	45.00	---	0.484	8.032	7.907	10.000	-----	.0627	.0160
	46.10	---	0.484	8.032	7.907	10.000	-----	.0627	.0160
	50.20	---	0.545	7.910	7.785	10.000	-----	.0608	.0179
	54.00	---	0.595	7.810	7.685	10.000	-----	.0593	.0194
	55.00	---	0.594	7.812	7.687	10.000	-----	.0593	.0194
$9^5/_8$	29.30	F-25	0.281	9.063	8.907	10.625	1,280	.0798	.0102
	32.30	H-40	0.312	9.001	8.845	10.625	2,270	.0787	.0113
	36.00	H-40	0.352	8.921	8.765	10.625	2,560	.0773	.0127
	36.00	J-55	0.352	8.921	8.765	10.625	3,520	.0773	.0127
	40.00	J-55	0.395	8.835	8.679	10.625	3,950	.0758	.0142
	36.00	K-55	0.352	8.921	8.765	10.625	3,520	.0773	.0127
	40.00	K-55	0.395	8.835	8.679	10.625	3,950	.0758	.0142
	40.00	C-75	0.395	8.835	8.679	10.625	5,390	.0758	.0142
	43.50	C-75	0.435	8.755	8.599	10.625	5,930	.0745	.0155
	47.00	C-75	0.472	8.681	8.525	10.625	6,440	.0732	.0168
	53.50	C-75	0.545	8.535	8.379	10.625	7,430	.0708	.0192
	40.00	L-80	0.395	8.835	8.679	10.625	5,750	.0758	.0142
	43.50	L-80	0.435	8.755	8.599	10.625	6,330	.0745	.0155
	47.00	L-80	0.472	8.681	8.525	10.625	6,870	.0732	.0168
	53.50	L-80	0.545	8.535	8.379	10.625	7,930	.0708	.0192
	40.00	N-80	0.395	8.835	8.679	10.625	5,750	.0758	.0142
	43.50	N-80	0.435	8.755	8.599	10.625	6,330	.0745	.0155
	47.00	N-80	0.472	8.681	8.525	10.625	6,870	.0732	.0168
	53.50	N-80	0.545	8.535	8.379	10.625	7,930	.0708	.0192
	40.00	C-90	0.395	8.835	8.679	10.625	6,460	.0758	.0142
	43.50	C-90	0.435	8.755	8.599	10.625	7,120	.0745	.0155
	47.00	C-90	0.472	8.681	8.525	10.625	7,720	.0732	.0168
	53.50	C-90	0.545	8.535	8.379	10.625	8,920	.0708	.0192
	40.00	C-95	0.395	8.835	8.679	10.625	6,820	.0758	.0142
	43.50	C-95	0.435	8.755	8.599	10.625	7,510	.0745	.0155

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Outside Diameter (in)	Nominal Weight With Coupling (lb/ft)	Grade	Wall Thickness (in)	Inside Diameter (in)	Drift Diameter (in)	Outside Diameter of Coupling (in)	Burst Strength (psi)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)
	47.00	C-95	0.472	8.681	8.525	10.625	8,150	.0732	.0168
	53.50	C-95	0.545	8.535	8.379	10.625	9,410	.0708	.0192
	43.50	P-110	0.435	8.755	8.599	10.625	8,700	.0745	.0155
	47.00	P-110	0.472	8.681	8.525	10.625	9,440	.0732	.0168
	53.50	P-110	0.545	8.535	8.379	10.625	10,900	.0708	.0192
	53.50	V-150	0.545	8.535	8.379	10.625	14,860	.0708	.0192
	58.40	V-150	0.595	8.435	8.279	10.625	16,230	.0691	.0209
	61.10	V-150	0.625	8.375	8.219	10.625	17,050	.0681	.0219
	71.80	V-150	0.750	8.125	7.969	10.625	18,060	.0641	.0259
$9^3/_4$	59.20 [b]	---	0.595	8.560	8.435	10.625	13,350	.0712	.0212
$9^7/_8$	62.80 [b]	---	0.625	8.625	8.500	10.625		.0723	.0225
10	22.75 [b]	---	0.209	9.582	9.457	-----	-----	.0892	.0080
	30.25 [b]	---	0.283	9.434	9.309	-----	-----	.0865	.0107
	30.07 [b]	---	0.290	9.420	9.295	-----	-----	.0862	.0109
	33.00 [b]	---	0.308	9.384	9.259	-----	-----	.0855	.0116
	41.50 [b]	---	0.400	9.200	9.075	-----	-----	.0822	.0149
	45.50 [b]	---	0.440	9.120	8.995	-----	-----	.0808	.0163
	50.50 [b]	---	0.492	9.016	8.891	-----	-----	.0790	.0182
	55.50 [b]	---	0.546	8.908	8.783	-----	-----	.0771	.0201
	60.00 [b]	---	0.610	8.780	8.655	-----	-----	.0749	.0223
$10^3/_4$	32.75	F-25	0.279	10.192	10.036	11.750	1,140	.1009	.0114
	32.75	H-40	0.279	10.192	10.036	11.750	1,820	.1009	.0114
	40.50	H-40	0.350	10.050	9.894	11.750	2,280	.0981	.0141
	40.50	J-55	0.350	10.050	9.894	11.750	3,130	.0981	.0141
	45.50	J-55	0.400	9.950	9.950	11.750	3,580	.0962	.0161
	51.00	J-55	0.450	9.850	9.694	11.750	4,030	.0942	.0180
	40.50	K-55	0.350	10.050	9.894	11.750	3,130	.0981	.0141
	45.50	K-55	0.400	9.950	9.950	11.750	3,580	.0962	.0161
	51.00	K-55	0.450	9.850	9.694	11.750	4,030	.0942	.0180
	51.00	C-75	0.450	9.850	9.694	11.750	5,490	.0942	.0180
	55.50	C-75	0.495	9.760	9.604	11.750	6,040	.0925	.0197

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Outside Diameter (in)	Nominal Weight With Coupling (lb/ft)	Grade	Wall Thickness (in)	Inside Diameter (in)	Drift Diameter (in)	Outside Diameter of Coupling (in)	Burst Strength (psi)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)
	51.00	L-80	0.450	9.850	9.694	11.750	5,860	.0942	.0180
	55.50	L-80	0.495	9.760	9.604	11.750	6,450	.0925	.0197
	51.00	N-80	0.450	9.850	9.694	11.750	5,860	.0942	.0180
	55.50	N-80	0.495	9.760	9.604	11.750	6,450	.0925	.0197
	51.00	C-90	0.450	9.850	9.694	11.750	6,590	.0942	.0180
	55.50	C-90	0.495	9.760	9.604	11.750	7,250	.0925	.0197
	51.00	C-95	0.450	9.850	9.694	11.750	6,960	.0942	.0180
	55.50	C-95	0.495	9.760	9.604	11.750	7,660	.0925	.0197
	51.00	P-110	0.450	9.850	9.694	11.750	8,060	.0942	.0180
	55.50	P-110	0.495	9.760	9.604	11.750	8,860	.0925	.0197
	60.70	P-110	0.545	9.660	9.504	11.750	9,760	.0906	.0216
	65.70	P-110	0.595	9.560	9.404	11.750	10,650	.0888	.0235
	71.10	P-110	0.650	9.450	9.294	11.750	11,240	.0867	.0255
	65.70	V-150	0.595	9.560	9.404	11.750	14,530	.0888	.0235
	71.10	V-150	0.650	9.450	9.294	11.750	15,330	.0867	.0255
11	26.75 [b]	---	0.224	10.552	10.396	11.866	-----	.1082	.0094
	35.39 [b]	---	0.310	10.380	10.224	11.866	-----	.1047	.0129
$11^3/_4$	38.00	F-25	0.300	11.150	10.994	12.750	1,120	.1208	.0133
	42.00	H-40	0.333	11.084	10.928	12.750	1,980	.1193	.0148
	47.00	J-55	0.375	11.000	10.844	12.750	3,070	.1175	.0166
	54.00	J-55	0.435	10.880	10.724	12.750	3,560	.1150	.0191
	60.00	J-55	0.489	10.772	10.616	12.750	4,010	.1127	.0214
	47.00	K-55	0.375	11.000	10.844	12.750	3,070	.1175	.0166
	54.00	K-55	0.435	10.880	10.724	12.750	3,560	.1150	.0191
	60.00	K-55	0.489	10.772	10.616	12.750	4,010	.1127	.0214
	60.00	C-75	0.489	10.772	10.616	12.750	5,460	.1127	.0214
	60.00	L-80	0.489	10.772	10.616	12.750	5,830	.1127	.0214
	60.00	N-80	0.489	10.772	10.616	12.750	5,830	.1127	.0214
	60.00	C-90	0.489	10.772	10.616	12.750	6,550	.1127	.0214

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Outside Diameter (in)	Nominal Weight With Coupling (lb/ft)	Grade	Wall Thickness (in)	Inside Diameter (in)	Drift Diameter (in)	Outside Diameter of Coupling (in)	Burst Strength (psi)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)
	60.00	C-95	0.489	10.772	10.616	12.750	6,920	.1127	.0214
	60.00	P-110	0.489	10.772	10.616	12.750	8,010	.1127	.0214
$11^7/_8$	71.80 [b]	---	0.582	10.711	10.625	12.750	------	.1114	.0255
12	31.50 [b]	---	0.243	11.514	11.358	13.116	------	.1288	.0111
	40.00 [b]	---	0.308	11.384	11.228	13.116	------	.1259	.0140
	38.70 [b]	---	0.325	11.350	11.194	13.116	------	.1251	.0147
$12^3/_4$	43.00 [b]	---	0.310	12.130	11.974	-----	-----	.1429	.0149
	45.45 [b]	---	0.330	12.090	11.934	-----	-----	.1420	.0159
	51.15 [b]	---	0.375	12.000	11.844	-----	-----	.1340	.0180
	53.00 [b]	---	0.390	11.970	11.814	-----	-----	.1391	.0187
	65.42 [b]	---	0.500	11.750	11.594	-----	-----	.1341	.0238
13	36.50 [b]	---	0.259	12.482	12.326	13.116	-----	.1513	.0128
	40.00 [b]	---	0.281	12.438	12.282	13.116	-----	.1503	.0139
	45.00 [b]	---	0.320	12.360	12.204	13.116	-----	.1484	.0158
	47.29 [b]	---	0.350	12.300	12.144	13.116	-----	.1470	.0172
	50.00 [b]	---	0.359	12.282	12.126	13.116	-----	.1465	.0176
	54.00 [b]	---	0.390	12.220	12.064	13.116	-----	.1451	.0191
$13^3/_8$	48.00	F-25	0.330	12.715	12.559	14.375	1,080	.1570	.0167
	48.00		0.330	12.715	12.559	14.375	1,730	.1570	.0167
	54.50	J-55	0.380	12.615	12.459	14.375	2,730	.1545	.0192
	61.00	J-55	0.430	12.515	12.359	14.375	3,090	.1521	.0216
	68.00	J-55	0.480	12.415	12.259	14.375	3,450	.1497	.0241
	54.50	K-55	0.380	12.615	12.459	14.375	2,730	.1545	.0192
	61.00	K-55	0.430	12.515	12.359	14.375	3,090	.1521	.0216
	68.00	K-55	0.480	12.415	12.259	14.375	3,450	.1497	.0241
	68.00	C-75	0.480	12.415	12.259	14.375	4,710	.1497	.0241
	72.00	C-75	0.514	12.347	12.191	14.375	5,040	.1481	.0257
	77.00	C-75	0.550	12.275	12.119	14.375	5,400	.1464	.0274
	85.00	C-75	0.608	12.159	12.003	14.375	5,970	.1436	.0302
	98.00	C-75	0.719	11.937	11.781	14.375	6,270	.1384	.0354

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Outside Diameter (in)	Nominal Weight With Coupling (lb/ft)	Grade	Wall Thickness (in)	Inside Diameter (in)	Drift Diameter (in)	Outside Diameter of Coupling (in)	Burst Strength (psi)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)
	68.00	L-80	0.480	12.415	12.259	14.375	5,020	.1497	.0241
	72.00	L-80	0.514	12.347	12.191	14.375	5,380	.1481	.0257
	68.00	N-80	0.480	12.415	12.259	14.375	5,020	.1497	.0241
	72.00	N-80	0.514	12.347	12.191	14.375	5,380	.1481	.0257
	77.00	N-80	0.550	12.275	12.119	14.375	5,760	.1464	.0274
	85.00	N-80	0.608	12.159	12.003	14.375	6,360	.1436	.0302
	98.00	N-80	0.719	11.937	11.781	14.375	6,680	.1384	.0354
	68.00	C-90	0.480	12.415	12.259	14.375	5,650	.1497	.0241
	72.00	C-90	0.514	12.347	12.191	14.375	6,050	.1481	.0257
	68.00	C-95	0.480	12.415	12.259	14.375	5,970	.1497	.0241
	72.00	C-95	0.514	12.347	12.191	14.375	6,390	.1481	.0257
	68.00	P-110	0.480	12.415	12.259	14.375	6,910	.1497	.0241
	72.00	P-110	0.514	12.347	12.191	14.375	7,400	.1481	.0257
	72.00	V-150	0.514	12.347	12.191	14.375	10,090	.1481	.0257
$13^1/_2$	81.40 [b]	---	0.580	12.340	12.250	14.375	-----	.1479	.0291
$13^5/_8$	88.20 [b]	---	0.625	12.375	12.250	14.375	-----	.1488	.0316
14	42.00 [b]	---	0.276	13.448	13.292	-----	-----	.1757	.0147
	50.00 [b]	---	0.328	13.344	13.188	-----	-----	.1730	.0174
	51.02 [b]	---	0.350	13.300	13.144	-----	-----	.1718	.0186
	57.00 [b]	---	0.375	13.250	13.094	-----	-----	.1705	.0199
	85.87 [b]	---	0.600	12.800	12.644	-----	-----	.1592	.0312
	92.67 [b]	---	0.650	12.700	12.544	-----	-----	.1567	.0337
	99.43 [b]	---	0.700	12.600	12.444	-----	-----	.1542	.0362
	106.13 [b]	---	0.750	12.500	12.344	-----	-----	.1518	.0386
	112.78 [b]	---	0.800	12.400	12.244	-----	-----	.1494	.0410
	119.37 [b]	---	0.850	12.300	12.144	-----	-----	.1470	.0434
15	47.50 [b]	---	0.291	14.418	14.262	-----	-----	.2019	.0166
	61.15 [b]	---	0.375	14.250	14.094	-----	-----	.1973	.0213
	59.33 [b]	---	0.380	14.240	14.084	-----	-----	.1970	.0216
16	55.00	F-25	0.312	15.376	15.188	17.000	850	.2297	.0190
	65.00	H-40	0.375	15.250	15.062	17.000	1,640	.2259	.0228

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Outside Diameter (in)	Nominal Weight With Coupling (lb/ft)	Grade	Wall Thickness (in)	Inside Diameter (in)	Drift Diameter (in)	Outside Diameter of Coupling (in)	Burst Strength (psi)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)
	75.00	J-55	0.438	15.124	14.936	17.000	2,630	.2222	.0265
	84.00	J-55	0.495	15.010	14.822	17.000	2,980	.2189	.0298
	75.00	K-55	0.438	15.124	14.936	17.000	2,630	.2222	.0265
	84.00	K-55	0.495	15.010	14.822	17.000	2,980	.2189	.0298
	109.00	K-55	0.560	14.688	14.500	17.000	3,950	.2096	.0391
	109.00	C-75	0.560	14.688	14.500	17.000	5,380	.2096	.0391
	109.00	N-80	0.560	14.688	14.500	17.000	5,740	.2096	.0391
17	73.20 [b]	---	0.393	16.214	16.027	-----	-----	.2554	.0254
18	70.58 [b]	---	0.375	17.250	17.063	-----	-----	.2890	.0257
	78.00 [b]	---	0.403	17.194	17.007	-----	-----	.2872	.0276
	80.00 [b]	---	0.410	17.180	16.992	-----	-----	.2867	.0280
	84.00 [b]	---	0.438	17.124	16.937	-----	-----	.2848	.0299
	87.50 [b]	---	0.456	17.088	16.900	-----	-----	.2836	.0311
	96.50 [b]	---	0.507	16.986	16.799	-----	-----	.2803	.0345
$18^5/_8$	87.50	H-40	0.435	17.775	17.567	20.000	1,630	.3069	.0301
	87.50	J-55	0.435	17.775	17.567	20.000	2,250	.3069	.0301
	87.50	K-55	0.435	17.775	17.567	20.000	2,250	.3069	.0301
20	94.00	F-25	0.438	19.124	18.936	21.000	960	.3553	.0333
	94.00	H-40	0.438	19.124	18.936	21.000	1,530	.3553	.0333
	94.00	J-55	0.438	19.124	18.936	21.000	2,110	.3553	.0333
	106.50	J-55	0.500	19.000	18.812	21.000	2,410	.3507	.0379
	133.00	J-55	0.635	18.730	18.542	21.000	3,060	.3408	.0478
	94.00	K-55	0.438	19.124	18.936	21.000	2,110	.3553	.0333
	106.50	K-55	0.500	19.000	18.812	21.000	2,410	.3507	.0379
	133.00	K-55	0.635	18.730	18.542	21.000	3,060	.3408	.0478
$21^1/_2$	92.50 [b]	---	0.395	20.710	20.522	22.500	-----	.4166	.0324
	103.00 [b]	---	0.445	20.610	20.422	22.500	-----	.4126	.0364
	114.00 [b]	---	0.495	20.510	20.322	22.500	-----	.4086	.0404

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Outside Diameter (in)	Nominal Weight With Coupling (lb/ft)	Grade	Wall Thickness (in)	Inside Diameter (in)	Drift Diameter (in)	Outside Diameter of Coupling (in)	Burst Strength (psi)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)
22	92.50 [b]	---	0.389	21.222	21.035	-----	-----	.4375	.0327
	103.00 [b]	---	0.436	21.128	20.941	-----	-----	.4336	.0365
	101.00 [b]	---	0.438	21.125	20.938	-----	-----	.4335	.0366
	114.00 [b]	---	0.486	21.028	20.841	-----	-----	.4295	.0406
	114.80 [b]	---	0.500	21.000	20.813	-----	-----	.4284	.0418
24	94.62 [b]	---	0.375	23.250	23.062	25.500	-----	.5251	.0344
	100.50 [b]	---	0.387	23.226	23.039	25.500	-----	.5240	.0355
	113.00 [b]	---	0.438	23.124	22.937	25.500	-----	.5194	.0401
	125.49 [b]	---	0.500	23.000	22.812	25.500	-----	.5139	.0457
	140.68 [b]	---	0.560	22.880	22.692	25.500	-----	.5085	.0510
	155.00	X-52	0.625	22.750	22.562	25.500	-----	.5028	.0568
	171.29 [b]	---	0.690	22.620	22.432	25.500	-----	.4970	.0625
	238.35 [b]	---	0.970	22.060	21.872	25.500	-----	.4727	.0868
	304.00 [b]	---	1.250	21.500	21.313	25.500	-----	.4490	.1105
24 1/2	88.00 [b]	---	0.325	23.850	23.663	25.500	-----	.5526	.0305
	100.50 [b]	---	0.375	23.750	23.562	25.500	-----	.5479	.0352
26	85.60 [b]	---	0.312	25.376	25.188	-----	-----	.6255	.0311
	136.17 [b]	---	0.500	25.000	24.812	-----	-----	.6071	.0495
	202.26 [b]	---	0.750	24.500	24.312	-----	-----	.5831	.0736
	265.00 [b]	---	1.000	24.000	23.812	-----	-----	.5595	.0971
30	157.70 [b]	---	0.500	29.000	28.812	36.625	-----	.8169	.0573
	234.29 [b]	---	0.750	28.500	28.312	36.625	-----	.7890	.0852
	235.00 [b]	---	0.750	28.500	28.212	36.625	-----	.7890	.0852
	309.72 [b]	---	1.000	28.000	27.813	36.625	-----	.7616	.1127
	310.00	X-52	1.000	28.000	27.813	36.625	-----	.7616	.1127
	383.81 [b]	---	1.250	27.500	27.312	36.625	-----	.7346	.1396
	453.15 [b]	---	1.500	27.000	26.812	36.625	-----	.7082	.1661
	524.04 [b]	---	1.750	26.500	26.312	36.625	-----	.6822	.1921
	533.00 [b]	---	1.750	26.500	26.312	36.625	-----	.6822	.1921
	593.60 [b]	---	2.000	26.000	25.812	36.625	-----	.6567	.2176

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Outside Diameter (in)	Nominal Weight With Coupling (lb/ft)	Grade	Wall Thickness (in)	Inside Diameter (in)	Drift Diameter (in)	Outside Diameter of Coupling (in)	Burst Strength (psi)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)
36	371.00 [b]	---	1.000	34.000	33.812	40.750	-----	1.123	.1356
	374.00	X-42	1.000	34.000	33.812	40.750	-----	1.123	.1356
	51.00 [b]	---	1.407	33.187	33.000	40.750	-----	1.070	.1891

a. See Figure C.1 for calculation formula.
b. Non-API Standard.

The casing capacity and displacement in barrels per foot is as follows:

Capacity = Inside Diameter^2 × .0009714

Displacement = Outside Diameter^2 - Inside Diameter^2 × .0009714

Example: The capacity and displacement of 9 5/8" P-110 53.5 lb/ft casing

Capacity = ID^2 × .0009714
= 8.535^2 × .0009714 (from Table 2.3 Casing Data)
= 72.846225 × .0009714
= .0708 bbl/ft

Displacement = OD^2 - ID^2 × .0009714
= 9.625^2 - 8.535^2 × .0009714
= 92.640625 - 72.846225 × .0009714
= 19.7944 × .0009714
= .0192 bbl/ft

Figure C.1 Casing Capacity and Displacement Calculation

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Appendix D Drill Collar Data

Outside Diameter (in)	Inside Diameter (in)	Weight per Foot (lb/ft)	Capacity [a] (bbl/ft)	Displacement [a] (bbl/ft)
4.00	1.50	36.7	.0022	.0133
4.00	1.75	34.5	.0030	.0125
4.00	2.00	32.0	.0039	.0116
4.00	2.25	29.2	.0049	.0106
4.25	1.50	42.2	.0022	.0153
4.25	1.75	40.0	.0030	.0145
4.25	2.00	37.5	.0039	.0136
4.25	2.25	34.7	.0049	.0126
4.50	1.50	48.1	.0022	.0175
4.50	1.75	45.9	.0030	.0167
4.50	2.00	43.4	.0039	.0158
4.50	2.25	40.6	.0049	.0148
4.75	1.50	54.3	.0022	.0197
4.75	1.75	52.1	.0030	.0189
4.75	2.00	49.6	.0039	.0181
4.75	2.25	46.8	.0049	.0170
4.75	2.50	43.6	.0061	.0159
5.00	1.50	60.8	.0022	.0221
5.00	1.75	58.6	.0030	.0213
5.00	2.00	56.1	.0039	.0204
5.00	2.25	53.3	.0049	.0194
5.00	2.50	50.1	.0061	.0182
5.25	1.50	67.6	.0022	.0246
5.25	1.75	65.4	.0030	.0238
5.25	2.00	62.9	.0039	.0229
5.25	2.25	60.1	.0049	.0219
5.25	2.50	56.9	.0061	.0207
5.25	2.75	53.4	.0073	.0194
5.50	1.50	74.8	.0022	.0272

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Outside Diameter (in)	Inside Diameter (in)	Weight per Foot (lb/ft)	Capacity [a] (bbl/ft)	Displacement [a] (bbl/ft)
5.50	1.75	72.6	.0030	.0264
5.50	2.00	70.1	.0039	.0255
5.50	2.25	67.3	.0049	.0245
5.50	2.50	64.1	.0061	.0233
5.50	2.75	60.6	.0073	.0221
5.50	3.00	56.8	.0087	.0207
5.75	1.50	82.3	.0022	.0299
5.75	1.75	80.1	.0030	.0291
5.75	2.00	77.6	.0039	.0282
5.75	2.25	74.8	.0049	.0272
5.75	2.50	71.6	.0061	.0261
5.75	2.75	68.1	.0073	.0248
5.75	3.00	64.3	.0087	.0234
6.00	1.50	90.1	.0022	.0328
6.00	1.75	87.9	.0030	.0320
6.00	2.00	85.4	.0039	.0311
6.00	2.25	82.6	.0049	.0301
6.00	2.50	79.4	.0061	.0289
6.00	2.75	75.9	.0073	.0276
6.00	3.00	72.1	.0087	.0262
6.00	3.25	67.9	.0103	.0247
6.25	1.50	98.0	.0022	.0356
6.25	1.75	95.8	.0030	.0349
6.25	2.00	93.3	.0039	.0339
6.25	2.25	90.5	.0049	.0329
6.25	2.50	87.3	.0061	.0318
6.25	2.75	83.8	.0073	.0305
6.25	3.00	80.0	.0087	.0291
6.25	3.25	75.8	.0103	.0276
6.25	3.50	71.3	.0119	.0259
6.50	1.50	107.0	.0022	.0389
6.50	1.75	104.8	.0030	.0381
6.50	2.00	102.3	.0039	.0372
6.50	2.25	99.5	.0049	.0362

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Outside Diameter (in)	Inside Diameter (in)	Weight per Foot (lb/ft)	Capacity [a] (bbl/ft)	Displacement [a] (bbl/ft)
6.50	2.50	96.3	.0061	.0350
6.50	2.75	92.8	.0073	.0338
6.50	3.00	89.0	.0087	.0324
6.50	3.25	84.8	.0103	.0308
6.50	3.50	80.3	.0119	.0292
6.75	1.50	116.0	.0022	.0422
6.75	1.75	113.8	.0030	.0414
6.75	2.00	111.3	.0039	.0405
6.75	2.25	108.5	.0049	.0395
6.75	2.50	105.3	.0061	.0383
6.75	2.75	101.8	.0073	.0370
6.75	3.00	98.0	.0087	.0356
6.75	3.25	93.8	.0103	.0341
6.75	3.50	89.3	.0119	.0325
7.25	1.50	134.0	.0022	.0487
7.25	1.75	131.8	.0030	.0479
7.25	2.00	129.3	.0039	.0470
7.25	2.25	126.5	.0049	.0460
7.25	2.50	123.3	.0061	.0449
7.25	2.75	119.8	.0073	.0436
7.25	3.00	116.0	.0087	.0422
7.25	3.25	111.8	.0103	.0407
7.25	3.50	107.3	.0119	.0390
7.25	3.75	102.4	.0137	.0372
7.25	4.00	97.3	.0155	.0354
7.50	1.50	144.0	.0022	.0524
7.50	1.75	141.8	.0030	.0516
7.50	2.00	139.3	.0039	.0507
7.50	2.25	136.5	.0049	.0497
7.50	2.50	133.3	.0061	.0485
7.50	2.75	129.8	.0073	.0472
7.50	3.00	126.0	.0087	.0458
7.50	3.25	121.8	.0103	.0443
7.50	3.50	117.3	.0119	.0427
7.50	3.75	.0137	.0137	.0409

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Outside Diameter (in)	Inside Diameter (in)	Weight per Foot (lb/ft)	Capacity [a] (bbl/ft)	Displacement [a] (bbl/ft)
7.50	4.00	.0155	.0155	.0390
7.75	1.50	154.0	.0022	.0560
7.75	1.75	151.8	.0030	.0552
7.75	2.00	149.3	.0039	.0543
7.75	2.25	146.5	.0049	.0533
7.75	2.50	143.3	.0061	.0521
7.75	2.75	139.8	.0073	.0509
7.75	3.00	136.0	.0087	.0495
7.75	3.25	131.8	.0103	.0479
7.75	3.50	127.3	.0119	.0463
7.75	3.75	122.4	.0137	.0445
7.75	4.00	117.3	.0155	.0427
8.00	1.50	165.0	.0022	.0600
8.00	1.75	162.8	.0030	.0592
8.00	2.00	160.3	.0039	.0583
8.00	2.25	157.5	.0049	.0573
8.00	2.50	154.3	.0061	.0561
8.00	2.75	150.8	.0073	.0549
8.00	3.00	147.0	.0087	.0535
8.00	3.25	142.8	.0103	.0520
8.00	3.50	138.3	.0119	.0503
8.00	3.75	133.4	.0137	.0485
8.00	4.00	128.3	.0155	.0467
8.00	4.25	122.8	.0175	.0447
8.25	1.50	176.0	.0022	.0640
8.25	1.75	173.8	.0030	.0632
8.25	2.00	171.3	.0039	.0623
8.25	2.25	168.5	.0049	.0613
8.25	2.50	165.3	.0061	.0601
8.25	2.75	161.8	.0073	.0589
8.25	3.00	158.0	.0087	.0575
8.25	3.25	153.8	.0103	.0560
8.25	3.50	149.3	.0119	.0543
8.25	3.75	144.4	.0137	.0525
8.25	4.00	139.3	.0155	.0507

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Outside Diameter (in)	Inside Diameter (in)	Weight per Foot (lb/ft)	Capacity [a] (bbl/ft)	Displacement [a] (bbl/ft)
8.25	4.25	133.8	.0175	.0487
8.50	1.50	187.0	.0022	.0680
8.50	1.75	184.8	.0030	.0672
8.50	2.00	182.3	.0039	.0663
8.50	2.25	179.5	.0049	.0653
8.50	2.50	176.3	.0061	.0641
8.50	2.75	172.8	.0073	.0629
8.50	3.00	169.0	.0087	.0615
8.50	3.25	164.8	.0103	.0600
8.50	3.50	160.3	.0119	.0583
8.50	3.75	155.4	.0137	.0565
8.50	4.00	150.3	.0155	.0547
8.50	4.25	144.8	.0175	.0527
8.75	1.50	199.0	.0022	.0724
8.75	1.75	196.8	.0030	.0716
8.75	2.00	194.3	.0039	.0707
8.75	2.25	191.5	.0049	.0697
8.75	2.50	188.3	.0061	.0685
8.75	2.75	184.8	.0073	.0672
8.75	3.00	181.0	.0087	.0658
8.75	3.25	176.8	.0103	.0643
8.75	3.50	172.3	.0119	.0627
8.75	3.75	167.4	.0137	.0609
8.75	4.00	162.3	.0155	.0590
8.75	4.25	156.8	.0175	.0570
9.00	1.50	210.2	.0022	.0764
9.00	1.75	208.0	.0030	.0756
9.00	2.00	205.5	.0039	.0747
9.00	2.25	202.7	.0049	.0737
9.00	2.50	199.5	.0061	.0725
9.00	2.75	196.0	.0073	.0712
9.00	3.00	192.2	.0087	.0698
9.00	3.25	188.0	.0103	.0683
9.00	3.50	183.5	.0119	.0667
9.00	3.75	178.7	.0137	.0649

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Outside Diameter (in)	Inside Diameter (in)	Weight per Foot (lb/ft)	Capacity [a] (bbl/ft)	Displacement [a] (bbl/ft)
9.00	4.00	173.4	.0155	.0631
9.00	4.25	168.0	.0175	.0610
9.25	1.50	222.4	.0022	.0808
9.25	1.75	220.2	.0030	.0800
9.25	2.00	217.7	.0039	.0791
9.25	2.25	214.9	.0049	.0781
9.25	2.50	211.7	.0061	.0769
9.25	2.75	208.2	.0073	.0757
9.25	3.00	204.3	.0087	.0743
9.25	3.25	200.2	.0103	.0728
9.25	3.50	195.6	.0119	.0711
9.25	3.75	190.8	.0137	.0694
9.25	4.00	185.7	.0155	.0675
9.25	4.25	180.1	.0175	.0655
9.50	1.50	234.9	.0022	.0854
9.50	1.75	232.7	.0030	.0846
9.50	2.00	230.2	.0039	.0837
9.50	2.25	227.3	.0049	.0826
9.50	2.50	224.2	.0061	.0815
9.50	2.75	220.7	.0073	.0802
9.50	3.00	216.8	.0087	.0788
9.50	3.25	212.7	.0103	.0773
9.50	3.50	208.2	.0119	.0757
9.50	3.75	203.3	.0137	.0739
9.50	4.00	198.2	.0155	.0720
9.50	4.25	192.7	.0175	.0700
9.75	1.50	247.7	.0022	.0900
9.75	1.75	245.6	.0030	.0892
9.75	2.00	243.0	.0039	.0883
9.75	2.25	240.2	.0049	.0873
9.75	2.50	237.0	.0061	.0861
9.75	2.75	233.5	.0073	.0849
9.75	3.00	229.7	.0087	.0835
9.75	3.25	225.5	.0103	.0820
9.75	3.50	221.0	.0119	.0803

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Outside Diameter (in)	Inside Diameter (in)	Weight per Foot (lb/ft)	Capacity [a] (bbl/ft)	Displacement [a] (bbl/ft)
9.75	3.75	216.2	.0137	.0786
9.75	4.00	211.0	.0155	.0767
9.75	4.25	205.5	.0175	.0747
10.00	1.50	260.9	.0022	.0948
10.00	1.75	258.8	.0030	.0940
10.00	2.00	256.3	.0039	.0931
10.00	2.25	253.4	.0049	.0921
10.00	2.50	250.2	.0061	.0909
10.00	2.75	246.7	.0073	.0897
10.00	3.00	242.9	.0087	.0883
10.00	3.25	238.7	.0103	.0868
10.00	3.50	234.2	.0119	.0851
10.00	3.75	229.4	.0137	.0834
10.00	4.00	224.2	.0155	.0815
10.00	4.25	218.7	.0175	.0795
10.25	1.50	274.5	.0022	.0997
10.25	1.75	272.2	.0030	.0989
10.25	2.00	269.8	.0039	.0980
10.25	2.25	267.0	.0049	.0970
10.25	2.50	263.7	.0061	.0958
10.25	2.75	260.3	.0073	.0946
10.25	3.00	256.4	.0087	.0932
10.25	3.25	252.2	.0103	.0917
10.25	3.50	247.7	.0119	.0900
10.25	3.75	242.8	.0137	.0883
10.25	4.00	237.7	.0155	.0864
10.25	4.25	232.2	.0175	.0844
10.50	1.50	288.3	.0022	.1048
10.50	1.75	286.1	.0030	.1040
10.50	2.00	283.6	.0039	.1031
10.50	2.25	280.8	.0049	.1020
10.50	2.50	277.6	.0061	.1009
10.50	2.75	274.1	.0073	.0996
10.50	3.00	270.3	.0087	.0982
10.50	3.25	266.0	.0103	.0967

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Outside Diameter (in)	Inside Diameter (in)	Weight per Foot (lb/ft)	Capacity [a] (bbl/ft)	Displacement [a] (bbl/ft)
10.50	3.50	261.6	.0119	.0951
10.50	3.75	256.8	.0137	.0933
10.50	4.00	251.5	.0155	.0914
10.50	4.25	246.0	.0175	.0894
10.75	1.50	302.4	.0022	.1099
10.75	1.75	300.3	.0030	.1091
10.75	2.00	297.8	.0039	.1082
10.75	2.25	294.9	.0049	.1072
10.75	2.50	291.8	.0061	.1060
10.75	2.75	288.3	.0073	.1048
10.75	3.00	284.4	.0087	.1034
10.75	3.25	280.3	.0103	.1019
10.75	3.50	275.7	.0119	.1002
10.75	3.75	270.9	.0137	.0985
10.75	4.00	265.8	.0155	.0966
10.75	4.25	260.2	.0175	.0946
11.00	1.50	317.0	.0022	.1152
11.00	1.75	314.8	.0030	.1144
11.00	2.00	312.3	.0039	.1135
11.00	2.25	309.5	.0049	.1125
11.00	2.50	306.3	.0061	.1113
11.00	2.75	302.8	.0073	.1100
11.00	3.00	299.0	.0087	.1086
11.00	3.25	294.8	.0103	.1071
11.00	3.50	290.3	.0119	.1055
11.00	3.75	285.4	.0137	.1037
11.00	4.00	280.2	.0155	.1019
11.00	4.25	274.8	.0175	.0998

a. SeeFigure D.1 for calculation formula.

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The capacity and displacement of a drill collar is calculated the same as casing.

Capacity = Inside Diameter^2 × .0009714

Displacement = Outside Diameter^2 - Inside Diameter^2 × .0009714

Figure D.1 Drill Collar Capacity and Displacement Calculation

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Appendix E Drill Pipe Data and Tool Joint Data

Table E.1 DRILCO Hevi-Wate Drill Pipe

Drill Pipe Data				Tool Joint Data							
Nominal Size (in)	Pipe-Only Weight per Foot (lb/ft)	Adjusted Weight per Foot w/Tool Joint (lb/ft)	Pipe Inside Diameter (in)	Connection Type	Outside Diameter [OD] (in)	Inside Diameter [ID] (in)	Ave.[a] ID (in)	Ave.[a] OD (in)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)	Max. Hook Load (klb)
$3^1/_2$	21.3	25.3	2.063	NC38(IF)	4.75	2.188	-------	-------	.0042	.0092	345,400
4	25.2	29.7	2.563	NC40(FH)	5.25	2.688	-------	-------	.0065	.0108	407,550
$4^1/_2$	33.9	41.0	2.750	NC46(IF)	6.25	2.875	-------	-------	.0074	.0149	548,075
5	42.3	49.3	3.000	NC50(IF)	6.50	3.063	-------	-------	.0088	.0180	691,185

a. See Figure E.1 for calculation formula.

Table E.2 CHANCE Spiral Wate

Drill Pipe Data				Tool Joint Data							
Nominal Size (in)	Pipe-Only Weight per Foot (lb/ft)	Adjusted Weight per Foot w/Tool Joint (lb/ft)	Pipe Inside Diameter (in)	Connection Type	Outside Diameter [OD] (in)	Inside Diameter [ID] (in)	Ave.[a] ID (in)	Ave.[a] OD (in)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)	Max. Hook Load (klb)
$3^1/_2$	21.3	26.7	2.250	NC38(IF)	4.75	2.313	-------	-------	-------	-------	310,500
4	25.2	32.7	2.563	NC40(FH)	5.25	2.688	-------	-------	-------	-------	407,550
$4^1/_2$	33.9	42.6	2.750	NC46(XH)	6.25	2.875	-------	-------	-------	-------	548,060
5	42.3	53.6	3.000	NC50(IF)	6.50	3.125	-------	-------	-------	-------	691,150
$5^1/_2$	-------	50.7	4.000	$5^1/_2$FH	7.25	4.000	-------	-------	-------	-------	1231100
$6^5/_8$	-------	57.0	5.000	$6^5/_8$FH	8.00	5.000	-------	-------	-------	-------	1630000

a. See Figure E.1 for calculation formula.

Table E.3 Grade E Drill Pipe

Drill Pipe Data				Tool Joint Data							
Nominal Size (in)	Pipe-Only Weight per Foot (lb/ft)	Adjusted Weight per Foot w/Tool Joint (lb/ft)	Pipe Inside Diameter (in)	Connection Type	Outside Diameter [OD] (in)	Inside Diameter [ID] (in)	Ave.[a] ID (in)	Ave.[a] OD (in)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)	Max.[b] Hook Load (klb)
$2^3/_8$	4.85	5.16	1.995	NC26(IF)	3.375	1.750	1.9833	2.4226	.0038	.0019	97817
		4.89	1.995	OH	3.125	2.000	1.9952	2.4107	.0038	.0020	97817

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Table E.3 Grade E Drill Pipe

Drill Pipe Data				Tool Joint Data							
Nominal Size (in)	Pipe-Only Weight per Foot (lb/ft)	Adjusted Weight per Foot w/Tool Joint (lb/ft)	Pipe Inside Diameter (in)	Connection Type	Outside Diameter [OD] (in)	Inside Diameter [ID] (in)	Ave.[a] ID (in)	Ave.[a] OD (in)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)	Max.[b] Hook Load (klb)
		4.97	1.995	SLH90	3.250	2.000	1.9952	2.4167	.0038	.0018	97817
		5.06	1.995	WO	3.375	2.000	1.9952	2.4405	.0038	.0019	97817
	6.65	6.92	1.815	NC26(IF)	3.375	1.750	1.8119	2.4226	.0032	.0025	138214
		6.83	1.815	OH	3.250	1.750	1.8119	2.4167	.0032	.0025	138214
		6.71	1.815	PAC	2.875	1.375	1.7904	2.3988	.0032	.0025	138214
		6.73	1.815	SLH90	3.250	2.000	1.8238	2.4167	.0032	.0024	138214
$2^7/_8$	6.85	7.36	2.441	NC31(IF)	4.125	2.125	2.4260	2.9345	.0057	.0026	135902
		6.85	2.441	OH	3.750	2.438	2.4409	2.9167	.0058	.0025	135902
		6.96	2.441	SLH90	3.875	2.438	2.4409	2.9226	.0058	.0025	135902
		7.19	2.441	WO	4.125	2.438	2.4409	2.9345	.0058	.0025	135902
	10.40	10.76	2.151	NC31(IF)	4.125	2.125	2.1498	2.9345	.0045	.0039	214344
		10.51	2.151	OH	3.875	2.156	2.1512	2.9226	.0045	.0038	214344
		10.15	2.151	PAC	3.125	1.500	2.1200	2.8869	.0044	.0037	214344
		10.51	2.151	SLH90	3.875	2.156	2.1512	2.9226	.0045	.0038	214344
		10.99	2.151	XH	4.250	1.875	2.1379	2.9640	.0044	.0041	214344
		10.28	2.151	NC26(SH)	3.375	1.750	2.1319	2.8988	.0044	.0037	214344
$3^1/_2$	9.50	10.44	2.992	NC38(IF)	4.750	2.688	2.9975	3.5595	.0087	.0036	194264
		9.89	2.992	OH	4.500	3.000	2.9924	3.5476	.0087	.0035	194264
		10.05	2.992	SLH90	4.625	3.000	2.9924	3.5536	.0087	.0036	194264
		10.20	2.992	WO	4.750	3.000	2.9924	3.5595	.0087	.0036	194264
	13.30	14.41	2.764	H90	5.250	2.750	2.7633	3.5833	.0074	.0050	271569
		13.77	2.764	NC38(IF)	4.750	2.688	2.7604	3.5595	.0074	.0049	271569
		13.77	2.764	OH	4.750	2.688	2.7604	3.5595	.0074	.0049	271569
		13.40	2.764	NC31(SH)	4.125	2.125	2.7336	3.5298	.0073	.0048	271569
		13.94	2.764	XH	4.750	2.438	2.7485	3.5595	.0073	.0050	271569
	15.50	16.39	2.602	NC38(IF)	5.000	2.563	2.6001	3.5714	.0066	.0058	322775
4	11.85	13.07	3.476	H90	5.500	2.813	3.4444	4.0714	.0115	.0046	230755
		13.51	3.476	NC46(IF)	6.000	3.250	3.4652	4.0952	.0117	.0046	230755
		12.10	3.476	OH	5.250	3.469	3.4757	4.0595	.0117	.0043	230755
		12.91	3.476	WO	5.750	3.438	3.4742	4.0833	.0117	.0045	230755
	14.00	15.06	3.340	NC40(FH)	5.250	2.813	3.3149	4.0595	.0107	.0053	285359
		15.41	3.340	H90	5.500	2.813	3.3419	4.0714	.0107	.0053	285359
		15.85	3.340	NC46(IF)	6.000	3.250	3.3357	4.0952	.0108	.0052	285359
		15.03	3.340	OH	5.500	3.250	3.3357	4.0714	.0108	.0053	285359
		14.37	3.340	SH	4.625	2.563	3.3030	4.0298	.0106	.0052	285359
	15.70	16.81	3.240	NC40(FH)	5.250	2.688	3.2137	4.0595	.0100	.0060	324118

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Table E.3 Grade E Drill Pipe

Drill Pipe Data				Tool Joint Data							
Nominal Size (in)	Pipe-Only Weight per Foot (lb/ft)	Adjusted Weight per Foot w/Tool Joint (lb/ft)	Pipe Inside Diameter (in)	Connection Type	Outside Diameter [OD] (in)	Inside Diameter [ID] (in)	Ave.[a] ID (in)	Ave.[a] OD (in)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)	Max.[b] Hook Load (klb)
		17.07	3.240	H90	5.500	2.813	3.2197	4.0714	.0101	.0060	324118
		17.51	3.240	NC46(IF)	6.000	3.250	3.2404	4.0952	.0102	.0061	324118
$4^1/_2$	13.75	15.21	3.958	H90	6.000	3.250	3.9242	4.5714	.0150	.0053	270034
		14.93	3.958	NC50(IF)	6.375	3.750	3.9481	4.5893	.0151	.0053	270034
		14.06	3.958	OH	5.750	3.969	3.9485	4.5595	.0151	.0050	270034
		14.79	3.958	WO	6.125	3.875	3.9540	4.5774	.0152	.0052	270034
	16.60	18.14	3.826	FH	6.000	3.000	3.8767	4.5714	.0146	.0057	330558
		17.81	3.826	H90	6.000	3.250	3.7986	4.5714	.0140	.0063	330558
		17.98	3.826	NC50(IF)	6.375	3.750	3.8224	4.5893	.0142	.0063	330558
		17.10	3.826	OH	5.875	3.750	3.8224	4.5655	.0142	.0061	330558
		16.79	3.826	NC38(SH)	5.000	2.688	3.7718	4.5238	.0138	.0061	330558
		18.37	3.826	NC46(XH)	6.250	3.250	3.7986	4.5833	.0140	.0064	330558
	20.00	21.63	3.640	FH	6.000	3.000	3.6095	4.5714	.0127	.0076	412358
		21.63	3.640	H90	6.000	3.000	3.6095	4.5714	.0127	.0076	412358
		21.62	3.640	NC50(IF)	6.375	3.675	3.6417	4.5893	.0129	.0076	412358
		22.09	3.640	NC46(XH)	6.250	3.000	3.6095	4.5833	.0127	.0077	412358
	22.82	24.07	3.500	NC50(IF)	6.375	3.675	3.5083	4.5893	.0120	.0085	471239
		24.59	3.500	NC46(XH)	6.250	3.000	3.4762	4.5833	.0117	.0087	471239
5	19.50	22.26	4.276	$5^1/_2$ FH	7.000	3.750	4.2510	5.0952	.0176	.0077	395595
		20.89	4.276	NC50(XH)	6.375	3.750	4.2510	5.0655	.0176	.0074	395595
	25.60	28.26	4.000	$5^1/_2$ FH	7.000	3.500	3.9762	5.0952	.0154	.0099	530144
		26.89	4.000	NC50(XH)	6.375	3.500	3.9762	5.0655	.0154	.0096	530144
$5^1/_2$	21.90	23.77	4.778	FH	7.000	4.000	4.7410	5.5714	.0218	.0083	437116
	24.70	26.33	4.670	FH	7.000	4.000	4.6381	5.5714	.0209	.0093	497222
$6^5/_8$	25.20	27.30	5.965	FH	8.000	5.000	5.9190	6.9286	.0340	.0126	489470

a. See Figure E.1 for calculation formula.
b. Values shown are for class drill pipe at 100% of maximum hook load.

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Table E.4 Grade X-95 Drill Pipe

Drill Pipe Data				Tool Joint Data							
Nominal Size (in)	Pipe-Only Weight per Foot (lb/ft)	Adjusted Weight per Foot w/Tool Joint (lb/ft)	Pipe Inside Diameter (in)	Connection Type	Outside Diameter [OD] (in)	Inside Diameter [ID] (in)	Ave.[a] ID (in)	Ave.[a] OD (in)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)	Max.[b] Hook Load (klb)
$2^3/_8$	6.65	7.01	1.995	NC26(IF)	3.375	1.750	1.9833	2.4226	.0038	.0019	175072
		6.89	1.995	SLH90	3.250	1.813	1.9863	2.4167	.0038	.0018	175072
$2^7/_8$	10.40	10.96	2.151	NC31(IF)	4.125	2.000	2.1438	2.9345	.0045	.0039	271503
		10.84	2.151	SLH90	4.000	2.000	2.1438	2.9286	.0045	.0039	271503
$3^1/_2$	13.30	14.63	2.764	H90	5.250	2.750	2.7633	3.5833	.0074	.0051	343988
		14.41	2.764	NC38(IF)	5.000	2.563	2.7544	3.5714	.0074	.0050	343988
		14.07	2.764	SLH90	4.750	2.563	2.7544	3.5595	.0074	.0049	343988
	15.50	16.69	2.602	NC38(IF)	5.000	2.438	2.5942	3.5714	.0065	.0059	408848
4	14.00	15.30	3.340	NC40(FH)	5.250	2.688	3.2137	4.0295	.0100	.0058	361454
		15.55	3.340	H90	5.500	2.813	3.3419	4.0714	.0108	.0053	361454
		16.14	3.340	NC46(IF)	6.000	3.250	3.3357	4.0952	.0108	.0055	361454
	15.70	17.55	3.240	NC40(FH)	5.500	2.438	3.2018	4.0714	.0100	.0061	410550
		17.17	3.240	H90	5.500	2.813	3.2197	4.0714	.0101	.0060	410550
		17.75	3.240	NC46(IF)	6.000	3.250	3.2404	4.0952	.0102	.0063	410550
$4^1/_2$	16.60	18.62	3.826	FH	6.000	3.000	3.8767	4.5714	.0146	.0057	418707
		18.39	3.826	H90	6.000	3.250	3.6986	4.5714	.0140	.0063	418707
		18.34	3.826	NC50(IF)	6.375	3.750	3.8224	4.5893	.0142	.0063	418707
	20.00	22.29	3.640	FH	6.000	2.500	3.5857	4.5714	.0125	.0078	522320
		21.79	3.640	H90	6.000	3.250	3.6214	4.5714	.0127	.0076	522320
		22.13	3.640	NC50(IF)	6.375	3.500	3.6333	4.5893	.0128	.0076	522320
		22.56	3.640	NC46(XH)	6.250	2.750	3.5976	4.5833	.0126	.0078	522320
	22.82	25.43	3.500	FH	6.250	2.250	3.4881	4.5833	.0118	.0086	596903
		25.43	3.500	NC50(IF)	6.375	2.500	3.4524	4.5893	.0116	.0089	596903
		24.06	3.500	NC46(XH)	6.250	2.750	3.4743	4.5833	.0117	.0087	596903
5	19.50	22.46	4.276	$5^1/_2$ FH	7.000	3.750	4.2510	5.0952	.0176	.0077	501087
		22.08	4.276	H90	6.500	3.250	4.2271	5.0714	.0174	.0076	501087
		21.44	4.276	NC50(XH)	6.375	3.500	4.2390	5.0655	.0175	.0075	501087
	25.60	28.45	4.000	$5^1/_2$ FH	7.000	3.500	3.9762	5.0952	.0154	.0099	671515
		27.86	4.000	NC50(XH)	6.500	3.000	3.9524	5.0714	.0152	.0098	671515
$5^1/_2$	21.90	24.37	4.778	FH	7.000	3.750	4.7290	5.5714	.0217	.0084	553681
		24.64	4.778	H90	7.000	3.500	4.7171	5.5714	.0216	.0085	553681
	24.70	27.76	4.670	FH	7.250	3.500	4.6140	5.5830	.0207	.0096	629814

a. See Figure E.1 for calculation formula.
b. Values shown are for class drill pipe at 100% of maximum hook load.

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Table E.5 Grade G-105 Drill Pipe

Drill Pipe Data				Tool Joint Data							
Nominal Size (in)	Pipe-Only Weight per Foot (lb/ft)	Adjusted Weight per Foot w/Tool Joint (lb/ft)	Pipe Inside Diameter (in)	Connection Type	Outside Diameter [OD] (in)	Inside Diameter [ID] (in)	Ave.[a] ID (in)	Ave.[a] OD (in)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)	Max.[b] Hook Load (klb)
$2^3/_8$	**6.65**	**7.01**	1.995	NC26(IF)	3.375	1.750	1.9833	2.4226	.0038	.0019	193500
		6.89	1.995	SLH90	3.250	1.813	1.9863	2.4167	.0038	.0018	193500
$2^7/_8$	10.40	10.96	2.151	NC31(IF)	4.125	2.000	2.1438	2.9345	.0045	.0039	300082
		10.84	2.151	SLH90	4.000	2.000	2.1438	2.9286	.0045	.0039	300082
$3^1/_2$	13.30	14.49	2.764	NC38(IF)	5.000	2.750	2.7485	3.5714	.0073	.0051	380197
		14.07	2.764	SLH90	4.750	2.563	2.7544	3.5595	.0074	.0049	380197
	15.50	16.88	2.602	NC38(IF)	5.000	2.125	2.5793	3.5714	.0064	.0059	451885
		16.96	2.602	NC40(4FH)	5.250	2.563	2.6001	3.5833	.0066	.0059	451885
4	14.00	15.90	3.340	NC40(FH)	5.500	2.438	3.2970	4.0714	.0106	.0055	399502
		15.55	3.340	H90	5.500	2.813	3.3419	4.0714	.0108	.0053	399502
		16.14	3.340	NC46(IF)	6.000	3.250	3.3357	4.0952	.0108	.0055	399502
	15.70	17.55	3.240	NC40(FH)	5.500	2.438	3.2018	4.0714	.0100	.0061	453765
		17.17	3.240	H90	5.500	2.813	3.2197	4.0714	.0101	.0060	453765
		17.75	3.240	NC46(IF)	6.000	3.250	3.2404	4.0952	.0102	.0063	453765
$4^1/_2$	16.60	18.62	3.826	FH	6.000	3.000	3.8767	4.5714	.0146	.0057	462781
		18.39	3.826	H90	6.000	3.000	3.8767	4.5714	.0146	.0057	462781
		18.34	3.826	NC50(IF)	6.375	3.750	3.8224	4.5893	.0142	.0063	462781
		18.88	3.826	NC46(XH)	6.250	3.000	3.8767	4.5833	.0146	.0058	462781
	20.00	22.29	3.640	FH	6.000	2.500	3.5857	4.5714	.0125	.0078	577301
		21.90	3.640	H90	6.000	3.000	3.6095	4.5714	.0127	.0076	577301
		22.13	3.640	NC50(IF)	6.375	3.500	3.6333	4.5893	.0128	.0076	577301
		22.75	3.640	NC46(XH)	6.250	2.500	3.5857	4.5833	.0125	.0079	577301
	22.82	25.13	3.500	NC50(IF)	6.500	3.250	3.4881	4.5952	.0118	.0087	659735
		25.25	3.500	NC46(XH)	6.250	2.500	3.4524	4.5833	.0116	.0088	659735
5	19.50	22.46	4.276	51/2 FH	7.000	3.750	4.2510	5.0952	.0176	.0077	553833
		22.32	4.276	H90	6.500	3.000	4.2152	5.0714	.0173	.0077	553833
		21.92	4.276	NC50(XH)	6.500	3.250	4.2271	5.0714	.0174	.0076	553833
	25.60	29.01	4.000	$5^1/_2$ FH	7.250	3.500	3.9762	5.1071	.0154	.0100	742201
		28.32	4.000	NC50(XH)	6.625	2.750	3.9405	5.0774	.0151	.0099	742201
$5^1/_2$	21.90	25.21	4.778	FH	7.250	3.500	4.7171	5.5830	.0216	.0087	611963
	24.70	27.76	4.670	FH	7.250	3.500	4.6140	5.5830	.0207	.0096	696111

a. See Figure E.1 for calculation formula.
b. Values shown are for class drill pipe at 100% of maximum hook load.

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Table E.6 Grade S-135 Drill Pipe

Drill Pipe Data				Tool Joint Data							
Nominal Size (in)	Pipe-Only Weight per Foot (lb/ft)	Adjusted Weight per Foot w/Tool Joint (lb/ft)	Pipe Inside Diameter (in)	Connection Type	Outside Diameter [OD] (in)	Inside Diameter [ID] (in)	Ave.[a] ID (in)	Ave.[a] OD (in)	Capacity[a] (bbl/ft)	Displacement[a] (bbl/ft)	Max.[b] Hook Load (klb)
$2^7/_8$	10.40	11.38	2.151	NC31(IF)	4.375	1.625	1.9774	2.4702	.0038	.0021	385820
		11.12	2.151	SLH90	4.125	1.625	1.9774	2.9345	.0038	.0046	385820
$3^1/_2$	13.30	14.69	2.764	NC38(IF)	5.000	2.125	2.7336	3.5714	.0073	.0051	488825
		14.69	2.764	SLH90	5.000	2.125	2.7336	3.5714	.0073	.0051	488825
		15.04	2.764	NC40(FH)	5.375	2.438	2.7485	3.5893	.0073	.0052	488825
	15.50	17.56	2.602	NC40(FH)	5.500	2.250	2.5852	3.5952	.0065	.0061	580995
4	14.00	16.18	3.340	NC40(FH)	5.500	2.000	3.2762	4.0714	.0104	.0057	513646
		15.55	3.340	H90	5.500	2.813	3.3419	4.0714	.0108	.0053	513646
		16.38	3.340	NC46(IF)	6.000	3.000	3.3238	4.0952	.0108	.0053	513646
	15.70	18.03	3.240	NC46(IF)	6.000	3.000	3.2286	4.0952	.0101	.0059	583413
$4^1/_2$	16.60	19.28	3.826	FH	6.250	3.000	3.7629	4.5833	.0138	.0067	595004
		18.42	3.826	H90	6.000	3.000	3.8767	4.5714	.0146	.0057	595004
		18.61	3.826	NC50(IF)	6.375	3.750	3.8224	4.5893	.0142	.0063	595004
		19.09	3.826	NC46(XH)	6.250	2.750	3.7748	4.5833	.0138	.0066	595004
	20.00	23.22	3.640	NC50(IF)	6.625	3.000	3.6095	4.6012	.0127	.0079	742244
		22.93	3.640	NC46(XH)	6.250	2.250	3.5738	4.5833	.0124	.0080	742244
	22.82	25.83	3.500	NC50(IF)	6.625	2.750	3.4643	4.6012	.0117	.0089	848230
5	19.50	23.40	4.276	51/2 FH	7.250	3.500	4.2390	5.1071	.0175	.0079	712070
		22.60	4.276	NC50(XH)	6.625	2.750	4.2033	5.0774	.0172	.0079	712070
	25.60	29.35	4.000	$5^1/_2$ FH	7.250	3.250	3.9643	5.1071	.0153	.0101	954259
$5^1/_2$	21.90	26.33	4.778	FH	7.250	3.000	4.6933	5.5830	.0214	.0089	786809
	24.70	28.87	4.670	FH	7.500	3.000	4.5905	5.5952	.0205	.0098	894999

a. See Figure E.1 for calculation formula.
b. Values shown are for class drill pipe at 100% of maximum hook load.

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The average inside diameter and average outside diameter are based on a joint of pipe that has a 1.5-foot tool joint and 30 feet of tube. The following formula was used:

Avg. ID = (30 × tube ID) + (1.5 × tool joint ID) ÷ 31.5

Example: Grade E 5-inch 19.50 lb/ft drill pipe with a 5 1/2 FH connection

Avg ID = (30 × 4.276) + (1.5 × 3.75) ÷ 31.5
= (128.28 + 5.625) ÷ 31.5
= 133.905 ÷ 31.5
= 4.2510 inches

Avg OD = (30 × 5) + (1.5 × 7) ÷ 31.5
= (150 + 10.5) ÷ 31.5
= 160.5 ÷ 31.5
= 5.0952 inches

The casing and displacement values for all drill pipe is based on the average inside diameter and the average outside diameter.

Capacity = Average Inside Diameter^2 × .0009714

Displacement = Avg. Outside Diameter^2 - Avg. Inside Diameter^2 × .0009714

To calculate pounds per foot:

lb/ft = 2.67 (AOD^2 - AID^2)

Example: S-135, 5" drill pipe, 19.5 lb/ft (tube wt.) with 5 1/2 FH tool joints

lb/ft = 2.67 (Avg. Outside Diameter^2 - Avg. Inside Diameter^2)
lb/ft = 2.67 (5.1071^2 - 4.239^2)
lb/ft = 2.67 (26.729934 - 17.969121)
lb/ft = 2.67 (8.760813)
lb/ft = 23.391371 or 23.4

Figure E.1 Average Inside Diameter and Average Outside Diameter Calculation

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Appendix F Glossary

A

abandon *v*: to cease producing oil and gas from a well when it becomes unprofitable. A wildcat well may be abandoned after it has proven nonproductive. Several steps are involved in abandoning a well: part of the casing is removed and salvaged; one or more cement plugs are placed in the borehole to prevent migration of fluids between the different formations penetrated by the borehole; and the well is abandoned. In many states, it is necessary to secure permission from official agencies before a well may be abandoned.

absolute permeability *n*: a measure of the ability of a single fluid (as water, gas, or oil) to flow through a rock formation when the formation is totally filled (saturated) with the single fluid. The permeability measure of a rock filled with a single fluid is different from the permeability measure of the same rock filled with two or more fluids. Compare *effective permeability.*

acid fracture *v*: to part or open fractures in productive, hard-limestone formations by using a combination of oil and acid or water and acid under high pressure. See *formation fracturing*.

acidize *v*: to treat oil-bearing limestone or other formations, using a chemical reaction with acid, to increase production. Hydrochloric or other acid is injected into the formation under pressure. The acid etches the rock, enlarging the pore spaces and passages through which the reservoir fluids flow. The acid is held under pressure for a period of time and then pumped out, and the well is swabbed and put back into production. Chemical inhibitors combined with the acid prevent corrosion of the pipe.

adjustable choke *n*: a choke in which a conical needle and seat vary the rate of flow. See *choke*.

air-actuated *adj*: powered by compressed air, as the clutch and brake system in drilling equipment.

air drilling *n*: a method of rotary drilling that uses compressed air as the circulation medium. The conventional method of removing cuttings from the wellbore is to use a flow of water or drilling mud. Compressed air removes the cuttings with equal or greater efficiency. The rate of penetration is usually increased considerably when air drilling is used. However, a principal problem in air drilling is the penetration of formations containing water, since the entry of water into the system reduces the ability of the air to remove the cuttings.

American Petroleum Institute *n*: 1. founded in 1920, this national oil trade organization is the leading standardizing organization on oil field drilling and producing equipment. It maintains departments of transportation, refining, and marketing in Washington, D.C., and a department of production in Dallas. 2. (slang) indicative of a job being properly or thoroughly done (as, "His work is strictly API"). 3. degrees API, used to designate API gravity. See *API gravity.*

angle of deflection *n*: in directional drilling, the angle, expressed in degrees, at which a well is deflected from the vertical by a whipstock or other deflecting tool. See *whipstock.*

annular blowout preventer *n*: a large valve, usually installed above the ram preventers, that forms a seal in the annular space between the pipe and wellbore or, if no pipe is present, on the wellbore itself. Compare *ram blowout preventer.*

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annular space *n*: 1. the space surrounding a cylindrical object within a cylinder. 2. the space around a pipe in a wellbore, the outer wall of which may be the wall of either the borehole or the casing; sometimes termed the annulus.

anticline *n*: an arched, inverted-trough configuration of folded and stratified rock layers. Compare *syncline*.

API *abbr*: American Petroleum Institute.

API gravity *n*: the measure of the density or gravity of liquid petroleum products in the United States, derived from specific gravity in accordance with the following equation:

$$\text{API gravity} = \frac{141.5}{\text{specific gravity}} - 131.5$$

API gravity is expressed in degrees, a specific gravity of 1.0 being equivalent to 10° API.

B

back off *v*: to unscrew one threaded piece (as a section of pipe) from another.

back up *v*: to hold one section of an object (as pipe) while another is being screwed into or out of it.

bail *n*: a cylindrical steel bar (similar to the handle or bail of a bucket, only much larger) that supports the swivel and connects it to the hook. Sometimes, the two cylindrical bars that support the elevators and attach them to the hook are called bails. *v*: to recover bottomhole fluids, samples, or drill cuttings by lowering a cylindrical vessel called a bailer to the bottom of a well, filling it and retrieving it. See *bailer*.

bailer *n*: a long cylindrical container, fitted with a valve at its lower end, used to remove water, sand, mud or oil from a well.

bailing line *n*: cable attached to the bailer, passed over a sheave at the top of the derrick, and spooled on a reel. See *sheave*.

barge *n*: any one of many types of flat-decked, shallow draft vessels, usually towed by a boat. A complete drilling rig may be assembled on a drilling barge, which usually is submersible; that is, it has a submersible hull or base that is flooded with water at the drilling site. Drilling equipment, crew quarters, and so forth are mounted on a superstructure above the water level.

barite or **baryte** *n*: barium sulfate $BaSO_4$; a mineral used to increase the weight of drilling mud. Its specific gravity is 4.2 (i.e., it is 4.2 times heavier than water). See *barium sulfate* and *mud*.

barium sulfate *n*: 1. a chemical combination of barium, sulfur, and oxygen. Also called barite. See *barite*. 2. a tenacious scale that is very difficult to remove.

barrel *n*: a measure of volume for petroleum products. One barrel is the equivalent of 42 U.S. gallons or 0.15899 cubic meters. One cubic meter equals 6.2897 barrels.

basket sub *n*: a fishing accessory run above a bit or mill to recover small pieces of metal or junk in a well.

bed *n*: a specific layer of earth or rock in contrast to other layers of different material lying above, below, or adjacent to it.

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belt *n*: a flexible band or cord connecting and passing about each of two or more pulleys to transmit power or impart motion.

bit *n*: the cutting or boring element used in drilling oil and gas wells. The bit consists of the cutting element and the circulating element. The circulating element permits the passage of drilling fluid and utilizes the hydraulic force of the fluid stream to improve drilling rates. In rotary drilling, several drill collars are joined at the bottom end of the drill string. The bit is attached to the end of the drill collar. Most bits used in rotary drilling are roller cone bits.

bit breaker *n*: a heavy plate that fits in the rotary table and hold the drill bit while it is being made up in or broken out of the drill string. See *bit*.

bit record *n*: a report on each bit used in a drilling operation that lists the bit type, the amount of footage the bit has drilled, and the nature of the formation penetrated.

blind ram *n*: an integral part of a blowout preventer that serves as the closing element. Its ends do not fit around the drill pipe but seal against each other and shut off the space below completely.

block *n*: any assembly of pulleys on a common framework; in mechanics one or more pulleys, or sheaves, mounted to rotate on a common axis. The crown block is an assembly of sheaves mounted on beams at the top of the derrick. The drill line is reeved over the sheaves of the crown block alternately with the sheaves of the traveling block, which is hoisted and lowered in the derrick by the drill line. When the elevators are attached to a hook on the traveling block, and when drill pipe is latched in the elevators, the pipe can be raised or lowered in the derrick. See *crown block*, *elevator*, *hook*, *reeve*, *sheave*, and *traveling block*; also see *drilling block*.

blooey line *n*: the discharge pipe from a well being drilled by air drilling. The blooey line is used to conduct the air or gas used for circulation away from the rig to reduce the fire hazard as well as to transport the cuttings a suitable distance from the well. See *air drilling*.

blowout n: an uncontrolled flow of gas, oil, or other well fluids into the atmosphere. A blowout, or gusher, occurs when formation pressure exceeds the pressure applied to it by the column of drilling fluid. A kick warns of an impending blowout. See *formation pressure*, *gusher*, and *kick*.

blowout preventer *n*: one of several valves installed at the wellhead to prevent the escape of pressure either in the annular space between the casing and drill pipe or in open hole (i.e., hole with no drill pipe) during drilling or completion operations. Blowout preventers on land rigs are located beneath the rig at the land's surface; on jackup or platform rigs, they are located at the water's surface; and on floating offshore rig, on the seafloor. See *annular blowout preventer*, *inside blowout preventer*, and *ram blowout preventer*.

boll-weevil *n*: (slang) an inexperienced rig or oil-field worker, sometimes shortened to "weevil."

bomb *n*: a thick-walled container, usually steel, used to hold sample of oil or gas under pressure. See *bottom-hole pressure*.

bond *n*: the state of one material adhering or being joined to another material (as cement to formation). *v*: to adhere or be joined to another material.

BOP *abbr*: blowout preventer.

borehole *n*: the wellbore; the hole made by drilling or boring. See *wellbore*.

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bottomhole *n*: the lowest or deepest part of a well. *adj*: pertaining to the bottom of the wellbore.

bottomhole choke *n*: a device with a restricted opening placed in the lower end of the tubing to control the rate of flow. See *choke*.

bottomhole pressure *n*: 1. the pressure at the bottom of a borehole. It is caused by the hydrostatic pressure of the drilling fluid in the hole and, sometimes, any back-pressure held at the surface as when the well is shut in with blowout preventers. When mud is being circulated, bottomhole pressure is the hydrostatic pressure plus the remaining circulating pressure required to move the mud up the annulus. 2. the pressure in a well at a point opposite the producing formation, as recorded by a bottomhole pressure bomb.

box *n*: the female section of a tool joint. See *tool joint*.

brake *n*: a device for arresting the motion of a mechanism, usually by means of friction, as in the draw works brake. Compare *electrodynamic brake* and *hydromatic brake*.

break out *v*: 1. to unscrew one section of pipe from another section, especially drill pipe while it is being withdrawn from the wellbore. During this operation, the tongs are used to start the unscrewing operation. See *tongs*. 2. to separate, as gas from liquid.

breakout cat-head *n*: a device attached to the shaft of the draw works that is used as a power source for unscrewing drill pipe; usually located opposite the driller's side of the draw works. See *cat-head*.

breakout tongs *n*: tongs that are used to start unscrewing one section of pipe from another section, especially drill pipe coming out of the hole. Also called lead tongs. See *tongs*.

bring in a well *v*: to complete a well and put it in producing status.

buck up *v*: to tighten up a threaded connection (as two joints of drill pipe).

bullet perforator *n*: a tubular device that, when lowered to a selected depth within a well, fires bullets through the casing to provide hole through which the well fluids may enter.

C

cable *n*: a rope of wire, hemp, or other strong fibers. See wire-rope.

cable-tool drilling *n*: a drilling method in which the hole is drilled by dropping a sharply pointed bit on the bottom of the hole. The bit is attached to a cable, and the cable is picked up and dropped, picked up and dropped, over and over, as the hole is drilled.

cap rock *n*: 1. impermeable rock overlying an oil or gas reservoir that tends to prevent migration of oil or gas out of the reservoir. 2. the porous and permeable strata overlying salt domes that may serve as the reservoir rock.

cased *adj*: pertaining to a wellbore in which casing is run and cemented. See **casing**.

cased hole *n*: a wellbore in which casing has been run.

casing *n*: steel pipe placed in an oil or gas well as drilling progresses to prevent the wall of the hole from caving in during drilling and to provide means of extracting petroleum if the well is productive.

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casing centralizer *n*: a device secured around the casing at regular intervals to center it in the hole. Casing that is centralized allows a more uniform cement sheath to form around the pipe.

casing coupling *n*: a tubular section of pipe that is threaded inside and used to connect two joints of casing.

casing elevator *n*: See *elevator.*

casing head *n*: a heavy steel, flanged fitting that connects to the first string of casing and provides a housing for the slips and packing assemblies by which intermediate strings of casing are suspended and the annulus sealed off. Also called a spool. See *annular space*.

casing shoe *n*: also called a guide shoe. See *guide shoe*.

casing string *n*: the entire length of all the joints of casing run in a well. Casing is manufactured in lengths of about 30 feet, each length or joint being joined to another as casing is run in a well. See *combination string*.

catch samples *v*: to obtain cuttings for geological information as formation are penetrated by the bit. The samples are obtained from drilling fluid as it emerges from the wellbore or, in cable-tool drilling, from the bailer. Cuttings are carefully washed until they are free of foreign matter, dried, and labeled to indicate the depth at which they were obtained. See *bailer*, *cable-tool drilling*, and *cuttings*.

cat-head *n*: a spool-shaped attachment on a winch around which rope for hoisting and pulling is wound. See *breakout cat-head* and *makeup cat-head.*

cat-line *n*: a hoisting or pulling line powered by the cat-head and used to lift heavy equipment on the rig. See *cat-head.*

caving *n*: collapse of the walls of the wellbore, also called sloughing.

cellar *n*: a pit in the ground to provide additional height between the rig floor and the wellhead to accommodate the installation of blowout preventers, rat hole, mouse hole, and so forth. It also collects drainage water and other fluids for subsequent disposal.

cement casing *v*: to fill the annulus between the casing and hole with cement to support the casing and prevent fluid migration between permeable zones.

cement channeling *n*: an undesirable phenomenon that can occur when casing is being cemented in a borehole. The cement slurry fails to rise uniformly between the casing and borehole wall, leaving spaces void of cement. Ideally, the cement should completely and uniformly surround the casing and form a strong bond to the borehole wall.

cementing *n*: the application of a liquid slurry of cement and water to various points inside and outside the casing. See *primary cementing*, *secondary cementing*, and *squeeze cementing*.

chain drive *n*: a drive system using a chain and chain gears to transmit power. Power transmissions use a roller chain, in which each link is made of side bars, transverse pins, and rollers on the pins. A double roller chain is made of two connected rows of links, a triple roller chain of three, and so forth.

chain tongs *n*: a tool consisting of a handle and releasable chain used for turning pipe or fittings of a diameter larger than that which a pipe wrench would fit. The chain is looped and tightened around the pipe or fitting, and the handle is used to turn the tool so that the pipe of fitting can be tightened or loosened.

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check valve *n*: a valve that permits flow in one direction only.

choke *n*: an orifice installed in a line to restrict the flow and control the rate of production. Surface chokes are part of the Christmas tree and contain a choke nipple, or bean, with a small-diameter bore that serves to restrict the flow. Chokes are also used to control the rate of flow of the drilling mud out of the hole when the well is closed in with the blowout preventer and a kick is being circulated out of the hole See *adjustable choke*, *blowout preventer*, *bottomhole choke*, *Christmas tree*, *kick*, *nipple*, and *positive choke*.

choke line *n*: an extension of pipe from the blowout preventer assembly used to direct well fluids from the annulus to the choke manifold.

choke manifold *n*: the arrangement of piping and special valves, called chokes, through which drilling mud is circulated when the blowout preventers are closed to control the pressures encountered during a kick. See *choke* and *blowout preventer.*

Christmas tree *n*: the control valves, pressure gauges, and chokes assembled at the top of a well to control the flow of oil and gas after the well has been drilled and completed.

circulate *v*: to pass from one point throughout a system and back to the starting point. For example, drilling fluid is circulated out of the suction pit, down the drill pipe and drill collars, out the bit, up the annulus, and back to the pits.

circulation *n*: the movement of drilling fluid out of the mud pits, down the drill string, up the annulus, and back to the mud pits.

combination string *n*: a casing string that has joints of various collapse resistance, internal yield strength, and tensile strength designed for various depths in a specific well to best withstand the conditions of that well. In deep wells, high tensile strength is required in the top casing joints to carry the load, whereas high collapse resistance and internal yield strength are needed for the bottom joints. In the middle of the casing, average qualities are usually sufficient. The most suitable combination of types and weights of pipe helps to ensure efficient production at a minimum cost.

come out of the hole *v*: to pull the drill string out of the wellbore. This withdrawal is necessary to change the bit, change from a core barrel to the bit, run electric logs, prepare for a drill stem test, run casing, and so on.

company man *n*: also called company representative, See *company representative*.

company representative *n*: an employee of an operating company whose job is to represent the company's interest at the drilling location.

complete a well *v*: to finish work on a well and bring it to productive status. See *well completion*.

compound *n*: a mechanism used to transmit power from the engines to the pump, draw works, and other machinery on a drilling rig. It is composed of clutches, chains and sprockets, belts and pulleys, and a number of shafts, both driven and driving. *v*: to connect two or more power-producing devices (as engines) to run one piece of driven equipment (as the draw works).

conductor pipe *n*: a short string of large-diameter casing used to keep the top of the wellbore open and to provide a means of conveying the up-flowing drilling fluid from the wellbore to the mud pit.

contract depth *n*: the depth of the wellbore at which the drilling contract is fulfilled.

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core *n*: a cylindrical sample taken from a formation for geological analysis. Usually a conventional core barrel is substituted for the bit and procures a sample as it penetrates the formation. See also *sidewall coring*. *v*: to obtain a formation sample for analysis.

core analysis *n*: laboratory analysis of a core sample to determine porosity, permeability, lithology, fluid content, angle of dip, geological age, and probable productivity of the formation.

core barrel *n*: a tubular device from 25 to 60 feet long run at the bottom of the drill pipe in place of a bit to cut a core sample.

core catcher *n*: the part of the core barrel that holds the formation sample.

core cutterhead *n*: the cutting element of the core barrel assembly. In design it corresponds to one of the three main types of bits: drag bits with blades for cutting soft formations; roller bits with rotating cutting for cutting medium formations; and diamond bits for cutting very hard formations.

coupling *n*: 1. in piping, a metal collar with internal threads used to join two sections of thread pipe. 2. in power transmission, a connection extending longitudinally between a driving shaft and a driven shaft. Most such couplings are flexible and compensate for minor misalignment of the two shafts.

crooked hole *n*: a wellbore that has deviated from the vertical. It usually occurs in areas where the subsurface formations are difficult to drill, such as a section of alternating hard and soft strata steeply inclined from the horizontal.

crown block *n*: an assembly of sheaves or pulleys mounted on beams at the top of the derrick over which the drill line is reeved. See *block*, *reeve*, and *sheave*.

cuttings *n pl*: the fragments of rock dislodged by the bit and brought to the surface in the drilling mud. Washed and dried samples of the cuttings are analyzed by geologists to obtain information about the formations drilled.

D

daylight tour *n*: (pronounced "tower") the shift of duty on a drilling rig that starts at or about daylight; also called morning tour. Compare *evening tour* and *graveyard tour*.

deadline *n*: the drill line from the crown block sheave to the anchor, so called because it does not move. Compare *fastline*.

deadline tie-down anchor *n*: a device to which the deadline is attached, securely fastened to the mast or derrick substructure. Also called a deadline anchor.

degasser *n*: the equipment used to remove unwanted gas from a liquid, especially from a drilling fluid.

density *n*: the mass or weight of a substance; often expressed in weight per unit volume. For instance, the density of a drilling mud may be 10 pounds per gallon (ppg), 74.8 pounds per cubic foot (lb/ft^3), or 1,198.2 kilograms per cubic meter (kg/m^3). Specific gravity and API gravity are other units of density. See *API gravity* and *specific gravity*.

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derrick *n*: a large load-bearing structure, usually of bolted construction. In drilling, the standard derrick has four legs standing at the corners of the substructure and reaching to the crown block. The substructure is an assembly of heavy beams used to elevate the derrick and provide space to install blowout preventers, casing heads, and so forth. Because the standard derrick must be assembled piece by piece, it has largely been replaced by the mast, which can be lowered and raised without disassembly. See *crown block*, *mast*, and *substructure*.

derrickman *n*: the crew member who handles the upper end of the drill string as it is being hoisted out of or lowered into the hole. He is also responsible for the conditioning of the drilling fluid and circulating machinery.

de-sander *n*: a centrifugal device for removing sand from drilling fluid to prevent abrasion of the pumps. It may be operated mechanically or by a fast-moving stream of fluid inside a special cone-shaped vessel, in which case it is sometimes called a hydrocyclone. See *de-silter*.

de-silter *n*: a centrifugal device for removing very fine particles, or silt, from drilling fluid to keep the amount of solids in the fluid to the lowest possible point. Usually, the lower the solids content of mud, the faster the rate of penetration. It works on the same principle as a de-sander. Compare *de-sander*.

development well *n*: 1. a well drilled in proven territory in a field to complete a pattern of production. 2. an exploitation well. See *exploitation well*.

deviation *n*: the inclination of the wellbore from the vertical. The angle of deviation, angle of drift, or drift angle is the angle in degrees that shows the variation from the vertical as revealed by a deviation survey. See *deviation survey*.

deviation survey *n*: an operation made to determine the angle from which a bit has deviated from the vertical during drilling. There are two basic deviation survey, or drift survey, instruments: one reveals the angle of deviation only; the other indicates both the angle and direction of deviation.

diamond bit *n*: a drilling bit that has a steel body surfaced with industrial diamonds. Cutting is performed by the rotation of the very hard diamonds over the rock surface.

diesel-electric power *n*: the power supplied to a drilling rig by diesel engines driving electric generators, used widely offshore and gaining popularity onshore.

diesel engine *n*: a high-compression, internal-combustion engine used extensively for powering drilling rigs. In a diesel engine, air is drawn into the cylinders and compressed to very high pressures; ignition occurs as fuel is injected into the compressed and heated air. Combustion takes place within the cylinder above the piston, and expansion of the combustion products imparts power to the piston.

directional drilling *n*: intentional deviation of a wellbore from the vertical. Although wellbores are normally drilled vertically, it is sometimes necessary or advantageous to drill at an angle from the vertical. Controlled directional drilling makes it possible to reach subsurface areas laterally remote from the point where the bit enters the earth. It involves the use of turbo-drills, Dyna-Drills, whipstocks, or other deflecting tools. See *Dyna-Drill*, *turbo-drill*, and *whipstock*.

discovery well *n*: the first oil or gas well drilled in a new field; the well that reveals the presence of a petroleum-bearing reservoir. Subsequent wells are development wells. Compare *development well*.

displacement fluid *n*: in oil well cementing, the fluid, usually drilling mud or salt water, that is pumped into the well after the cement to force the cement out of the casing and into the annulus.

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doghouse *n*: 1. a small enclosure on the rig floor used as an office for the driller or as a storehouse for small objects. 2. any small building used as an office or for storage.

double *n*: a length of drill pipe, casing, or tubing consisting of two joints screwed together. Compare *thribble* and *fourble*. See *joint*.

double-board *n*: the name used for the working platform of the derrickman, or monkey board, when it is located at a height in the derrick or mast equal to two lengths of pipe joined together. Compare *fourble board* and *thribble board*. See *monkey board*.

draw works *n*: the hoisting mechanism on a drilling rig. It is essentially a large winch that spools off or takes in the drill line and thus raises or lowers the drill string and bit.

drill bit *n*: the cutting or boring element used for drilling. See *bit*.

drill collar *n*: a heavy, thick-walled tube, usually steel, used between the drill pipe and the bit in the drill string. Drill collars are used to put weight on the bit so that the bit can drill.

driller *n*: the employee directly in charge of a drilling rig and crew. His main duty is operation of the drilling and hoisting equipment, but he is also responsible for the operation of downhole tools, and pipe measurement.

drilling block *n*: a lease or a number of leases of adjoining tracts of land that constitute a unit of acreage sufficient to justify the expense of drilling a wildcat.

drilling contractor *n*: an individual or group of individuals that own a drilling rig or rigs and contract their services for drilling wells to a certain depth.

drilling crew *n*: a driller, derrickman, and two or more helpers who operate a drilling rig for one tour each day. See *derrickman*, *driller*, and *tour*.

drilling fluid *n*: circulating fluid, one function of which is to force cuttings out of the wellbore and to the surface. While a mixture of clay, water, and other chemical additives is the most common drilling fluid, wells can also be drilled using air, gas, or water as the drilling fluid. Also called circulating fluid. See *mud*.

drilling foreman *n*: the supervisor of drilling operations on a rig; also the tool pusher or superintendent.

drill line *n*: a wire rope used to support the drilling tools.

drilling rate *n*: the speed with which the bit drills the formation; usually called the rate of penetration.

drilling rig *n*: See *rig*.

drill pipe *n*: the heavy seamless tubing used to rotate the bit and circulate the drilling fluid. Joints of pipe 30 feet long are coupled together by means of tool joints.

drill ship *n*: a ship constructed to permit a well to be drilled from it at an offshore location. While not as stable as other floating structures (as a semisubmersible), drill ships, or ship shapes, are capable of drilling exploratory wells in relatively deep waters. They may have a ship hull, a catamaran hull, or a trimaran hull. See *semisubmersible drilling rig*.

drill stem *n*: all members in the assembly used for drilling by the rotary method from the swivel to the bit, including the kelly, drill pipe and tools joints, drill collars, stabilizers, and various subsequent items. Compare *drill string*.

drill-stem test *n*: a method of gathering data on the potential productivity of a formation before installing casing in a well. See *formation testing*.

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drill string *n*: the column, or string, of drill pipe with attached tool joints that transmits fluid and rotation power from the kelly to the drill collars and bit. Often, especially in the oil field, term is loosely applied to include both drill pipe and drill collars. Compare *drill stem*.

drum *n*: 1. a cylinder around which wire rope is wound in the draw works. The draw works drum is that part of the hoist upon which the drill line is wound. 2. a steel container of general cylindrical form. Refined products are shipped in steel drums with capacities of about 50 to 55 U.S. gallons (about 200 liters).

DST *abbr*: drill-stem test

Dyna-Drill *n*: a downhole motor driven by drilling fluid that imparts rotary motion to a drilling bit connected to the tool, thus eliminating the need to turn the entire drill string to make hole. The Dyna-Drill, a trade name, is used in straight and directional drilling.

dynamic positioning *n*: a method by which a floating offshore drilling rig is maintained in position over an offshore well location. Generally, several motors called thrusters are located on the hull(s) of the structure and are actuated by a sensing system. A computer to which the system feeds signals then directs the thrusters to maintain the rig on location.

E

effective permeability *n*: a measure of the ability of a single fluid to flow through a rock when the pore spaces of the rock are not completely filled or saturated with the fluid. Compare *absolute permeability* and *relative permeability*.

electric well log *n*: a record of certain electrical characteristics of formation traversed by the borehole, made to identify the formation, determine the nature and amount of fluids they contain, and estimate their depth. Also called an electric log or electric survey.

electrodynamic brake *n*: a device mounted on the end of the draw works shaft of a drilling rig. The electrodynamic brake (sometimes called a magnetic brake) serves as an auxiliary to the mechanical brake when pipe is lowered into a well. The braking effect in an electrodynamic brake is achieved by means of the interaction of electric currents with magnets, with other currents, or with themselves.

elevator *n*: a set of clamps that grips a stand, or column of casing, tubing, or drill pipe so that the stand can be raised or lowered into the hole.

evening tour *n*: (pronounced "tower") the shift of duty on a drilling rig that starts in the afternoon and runs through the evening. Compare *daylight tour* and *graveyard tour*.

exploitation well *n*: a well drilled to permit more effective extraction of oil from a reservoir. It is sometimes called a development well. See *development well*.

exploration well *n*: a wildcat. See *wildcat*.

F

fastline *n*: the end of the drill line that is affixed to the drum or reel of the draw works, so called because it travels with greater velocity than any other portion of the line. Compare *deadline*.

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fault *n*: a break in subsurface strata. Often strata on one side of the fault line has been displaced (upward, downward, or laterally) relative to its original positions.

field *n*: a geographical area in which a number of oil and gas wells produce from a continuous reservoir. A field may refer to surface area only or to underground productive formations as well. In a single field, there may be several separate reservoirs at varying depths.

fill the hole *v*: to pump drilling fluid into the wellbore while the pipe is being withdrawn in order to ensure that the wellbore remains full of fluid even though the pipe is withdrawn. Filling the hole lessens the danger of blowout or of caving of the wall of the wellbore.

filter cake *n*: 1. compacted solid or semisolid material remaining on a filter after pressure filtration of mud with the standard filter press. Thickness of the cake is reported in thirty-seconds of an inch or in millimeters. 2. the layer of concentrated solids from the drilling mud that forms on the walls of the borehole opposite permeable formations; also called wall cake or mud cake.

fingerboard *n*: a rack that supports the tops of the stands of pipe being stacked in the derrick or mast. It has several steel finger-like projections that form a series of slots into which the derrickman can set a stand of drill pipe as it is pulled out of the hole.

fish *n*: an object left in the wellbore during drilling operations that must be recovered or drilled around before work can proceed. It can be anything from a piece of scrap metal to a part of the drill string. *v*: 1. to recover from a well any equipment left there during drilling operations, such as a lost bit or drill collar or part of the drill string. 2. to remove from an older well certain pieces of equipment, such as packers, liners, or screen pipe, to allow reconditioning of the well.

fishing tool *n*: a tool designed to recover equipment lost in the well.

float collar *n*: a special coupling device, inserted one or two joints above the bottom of the casing string, that contains a check valve to permit fluid to pass downward but not upward through the casing. The float collar prevents drilling mud from entering the casing while it is being lowered, allowing the casing to float during its descent, which decreases the load on the derrick. The float collar also prevents a back flow of cement during the cementing operation.

floorman *n*: a drilling crew member whose work station is on the derrick floor. On rotary drilling rigs, there are at least two and usually three or more floormen on each crew. Also called rotary helper and roughneck.

fluid *n*: a substance that flows and yields to any force tending to change it shape. Liquids and gases are fluids.

formation *n*: a bed or deposit composed throughout of substantially the same kinds of rock; a lithologic unit. Each different formation is given a name, frequently as a result of the study of the formation outcrop at the surface and sometimes based on fossils found in the formation.

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formation fracturing *n*: a method of stimulating production by increasing the permeability of the producing formation. Under extremely high hydraulic pressure, a fluid (as water, oil, alcohol, dilute hydrochloric acid, liquefied petroleum gas, or foam) is pumped downward through tubing or drill pipe and forced into the perforations in the casing. The fluid enters the formation and parts or fractures it. Sand grains, aluminum pellets, glass beads, or similar materials are carried in suspension by the fluid into the fractures. These are called propping agents or proppants. When the pressure is released at the surface, the fracturing fluid returns to the well, and the fractures partially close on the proppants, leaving channels for oil to flow through them to the well. This process is often called a frac job. See *propping agent*.

formation pressure *n*: the force exerted by fluids in a formation, recorded in the hole at the level of the formation with the well shut in. It is also called reservoir pressure or shut-in bottom-hole pressure. See *reservoir pressure* and *shut-in bottom-hole pressure*.

formation testing *n*: the gathering of data on a formation to determine its potential productivity before installing casing in a well. The conventional method is the drill stem test. Incorporated in the drill stem testing tool are a packer, valves or ports that may be opened and closed from the surface, and a pressure-recording device. The tool is lowered to bottom on a string of drill pipe and the packer set, isolating the formation to be tested from the formations above and supporting the fluid column above the packer. A port on the tool is opened to allow the trapped pressure below the packer to bleed off into the drill pipe, gradually exposing the formation to atmospheric pressure and allowing the well to produce to the surface, where the well fluids may be sampled and inspected. From a record of the pressure readings, a number of facts about the formation may be inferred.

fourable *n*: a section of drill pipe, casing or tubing consisting of four joints screwed together. Compare *double* and *thribble*. See *joint*.

fourable board *n*: the name used for the working platform of the derrickman, or monkey board, when it is located at a height in the derrick equal to approximately four lengths of pipe joined together. Compare *double board* and *thribble board*. See *monkey board*.

fracturing *n*: shortened form of formation fracturing. See *formation fracturing*.

G

gas-cut mud *n*: a drilling mud that has entrained formation gas giving the mud a characteristically fluffy texture. When entrained gas is not released before the fluid returns to the well, the weight or density of the fluid column is reduced. Because a large amount of gas in mud lowers its density, gas-cut mud must be treated to lessen the chance of a blowout.

gas sand *n*: a stratum of sand or porous sandstone from which natural gas is obtained.

gas show *n*: the gas that appears in drilling fluid returns, indicating the presence of a gas zone.

geologist *n*: a scientist who gathers and interprets data pertaining to the strata of the earth's crust.

geology *n*: the science that relates to the study of the structure, origin, history, and development of the earth and its inhabitants as revealed in the study of rocks, formations, and fossils.

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graveyard tour *n*: (pronounced "tower") the shift of duty on a drilling rig that starts at or about midnight. Compare *daylight tour* and *evening tour.*

gravity *n*: the attraction exerted by the earth's mass on objects at its surface; the weight of a body. See *API gravity* and *specific gravity.*

guide shoe *n*: a short, heavy, cylindrical section of steel filled with concrete and rounded at the bottom, which is placed at the end of the casing string. It prevents the casing from snagging on irregularities in the borehole as it is lowered. A passage through the center of the shoe allows drilling fluid to pass up into the casing while it is being lowered and cement to pass out during cementing operations. Also called casing shoe.

gun-perforate *v*: to create holes in casing and cement set through a productive formation. A common method of completing a well is to set casing through the oil-bearing formation and cement it. A perforating gun is then lowered into the hole and fired to detonate high-powered jets or shoot steel projectiles (bullets) through the casing and cement and into the pay zone. The formation fluids flow out of the reservoir through the perforations and into the wellbore. See *jet-perforate* and *perforating gun.*

gusher *n*: an oil well that has come in with such great pressure that the oil jets out of the well like a geyser. In reality, a gusher is a blowout and is extremely wasteful of reservoir fluids and drive energy. In the early days of the oil industry, gushers were common and many times were the only indication that a large reservoir of oil and gas had been struck. See *blowout*.

H

hoist *n*: an arrangement of pulleys and wire rope or chain used for lifting heavy objects; a winch or similar device; the draw works. See *draw works*.

hoisting drum *n*: the large, flanged spooled in the draw works on which the hoisting cable is wound. See *draw works*.

hook *n*: a large hook-shaped device from which the swivel is suspended. It is designed to carry maximum loads ranging from 100 to 650 tons and turns on bearings in its supporting housing. A strong spring within the assembly cushions the weight of a stand (90 feet) of drill pipe, thus permitting the pipe to be made up and broken out with less damage to the tool joint threads. Smaller hooks without the spring are used for handling tubing and sucker rods. See *stand* and *swivel.*

hopper *n*: a large funnel- or cone-shaped device into which dry components (as powdered clay or cement) can be poured in order to uniformly mix the components with water (or other liquids). The liquid is injected through a nozzle at the bottom of the hopper. The resulting mixture of dry material and liquid may be drilling mud to be used as the circulating fluid in a rotary drilling operation or may be cement slurry used to bond casing to the borehole.

hydraulic fracturing *n*: an operation in which a specially blended liquid is pumped down a well and into a formation under pressure high enough to cause the formation to crack open. The resulting cracks or fractures serve as passages through which oil can flow into the wellbore. See *formation fracturing*.

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hydrocarbons *n*: organic compounds of hydrogen and carbon, whose densities, boiling points, and freezing points increase as their molecular weights increase. Although composed only of two elements, hydrocarbons exist in a variety of compounds, because of the strong affinity of the carbon atom for other atoms and for itself. The smallest molecules of hydrocarbons are gaseous; the largest are solids. Petroleum is a mixture of many different hydrocarbons.

hydromatic brake *n*: a device mounted on the end of the draw works shaft of a drilling rig. The hydromatic brake (often simply called the hydromatic) serves as an auxiliary to the mechanical brake when pipe is lowered into the well. The braking effect in a hydromatic brake is achieved by means of a runner or impeller turning in a housing filled with water.

I

impermeable *adj*: preventing the passage of fluid. A formation may be porous yet impermeable if there is an absence of connecting passages between the voids within it. See *permeability.*

inland barge rig *n*: a drilling structure consisting of a barge upon which the drilling equipment is constructed. When moved from one location to another, the barge floats, but when stationed on the drill site, the barge is submerged to rest on the bottom. Typically, inland barge rigs are used to drill wells in marshes, shallow inland bays, and in areas where the water covering the drill site is not too deep.

instrumentation *n*: a device or assembly of devices designed for one or more of the following functions: to measure operating variables (as pressure, temperature, rate of flow, speed of rotation, etc.); to indicate these phenomena with visible or audible signals; to record them, to control them within a predetermined range; and to stop operations if the control fails. Simple instrumentation might consist of an indicating pressure gauge only. In a completely automatic system, the desired range of pressure, temperature, and so on is predetermined and preset.

intermediate casing string *n*: the string of casing set in a well after the surface casing, but before the production casing, to keep the hole from caving and to seal off troublesome formations. The string is sometimes called protection casing.

J

jackup drilling rig *n*: an offshore drilling structure with tubular or derrick legs that support the deck and hull. When positioned over the drilling site, the bottoms of the legs rest on the seafloor. A jackup rig is towed or propelled to a location with its legs up. Once the legs are firmly positioned on the bottom, the deck and hull height are adjusted and leveled.

jet bit *n*: a drilling bit having replaceable nozzles though which the drilling fluid is directed in a high-velocity stream to the bottom of the hole to improve efficiency of the bit. See *bit*.

jet gun *n*: an assembly, including a carrier and shaped charges, that is used in jet perforating.

jet-perforate *v*: to create a hole through the casing with a shaped charge of high explosives instead of a gun that fires projectiles. The loaded charge is lowered into the hole to the desired depth. Once detonated, the charges emit short, penetrating jets of high-velocity gases that cut holes in the casing and cement and some distance into the formation. Formation fluids then flow into the wellbore through these perforations. See *bullet perforator* and *gun-perforate*.

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joint *n*: a single length (about 30 feet) of drill pipe or of drill collar, casing, or tubing, that has threaded connections at both ends. Several joints screwed together constitute a stand of pipe. See *stand*, *single*, *double*, *thribble*, and *fourble*.

junk *n*: metal debris lost in a hole. Junk may be a lost bit, pieces of a bit, milled pieces of pipe, wrenches, or any relatively small object that impedes drilling and must be fished out of the hole. *v*: to abandon (as a nonproductive well).

K

kelly *n*: the heavy steel member, four- or six-sided, suspended from the swivel through the rotary table and connected to the topmost joint of drill pipe to turn the drill string as the rotary table turns. It has a bored passageway that permits fluid to be circulated into the drill string and up the annulus, or vice versa. See *drill stem*, *rotary table*, and *swivel*.

kelly bushing *n*: a special device that, when fitted into the master bushing, transmits torque to the kelly and simultaneously permits vertical movement of the kelly to make hole. It may be shaped to fit the rotary opening or have pins for transmitting torque. Also called the drive bushing. See *kelly* and *master bushing*.

kelly spinner *n*: a pneumatically operated device mounted on top of the kelly that, when actuated, causes the kelly to turn or spin. it is useful when the kelly or a joint of pipe attached to it must be spun up; that is, rotated rapidly in order to make it up.

kick *n*: an entry of water, gas, oil, or other formation fluid into the wellbore. It occurs because the pressure exerted by the column of drilling fluid is not great enough to overcome the pressure exerted by the fluids in the formation drilled. If prompt action is not taken to control the kick or kill the well, a blowout will occur. See *blowout*.

L

LACT unit *n*: an automated system for measuring and transferring oil from a lease gathering system into a pipeline. See *lease automatic custody transfer*.

latch on *v*: to attach elevators to a section of pipe to pull it out of or run it into the hole.

lead tongs *n*: (pronounced "leed") the pipe tongs suspended in the derrick or mast and operated by a wireline connected to the breakout cat-head. Also called breakout tongs.

lease *n*: 1. a legal document executed between a land-owner, as lessor, and a company or individual, as lessee, that grants the right to exploit the premises for minerals or other products. 2. the area where production wells, stock tanks, separators, LACT units, and other production equipment are located. See *LACT unit* and *lease automatic custody transfer*.

lease automatic custody transfer *n*: the measurement and transfer of oil from the producer's tanks to the connected pipeline on an automatic basis without a representative of either having to be present. See *LACT unit*.

location *n*: the place where a well is drilled.

log *n*: a systematic recording of data, as from the driller's log, mud log, electrical well log, or radioactivity log. Many different logs are run in wells being produced or drilled to obtain various characteristics of downhole formations.

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M

magnetic brake *n*: also called an electrodynamic brake. See *electrodynamic brake*.

make a connection *v*: to attach a joint of drill pipe onto the drill string suspended in the wellbore to permit deepening of the wellbore.

make a trip *v*: to hoist the drill string out of the wellbore to perform one of a number of operations such as changing bits, taking a core, and so forth, and then to return the drill string to the wellbore.

make hole *v*: to deepen the hole made by the bit; to drill ahead.

make up *v*: 1. to assemble and join parts to form a complete unit (as to make up a string of casing). 2. to screw together two threaded pieces. 3. to mix or prepare (as to make up a tank of mud). 4. to compensate for (as to make up for lost time).

make up a joint *v*: to screw a length of pipe into another length of pipe.

makeup cat-head *n*: a device attached to the shaft of the draw works that is used as a power source for screwing together joints of pipe; usually located on the driller's side of the draw works. See *cat-head*.

mast *n*: a portable derrick capable of being erected as a unit, as distinguished from a standard derrick that cannot be raised to a working position as a unit. For transporting by land, the mast can be divided into two or more sections to avoid excessive length extending from truck beds on the highway. Compare *derrick*.

master bushing *n*: a device that fits into the rotary table. It accommodates the slips and drives the kelly bushing so that the rotating motion of the rotary table can be transmitted to the kelly. Also called rotary bushing. See *slips* and *kelly bushing*.

mechanical rig *n*: a drilling rig in which the source of power is one or more internal-combustion engines and in which the power is distributed to rig components through mechanical devices (as chains, sprockets, clutches, and shafts). It is also called a power rig.

mill *n*: a downhole tool with rough, sharp, extremely hard cutting surfaces for removing metal by grinding or cutting. Mills are run on drill pipe or tubing to grind up debris in the hole, remove stuck portions of drill stem or sections of casing for sidetracking, and ream out tight spots in the casing. They are also called junk mills, reaming mills, and so forth, depending on what use they have. *v*: to use a mill to cut or grind metal objects that must be removed from a well.

mix mud *v*: to prepare drilling fluids from a mixture of water or other fluids and one or more of the various dry mud-making materials (as clay, weighting materials, chemicals, etc.).

monkey board *n*: the derrickman's working platform. As pipe or tubing is run into or out of the hole, the derrickman must handle the top end of the pipe, which may be as high as 90 feet in the derrick or mast. The monkey board provides a small platform to raise him to the proper height to be able to handle the top of the pipe. See *double board*, *fourable board*, and *thribble board*.

morning tour *n*: (pronounced "tower") also called daylight tour. See *daylight tour*.

motorman *n*: the crew member on a rotary drilling rig responsible for the care and operation of drilling engines.

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mouse hole *n*: an opening through the rig floor, usually lined with pipe, into which a length of drill pipe is placed temporarily for later connection to the drill string.

mouse hole connection *n*: the procedure of adding a length of drill pipe or tubing to the active string in which the length to be added is placed in the mouse hole, made up to the kelly, then pulled out of the mouse hole, and subsequently made up into the string.

mud *n*: the liquid circulated through the wellbore during rotary drilling operations. In addition to its function of bringing up cuttings to the surface, drilling mud cools and lubricates the bit and drill stem, protects against blowouts by holding back subsurface pressures, and deposits a mud cake on the wall of the borehole to prevent loss of fluids to the formation. Although it originally was a suspension of earth solids (especially clays) in water, the mud used in modern drilling operations is a more complex, three-phase mixture of liquids, reactive solids, and inert solids. The liquid phase may be fresh water, seawater, and may contain one or more conditioners. See *drilling fluid*.

mud analysis *n*: examination and testing of the drilling mud to determine its physical and chemical properties.

mud cake *n*: the sheath of mud solids that forms on the wall of the hole when the liquid from the mud filters into the formation; also called wall cake or filter cake.

mud circulation *n*: the act of pumping mud downward to the bit and back up to the surface by normal circulation or reverse circulation. See *normal circulation* and *reverse circulation*.

mud conditioning *n*: the treatment and control of drilling mud to ensure that it has the correct properties. Conditioning may include the use of additives, the removal of sand or other solids, the removal of gas, the addition of water, and other measures to prepare the mud for conditions encountered in a specific well.

mud engineer *n*: a person whose duty is to test and maintain the properties of the drilling mud that are specified by the operator.

mud gun *n*: a pipe that shoots a jet of drilling mud under high pressure into the mud pit to mix additives with the mud.

mud man *n*: also called a mud engineer. See *mud engineer*.

mud pit *n*: 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. Modern rotary drilling rigs are generally provided with three or more pits, usually fabricated steel tanks fitted with built-in piping, valves and mud agitators. Mud pits are also called shaker pits, settling pits, and suction pits, depending of their main purpose. See *shaker pit*, *settling pit* and *suction pit*.

mud pump *n*: a large, reciprocating pump used to circulate the mud on a drilling rig. A typical mud pump is a single- or double-acting, two- or three-cylinder piston pump whose pistons travel in replaceable liners and are driven by a crankshaft actuated by an engine or motor. Also called a slush pump.

mud-return line *n*: a trough or pipe placed between the surface connections at the wellbore and the shale shaker, through which drilling mud flows upon its return to the surface from the hole.

mud screen *n*: also called a shale shaker. See *shale shaker*.

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N

natural gas *n*: a highly compressible, highly expandable mixture of hydrocarbons having a low specific gravity and occurring naturally in a gaseous form. Besides hydrocarbon gases, natural gas may contain appreciable quantities of nitrogen, helium, carbon dioxide, and contaminants (as hydrogen sulfide and water vapor). Although gaseous at normal temperatures and pressures, certain of the gases comprising the mixture that is natural gas are variable in form and may be found either as gases or as liquids under suitable conditions of temperature and pressure.

needle valve *n*: a globe valve that incorporates a needle-point disk to produce extremely fine regulation of flow.

nipple *n*: a tubular pipe fitting threaded on both ends and less than 12 inches long.

nipple up *v*: in drilling, to assemble the blowout-preventer stack on the wellhead at the surface.

normal circulation *n*: the smooth, uninterrupted circulation of drilling fluid down the drill stem, out the bit, up the annular space between the pipe and the hole, and back to the surface. See *mud circulation* and *reverse circulation*.

O

offshore drilling *n*: drilling for oil in an ocean, gulf, or sea, usually on the continental shelf. A drilling unit for offshore operations may be a mobile floating vessel with a ship or barge hull, a semisubmersible or submersible base, a self-propelled or towed structure with jacking legs (jackup drilling rig), or a permanent structure used as a production platform when drilling is completed. In general, wildcat wells are drilled from mobile floating vessels (as semisubmersible rigs and drill ships) or from jack-ups, while development wells are drilled from platforms. See *drill ship*, *jackup drilling rig*, *platform*, *semisubmersible drilling rig* and *wildcat*.

oil field *n*: the surface area overlying an oil reservoir or reservoirs. Commonly, the term includes not only the surface area, but may include the reservoir, the wells, and production equipment as well.

oil sand *n*: 1. a sandstone that yields oil. 2. (by extension) any reservoir that yields oil, whether or not it is sandstone.

oil zone *n*: a formation or horizon of a well from which oil may be produced. The oil zone is usually immediately under the gas zone and on top of the water zone if all three fluids are present and segregated.

open *adj*: 1. of a wellbore, having no casing. 2. of a hole, having no drill pipe or tubing suspended in it.

open hole *n*: 1. any wellbore in which casing has not been set. 2. open or cased hole in which no drill pipe or tubing is suspended.

operator *n*: the person or company, either proprietor or lessee, actually operating an oilwell or lease. Compare *unit operator*.

overshot *n*: a fishing tool that is attached to tubing or drill pipe and lowered over the outside wall of pipe lost or stuck in the wellbore. A friction device in the overshot, usually either a basket or a spiral grapple, firmly grips the pipe, allowing the lost fish to be pulled from the hole.

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P

P&A *abbr*: plug and abandon.

pay sand *n*: the producing formation, often one that is not even sandstone. It is also called pay, pay zone, and producing zone.

perforate *v*: to pierce the casing wall and cement to provide holes through which formation fluids may enter or to provide holes in the casing so that materials may be introduced into the annulus between the casing and the wall of the borehole. Perforating is accomplished by lowering into the well a perforating gun, or perforator, that fires electrically detonated bullets or shaped charges from the surface. See *perforating gun*.

perforating gun *n*: a device fitted with shaped charges or bullets that is lowered to the desired depth in a well and fired to create penetrating holes in casing, cement and formation. See *gun-perforate*.

permeability *n*: 1. a measure of the ability of fluids to flow through a porous rock. 2. fluid conductivity of a porous medium. 3. the ability of a fluid to flow within the interconnected pore network of a porous medium. See *absolute permeability*, *effective permeability*, and *relative permeability*.

petroleum *n*: oil or gas obtained from the rocks of the earth. See *hydrocarbons*.

pin *n*: the male section of the tool joint. See *tool joint*.

pipe ram *n*: a sealing component for a blowout preventer that closes the annular space between the pipe and the blowout preventer or wellhead. See *annular space* and *blowout preventer*.

platform *n*: an immobile, offshore structure constructed on pilings from which wells are drilled, produced, or both.

plug and abandon *v*: to place a cement plug into a dry hole and abandon it.

pore *n*: an opening or space within a rock or mass of rocks, usually small and often filled with some fluid (as water, oil, gas, or all three). Compare *vug*.

porosity *n*: the condition of something that contains pores (as a rock formation). See *pore*.

positive choke *n*: a choke in which the orifice size must be changed to change the rate of flow through the choke. See *choke* and *orifice*.

pressure *n*: the force that a fluid (liquid or gas) exerts when it is in some way confined within a vessel, pipe, hole in the ground, and so forth, such as that exerted against the inner wall of a tank or that exerted on the bottom of the wellbore by drilling mud. Pressure is often expressed in terms of force per unit of area, as pounds per square inch (psi).

pressure gauge *n*: an instrument for measuring fluid pressure that usually registers the difference between atmospheric pressure and the pressure of the fluid by indicating the effect of such pressures on a measuring element (as a column of liquid, a weighted piston, a diaphragm, or other pressure-sensitive device).

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pressure gradient *n*: a scale of pressure differences in which there is a uniform variation of pressure from point to point. For example, the pressure gradient of a column of water is about 0.433 psi/ft of vertical elevation (9.794 kPa/m). The normal pressure gradient in a well is equivalent to the pressure exerted at any given depth by a column of 10 percent salt water extending from that depth to the surface (i.e., 0.465 psi/ft or 10.518 kPa/m).

pressure relief valve *n*: a valve that opens at a preset pressure to relieve excessive pressures within a vessel or line; also called a relief valve, safety valve, or pop valve.

preventer *n*: shortened form of blowout preventer. See *blowout preventer.*

primary cementing *n*: the cementing operation that takes place immediately after the casing has been run into the hole; used to provide a protective sheath around the casing, to segregate the producing formation, and to prevent the migration of undesirable fluids. See *secondary cementing* and *squeeze cementing*.

prime mover *n*: an internal-combustion engine that is the source of power for a drilling rig in oilwell drilling.

production *n*: 1. the phase of the petroleum industry that deals with bringing the well fluids to the surface and separating them and with storing, gauging, and otherwise preparing the product for the pipeline. 2. the amount of oil or gas produced in a given period.

proppant *n*: also called propping agent. See *propping agent*.

propping agent *n*: a granular substance (as sand grains, aluminum pellets, or other material) carried in suspension by the fracturing fluid that serves to keep the cracks open when the fracturing fluid is withdrawn after a fracture treatment.

psi *abbr*: pounds per square inch. See *pressure*.

pump *n*: a device that increases the pressure on a fluid or raises it to a higher level. Various types of pumps include the reciprocating pump, centrifugal pump, rotary pump, jet pump, sucker rod pump, hydraulic pump, mud pump, submersible pump, and bottomhole pump.

pump pressure *n*: fluid pressure from the action of the pump.

R

radioactivity well logging *n*: the recording of the natural or induced radioactive characteristics of subsurface formations. A radioactivity log, also known as a radiation log, normally consists of two recorded curves: a gamma ray curve and a neutron curve. Both indicate the types of rock in the formation and the types of fluids contained in the rocks. The two logs may be run simultaneously in conjunction with a collar locator in a cased or uncased hole.

ram *n*: the closing and sealing component on a blowout preventer. One of three types - blind, pipe, or shear - may be installed in several preventers mounted in a stack on top of the wellbore. Blind rams, when closed, form a seal on a hole that has no drill pipe in it; pipe rams, when closed, seal around the pipe; shear rams cut through drill pipe and then form a seal. See *blind ram*, *pipe ram*, and *shear ram*.

ram blowout preventer *n*: a blowout preventer that uses rams to seal off pressure on a hole that is with or without pipe. It is also called a ram preventer. See *blowout preventer* and *ram*.

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rat hole *n*: 1. a hole in the rig floor 30 to 35 feet deep, lined with casing that projects above the floor, into which the kelly and swivel are placed when hoisting operations are in progress. 2. a hole of a diameter smaller than the main hole that is drilled in the bottom of the main hole. *v*: to reduce the size of the wellbore and drill ahead.

reeve *v*: to pass (as the end of a rope) through a hole or opening in a block or similar device.

reeve the line *v*: to string wire-rope drill line through the sheaves of the traveling and crown blocks to the hoisting drum.

relative permeability *n*: a measure of the ability of two or more fluids (as water, gas, and oil) to flow through a rock formation when the formation is totally filled with several fluids. The permeability measure of a rock filled with two or more fluids is different from the permeability measure of the same rock filled with only one fluid. Compare *absolute permeability.*

reserve pit *n*: 1. (obsolete) a mud pit in which a supply of drilling fluid was stored. 2. a waste pit, usually excavated, earthen-walled pit. It may be lined with plastic to prevent contamination of the soil.

reservoir *n*: a subsurface, porous, permeable rock body in which oil and/or gas is stored. Most reservoir rocks are limestones, dolomites, sandstones, or a combination of these. The three basic types of hydrocarbon reservoirs are oil, gas, and condensate. An oil reservoir generally contains three fluids - gas, oil, and water - with oil the dominant product. In the typical reservoir, these fluids occur in different phases because of the variance in their gravities. Gas, the lightest, occupies the upper part of the reservoir rocks; water, the lower part; and oil, the intermediate section. In addition to occurring as a cap or in solution, gas may accumulate independently of the oil; if so, the reservoir is called a gas reservoir. Associated with the gas, in most instances, are salt water and some oil. In a condensate reservoir, the hydrocarbons may exist as a gas, but when brought to the surface, some of the heavier ones condense to a liquid or condensate.

reservoir pressure *n*: the pressure in a reservoir under normal conditions.

reverse circulation *n*: the return of drilling fluid through the drill stem. The normal course of drilling fluid circulation is downward through the drill stem and upward through the annular space surrounding the drill stem. For special problems, normal circulation is sometimes reversed, and the fluid returns to the surface through the drill stem, or tubing, after being pumped down the annulus.

rig *n*: the derrick or mast, draw works, and attendant surface equipment of a drilling unit.

rig down *v*: to dismantle the drilling rig and auxiliary equipment following the completion of drilling operations; also called tear down.

rig up *v*: to prepare the drilling rig for making hole; to install tools and machinery before drilling is started.

roller cone bit *n*: a drilling bit made of two, three, or four cones, or cutters, that are mounted on extremely rugged bearings. Also called rock bits. The surface of each cone is made up of rows of steel teeth or rows of tungsten carbide inserts. See *bit*.

rotary bushing *n*: also called master bushing. See *master bushing*.

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rotary drilling *n*: a drilling method in which a hole is drilled by a rotating bit to which downward force is applied. The bit is fastened to and rotated by the drill stem, which also provides a passageway through which the drilling fluid is circulated. Additional joints of drill pipe are added as drilling progresses.

rotary helper *n*: a worker on a drilling rig, subordinate to the driller, sometimes called a roughneck, floorman, or rig crewman.

rotary hose *n*: a reinforced, flexible tube on a rotary drilling rig that conducts the drilling fluid from the mud pump and standpipe to the swivel and kelly; also called the mud hose or kelly hose. See *kelly*, *mud pump*, *standpipe*, and *swivel*.

rotary table *n*: the principal component of a rotary or rotary machine, used to turn the drill stem and support the drilling assembly. It has a beveled gear arrangement to create the rotational motion and an opening into which bushings are fitted to drive and support the drilling assembly.

roughneck *n*: also called a rotary helper. See *rotary helper*.

round trip *n*: the action of pulling out and subsequently running back into the hole a string of drill pipe or tubing. It is also called tripping.

roustabout *n*: 1. a worker on an offshore rig who handles the equipment and supplies that are sent to the rig from the shore base. The head roustabout is very often the crane operator. 2. a worker who assists the foreman in the general work around a producing oil well, usually on the property of the oil company. 3. a helper on a well-servicing unit.

run in *v*: to go into the hole with tubing, drill pipe, and so forth.

S

samples *n pl*: 1. the well cuttings obtained at designated footage intervals during drilling. From an examination of these cuttings, the geologist determines the type of rock and formation being drilled and estimates oil and gas content. 2. small quantities of well fluids obtained for analysis.

sand *n*: 1. an abrasive material composed of small quartz grains formed from the disintegration of preexisting rocks. Sand consists of particles less than 2 millimeters and greater than $^{1}/_{16}$ of a millimeter in diameter. 2. sandstone.

scratcher *n*: a device fastened to the outside of casing that removes the mud cake from the wall of the hole to condition the hole for cementing. By rotating or moving the casing string up and down as it is being run into the hole, the scratcher, formed of stiff wire, removes the cake so that the cement can bond solidly to the formation.

secondary cementing *n*: any cementing operation after the primary cementing operation. Secondary cementing includes a plug-back job, in which a plug of cement is positioned at a specific point in the well and allowed to set. Wells are plugged to shut off bottom water or to reduce the depth of the well for other reasons. See *primary cementing* and *squeeze cementing*.

seismograph *n*: a device that detects reflections of vibrations in the earth, used in prospecting for probable oil-bearing structures. Vibrations are created by discharging explosives in shallow boreholes, by striking the surface with a heavy blow, or by generating low-frequency sound waves. The type and velocity of the vibrations as recorded by the seismograph indicate the general characteristics of the section of earth through which the vibration pass.

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semi-submersible drilling rig *n*: a floating, offshore drilling structure that has hulls submerged in the water but not resting on the seafloor. Living quarters, storage space, and so forth are assembled on the deck. Semisubmersible rigs are either self-propelled or towed to a drilling site and either anchored or dynamically positioned over the site or both. Semi-submersibles are more stable than drill ships and are used extensively to drill wildcat wells in rough water such as the North Sea. See *dynamic positioning*.

set casing *v*: to run and cement casing at a certain depth in the wellbore. Sometimes, the term "set pipe" is used when referring to setting casing.

settling pit *n*: the mud pit into which mud flows and in which heavy solids are allowed to settle out. Often auxiliary equipment (as de-sanders) must be installed to speed up this process.

shaker *n*: shortened form of shale shaker. See *shale shaker*.

shaker pit *n*: the mud pit adjacent to the shale shaker, usually the first pit into which the mud flows after returning from the hole.

shale *n*: a fine-grained sedimentary rock composed of consolidated silt and clay or mud. Shale is the most frequently occurring sedimentary rock.

shale shaker *n*: a series of trays with sieves that vibrate to remove cuttings from the circulating fluid in rotary drilling operations. The size of the openings in the sieve is carefully selected to match the size of the solids in the drilling fluid and the anticipated size of the cuttings. Also called a shaker.

shaped charge *n*: a relatively small container of high explosive that is loaded into a perforating gun. Upon detonation, the charge releases a small, high-velocity stream of particles (a jet) that penetrates the casing, cement, and formation. See *gun-perforate*.

shear ram *n*: the components in a blowout preventer that cut, or shear, through drill pipe and form a seal against well pressure. Shear rams are used in mobile offshore drilling operations to provide a quick method of moving the rig away from the hole when there is no time to trip the drill stem of the hole.

sheave *n*: (pronounced "shiv") a grooved pulley.

show *n*: the appearance of oil or gas in cuttings, samples, cores, and so forth of drilling mud.

shut down *v*: to stop work temporarily or to stop a machine or operation.

shut-in bottomhole pressure *n*: the pressure at the bottom of a well when the surface valves on the well are completely closed. The pressure caused by fluids that exist in the formation at the bottom of the well.

sidetrack *v*: to drill around broken drill pipe or casing that has become lodged permanently in the hole, using a whipstock, turbo-drill, or other mud motor. See *directional drilling*, *turbo-drill*, and *whipstock*.

sidewall coring *n*: a coring technique in which core samples are obtained from a zone that has already been drilled. A hollow bullet is fired into the formation wall to capture the core and then retrieved on a flexible steel cable. Core samples of this type usually range from $^3/_4$ to $1^3/_{16}$ inches in diameter and from $^3/_4$ to 1 inch in length. This method is especially useful in soft rock areas.

single *n*: a joint of drill pipe. Compare *double*, *thribble*, and *fourable*.

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slips *n pl*: wedge-shaped pieces of metal with teeth or other gripping elements that are used to prevent pipe from slipping down into the hole or to hold pipe in place. Rotary slips fit around the drill pipe and wedge against the master bushing to support the pipe. Power slips are pneumatically or hydraulically actuated devices that allow the crew to dispense with the manual handling of slips when making a connection. Packers and other downhole equipment are secured in position by slips that engage the pipe by action directed at the surface.

slurry *n*: a plastic mixture of cement and water that is pumped into a well to harden; there it supports the casing and provides a seal in the wellbore to prevent migration of underground fluids.

sonic logging *n*: the recording of the time required for a sound wave to travel a specific distance through a formation. Difference in observed travel times is largely caused by variations in porosities of the medium, an important determination. The sonic log, which may be run simultaneously with a spontaneous potential log or a gamma ray log, is useful for correlation and often is used in conjunction with other logging services for substantiation of porosities. It is run in an uncased hole.

spear *n*: a fishing tool used to retrieve pipe lost in a well. The spear is lowered down the hole and into the lost pipe, and when weight, torque, or both are applied to the string to which the spear is attached, the slips in the spear expand and tightly grip the inside of the wall of the lost pipe. Then the string, spear, and lost pipe are pulled to the surface.

specific gravity *n*: the ratio of the weight of a given volume of a substance at a given temperature to the weight of an equal volume of a standard substance at the same temperature. For example, if 1 cubic inch of water at 39°F weighs 1 unit and 1 cubic inch of another solid or liquid at 39°F weighs 0.95 unit, then the specific gravity of the substance is 0.95. In determining the specific gravity of gases, the comparison is made with the standard of air or hydrogen. See *gravity.*

spinning cat-head *n*: a spooling attachment on the makeup cat-head to permit use of a spinning chain to spin up or make up drill pipe. See *spinning chain.*

spinning chain *n*: a Y-shaped chain used to spin up (tighten) one joint of drill pipe to another. In use, one end of the chain is attached to the tongs, another end to the spinning cat-head, and the third end is free. The free end is wrapped around the tool joint, and the cat-head pulls the chain off the joint, causing the to spin (turn) rapidly and tighten up. After the chain is pulled off the joint, the tongs are secured in the same spot, and continued pull on the chain (and thus on the tongs) by the cat-head makes up the joint to final tightness.

spud *v*: to move the drill stem up and down in the hole over a short distance without rotation. Careless execution of this operation creates pressure surges that can cause a formation to break down, which results in lost circulation. See *spud in.*

spud in *v*: to being drilling, to start the hole.

squeeze cementing *n*: the forcing of cement slurry by pressure to specified points in a well to cause seals at the points of squeeze. It is a secondary cementing method that is used to isolate a producing formation, seal off water, repair casing leaks, and so forth. See *cementing.*

stab *v*: to guide the end of a pipe into a coupling or tool joint when making a connection. See *coupling* and *tool joint.*

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stabbing board *n*: a temporary platform erected in the derrick or mast some 20 to 40 feet above the derrick floor. The derrickman or another crew member works on the board while casing is being run in a well. The board may be wooden or fabricated of steel girders floored with anti-skid material and powered electrically to raise or lower it to the desired level. A stabbing board serves the same purpose as a monkey board but is temporary instead of permanent.

stake a well *v*: to locate precisely on the surface of the ground the point at which a well is to be drilled. After exploration techniques have revealed the possibility of the existence of a subsurface hydrocarbon-bearing formation, a certified and registered land surveyor drives a stake into the ground to mark the spot where the well is to be drilled.

stand *n*: the connected joints of pipe racked in the derrick or mast when making a trip. On a rig, the usual stand is 90 feet long (three lengths of pipe screwed together) or a thribble. Compare *double* and *fourble*.

standpipe *n*: a vertical pipe rising along the side of the derrick or mast, which joins the discharge line leading from the mud pump to the rotary hose and through which mud is pumped going into the hole. See *mud pump* and *rotary hose*.

stimulation *n*: any process undertaken to enlarge old channels or create new ones in the producing formation of a well (e.g., acidizing or formation fracturing) See *acidize*.

stratification *n*: the natural layering or lamination characteristic of sediments and sedimentary rocks.

stratigraphic trap *n*: a petroleum trap that occurs when the top of the reservoir bed is terminated by other beds or by a change of porosity or permeability within the reservoir itself. Compare *structural trap*. See *trap*.

string *n*: the entire length of casing, tubing, or drill pipe run into a hole; the casing string. Compare *drill string* and *drill stem*.

string up *v*: to thread the drill line through the sheaves of the crown block and traveling block. One end of the line is secured to the hoisting drum and the other to the derrick substructure. See *sheave*.

structural trap *n*: a petroleum trap that is formed because of deformation (as folding or faulting) of the rock layer that contains petroleum. Compare stratigraphic trap. See *trap*.

stuck pipe *n*: drill pipe, drill collars, casing, or tubing that has inadvertently become immobile in the hole. It may occur when drilling is in progress, when casing is being run in the hole, or when the drill pipe is being hoisted.

sub *n*: a short, threaded piece of pipe used to adapt parts of drill string that cannot otherwise be screwed together because of differences in thread size or design. A sub may also perform a special function. Lifting subs are used with drill collars to provide a shoulder to fit the drill pipe elevators. A kelly saver sub is placed between the drill pipe and kelly to prevent excessive thread wear of the kelly and drill pipe threads. A bent sub is used when drilling a directional hole. Sub is a sort expression for substitute.

submersible drilling rig *n*: an offshore drilling structure with several compartments that are flooded to cause the structure to submerge and rest on the seafloor. Most submersible rigs are used only in shallow water.

substructure *n*: the foundation on which the derrick or mast and usually the draw works sit; contains space for storage and well control equipment.

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suction pit *n*: the mud pit from which mud is picked up by the suction of the mud pumps; also called a sump pit and mud suction pit.

surface casing *n*: also called surface pipe. See *surface pipe*.

surface data logging *n*: the recording of information derived from examination and analysis of formation cuttings made by the bit and mud circulated out of the hole. A portion of the mud is diverted through a gas-detecting device. Cuttings brought up by the mud are examined under ultraviolet light to detect the presence of oil and gas. Surface data logging is often carried out in a portable laboratory set up at the well.

surface pipe *n*: the first string of casing (after the conductor pipe) that is set in a well, varying in length from a few hundred to several thousand feet. Some states require a minimum length to protect freshwater sands. Compare *conductor pipe*.

swivel *n*: a rotary tool that is hung from the rotary hook and traveling block to suspend and permit free rotation of the drill stem. It also provides a connections for the rotary hose and passageway for the flow of drilling fluid into the drill stem.

syncline *n*: a down-warped, trough-shaped configuration of folded, stratified rocks. Compare *anticline*.

T

TD *abbr*: total depth.

thread protector *n*: a device that is screwed onto or into pipe threads to protect the threads from damage when the pipe is not in use. Protectors may be metal or plastic.

thribble *n*: a stand of pipe made up of three joints and handled as a unit. See *stand*. Compare *single*, *double*, and *fourble*.

thribble board *n*: the name used for the working platform of the derrickman, or monkey board, when it is located at a height in the derrick equal to three lengths of pipe joined together. Compare *double board* and *fourble board*. See *monkey board*.

throw the chain *n*: to flip the spinning chain up from a tool joint box so that the chain wraps around the tool joint pin after it is stabbed into the box. The stand or joint of drill pipe is turned or spun by a pull on the spinning chain from the cat-head or draw works.

tight formation *n*: a petroleum- or water-bearing formation of relatively low porosity and permeability. See *porosity* and *permeability*.

tight hole *n*: a well about which information is restricted and passed only to those authorized for security or competitive reasons.

tongs *n pl*: the large wrenches used for turning when making up or breaking out drill pipe, casing, tubing, or other pipe; variously called casing tongs, rotary tongs, and so forth according to the specific use. Power tongs are pneumatically or hydraulically operated tools that serve to spin the pipe up tight and, in some instances, to apply the final makeup torque. See also *chain tongs*.

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tool joint *n*: a heavy coupling element for drill pipe made of special alloy steel. Tool joints have coarse, tapered threads and seating shoulders designed to sustain the weight of the drill stem, withstand the strain of frequent coupling and uncoupling, and provide a leakproof seal. The male section of the joint, or the pin, is attached to one end of a length of drill pipe, and the female section, or box, is attached to the other end. The tool joint may be welded to the end of the pipe or screwed on or both. A hard metal facing is often applied in a band around the outside of the tool joint to enable it to resist abrasion from the walls of the borehole.

tool pusher *n*: an employee of a drilling contractor who is in charge of the entire drilling crew and the drilling rig. Also called a drilling rig foreman, manager, supervisor, or rig superintendent. See *drilling foreman*.

torque *n*: the turning force that is applied to a shaft or other rotary mechanism to cause it to rotate or tend to do so. Torque is measured in foot-pounds, joules, meter-kilograms, and so forth.

torque converter *n*: a connecting device between a prime mover and the machine actuated by it. The elements that pump the fluid in the torque converter automatically increase the output torque of the engine to which the torque is applied, with an increase of load on the output shaft. Torque converters are used extensively on mechanical rigs that have a compound. See *mechanical rig*.

total depth *n*: the maximum depth reached in a well.

tour *n*: (pronounced "tower") an 8- or 12-hour shift worked by a drilling crew or other oil field workers. The most common divisions of tours are daylight, evening, and graveyard, if 8-hour tours are employed.

transmission *n*: the gear or chain arrangement by which power is transmitted from the prime mover to the draw works, mud pump, or rotary table of a drilling rig. See *prime mover*.

trap *n*: layers of buried rock strata that are arranged so that petroleum accumulates in them.

traveling block *n*: an arrangement of pulleys, or sheaves, through which drilling cable is reeved and that moves up and down in the derrick or mast. See *block*, *crown block*, and *sheave*.

tricone bit *n*: a type of bit in which three cone-shaped cutting devices are mounted in such a way that they inter-mesh and rotate together as the bit drills. The bit body may be fitted with nozzles, or jets, through which the drilling fluid is discharged. A one-eyed bit is used in soft formations to drill a deviated hole. See *directional drilling* and *bit*.

trip *n*: the operation of hoisting the drill stem from and returning it to the wellbore. See *make a trip*.

turbo-drill *n*: a drilling tool that rotates a bit attached to it by the action of the drilling mud on the turbine blades built into the tool. When a turbo-drill is used, rotary motion is imparted only at the bit; therefore, it is unnecessary to rotate the drill stem. Although straight holes can be drilled with the tool, it is used most often in directional drilling.

U

unit operator *n*: the oil company in charge of development and producing in an oil field in which several companies have joined together to produce the field.

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V

valve *n*: a device used to control the rate of flow in a line, to open or shut off a line completely, or to serve as an automatic or semiautomatic safety device. Those with extensive usage include the gate valve, plug valve, globe valve, needle valve, check valve, and pressure relief valve. See *check valve*, *needle valve* and *pressure relief valve*.

V-belt *n*: a belt with a trapezoidal cross-section that is made to run in sheaves or pulleys, with grooves of corresponding shape. See *belt*.

vug *n*: a cavity in a rock.

W

waiting on cement *adj*: pertaining to or during the time when drilling or completion operations are suspended so the cement in a well can harden sufficiently.

wall cake *n*: also called filter cake and mud cake. See *filter cake and mud cake*.

weevil *n*: shortened form of boll weevil. See *boll weevil*.

weight indicator *n*: an instrument near the driller's position on a drilling rig. It shows both the weight of the drill stem that is hanging from the hook (hook load) and the weight that is placed on the bit by the drill collars (weight on bit).

weighting material *n*: a material that has high specific gravity and is used to increase the density of drilling fluids or cement slurries.

wellbore *n*: a borehole; the hole drilled by the bit. A wellbore may have casing in it or may be open (i.e., uncased), or a portion of it may be cased and a portion of it may be open. Also called borehole or hole. See *cased* and *open*.

well completion *n*: the activities and methods necessary to prepare a well for the production of oil and gas; the method by which a flow line for hydrocarbons is established between the reservoir and the surface. The method of well completion used by the operator depends on the individual characteristics of the producing formation or formations. These techniques include open-hole completions, sand exclusion completions, tubingless completions, multiple completions, and miniaturized completions.

wellhead *n*: the equipment installed at the surface of the wellbore. A wellhead includes such equipment as the casing head and tubing head. *adj* pertaining to the wellhead (as wellhead pressure).

well logging *n*: the recording of information about subsurface geologic formations. Logging methods include records kept by the driller, mud and cutting analyses, core analysis, drill stem tests, and electric and radioactivity procedures. See *electric well log*, *mud logging*, *radioactivity well logging*, and *sonic logging*.

well stimulation *n*: any of several operations used to increase the production of a well. See *acidize* and *formation fracturing*.

whipstock *n*: a long, steel casing that uses an inclined plane to cause the bit to deflect from the original borehole at a slight angle. Whipstocks are sometimes used in controlled directional drilling, to straighten crooked boreholes, and to sidetrack to avoid unretrieved fish. See *directional drilling*, *fish*, and *sidetrack*.

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wildcat *n*: 1. a well drilled in an area where no oil or gas production exists. With present-day exploration methods and equipment, about one wildcat out of every nine proves to be productive although not necessary profitable. 2. (nautical) a geared sheave of a windlass used to pull anchor chain. *v*: to drill wildcat wells.

wireline *n*: a slender, rodlike or threadlike piece of metal, usually small in diameter, this is used for lowering special tools (such as logging sondes, perforating guns, and so forth) into the well. Compare *wire rope*.

wire rope *n*: a cable composed of steel wires twisted around a central core of hemp or other fiber to create a rope of great strength and considerable flexibly. Wire rope is used as drill line (in rotary and cable-tool rigs), coring line, servicing line, winch line, and so on. It is often called cable or wireline; however, wireline is a single, slender metal rod, usually very flexible. Compare *wireline*.

WOC *abbr*: waiting on cement.

worm *n*: a new and inexperienced worker on a drilling rig.

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