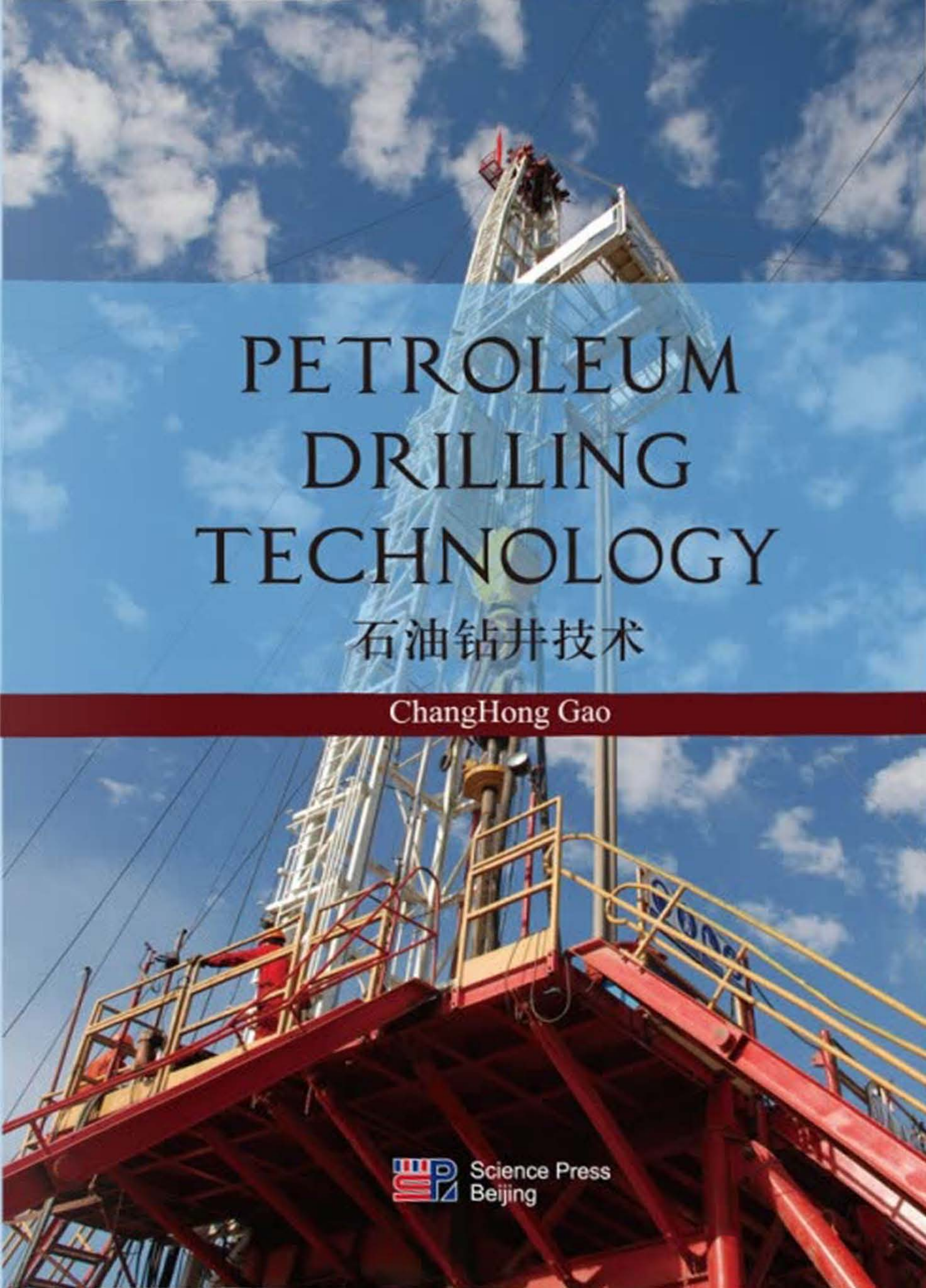

PETROLEUM DRILLING TECHNOLOGY

石油钻井技术

ChangHong Gao

Science Press
Beijing

Petroleum Drilling Technology

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Preface

After some years of experiences in university and industry, the author realizes the need for a precise and concise guide book for drilling engineers and university students.

This book covers the most important aspects of petroleum drilling technology. Chapter 1 introduces the components of rotary drilling system and top drive system. Chapter 2 discusses properties of drilling fluid and flow of drilling mud. Chapter 3 presents casing design method. Chapter 4 talks about the deviation tools and trajectory design for directional drilling. Chapter 5 introduces the mud hydraulics concepts and optimization process. Chapter 6 introduces underbalanced drilling method, followed by cementing and perforating operations in Chapter 7. Chapter 8 discusses the common problems encountered during drilling operations. Finally, Chapter 9 presents basic properties of oil, gas and rock.

After reading this book, the readers gain valuable knowledge in modern drilling technology in the most concise and straightforward manner, without struggling through tedious and excessive descriptions. A few illustrative examples are included to make theories easy to understand. This book serves as a textbook for students studying petroleum engineering, as well as a reference book for engineers in drilling industry.

The Author is grateful for the financial support from Shandong province government through the prestigious Taishan Scholar program. Dongying city government also provided financial support through Yellow River Delta Scholar program.

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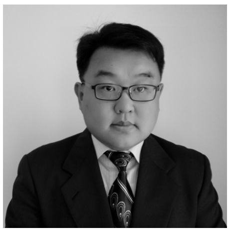
About the Author



Changhong Gao received his degrees in petroleum engineering from China University of Petroleum, University of Tulsa and Curtin University. He worked for Sinopec as a field engineer and research engineer. He also taught at United Arab Emirates University, University of Aberdeen and Petroleum Institute of Abu Dhabi.

In 2013, he was elected Taishan Scholar by Shandong province government, as well as Yellow River Delta Scholar by Dongying city government. His teaching and research interests include drilling mud, production system design and enhanced oil recovery. He has published more than 30 journal papers and presented a few papers at SPE and APPEA conferences.

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Chapter 1　Drilling systems

A traditional rotary drilling rig is shown in Fig. 1-1. The rig consists of hoisting system, rotary system and mud circulation system.

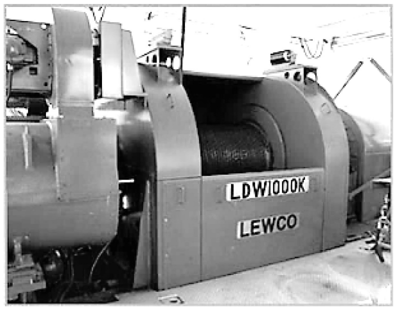
Fig. 1-1　Rotary drilling rig

1.1　Hoisting system

Function of hoisting system is to raise and lower drill string during drilling operation. It consists of derrick and other components.

1.1.1　Draw-works and wire rope

The lifting and lowering of drill string is achieved by spooling wire rope (also named drill line) onto the drum inside the draw-works, as shown in Fig. 1-2. It also contains necessary clutches and gears to control speed and brake. The drill line on the same side as the draw-works is named fastline. The other side of drill line in anchored, which is named deadline. The wire rope needs to be cut periodically to avoid wear.



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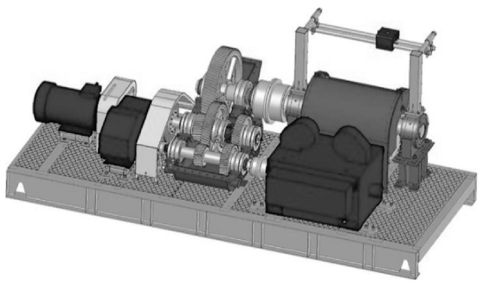

(b)

Fig. 1-2　Draw-works

1.1.2　Crown block and traveling block

Crown block is seated on top of drilling rig, while traveling block moves up and down during drilling operations, to raise or lower drill string. Both blocks contain several sheaves for drill line to go through. Crown block, traveling block and drill line form a typical block and tackle system, while the feeding of drill line is controlled by draw-works. This system effectively reduces load on drill line. Typical crown block and traveling block are presented in Fig. 1-3 and Fig. 1-4.

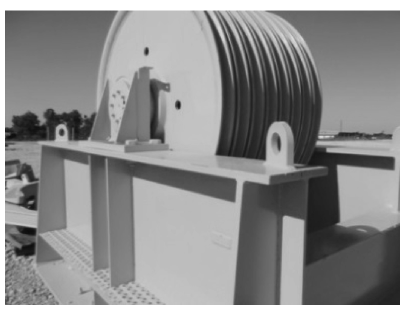

Fig. 1-3　Crown block

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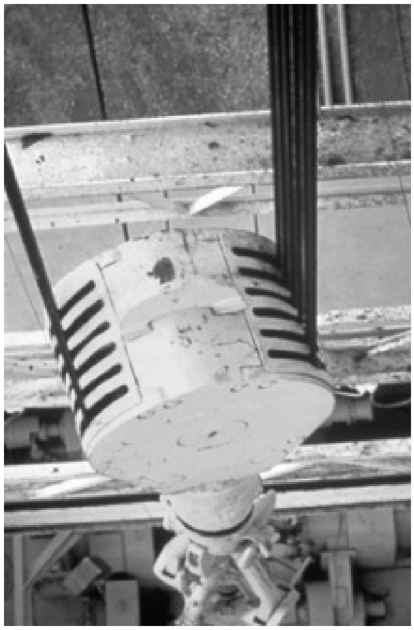


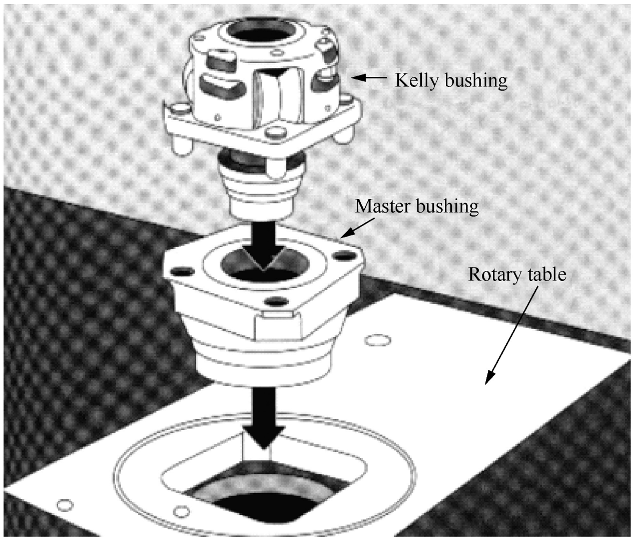
Fig. 1-4 Traveling block

1.2 Rotary system

The function of rotary system is to generate rotation to rotate the drill string. Power is supplied to a series of gearing under the rotary table. Then rotation is transmitted to the revolving section of the drill floor that provides power to turn the drill string. This section introduces the common components of drill string.

1.2.1 Kelly and kelly bushing

Kelly is a square or hexagon shaped pipe that fits into kelly bushing in the rig's rotary table. The main function of a kelly is to transfer energy from the rotary table to the rest of the drill string. Kelly bushing is an adapter that serves to connect the rotary table to the kelly. The kelly bushing has an inside diameter profile that matches that of the kelly. It is connected to the rotary table by four large steel pins that fit into mating holes in the rotary table, as seen in Fig. 1-5. The rotary motion and power are transmitted through the kelly bushing and the kelly to the drill string. As the rotary table turns, kelly turns with it.



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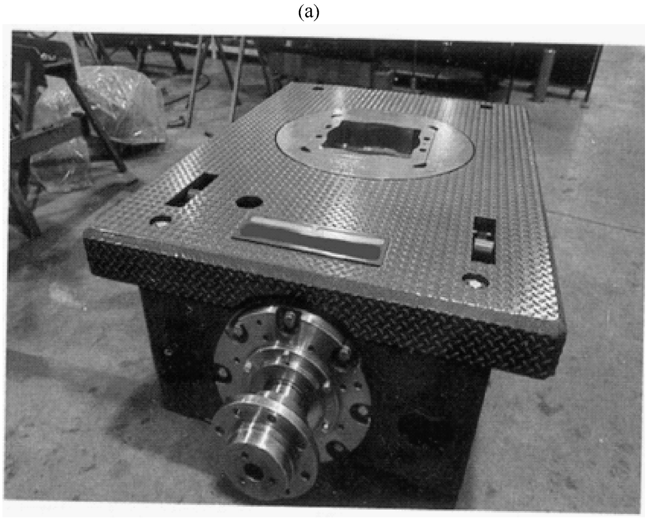

(b)

Fig. 1-5　Rotary table

1.2.2　Swivel

Swivel serves two important functions: (1) it allows free rotation of kelly connected below; (2) it is also the pathway for drilling mud to enter the kelly and the drill string below. The rotation is achieved by the bearing inside swivel. Drilling mud enters the swivel through goose neck and the rotary hose connected to it, as seen in Fig. 1-6.

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Fig. 1-6　Swivel

1.2.3　Drill pipe and drill collar

When drilling extends to deeper strata, we need to add more drill pipes to reach the desired depth. Drill pipes are ordinary steel pipes with male and female threads at the ends, therefore，they can be connected to each other with a tong (Fig. 1-7). This operation is to make a connection.

Each pipe is around 9~10 meters in length, while the derrick is around 30 meters tall. During drilling, a rotary rig can only drill single drill pipe respectively. But when the drill pipes have to be pulled from the well (namely make a trip), for instance to change worn drill bit, we can pull 3 drill pipes at one time. This saves valuable time. Common drill pipe dimensions are given in the appendixC.

Fig. 1-7　Drill pipe connection

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Drill collars are thick walled steel pipes. Its unit mass is much higher than a drill pipe. Collars apply extra weight on drill bit, which aids bit to break rock more effectively. It also helps drill string remain in tension, thus drill string maintains a straight line while drilling. Common drill collar dimensions are given in the appendixB.

1.2.4 Drill bits

Drill bit is at the bottom of the drill string. It breaks rock into small cuttings, and drilling fluid (commonly mud) carries cuttings to surface. There are two common types of bits, fixed cutter bit and rolling cutter bit.

(1) Rolling cutter bit is also named three cone bit or tricone bit, as seen in Fig. 1-8. As the name indicates, it is equipped with three rolling cones. Cutters made of tungsten carbide are inserted into the cone body. During drilling, not only the bit body rotates on its main axis, the three cones also rotate on their own axis. A tricone bit works like a hammer. The cutters eat into the rocks and fracture the rocks. The bit comes with 3 nozzles for mud to come through.

Fig. 1-8 Roller cone bit

(2) Fixed cutter bit is also named PDC bit: Polycrystalline diamond compact bit. As the name indicates, it has no moving parts. Its cutters are made of artificial diamond polycrystalline. As we know, diamond is the hardest material and it cuts rocks easily. A PDC bit works like a chisel. The cutters shear the rocks off layer by layer. PDC bits are much more expensive than tricone bits, but they are suitable for drilling hard

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formations. They also last longer than tricone bits, thus reducing the frequency of trips. This is especially important for offshore drilling, where the rent for drillship is expensive. Therefore, PDC bits have become dominant in drilling market.

PDC cutters are made up of a working component, the diamond table and a supporting component called the substrate, as shown in Fig. 1-9. Substrates are comp-

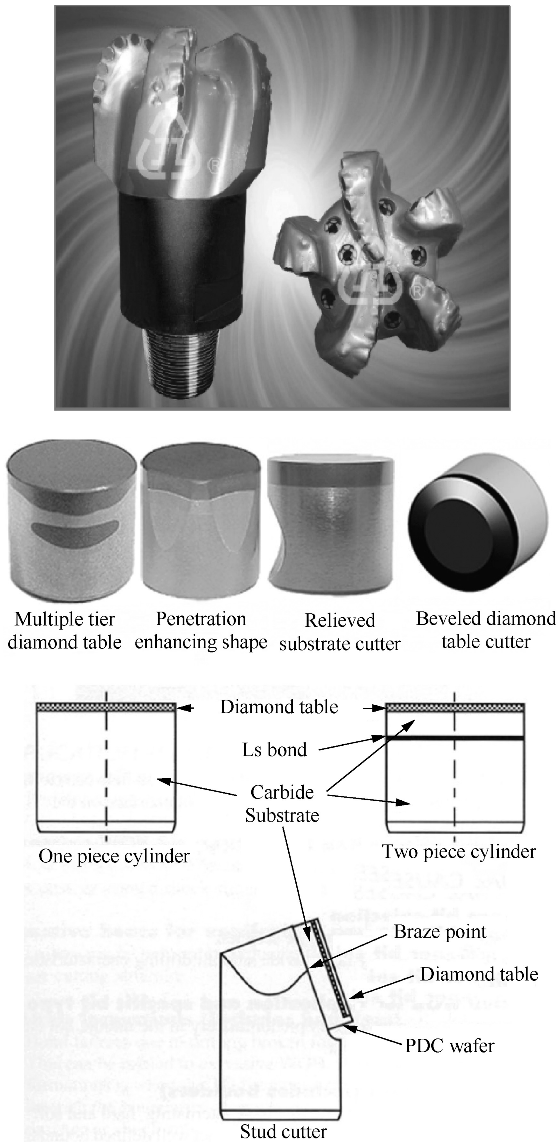

Fig. 1-9 PDC bit and cutters

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osite material made from tungsten carbide grains bonded by metallic binder. This material bonds efficiently with diamond table, but is very hard and prevents erosive damage to a working cutter.

Different configurations work well on different formations, so a number of different drill bits may be inserted and used on one well. Additionally, drill bits have to be changed due to wear and tear. Drilling engineers choose the drill bits according to the type of formations encountered, whether or not directional drilling is required, for specific temperatures, and if well logging is being done.

When a drill bit has to be changed, the drill pipe (typically in 30-feet increments) is hoisted out of the well, until the complete drill string has been removed from the well. Once the drill bit has been changed, the complete drill string is again lowered into the well.

1.2.5 Other accessories on drill string

During drilling, drill pipe can get stuck due to several reasons. A jar is required to free stuck pipe when upward or downward movement is necessary to free the pipe. Today, there are two primary types, hydraulic and mechanical jars. While their respective designs are quite different, their operations are similar. Energy is stored in the drill string and suddenly released by the jar when it fires. Jars can be designed to strike up, down or both.

Reamer, as shown in Fig.1-10, is often run behind bit to maintain a gauge hole when drilling through hard formations. Reamer contains 3 to 6 cutters made of tungsten carbide. Stabilizers (Fig. 1-11) are placed along the drill string to centralize the drill string, provide extra stiffness to the bottom hole assembly (BHA), and control devia-

Fig. 1-10 Reamer

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tion. Shock sub is placed between collar and bit to absorb the shock and vibration caused by movement of drill string, thus prolong the life of bit. After introducing the components on drill string, the complete drill string is presented in Fig. 1-12.

Fig. 1-11　Stabilizer

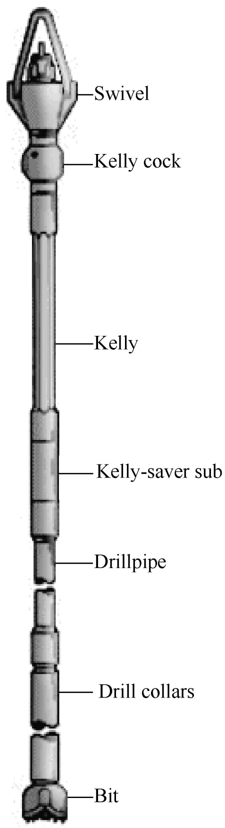

Fig. 1-12　The complete drill string

1.3 Mud circulation system

Drilling fluid is circulated during drilling. Commonly used drilling fluid is mud, a mixture of water, clay, chemicals and weight materials. Details of mud will be introduced in chapter 2.

Circulation of drilling mud is vital in drilling operations. ①When bit cuts rocks, a lot of heat is generated due to friction. Mud cools the bit and string. ②Mud also carries cuttings to surface, so the bit can reach fresh rock surface, rather than grinds cuttings into smaller pieces. ③When drilling through high-pressure formation, the mud hydrostatic pressure overbalances formation pressure, so that the formation fluid will not enter the well. A kick refers to the scenario when formation fluid begins to enter the well. If not properly controlled, the kick may develop into a blowout accident. A rig must be equipped with blowout preventer (BOP) to control the well.

The circulation of mud is presented in Fig.1-13. Mud starts from mud pump, then travels through standpipe, rotary hose, swivel, kelly, drill pipes, drill collars and drill bit. Mud flows through the nozzles at bottom of bit, then travels upward into the annulus. Mud passes blowout preventer, reaches surface through mud return line, and goes through series of conditioning equipment including shale shaker, desander and desilter. Mud, free of cuttings and debris, returns to mud pits and is ready for another circulation.

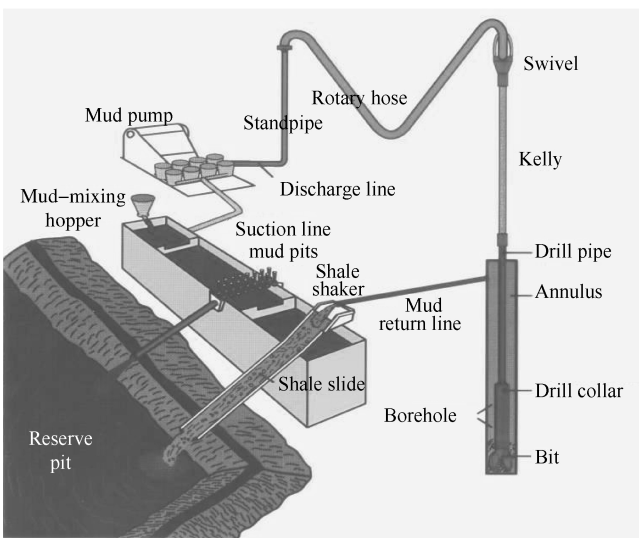

Fig. 1-13 Mud circulation

A mud pump is a reciprocating piston/plunger device designed to circulate drilling fluid under high pressure up to 7500 psi (or 52000 kPa) down the drill string and back up the annulus.

A pump with double-action strokes in two cylinders is called duplex pump. A pump with single-action strokes in three cylinders is called triplex pump (Fig. 1-14). Triplex pumps are lighter and more compact than duplex pumps. Their output pressure are more stable, and they are cheaper to operate. For these reasons, the majority of pumps in operation are of the triplex design. Normally, duplex pumps can handle higher flow rates, and triplex pumps can provide higher working pressure.

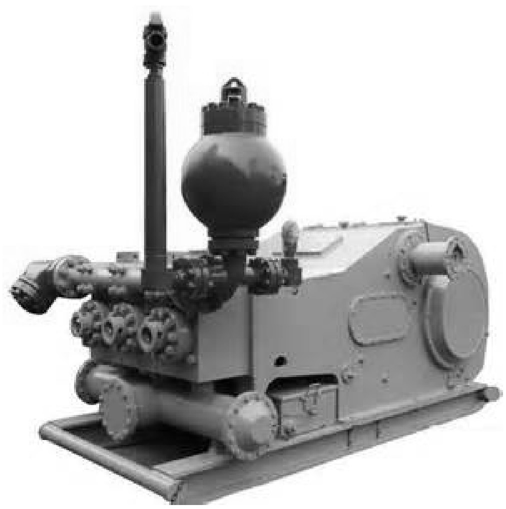

Fig. 1-14 A triplex mud pump with pulsation dampener

However, for a given pump of fixed horsepower, the flow rate and working pressure can be adjusted by changing the sizes of the liners inside the pump. Changing the speed of the prime mover can also affect the mud flow rate in a certain range.

A pulsation dampener is often installed on mud pump, as seen in Fig. 1-14. It contains a gas chamber in the upper portion, which is separated from mud by a flexible diaphragm. The device greatly dampens the pressure surges developed by the positive displacement pump.

Normally, we need at least two mud pumps on site. One is for pumping mud, the other is for backup. When mud circulates, obviously it has to lift cuttings and overcome pressure loss. This aspect will be discussed in chapter 2 and chapter 5.

Mud pits are required to hold excessive mud at the surface. A mud pit is a large tank

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that holds drilling fluid on the rig or at a mud-mixing plant. For land rigs, most mud pits are rectangular steel construction, with partitions that hold about 200 barrels each. They are set in series for the active mud system. On most offshore rigs, pits are constructed into the drilling vessel and are larger, holding up to 1000 barrels.

Earthen mud pits were the earliest type of mud pit, but environmental protection concern has led to less frequent use of open pits in the ground. Today, earthen pits are used only to store used or waste mud and cuttings prior to disposal.

1.4 Solid control equipment

After mud returns to surface, it carries cuttings that must be removed by shale shaker, desander and desilter, before returning to mud pump.

1.4.1 Shale shaker

Shake shakers remove relatively large cuttings from mud. The most important components on a shale shaker are screen mesh, screen basket and vibrator. A shale shaker is shown in Fig. 1-15.

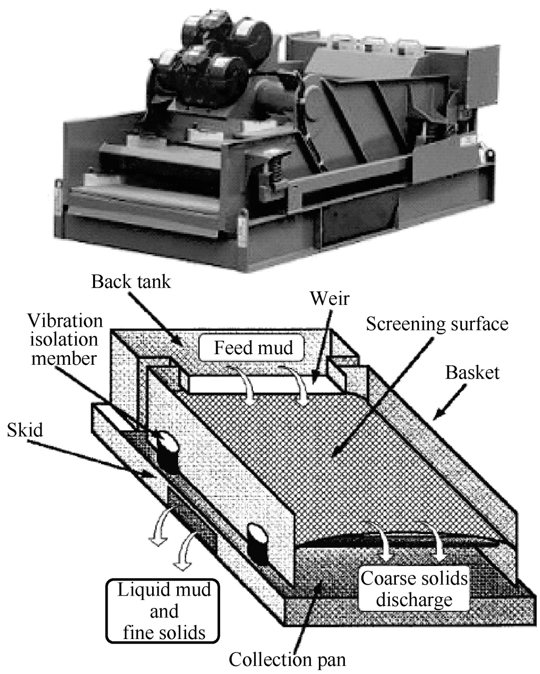

Fig. 1-15 Shale shaker

Just like threads are woven together to create cloth, metal wire can be woven to create metal cloth. Screen mesh is very thin yet strong cloth designed to maximize screen life and conductance. Manufacturers build their screens with multiple layers of mesh over a very sturdy backing cloth to further protect the cloth against solids loading and wear. The multiple layers of mesh pushes out near sized particles, which may get stuck in the openings, and clog/blind the mesh.

Screen basket, also named screen bed, is responsible for transferring the shaking intensity of the machine, while keeping the shaking motion even throughout the entire basket. It must do all that while holding the screens securely in place, eliminating drilled solids bypass to the hopper and allowing for easy operation and maintenance.

Vibrator applies the vibratory force and motion to the shaker bed. A vibrator is a specialized motor built for the purpose of vibrating. It contains an electric motor to provide the rotary motion. It also employs a set of eccentric weights to provide an omnidirectional force. To produce the proper linear motion, a counter-rotating vibrator is added in parallel to the first.

1.4.2 Desander and desilter

Desander and desilter are solid control equipment with a set of hydrocyclone that separate sand and silt from the drilling fluids. Desanders are installed on the top of the mud tank following the shale shaker and the degasser, but before the desilter. These devices are shown in Fig. 1-16.

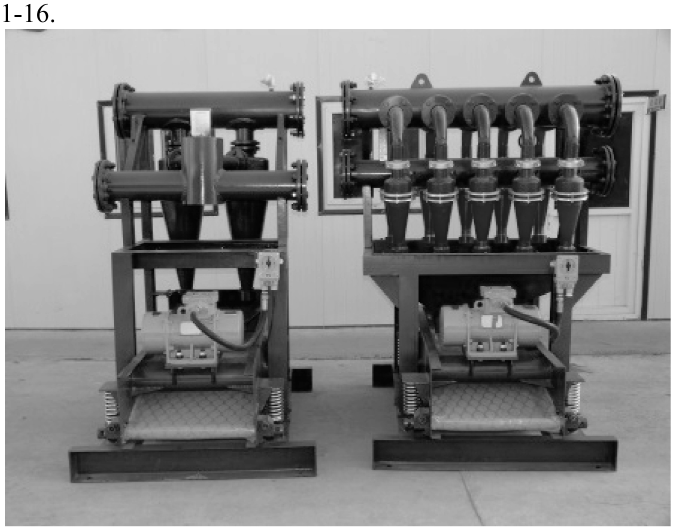

Fig. 1-16 Desander (left) and desilter

Desander removes the abrasive solids from the drilling fluids which cannot be removed by shakers. Normally desander separates particles of 45~74μm, and 15~44μm for desilter. Their structures are given in Fig. 1-17 and Fig. 1-18. A centrifugal pump is used to pump the drilling fluids from mud tank into the set of hydrocyclones.

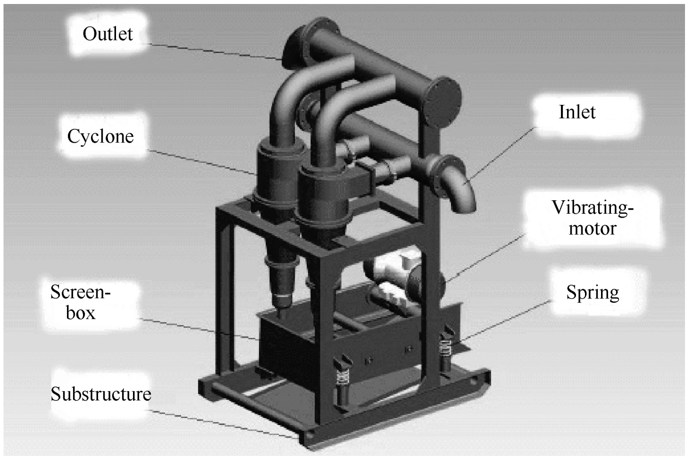

Fig. 1-17 Structure of desander

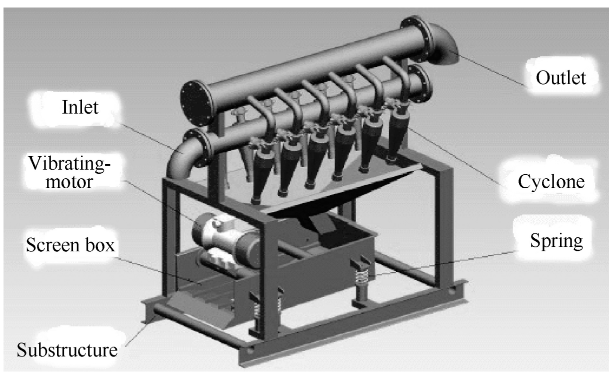

Fig. 1-18 Structure of desilter

After mud enters hydrocyclone, it forms a strong swirl due to the shape of hydrocyclone. The heavy particles spin to the inner wall and fall downward to underflow, while the mud flows upward to overflow, as seen in Fig. 1-19.

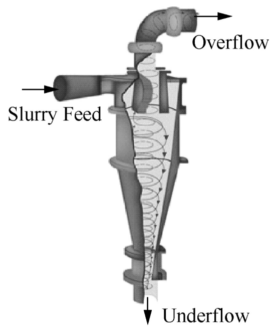

Fig. 1-19 Hydrocyclone

Desanders have no moving parts. The larger the internal diameter of the desander is, the greater the amount of drilling fluids it is able to process and the larger the size of the solids removed. Desanders are preceded by shale shaker and a vacuum degasser. Desanders are widely used in oilfield drilling. Practices have proved that hydrocyclone desanders are economic and effective equipment.

1.5 Well control equipment

Blowout preventer (BOP) is a stack of valves that close the well when a kick is detected. BOP is seated in the cellar under the rotary table. There are four types of BOP.

(1) An annular BOP closes the annulus around any shape of drill pipe, such as the drill string, the casing or the non-cylindrical object, such as the kelly. Drill pipe including a larger-diameter tool joints (threaded connectors) can be "stripped" (i.e. moved vertically while pressure is contained below) through an annular preventer by careful control of the hydraulic closing pressure. Annular preventers are available for working pressures of 2000, 5000, and 10000 psig①.

Annular BOP are also effective at maintaining a seal around the drill pipe even as it rotates during drilling. Regulations typically require that an annular preventer be able to completely close a wellbore, but annular preventers are generally not as effective as ram preventers in maintaining a seal on an open hole. Annular BOP is typically located at the top of a BOP stack, with one or two annular preventers positioned above a series of several ram preventers.

Ram preventers are equipped with two packing elements on opposite sides that close by moving towards each other. Ram type preventers include pipe ram, blind ram

① psig refers to gadge pressure,1 psig=6.895kpa+atmospheric pressure.

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and shear ram. A double ram BOP is shown in Fig. 1-20. Ram preventers are available for working pressures of 2000, 5000, 10000, and 15000 psig.

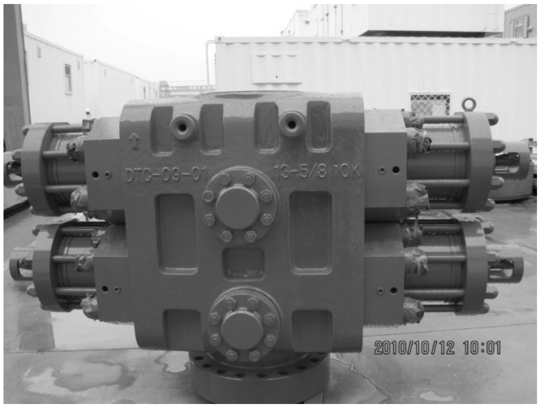

Fig. 1-20　Double ram BOP

(2) Pipe ram is also to seal off the annulus around pipe, but not obstruct flow within the drill pipe. Pipe rams have semicircular openings which match the diameter of pipe sizes for which they are designed. However, variable-bore pipe rams can accommodate tubing in a wider range of outside diameters than standard pipe rams, but typically with some loss of pressure capacity and longevity. Pipe ram should not be closed if there is no pipe in the hole.

(3) Blind ram closes the well when no drill pipe or casing is present in the well. If a pipe exits in the well and the blind ram is closed, the pipe will be flattened but the flow can not be stopped.

(4) Shear ram is able to cut through the drill pipe and seal the well completely. The upper portion of the severed drill string is freed from the ram, while the lower portion may be dropped in the well. Shear rams are activated when all pipe rams and annular preventers have failed.

Both annular preventers and ram preventers are closed hydraulically with high pressure fluid accumulators. They are storage devices for nitrogen-pressurized hydraulic fluid, which is used in operating the blowout preventers. The accumulator is able to supply sufficient high-pressure fluid to close all of the units in the BOP stack at least once and still has a reserve. For safety, accumulator pumps rely on a electricity source independent from the rig power. Therefore, the BOP stack can still be closed even at rig power loss.

The accumulator is equipped with a pressure-regulating system. It is thus able to

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vary the closing pressure on the preventers when stripping (lower pipe with the preventer closed). Usually, the hydraulic closing pressure during stripping is reduced until there is slight leakage of well fluid.

Stripping is easily done with annular preventers. When well pressure is too high for annular preventers, upper and lower pipe rams spaced far apart are opened and closed alternately as the tool joints are lowered through. Kill line and chock line are installed between pipe rams. Kill line allows heavy fluid to be pumped into annulus, while choke line allows fluids to be released from annulus.

The BOP stack is attached to the casing with casing head. The casing head is welded to the first casing string. It provides support and seal for subsequent casing strings. After all components have been introduced, the complete rotary drilling system is shown in Fig.1-21.

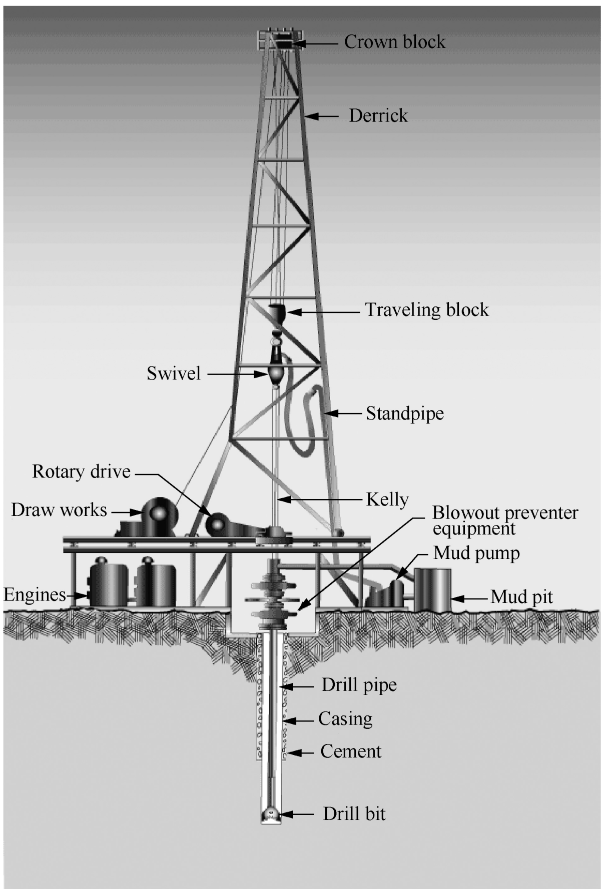

Fig. 1-21 Complete rotary drilling system

1.6 Efficiency of hoisting system

The hoisting system for rotary rig is equivalent to the block-tackle in Fig. 1-22. The system efficiency is compromised due to friction. The more ropes strung through the sheaves, the lower system efficiency is.

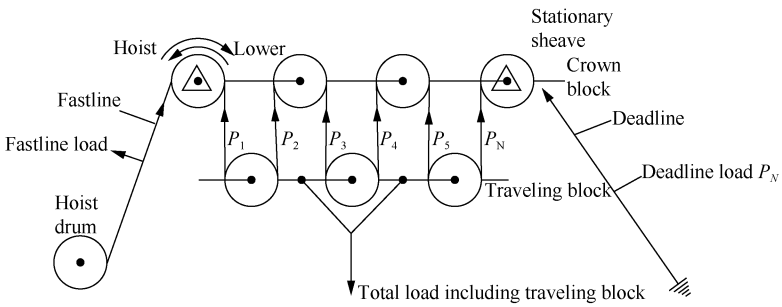

Fig. 1-22 Hoisting system

The following parameters are defined: FL is fastline load; P_N is deadline load; N is number of lines; EF is block-tackle efficiency factor; K is efficiency per sheave; P_s is line load if friction is ignored.

Now start form the Fastline. After the rope goes through the first sheave, the pull is reduced by friction. Therefore,

$$P_1 = \mathrm{FL}K$$

Similarly,

$$P_2 = P_1K = \mathrm{FL}K^2$$

$$P_3 = P_2K = \mathrm{FL}K^3;\ \text{and}\ P_N = \mathrm{FL}K^N$$

For the total weight,

$$W = P_1 + P_2 + P_3 + \cdots + P_N = \mathrm{FL}(K + K^2 + K^3 + \cdots + K^N);$$

$$\text{while}\quad K + K^2 + K^3 + \cdots + K^N = \frac{K(1-K^N)}{1-K},$$

Therefore,

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$$W = \mathrm{FL}\frac{K(1-K^N)}{1-K} \text{ and } \mathrm{FL}=\frac{W(1-K)}{K(1-K^N)}$$

If friction is ignored,

$$\mathrm{FL} = P_1 = P_2 = P_3 = P_N$$

and, $W = NP_s$ hence, $P_s = W/N$

Therefore,

$$\mathrm{EF} = P_s/\mathrm{FL} = \frac{K(1-K^N)}{N(1-K)}$$

Assume K=0.9615, then EF can be calculated for different N. Based on the results in Table 1-1, we understand why we use 8 or 10 lines.

Table 1-1 Effect of number of drill lines on efficiency

Number of lines	EF
6	0.874
8	0.842
10	0.811
12	0.782

Next we will carry out some easy volume calculations.

Example 1-1: Calculation of volume capacity of drill pipe

The drilling data and related information are given below. In oil and gas industry, we often use both metric units and field units. The conversion factors are given in appendixA.

Hole depth = 10000 ft (3048 m)

Bit size = 8.5 in (216mm)

Drill pipe size = 5 in OD/4.3 in ID (127mm OD/109mm ID)

Drill pipe mass per unit length = 19.5 lb/ft (29.02 kg/m)

Collar length = 1000 ft (305m)

Collar size = 8 in OD/3 in ID (203mm OD/76mm ID)

Collar mass per unit length = 150 lb/ft (223 kg/m)

Mud density = 75 pcf[①] (1200 kg/m^3)

① pcf=1b/ft^3.

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Steel density = 490 pcf (7849 kg/m^3)

Weight of hook and traveling block = 24000 lb (10890kg)

Number of lines through traveling block = 10

Block and tackle efficiency factor = 0.81

Efficiency factor per sheave = 0.9615.

1) Calculate the volume capacity of drill pipes and drill collars.

(1)Solution in field units :

Length of drill pipe = 10000 ft – 1000 ft = 9000 ft ;

Area of drill pipe = $0.25\pi \times ID^2 = 0.25 \times \pi \times (4.3\text{in})^2 = 14.5\ \text{in}^2 = 0.101\ \text{ft}^2$;

Volume of drill pipe = Length × Area = $9000 \times 0.101 = 909\ (\text{ft}^3)$.

(2)Solution in metric units:

Length of drill pipe = 3048 m – 305 m = 2743 m

Area of drill pipe = $0.25\pi ID^2 = 0.25 \times \pi \times (109\text{mm})^2 = 9369\ \text{mm}^2$

Volume = length × area = $2743 \times 9369 = 25.7\ \text{m}^3$

With similar approach, volume of collar = 49.1ft^3 = 1.39 m^3.

2) Calculate the volume capacity of annulus.

Volume of annulus between wellbore and drill collar $= 305\text{m} \times 0.25 \times \pi \times [(216\text{mm})^2 - (203\text{mm})^2] = 1.305\text{m}^3 = 46.08\text{ft}^3$

Volume of annulus between wellbore and drill pipe $= 2743\text{m} \times 0.25 \times \pi \times [(216\text{mm})^2 - (127\text{mm})^2] = 65.77\ \text{m}^3 = 2322\ \text{ft}^3$

Total volume of annulus is the summation of above two volumes.

3) Calculate weight of drill string in mud and in air :

Mass of drill pipe in air = 19.5 lb/ft × 9000 ft = 175500 lb = 79610 kg ;

Mass of collar in air = 150 lb/ft × 1000 ft = 150000 lb = 68040 kg ;

Total weight in air = 325500 lb = 147650 kg ;

Total weight in mud = 325500 lb (1–75/490) = 275678 lb = 125000 kg.

(4) Calculate deadline load and fast line load :

Hook load = 275678 lb + 24000 lb = 299678 lb ;

If friction is ignored under static condition,

FL_s = static fastline load = Hook load/N = 299678lb/10 = 29968lb ;

Under dynamic condition,

FL_d = dynamic fastline load = FL_s/EF = 29968 lb/0.81 = 36997 lb

DL_d = dynamic deadline load = $FL_d \times 0.9615^{10}$ = 24980 (lb)

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1.7 Top drive system

Now we understand how the traditional rotary drilling system works. In recent years, the more advanced top drive drilling system has gained more popularity, especially in directional drilling and offshore drilling. It is briefly introduced here.

Top drives are the drilling machines that hang below, and travel with, the traveling block and rotate drill pipe from the top of the string, as opposed to using rotary table and kelly. The top drive connects to the top of the drill string, providing rotational torque to the string while simultaneously supplying drilling fluids and supporting the string.

The drilling torque produced by the top drive motor is reacted through guide beam or guide rails and transmitted into substructure. The pipe handler is connected directly underneath the top drive transmission. This pipe handler is remotely controlled by the driller to make up or disconnect drill pipes without manual intervention. The top drive motor is presented in Fig. 1-23.

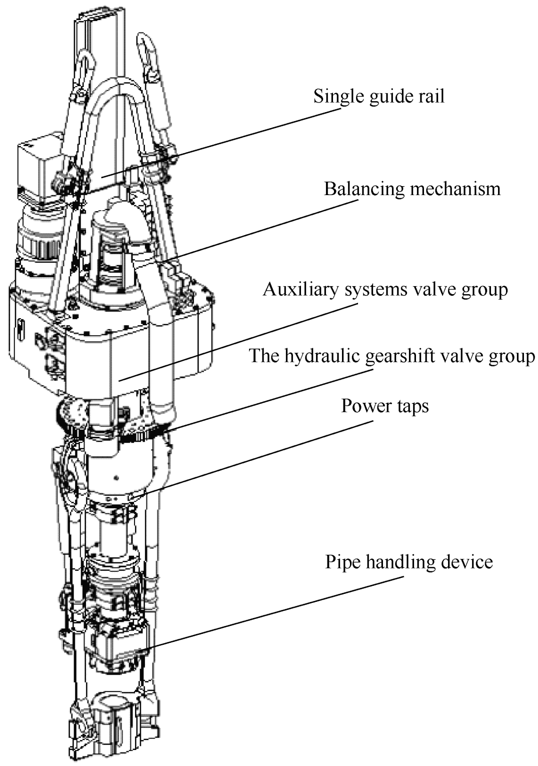

Fig. 1-23 Top drive motor

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Rotary rig only drills one pipe joint at one time, but for the top drive, greater benefit is achieved by drilling with triple pipes as one stand. With the drill pipe being supported and rotated from the top, an entire stand of drill pipe can be drilled down at one time. Compared to kelly drilling, where a connection is made after drilling down a single joint of pipe, top drive drilling results in faster drilling by eliminating every two out of three connections. Top drive is easier to operate than rotary drilling system. Drillers and rig crews usually become comfortable with top drives in a matter of hours.

The top drive drilling system is recognized as one of the most significant advancements in drilling technology since the introduction of the rotary table. When compared to conventional rotary drilling rigs, those equipped with top drive systems drill faster and safer, with far less instances of stuck drill pipe.

Reducing risk and increasing safety during the drilling process, top drives remove much of the manual labor that was previously required to drill wells. Many times, top drives are completely automated, offering rotational control and maximum torque, as well as control over the weight on the bit.

Top drives can be used in all environments and on all types of rigs, from truck-mounted units to the largest offshore rig. Although top drives can be used on both onshore and offshore rigs, there are some differences between the two. For example, on an offshore rig, the top drive travels up and down the vertical rails to avoid the mechanism from swaying with the waves of the ocean.

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Chapter 2　Drilling mud

Drilling fluid plays a very important role in successful drilling operations. Drilling fluid, despite their different compositions, serve the following purposes. ① Cool and lubricate drill bit and drill string. ② Transport cuttings to surface. ③ Control formation pressure. ④ Drilling mud forms a layer of mud cake on rock surface, thus reducing filtrate and the risk of caving in.

2.1　Types of drilling fluid

There are three types of drilling mud: ① water-based mud; ② oil-based mud; ③ synthetic-based mud. Some wells use air or foam as drilling fluid. Such type of drilling fluid will be introduced in Chapter 6. Water-based mud is the most common drilling fluid, because it is relatively inexpensive and easy to handle.

2.1.1　Water-based mud (WBM)

WBM contains : ① water as the continuous phase; ② clay (often bentonite clay) to produce initial viscosity; ③ weighting agent (often barite) to increase mud density in necessary; ④ chemicals to adjust mud properties.

The layered structure of bentonite clay allows water to enter the space between the layers. As such, clay expands significantly in water and generates high viscosity and yield point. This property helps mud to suspend and transport cuttings. Barite, which is barium sulphate ($BaSO_4$) in nature, has a specific gravity of 4.2 and is used to increase mud density above 1.2kg/L. Barite is the most common weight material for mud because of its low cost and high purity.

WBM requires various chemical additives to adjust its properties. ① Mud thickeners are added to mud to boost its viscosity. Common mud thickeners include CMC (carboxymethyl cellulose), HEC (hydroxyethyl cellulose), Xanthan and chemical ly modified starch. ② Mud thinners are added to mud to reduce mud viscosity when mud is too viscous. Common mud thinners are lignosulphonate and certain surfactants. ③ When drilling through shale zone, the low-salinity mud contacts shale and causes shale to swell. Thus wellbore may cave in and cause stuck pipe. Shale inhibitors are added to battle shale instability. Alternatively, oil-based mud can effectively inhibit shale swelling.

2.1.2 Oil-based mud (OBM)

For OBM, a petroleum product such as diesel fuel serves as the base fluid. OBM has some advantages, including increased lubricity, enhanced shale inhibition and greater cleaning abilities with less viscosity. OBM also withstands greater heat without breaking down.

The use of OBM has special limitations. Its cost is higher than WBM. Cuttings have to be treated carefully before disposal because it contains diesel, which has negative impact on environment. If OBM is used as drill in fluid, the diesel in OBM may interfere with oil shows, also may contaminate reservoir oil sample. It may be a good solution to use OBM for drilling through shale zone, and change to WBM afterwards.

2.1.3 Synthetic-based mud (SBM)

SBM is also known as low toxicity oil based mud. SBM employs synthetic oil as the base fluid. SBM is most often used on offshore rigs because it has the properties of an oil-based mud, but the toxicity of the fluid fumes are much less than OBM. This is important when men work with the fluid in an enclosed space such as offshore drilling rig. Synthetic-based fluid poses the same environmental and analysis problems as oil-based fluid.

2.2 Mud density calculations

Mud density is often named mud weight in oil industry. According to the formation pressure encountered, mud density needs to be adjusted from time to time. To increase mud density, weight materials such as barite are often mixed into mud. To decrease mud density, water or diesel is added to original mud. The mud density calculations simply follow two balance rules.

$$\text{Mass Balance: } M_1 + M_2 = M_3 \text{ or, } \rho_1 V_1 + \rho_2 V_2 = \rho_3 V_3 \tag{2-1}$$

$$\text{Volume Balance: } V_1 + V_2 = V_3 \tag{2-2}$$

where, M_1 is mass of original mud; V_1 is volume of original mud; ρ_1 is density of

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original mud. And M_2, V_2, ρ_2 refer to the mass, volume and density of added material, respectively. Similarly, M_3, V_3, ρ_3 are parameters for final mud, respectively. The units of mass, volume and density have to be consistent.

Example 2-1: Calculation for mud density increases

Mud with volume of 1000 bbl[①] contains 8% clay by weight/mass. Clay density is 2.5kg/L. Barite is to be added to the mud to increase mud density to 1.2 kg/L. Calculate the final volume (bbl) of mud and the mass (kg) of barite required. Hint: This question involves two steps. First, clay is added to water to produce original mud. Second, barite is added to mud to increase mud density. We need to calculate the density of original mud :

$$\rho_1 = \frac{\text{mass of water} + \text{mass of clay}}{\text{volume of water} + \text{volume of clay}} \tag{2-3}$$

We assume 100kg of mud. It contains 8kg clay and 92 kg water.

$$\rho_1 = \frac{100\text{kg}}{\dfrac{92\text{kg}}{1.0\text{kg/L}} + \dfrac{8\text{kg}}{2.5\text{kg/L}}} = 1.05\text{kg/L}$$

Apply mass balance and volume balance as follows:

$$\rho_1 V_1 + \rho_2 V_2 = \rho_3 V_3$$

$$V_1 + V_2 = V_3$$

Volumes of water and clay are unknown. Other parameters are also given. The above equations become:

$$1.05\text{kg/L} \times 1000\text{bbl} + 4.2\text{kg/L} \times V_2 = 1.2\text{kg/L} \times V_3$$

$$1000\text{bbl} + V_2 = V_3$$

We have 2 equations with 2 unknowns. Solve these two equations and get

Volume of barite added, $V_2 = 111.11$ bbl,

Volume of final mud, $V_3 = 1111.11$ bbl.

Mass of barite added = volume of barite × density of barite

① Bbl=barrel, 1bbl=158.9873L.

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$$= 111.11\text{bbl} \times 159\text{L/bbl} \times 4.2\text{kg/L} = 44170\text{kg}$$

Example 2-2: Calculation for mud density decreases

A mud has volume of 1000m^3 and density of 1.2 kg/L. Water is to be added to the mud to reduce mud density to 1.1 kg/L. Calculate the mass (kg) of water required.

Apply the two balance rules as follows. Unit conversion is not necessary as long as the conversion factor is cancelled from both sides :

$$1.2\ \text{kg/L} \times 1000\ \text{m}^3 + 1.0\ \text{kg/L} \times V_2 = 1.1\ \text{kg/L} \times V_3$$

$$1000\text{m}^3 + V_2 = V_3$$

$$V_2 = 333.33\ \text{m}^3$$

2.3 Basics of Newtonian and non-Newtonian fluid

Some basic concepts of Newtonian and non-Newtonian fluids are introduced here. Newtonian fluid exhibits linear relationship between shear stress and shear strain. For Newtonian fluid, viscosity is only influenced by change in pressure and temperature.

$$\tau = \mu\gamma \tag{2-4}$$

where, τ is shear stress; γ is shear strain; μ is viscosity.

The unit for viscosity is poise or centipoise (cP).

$$1\ \text{poise} = 100\text{cP} = 1\text{g/(cm} \cdot \text{s)}$$

$$1\text{cP} = 0.001\ \text{kg/m} \cdot \text{s} = 6.719 \times 10^{-4}\ \text{lbm/(ft} \cdot \text{s)}$$

Fluid flow pattern can be laminar or turbulent, according to fluid Reynolds number. Fluid Reynolds number is defined as:

$$Re = \frac{\rho v D}{\mu} \tag{2-5}$$

where, Re is fluid Reynolds number, dimensionless; ρ is fluid density , kg/m^3; v is fluid velocity , m/s; D is pipe inner diameter , m; μ is viscosity , kg/(m • s).

Flow is laminar when Re is less than 2000. Flow is regarded as turbulent if Re goes above 3000. This criterion may be different from book to book. Some books use Re of 2200 as the boundary. Here 3000 is regarded as the criterion.

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It is often not convenient to use the units in Eq. (2-5a) and Eq. (2-5b). When using the common metric units and field units in Table 2-1, *Re* is expressed as Eq. (2-5a) and (2-5b), respectively.

Table 2-1　Common units for *Re*

Parameter	Symbol	Metric units	Field Units
Fluid Density	ρ	kg/L	lb/gal
Fluid Velocity	v	m/s	Ft/min
Pipe Diameter	D	mm	in
Viscosity	μ	cP	cP

$$Re = 1000\frac{\rho v D}{\mu} \tag{2-5a}$$

$$Re = 15.46\frac{\rho v D}{\mu} \tag{2-5b}$$

For non-Newtonian fluids, the relationship between shear stress (τ) and shear strain (γ) is no longer linear. Therefore, the viscosity is not constant. The examples include drilling mud, cement, mayonnaise, tomato ketchup and tooth paste. Three types of non-Newtonian fluids are recognized: Bingham plastic fluid, power law fluid and time-dependent fluid.

For Bingham plastic fluid, deformation occurs after a minimum value of shear stress is exceeded. This value is referred to as the yield stress or yield point (YP). Beyond YP, the relationship between shear stress and strain is linear, with a constant viscosity known as plastic viscosity (PV). The Eq. (2-6) stands for Bingham plastic fluid:

$$\tau = \mathrm{YP} + \mathrm{PV}\gamma = \mathrm{YP} - \mathrm{PV}\frac{\mathrm{d}v}{\mathrm{d}r} \tag{2-6}$$

PV and YP are affected by pressure and temperature. These parameters are measured with mud viscometer. Mud measurements will be introduced later.

For power law fluid, the relationship is expressed with the Eq. (2-7):

$$\tau = k\gamma^{n} \tag{2-7}$$

where, k is consistency index; n is flow behavior index.The value n is an indication of non-Newtonian behavior, and high value of k indicates the thickness of fluid is high. Behaviors of various fluids are plotted in Fig. 2-1. Non-Newtonian fluid is a very complex topic, therefore the discussions on Herschel-Bulkley fluid and time-dependent fluid are not included here.

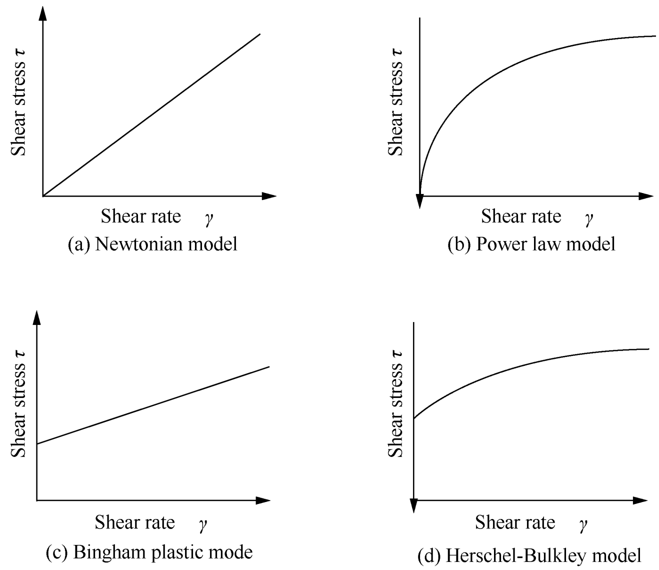

Fig. 2-1 Behaviors of Newtonian and non-Newtonian fluids

2.4 Laminar flow of bingham plastic fluid in pipe

During steady-state flow of fluid in a pipe, the differential pressure causes fluid to flow at constant velocity. The differential pressure acting on pipe end area balances the shear force acting on surface of inner wall, as seen in Fig. 2-2. Equilibrium between the forces is established:

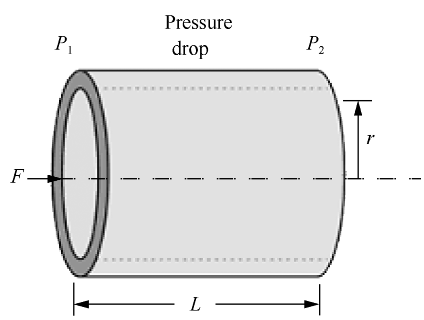

Fig. 2-2 Pressure loss in pipe flow

$$(P_1 - P_2)\pi r^2 = 2\tau\ \pi r L$$

where, P_1 is pressure upstream pipe; P_2 is pressure downstream pipe; r is radius of pipe; τ is shear stress at pipe wall; L is length of pipe.

Or,

$$\tau = \frac{\Delta P r}{2L} \tag{2-8}$$

At the pipe wall,

$$r = \frac{D}{2} \text{ and } \tau_w = \frac{\Delta P D}{4L}$$

Recall that,

$$\tau = \mathrm{YP} + \mathrm{PV}\left(\frac{-\mathrm{d}v}{\mathrm{d}y}\right) = \frac{\Delta P r}{2L} \tag{2-9}$$

Integrate with respect to r yields,

$$\begin{aligned} &\int \frac{\Delta P r}{2L}\mathrm{d}r = \int \mathrm{YPd}r - \int \mathrm{PV}\frac{\mathrm{d}v}{\mathrm{d}r}\mathrm{d}r \\ &\frac{\Delta P}{2L}\frac{r^2}{2} = \mathrm{YP}r - \mathrm{PV}\,v + C \end{aligned} \tag{2-10}$$

At pipe wall, r=R and v=0, we can find:

$$C = \frac{\Delta P R^2}{4L} - \mathrm{YP}R \tag{2-11}$$

Eq. (2-10) transforms into:

$$\frac{\Delta P}{4L}r^2 = \mathrm{YP}r - \mathrm{PV}\,v + \left(\frac{\Delta P R^2}{4L} - \mathrm{YP}R\right) \tag{2-12}$$

The velocity profile can be found as:

$$v = \frac{\Delta P}{4L\mathrm{PV}}(R^2 - r^2) + \frac{\mathrm{YP}}{\mathrm{PV}}(r - R) \tag{2-13}$$

Now integrate velocity to obtain expression of flow rate, as flow rate is used more conveniently.

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$$
\begin{aligned}
Q &= \int_0^R 2v\pi r\mathrm{d}r \\
&= 2\pi\int_0^R \left[\frac{\varDelta P}{4L\mathrm{PV}}(R^2 - r^2) + \frac{\mathrm{YP}}{\mathrm{PV}}(r - R)\right] r\mathrm{d}r \\
&= 2\pi\left[\frac{\Delta P}{4L\mathrm{PV}}\left(R^2\frac{r^2}{2} - \frac{r^4}{4}\right) + \frac{\mathrm{YP}}{\mathrm{PV}}\left(\frac{r^3}{3} - \frac{r^2 R}{2}\right)\right]_0^R \\
&= 2\pi\left[\frac{\Delta P}{4L\mathrm{PV}}\left(\frac{R^4}{2} - \frac{R^4}{4}\right) + \frac{\mathrm{YP}}{\mathrm{PV}}\left(\frac{R^3}{3} - \frac{R^3}{2}\right)\right] \\
&= \frac{\pi\Delta P}{8L\mathrm{PV}}R^4 - \frac{\pi\mathrm{YP}}{3\mathrm{PV}}R^3
\end{aligned}
$$

And the expression of average velocity is given as:

$$
\bar{v} = \frac{Q}{A} = \frac{\dfrac{\pi\Delta PR^4}{8L\mathrm{PV}} - \dfrac{\pi\mathrm{YP}R^3}{3\mathrm{PV}}}{\pi R^2} = \frac{\Delta PR^2}{8L\mathrm{PV}} - \frac{\mathrm{YP}R}{3\mathrm{PV}} \tag{2-14}
$$

Rearrange Eq. (2-14) to obtain expression of pressure loss in pipe flow:

$$
\Delta P = \frac{8L\mathrm{PV}\bar{v}}{R^2} + \frac{8L\mathrm{YP}}{3R} \tag{2-15}
$$

Table 2-2　Field units and metric units

Parameter	Symbol	Field Units	Metric units
Fluid Density	ρ	lb/gal	kg/L
Fluid Velocity	v	ft/min	m/s
Pipe Length	L	foot	meter
Pipe Diameter	D	in	mm
Plastic Viscosity	PV	cP	cP
Yield Point	YP	lb/100ft^2	lb/100ft^2

When using the field units given in Table 2-2, Eq. (2-15) is converted to:

$$
\Delta P = \frac{L\mathrm{PV}\bar{v}}{90000D^2} + \frac{L\mathrm{YP}}{225D} \tag{2-16}
$$

When using the metric units given in Table 2-2, Eq. (2-15) is converted to:

$$
\Delta P = \frac{32L\mathrm{PV}\bar{v}}{D^2} + \frac{2.554L\mathrm{YP}}{D} \tag{2-17}
$$

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Now we assume a Newtonian fluid with effective viscosity (μ_{e}) flows in the same pipe and causes the same pressure loss. For a Newtonian fluid, YP is zero, and pressure loss expressed with Eq. (2-17) becomes:

$$\Delta P = \frac{32000 L \mu_{\mathrm{e}} \bar{v}}{D^2}$$

The Newtonian fluid and non-Newtonian fluid produces the same pressure loss, therefore the relationship below is valid:

$$\frac{32000 L \mu_{\mathrm{e}} \bar{v}}{D^2} = \frac{32000 L \mathrm{PV} \bar{v}}{D^2} + \frac{2554 L \mathrm{YP}}{D}$$

The effective viscosity is expressed as:

$$\mu_{\mathrm{e}} = \mathrm{PV} + \frac{2554}{32000} \frac{D}{\bar{v}} \mathrm{YP} \tag{2-18}$$

Recall the expression of *Re*. Flow becomes turbulent when *Re* exceeds 3000. We define the velocity when flow becomes turbulent as the critical velocity (v_{c}).

$$Re = \frac{\rho v_{\mathrm{c}} D}{\mu_{\mathrm{e}}} = \frac{\rho v_{\mathrm{c}} D}{\mathrm{PV} + \dfrac{2554}{32000} \dfrac{D}{v_{\mathrm{c}}} \mathrm{YP}} = 3000 \tag{2-19}$$

Rearrange Eq. (2-19) to obtain:

$$\frac{1}{3} \rho D v_{\mathrm{c}}^2 - \mathrm{PV} v_{\mathrm{c}} - 0.08 D \mathrm{YP} = 0 \tag{2-20}$$

Solve Eq. (2-20) for critical velocity:

$$\begin{aligned} v_{\mathrm{c}} &= \frac{\mathrm{PV} + \sqrt{\mathrm{PV}^2 + 4\left(\dfrac{\rho D}{3}\right) 0.08 D \mathrm{YP}}}{\dfrac{2}{3} \rho D} \\ &= 1.5 \frac{\mathrm{PV} + \sqrt{\mathrm{PV}^2 + 0.1 \rho D^2 \mathrm{YP}}}{\rho D} \end{aligned} \tag{2-21}$$

With field units, the critical velocity is expressed as:

$$v_{\mathrm{c}} = \frac{97 \mathrm{PV} + 97 \sqrt{\mathrm{PV}^2 + 8.2 \rho D^2 \mathrm{YP}}}{\rho D} \tag{2-22}$$

Example 2-3: Pressure loss in drill pipe

You are provided with drilling data as follows. ① Determine if flow is laminar or turbulent. ② Calculate pressure gradient (pressure loss per meter).

$$\text{Mud YP} = 10\ \text{lb/100ft}^2$$

$$\text{Mud PV} = 15\ \text{cP}$$

$$\text{Mud density} = 1.2\ \text{kg/L}\ (10\ \text{lb/gal})$$

$$\text{Drill pipe ID} = 114\ \text{mm}\ (4.5\ \text{in})$$

$$\text{Flow rate} = 0.01\ \text{m}^3/\text{s}\ (21.2\ \text{ft}^3/\text{min})$$

(1) We need to calculate mud velocity and compare with critical velocity :

Pipe cross sectional area $A_p = 0.25\pi D^2 = 0.25\times3.14\times(0.114\ \text{m})^2 = 0.01\ \text{m}^2$

Mud velocity $v = Q/A_p = 0.01/0.01 = 1(\text{m/s})$

Critical velocity $v_c = 1.54$ m/s

If we use field units,

Pipe cross sectional area $A_p = 0.25\pi D^2 = 0.25\times3.14\times(4.5\text{in})^2 = 15.9\ \text{in}^2$

Mud velocity $v = Q/A_p = 21.2\times144/15.9 = 192$ ft/min, where 144 is conversion factor.

With Eq. (2-22), critical velocity is 312 ft/min. Mud velocity is less than critical velocity, therefore flow is laminar flow.

(2) Calculate pressure loss with Eq. (2-17) :

$\text{D}P/\text{D}L$=261 Pa/m=0.012 psi/ft

2.5 Laminar flow of Bingham plastic fluid in annulus

We can approximately treat flow in annulus as flow between two parallel plates, as shown in Fig. 2-3. The plate has length of L, width of E, and the vertical distance between plates is W.

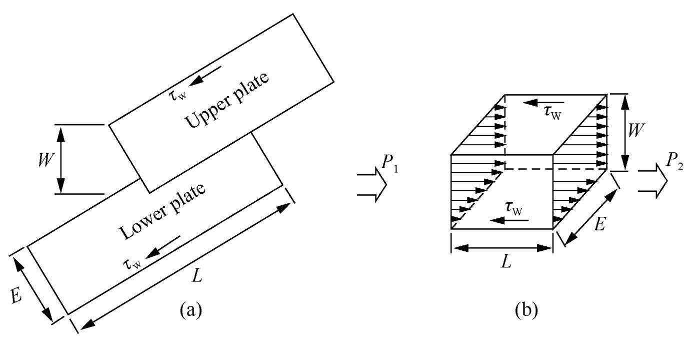

Fig. 2-3 Fluid flow between parallel plates

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$$\Delta PWE = 2\tau_{\mathrm{w}} LE \tag{2-23}$$

$$\tau_{\mathrm{w}} = \frac{\Delta PW}{2L} \tag{2-24}$$

Assume W=2Y, then

$$\tau_{\mathrm{w}} = \frac{\Delta P2Y}{2L} = \frac{\Delta PY}{L} \tag{2-25}$$

At any distance y from the center, Eq. (2-25) may be modified to give shear stress at any point:

$$\tau = \frac{\Delta Py}{L} \tag{2-26}$$

Now recall the shear stress for Bingham plastic fluid,

$$\tau = \mathrm{YP} + \mathrm{PV}\left(\frac{-\mathrm{d}v}{\mathrm{d}y}\right) \tag{2-27}$$

Combining Eq. (2-26) and Eq. (2-27), we get

$$\frac{\Delta Py}{L} = \mathrm{YP} - \mathrm{PV}\left(\frac{\mathrm{d}v}{\mathrm{d}y}\right) \tag{2-28}$$

Integrate with respect to Y,

$$\begin{gathered} \int \frac{\Delta P}{L} y\mathrm{d}y = \int \mathrm{YPd}y - \int \mathrm{PVd}v \\ \left(\frac{\Delta P}{L}\right)\frac{y^2}{2} = \mathrm{YP}y - \mathrm{PV}v + C \end{gathered} \tag{2-29}$$

At the wall ($y = Y$), velocity is zero. We can solve for the constant :

$$C = \left(\frac{\Delta P}{2L}\right)Y^2 - \mathrm{YP}Y \tag{2-30}$$

$$v = \frac{\Delta P}{2L\mathrm{PV}}(Y^2 - y^2) + \frac{\mathrm{YP}}{\mathrm{PV}}(y - Y) \tag{2-31}$$

We want to express with flow rate, rather than velocity. Now we integrate velocity to obtain expression of flow rate.

Note that,

$$dQ=v dA=2vE dy$$

$$\begin{aligned}Q &= \int_0^Y \left[\frac{\Delta P}{2L\mathrm{PV}}(Y^2-y^2)+\frac{\mathrm{YP}}{\mathrm{PV}}(y-Y)\right]2E\,\mathrm{d}y \\ &= \left[\frac{\Delta P}{2L\mathrm{PV}}(Y^2y-\frac{y^3}{3})+\frac{\mathrm{YP}}{\mathrm{PV}}\left(\frac{y^2}{2}-yY\right)\right]_0^Y 2E \\ &= \left[\frac{\Delta P}{2L\mathrm{PV}}\left(Y^3-\frac{Y^3}{3}\right)+\frac{\mathrm{YP}}{\mathrm{PV}}\left(\frac{Y^2}{2}-Y^2\right)\right]2E \\ &= \left[\frac{\Delta P}{L\mathrm{PV}}\left(\frac{2}{3}Y^3\right)-\frac{\mathrm{YP}}{\mathrm{PV}}Y^2\right]E\end{aligned}$$

And the average velocity is expressed as:

$$\overline{v}=\frac{Q}{A}=\frac{\left(\frac{2\Delta P}{3L\mathrm{PV}}Y^3-\frac{\mathrm{YP}}{\mathrm{PV}}Y^2\right)E}{2YE}=\frac{\Delta PY^2}{3L\mathrm{PV}}-\frac{\mathrm{YP}Y}{2\mathrm{PV}} \tag{2-32}$$

Now, considering the annulus, Let D_{h} be the diameter of outer hole, and D_{p} be the outer diameter of inner pipe.

$$Y=\frac{W}{2}=\frac{1}{2}\left(\frac{D_{\mathrm{h}}-D_{\mathrm{p}}}{2}\right)=\left(\frac{D_{\mathrm{h}}-D_{\mathrm{p}}}{4}\right) \tag{2-33}$$

Rearrange to obtain expression of pressure loss :

$$\Delta P=\frac{48L\mathrm{PV}\overline{v}}{(D_{\mathrm{h}}-D_{\mathrm{p}})^2}+\frac{6L\mathrm{YP}}{(D_{\mathrm{h}}-D_{\mathrm{p}})} \tag{2-34}$$

Pressure loss can be converted to field units or metric units given in Table 2-2.

$$\Delta P=\frac{L\mathrm{PV}\overline{v}}{60000(D_{\mathrm{h}}-D_{\mathrm{p}})^2}+\frac{L\mathrm{YP}}{200(D_{\mathrm{h}}-D_{\mathrm{p}})} \tag{2-35}$$

$$\Delta P=\frac{48L\mathrm{PV}\overline{v}}{(D_{\mathrm{h}}-D_{\mathrm{p}})^2}+\frac{2.874L\mathrm{YP}}{(D_{\mathrm{h}}-D_{\mathrm{p}})} \tag{2-36}$$

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To determine laminar flow or turbulent flow, we need to find critical velocity with similar approach.

$$\frac{48L\mu_{\mathrm{e}}\overline{v}}{(D_{\mathrm{h}}-D_{\mathrm{p}})^2}=\frac{48L\mathrm{PV}\overline{v}}{(D_{\mathrm{h}}-D_{\mathrm{p}})^2}+\frac{2.874L\mathrm{YP}}{(D_{\mathrm{h}}-D_{\mathrm{p}})}$$

$$\mu_{\mathrm{e}}=\mathrm{PV}+\frac{2.874}{48}\frac{D_{\mathrm{e}}\mathrm{YP}}{\overline{v}}$$

where, $D_{\mathrm{e}} = D_{\mathrm{h}} - D_{\mathrm{p}}$.

Input effective viscosity into *Re* and regard 3000 as the boundary of laminar flow.

$$3000=1000\frac{\rho v_{\mathrm{c}}D_{\mathrm{e}}}{\mathrm{PV}+\dfrac{2.874}{48}\dfrac{D_{\mathrm{e}}\mathrm{YP}}{v_{\mathrm{c}}}}$$

Solve the equation to find critical velocity.

$$v_{\mathrm{c}}=1.5\left(\frac{\mathrm{PV}+\sqrt{\mathrm{PV}^2+0.08\rho D_{\mathrm{e}}^2\mathrm{YP}}}{\rho D_{\mathrm{e}}}\right) \tag{2-37}$$

And in field units, critical velocity is expressed as:

$$v_{\mathrm{c}}=\frac{97\mathrm{PV}+97\sqrt{PV^2+6.2\rho D_{\mathrm{e}}^2\mathrm{YP}}}{\rho D_{\mathrm{e}}} \tag{2-38}$$

Example 2-4: Pressure loss in annulus

You are provided with drilling data as follows : ① Determine if flow is laminar or turbulent ; ② Calculate pressure gradient (pressure loss per meter).

Mud YP = 10 lb/100ft^2

Mud PV = 15 cP

Mud density = 10 lb/gal (1.2 kg/L)

Drill pipe OD = 5.5 in (140 mm)

Flow rate = 21.2 ft^3/min (0.01 m^3/s)

Bit size = 10 in (250mm)

(1) We need to calculate mud velocity in annulus and compare it with critical velocity. If we use field units, the annulus cross sectional area is:

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$$A_n=0.25\pi(D_h^2-D_p^2)=0.25\times 3.14\times[(10\text{in})^2-(4.5\text{in})^2]=48.3\ \text{in}^2$$

Mud velocity is:

$v=Q/A_n=21.2\times 144/48.3=63.2$ ft/min, where, 144 is a conversion factor.

Calculate critical velocity with Eq. (2-38), $v_c = 276$ ft/min. Flow is laminar.

(2) Calculate pressure loss with Eq. (2-35), $\mathrm{D}P/\mathrm{D}L = 0.012$ psi/ft

2.6 Turbulent flow of mud in annulus

Turbulent flow in annulus may cause erosion of wellbore. Therefore, it is recommended to maintain laminar flow in annulus. But if turbulent flow does occur, the Eq. (2-39) and Eq. (2-40) are used to calculate the pressure loss in annulus.

$$\Delta P = 5546.78\frac{\rho^{0.8}Q^{1.8}\mathrm{PV}^{0.2}L}{(D_h - D_p)^3(D_h + D_p)^{1.8}} \tag{2-39}$$

$$\Delta P = 8.91\times 10^{-5}\frac{\rho^{0.8}Q^{1.8}\mathrm{PV}^{0.2}L}{(D_h - D_p)^3(D_h + D_p)^{1.8}} \tag{2-40}$$

2.7 Flow through nozzles

Significant pressure loss occurs when mud flows through nozzles on drilling bit. We can use the Eq. (2-41) to calculate pressure loss across nozzles, where density is expressed in lbm/gal, and mud velocity is expressed in ft/s.

$$\Delta P = \frac{\rho v_n^2}{1113} \tag{2-41}$$

When density is expressed in kg/L and velocity in m/s, the Eq. (2-41) transforms into:

$$\Delta P = 0.555\rho v_n^2 \tag{2-42}$$

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2.8 Mud measurements

Mud properties must be monitored carefully during drilling operations. Failure to control mud properties may lead to disastrous outcomes. This section discusses the methods to measure and monitor mud properties.

2.8.1 Mud density

At drilling site, mud density (also called mud weight) is roughly measured with mud balance, as shown in Fig. 2-4. Mud is poured in the small cup. Then adjust the rider until the bubble in the level glass stays in the middle. You can find the mud density from reading on the arm.

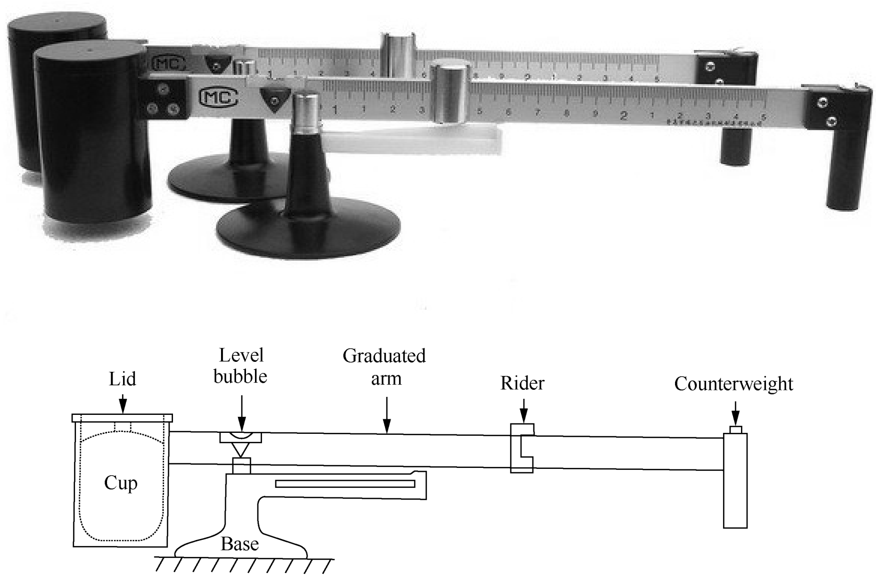

Fig. 2-4 Mud balance

2.8.2 Mud viscosity

Mud viscosity is measured with mud viscometer, as seen in Fig. 2-5. It is a basic torque-type viscometer. Sleeve and bob are immersed in the mud that fills the cup. The sleeve, driven by the motor, rotates at varied speeds. The resulting torque drives the bob to deflect to a certain extent. The speed of rotation is controlled at 3, 6, 30, 60, 100,

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200, 300, 600 r/min. The deflection is observed from the small window on top.

The mud plastic viscosity and yield point can be easily calculated with the readings at 300 and 600 r/min.

$$PV = \theta_{600} - \theta_{300}$$

$$YP = \theta_{300} - PV$$

Where, θ_{600} refers to the viscometer reading at 600 r/min, while θ_{300} is the reading at 300r/min.

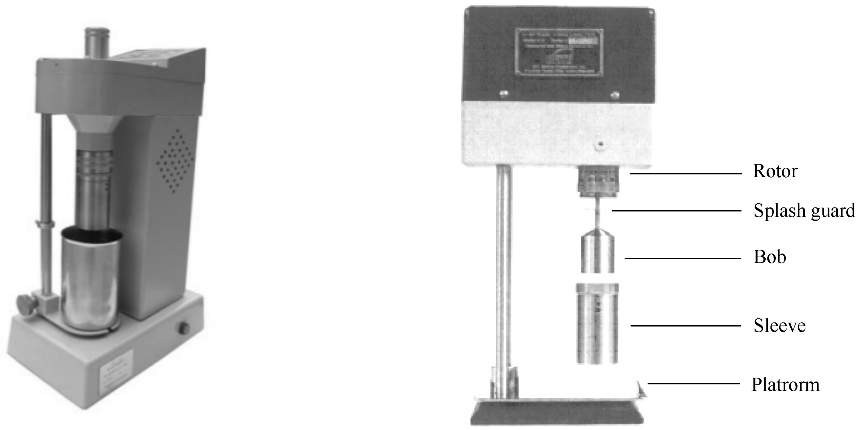

Fig. 2-5 Mud viscometer

Another measurement of mud viscosity is obtained by Marsh Funnel, as seen in Fig. 2-6. Marsh Funnel cannot give a measurement of viscosity. It works by the principle that thick mud needs more time to pass the small outlet at the bottom of the funnel. The Marsh Funnel is filled with 1500 mL of mud and the time (in seconds) required to discharge 950 mL of mud is recorded.

Fig. 2-6 Marsh Funnel

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2.8.3 Mud filtrate loss

During drilling, mud filtrate loss is another important mud property to be monitored carefully. When the mud hydrostatic pressure is higher than the formation pressure, mud filters into the rock pores. The water phase and small clay particles enter the pore space, while the large clay particles accumulate at the rock surface to form a layer of mud cake or filter cake.

High volume of filtrate loss is unfavorable for production and logging operations. Filtrate may impair rock permeability, which is one of the major causes of formation damage. Deep invasion of filtrate also makes logging difficult, because the logging tool has to detect the oil that is pushed to the deep reservoir. Therefore, low filtrate loss and thin yet tough mud cake are ideal. CMC and chemically modified starch are often added to mud to reduce filtrate loss.

Filter press measures mud filtrate loss, as seen in Fig. 2-7. Seated on the frame, the mud cup contains the mud sample to be tested. At the bottom of the cup lies a thin filter paper which imitates the porous rock. Pressure (often 100 psi) is supplied by a bullet-shaped charge which contains pressurized carbon dioxide. Filtrate flows through the small drainage hole at the bottom of mud cup, and gets collected in the graduated cylinder beneath.

Fig. 2-7 Filter press

For filtrate tests, we often collect filtrate for 7.5 minutes and report the filtrate loss for 30 minutes. The filtrate loss for 30 minutes doubles that for 7.5 minutes. For example, the loss for 7.5 minutes is measured to be 10 mL, then the loss for 30 minutes is reported as 20 mL.

2.8.4 Other measurements

The pH of mud needs to be monitored and controlled carefully during drilling. The mud pH can be easily measured with pH paper and pH meter. While drilling through formation rich in calcium, the pH of mud needs to be high. This can avoid dissolving of rock materials in the mud, which results in erosion of borehole. If starch is used as mud additive, the pH of mud should also be high to avoid bacteria attack on starch.

Sand particles in mud cause erosion in circulation system. The sand content of mud is measured by using a 200 mesh sieve and a glass tube calibrated to read directly the percentage of sand by volume. As previously described, desanders and desilters are in place to maintain sand content at low level.

Salt can enter and contaminate mud when salt formations are drilled. The chloride concentration of mud filtrate is measured by titration with silver nitrate solution. Chloride concentration can be calculated with the following relation:

$$\text{Chloride concentration (mg/L)} = 1000V_{\mathrm{tf}}$$

$$\text{NaCl concentration (mg/L)} = 1650V_{\mathrm{tf}}$$

Where, V_{tf} is the volume of silver nitrate required to reach the endpoint per milliliter of mud filtrate used in the titration.

Mud property is affected by many factors. Remediation methods are applied to battle mud problems.Some common approaches are given as follows.

(1) Mud viscosity increases when solid content increases. Therefore the solid control equipment (shale shaker, desander, desilter) are in place to remove the excessive solids in mud.

(2) While drilling through salt dome, contamination by sodium leads to increases in mud viscosity, yield point and filter loss. While drilling through anhydrite and gypsum, the calcium also causes similar effects. Calcium is removed from mud by adding soda ash (Na_2CO_3), which forms insoluble calcium carbonate.

(3) When carbon dioxide enters mud, carbonate ions and bicarbonate ions are produced. These ions lead to unacceptable filtrate loss and gel strength that can not be corrected by chemical additives, unless they are removed from mud. In this case,

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calcium hydroxide is added to convert bicarbonate ions to carbonate ions, then precipitate as calcium carbonate.

(4) Previously, modified starch and CMC were introduced as mud thickeners. They can also battle excessive filtrate loss. Starch is insensitive to water hardness and salinity. But it degrades under high temperature and bacteria attacks. CMC can stand high temperature, but loses function at high salinity.

As we can see, mud properties must be monitored closely and chemical additives such as mud thinner, thickener and filtrate inhibitor are required to achieve desirable mud properties.

Chapter 3 Casing design

In this chapter, we first need to understand some basic concepts of rock mechanics. Then we will move on to casing design. Casing design includes three aspects, namely, determination of casing setting depth, selection of casing size and selection of casing grade.

3.1 Overburden stress

Now we consider a layer of rock that is buried at a depth of 1000 ft. In other words, 1000 ft of rock lies above the zone. Overburden stress is caused by weight of the rock overlying above the zone of consideration. Overburden gradient (stress divided by depth) is often used instead of overburden stress. Overburden gradient normally varies from 0.8 to 1 psi/ft. It varies from field to field, and increases with depth.

3.2 Pore pressure

Pore pressure, also referred to as formation pressure, is defined as the pressure exerted by the formation fluid on the wall of the rock pores. The formation fluid, together with rock grains, support the overburden stress.

A formation with normal pore pressure indicates the pressure is equivalent to the hydrostatic pressure of a column of formation water. Normal pore pressure gradient is around 0.465 psi/ft (or 3.2 kPa/m). For instance, a formation at 10000 ft should be pressurized at 4650 psi.

If the formation pressure is higher than normal pore pressure, it is named abnormal pore pressure. Formations with abnormal pore pressure are isolated from the environment by an impermeable boundary. The pore fluid thus has to support a higher overburden stress. The abnormal pore pressure gradient can be even higher than overburden gradient, but often ranges between 0.8 and 1.0 psi/ft. The techniques for prediction and detection of abnormal pore pressure are not covered in this book.

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3.3 Fracture pressure

During drilling operation, if the mud hydrostatic pressure exceeds formation fracture pressure, the formation rock will break down and mud will leak into formations. The loss of mud is loss of money. Therefore, we need to monitor mud density carefully.

Rock fracture pressure is determined by the tensile strength of rock. The tensile strength is defined as the pulling force that is required to rupture a rock sample, divided by the cross sectional area of the rock sample. The tensile strength of rock is only 10% compressive strength. Thus, rock is more likely to fail in tension than in compression.

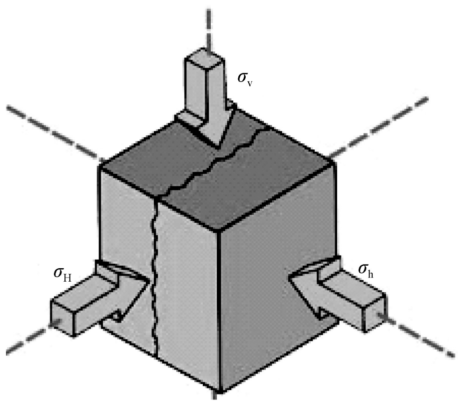

Fig. 3-1 Three principal stresses

Let's look at a rock sample buried underground, as shown in Fig. 3-1. Three perpendicular stresses apply to the rock sample. The vertical stress is the overburden stress, which is normally much higher than the horizontal stress. The other two horizontal stresses directly influence the fracturing of rock. In theory, the pressure required to rupture a rock should be greater than the minimum principal stress. Based on the above explanation, we can understand the fact that most fractures are created in the vertical direction.

Fracture pressure can be directly obtained by leak-off test. ① Fill the well with mud while the drill string is suspended in the well. ② Close the annular BOP, as seen in Fig. 3-2. ③ Pump the mud in small increment, for instance 1/4 barrel. ④ Plot injection pressure versus injected volume or time.

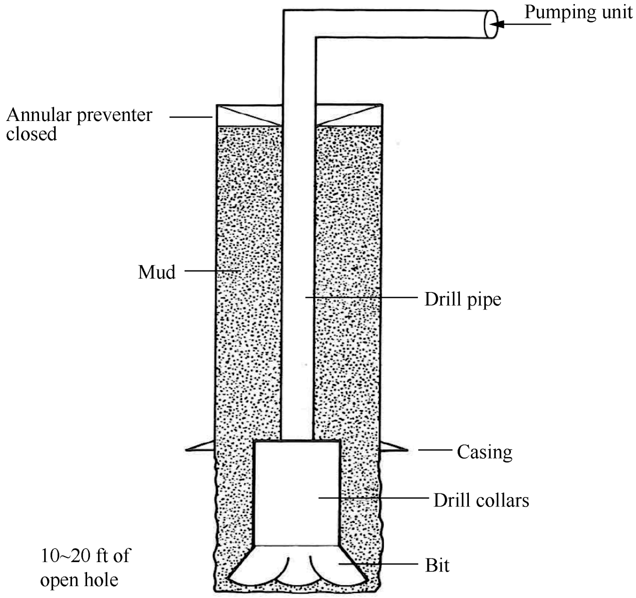

Fig. 3-2 Leak-off test equipment

The injection pressure will first build up linearly when mud is injected. The pressure will become nonlinear when rock starts to break down. At point B in Fig. 3-3, the pressure will suddenly drop, which indicates a fracture has been created. Afterwards, fracture propagates to deep formation at lower pressure. Note that we need to add mud hydrostatic pressure to pump injection pressure to obtain the fracture pressure.

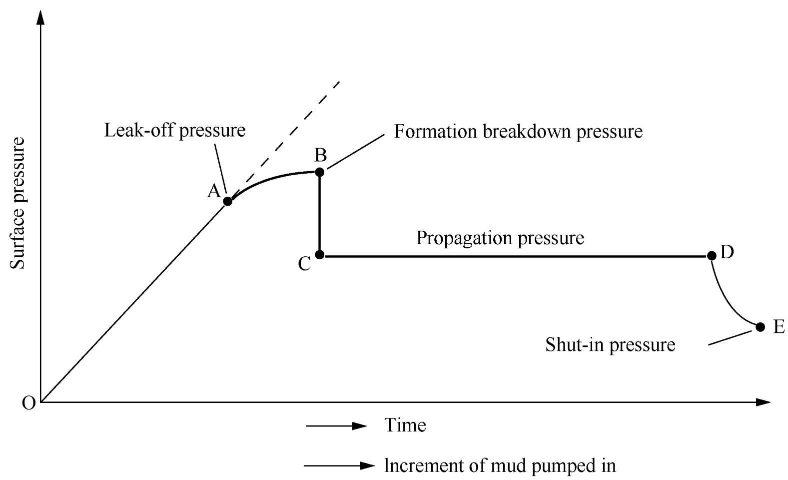

Fig. 3-3 Results of typical leak-off test

Fracture pressure can also be predicted with various rock mechanics models. For example,

Hubbert and Willis Method: $\mathrm{FP} = \frac{1}{3}\mathrm{OS} + \frac{2}{3}\mathrm{PP}$

Eaton Method: $\mathrm{FP} = \frac{\mathrm{PR}}{1-\mathrm{PR}}(\mathrm{OS}-\mathrm{PP}) + \mathrm{PP}$

where, FP is fracture pressure; OS is overburden stress; PP is pore pressure; PR is poisson's ratio.

3.4 Introduction to casing

Casing is steel pipe in nature. After we drill to certain depth, casings are run into wells. Drilling is done in the following steps. ① We first hammer the conductor pipe into the shallow surface, or we can drill the top section then run the conductor into well. Afterwards, cement is injected into the annular space between the conductor pipe and wellbore. ② We continue drilling to a certain depth, then run surface casing into the well and inject cement into annulus. ③ Drilling continues to certain depth, and intermediate casing is run and cement is injected. ④ Finally, drilling reaches the production zone. The production casing is run and cemented. In the end, we have a stable wellbore that looks like a telescope, as shown in Fig. 3-4 and Fig. 3-5.

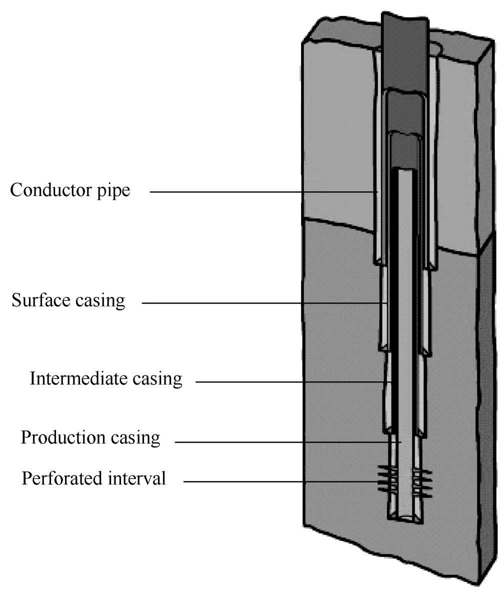

Fig. 3-4 Casing program

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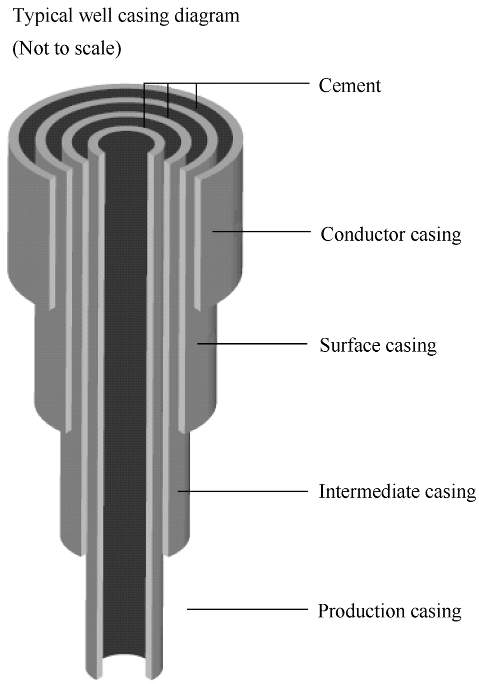

Fig. 3-5　Typical casing diagram

Sometimes, production liner is run instead of production casing. Liner is connected to the intermediate casing by a liner hanger. Liner does not run to surface, thus liner is a cheaper option.

The outer diameter of conductor pipe is often between 20 and 30 in. When drilling the subsequent section, a smaller bit is used to so that it can pass through the previoous stage of casing. fit into the previous stage of casing. It is obvious that the subsequent stage of casing is also smaller to be able to go through the previous casing. The diameter of production casing or liner is often 8 to 10 in only.

Casing guide shoe or float shoe is often equipped at the bottom of each casing string. They are shown in Fig. 3-6 and Fig. 3-7. The float shoe contains a one-way valve. It allows cement to be injected into the casing-hole annulus, but prevents cement from backflow. The float shoe also takes advantage of buoyant force, thus reducing hook load.

Fig. 3-6　Casing shoe

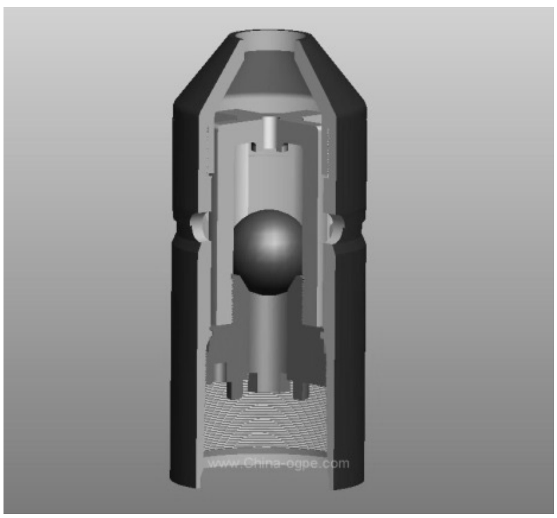

Fig. 3-7　Float shoe

Casings serve the following important functions. ① Support weak formations. Without casing, the well may cave in and well may be buried. ② Prevent contamination of fresh water zone located near surface. After casing is run and cemented, the drilling mud can no longer pollute fresh water. ③ To provide connection for blowout preventer and wellhead equipment. During drilling, BOP is seated on the top of casing to control well pressure. ④ To isolate production zones. After casing is run and cemented, we can

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choose to perforate the formations with desirable oil and gas flow.

A well with casings and cement is referred to as cased well or cased hole. It is worth mentioning that several completion options are available, as seen in Fig. 3-8. Some wells are completed as open hole, i.e. without production casing and cement, if the formation is strong. The isolation of zones can be achieved by packers that are in direct contact with wellbore.

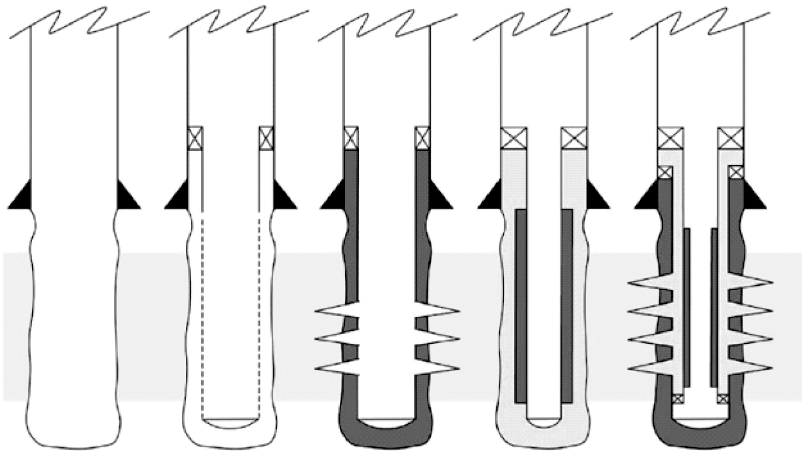

Fig. 3-8   Well completion methods

3.5 Casing setting depth

As mentioned previously, the different stages of casings need to be set at certain depths. We need to rely on pore pressure and fracture pressure data to determine casing setting depths.

Pore pressure gradient and fracture pressure gradient versus depth are plotted in Fig. 3-9. Sometimes, these curves are expressed as equivalent mud density. The procedures to determine casing setting depths are as follows: ① Apply a safety margin (often 100 to 200 psi) to pore pressure and fracture pressure to obtain two new curves; ② Start from the new pore pressure gradient curve at bottom, draw a straight line upwards to intersect the new fracture pressure curve. ③ From the intersection, draw a line to left to intersect pore pressure curve. ④ Repeat steps ② and ③, until no more

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intersections are made. These procedures are further explained in the example as follow.

Example 3-1: You are provided with pore pressure and fracture pressure data in Table 3-1. Determine casing setting depths and density of mud for drilling each zone. Apply safety margin of 200 psi. Fresh water zone is located at 300 to 400 ft from surface.

Table 3-1 Pore pressure and fracture pressure data

Depth/ft	Original pore pressure gradient/(psi/ft)	Original fracture pressure gradient/(psi/ft)	Adjusted pore pressure gradient/(psi/ft)	Adjusted fracture pressure gradient /(psi/ft)
3000	0.41	0.81	0.48	0.73
5000	0.46	0.83	0.50	0.79
6000	0.47	0.83	0.50	0.80
7000	0.48	0.83	0.51	0.80
8000	0.50	0.83	0.53	0.81
8500	0.53	0.84	0.55	0.82
9000	0.60	0.85	0.62	0.83
9500	0.70	0.89	0.72	0.87
10000	0.86	0.93	0.88	0.91

Solution: We first apply safety margin to both pore pressure and fracture pressure data.

At 3000ft, original pore pressure is $0.41 \times 3000=1230$ psi. After considering safety margin, the pore pressure gradient becomes:

$$(1230 \text{ psi}+200 \text{ psi})/3000 \text{ ft}=0.48 \text{ psi/ft}.$$

At 3000 ft, original fracture pressure is $0.8 \times 3000=2400$ psi. After considering safety margin, the pore pressure gradient becomes:

$$(2400 \text{ psi}-200 \text{ psi})/3000 \text{ ft}=0.73 \text{ psi/ft}.$$

Repeat the calculations for data at each depth. Next, we plot the adjusted data versus depth in Fig. 3-9. With the procedures described previously, we can obtain the setting depths for each casing, as well as the mud gradient. We can also convert mud gradient to mud density by a conversion factor.

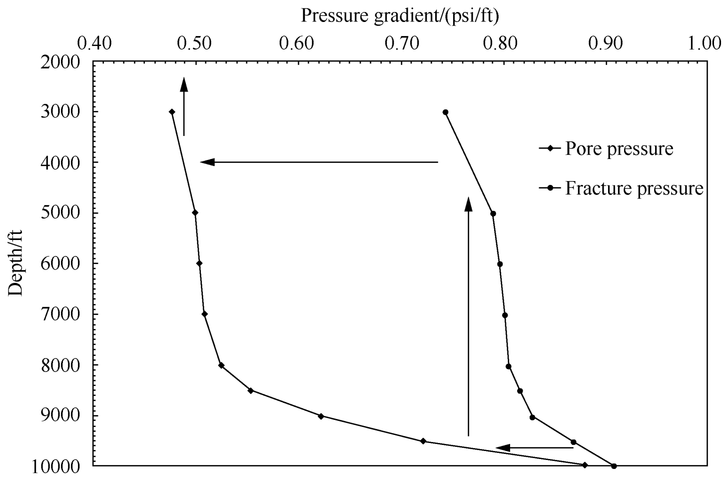

Fig. 3-9 Graph solution for casing setting depths

The conductor casing is set at 450 ft to protect fresh water zone. The surface casing is run to 4000 ft. For drilling to 4000 ft, a mud with density of 9.24 lb/gal (1.11 kg/L) can be used. When drilling continues to deeper formations, a heavier mud must be used to prevent kick. The solution is summarized in the Table 3-2.

Table 3-2 Setting depth and mud density

Casing stage	Depth/ft	Mud gradient/(psi/ft)	Mud density/(lb/gal)
Conductor pipe	450	0.48	9.24
Surface casing	4000	0.48	9.24
Intermediate casing	9600	0.77	14.82
Production casing	10000	0.88	16.94

3.6 Casing size selection

In the previous section, we discussed how to determine casing setting depths and mud weights. Another important issue during drilling is to decide the bit size and casing size. We need to rely on Table 3-3. Let's look at an example.

Example 3-2: Casing size and bit size selection

The top hole size is 24 in. Determine sizes of all stages of casings and the sizes of drill bits.

We obviously need to run a conductor that is smaller than 24 in top hole. Look up Table 3-3 and find out a casing of 20 in can do the job. The selection is 20 in conductor and 24 in bit to drill this zone.

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Afterwards, the drill bit must pass through the conductor pipe and continues with drilling. As such, the drill bit must be smaller than 20 in. Look up Table 3-4 and we can find a bit of $17\frac{1}{2}$ in can pass through the 20 in conductor. We go back to Table 3-3 and find a surface casing of $13\frac{3}{8}$ in should be set into the well drilled by 17.5 inch bit.

According to Table 3-4, a $12\frac{1}{4}$ in bit can pass through the $13\frac{3}{8}$ in (48 lb/ft) casing to continue with drilling. Check with Table 3-3 and find a $9\frac{5}{8}$ in (40 lb/ft) intermediate casing should be set afterwards.

According to Table 3-4, an $8\frac{5}{8}$ in bit can pass through the $9\frac{5}{8}$ in (40 lb/ft) intermediate casing to drill to production zone. Check with Table 3-3 and find a 7 in production casing should be set. The results are summarized in Table 3-5.

Table 3-3　Common bit sizes for formation being drilled

Casing size (OD)/in	Coupling size (OD)/in	Common bit size/in
$4\frac{1}{2}$	5.000	6; $6\frac{1}{8}$; $6\frac{1}{4}$
5	5.563	$6\frac{1}{2}$; $6\frac{3}{4}$
$5\frac{1}{2}$	6.050	$7\frac{7}{8}$; $8\frac{3}{8}$
6	6.625	$7\frac{7}{8}$; $8\frac{3}{8}$; $8\frac{1}{2}$
$6\frac{5}{8}$	7.390	$8\frac{1}{2}$; $8\frac{5}{8}$; $8\frac{3}{4}$
7	7.656	$8\frac{5}{8}$; $8\frac{3}{4}$; $9\frac{1}{2}$
$7\frac{5}{8}$	8.500	$9\frac{7}{8}$; $10\frac{5}{8}$; 11
$8\frac{5}{8}$	9.625	11; $12\frac{1}{4}$
$9\frac{5}{8}$	10.625	$12\frac{1}{4}$; $14\frac{3}{4}$
$10\frac{3}{4}$	11.750	15
$13\frac{3}{8}$	14.375	$17\frac{1}{2}$
16	17.000	20
20	21.000	24; 26

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Table 3-4　Common bit sizes that pass through previous casing

Casing (OD)/in	Unit weight/(lbm/ft)	Internal diameter/in	Common bit size/in
$4\frac{1}{2}$	9.5	4.090	$3\frac{7}{8}$
	10.5	4.052	$3\frac{7}{8}$
	11.6	4.000	$3\frac{7}{8}$
	13.5	3.920	$3\frac{3}{4}$
5	11.5	4.560	$4\frac{1}{4}$
	13.0	4.494	$4\frac{1}{4}$
	15.0	4.408	$4\frac{1}{4}$
	18.0	4.276	$3\frac{7}{8}$
$5\frac{1}{2}$	13.0	5.044	$4\frac{3}{4}$
	14.0	5.012	$4\frac{3}{4}$
	15.5	4.950	$4\frac{3}{4}$
	17.0	4.892	$4\frac{3}{4}$
	20.0	4.778	$4\frac{5}{8}$
	23.0	4.670	$4\frac{1}{4}$
$6\frac{5}{8}$	17.0	6.010	6
	20.0	6.049	$5\frac{5}{8}$
	24.0	5.921	$5\frac{5}{8}$
	28.0	5.791	$5\frac{5}{8}$
	32.0	5.675	$4\frac{3}{4}$

Continued

Casing (OD)/in	Unit weight/(lbm/ft)	Internal diameter/in	Common bit size/in
7	17.0	6.538	$6\frac{1}{4}$
	20.0	6.456	$6\frac{1}{4}$
	23.0	6.366	$6\frac{1}{4}$
	26.0	6.276	$6\frac{1}{8}$
	29.0	6.184	6
	32.0	6.094	6
	35.0	6.006	6
	38.0	5.920	$5\frac{5}{8}$
$7\frac{5}{8}$	20.0	7.125	$6\frac{3}{4}$
	24.0	7.025	$6\frac{3}{4}$
	26.4	6.969	$6\frac{3}{4}$
	29.7	6.875	$6\frac{3}{4}$
	33.7	6.765	$6\frac{1}{2}$
	39.0	6.625	$6\frac{1}{2}$
$8\frac{5}{8}$	24.0	8.097	$7\frac{7}{8}$
	28.0	8.017	$7\frac{7}{8}$
	32.0	7.921	$6\frac{3}{4}$
	36.0	7.825	$6\frac{3}{4}$
	40.0	7.725	$6\frac{3}{4}$
	44.0	7.625	$6\frac{3}{4}$
	49.0	7.511	$6\frac{3}{4}$

Continued

Casing (OD)/in	Unit weight/(lbm/ft)	Internal diameter/in	Common bit size/in
$9\frac{5}{8}$	29.3	9.063	$8\frac{3}{4}$; $8\frac{1}{2}$
	32.3	9.001	$8\frac{3}{4}$; $8\frac{1}{2}$
	36.0	8.921	$8\frac{3}{4}$; $8\frac{1}{2}$
	40.0	8.835	$8\frac{5}{8}$; $8\frac{1}{2}$
	43.5	8.755	$8\frac{5}{8}$; $8\frac{1}{2}$
	47.0	8.681	$8\frac{1}{2}$
	53.5	8.535	$7\frac{7}{8}$
$10\frac{3}{4}$	32.75	10.192	$9\frac{7}{8}$
	40.5	10.050	$9\frac{7}{8}$
	45.5	9.950	$9\frac{5}{8}$
	51.0	9.850	$9\frac{5}{8}$
	55.0	9.760	$9\frac{5}{8}$
	60.7	9.660	$8\frac{3}{4}$; $8\frac{1}{2}$
	65.37	9.560	$8\frac{3}{4}$; $8\frac{1}{2}$
$11\frac{3}{4}$	38.0	11.154	11
	42.0	11.084	$10\frac{5}{8}$
	47.0	11.000	$10\frac{5}{8}$
	54.0	10.880	$10\frac{5}{8}$
	60.0	10.772	$10\frac{5}{8}$

Continued

Casing (OD)/in	Unit weight/(lbm/ft)	Internal diameter/in	Common bit size/in
$13\frac{3}{8}$	48.0	12.715	$12\frac{1}{4}$
	54.5	12.615	$12\frac{1}{4}$
	61.0	12.515	$12\frac{1}{4}$
	68.0	12.415	$12\frac{1}{4}$
	72.0	12.347	11
16	55.0	15.375	15
	65.0	15.250	15
	75.0	15.125	$14\frac{3}{4}$
	84.0	15.010	$14\frac{3}{4}$
	109.0	14.688	$14\frac{3}{4}$
$18\frac{5}{8}$	87.5	17.755	$17\frac{1}{2}$
20	94.0	19.124	$17\frac{1}{2}$

Table 3-5 Summary of casing and bit sizes

Casing stage	Casing size/in	Bit size/in
Conductor	20	24
Surface casing	13-3/8	17-1/2
Intermediate casing	9-5/8	12-1/4
Production casing	7	8-5/8

3.7 Casing grades selection

After determining the casing depths and sizes, we need to select casing grades based on strength properties, including yield strength, collapse strength and burst strength. Casing properties are given in the appendixD.

American Petroleum Institute (API) defines the yield strength as the tensile stress required to produce a total elongation of 0.5% of the gauge length. Yield strength applies to both casing body and casing coupling. The yield strength of coupling may be higher or lower than casing body. While running casing, tensile forces in casing originate from the own weight of casing. We can understand the uppermost joint of casing is considered the weakest in tension.

Collapse strength is defined as the maximum external pressure required to collapse a pipe. If the casing is empty or partially empty, the mud outside the casing applies pressure to the external casing wall, due to the hydrostatic pressure induced by mud. We understand the mud hydrostatic pressure is the highest at the bottom and zero at surface. As a result, the collapse pressure is the highest at the bottom too.

Burst strength is defined as the maximum internal pressure required to burst a pipe. Assume a casing has been set, drilling continues but a kick occurs. The high pressure of formation fluid enters the casing and applies pressure on the internal wall of casing. This is the origin of burst pressure. We will learn casing grade design based on an example.

Example 3-3: Casing grades selection

You are provided with the drilling data for a vertical well (Table 3-6). Select casing grades based on yield, collapse and burst. A gas zone is located at 10000 ft, while another gas zone at 14000 ft. Use a safety factor of 1.1 for burst, 0.85 for collapse and 1.8 for tension.

Table 3-6 Drilling program for example 3-3

Depth /ft	Hole diameter /in	Casing OD /in	Mud density /(lb/ft^3)	Formation pressure /(psi/ft)
500	26	20	65	0.46
6000	17.5	13-3/8	67	0.46
10000	12.25	9-5/8	73	0.48
14000	8.5	7	87	0.50

(1) Conductor.

Collapse pressure at surface = 0 psi

Collapse pressure at shoe = 65 × 500/144 = 226 (psi)

Burst pressure at surface = 0 psi

Burst pressure at shoe = 6000 × 0.46 – (6000 – 500) × 0.46 – 226 = 4 (psi)

When calculating burst pressure, we need to consider the following factors:

Pore pressure from interval beneath = 6000 ft × 0.46 psi/ft =2760 (psi);

Hydrostatic pressure of fluid from interval beneath

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= (6000 ft – 500 ft) × 0.46 psi/ft = 2530 psi

We also consider the collapse pressure at shoes that works against burst pressure. Look up casing table in appendixD and select grade K-55 (94 lb/ft) casing with collapse pressure of 520 psi, burst pressure of 2110 psi, and yield strength of 1479000 lb.

(2) Surface Casing.

Collapse pressure at surface = 0 psi

Collapse pressure at shoe = 67 × 6000/144 = 2792 (psi)

Burst pressure at surface = 10000 × 0.48 – 10000 × 0.1 = 3800 (psi)

Burst pressure at casing shoe

= 10000 × 0.48 – (10000 – 6000) × 0.1 – 6000 × 0.46 = 1640 (psi)

For the burst calculation, a gas zone exists at 10000 ft with gas weight of 0.1 psi/ft. Adjust the previous results after considering safety factors.

Collapse pressure at surface = 0 psi

Collapse pressure at shoe = 2792 psi × 0.85 = 2373 psi

Burst pressure at surface = 3800 psi × 1.1 = 4180 psi

Burst pressure at casing shoe = 1640 psi × 1.1 = 1804 psi

Next, we plot collapse pressure versus depth, as shown in Fig. 3-10. We go to the casing table in the appendixD and find the data for 13.375 in casing. Assume we have two types of casings available, J55 (61 lb/ft) and L80 (72 lb/ft). Their collapse ratings are 1540 psi and 2670 psi, respectively. Also plot these two ratings in the graph below.

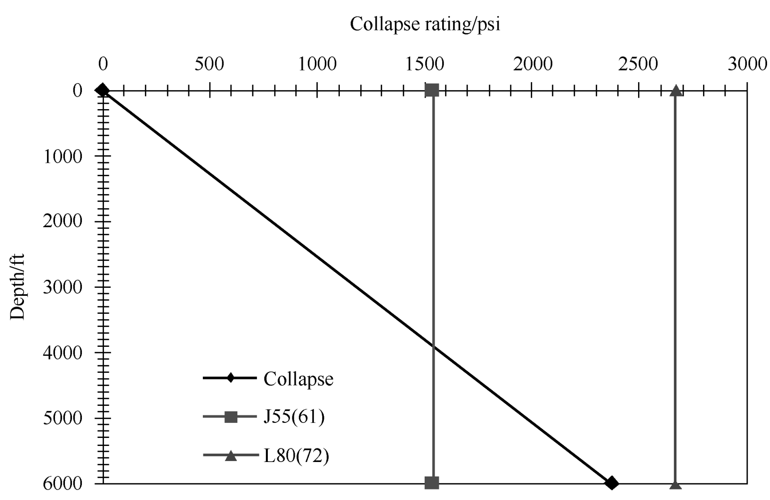

Fig. 3-10 Collapse design for surface casing

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Base on the graph, we can conclude that the J55 casing can satisfy collapse requirement to 3800 ft, while the L80 casing always meets burst requirement. Next, we need to conduct design based on burst. Plot burst ratings in Fig. 3-11, and we find J55 casing can stand burst from 2800 to 6000 ft, while L80 casing is valid all the way.

We can summarize the design results as follows.

Based on collapse: J55 for 0~3800 ft, and L80 for 3800~6000 ft;

Based on burst: L80 for 0~2800 ft, and J55 for 2800~6000 ft.

Combining collapse and burst, we have the design as follows:

L80 to 2800 ft; J55 from 2800 to 3800 ft; L80 from 3800 to 6000 ft.

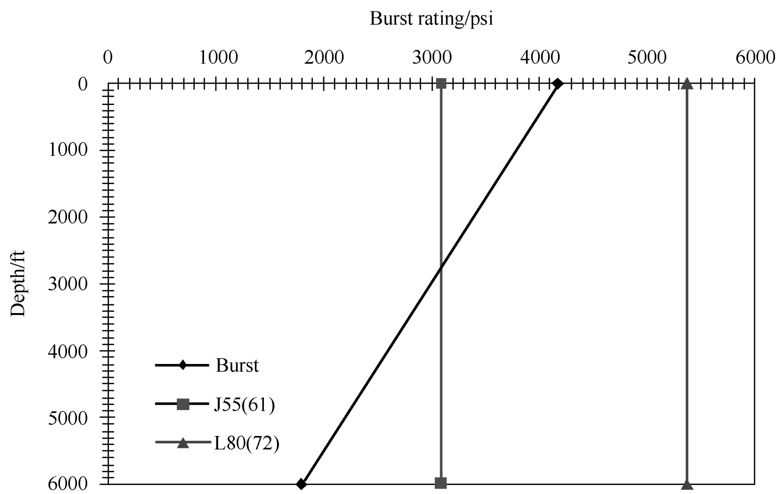

Fig. 3-11　Burst design for surface casing

Finally, we need to check if the casings can stand the tensile force.

Weight of bottom L80 casings = (6000 – 3800) × 72 = 158400 (lb)

Yield strength of L80 casing = 1650000 lb

Check safety: 1650000/158400 = 10.4 >1.8

Weight of middle J55 casings = (3800 – 2800) × 61 = 61000 (lb)

Yield strength of J55 casing = 962000 lb

Check safety: 962000/(158400+61000) = 4.4 >1.8

Weight of top L80 casings = 2800 × 72 = 201600 lb

Check safety: 1650000/(158400+61000+201600) = 3.9 >1.8

All results are higher than 1.8, the required safety factor. Therefore, the design is valid.

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(3) Intermediate casing.

Collapse pressure at surface = 0 psi

Collapse pressure at shoe = 73 × 10000/144 = 5069 (psi)

Burst pressure at surface = 14000 × 0.5 – 14000 × 0.1 = 5600 (psi)

Burst pressure at casing shoe

= 14000 × 0.5 – (14000 – 10000) × 0.1 – 10000 × 0.48 = 1800 (psi)

For the burst calculation, a gas zone exists at 14000 ft with gas weight of 0.1 psi/ft. Adjust the previous results after considering safety factors.

Collapse pressure at surface = 0 psi

Collapse pressure at shoe = 5069 psi × 0.85 = 4309 psi

Burst pressure at surface = 5600 psi × 1.1 = 6160 psi

Burst pressure at casing shoe = 1800 psi × 1.1 = 1980 psi

We plot collapse and burst in Fig. 3-12 and Fig. 3-13. Based on the graphs, we can determine the casings' lengths:

Based on collapse, L80(40) for 0~7200 ft, L80(47) for 7200~10000 ft;

Based on burst, L80(47) for 0~1000 ft, and L80(40) for 1000~10000 ft.

Combining collapse and burst design, we can have the following design:

L80(47) to 1000 ft; L80(40) to 7200 ft; L80(47) to 10000 ft.

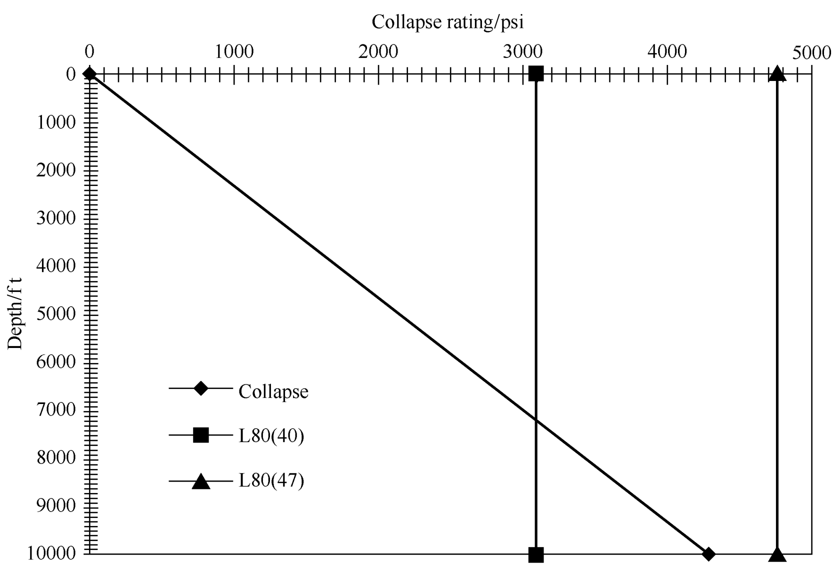

Fig. 3-12 Collapse design for intermediate casing

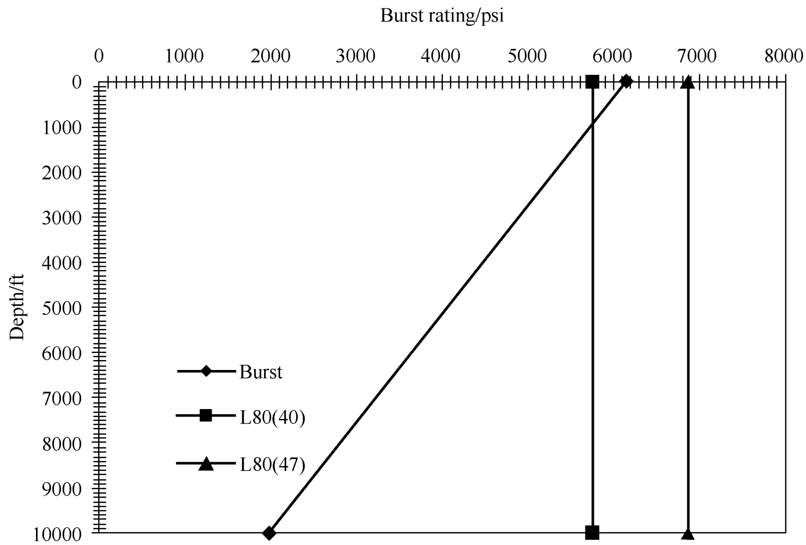

Fig. 3-13 Burst design for intermediate casing

Again, we need to check if the casings can stand the tensile force.

Weight of bottom L80 casings = (10000 – 7200) × 47 = 131600 (lb)

Yield strength of L80 casing = 1086000 lb

Check safety: 1086000/131600 = 8.3 >1.8

Weight of middle L80 casings = (7200 – 1000) × 40 = 248000 lb

Yield strength of L80 casing = 916000 lb

Check safety: 916000/(131600+248000) = 2.4 >1.8

Weight of top L80 casings = 1000 × 47 = 47000 (lb)

Check safety: 1086000/(131600+248000+47000) = 2.5 >1.8

All results are higher than the required safety factor, Therefore, the design is valid.

(4) Production Casing.

Collapse pressure at surface = 0 psi

Collapse pressure at shoe = 87 × 14000/144 = 8458 psi

Burst pressure at surface = 14000 × 0.5 – 14000 × 0.1 = 5600 psi

Burst pressure at casing shoe = 0 psi

Apply safety factors and plot these date in Fig. 3-14 and Fig. 3-15.

Collapse pressure at surface = 0 psi

Collapse pressure at shoe = 8458 psi × 0.85 = 7189 psi

Burst pressure at surface = 5600 psi × 1.1 = 6160 psi

Burst pressure at casing shoe = 0 psi

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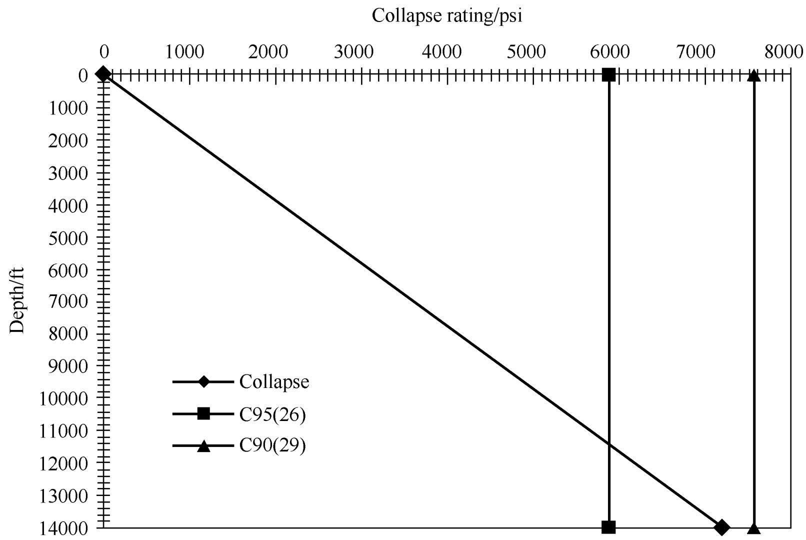

Fig. 3-14 Collapse design for production casing

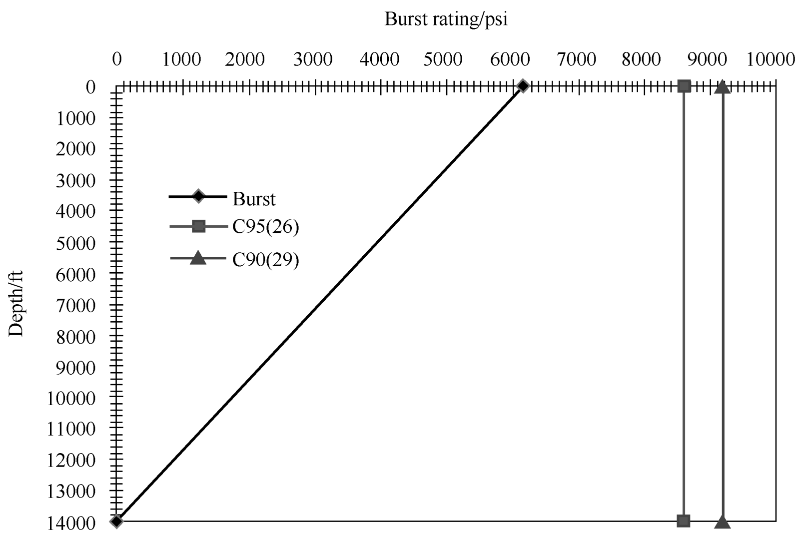

Fig. 3-15 Burst design for production casing

Based on collapse (Fig. 3-14), C95 runs to 11500 ft, and C90 runs to 14000 ft.

Based on burst (Fig. 3-15), either choice is valid.

Combing both factors, we decide C95 runs to 11500 ft, and C90 runs to 14000 ft. Next, we need to check on tensile.

Weight of bottom C90 casings = (14000 – 11500) × 29 = 72500 (lb)

Yield strength of C90 casing = 760000 lb

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Check safety: 760000/72500 = 10.5 >1.8

Weight of top C95 casings = 11500 × 26 = 299000 (lb)

Yield strength of C95 casing = 717000 lb

Check safety: 717000/(72500+299000) = 1.9 >1.8

The design meets the tensile requirement. In reality, the casing selection is often limited by availability of casings in the warehouse or onsite.

Chapter 4 Directional drilling

In the earlier years, most wells drilled were straight wells. Thanks to the development of drilling techniques, nowadays most wells drilled are directional wells and horizontal wells. This chapter introduces tools for directional drilling and well trajectory design.

4.1 Reasons for drilling directional wells

For offshore field, several wells are drilled from one platform or island. The wells have to deviate from vertical to reach reservoir boundary. Therefore, directional wells and horizontal wells have gained widespread applications worldwide. If the reservoir is located beneath a mountain or environmentally sensitive area, or beneath populated region, it is more economical and less polluting to drill directional wells or horizontal wells to develop these difficult-to-reach reservoirs. When the well's oil rate is reduced, a sidetrack well can be drilled to reach the reservoir with high oil saturation. If a blowout occurs, a relief well can be drilled to intersect the blowing well, in order to kill the well with heavy mud. If a reservoir is located beneath a salt dome, well completion is often very challenging. It is thus wise to drill a directional well to bypass the salt dome.

4.2 Geometry of directional well

Before we get into well trajectory calculations, we need to first learn about several basic parameters.

(1) Inclination is the angle between the vertical and the tangent to the well path at any point.

(2) Azimuth is the angle measured on horizontal plane between the true north and a point on the well path.

(3) Kick off point (KOP) is the point where the well starts to deviate from vertical.

(4) Dog leg severity (DLS) is the angular change over certain depth interval (100 ft or 100 m) on the well path.

(5) Measured depth (MD) is the length of the well path from the surface to certain

point on the well path.

(6) True vertical depth (TVD) is the vertical depth from surface to certain point on well path.

(7) Horizontal displacement is the horizontal distance from the rotary table center to the target zone.

Inclination(θ), azimuth(Φ), and TVD (z) are further illustrated in Fig. 4-1.

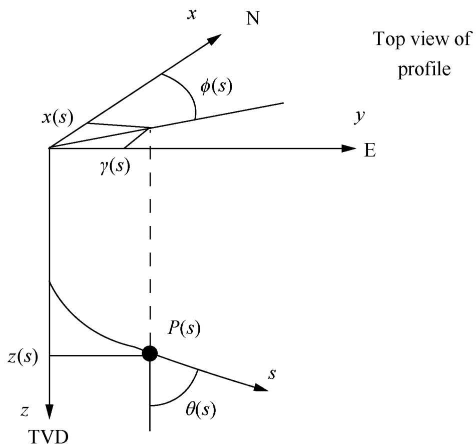

Fig. 4-1 Trajectory parameters for directional well

There are 4 common types of trajectories for directional wells. They are illustrated in Fig. 4-2. The first type deviates at shallow depth, and the inclination angle is held till well reaches target. The second type is also named the S type. The well is deflected at shallow depth, and the inclination angle is held. However inclination angle is reduced

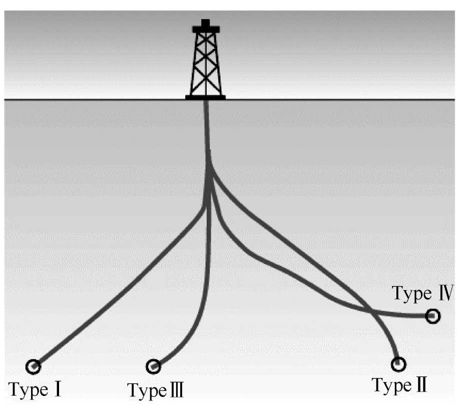

Fig. 4-2 Common well trajectories

later while the target is reached. For the third type, well is deflected at deeper location, and well reaches the target while the inclination angle is still being built up. The fourth type is also named horizontal well. This type of well often needs one or two build-up sections to reach horizontal.

4.3　Deflection tools

There are 4 common deflection tools: Bent sub, whip stock, down hole mud motor and rotary steerable system. Bent sub and whip stock are outdated, thus they are not introduced here.

Down hole mud motor (or drilling motor) is a progressive cavity positive displacement (PCPD) pump placed in the drill string to provide additional power to the bit while drilling. The PCPD pump uses drilling mud to create eccentric motion in the power section of the motor which is transferred as concentric power to the bit (see Fig. 4-3).

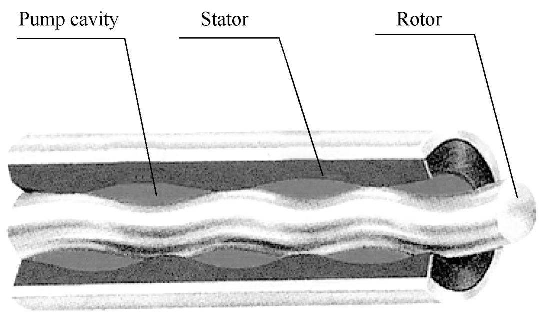

Fig. 4-3　Progressive cavity pump

The majority of mud motor is used in the drilling of directional holes. Although other methods may be used to steer the bit to the desired target zone, they are more time consuming which adds to the cost of the well. Mud motors can be configured to have a bend in them using different settings on the motor itself. Typical mud motors can be modified from 0 degrees to 4 degrees with approximately six increments in deviation per degree of bend. The amount of bend is determined by rate of climb needed to reach the target zone. By using a measurement while drilling (MWD) tool, a directional driller can steer the bit to the desired target zone.

Rotary steerable system (RSS) is an advanced drilling technology used in directional drilling. It employs the use of specialized down-hole equipment to replace

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conventional directional tools such as mud motors.

The methods used to direct the well path fall into two broad categories, these being “push-the-bit” and “point-the-bit”. Push-the-bit tools use pads on the outside of the tool which press against the well bore thereby causing the bit to press on the opposite side causing a direction change. Point-the-bit technologies cause the direction of the bit to change relative to the rest of the tool by bending the main shaft running through it (Fig. 4-4). The latter requires a non-rotating housing or reference housing in order to create this deflection within the shaft.

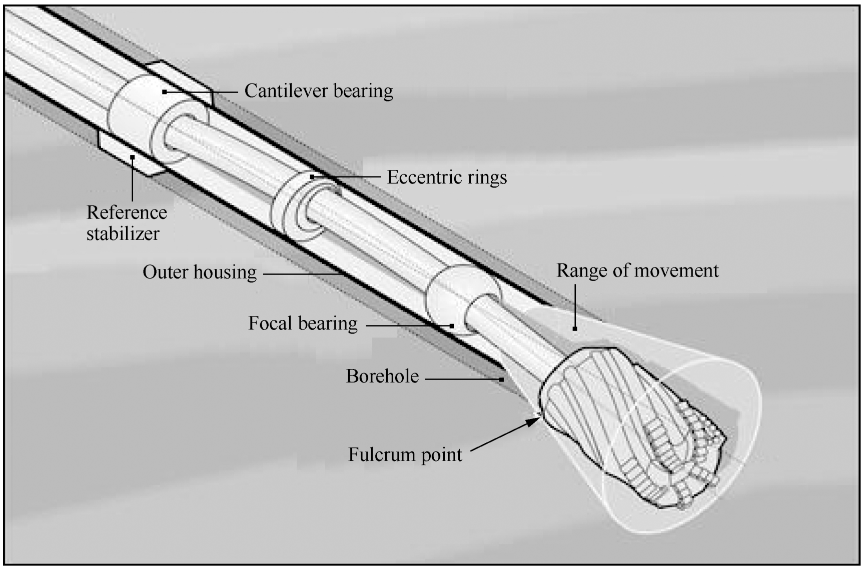

Fig. 4-4 Rotary steerable system

They are generally programmed by the MWD engineer or directional driller who transmits commands using either pressure fluctuations in the mud column or variations in the drill string rotation, and gradually steers into the desired direction. In other words, a tool designed to drill directionally with continuous rotation from the surface, eliminating the need to “slide” a mud motor.

The advantages of this technology are many for both main groups of users: Geoscientists and drillers. Continuous rotation of the drill string allows for improved transportation of drilled cuttings to the surface resulting in better hydraulic performance, better weight transfer for the same reason allows a more complex bore to be drilled, and reduced well bore tortuosity due to utilizing a steady steering model. The well

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geometry therefore is less aggressive and the wellbore is smoother than those drilled with a motor. This last benefit concerns geoscientists, because better measurements of the properties of the formation can be obtained, and the drillers, because the well casing or production string can be more easily run to the bottom of the hole.

4.4 Trajectory design

(1) Type I directional well.

This simple trajectory is shown in Fig. 4-5, where, AB is length of vertical section, where point B is the KOP; BC is length of curvature; CD is length of tangent; XY is horizontal departure; OB and OC are radius of curvature.

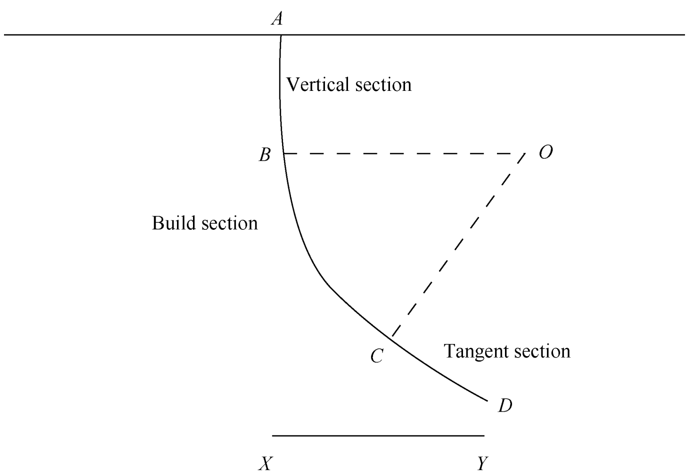

Fig. 4-5 Type I directional well (build and hold)

Radius of curvature = $OB = OC = \dfrac{180}{\pi \mathrm{DLS}}$

Maximum inclination angle:

$$\alpha = \arcsin\left(\frac{OB}{\sqrt{(OB-XY)^2+(\mathrm{TVD}-AB)^2}}\right) - \arctan\left(\frac{OB-XY}{\mathrm{TVD}-AB}\right)$$

Total measured depth (MD):

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$$\mathrm{MD} = AB + \frac{\alpha}{\mathrm{DLS}} + \left(\frac{OB}{\tan\left\{ \arcsin\left[\dfrac{OB}{\sqrt{(OB - XY)^2 + (\mathrm{TVD} - AB)^2}} \right] \right\}} \right)$$

Example 4-1: Design a type I trajectory

You are provided with the data: TVD is 9650 ft; *XY* is 2655 ft; KOP is 1600 ft; DLS is 2°./100 ft. Calculate radius of curvature, maximum inclination angle and measured depth.

Solution:

Radius of curvature = $OB = OC = \dfrac{180}{\pi \mathrm{DLS}} = \dfrac{180}{3.1416 \times 2/100} = 2865$ (ft)

$$\alpha = \arcsin\left(\frac{OB}{\sqrt{(OB - XY)^2 + (\mathrm{TVD} - AB)^2}} \right) - \arctan\left(\frac{OB - XY}{\mathrm{TVD} - AB} \right)$$

$$= \arcsin\left(\frac{2865}{\sqrt{(2865 - 2655)^2 + (9650 - 1600)^2}} \right) - \arctan\left(\frac{2865 - 2655}{9650 - 1600} \right) = 19.34 \ \text{(deg)}.$$

$$\mathrm{MD} = AB + \frac{\alpha}{\mathrm{DLS}} + \frac{OB}{\tan\left\{ \arcsin\left[\dfrac{OB}{\sqrt{(OB - XY)^2 + (\mathrm{TVD} - AB)^2}} \right] \right\}}$$

$$= 160 + \frac{19.34}{2/100} + \frac{2865}{\tan\left\{ \arcsin\left[\dfrac{2865}{\sqrt{(2865 - 2655)^2 + (9650 - 1600)^2}} \right] \right\}} = 10091 \ \text{(ft)}$$

(2) Type II directional well.

The S type trajectory is shown in Fig. 4-6, where *AB* is length of vertical section, and point *B* is the KOP; *BC* is length of curvature for first build section; *CD* is length of tangent; *DE* is length of curvature for second build section; *OB* and *OC* are radius of curvature for first build section; *QD* and *QE* are radius of curvature for second build section.

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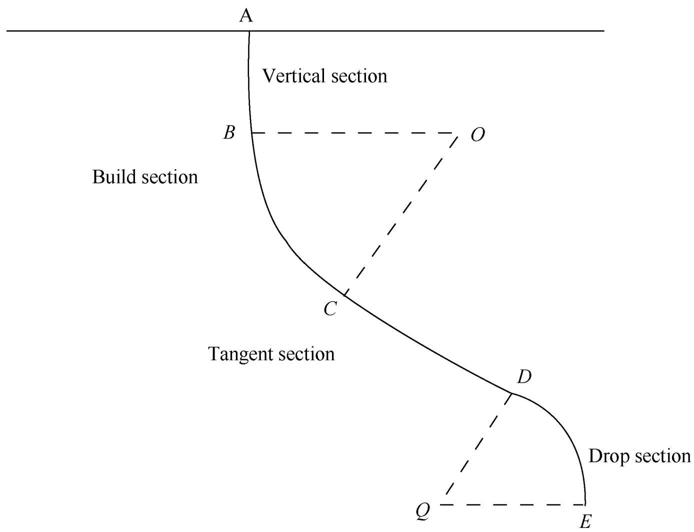

Fig. 4-6 S type trajectory

For this trajectory, its maximum inclination angle is expressed as:

$$\alpha = \arctan\left(\frac{\text{TVD} - AB}{OB + QD - XY}\right) - \arccos\left\{\frac{OB + QD}{\text{TVD} - AB}\ \sin\left[\arctan\left(\frac{\text{TVD} - AB}{OB + QD - XY}\right)\right]\right\}$$

(3) Horizontal well.

For drilling horizontal well, often we need to build twice to reach horizontal, as seen in Fig. 4-7. For design of horizontal well, normally the driller needs to determine dog leg severity for both builds, then KOP and horizontal departure can be calculated.

The radius of curvature for upper build: $R_1 = OB = \dfrac{180}{\pi \text{DLS}_1}$

The radius of curvature for lower build: $R_2 = QD = \dfrac{180}{\pi \text{DLS}_2}$

TVD of inclined section = $R_1 \sin\theta_1 + CD\cos\theta_1 + R_2 \sin\theta_2$

Where, DLS_1 is the dog leg severity for upper build section; and θ_1 is the inclination angle for upper build section.

Example 4-2: Horizontal well design

You need to design a trajectory for combination horizontal well with two build sections. Calculate KOP with the data given below.

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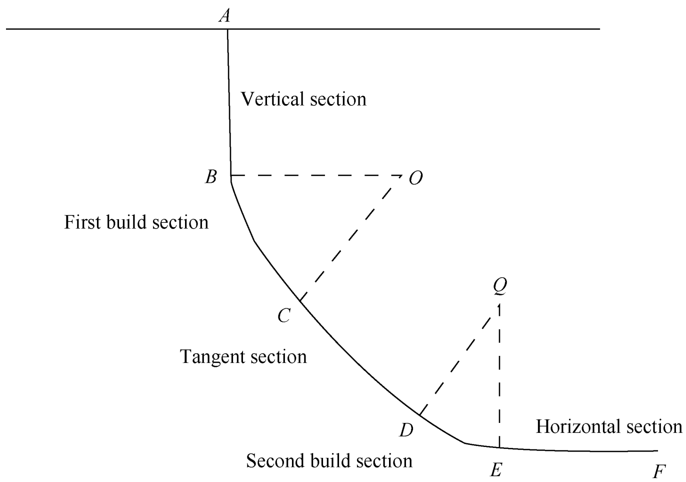

Fig. 4-7 Trajectory of horizontal well

For upper build: DLS=5°/100 ft to reach 75°. inclination

For lower build: DLS=12°/100 ft to reach horizontal

Length of tangent = 350 ft; TVD = 7500 ft

Solution:

$$R_1 = \frac{180 \times 100}{\pi \times 5} = 1146 \ \text{(ft)}$$

$$R_2 = \frac{180 \times 100}{\pi \times 12} = 477 \ \text{(ft)}$$

TVD of inclined section $= R_1 \sin\theta_1 + CD\cos\theta_1 + R_2 \sin\theta_2$

$$= 1146 \times \sin 75° + 350 \times \cos 75° + 477 \times \sin 15° = 1214 \ \text{(ft)}$$

KOP = TVD – 1214 = 7500 – 1214 = 6285 (ft)

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Chapter 5　Mud hydraulics

Mud pump provides the energy for mud circulation and hole cleaning. A typical triplex mud pump is shown in Fig. 5-1. Mud pumps rely on piston movement to circulate mud. The double-action stroke (Fig. 5-2) is used for duplex (two pistons) pumps. The single-action stroke (Fig. 5-3) is used for triplex pumps. Normally, duplex pumps can handle higher flow rates, and triplex pumps can provide higher pressure.

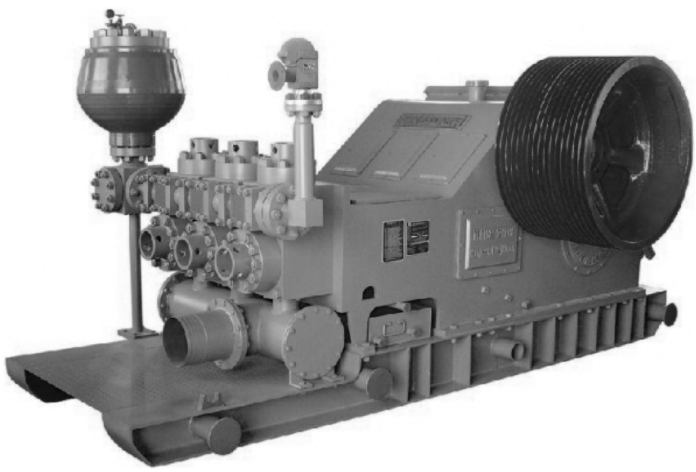

Fig. 5-1　Triplex mud pump

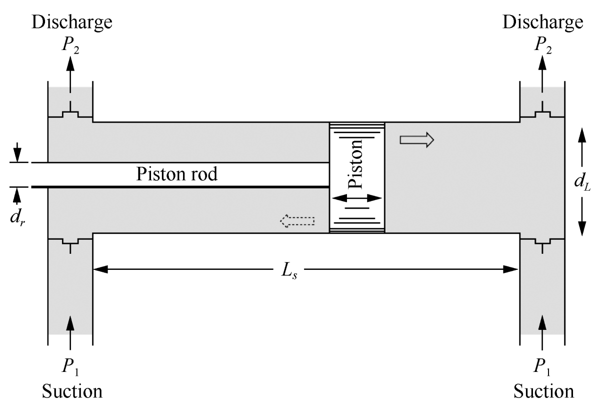

Fig. 5-2　Double action stroke

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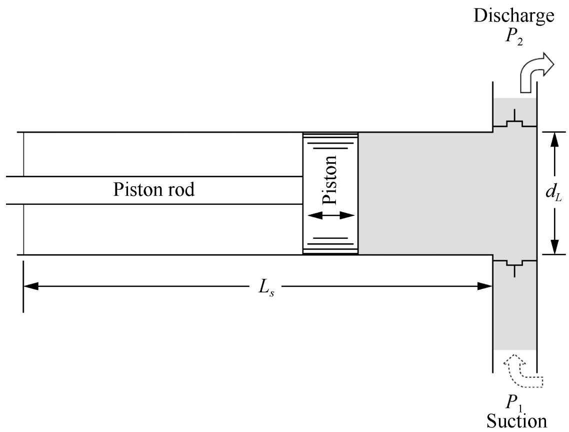

Fig. 5-3 Single action stroke

Good hole cleaning leads to good ROP (rate of penetration). Mud pump should produce a mud velocity that is able to lift cuttings during drilling. Mud pump should also overcome the pressure loss for mud circulation. Accordingly, mud pump should meet two requirement: Flow rate capacity and pressure capacity.

5.1 Flow rate capacity requirement

The mud velocity must exceed cutting slip velocity in order to lift cutting to surface. But due to the complex nature of cutting geometry and non-Newtonian fluid, the cutting slip velocity is not easy to obtain in reality. Theoretically, the slip velocity for an object in Newtonian fluid is expressed as:

$$v_{\mathrm{s1}} = 1.89\sqrt{\frac{d_{\mathrm{s}}}{f_{\mathrm{p}}}\frac{\rho_{\mathrm{s}} - 7.48\rho_{\mathrm{f}}}{7.48\rho_{\mathrm{f}}}} \tag{5-1}$$

where, v_{sl} is cutting slip velocity, ft/s; d_{s} is equivalent cutting diameter, in; ρ_{s} is cutting density, lb/ft^3; ρ_{f} is fluid density, lb/gal; f_{p} is particle friction factor.

If SI units are used, the constants 1.89 and 7.48 in Eq. (5-1) should be changed to 2.97 and 1, respectively. In the Eq. (5-1), the equivalent cutting diameter depends on many factors, and actually cuttings are of various sizes. It is understood that a small cutting size is produced at low ROP and high rotary speed. The following equation is proposed to estimate cutting size. The equation is for American field units. For SI units, 0.2 is replaced with 0.0167.

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$$d_s = 0.2\frac{\mathrm{ROP}}{\mathrm{RPM}} \tag{5-2}$$

where, ROP is rate of penetration, ft/hr; RPM is rotary speed of bit, r/mim.

On the other hand, the particle friction factor is determined by *Re*, shape of cutting and the type of suspending fluid. The value is normally between 0 and 2. And we can use 1 as an estimate for this factor.

On top of cutting slip velocity, we also need to take account of a margin for cutting to move upwards. This margin is named transport velocity.

$$v_{\mathrm{tr}} = \frac{\pi d_{\mathrm{b}}^2}{4}\frac{\mathrm{ROP}}{3600AC_{\mathrm{p}}} \tag{5-3}$$

where, d_{b} is bit diameter, in; C_{p} is cutting concentration, volume fraction; A is annulus cross sectional area, in^2. And the minimum required mud velocity,

$$v_{\min} = v_{\mathrm{sl}} + v_{\mathrm{tr}} \tag{5-4}$$

Finally, the minimum required mud flow rate,

$$q_{\min} = 3.1167\, v_{\min} A \tag{5-5}$$

The constant 3.1167 in Eq. (5-5) should be changed to 60 for SI units.

Example 5-1: Minimum mud flow rate to lift cuttings. The following parameters are given:

Cutting diameter = 5 mm;

Cutting specific gravity = 2.5;

Mud specific gravity = 1.3;

Well bore diameter = 0.61 m;

Drill pipe OD = 0.168 m;

ROP = 25 m/hr;

Rotary speed = 60 r/min;

Cutting concentration = 13%.

Calculate: ① cutting slip velocity; ② cutting transport velocity; ③ minimum required mud flow rate.

With Eq. (5-1), we can obtain a slip velocity of 0.2 m/s or 0.66 ft/s. The cross sectional area of the annulus is calculated to be 0.27 m^2. With Eq. (5-3), the transport

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velocity is 0.058 m/s or 0.19 ft/s. Therefore, the minimum mud velocity is 0.258 m/s, and the minimum mud flow rate is 4.18 m^3/min or 1104 gal/min.

Example 5-2: Mud pump factor (Fig. 5-2)

Mud pumps are simple piston pumps. Both duplex and triplex pumps are common. Pump factor is defined as volume displaced per stroke. D_r = piston rod diameter; D_i= inner diameter of pump chamber; L_s = stroke length; E_v = volumetric efficiency.

On the forward stroke, the volume displaced is given by:

$$\frac{\pi}{4}D_i^2 L_s$$

On the backward stroke, the volume displaced is given by:

$$\frac{\pi}{4}\left(D_i^2 - D_r^2\right)L_s$$

Total volume displaced per complete pump cycle is given by:

$$\frac{\pi}{4}\left(2D_i^2 - D_r^2\right)L_s E_v n$$

where, n is the number of cylinders. For example, a duplex pump (n=2) has 6.5 in inner diameter, 2.5 in rod diameter, and 18 in stroke length. Calculate its pump factor:

$$\begin{aligned} F_p &= \frac{\pi}{4}\left(2D_i^2 - D_r^2\right)L_s E_v n \\ &= \frac{\pi}{4}\left(2\times 6.5^3 - 2.5^2\right)\times 18\times 0.9\times 2 \\ &= 1991\left(\frac{\text{in}^3}{\text{stroke}}\right) = 0.205\left(\frac{\text{bbl}}{\text{stroke}}\right) \end{aligned}$$

5.2 Pressure requirement

While mud is in circulation, pressure loss occurs wherever mud flows through, from the pump to the surface line and into drill pipe, then through bit nozzles to the annulus, and returns to surface. The mud pump needs to produce a pressure to overcome the total pressure loss.

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Example 5-3: Nozzle size calculation

A mud pump generates a mud flow rate of 700 gal/min and a maximum pressure of 2200 psi. The mud density is 10 lb/gal. The pressure losses in various flow paths are given below. Calculate the suitable nozzle size for the drill bit.

Pressure loss in surface equipment = 50 psi

Pressure loss inside drill pipes = 650 psi

Pressure loss inside drill collars = 400 psi

Pressure loss in annulus around drill collars = 30 psi

Pressure loss in annulus around drill pipes = 70 psi

The total pressure losses in the circulation is 1200 psi. The allowed pressure loss at the drill bit is 2200 – 1200=1000 psi. According to the Eq. (2-41):

$$\text{Velocity at nozzle} = 33.36\sqrt{\frac{\Delta P}{\rho}} = 333.6 \text{ (ft/s)}$$

Total area of nozzle = $0.32Q/333.6 = 0.67$ (in^2)

There are 3 nozzles, so each nozzle area is 0.67/3=0.22 (in^2)

And it is easy to obtain the nozzle diameter = 0.53 in

The nozzle size is often expressed in 1/32 in. Therefore, the size is expressed as 17/32.

5.3 Mud hydraulics optimization

Drilling hydraulics is considered the most important factor in drilling performance. The rate of penetration can be significantly increased with hydraulics optimization to minimize drilling cost. The goal of the optimization is to make the maximum usage of the pump's power to allow the bit to drill at maximum efficiency. This is achieved by minimizing the energy loss due to friction in the circulating system and using the saved energy to improve bit hydraulics.

5.3.1 Maximum bit horsepower criterion

This design states that within the maximum available pump pressure, mud flow rate and nozzle size should be chosen so the bit will gain the maximum possible horsepower to clean the bottom hole.

In the earlier time, engineers believed the mud pump should be operated at maximum horsepower to give the maximum horse power at the bit. They reasoned that

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the penetration rate would increase with hydraulic horsepower, until the cuttings were removed as fast as they were generated. After the perfect cleaning level was achieved, there should be no further increase in the penetration rate.

Later, several authors pointed out that due to the frictional pressure loss in the drill string and annulus, the hydraulic power developed at the bottom of the hole is different from the hydraulic power developed by the pump. They concluded that bit horsepower rather than pump horsepower was the important parameter.

The pressure drop at the bit is expressed as:

$$\Delta P_{\mathrm{b}} = P_{\mathrm{p}} - Cq^{m} \tag{5-6}$$

where, P_{p} is the mud pump pressure. While the bit horsepower is expressed as:

$$\mathrm{HP}_{\mathrm{b}} = \frac{\Delta P_{\mathrm{b}} q}{1714} \tag{5-7}$$

Therefore, substituting the pressure loss equation gives:

$$\mathrm{HP}_{\mathrm{b}} = \frac{(P_{\mathrm{p}} - Cq^{m})q}{1714} \tag{5-8}$$

When the horsepower reaches maximum,

$$\frac{\partial \mathrm{HP}_{\mathrm{b}}}{\partial q} = \frac{P_{\mathrm{p}} - (m+1)Cq^{m}}{1714} = 0 \tag{5-9}$$

To solve for the root,

$$P_{\mathrm{p}} = (m+1)Cq^{m} = (m+1)\Delta P_{\mathrm{d}}$$

$$\Delta P_{\mathrm{d}} = \frac{P_{\mathrm{p}}}{m+1} \tag{5-10}$$

The pressure loss ΔP_{d} refers to the total pressure loss in the circulation system exclusive that at the bit. It is also named the parasitic pressure loss. It is shown the maximum bit horsepower is reached when the parasitic pressure loss is $1/(m+1)$ times mud pump pressure.

$$\Delta P_{\mathrm{b}} = P_{\mathrm{p}} - \Delta P_{\mathrm{d}} = P_{\mathrm{p}} - \frac{P_{\mathrm{p}}}{m+1} = \frac{m}{m+1} P_{\mathrm{p}} \tag{5-11}$$

In conclusion, the bit horsepower is maximum when pressure loss at the bit is $m/(m+1)$ times pump pressure. The value of m is often regarded as 1.8.

5.3.2 Maximum jet impact force criterion

This design states that within the maximum available pump pressure, the mud flow rate and the nozzle size should be chosen so the bit will exert the maximum possible jet impact force to clean the bottom hole. The impact force is expressed as:

$$F_j = 0.01823 C_{\mathrm{d}} q \sqrt{\rho \Delta P_{\mathrm{b}}} = 0.01823 C_{\mathrm{d}} q \sqrt{\rho \left(P_{\mathrm{p}} - C q^m \right)} \tag{5-12}$$

For the impact force to reach maximum,

$$\frac{\mathrm{d}F_j}{\mathrm{d}q} = 0.009115 C_{\mathrm{d}} \sqrt{\rho} \left[\frac{2P_{\mathrm{p}} q - (m+2) C q^{m+1}}{\sqrt{P_{\mathrm{p}} q^2 - C q^{m+2}}} \right] = 0 \tag{5-13}$$

Solve for the root,

$$\Delta P_{\mathrm{d}} = \frac{2P_{\mathrm{p}}}{m+2} \tag{5-14}$$

This shows the jet force is maximum when parasitic pressure loss is $2/(m+2)$ times the mud pump pressure.

Since

$$\Delta P_{\mathrm{b}} = P_{\mathrm{p}} - \Delta P_{\mathrm{d}} = P_{\mathrm{p}} - \frac{2P_{\mathrm{p}}}{m+2} = \frac{m}{m+2} P_{\mathrm{p}} \tag{5-15}$$

This shows the jet force is maximum when the pressure loss at bit is $m/(m+2)$ times the mud pump pressure.

5.3.3 Maximum nozzle velocity criterion

This criterion states that within the maximum available pump pressure, the mud flow rate and the nozzle size should be chosen so the bit will create the maximum possible jet velocity to clean the bottom hole. Recall Eq. (2-41), we see that the nozzle velocity can be increased by reducing the flow rate so the parasitic pressure loss is reduced. In field applications, the flow rate is set to the minimum flow rate determined by the minimum annular velocity required to lift cuttings.

5.4 Discussions

Three criteria have been introduced, but which one is the best? Commonly, drilling engineers apply the maximum bit hydraulic horsepower or the maximum bit hydraulic impact force criterion at shallow to middle depths, and shift to the maximum nozzle velocity at deeper depths.

Between the maximum bit hydraulic horsepower and the maximum bit hydraulic impact force criteria, neither criterion has been proved better in all cases because there is little difference in the application of the two procedures. If the jet impact force is the maximum, the hydraulic horsepower will be within 90% of the maximum and vice versa.

The concept of bit hydraulic horsepower was introduced as a design criterion in the early 1950s. It is a measure of the work required to squeeze mud through the bit nozzles. This work is related to the removal of cuttings from below the bit. Bit hydraulic horsepower is the most common design procedure, probably because it was used first.

The concept of hydraulic impact force as a design criterion was introduced in the mid 1950s. Hydraulic impact force is a measure of the force exerted by the fluid at the exits of the bit nozzles. This fluid impact force cleans the bottom hole by direct erosion and by cross flow beneath the bit.

Hydraulic impact force below the bit seems more logical than the bit hydraulic horsepower when considering design procedures for bottom hole cleaning. Rock bits with jet nozzles extended closer to the bottom of the hole are widely used. Both laboratory and field tests have shown better bottom hole cleaning with extended bit nozzles.

Since extending the nozzles does not change the bit hydraulic horsepower but does change the hydraulic impact force on the bottom of the hole, it is believed that the latter relates more directly to hole cleaning.

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Chapter 6 Underbalanced drilling

In normal drilling operations, the pressure in the well is higher than the formation pressure, thus the formation fluid is safely sealed. But this also allows some drilling mud to enter the formation and cause damage to rock permeability.

Underbalanced drilling (UBD) is a procedure used to drill oil and gas wells while the pressure in the wellbore is kept lower than the fluid pressure in the formation being drilled. As the well is being drilled, formation fluid flows into the wellbore and up to the surface.

This is the opposite of the usual situation, where the wellbore is kept at the pressure above the formation to prevent formation fluid from entering the well. In such a conventional overbalanced well, the invasion of fluid is considered a kick, and if the well is not shut-in it can lead to a blowout, a dangerous situation.

6.1 Benefits of underbalanced drilling

Underbalanced wells have several advantages over conventional drilling.

(1) Formation damage due to drilling mud invasion is eliminated. In a conventional well, drilling mud is forced into the formation in a process called invasion, which frequently causes formation damage—formation damage refer to a decrease in the ability of the formation to transmit oil into the wellbore at a given pressure and flow rate. It may or may not be repairable. In underbalanced drilling, if the underbalanced state is maintained until the well becomes productive, invasion does not occur and formation damage can be completely avoided.

Moreover, some rock formations have a reactive tendency to water. When mud is used, the water in the mud reacts with the formation (mostly clay) and causes formation damage (reduction in permeability and porosity). Underbalanced drilling can prevent this damage.

(2) Increased rate of penetration (ROP). With less pressure at the bottom of the wellbore, it is easier for the drill bit to cut and remove rock.

(3) Reduction of lost circulation. Lost circulation occurs when drilling mud flows into the formation uncontrollably. Large amounts of mud can be lost before a proper

mud cake forms, or the loss can continue indefinitely. If the well is drilled underbalanced, mud will not enter the formation and this problem can be avoided.

(4) Differential sticking is eliminated. Differential sticking occurs when the drill pipe is pressed against the wellbore wall so that part of its circumference will see only reservoir pressure, while the rest will continue to be pushed by wellbore pressure. As a result, the pipe becomes stuck to the wall, and can require thousands of pounds of force to remove, which may prove impossible. Because the reservoir pressure is greater than the wellbore pressure in UBD, the pipe is pushed away from the walls, eliminating differential sticking.

6.2 How to achieve underbalanced condition

If the formation pressure is relatively high, using a lower density mud will reduce the well bore pressure below the pore pressure of the formation.

Sometimes an inert gas is injected into the drilling mud to reduce its equivalent density and hence its hydrostatic pressure throughout the well depth. Commonly used in underbalanced operations, nitrogen is preferred for its somewhat low cost of generation and minimal potential for down hole fires. But air, reduced oxygen air, processed flue gas and natural gas have all been used in this operation. While pure nitrogen can be purchased, it is cost-prohibitive. Therefore, nitrogen is more commonly produced onsite with a membrane unit, resulting in a 95% level of purity.

There are several kinds of drilling fluids for underbalanced drilling. The most common options are listed below.

(1) Dry air. This is also known as dusting. Here, air compressors combined with a booster (which takes the head from the compressors and increases the pressure of the air, but does not increase the volume of air going down hole) are used and the only fluid injected into the well is a small amount of oil to reduce corrosion.

(2) Mist. A small amount of foaming agent (soap) is added into the flow of air. Fine particles of water and foam in an atmosphere of air bring cuttings back to the surface.

(3) Foam. A larger amount of foaming agent is added into the flow. Bubbles and slugs of bubbles bring cuttings back to the surface.

(4) Stable foam. An even larger amount of foaming agent is added into the flow. This is the consistency of a shaving cream.

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(5) Aerated mud. Air or another gas is injected into the flow of drilling mud. Degassing units are required to remove air before it can be re-circulated.

An important factor to successful underbalanced drilling is that, drilling and completion operations must remain underbalanced at all times during operations. To accomplish this, pre-planning and onsite engineering are critical to the success of underbalanced drilling procedures.

Underbalanced drilling is usually more expensive than conventional drilling, and has safety issues of its own. Technically the well is always in a kick condition unless a heavier fluid is displaced into the well. Air drilling requires a faster up hole volume as the cuttings will fall faster down the annulus when the compressors are off, compared to having a higher viscosity fluid in the hole.

Because air is compressible, mud-pulse telemetry measurement-while-drilling (MWD) tools do not work, because they require an incompressible fluid. Common technologies used to eliminate this problem are either electromagnetic MWD tools or wire-line MWD tools. Corrosion is also a problem, but can be largely avoided using a coating oil or rust inhibitors. Typically used for only a section of the entire drilling process, underbalanced drilling can not be used in most shale environments.

6.3 Underbalanced drilling operations

There are four main operation techniques to achieve underbalanced condition, including using lightweight drilling fluids, gas injection down the drill pipe, gas injection through a parasite string and foam injection.

Using light-weight drilling fluids, such as fresh water, diesel and crude oil, is the simplest way to reduce wellbore pressure. A negative aspect for this approach is that in most reservoirs the pressure in the wellbore cannot be reduced enough to achieve underbalanced condition.

The method of injecting gas down the drill pipe involves adding air or nitrogen to the drilling fluid that is pumped directly down the drill pipe. Advantages to this technique include improved penetration, decreased amount of gas required and that the wellbore does not have to be designed specifically for underbalanced drilling. On the other hand, disadvantages include the risk of overbalanced conditions during shut-in and the requirement of rare MWD tools.

In performing the gas injection via parasite string**,** a second pipe is run outside of the intermediate casing (Fig. 6-1). This technique applies constant bottom hole pressure and requires no operational differences or unique MWD systems.

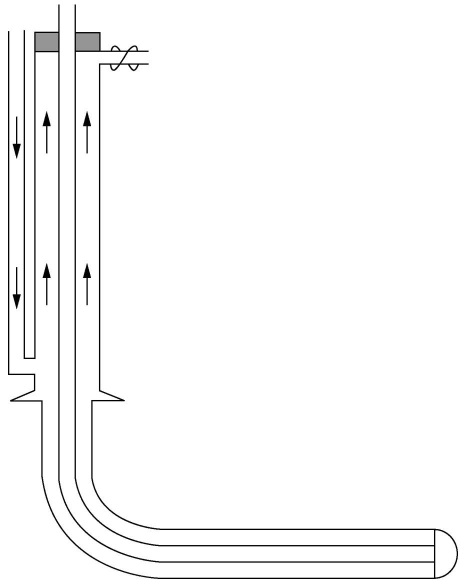

Fig. 6-1 Parasite string injection method

A less common underbalanced application, nitrogen foam is less damaging to reserves that exhibit water sensitivities. While the margin of safety is increased using foams, the additional nitrogen needed to generate stable foam makes this technique more costly. Additionally, there are temperature limits to using foam in underbalanced drilling, limiting the technique to wells measuring less than 12000 ft deep.

6.4 Surface equipment for underbalanced drilling

Fig. 6-2 shows a layout of surface equipment in a closed system using aerated liquid as the drilling fluid. The liquid pump is usually the same pump as for mud drilling. The nitrogen pumpers are gas compressors. The nitrogen gas is usually obtained using nitrogen generators. Liquid nitrogen has been employed in offshore UBD operations. A 4-phase separator (Fig. 6-3) separates gas, oil, drilling fluid and drilling solids.

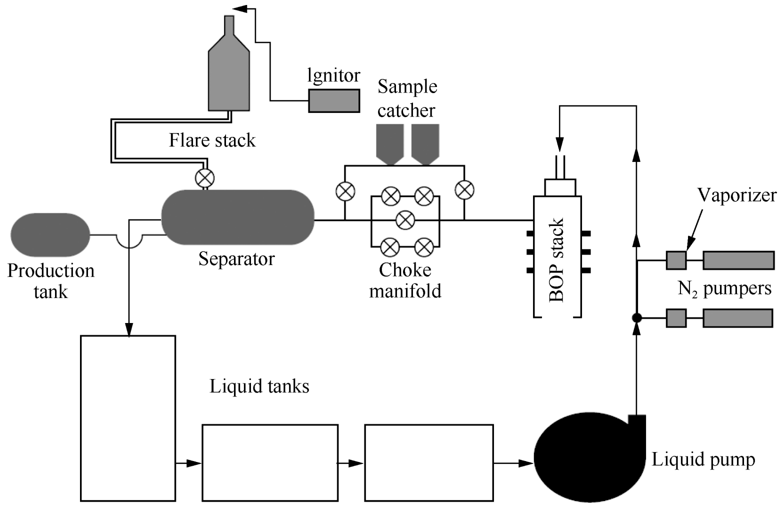

Fig. 6-2 Surface equipment for UBD

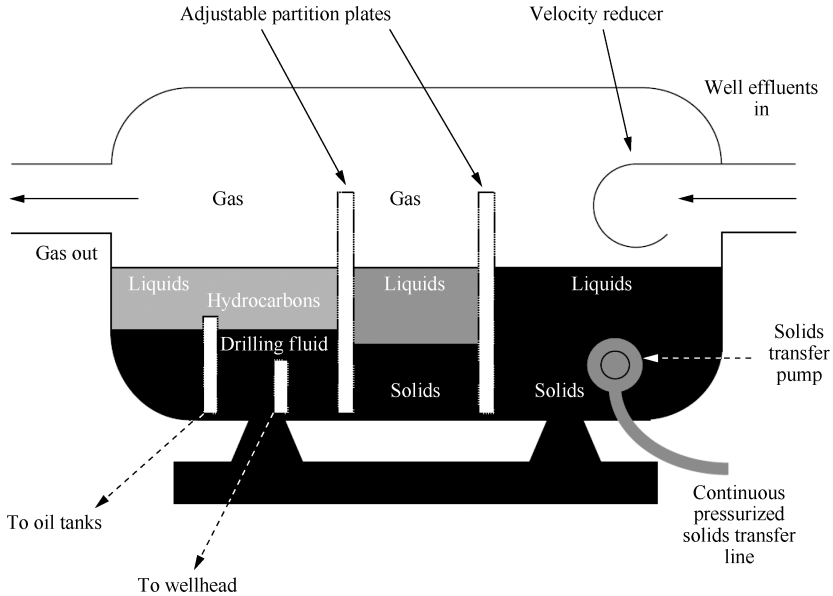

Fig. 6-3 Separator for UBD

The rotating head used in gas drilling is not popular in UBD operations due to its low pressure rating. Rotating blowout preventers are often used in UBD. They can handle up to 2500-psi wellhead pressure.

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Chapter 7　Cementing and perforation

Cementing is performed when the cement slurry is deployed into the well via pumps, displacing the drilling fluids still inside the well, and replacing them with cement. The cement slurry flows to the bottom of the wellbore through casing. From there, it fills in the annulus between the casing and the actual wellbore, and hardens. This creates a seal so that outside materials cannot enter the well flow, also permanently positions the casing in place.

Before the production casing is cemented, multiple logging tools are lowered into the well. These tools normally include permeable zone logging tools, resistivity logging tools and porosity logging tools. Permeable zone logs, such as spontaneous potential log and gamma ray log, record the natural charges and gamma ray emissions to locate the reservoirs.

Resistivity log tools send electric currents into the rocks, the rock zones that contain oil and gas show high resistivity because oil and gas do not transmit electricity. Porosity logs include density log, neutron log and sonic log. Density log tool emits gamma ray into formations and detects the returned gamma ray, and determines rock density and porosity accordingly. Neutron log tool emits fast neutrons into formations and detects the returned neutron, thus determines rock porosity. Sonic log tool sends sound waves into rock formations and records the sound travel time to the receiver, thus determines speed of sound in the rock and rock porosity.

Logging can also be done while drilling. This operation is named logging while drilling (LWD). Multiple logging tools are attached to the drill string and logging is conducted while drilling proceeds.

7.1　Functions of cement

Part of the process of preparing a well for further drilling, production or abandonment, cementing a well is the procedure of developing and pumping cement into place in a wellbore. After casing is run into a drilled well, cement is injected through the casing to wellbore annulus.

The most important function of cementing is to achieve long-term zonal isolation. Besides, cement also has the following functions: ① To support the vertical and radial loads applied to the casing. ② Isolate porous formations from the producing zone formations. ③ Exclude unwanted subsurface fluids from the producing interval. ④ Protect casing from corrosion. ⑤ In directional drilling, cementing is used to plug an existing well, in order to run a directional well from that point. ⑥ Cementing is used to plug a well to abandon it.

7.2 Selection of cement grades

Cement was first discovered by an English brick layer named Joseph Aspdin in 1824. He called it Portland cement for the reason that the cement he discovered resembled the limestone found in Portland. Portland cement contains 60% ~ 70% Lime (CaO), 20%~25% Silica (SiO_2), 5%~10% Alumina (Al_2O_3), and 2%~3% Ferric oxide (Fe_2O_3).

Cementing service companies stock various types of cement and have special transport equipment to handle this material in bulk. Bulk-cement storage and handling equipment are moved out to the rig, making it possible to mix large quantities of cement at the site. The cementing crew mixes the dry cement with water, using a device called jet-mixing hopper. The dry cement is gradually added to the hopper, and a jet of water thoroughly mixes with the cement to make a slurry.

The API has classified 9 types of cement as follows.

Class A: Intended for 0~6000 ft (1830 m) depth, when special properties are not required. Available only in ordinary type.

Class B: Intended for 0~6000 ft depth, when conditions require moderate to high sulfate resistance. Available in moderate and high sulfate resistant types.

Class C: Intended for 0~6000 ft depth, when conditions require high early strength. Available in ordinary, moderate and high sulfate resistant types.

Class D: Intended for 6000~10000 ft (1830 to 3050 m) depth under moderately high temperatures and pressures. Available in moderate and high sulfate resistant types.

Class E: Intended for 10000~14000 ft (3050 to 4270 m) depth under conditions of high temperatures and pressures. Available in moderate and high sulfate resistant types.

Class F: Intended for 10000~16000 ft (3050 to 4880 m) depth under conditions of extremely high temperatures and pressures. Available in moderate and high sulfate resistant types.

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Class G. Intended for 0~8000 ft (2400 m) depth, can be used with accelerators and retarders to cover a wide range of well depths and temperatures. Available in moderate and high sulfate resistant types.

Class H. Intended for 0~8000 ft (2400 m) depth, can be used with accelerators and retarders to cover a wide range of well depths and temperatures. Available only in moderate sulfate resistant type.

Class I. Intended for 12000~16000 ft 3660~4880 m depth, can be used under conditions of extremely high temperatures and pressures or can be mixed with accelerators and retarders to cover a range of well depth and temperatures.

7.3 Preparing the cement

In preparing a well for cementing, it is important to establish the amount of cement required for the job. This is done by measuring the diameter of the borehole along its depth, using a caliper log. Utilizing both mechanical and sonic means, caliper logs measure the diameter of the well at numerous locations simultaneously in order to accommodate for irregularities in the wellbore diameter and determine the volume of the open hole.

Additionally, the required physical properties of the cement are essential before commencing cementing operations. The proper cement properties are also determined, including the density and viscosity of the material, before actually pumping the cement into the hole.

Special mixers, including hydraulic jet mixers, re-circulating mixers or batch mixers, are used to combine dry cement with water to create the wet cement, also known as slurry. The cement used in the well cementing process is Portland cement, and it is calibrated with additives to form 1 of 9 different API classes of cement. Each is employed for various situations. Additives can include accelerators, which shorten the setting time required for the cement, as well as retarders, which do the opposite and make the cement setting time longer.

In order to decrease or increase the density of the cement, lightweight and heavyweight additives are added. Lightweight solids commonly used to reduce slurry density include bentonite and solid hydrocarbons. Heavyweight solids commonly used to increase slurry density include barite and hematite.

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Additives can be added to transform the compressive strength of the cement, as well as flow properties and dehydration rates.

When cementing shallow wells, it may be necessary to accelerate the cement hydration to reduce waiting time. Common cement accelerators are calcium chloride, sodium chloride, gypsum and sodium silicate. Common cement retarder is calcium lignosulfonate. It also reduces cement viscosity when necessary.

Extenders can be used to expand the cement in an effort to reduce the cost of cementing, and antifoam additives can be added to prevent foaming within the well. In order to plug lost circulation zones, bridging materials are required.

7.4 Cementing the well

After casing is run into the well, an L-shaped cementing head is fixed to the top of the wellhead to receive the slurry from the pumps. Two wiper plugs, or cementing plugs sweep the inside of the casing and prevent mixing. They are often called bottom plug and top plug. The cementing process is shown in Fig. 7-1.

Keeping the drilling fluids from mixing with the cement slurry, the bottom plug is introduced into the well, and cement slurry is pumped into the well behind it. The bottom plug is then caught just above the bottom of the wellbore by the float collar, which functions as a one-way valve allowing the cement slurry to enter the well. The plugs are presented in Fig. 7-2.

Then the pressure on the cement being pumped into the well is increased until a diaphragm is broken within the bottom plug, permitting the slurry to flow through it and up the outside of the casing string.

After the proper volume of cement is pumped into the well, a top plug is pumped into the casing pushing the remaining slurry through the bottom plug. Once the top plug reaches the bottom plug, the pumps are turned off, and the cement is allowed to set.

The amount of time it takes cement to harden is called thickening time. For setting wells at deep depths, under high temperature or pressure, as well as in corrosive environments, special cements can be employed.

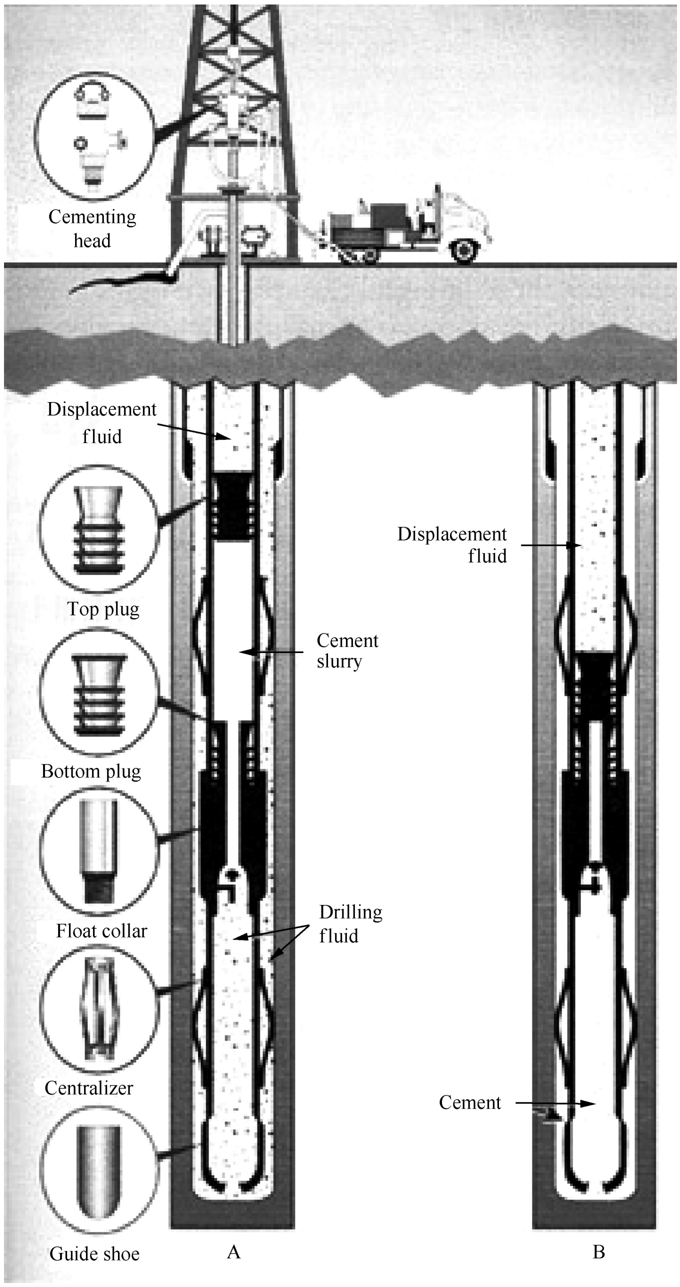

Fig. 7-1　The cementing operation

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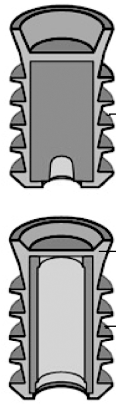

Fig. 7-2 Cement plugs

Example 7-1: Cement slurry volume calculation

You are required to obtain the volume of cement slurry with the information provided here.

Bit size = 20 in

Casing OD = 16 in

Cement height = 600 m

Cement weight = 50 kg/sack[①]

Cement specific gravity = 3.14

$CaCl_2$ concentration = 2% (weight of cement)

$CaCl_2$ specific gravity = 1.83

Water cement ratio = 20 L (water per sack of cement)

Excess factor = 1.5

Solution: Each sack of cement needs to mix with $CaCl_2$ and water to produce slurry. Let's look at the volume of slurry produced by one sack of cement.

Volume of cement per sack = 50 kg/(3.14 kg/L) = 15.92 L

Volume of $CaCl_2$ added to cement = (50 kg × 2%)/(1.83 kg/L) = 1/1.83 = 0.55 L

Volume of water added to cement = 20 L

Therefore, Volume of slurry produced by one sack of cement = 15.92+0.55+20= 36.47 L

The cross sectional area of annulus = $0.25 \times 3.14 \times [(20\ \text{in})^2 - (16\ \text{in})^2] = 0.073\ \text{m}^2$

The slurry volume required = $0.073\ \text{m}^2 \times 600\ \text{m} \times 1.5 = 65700\ \text{L}$

Number of sacks required = 65700/36.47 = 1801

① 1 sack = 94 lb = 42.64 kg.

7.5 Well perforation

Since the pay zone is sealed off by the production string and cement, perforations must be made in order for the oil or gas to flow into the wellbore. Perforations are simply holes that are made through the casing and cement and extend some distance into the formation (Fig. 7-3). The most common method of perforating incorporates shaped-charge explosives, similar to those used in armor-piercing shells.

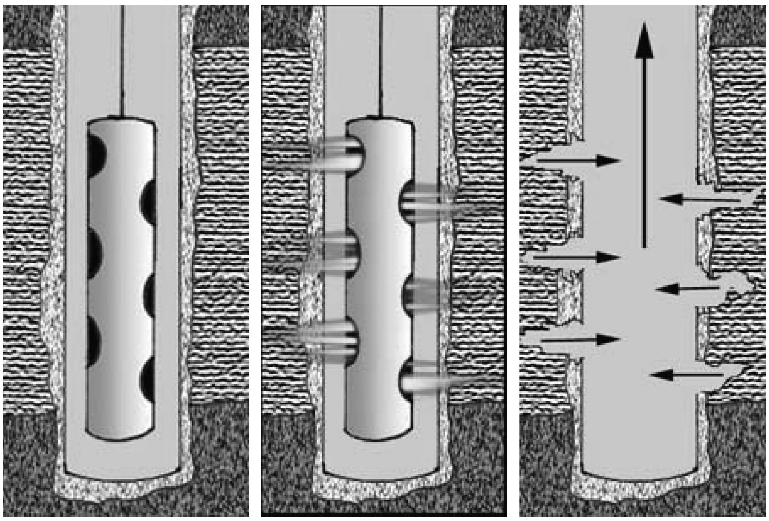

Fig. 7-3 The perforation process

Bullet guns were the first commercial perforating devices. A hardened steel bullet was fired from a short-barrel gun powered by a gas-producing explosive. These guns first saw commercial use in the early 1930s. The wall thickness and hardness of the casing and the hardness of the formation limit bullet perforating. Bullet guns are still used in some applications, usually in soft formations for deep penetration or brittle formations in which the shattering produced by the bullet can help break down the formation around the perforation.

During the 1930s and 1940s, work in the area of shaped charges progressed in the military arena. The bazooka, with its armor-piercing charges, was one of the first large-scale use of the technology pioneered by Henry Mohaupt and others. This technology was accepted by the oil industry in the late 1940s and early 1950s, and became the most used perforating method by the mid- to-late 1950s.

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Shaped charges accomplish penetration by creating a jet of high-pressure, high-velocity gas. The charges are arranged in a tool called gun that is lowered into the well opposite the producing zone (Fig. 7-4). Usually the gun is attached to wire line. When the gun is in position, the charges are fired by electronic means from the surface. After the perforations are made, the tool is retrieved. Perforating is usually performed by a service company that specializes in this technique.

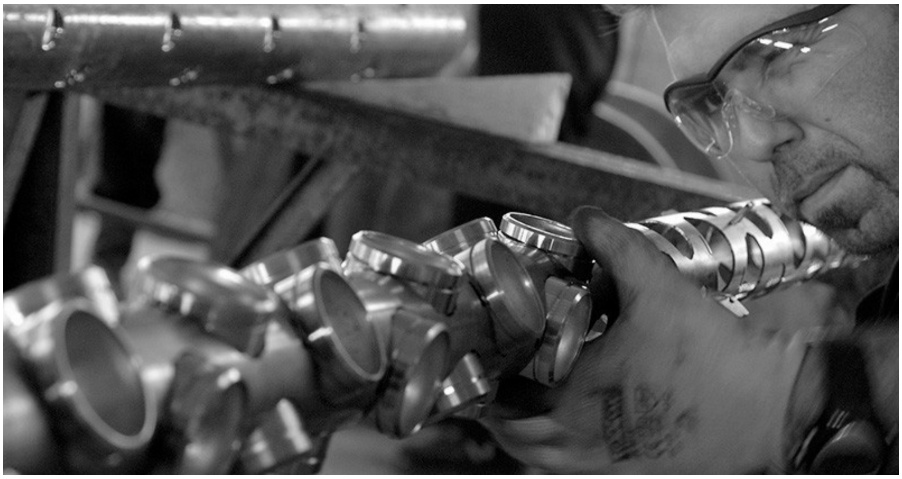

Fig. 7-4 Loaded perforation gun

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Chapter 8　Drilling problems and drilling costs

Common issues facing drilling operations include stuck pipe, shale sloughing, lost circulation and kick. The remediation methods are presented in this chapter. Drilling is an expensive operation. The cost of drilling is also discussed in this chapter.

8.1　Stuck pipe

During drilling, drill pipe can get stuck for the following reasons. ① The mud pressure is much higher than formation pressure. The drill pipe is pushed against well bore due to the high pressure difference. ② Drill pipe is buried by cuttings. If the drill pipe is left motionless in the well for long time, the cuttings fall down and bury the pipe. ③ While drilling a directional well, the dog leg severity is too high, and the pipe is stuck at buildup section.

The following operations can possibly reduce the risk of stuck pipe. ① Reduce the differential pressure by reducing mud density. ② Reduce solids content in mud. ③ Reduce friction by addition of oil to mud, or using oil based mud if possible. ④ Reduce the time duration for drill pipe being static. ⑤ Reduce dog leg severity.

If the pipe is already stuck, several operations can be carried out to free the stuck pipe. ① Inject diesel oil down the drill pipe. Drill pipe and annulus can be regarded as a U-tube. The higher pressure from the annulus side forces diesel to back flow. After diesel flows out of drill pipe, the mud hydrostatic pressure decreases, thus reducing the differential pressure. During backflow, drill pipe should be worked constantly and hopefully stuck pipe may be freed. ② A mixture of diesel and surfactant can be injected through the drill pipe. The mixture reaches the stuck point, and reduces friction factor. Drill pipe should be worked constantly during this operation. ③ If we cannot free the pipe with the previous methods, we can retrieve the pipe above the stuck point with a back-off operation.

8.2　Shale sloughing

Drillers often encounter shale zone when drilling a well. Shale is a weak sedimentary rock composed of clay, silt and water. Shale can break off from wellbore and cause uneven wellbore size, stuck pipe, even loss of well. Shale sloughing is caused by several factors. ① During drilling, mud flows in the annulus and erodes shale zone. ② Drilling a well changes the subsurface stress field, thus causing shale to break off. ③ The salinity of mud is often much less than that of pore water. Shale absorbs water of low salinity and swells.

Shale sloughing can be prevented or reduced by the following methods. ① Create laminar flow in annulus to reduce turbulence and erosion. ② Use KCl polymer mud. Potassium can inhibit shale swelling, while polymer increases mud viscosity and reduces filtrate loss. ③ Use oil based mud. Oil based mud is excellent in stabilizing shale.

8.3 Lost circulation

Lost circulation occurs when mud hydrostatic pressure exceeds formation fracture pressure. As a result, fractures are created and mud flows quickly into the formation. This is indicated with a decrease in pit volume. We can combat lost circulation with the following actions. ① Reduce mud hydrostatic pressure by reducing mud density. ② Squeeze bridging materials into thief zone. Common bridging materials include glass fiber, nut hull and ground asphalt.

8.4 Well kick

A kick occurs when formation pressure is higher than mud hydrostatic pressure. Some phenomena indicate well kick has happened. ① Increase in pit volume. During normal drilling operation, mud pit volume should remain relatively stable. When a kick occurs, formation fluid enters the well and pit, increasing the pit volume. ② Increase in rate of penetration (ROP). A kick often occurs while drilling through abnormally pressured formation. For such formations, the rocks often have higher porosity than adjacent formations. Therefore, ROP increases while drilling abnormally pressured formations. However, other factors may also cause increase in ROP. ③ Decrease in mud circulation pressure. Formation fluid, such as formation water, oil or gas, normally has lower density than mud in circulation. When formation fluid mixes with mud, the mud density and circulation pressure are therefore reduced. ④ Oil and gas show clearly indicates formation fluid has entered well. ⑤ Increase in chloride concentration.

Formation water has very high salinity. Invasion of formation water causes increase in chloride ions.

Once kick occurs, the well should be shut in and a killing operation is carried out to prevent further development of blowout. This requires injection of heavy mud into the well to overbalance formation pressure. We will learn about kill design with an example.

Example 8-1: Design of well killing operation

A kick was encountered at a depth of 10000 ft. Current mud density is 75 pcf (lb/ft^3). The well was shut in and the pressures are recorded:

DPSIP (drill pipe shut in pressure) = 200 psi;

CSIP (casing shut in pressure) = 400 psi.

The volume capacities are calculated here:

Capacity of drill string = 175 bbl;

Capacity of annulus = 480 bbl.

(1) Calculate formation pressure.

(2) Calculate density of kill mud.

(3) Obtain the total time for the kill mud to replace the original mud.

(4) Total number of pump strokes requires. Pump speed is 30 strokes per minute, and pump capacity is 0.1 bbl per stroke.

Solution.

(1) We use DPSIP to obtain formation pressure.

Formation Pressure P_F = DPSIP + Mud hydrostatic pressure

= 200 psi + 75 × (10000/144) = 5408 psi

(2) Hydrostatic pressure of kill mud must balance formation pressure. We normally need to apply 100 to 200 psi of extra pressure to make sure the mud hydrostatic pressure will overbalance formation pressure.

$$\text{Kill mud density } \rho_2 = (5408+200) \times (144/10000) = 81 \text{ pcf}$$

(3) The total circulation time for kill mud depends on the total volume capacity and pump capacity.

$$\text{Total time} = (175+480)/(30 \times 0.1) = 218 \text{ min}$$

(4) The total number of strokes is thus,

$$\text{Total strokes} = (175+480)/0.1 = 6550 \text{ strokes}$$

8.5 Drilling costs

The costs of drilling includes expenses from the following main sources.

8.5.1 Leases

The right to enter and drill on the property owner's land is accomplished by obtaining a lease. The lease is subject to title search and proper recording in much the same way as real estate. Many times the bonus for a mineral lease exceeds the value of the property itself. Between legal cost for title work and lease bonus, wells see costs in excess of $1000000 for leasing alone. Some leases with multiple mineral and land owners take several months if not years to negotiate and finalize.

8.5.2 Site preparation

Most times, a road must be built to the site. Good roads are a necessity in order for trucks and heavy equipment to reach the well. Once at the site, a level area is cleared about 2/3 the size of a football field. Bulldozers, dump trucks, excavators and road graders are typically used for this process. Generally, this process takes between 2 and 3 weeks, but if extensive road work is needed, it can take much longer. Construction of roads and drilling site is a major cost factor which can easily exceed $400000 per location.

8.5.3 Well drilling

After the site is prepared, the drilling rig can be moved into position. A rotary rig is capable of drilling over 1000 feet per day. The drilling operation is a very complicated one requiring enormous amounts of planning and teamwork. A modern drilling project can encompass the use of 30~40 different individual companies to fully complete the process.

Costs depend on the depth and complexity of the well. Modern horizontal well drilling costs can easily exceed $4000000 just in the drilling phase. Without drilling complications these wells generally take about 3 weeks for the drilling phase.

8.5.4 Rig mobilization

Moving drilling rig is not a simple task. Every time a new well is drilled, a drilling rig must be moved in and assembled. The process normally takes 3~5 days. After the well is drilled the rig must be cleaned and disassembled and moved off location. Rig mobilization and assembly expenses vary depending on how far the rig must be transported, but generally run between USD100000 and USD350000.

8.5.5 Miscellaneous costs

Costs outlines above are only some of the costs incurred preparing, drilling, completing and producing of an oil or gas well. In total, this complete process will encompass 40~50 different individual contracting companies and hundreds of additional minor expenses.

The most common practice of cost evaluation is to calculate the cost per unit depth drilled. During drilling, most of the time is spent on drilling the well or making a trip to change the worn bit. The drilling cost can be expressed as

$$C_\mathrm{f} = \frac{C_\mathrm{b} + C_\mathrm{r}(t_\mathrm{b} + t_\mathrm{c} + t_\mathrm{t})}{\Delta D}$$

where, C_f is drilling cost per unit length; C_b is cost of bit; C_r is cost of rig per unit time; t_b is total rotating time; t_c is non-rotating time; t_t is trip time; ΔD is a given depth drilled.

Example 8-2: Evaluation of drilling cost

The drilling records for three bits are given in the table below. The operating cost of the rig is USD1000 per hour. The trip time is 7 hours. Determine the drilling cost for each bit.

Bit	Bit cost /USD	Rotating time /h	Connection time /h	Penetration rate /(ft/h)	Cost /(USD/ft)
A	2000	15	0.1	14	114.8
B	5000	60	0.5	12	100.7
C	5000	90	0.5	10	113.9

For bit A,

$$C_\mathrm{f} = \frac{2000 + 1000 \times (15 + 0.1 + 7)}{15 \times 14} = 114.8\ \text{USD/ft}$$

For bits B and C, similar calculations are carried out and the answers are presented in the table. It can be concluded bit B leads to lowest cost. However, the drilling cost formula ignores risk factors. The cost analysis must incorporate engineering judgments.

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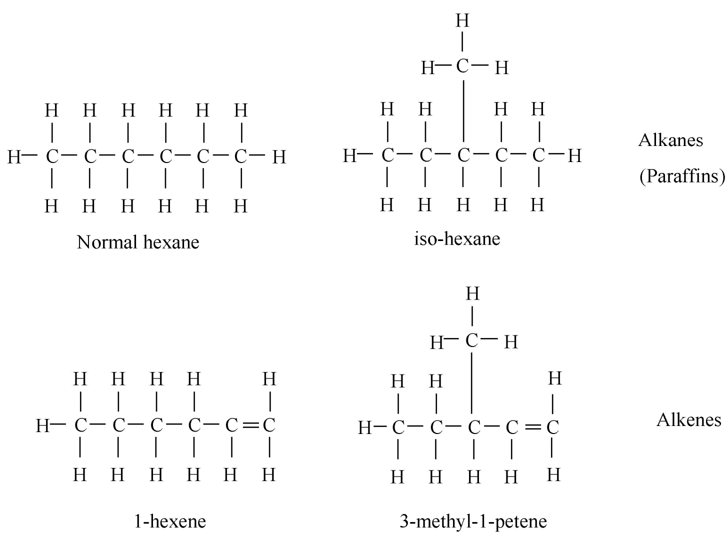
Chapter 9 Properties of hydrocarbon and rock

It is necessary for engineers in oil and gas industry to be equipped with knowledge in properties of hydrocarbon and reservoir rock. This chapter presents the most important concepts related to properties of natural gas, crude oil and reservoir rock. This chapter covers the definitions of key parameters, as well as the most widely used methods to predict oil and gas properties.

Originally, hydrocarbon and water are sealed in reservoir rocks. Before the reservoir comes on stream, the fluids in the reservoir are maintained under initial reservoir pressure and temperature. After the production begins, reservoir pressure starts to decline, and the oil and gas properties also change with changing reservoir conditions.

Crude oil is a mixture of light to heavy hydrocarbons, plus some sulphur, oxygen, nitrogen and metallic components. According to different structures, hydrocarbons are classified as paraffin (alkane), olefin (alkene), naphthene and aromatics. Some examples are given in Fig. 9-1.



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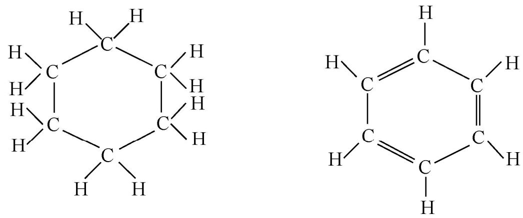

Cyclohexane Benzene

Naphthenes Aromatics

Fig. 9-1 Different types of hydrocarbons

9.1 Phase behavior

Reservoir fluids may exist as vapor or liquid, even solid phases. The change in phases can be directly mapped on a pressure-temperature（*P*-*T*） diagram. A typical *P*-*T* diagram is shown in Fig. 9-2.

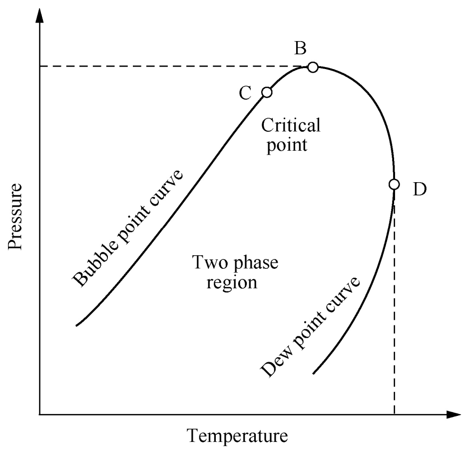

Fig. 9-2 A typical *P*-*T* diagram

The phase envelope is formed by connecting bubble point curve and dew point curve. Bubble point curve separates liquid phase from two phase regions. Two phases coexist inside the envelope. The two curves converge at critical point. The pressure and temperature at critical point are named critical pressure and critical temperature.

Cricondentherm refers to the maximum temperature beyond which liquid cannot form regardless of pressure（point D in the *P*-*T* diagram）. Cricondenbar refers to the maximum pressure beyond which gas cannot form regardless of temperature（point B

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in the *P*-*T* diagram). Different types of oil and gas reservoirs are defined based on their *P*-*T* diagrams.

9.1.1　Oil reservoir

If the reservoir temperature is lower than the critical temperature of the reservoir fluid, the reservoir is referred to as an oil reservoir. Oil reservoirs can be further classified into three types as follows.

(1) Saturated reservoir: If the initial reservoir pressure is equal to the bubble point pressure of reservoir fluid, the reservoir is referred to as saturated reservoir.

(2) Undersaturated reservoir: If the initial reservoir pressure is higher than the bubble point pressure of reservoir fluid, the reservoir is referred to as undersaturated reservoir.

(3) Gas cap reservoir: If the initial reservoir pressure is below the bubble point pressure of reservoir fluid, the reservoir is referred to as gas cap reservoir. A gas zone lies above the oil zone.

9.1.2　Gas reservoir

If the reservoir temperature is above the critical temperature of hydrocarbon in the reservoir, the reservoir is classified as a gas reservoir. Gas reservoirs can be further classified as three types.

(1) Retrograde condensate reservoir: If the reservoir temperature lies between the critical temperature and the cricondentherm of the reservoir hydrocarbon system, the reservoir is classified as retrograde condensate reservoir. This type of reservoir demonstrates very unique thermodynamic behavior, which is illustrated in Fig. 9-3. At point 1, the hydrocarbon exists as vapor phase. As pressure decline, it expands in volume. While pressure further declines into the two-phase region, it begins to condense rather than expand further. The condensate volume reaches maximum at point 3. Afterwards the condensate begins to vaporize while pressure declines further (see point in Fig. 9-3 4).

(2) Wet gas reservoir: For this type of reservoir, its temperature is above the cricondentherm. Hence, the original hydrocarbon is in vapor state. However, while the gas flows to surface, its pressure and temperature reduce and a liquid phase begins to condense. This type of reservoir is classified as wet gas reservoir.

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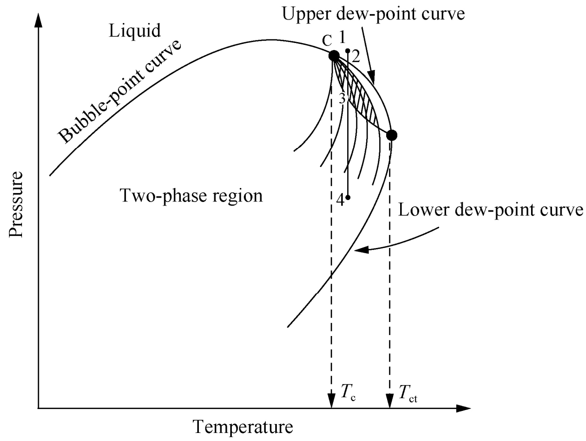

Fig. 9-3 *P-T* diagram for retrograde condensate

(3) Dry gas reservoir: For dry gas reservoir, the produced gas always exists as vapor phase. The only liquid produced is water.

9.2 Properties of natural gas

Natural gas is a naturally occurring hydrocarbon gas mixture consisting primarily of methane, but commonly including varying amounts of other higher alkanes, and sometimes a small percentage of carbon dioxide, nitrogen, hydrogen sulfide, or helium.

Natural gas is an important source of energy for heating, cooking, and electricity generation. It is also a major feedstock for production of plastics and fertilizers. When a gas is stored at ambient pressure and temperature, it behaves like an ideal gas. When pressure and temperature increase, its behavior deviates from ideal gas.

9.2.1 Ideal gas law

An ideal gas abides by the ideal gas law:

$$PV = nRT \tag{9-1}$$

where, P is absolute pressure, psia①; V is volume, ft^3; T is absolute temperature, °R; n is number of moles of gas, lb-mole; R is universal gas constant (10.73 for the above units).

It is clear that:

① Psia refers to absolute pressure, 1psia=6.985kPa.

$$n = \frac{m}{M} \tag{9-2}$$

Where, m is the mass of gas; M is the gas molecular weight.

Therefore,

$$PV = \frac{m}{M} RT \tag{9-3}$$

And the density of gas is expressed as:

$$\rho_g = \frac{m}{V} = \frac{PM}{RT} \tag{9-4}$$

Natural gas is a mixture of components. The apparent molecular weight of the mixture depends on the molecular weight of each component and its fraction.

$$M_a = \sum_{i=1}^{n} y_i M_i \tag{9-5}$$

where, M_a is apparent molecular weight of a gas mixture; M_i is molecular weight of a component in the mixture; y_i is mole fraction of a component in the mixture.

The specific gravity of gas is defined as the ratio of gas density to air density.

$$\gamma_{\mathrm{g}} = \frac{\rho_{\mathrm{g}}}{\rho_{\mathrm{a}}} \tag{9-6}$$

Incorporate the density, then specific gravity can be expressed as:

$$\gamma_{\mathrm{g}} = \frac{M_{\mathrm{a}}}{29} \tag{9-7}$$

9.2.2 Properties of real gas

For gases under high pressure, the ideal gas law leads to high errors. The ideal gas law must be adjusted to suit real gases under high pressure and high temperature. A parameter named gas compressibility factor（a.k.a. gas Z factor）is introduced.

$$PV = ZnRT \tag{9-8}$$

The determination of gas Z factor follows the steps.

（1）Calculate the pseudo-critical properties:

$$P_{\mathrm{pc}} = \sum_{i=1}^{n} y_i P_{\mathrm{c}i} \tag{9-9}$$

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$$T_{pc} = \sum_{i=1}^{n} y_i T_{ci} \tag{9-10}$$

If the composition is unknown, the pseudo-critical properties can be estimated by the following equations:

$$P_{pc} = 677 + 15\gamma_g - 37.5\gamma_g^2 \tag{9-11}$$

$$T_{pc} = 168 + 32.5\gamma_g - 12.5\gamma_g^2 \tag{9-12}$$

(2) Calculate pseudo-reduced pressure and temperature:

$$P_{pr} = \frac{P}{P_{pc}} \tag{9-13}$$

$$T_{pr} = \frac{T}{T_{pc}} \tag{9-14}$$

where, P is system pressure, psia; T is system temperature, ºR; P_{pc} is pseudo-critical pressure, psia; T_{pc} is pseudo-critical temperature, ºR; P_{pr} is pseudo-reduced pressure; T_{pr} is pseudo-reduced temperature.

(3) Find Z factor from Fig. 9-4. Several methods have been developed to directly calculate gas Z factor. These methods are not introduced here.

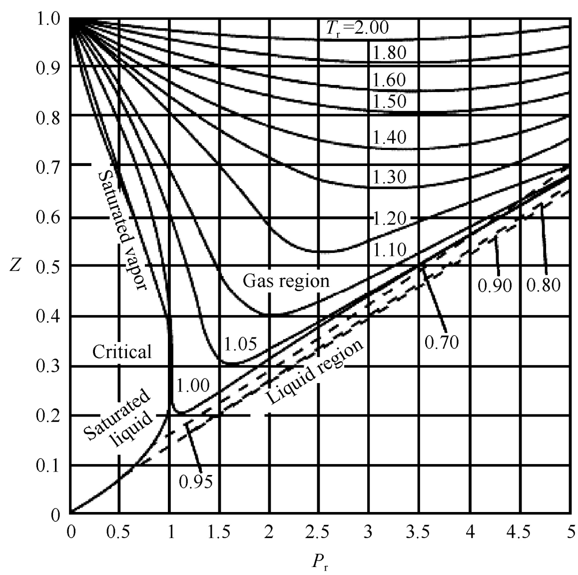

Fig. 9-4 Gas Z factor chart

Example 9-1: A natural gas contains 85% Methane, 10% Ethane and 5% Propane. The gas is under 3000 psia and 200 ºF. ① Find the apparent molecular weight and specific gravity for the gas mixture. ② Find the Z factor for this gas mixture.

Solutions:

Molecular weight of Methane = 16

Molecular weight of Ethane = 30

Molecular weight of Propane = 44

Therefore,

Apparent molecular weight = 0.85×16+0.1×30+0.05×44 = 13.6+3+2.2 = 18.8

Gas specific gravity = 18.8/29 = 0.648

Critical pressure for methane = 666.4 psia

Critical pressure for ethane = 706.5 psia

Critical pressure for propane = 616.4 psia

Pseudo-critical pressure = 0.85×666.4+0.1×706.5+0.05×616.4 = 667.9 psia

Critical temperature for methane = 343.3 ºR

Critical temperature for ethane = 549.9 ºR

Critical temperature for propane = 666.1 ºR

Pseudo-critical temperature = 0.85×343.3+0.1×549.9+0.05×666.1 = 380.1 ºR

Pseudo-reduced pressure = P/P_{pc} = 3000/667.9 = 4.5

Pseudo-reduced temperature = T/T_{pr} = (200-32+491)/380.1 = 1.73

According to Fig. 9-4, you can find Z factor is 0.92.

9.2.3 Compressibility of gas

The compressibility of gas is defined as the change in volume per unit volume for a unit change in pressure. Gas is very compressible. Therefore, its compressibility is high.

The gas compressibility is expressed as:

$$C_g = -\frac{1}{V}\left(\frac{\partial V}{\partial P}\right)_T \tag{9-15}$$

Recall the gas equation of state,

$$V = \frac{nRTZ}{P} \tag{9-16}$$

Derive the gas equation of state,

$$\left(\frac{\partial V}{\partial P}\right)_T = nRT\left(\frac{1}{P}\frac{\partial Z}{\partial P} - \frac{Z}{P^2}\right) \tag{9-17}$$

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Combine the derivative and the definition of gas compressibility, we find

$$C_g = \frac{1}{P} - \frac{1}{Z}\frac{\partial Z}{\partial P} \tag{9-18}$$

It is clear we need to find the slope of Z at certain pressure for compressibility. This approach is further illustrated in Fig. 9-5.

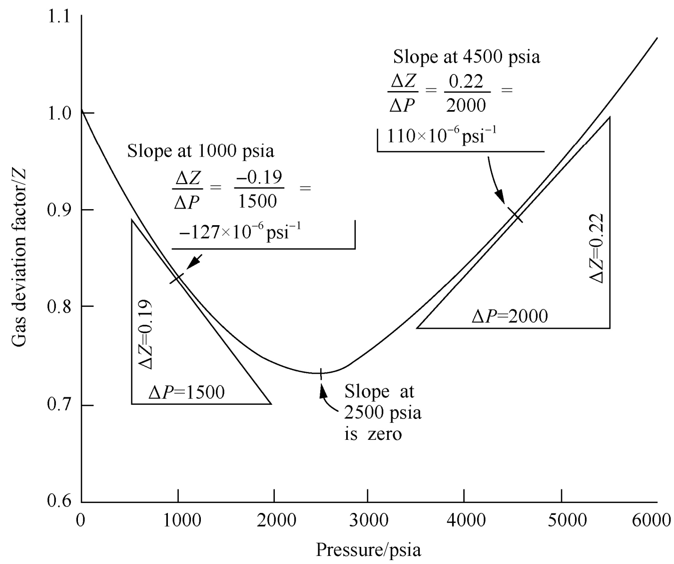

Fig. 9-5 Obtain gas compressibility from gas Z factor

9.2.4 Gas formation volume factor

The gas formation volume factor is defined as the ratio of gas volume at certain pressure and temperature to that at standard conditions (60ºF and 14.7 psia).

$$B_g = \frac{V_{P,T}}{V_{sc}} \tag{9-19}$$

where, B_g is gas formation volume factor; $V_{P,T}$ is volume of gas under certain pressure and temperature; V_{sc} is volume of gas under standard conditions.

Apply the gas equation of state,

$$B_g = \frac{P_{sc}}{T_{sc}}\frac{ZT}{P} \tag{9-20}$$

For the standard conditions, pressure is at 14.7 psia, and temperature at 520ºR.

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And the above equations becomes

$$B_g = 0.02827\frac{ZT}{P} \tag{9-21}$$

9.2.5 Gas viscosity

Gas viscosity is affected by pressure, temperature and gas composition. Under low pressure, gas viscosity increases as temperature increases. Under high pressure, gas viscosity decreases as temperature is raised.

Gas viscosity can be measured in laboratory. If measurement is not available, gas viscosity is often estimated with available charts. Lee method can calculate gas viscosity, but this method can not be used on sour gas unless the related factors have been corrected.

$$\mu_g = \frac{K}{10^4}\exp\left[X\left(\frac{\rho_g}{62.4}\right)^Y\right] \tag{9-22}$$

$$K = \frac{(9.4+0.02M_a)T^{1.5}}{209+19M_a+T} \tag{9-23}$$

$$X = 3.5+\frac{986}{T}+0.01M_a \tag{9-24}$$

$$Y = 2.4-0.2X \tag{9-25}$$

where, ρ_g is gas density under certain pressure and temperature, lb/ft^3; T is system temperature, $^{\circ}$R; M_a is apparent molecular weight of gas mixture.

9.3 Properties of crude oil

Under reservoir pressure, significant amount of hydrocarbon is dissolved in crude oil. When oil is produced, pressure and temperature reduce, and gas is liberated from oil phase. Changes in pressure, temperature and dissolved gas lead to changes in oil properties. The most important oil properties include oil density, solution gas oil ratio, oil formation volume factor and oil viscosity.

9.3.1 Oil specific gravity

This parameter is defined as the ratio of crude oil density to that of water. Crude oil

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specific gravity often ranges from 0.8 to 0.9 typically :

$$\gamma_o = \frac{\rho_o}{\rho_w} \tag{9-26}$$

where, γ_o is specific gravity oil; ρ_o is density of oil; ρ_w is density of water.

9.3.2 API gravity

API gravity is often used by industry. It is defined by the equation below. API gravity often ranges from 50 for light oil to 10 for heavy oil and water.

$$\text{API Gravity} = \frac{141.5}{\gamma_o} - 131.5 \tag{9-27}$$

9.3.3 Solution gas oil ratio

Solution GOR (or gas solubility) is defined as the amount of gas that evolves from oil as pressure is reduced. It often carries the unit of SCF[①]/STB[②] or SCM[③]/. Its trend is expressed in Fig. 9-6, where Pb represents bubble point pressure.

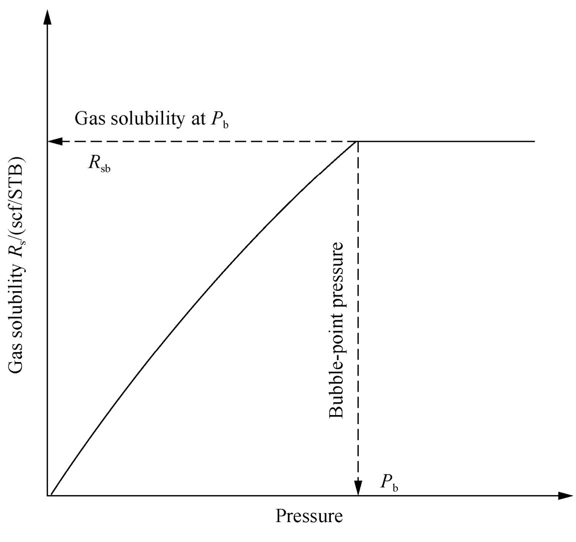

Fig. 9-6 Behavior of gas solubility versus pressure

① SCF=standard cubit feet.

② STB=stock tank barrel.

③ SCM=standard cubic meter.

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When pressure reduces but still above bubble point pressure, no gas is liberated and solution gas GOR remains constant. After pressure goes below bubble point pressure, gas begins to liberate and GOR is reduced. In fact, any pressure below original bubble point pressure is also a bubble point pressure, since oil is still saturated with gas at this point.

Gas solubility below bubble point pressure can be predicted by five various correlations. Here only the Standing correlation is presented. Standing correlation is based on California oil.

$$R_s = \gamma_g \left[\left(\frac{P}{18.2} + 1.4 \right) 10^x \right]^{1.2048} \tag{9-28}$$

$$x = 0.0125\,\text{API} - 0.00091\,T \tag{9-29}$$

where, P is system pressure, psia; T is system temperature, ºF; γ_g is specific gravity for solution gas; API is API gravity of oil.

9.3.4 Oil formation volume factor

The oil FVF, B_o, is defined as the ratio of the volume of oil containing solution gas at the prevailing pressure and temperature, to the volume of oil at standard conditions. When system pressure declines from initial reservoir pressure, oil first expands, therefore, oil formation volume factor increases. Below the bubble point pressure, gas is liberated, thus oil shrinks and B_o decreases. This trend is plotted in Fig. 9-7, where Pi represents initial reservoir pressure.

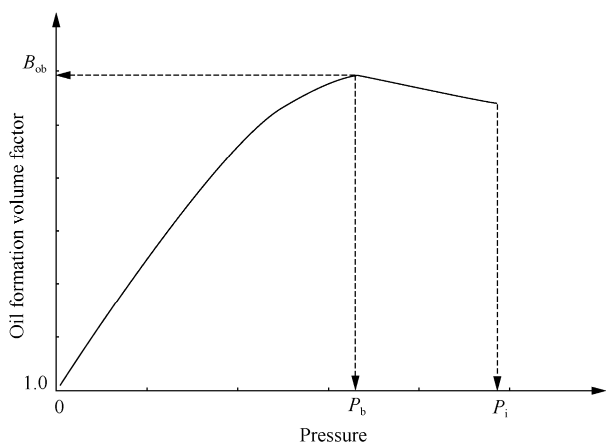

Fig. 9-7 Trend of oil formation volume factor versus pressure

There are a few correlations available for prediction of oil formation volume factor under saturated conditions. Standing summarized a correlation for oil formation volume factor based on 105 experiments for 22 California oil samples. This method can only be used for oil at or below bubble point pressure.

$$B_{\mathrm{o}} = 0.9759 + 0.00012\left[R_{\mathrm{s}}\left(\frac{\gamma_{\mathrm{g}}}{\gamma_{\mathrm{o}}}\right)^{0.5} + 1.25\,T\right]^{1.2} \tag{9-30}$$

where, T is temperature, ºF; γ_{o} is specific gravity of stock tank oil; γ_{g} is specific gravity of solution gas.

9.3.5 Oil viscosity

Oil viscosity is strongly affected by oil composition, pressure, temperature and gas solubility. Oil viscosity is reduced at high temperature. Solution gas lightens oil and leads to a reduction in oil viscosity.

When we talk about oil viscosity, we should clarify dead oil viscosity, under-saturated oil viscosity or saturated oil viscosity. Dead oil viscosity is the viscosity for oil at surface conditions. The solution gas has escaped.Saturated oil viscosity is the viscosity of oil at or below bubble point pressure. Under-saturated oil viscosity is measured at pressure higher than bubble point pressure.

Oil viscosity should be measured in lab under certain pressure and temperature when possible. Beggs and Robinson developed a correlation for dead oil viscosity based on 460 measurements.

$$\mu_{\mathrm{od}} = 10^{x} - 1 \tag{9-31}$$

where, $x = 10^{y}\,T^{-1.163}$; $y = 3.0324 - 0.02023\ \mathrm{API}$; T is temperature, ºF.

Beggs and Robinson also developed a correlation for saturated oil viscosity based on 2073 measurements.

$$\mu_{\mathrm{os}} = a\,\mu_{\mathrm{od}}^{\mathrm{b}} \tag{9-32}$$

Where, $a = 10.715(R_{\mathrm{s}} + 100)^{-0.515}$; $b = 5.44(R_{\mathrm{s}} + 150)^{-0.338}$; R_{s} is gas solubility, scf/STB.

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9.4 Basic rock properties

For drilling engineers, it is essential to understand basic rock properties that include porosity, permeability and electrical resistivity.

9.4.1 Porosity

Rock porosity is defined as the ratio of pore volume to bulk volume. Most of the pores are interconnected inside porous rocks, therefore fluid such as gas, oil and water can flow through. But some pores are isolated and disconnected from other pores, due to cementation and compaction. This phenomenon leads to two different types of porosity. Absolute porosity takes into account all pore spaces, while effective porosity considers only the connected pore spaces. It is obvious that effective porosity plays an important role in petroleum production. Oil bearing sandstones often have porosity that ranges from 15% ~ 25%. Porosity of limestone and dolomite is usually lower.

Rock porosity can be easily measured with saturation method. Dry rock sample is saturated with a brine with known density. The weight difference before and after saturation can tell the effective porosity.

9.4.2 Permeability

Permeability indicates the rock's capability to transmit fluids. It directly controls the fluid flow rate in reservoir. Permeability was first defined by Henry Darcy in 1856. He conducted experiments on flow of water through porous media and summarized the equation below, which is named Darcy's law.

$$Q = \frac{KA}{\mu} \frac{\mathrm{d}P}{\mathrm{d}L} \tag{9-33}$$

where, Q is flow rate through porous medium, cm^3/s; K is permeability of porous medium, D; μ is viscosity of fluid, cP; $\frac{\mathrm{d}P}{\mathrm{d}L}$ is pressure gradient, atm/cm.

Permeability is often conveniently measured by flowing dry gas, such as nitrogen, through porous medium. Klinkenberg in 1941 discovered that permeability measurements made with gas as the flowing fluid showed different results from permeability measurements made with a liquid. Permeability measured with gas is always higher than that measured with liquid.

It should be pointed out that reservoir porosity and permeability vary vertically and laterally. This is named reservoir heterogeneity. It has been proposed that most reservoirs are laid down in a body of water by a long-term process. As a result of subsequent physical and chemical reorganization, such as compaction, solution and cementation, the reservoir characteristics are further changed.

9.4.3 Electrical conductivity and resistivity

Electrical conductivity is the ability of a material to transmit an electric current. Except certain clay minerals, reservoir rocks do not conduct electricity. Oil, gas and pure water do not conduct electricity either. Reservoir rocks containing water have good conductivity, because large quantities of salts are dissolved in reservoir water.

Resistivity is the reciprocal of conductivity, as defined in the Ep.(9-34).

$$R = \frac{rA}{L} \tag{9-34}$$

where, R is Resistivity, Ω·m; r is resistance of material, Ω; A is cross sectional area of material, m^2; L is length of material, m.

The rock resistivity is of particular interests to logging engineers. When resistivity log shows high resistivity, it may indicate existence of hydrocarbon. Archie proposed a relation to investigate the water saturation in reservoir, which is the most important equation in resistivity logging:

$$R_{\mathrm{t}} = \frac{aR_{\mathrm{w}}}{\phi^m S_{\mathrm{w}}^n} \tag{9-35}$$

where, a is tortuosity factor; m is cementation factor/exponent; n is saturation factor/exponent; R_{t} is resistivity of rock containing fluids, Ω·m; R_{w} is resistivity of formation water, Ω·m; S_{w} is water saturation.

The tortuosity factor is meant to correct for variation in compaction, pore structure and grain size. The parameter is called the tortuosity factor and clearly is related to the path length of the current flow. The value lies in the range 0.5 ~ 1.5.

The cementation factor models how much the pore network increases the resistivity. It is related to the permeability of the rock. High rock permeability yields low cementation exponent. For unconsolidated sands, the factor has been observed near 1.3. For consolidated sandstones, common values are 1.8 ~ 2.0. In carbonate rocks, the cementation exponent shows higher variance and values between 1.7 and 4.1 have been observed.

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The saturation exponent usually is fixed to values close to 2. In logging interpretation for a certain zone, rock porosity in Archie relation is obtained with porosity logs. Resistivity of formation water is obtained by applying Archie relation to a nearby zone that is saturated with formation brine only. Therefore, the water saturation and certainly the hydrocarbon saturation are obtained.

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Appendix A

Unit conversion factors

Quantity	U S field unit	To SI unit	To U.S. field unit	Sl unit
Length	feet(ft)	0.3084	3.2808	meter(m)
	mile(mi)	1.609	0.6214	kilometer(km)
	inch(in)	25.4	0.03937	millimeter(mm)
Mass	ounce(oz)	28.3495	0.03527	gram(g)
	pound(lb)	0.4536	2.205	kilogram(kg)
	lbm	0.0311	32.17	slug
Volume	gallon(gal)	0.003785	264.172	meter^3(m^3)
	cu.ft(ft^3)	0.028317	35.3147	meter^3(m^3)
	barrel(bbl)	0.15899	6.2898	meter^3(m^3)
	Mcf(60°F, 4.7psia)	28.317	0.0353	Mm^3(15°C) (101.325kPa) (M=1.000)
Area	acre	4.0469×10^{3}	2.471×10^{-4}	meter^2(m^2)
	sq.ft(ft^2)	9.29×10^{-2}	10.764	meter^2(m^2)
	sq.mile	2.59	0.386	(km)^2
Pressure	lb/in^2(psi)	6.8948	0.145	kPa(1.000Pa)
	psi	0.0680	14.696	atm
	psi/ft	22.62	0.0442	kPa/m
	inch(Hg)	3.3864×10^{3}	0.2953×10^{-3}	Pa
Temperature	Fahrenheit(°F)	0.5556(°F−32)	1.8C+32	Celsius(°C)
	Rahrenheit(°R)	0.5556	1.8	Kelvin(K)
Energy(work)	Btu	252.16	3.966×10^{-3}	cal
	Btu	1.0551	0.9478	kilojoule(kJ)
	ft−lbf	1.3558	0.73766	joule(J)
	hp−hr	0.7457	1.341	kW·h
Viscosity	cP	0.001	1.000	Pa·s
	lb/ft·s	1.4882	0.672	kg/(m·sec) or (Pa·s)
	lbf·s/ft^2	479	0.0021	dyne·s/cm^2 (poise)
Thermal conductivity	Btu·ft/hr·ft^2·°F	1.7307	0.578	W/(m·K)
Specific heat	Btu/(lbm·°F)	1	1	cal/(g·°C)
	Btu/(lbm·°F)	4.184×10^{3}	2.39×10^{-4}	J(kg·K)
Density	lbm/ft^3	16.02	0.0624	kg/m^3

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Appendix B

API drill collar weight(lb/ft)

Drill collar OD /in	Drill Collar ID/in												
	1	11/4	11/2	13/4	2	21/4	21/2	23/4	3	31/4	31/2	33/4	4
27/8	19	18	16										
3	21	20	18										
31/8	22	22	20										
31/4	26	24	22										
31/2	30	29	27										
33/4	35	33	32										
4	40	39	37	35	32	29							
41/8	43	41	39	37	35	32							
41/4	46	44	42	40	38	35							
41/2	51	50	48	46	43	41							
43/4			54	52	50	47	44						
5			61	59	56	53	50						
51/4			68	65	63	60	57						
51/2			75	73	70	67	64	60					
53/4			82	80	78	75	72	67	64	60			
6			90	88	85	83	79	75	72	68			
61/4			98	96	94	91	88	83	80	76	72		
61/2			107	105	102	99	96	91	89	85	80		
63/4			116	114	111	108	105	100	98	93	89		
7			125	123	120	117	114	110	107	103	98	93	84
71/4			134	132	130	127	124	119	116	112	108	103	93
71/2			144	142	139	137	133	129	126	122	117	113	102
73/4			154	152	150	147	144	139	136	132	128	123	112
8			165	163	160	157	154	150	147	143	138	133	122
81/4			176	174	171	168	166	160	158	154	149	144	133
81/2			187	185	182	179	176	172	169	165	160	155	150
9			210	208	206	203	200	195	192	188	184	179	174
91/2			234	232	230	227	224	220	216	212	209	206	198
93/4			248	245	243	240	237	232	229	225	221	216	211
10			264	289	257	254	251	246	243	239	235	230	225
11			317	315	313	310	307	302	299	295	291	286	281
12			379	377	374	371	368	364	361	357	352	347	342

Appendix C:API Drill pipe dimensional data

Pipe OD /in	Nominal weight /(Ib/ft)	Pipe ID /in
23/8	4.85	1.995
	6.65	1.815
27/8	6.85	2.441
	10.4	2.151
31/2	9.50	2.992
	13.30	2.764
	15.50	2.602
4	11.85	3.476
	14.00	3.340
	15.70	3.240
41/2	13.75	3.958
	16.60	3.826
	20.00	3.640
	22.82	3.500
5	16.25	4.408
	19.50	4.276
	25.60	4.000
51/2	19.20	4.892
	21.90	4.778
	24.70	4.670
65/8	25.20	5.965
	27.20	5.901

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Appendix D: casing table

O D /in	Nominal weight *T&C* /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
4.5	9.5	J-55	3310	4380	101			152	0.205	4.09
4.5	9.5	K-55	3310	4380	112			152	0.205	4.09
4.5	9.5	WC-50*	3150	4000	107			138	0.205	4.09
4.5	10.5	J-55	4010	4790	132		203	166	0.224	4.052
4.5	10.5	K-55	4010	4790	146		249	166	0.224	4.052
4.5	10.5	WC-50*	3780	4400	122			150	0.224	4.052
4.5	11.6	J-55	4960	5350	154	162	225	184	0.25	4
4.5	11.6	K-55	4960	5350	170	180	277	184	0.25	4
4.5	11.6	WC-50*	4640	4900	141	149		167	0.25	4
4.5	11.6	L-80	6350	7780		212	291	267	0.25	4
4.5	11.6	HCL-80	8650	7780		223	312	267	0.25	4
4.5	11.6	N-80	6350	7780		223	304	267	0.25	4

Continued

O D /in	Nominal weight *T&C* /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
4.5	11.6	HCN-80	8650	7780		223	312	267	0.25	4
4.5	11.6	S-95	8650	9240		245	338	317	0.25	4
4.5	11.6	HCP-110	8650	10690		279	385	367	0.25	4
4.5	11.6	P-110	7580	10690		279	385	367	0.25	4
4.5	13.5	L-80	8540	9020		257	334	307	0.29	3.92
4.5	13.5	HCL-80	10380	9020		270	359	307	0.29	3.92
4.5	13.5	N-80	8540	9020		270	349	307	0.29	3.92
4.5	13.5	HCN-80	10380	9020		270	359	307	0.29	3.92
4.5	13.5	S-95	10380	10710		297	388	364	0.29	3.92
4.5	13.5	P-110	10680	12410		338	443	422	0.29	3.92
4.5	13.5	HCP-110	11250	12410		338	443	422	0.29	3.92
4.5	15.1	L-80	11090	10480		308	384	353	0.337	3.826
4.5	15.1	HCL-80	12330	10480		325	408	353	0.337	3.826
4.5	15.1	S-95	12330	12450		357	446	419	0.337	3.826

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Continued

O D /in	Nominal weight *T&C* /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
4.5	15.1	P-110	14350	14420		406	509	485	0.337	3.826
4.5	15.1	Q-125	15840	16380		438	554	551	0.337	3.826
4.5	15.1	LS-140	17240	18350		487	616	617	0.337	3.826
4.5	15.1	V-150	18110	19660		519	658	661	0.337	3.826
4.5	15.1	HCP-110	14341	14420		406	509	485	0.337	3.826
5	13	J-55	4140	4870	169	182	252	208	0.253	4.494
5	13	K-55	4140	4870	186	201	309	208	0.253	4.494
5	15	J-55	5560	5700	207	223	293	241	0.296	4.408
5	15	K-55	5560	5700	228	246	359	241	0.296	4.408
5	15	L-80	7250	8290		295	379	350	0.296	4.408
5	15	HCL-80	9380	8290		311	408	350	0.296	4.408
5	15	N-80	7250	8290		311	396	350	0.296	4.408
5	15	HCN-80	9380	8290		311	408	350	0.296	4.408
5	15	S-95	9380	9840		342	441	416	0.296	4.408

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O D /in	Nominal weight *T&C* /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
5	15	P-110	8850	11400		388	503	481	0.296	4.408
5	15	V-150	10250	15540		497	651	656	0.296	4.408
5	18	L-80	10500	10140		377	457	422	0.362	4.276
5	18	HCL-80	11880	10140		396	492	422	0.362	4.276
5	18	N-80	10500	10140		396	477	422	0.362	4.276
5	18	HCN-80	11880	10140		396	492	422	0.362	4.276
5	18	S-95	12030	12040		436	532	501	0.362	4.276
5	18	P-110	13470	13940		495	606	580	0.362	4.276
5	18	Q-125	14830	15840		535	661	659	0.362	4.276
5	18	LS-140	16080	17740		594	735	738	0.362	4.276
5	18	V-150	16860	19010		634	785	791	0.362	4.276
5	21.4	L-80	12760	12240		466	510	501	0.437	4.126
5	21.4	N-80	12760	12240		490	537	501	0.437	4.126
5	21.4	P-110	17550	16820		613	671	689	0.437	4.126

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Continued

O D /in	Nominal weight *T&C* /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
5	21.4	Q-125	19940	19120		662	724	783	0.437	4.126
5	23.2	L-80	13830	13380		513	510	543	0.478	4.044
5	23.2	HCL-80	15820	13380		540	516	543	0.478	4.044
5	23.2	N-80	13830	13380		540	537	543	0.478	4.044
5	23.2	HCN-80	15820	13380		540	537	543	0.478	4.044
5	23.2	S-95	16430	15890		594	590	645	0.478	4.044
5	23.2	P-110	19020	18400		675	671	747	0.478	4.044
5	23.2	Q-125	21620	20910		729	724	849	0.478	4.044
5	24.1	L-80	14400	14000		538	510	566	0.5	4
5	24.1	N-80	14400	14000		558	537	566	0.5	4
5	24.1	P-110	19800	19250		708	671	778	0.5	4
5	24.1	Q-125	22500	21880		765	724	884	0.5	4
5	24.1	V-150	27000	26250		907	858	1060	0.5	4
5.5	14	J-55	3120	4270	172			222	0.244	5.012

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O D /in	Nominal weight *T&C* /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
5.5	14	WC-50*	2970	3900*	158			201	0.244	5.012
5.5	15.5	J-55	4040	4810	202	217	300	248	0.275	4.95
5.5	15.5	K-55	4040	4810	222	239	366	248	0.275	4.95
5.5	15.5	WC-50*	3810	4400*	185	199		226	0.275	4.95
5.5	17	J-55	4910	5320	229	247	329	273	0.304	4.892
5.5	17	K-55	4910	5320	252	272	402	273	0.304	4.892
5.5	17	WC-50*	4590	4900*	210	227		248	0.304	4.892
5.5	17	L-80	6390	7740		338	428	397	0.304	4.892
5.5	17	HCL-80	8580	7740		356	462	397	0.304	4.892
5.5	17	N-80	6390	7740		348	446	397	0.304	4.892
5.5	17	HCN-80	8580	7740		356	462	397	0.304	4.892
5.5	17	S-95	8580	9190		392	498	471	0.304	4.892
5.5	17	HCP-110	8580	10640		445	568	546	0.304	4.892
5.5	17	P-110	7480	10640		445	568	546	0.304	4.892

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Continued

O D /in	Nominal weight *T&C* /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
5.5	17	HCQ-125	8580	12090		481	620	620	0.304	4.892
5.5	17	Q-125	7890	12090		481	620	620	0.304	4.892
5.5	20	L-80	8830	9190		416	503	466	0.361	4.778
5.5	20	HCL-80	10630	9190		438	542	466	0.361	4.778
5.5	20	N-80	8830	9190		428	524	466	0.361	4.778
5.5	20	HCN-80	10630	9190		438	542	466	0.361	4.778
5.5	20	S-95	10630	10910		482	585	554	0.361	4.778
5.5	20	P-110	11100	12630		548	667	641	0.361	4.778
5.5	20	Q-125	12080	14360		592	728	729	0.361	4.778
5.5	20	V-150	13460	17230		701	865	874	0.361	4.778
5.5	20	P-110 (EC)	12090	14360		445	568	729	0.361	4.778
5.5	20	HCP-110	12440	14770		445	568	729	0.361	4.778
5.5	23	L-80	11160	10560		489	550	530	0.415	4.67
5.5	23	HCL-80	12450	10560		514	551	530	0.415	4.67

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Continued

O D /in	Nominal weight *T&C* /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
5.5	23	N-80	11160	10560		502	579	530	0.415	4.67
5.5	23	HCN-80	12450	10560		514	579	530	0.415	4.67
5.5	23	S-95	12940	12540		566	637	630	0.415	4.67
5.5	23	P-110	14540	14530		643	724	729	0.415	4.67
5.5	23	Q-125	16070	16510		694	782	829	0.415	4.67
5.5	23	V-150	18390	19810		823	927	995	0.415	4.67
5.5	23	P-110(EC)	16220	16510		643	725	829	0.415	4.67
5.5	23	HCP-110	16520	16980		643	725	829	0.415	4.67
5.5	26	P-110	17400	16660		748	724	826	0.476	4.548
5.5	26	Q-125	19770	18930		808	782	939	0.476	4.548
5.5	26	V-150	23720	22720		957	927	1127	0.476	4.548
5.5	26	P-110(EC)	19770	18930				939	0.476	4.548
5.5	26	HCP-110	20330	19470				939	0.476	4.548
5.625	26.7	L-80	12420	11870		488	550	617	0.477	4.671

Continued

O D /in	Nominal weight *T&C* /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
5.625	26.7	HCL-80	14750	11870		501	550	617	0.477	4.671
5.625	26.7	P-110	17080	16320		642	724	849	0.477	4.671
5.75	16.5	J-55	3720	4620			314	234	0.276	5.198
5.75	18.1	J-55	4520	5090			344	286	0.304	5.142
5.75	18.1	L-80	5700	7400			447	416	0.304	5.142
5.75	18.1	N-80	5700	7400			466	416	0.304	5.142
5.75	18.1	P-110	6640	10180			594	572	0.304	5.142
5.75	19.7	J-55	5410	5610			377	313	0.335	5.08
5.75	19.7	L-80	7030	8160			490	456	0.335	5.08
5.75	19.7	N-80	7030	8160			511	456	0.335	5.08
5.75	19.7	P-110	8530	11220			651	627	0.335	5.08
5.75	21.8	L-80	8740	9130			545	507	0.375	5
5.75	21.8	N-80	8740	9130			568	507	0.375	5
5.75	21.8	P-110	10960	12550			723	697	0.375	5

Continued

O D /in	Nominal weight *T&C* /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
5.75	24.2	L-80	10650	10230			605	563	0.42	4.91
5.75	24.2	N-80	10650	10230			630	563	0.42	4.91
5.75	24.2	P-110	13700	14060			803	774	0.42	4.91
6.625	20	H-40	2520	3040	184			229	0.288	6.049
6.625	20	J-55	2970	4180	245	266	374	315	0.288	6.049
6.625	20	K-55	2970	4180	267	290	453	315	0.288	6.049
6.625	24	J-55	4560	5110	314	340	453	382	0.352	5.921
6.625	24	K-55	4560	5110	342	372	548	382	0.352	5.921
6.625	24	L-80	5760	7440		473	592	555	0.352	5.921
6.625	24	N-80	5760	7440		481	615	555	0.352	5.921
6.625	24	P-110	6730	10230		641	786	763	0.352	5.921
6.625	28	L-80	8170	8810		576	693	651	0.417	5.791
6.625	28	N-80	8170	8810		586	721	651	0.417	5.791
6.625	28	P-110	10160	12120		781	922	895	0.417	5.791

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Continued

O D /in	Nominal weight *T&C* /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
6.625	32	L-80	10320	10040		666	783	734	0.475	5.675
6.625	32	N-80	10320	10040		677	814	734	0.475	5.675
6.625	32	P-110	13220	13800		904	1040	1009	0.475	5.675
6.625	32	Q-125	14530	15680		989	1138	1147	0.475	5.675
7	20	H-40	1970	2720	176			230	0.272	6.456
7	20	J-55	2270	3740	234	257	373	316	0.272	6.456
7	20	K-55	2270	3740	254	281	451	316	0.272	6.456
7	20	WC-50	2160	3400	214			287	0.272	6.456
7	23	J-55	3270	4360	284	313	432	366	0.317	6.366
7	23	K-55	3270	4360	309	341	522	366	0.317	6.366
7	23	WC-50*	3110	4000	261	287		333	0.317	6.366
7	23	L-80	3830	6340		435	565	532	0.317	6.366
7	23	HCL-80	5650	6340		485	614	532	0.317	6.366
7	23	N-80	3830	6340		442	588	532	0.317	6.366

Continued

O D /in	Nominal weight *T&C* / (lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
7	23	HCN-80	5650	6340		485	614	532	0.317	6.366
7	23	S-95	5650	7530		512	659	632	0.317	6.366
7	23	P-110	4440	8720				732	0.317	6.241
7	23	HCP-110	5710	8720				732	0.317	6.241
7	26	J-55	4320	4980	334	367	490	415	0.362	6.276
7	26	K-55	4320	4980	364	401	592	415	0.362	6.276
7	26	WC-50	4060	4600	306	337		377	0.362	6.276
7	26	L-80	5410	7240		511	641	604	0.362	6.276
7	26	HCL-80	7800	7240		570	696	604	0.362	6.276
7	26	N-80	5410	7240		519	667	604	0.362	6.276
7	26	HCN-80	7800	7240		570	696	604	0.362	6.276
7	26	S-95	7800	8600		602	747	717	0.362	6.276
7	26	HCP-110	7800	9950		693	853	830	0.362	6.276
7	26	P-110	6230	9950		639	853	830	0.362	6.276

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O D /in	Nominal weight T & C /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
7	29	L-80	7020	8160		587	718	676	0.408	6.184
7	29	HCL-80	9200	8160		655	780	676	0.408	6.184
7	29	N-80	7020	8160		597	746	676	0.408	6.184
7	29	HCN-80	9200	8160		655	780	676	0.408	6.184
7	29	S-95	9200	9690		692	836	803	0.408	6.184
7	29	HCP-110	9200	11220		797	955	929	0.408	6.184
7	32	L-80	8610	9060		661	791	745	0.453	6.094
7	32	HCL-80	10400	9060		738	832	745	0.453	6.094
7	32	N-80	8610	9060		672	823	745	0.453	6.094
7	32	HCN-80	10400	9060		738	860	745	0.453	6.094
7	32	S-95	10400	10760		779	922	885	0.453	6.094
7	32	P-110	10780	12460		897	1053	1025	0.453	6.094
7	32	Q-125	11720	14160		996	1152	1165	0.453	6.094
7	32	V-150	13020	16990		1180	1370	1398	0.453	6.094

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O D /in	Nominal weight T & C /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
7	35	L-80	10180	9960		734	833	814	0.498	6.004
7	35	HCL-80	11600	9960		819	832	814	0.498	6.004
7	35	N-80	10180	9960		746	876	814	0.498	6.004
7	35	HCN-80	11600	9960		819	876	814	0.498	6.004
7	35	S-95	11650	11830		865	964	966	0.498	6.004
7	35	P-110	13020	13700		996	1096	1119	0.498	6.004
7	35	Q-125	14310	15560		1106	1183	1272	0.498	6.004
7	35	V-150	16220	18680		1311	1402	1526	0.498	6.004
7	38	L-80	11390	10800		801	832	877	0.54	5.92
7	38	HCL-80	12700	10800		831	832	877	0.54	5.92
7	38	N-80	11390	10800		814	876	877	0.54	5.92
7	38	HCN-80	12700	10800		831	876	877	0.54	5.92
7	38	S-95	13440	12830		944	964	1041	0.54	5.92
7	38	P-110	15140	14850		1087	1096	1205	0.54	5.92

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O D /in	Nominal weight T & C / (lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
7	38	Q-125	16750	16880		1207	1183	1370	0.54	5.92
7	38	V-150	19240	20250		1430	1402	1644	0.54	5.92
7	41	P-110	16990	16230		1111	1096	1307	0.59	5.82
7	41	Q-125	19300	18440		1244	1183	1485	0.59	5.82
7	41	V-150	22820	22130		1488	1402	1782	0.59	5.82
7.625	24	H-40	2030	2750	212			276	0.3	7.025
7.625	26.4	J-55	2890	4140	315	346	483	414	0.328	6.969
7.625	26.4	K-55	2890	4140	342	377	581	414	0.328	6.969
7.625	26.4	WC-50	2770	3800	289	317		376	0.328	6.969
7.625	26.4	L-80	3400	6020		482	635	602	0.328	6.969
7.625	26.4	HCL-80	4850	6020		533	691	602	0.328	6.969
7.625	26.4	N-80	3400	6020		490	659	602	0.328	6.969
7.625	26.4	HCN-80	4850	6020		553	691	602	0.328	6.969
7.625	26.4	S-95	4850	7150		568	740	714	0.328	6.969

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O D /in	Nominal weight T & C /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
7.625	26.4	HCP-110	4850	8280		654	845	827	0.328	6.969
7.625	26.4	P-110	3920	8280		654	845	827	0.328	6.969
7.625	29.7	L-80	4790	6890		566	721	683	0.375	6.875
7.625	29.7	HCL-80	7150	6890		650	785	683	0.375	6.875
7.625	29.7	N-80	4790	6890		575	749	683	0.375	6.875
7.625	29.7	HCN-80	7150	6890		650	785	683	0.375	6.875
7.625	33.7	L-80	6560	7900		664	820	778	0.43	6.765
7.625	33.7	HCL-80	8800	7900		762	894	778	0.43	6.765
7.625	33.7	N-80	6560	7900		674	852	778	0.43	6.765
7.625	33.7	HCN-80	8800	7900		762	894	778	0.43	6.765
7.625	33.7	S-95	8800	9380		783	957	923	0.43	6.765
7.625	33.7	HCP-110	8800	10860		901	1093	1069	0.43	6.765
7.625	33.7	P-110	7870	10860		901	1093	1069	0.43	6.765
7.625	33.7	HCQ-125	8800	12340		1009	1197	1215	0.43	6.765

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O D /in	Nominal weight T & C / (lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
7.625	33.7	Q-125	8350	12340		1009	1197	1215	0.43	6.765
7.625	33.7	V-150	8850	14800		1207	1424	1458	0.43	6.765
7.625	39	L-80	8820	9180		786	945	895	0.5	6.625
7.625	39	HCL-80	10600	9180		901	1029	895	0.5	6.625
7.625	39	N-80	8820	9180		798	981	895	0.5	6.625
7.625	39	HCN-80	10600	9180		901	1029	895	0.5	6.625
7.625	39	S-95	10600	10900		926	1101	1063	0.5	6.625
7.625	39	P-110	11080	12620		1066	1258	1231	0.5	6.625
7.625	39	Q-125	12060	14340		1194	1379	1399	0.5	6.625
7.625	39	V-150	13440	17210		1428	1640	1679	0.5	6.625
7.625	42.8	L-80	10810	10320		891	1053	998	0.562	6.501
7.625	42.8	N-80	10810	10320		905	1093	998	0.562	6.501
7.625	42.8	P-110	13920	14190		1210	1402	1372	0.562	6.501
7.625	42.8	Q-125	15350	16120		1355	1536	1559	0.562	6.501

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O D /in	Nominal weight T & C /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
7.625	45.3	HCL-80	12900	10920		1086	1177	1051	0.595	6.435
7.625	45.3	N-80	11510	10920		962	1152	1051	0.595	6.435
7.625	45.3	HCN-80	12900	10920		1086	1208	1051	0.595	6.435
7.625	45.3	S-95	13660	12970		1116	1293	1248	0.595	6.435
7.625	45.3	P-110	15430	15020		1285	1477	1446	0.595	6.435
7.625	45.3	Q-125	17090	17070		1439	1619	1643	0.595	6.435
7.625	45.3	V-150	19660	20480		1721	1926	1971	0.595	6.435
7.625	47.1	L-80	12040	11480		997	1160	1100	0.625	6.375
7.625	47.1	N-80	12040	11480		1013	1205	1100	0.625	6.375
7.625	47.1	T-95	14300	13630		1159	1300	1306	0.625	6.375
7.625	47.1	P-110	16550	15780		1353	1545	1512	0.625	6.375
7.625	47.1	Q-125	18700	17930		1515	1672	1718	0.625	6.375
7.625	51.2	T-95	15580	14980				1423	0.687	6.251
7.625	55.3	T-95	16850	16350				1539	0.75	6.125

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O D /in	Nominal weight T & C / (lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
7.75	46.1	L-80	11340	10750		841	1001	1070	0.595	6.56
7.75	46.1	HCL-80	13320	10750		965	1091	1070	0.595	6.56
7.75	46.1	S-95	13320	12760		992	1168	1271	0.595	6.56
7.75	46.1	T-95	13320	12760		978	1129	1271	0.595	6.56
7.75	46.1	P-110	14990	14780		1142	1334	1471	0.595	6.56
7.75	46.1	Q-125	16580	16790		1279	1462	1672	0.595	6.56
8.625	24	HCK-55	1780	2950	326			381	0.264	8.097
8.625	24	J-55	1370	2950	244			381	0.264	8.097
8.625	24	WC-50*	1330	2700*	237			347	0.264	8.097
8.625	28	WC-50*	1800	3100*	285	319		397	0.304	8.017
8.625	32	J-55	2530	3930	372	417	579	503	0.352	7.921
8.625	32	K-55	2530	3930	402	452	690	503	0.352	7.921
8.625	32	HCK-55	4130	3930	497	556	749	503	0.352	7.921
8.625	32	WC-50*	2440	3600*	341	383		457	0.352	7.921

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O D /in	Nominal weight T & C /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
8.625	36	J-55	3450	4460	434	486	654	568	0.4	7.825
8.625	36	K-55	3450	4460	468	526	780	568	0.4	7.825
8.625	36	HCK-55	5300	4460	579	648	847	568	0.4	7.825
8.625	36	L-80	4100	6490		678	864	827	0.4	7.825
8.625	36	HCL-80	6060	6490		779	945	827	0.4	7.825
8.625	36	N-80	4100	6490		688	895	827	0.4	7.825
8.625	36	HCN-80	6060	6490		779	945	827	0.4	7.825
8.625	40	L-80	5520	7300		776	966	925	0.45	7.725
8.625	40	HCL-80	7900	7300		892	1057	925	0.45	7.725
8.625	40	N-80	5520	7300		788	1001	925	0.45	7.725
8.625	40	HCN-80	7900	7300		892	1057	925	0.45	7.725
8.625	40	S-95	7900	8670		915	1127	1098	0.45	7.725
8.625	40	HCP-110	7900	10040		1055	1228	1271	0.45	7.725
9.625	32.3	H-40	1370	2270	254			365	0.312	9.001

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O D /in	Nominal weight *T* & *C* /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
9.625	32.3	WC-40	1370	2300*	241			365	0.312	9.001
9.625	36	H-40	1720	2560	294			410	0.352	8.921
9.625	36	J-55	2020	3520	394	453	639	564	0.352	8.921
9.625	36	K-55	2020	3520	423	489	755	564	0.352	8.921
9.625	36	HCK-55	2980	3520	526	605	829	564	0.352	8.921
9.625	36	WC-50*	1930	3200*	361	415		513	0.352	8.921
9.625	40	J-55	2570	3950	452	520	714	630	0.395	8.835
9.625	40	K-55	2570	3950	486	561	843	630	0.395	8.835
9.625	40	WC-50*	2480	3600*	414	476		573	0.395	8.835
9.625	40	HCK-55	4230	3950	604	64	926	630	0.395	8.835
9.625	40	L-80	3090	5750		727	947	916	0.395	8.835
9.625	40	HCL-80	4230	5750		837	1042	916	0.395	8.835
9.625	40	N-80	3090	5750		737	979	916	0.395	8.835
9.625	40	HCN-80	4230	5750		837	1042	916	0.395	8.835

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O D /in	Nominal weight T & C /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
9.625	40	S-95	4230	6820		858	1106	1088	0.395	8.835
9.625	43.5	L-80	3810	6330		813	1038	1005	0.435	8.755
9.625	43.5	HCL-80	5600	6330		936	1142	1005	0.435	8.755
9.625	43.5	N-80	3810	6330		825	1074	1005	0.435	8.755
9.625	43.5	HCN-80	5600	6330		936	1142	1005	0.435	8.755
9.625	43.5	S-95	5600	7510		959	1213	1193	0.435	8.755
9.625	43.5	HCP-110	5600	8700		1106	1388	1381	0.435	8.755
9.625	47	HCL-80	7100	6870		1027	1234	1086	0.472	8.681
9.625	47	N-80	4760	6870		905	1161	1086	0.472	8.681
9.625	47	HCN-80	7100	6870		1027	1234	1086	0.472	8.681
9.625	47	S-95	7100	8150		1053	1311	1289	0.472	8.681
9.625	47	HCP-110	7100	9440		1213	1500	1493	0.472	8.681
9.625	47	P-110	5300	9440		1213	1500	1493	0.472	8.681
9.625	47	HCQ-125	7100	10730		1361	1650	1697	0.472	8.681

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O D /in	Nominal weight T & C / (lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
9.625	47	Q-125	5640	10730		1361	1650	1697	0.472	8.681
9.625	53.5	L-80	6620	7930		1047	1286	1244	0.545	8.535
9.625	53.5	HCL-80	8850	7930		1205	1414	1244	0.545	8.535
9.625	53.5	N-80	6620	7930		1062	1329	1244	0.545	8.535
9.625	53.5	HCN-80	8850	7930		1205	1414	1244	0.545	8.535
9.625	53.5	S-95	8850	9410		1235	1502	1477	0.545	8.535
9.625	53.5	HCP-110	8850	10900		1422	1718	1710	0.545	8.535
9.625	53.5	P-110	7950	10900		1422	1718	1710	0.545	8.535
9.625	53.5	HCQ-125	8850	12390		1595	1890	1943	0.545	8.535
9.625	53.5	Q-125	8440	12390		1595	1890	1943	0.545	8.535
9.625	53.5	V-150	8960	14860		1909	2251	2332	0.545	8.535
9.75	59.2	S-95	9750	10150		1204	1469	1626	0.595	8.56
9.75	59.2	HCP-110	9750	11750		1387	1681	1882	0.595	8.56
9.75	59.2	P-110	9490	11750		1387	1681	1882	0.595	8.56

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O D /in	Nominal weight T & C /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
9.75	59.2	Q-125	10210	13350		1555	1850	2139	0.595	8.56
9.875	62.8	S-95	10180	10520		1123	1385	1725	0.625	8.625
9.875	62.8	P-110	10280	12180		1294	1584	1998	0.625	8.625
9.875	62.8	Q-125	11140	13840		1451	1743	2270	0.625	8.625
10.75	32.75	H-40	840	1820	205			367	0.279	10.192
10.75	32.75	WC-40	840	1800*	224			367	0.279	10.192
10.75	40.5	H-40	1390	2280	314			457	0.35	10.05
10.75	40.5	J-55	1580	3130	420		700	629	0.35	10.05
10.75	40.5	K-55	1580	3130	450		819	629	0.35	10.05
10.75	40.5	WC-50*	1530	2900*	385			572	0.35	10.05
10.75	40.5	HCK-55	2100	3130	562		911	629	0.35	10.05
10.75	40.5	N-80	1730	4560	597		964	915	0.35	10.05
10.75	40.5	HCN-80	2100	4560	681		1034	915	0.35	10.05
10.75	45.5	J-55	2090	3580	493		796	715	0.4	9.95

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O D /in	Nominal weight T & C /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
10.75	45.5	K-55	2090	3580	528		931	715	0.4	9.95
10.75	45.5	WC-50*	1990	3300*	451			650	0.4	9.95
10.75	45.5	HCK-55	3130	3580	659		1037	715	0.4	9.95
10.75	45.5	N-80	2470	5210	701		1097	1040	0.4	9.95
10.75	45.5	HCN-80	3130	5210	799		1175	1040	0.4	9.95
10.75	51	J-55	2700	4030	565		891	801	0.45	9.85
10.75	51	K-55	2700	4030	606		1043	801	0.45	9.85
10.75	51	HCN-80	4460	5860	916		1316	1165	0.45	9.85
10.75	51	S-95	4460	6960	937		1392	1383	0.45	9.85
10.75	51	HCP-110	4460	8060	1080		1594	1602	0.45	9.85
10.75	51	P-110	3660	8060	1080		1594	1602	0.45	9.85
10.75	51	HCQ-125	4660	9160	1213		1758	1820	0.45	9.85
10.75	51	Q-125	3740	9160	1213		1758	1820	0.45	9.85
10.75	55.5	HCK-55	5220	4430	843		1271	877	0.495	9.76

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O D /in	Nominal weight T & C /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
10.75	55.5	L-80	4020	6450	884		1303	1276	0.495	9.76
10.75	55.5	HCL-80	5950	6450	1010		1441	1276	0.495	9.76
10.75	55.5	N-80	4020	6450	895		1345	1276	0.495	9.76
10.75	55.5	HCN-80	5950	6450	1021		1441	1276	0.495	9.76
10.75	55.5	S-95	5950	7660	1043		1524	1515	0.495	9.76
10.75	55.5	HCP-110	5950	8860	1203		1745	1754	0.495	9.76
10.75	55.5	P-110	4610	8860	1203		1745	1754	0.495	9.76
10.75	55.5	HCQ-125	5950	10070	1351		1925	1993	0.495	9.76
10.75	55.5	Q-125	4850	10070	1351		1925	1993	0.495	9.76
11.75	42	H-40	1040	1980	307		554	478	0.333	11.084
11.75	42	WC-40	1040	2000*	293			478	0.333	11.084
11.75	47	J-55	1510	3070	477		807	737	0.375	11
11.75	47	K-55	1510	3070	509		935	737	0.375	11
11.75	47	HCK-55	2000	3070	638		1054	737	0.375	11

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O D /in	Nominal weight T & C /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
11.75	54	J-55	2070	3560	568		931	850	0.435	10.88
11.75	54	K-55	2070	3560	606		1079	850	0.435	10.88
11.75	54	HCK-55	3100	3560	760		1216	850	0.435	10.88
11.75	60	J-55	2660	4010	649		1042	952	0.489	10.772
11.75	60	K-55	2660	4010	693		1208	952	0.489	10.772
11.75	60	HCK-55	4360	4010	869		1361	952	0.489	10.772
11.75	60	L-80	3180	5830	913		1399	1384	0.489	10.772
11.75	60	HCL-80	4410	5830	1055		1555	1384	0.489	10.772
11.75	60	N-80	3180	5830	924		1440	1384	0.489	10.772
11.75	60	HCN-80	4410	5830	1055		1555	1384	0.489	10.772
11.75	60	S-95	4410	6920	1077		1638	1644	0.489	10.772
11.75	60	HCP-110	4410	8010	1242		1877	1903	0.489	10.772
11.75	60	P-110	3610	8010	1242		1877	1903	0.489	10.772
11.75	60	HCQ-125	4410	9100	1396		2074	2163	0.489	10.772

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O D /in	Nominal weight T & C /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
11.75	60	Q-125	3680	9100	1396		2074	2163	0.489	10.772
11.75	65	L-80	3870	6360	1007		1521	1505	0.534	10.682
11.75	65	HCL-80	5740	6360	1152		1691	1505	0.534	10.682
11.75	65	N-80	3870	6360	1019		1566	1505	0.534	10.682
11.75	65	HCN-80	5740	6360	1164		1691	1505	0.534	10.682
11.75	65	S-95	5740	7560	1189		1781	1788	0.534	10.682
11.75	65	HCP-110	5740	8750	1371		2041	2070	0.534	10.682
13.375	48	H-40	740	1730	322		607	541	0.33	12.715
13.375	48	WC-40	740	1700*	308			541	0.33	12.715
13.375	54.5	J-55	1130	2730	514		909	853	0.38	12.615
13.375	54.5	K-55	1130	2730	547		1038	853	0.38	12.615
13.375	54.5	HCK-55	1400	2730	689		1194	853	0.38	12.615
13.375	54.5	WC-50*	1110	2500*	470			776	0.38	12.615
13.375	61	J-55	1540	3090	595		1025	962	0.43	12.515

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O D /in	Nominal weight T & C /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
13.375	61	K-55	1540	3090	633		1169	962	0.43	12.515
13.375	61	HCK-55	2040	3090	798		1345	962	0.43	12.515
13.375	61	WC-50*	1490	2800*	544			874	0.43	12.515
13.375	68	J-55	1950	3450	675		1140	1069	0.48	12.415
13.375	68	K-55	1950	3450	718		1300	1069	0.48	12.415
13.375	68	HCK-55	2850	3450	905		1496	1069	0.48	12.415
13.375	68	L-80	2260	5020	952		1545	1556	0.48	12.415
13.375	68	HCL-80	2910	5020	1093		1732	1556	0.48	12.415
13.375	68	N-80	2260	5020	963		1585	1556	0.48	12.415
13.375	68	HCN-80	2910	5020	1103		1732	1556	0.48	12.415
13.375	68	S-95	2910	5970	1125		1812	1847	0.48	12.415
13.375	68	HCP-110	2910	6910	1297		2079	2139	0.48	12.415
13.375	68	P-110	2340	6910	1297		2079	2139	0.48	12.415
13.375	72	L-80	2670	5380	1029		1650	1661	0.514	12.347

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O D /in	Nominal weight *T* & *C* /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
13.375	72	HCL-80	3470	5380	1181		1850	1661	0.514	12.347
13.375	72	N-80	2670	5380	1040		1693	1661	0.514	12.347
13.375	72	HCN-80	3470	5380	1192		1850	1661	0.514	12.347
13.375	72	S-95	3470	6390	1215		1935	1973	0.514	12.347
13.375	72	HCP-110	3470	7400	1402		2221	2284	0.514	12.347
13.375	72	P-110	2890	7400	1402		2221	2284	0.514	12.347
13.375	72	HCQ-125	3470	8410	1577		2463	2596	0.514	12.347
13.375	72	Q-125	2880	8410	1577		2463	2596	0.514	12.347
13.625	88.2	S-95	5930	7630			1885	2425	0.625	12.375
13.625	88.2	HCP-110	5930	8830			2163	2808	0.625	12.375
13.625	88.2	P-110	4570	8830			2163	2808	0.625	12.375
13.625	88.2	HCQ-125	5930	10030			2399	3191	0.625	12.375
13.625	88.2	Q-125	4800	10030			2399	3191	0.625	12.375

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O D /in	Nominal weight T & C /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
16	65	H-40	630	1640	439		781	736	0.375	15.25
16	65	WC-40	630	1600*	422			736	0.375	15.25
16	75	J-55	1020	2630	710		1200	1178	0.438	15.124
16	75	K-55	1020	2630	752		1331	1178	0.438	15.124
16	84	J-55	1410	2980	817		1351	1326	0.495	15.01
16	84	K-55	1410	2980	865		1499	1326	0.495	15.01
16	84	N-80	1480	4330	1167		1898	1929	0.495	15.01
16	84	HCN-80	1910	4330	1342		1898	1929	0.495	15.01
16	84	HCP-110	1910	5960	1575		2518	2652	0.495	15.01
18.625	87.5	J-55	630	2250	754		1329	1368	0.435	17.755
18.625	87.5	K-55	630	2250	794		1427	1368	0.435	17.755
18.625	87.5	N-80	630	3270	1079		1887	1990	0.435	17.755

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O D /in	Nominal weight T & C /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
18.625	94.5	H-40	780	1760	609		1067	1068	0.468	17.689
18.625	94.5	J-55	780	2420	821		1427	1469	0.468	17.689
18.625	94.5	K-55	780	2420	865		1533	1469	0.468	17.689
18.625	94.5	N-80	780	3520	1174		2027	2137	0.468	17.689
18.625	106	H-40	1140	2000	703		1206	1208	0.531	17.563
18.625	106	J-55	1140	2740	948		1613	1661	0.531	17.563
18.625	106	K-55	1140	2740	998		1733	1661	0.531	17.563
18.625	106	N-80	1150	3990	1356		2292	2416	0.531	17.563
18.625	117.5	H-40	1500	2230	795		1342	1344	0.593	17.439
18.625	117.5	J-55	1510	3060	1072		1795	1849	0.593	17.439
18.625	117.5	K-55	1510	3060	1129		1929	1849	0.593	17.439
18.625	117.5	N-80	1620	4460	1534		2551	2689	0.593	17.439

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O D /in	Nominal weight T & C /(lbs/ft)	Grade	Collapse /psi	Burst /psi	Joint strength /1000 lbs			Body yield /1000 lbs	Wall /in	I D /in
					STC	LTC	BTC			
20	94	H-40	520	1530	581		1041	1077	0.438	19.124
20	94	J-55	520	2110	783	907	1402	1480	0.438	19.124
20	94	K-55	520	2110	824	955	1479	1480	0.438	19.124
20	106.5	J-55	770	2410	913	1056	1595	1685	0.5	19
20	106.5	K-55	770	2410	960	1113	1683	1685	0.5	19
20	106.5	N-80	770	3500	1307	1514	2281	2450	0.5	19
20	133	K-55	1500	3060	1253	1453	2123	2125	0.635	18.73
20	133	L-80	1600	4450	1692	1958	2849	3091	0.635	18.73
20	133	N-80	1600	4450	1707	1976	2877	3091	0.635	18.73
20	169	K-55	2500	3910	1402	1732	2689	2692	0.812	18.376
20	169	L-80	3020	5680	2202	2549	3610	3916	0.812	18.376
20	169	N-80	3020	5680	2221	2573	3645	3916	0.812	18.376

Notes: LTC long thread and coupling; STC. Short thread and conpling; BTC. Butters thread and coupling.