Course Name: Drilling I

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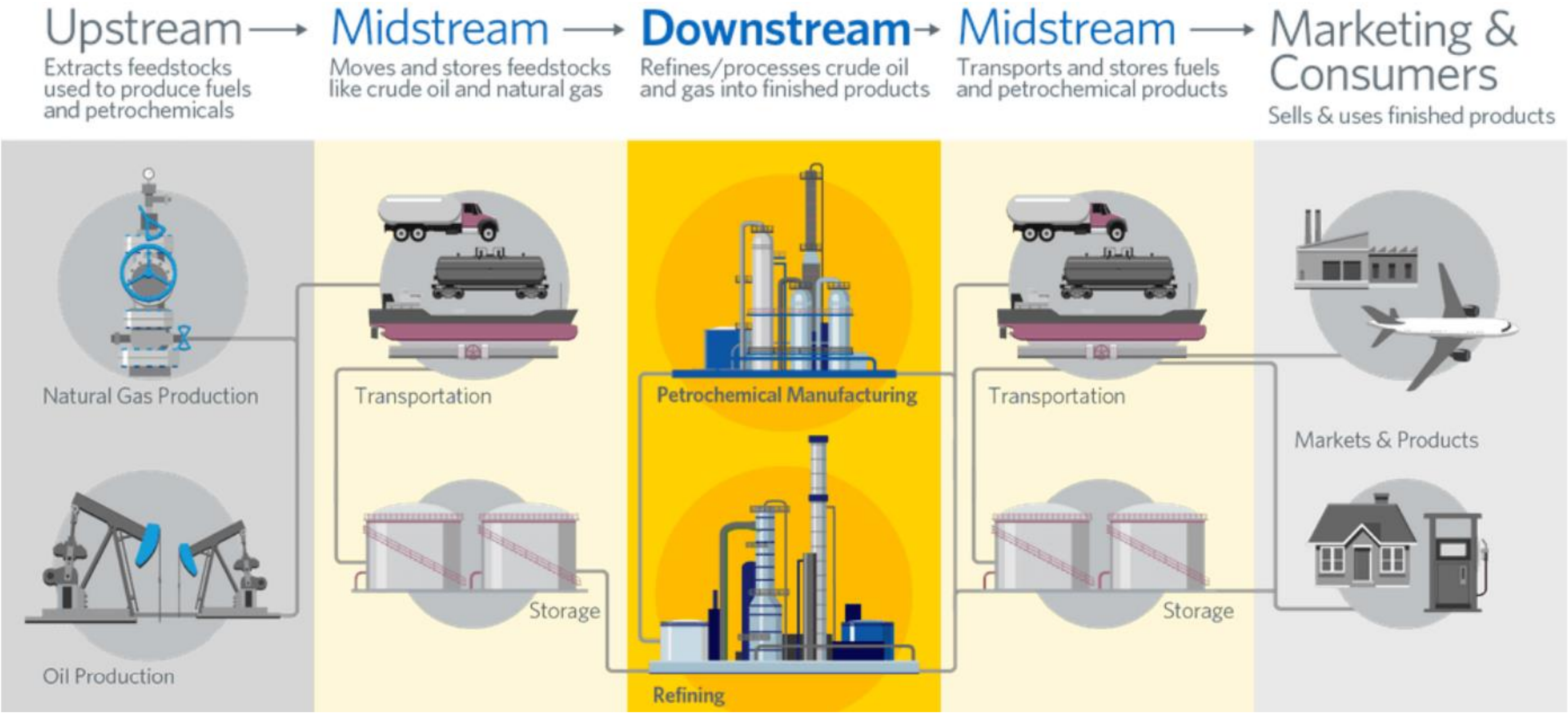
Class 3rd

Life of an Oil or Gas Industry



Life of an Oil or Gas Field

1. Exploration (wildcat and exploration Wells**):** In order to find out: Whether there are any hydrocarbons at that location, How much oil or gas might be present, and What depth the oil or gas occurs at Exploration activities. A wildcat well is an exploration well drilled in an area that isn't known to be an oilfield.

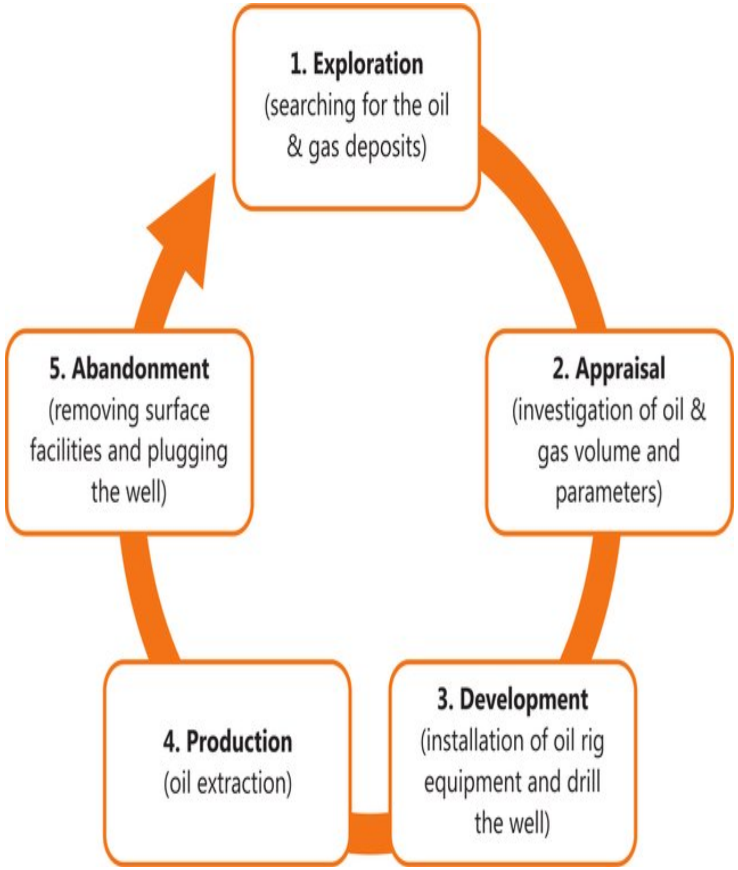
2. Appraisal: If a company is successful with their exploration drilling and make an oil or gas discovery, then they move into the appraisal phase of the lifecycle. The purpose of this phase is to reduce the uncertainty about the size of the oil or gas field and its properties.

During appraisal, more wells are drilled to collect information and samples from the reservoir. Another seismic survey might also be acquired in order to better image the reservoir.

3. Development: The development stage takes place after successful appraisal and before full-scale production. To develop the oil or gas field, including how many wells need to be drilled to produce the oil or gas, to decide the best design for the production wells, to decide what production facilities are required to process the oil/gas before it is sent to a refinery or customer, and to decide what the best export route might be for the oil and gas.

4. Production: Production is the phase during which hydrocarbons are extracted from an oil or gas field.

5. Decommissioning (Abandonment): Decommissioning is the term used for removing the production facilities and restoring oil and gas sites that are no longer profitable.



Oil or Gas System

Oil and gas fields result from the occurrence of four features:-

(1) Source rocks: rocks from which hydrocarbons have been generated.

(2) Migration:

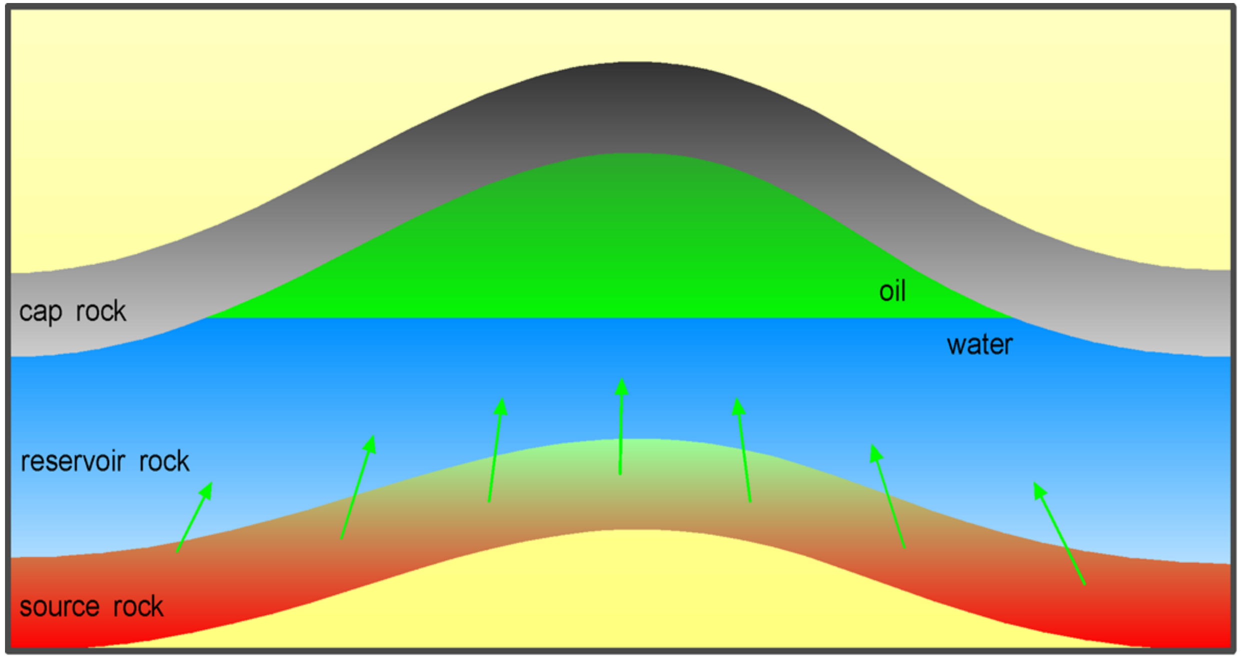
- Primary migration (from the source rock to a porous rock).
- Secondary migration (along the porous rock to the trap, movement to or within the reservoir entrapment).

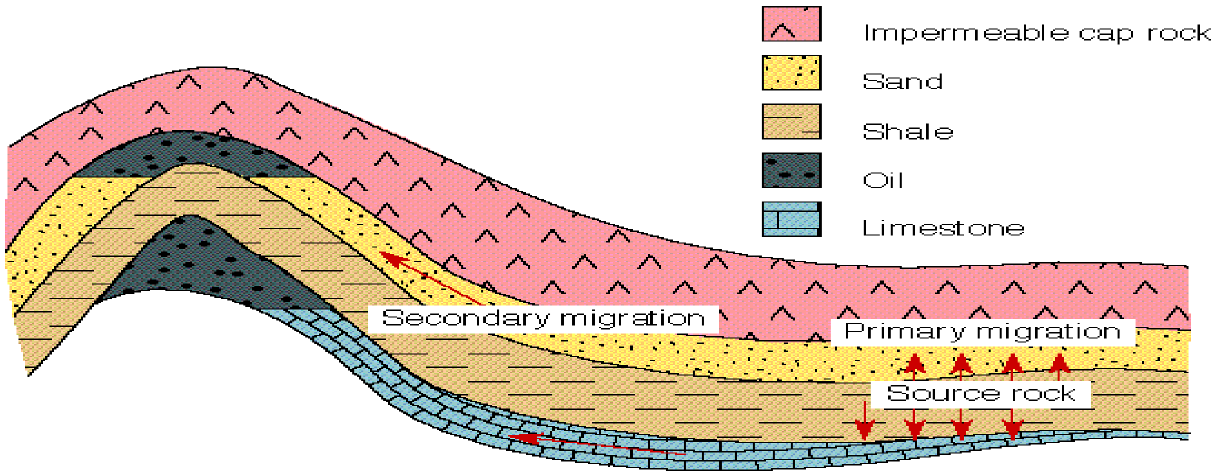
(3) Reservoir rocks: rock that contains connected pore spaces to reserve the fluid.

- Clastic rocks (ex. sandstone, shale)
- Carbonate rocks (ex. Limestone)

(4) Seals: relatively impermeable rock that forms a barrier, cap or seal above and around reservoir rock so that fluids cannot migrate beyond the reservoir (ex. Shale).

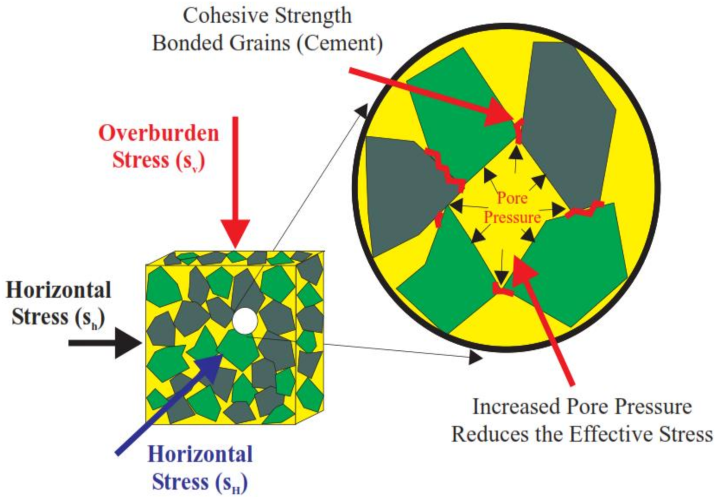
(5) Traps: rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through.

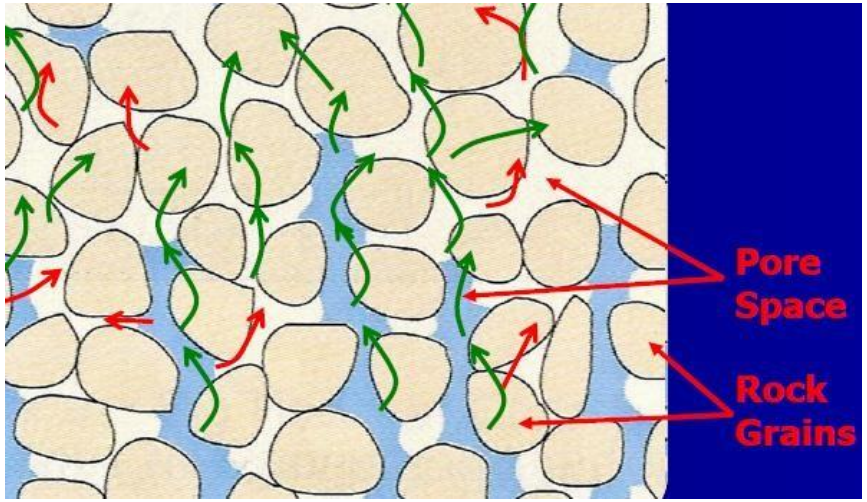


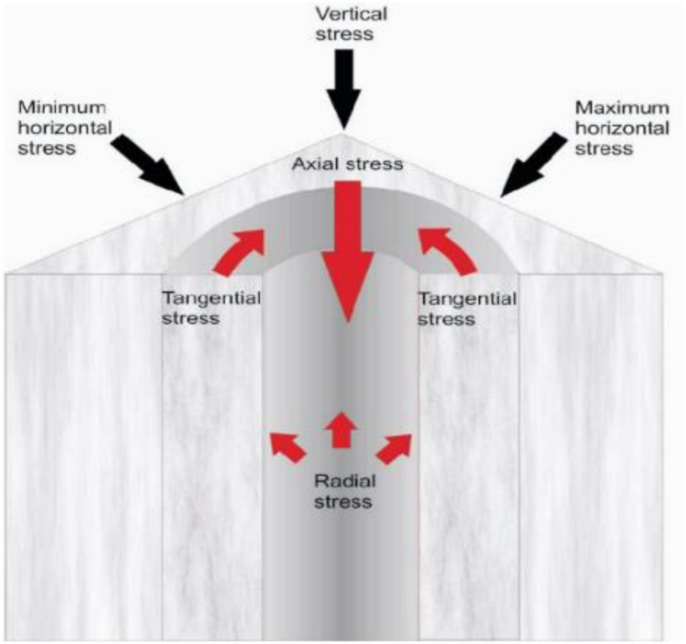


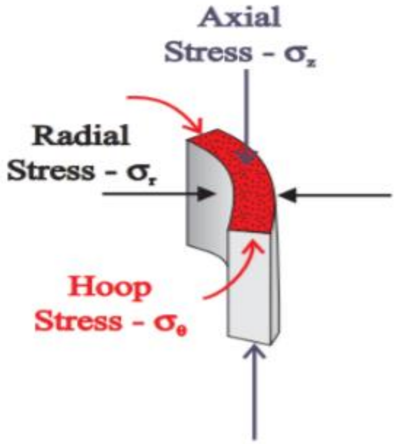
Drilling System Forces (Pressures and Stresses)

- **Pressure** transfers via fluid while **Stress** via solid.
- **Field** Stresses (Vertical, Maximum Horizontal, and Minimum Horizontal).
- **Wellbore** Stresses (Radial, Tangential, and Axial).
- **Radial** includes Hydrostatic Pressure + Circulation Pressure.
- **Pore** (Formation) **Pressure** especially in case of Abnormal pressure.









Drilling System Forces (Pressures and Stresses)

- When petroleum is produced from reservoir rocks, pressure of fluid in pore space decreases, but overburden is still the same. This will result in the reduction of bulk volume of rock and pore spaces. The reduction on volume in relation to pressure is called "pore volume compressibility (c_f)" or "formation **compressibility**".
- **Formation Fluid (Pore) Pressure**: is defined as the pressure of the fluids in the pore spaces of the rock.
- **Formation Fracture Pressure** (formation strength): is the pressure required to fracture a given formation.
- **Hydrostatic pressure** (Static Pressure): it is the pressure exerted by the length of liquid column.
- **Mud Circulation Pressure**: (Dynamic Pressure, Pump pressure): is the pressure required to circulate the mud down the hole and up to the surface.

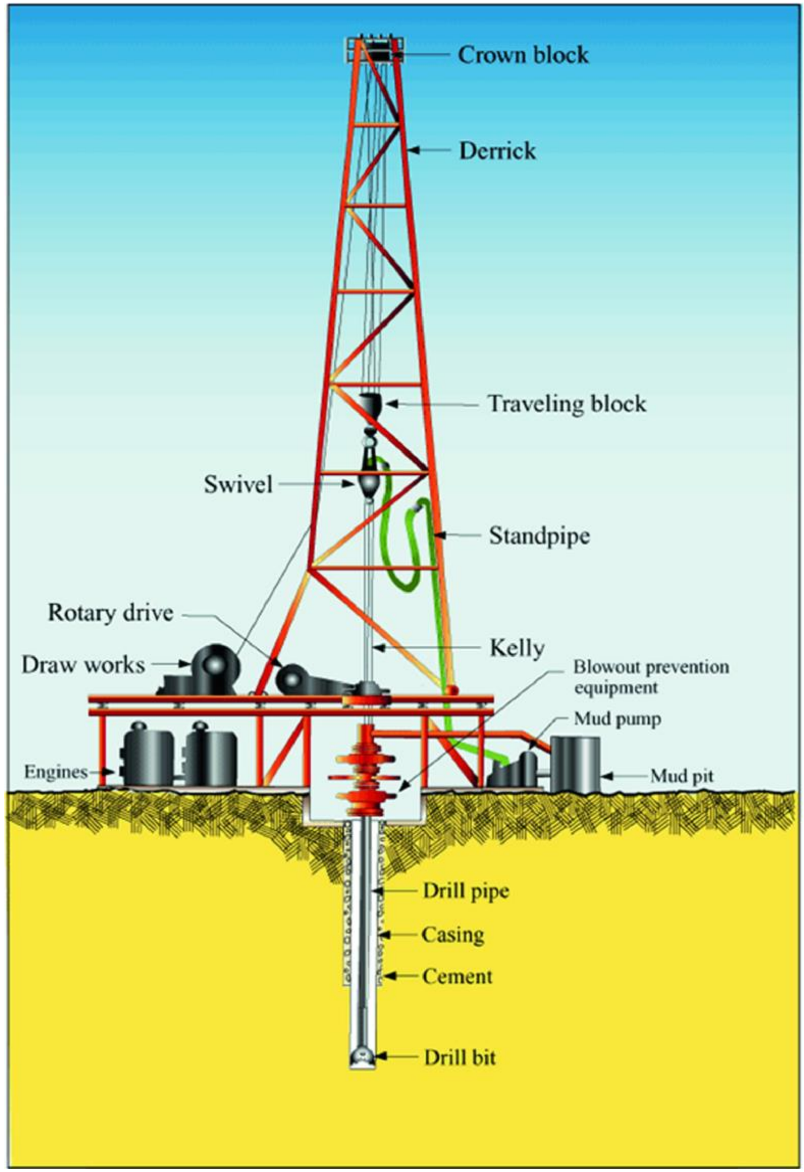
Age	Formation	Depth (m)	Lithology	Discription
L. Miocene	U.Fars	20		Sandstone rock with Marl
Middle-Early Miocene	L.Fars	294		Anhydrite rock with few Dolomite
	Jeribe	380		Dolomite rocks
Middle-Late Eocene	Dammam	425		Dolomite rocks with few of limestone rock
Early Eocene-Paleocene	Rus	636		Anhydrite rock with few Dolomite
	Um Er-Radhuma	724		Dolomite rock with few of Anhydrite rocks
Late Cretaceous	Tayarat	1179.5		Argilliaceous Dolomite rock
	Shiranish	1269		Limestone rock with Marl
	Hartha	1473		Limestone rock with Dolomite rock
	Sadi	1579		Chalky Limestone with marly Limestone
	Tanuma	1819		Shale rock with Marl
	Khasib	1878		Marly Limestone rock
M.Cretaceous	Kifil	1927		Anhydrite rock with Shale rock
	Mishrif	1944		Limestone rock with few Shale rock
	Rumaila	2110		Marly Limestone rock
	Ahmadi	2148		Shale rock with Marl rock with few of Limestone rock
	Mauddud	2223		Chalky Limestone with few of Shale
	Nahr Umr	2321		Sdndstone rock contain few of Shale
	Shuaiba	2526		Dolomite rock
E.Cretaceous	Zubair	2586		Sand stone rock with few of shale with Limestone
	Ratawi	3103		Argilliaceous Limestone rock with few of Sandstone rock
	Yamama	3178		Limestone rock
	Sulaiy	3437		Argilliaceous Limestone rock
	Qutnia	3724		

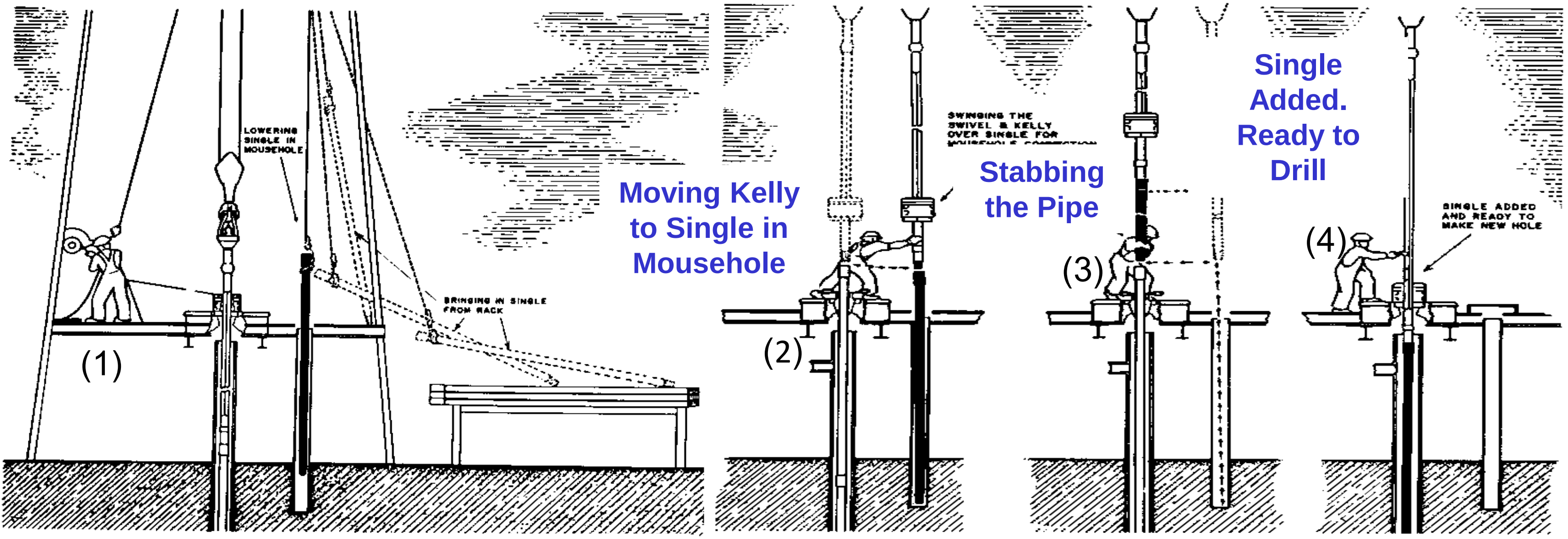
Drilling Equipment

- While the bit cuts the rock at the bottom of the hole, surface pumps are forcing drilling fluids down the hole through the inside of the drill pipe and out the bit. The fluid (with the cuttings) then flows out the center of the drill bit and is forced back up the outside of the drill pipe onto the surface of the ground where it is cleaned of debris and pumped back down the hole. This is an endless cycle that is maintained as long as the drill bit is turning in the hole.

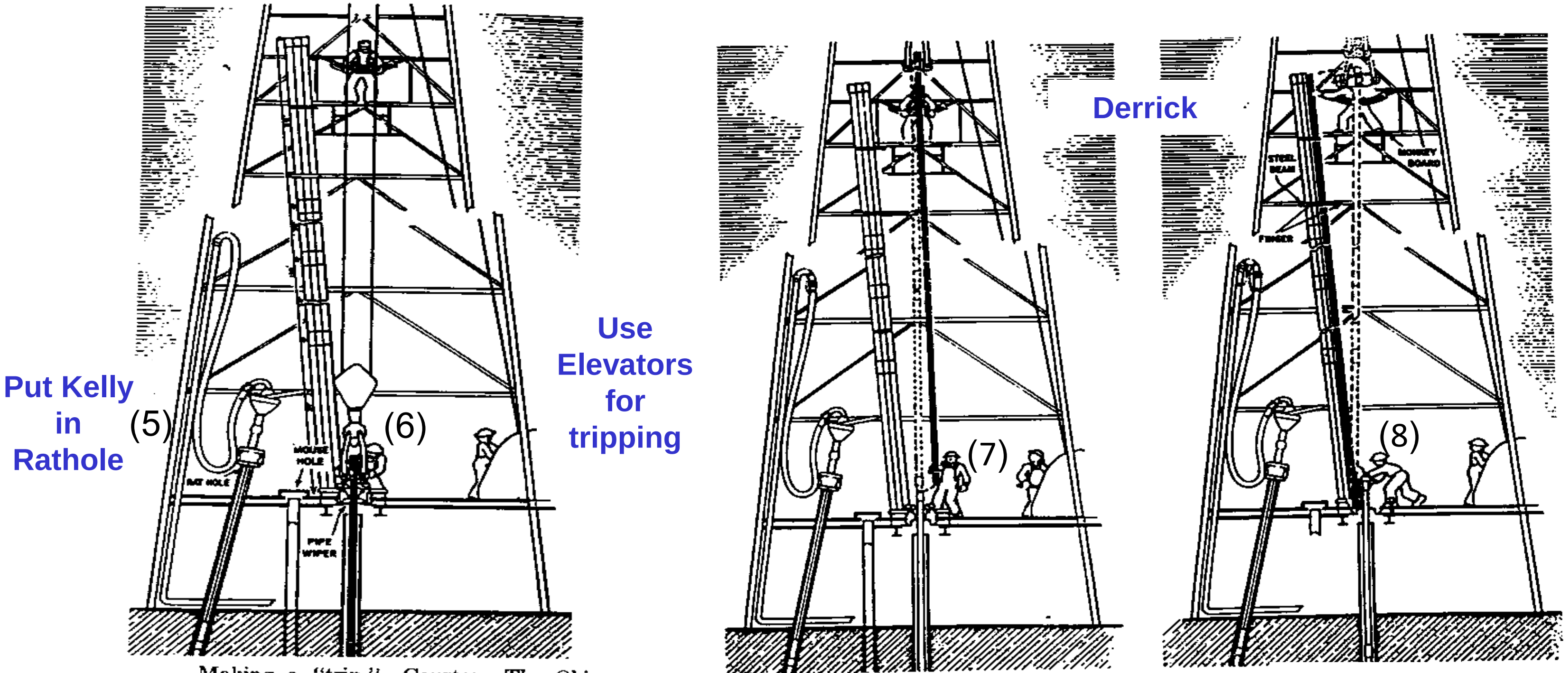
- The working platform for drilling work is called drilling rig. In generally, there are four main systems of a rotary drilling process including: Rig power system, hoisting system, drill string components, and circulating system.

- When selecting the minimum rig size specifications for a given well, the following factors must be considered: Drawworks, & hoisting equipment, Mud Pumps, Rotary driving system (table and/or TDS), Derrick & Substructure, Drillstring, Blowout prevention equipment, Solids control equipment, Other special requirements.





Making a Connection / Tripping In



Making a "trip." Courtesy The Ohio Oil Company.

Tripping Out

(1) التقاط انابيب منفردة (Single Pipe) بالرافعة اليدوية (Catline) ووضعها في حفرة الفأر (Mousehole) لتحضيرها للربط.

(2) دفع الانبوب المضلع من الوضع العمودي مقابل حفرة البئر الى الوضع المائل مقابل ال (Mousehole) لربط ال (Single Pipe).

(3) وضع ال(Single Pipe) على المنضدة الدوارة (Rotary Table) مقابل حفرة البئر وربط الانبوب المنفرد بالأنبوب المضلع.

(4) انزال الانبوب المنفرد الى البئر والتهيؤ للحفر.

(5) وضع الانبوب المضلع في حفرة الجرذ (Rathole) لسحب الانابيب او انزالها دون اجراء عملية الحفر.

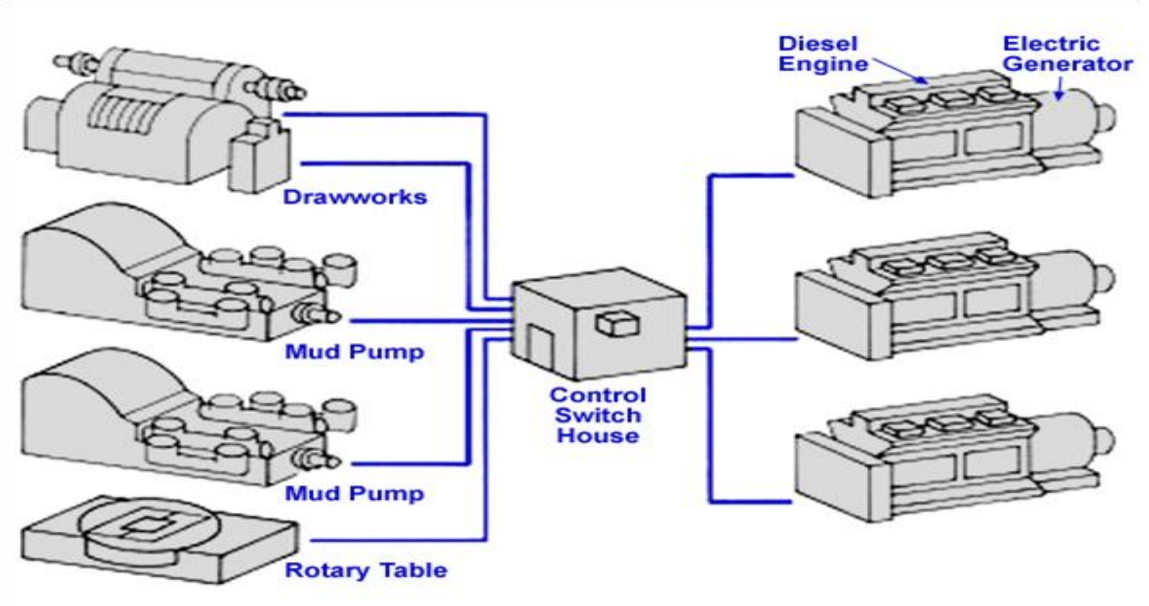
(6) استخدام الرافعة الرئيسية (Drawworks) لانزال الانابيب.

(7) استخدام ال(Drawworks) لسحب الانابيب.

(8) دفع الانابيب المسحوبة وتنظيمها على جانب السارية (Mast) بمساعدة عامل فوق يسمى ال (Derrickman) ليتم تثبيتها في ال (Derrick).

Rig Power System

- The most of the generated power is consumed by the hoisting and fluid circulation systems. However, in most cases these two systems are not used simultaneously.
- Rig power system performance characteristics generally are stated in terms of output horsepower. A common drilling rig requires approximately 1000-3000 horse power to maintain the operation.
- Each drilling rig is designed to drill in a given range Of depths taking into account the power rating.
- Generally, the mechanical efficiency of the generator is favorable to work in low depths and medium temperature environment.
- Rigs use both AC and DC power. The AC power system runs the lighting and suchlike. The DC power system runs the machinery, drawworks, mud pumps, rotary etc.



Required Horsepower

- **As a rule of thumb**, the drawworks should have 1 HP for every 10 ft to be drilled. Hence for 20,000 ft well, the drawworks should have 2000 HP.
- The power output by the drawworks, $\mathbf{HP_d}$ will be proportional to the drawworks load, which is equal to the load on the fast line $\mathbf{F_f}$, times the velocity of the fast line $\mathbf{v_f}$ (ft/min.).

$$HP_d = \frac{F_f v_f}{33{,}000}$$

- The Rotary Horsepower requirement is usually between 1.5 to 2 times the rotary speed, depending on the hole depth. Hence for rotary speed of 200 RPM, the power requirement is about 400 HP.

The horsepower requirements of the pumps depends on the flow-rate and the pressure.

$$HP = \frac{Flow\ Rate(gpm) x\ Pressure(psi)}{1714}$$

Calculate the power requirement for the following pump:

- Flowrate = 1200 gpm,
- Pressure = 2000 psi,
- Mechanical Efficiency = 0.85

Solution:

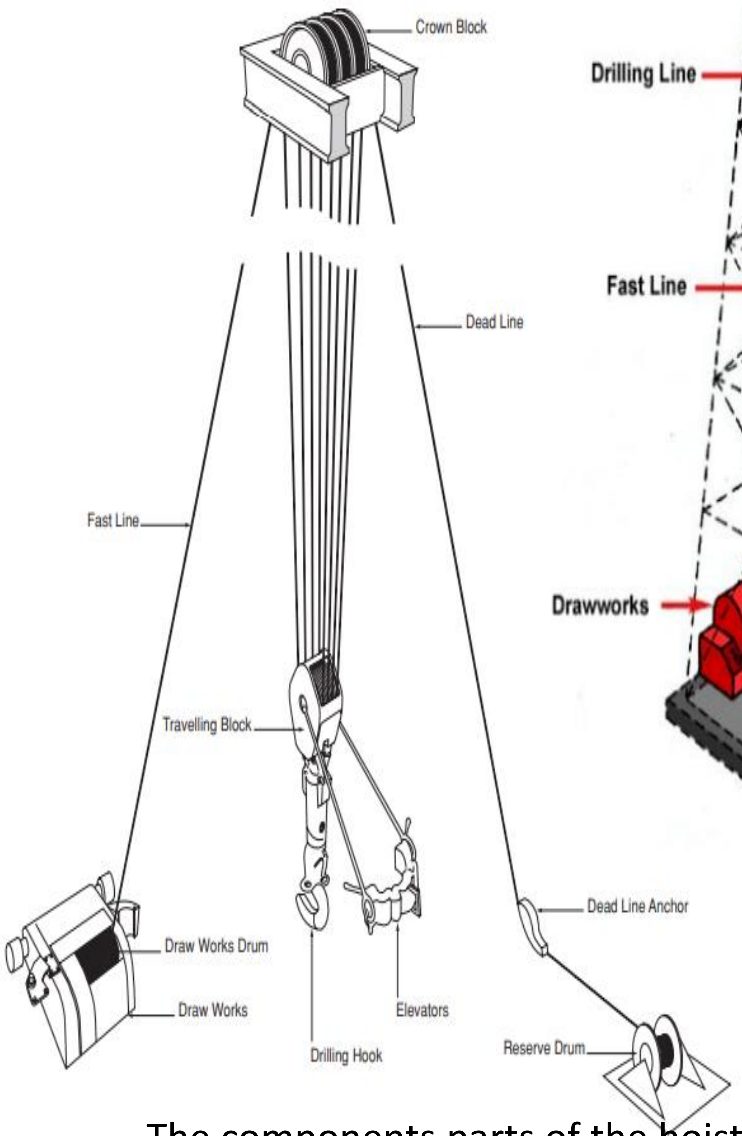
HP = 1200* 2000/ 1714

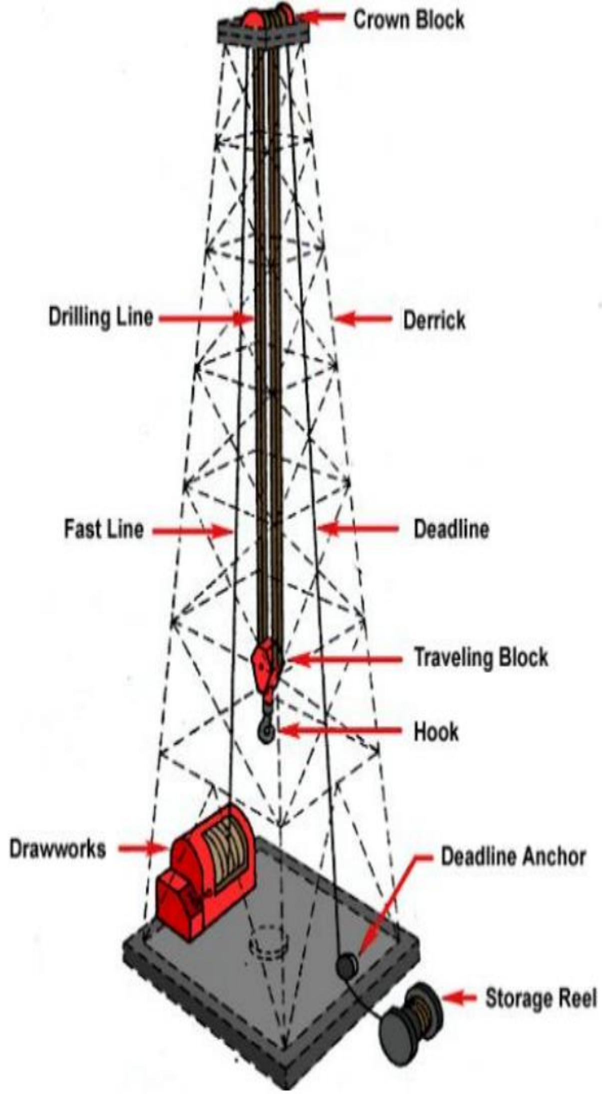
HP = 1378.5 horse power

HP for pump with 85% efficiency = 1378.5/ 0.85 = 1622 HP

Hoisting System

- The hoisting system is a large pulley system which is used to lower and raise equipment into and out of the well. In particular, the hoisting system is used to raise and lower the drillstring and casing into and out of the well.
- The drawworks consists of a large revolving drum, around which a wire rope (drilling line) is spooled. The drum of the drawworks is connected to an electric motor and gearing system.
- The driller controls the drawworks with a clutch and gearing system when lifting equipment out of the well and a brake (friction and electric) when running equipment into the well.
- The drilling line is threaded (reeved) over a set of sheaves in the top of the derrick, known as the crown block and down to another set of sheaves known as the travelling block.
- A large hook with a locking device is suspended from the travelling block. This hook is used to suspend the drillstring.
- A set of clamps, known as the elevators, used when running, or pulling, the drillstring or casing into or out of the hole, are also connected to the travelling block.
- Having reeved the drilling line around the crown block and travelling block, one end of the drilling line is secured to an anchor point somewhere below the rig floor. Since this line does not move it is called the deadline. The other end of the drilling line is wound onto the drawworks and is called the fastline.





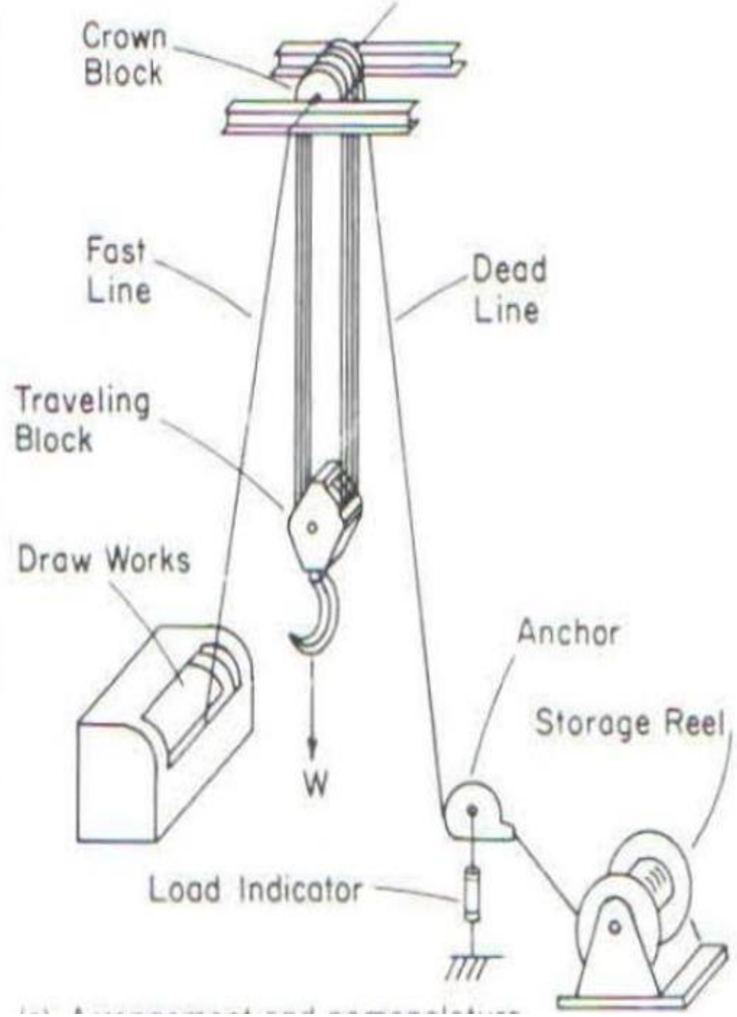
The components parts of the hoisting system

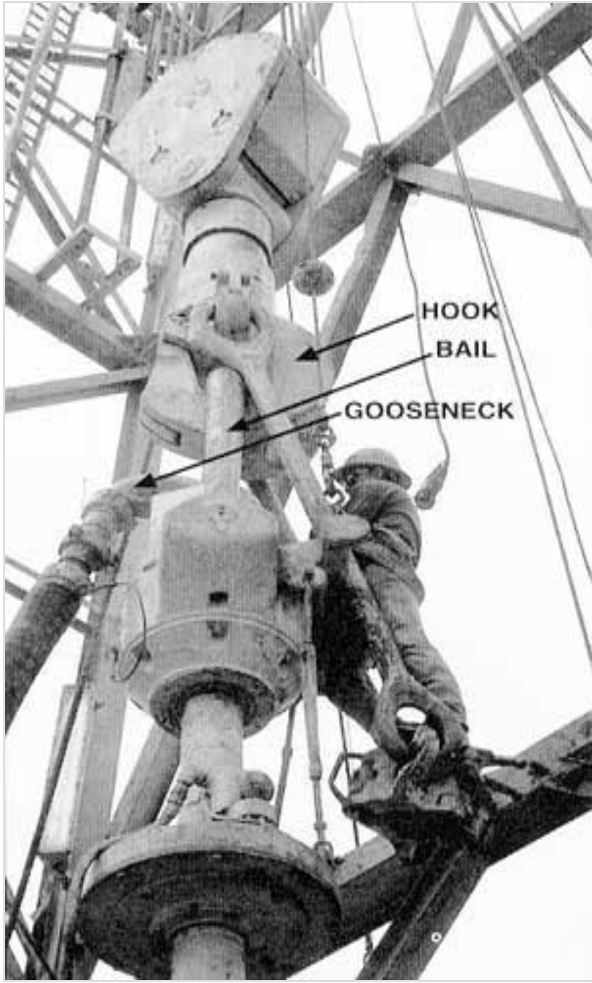
Derricks or Masts

- In practice, the Derricks or Masts named by drilling crew are the same where these structures provide the necessary height required to raise sections of pipe from or lower them into the hole and support to lift loads in and out of the well, and must be strong enough to support the hook load, deadline and fast-line loads, pipe setback and wind loads.
- Conceptually, a mast stands independently on the rig floor and is raised as a single piece unit. Unlike the mast, the derrick cannot be lowered or raised as a single unit. Today masts are much more common than Derrick's manufacturers for easier assembly and disassembly. Generally, masts are raised using the draw works.
- Masts are classified into Cantilever, Folding, and Telescoping.

Hoisting System

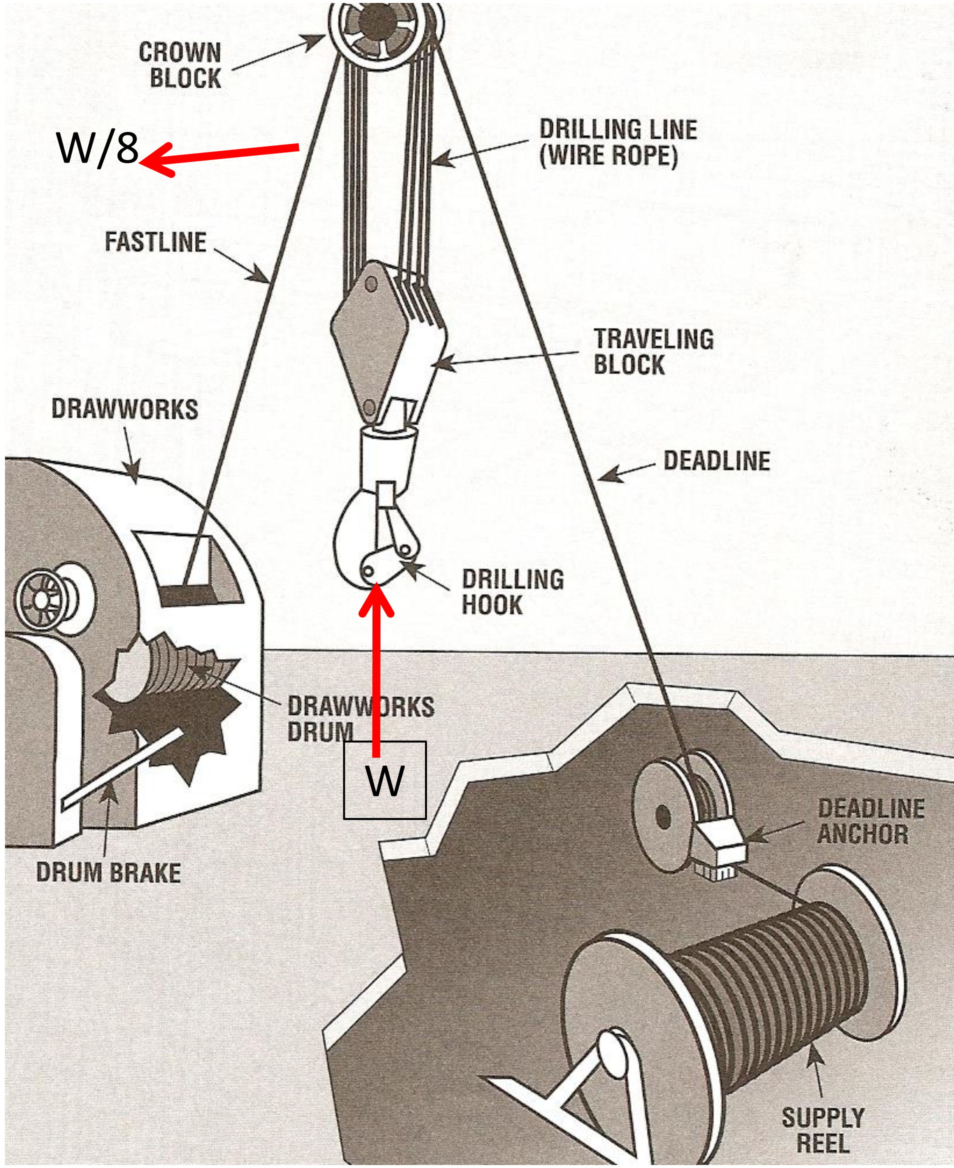
- Block and tackle is comprised of the crown block, the travelling block, and the drilling line.
- The principal function of the block and tackle is to provide a mechanical advantage which permits easier handling of large loads.
- The wire line used is threaded up and over the crown block, back down and to the travelling block, back up to the crown block, then down to the drawworks.
- The drawworks main drum stores the excess used line as the string is raised or lowered.
- Anchor Point is a fixed position in one corner of the rig floor and would normally be on the other side of the rig floor from the draw-works.
- The dead line base is bolted to the main substructure.
- For rig capacity up to 200 ton crown block and traveling block have 5 sheaves each so operates with 10 lines.

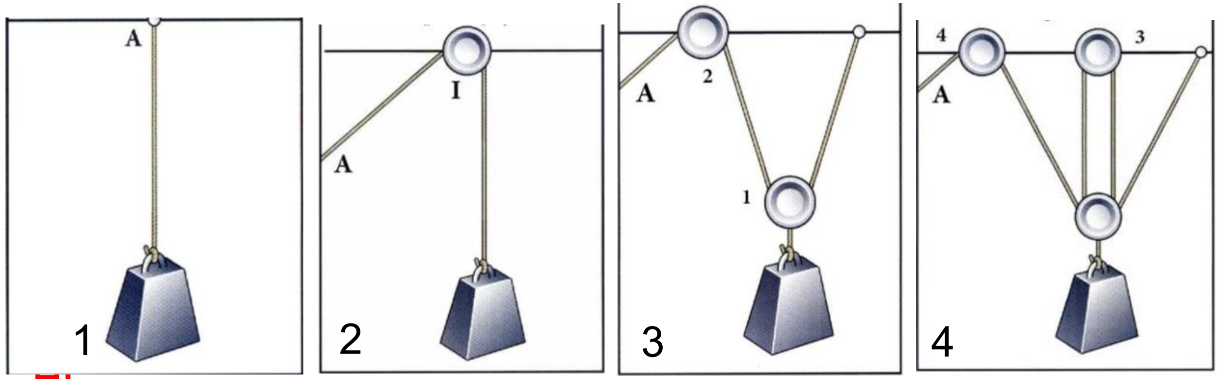




Hoisting System “Pully (نظام البكرات)“

- A pulley transfers a force along a rope without changing its magnitude.
- There is a force (tension) on the rope that is equal to the weight of the object. This force or tension is the same all along the rope. For this simple pulley system, the force is equal to the weight.
- In the Figure 3, the pulley is moveable. As the rope is pulled up, it can also move up. Now the weight is supported by both the rope end attached to the upper bar and the end held by the person! Each side of the rope is supporting the weight, so each side carries only half the weight. So the force needed to hold up the pulley in this example is 1/2 the weight!.
- 8 strands showing so force to pull by drawworks = 1/8 weight of the hook and load. Still have to do the same amount of work.

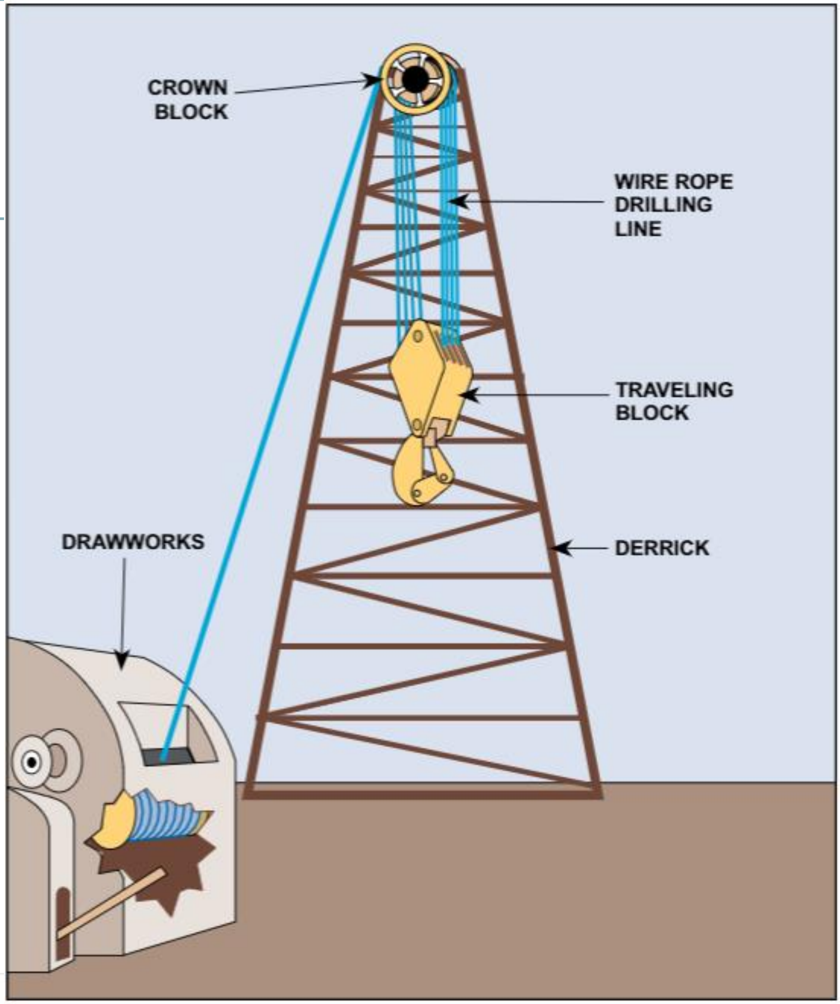




Drawworks

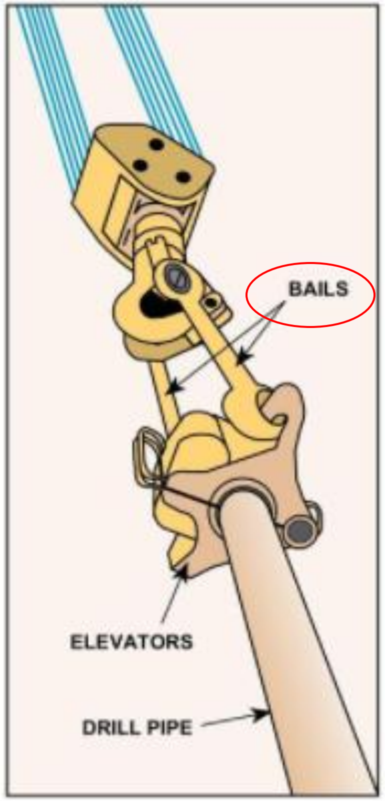
- Drawworks is an assembly of a rotating drum, a series of tools for changing speed and for reversing. It also contains the main brake stopping the drilling line.
- The drilling line is wound a number of times around the drum of Drawworks and passes to the crown and traveling blocks.
- Drawworks is driven by 2 or 3 electric DC motors that offers four hoisting speeds and two rotary speeds.
- The cathead is a shaft with a lifting head that extends on either side of the drawworks. It is used in making up and breaking out tool joints in the drill string.
- The drawworks is a complicated mechanical system with many functions:

1. To lift drill string, casing, or tubing string, or to pull in excess of these string loads to free stuck pipe.
2. Provide the braking systems on the hoist drum for lowering drill string, casing string, or tubing string into the borehole.
3. Transmit power from the prime movers to the rotary drive sprocket to drive the rotary table
4. Transmit power to the catheads for breaking out and making up drill string, casing and tubing string.



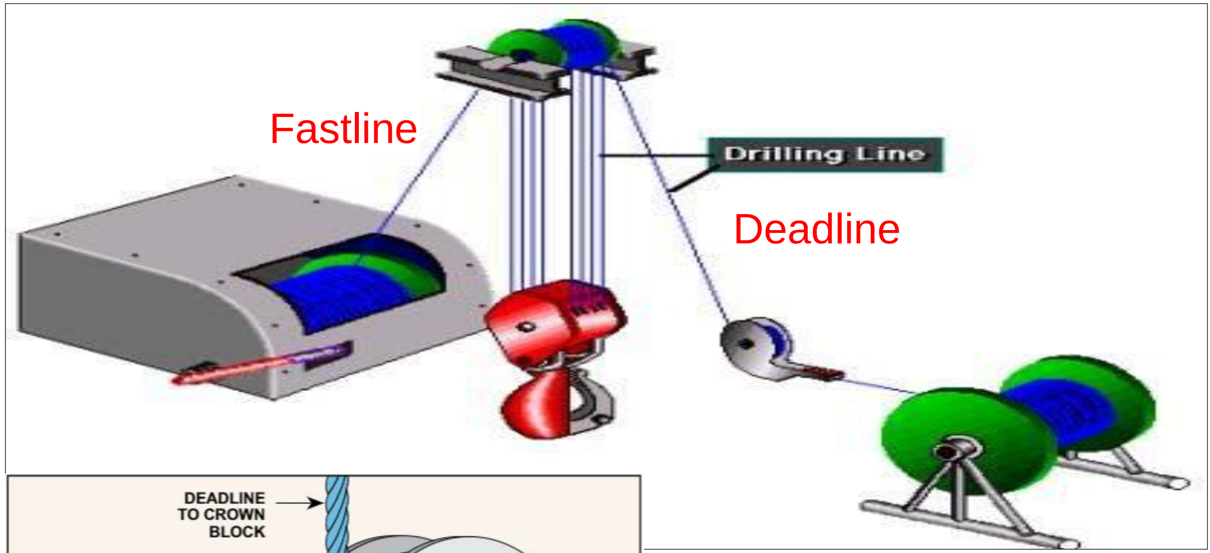
Hoisting System – Crown Block

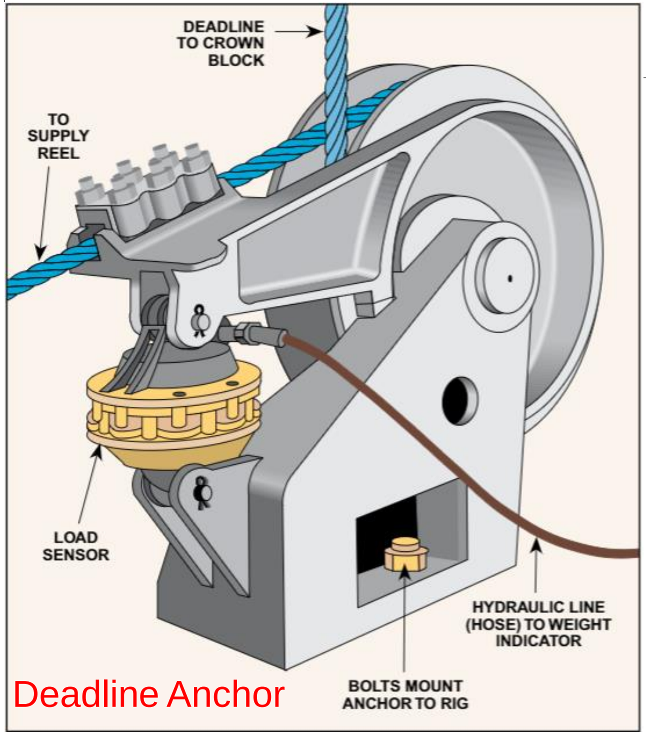
- A Crown Block is stationary and is firmly fastened to the top of the derrick.
- It contains a number of sheaves on which the drilling line is wound. Each sheave inside the crown block acts as an individual pulley.
- The crown block takes the drilling line from the hoisting drum to the traveling block.
- Travelling Block is a block containing a number of sheaves which is always less than those in the crown block.
- The hook and bails hang below the Travelling Block to facilitate drilling with the swivel and running pipe.
- The hook connects the Kelly or Top Drive with the travelling Block and carries the entire drilling load.



Hoisting System – Drilling Line and Deadline Anchor

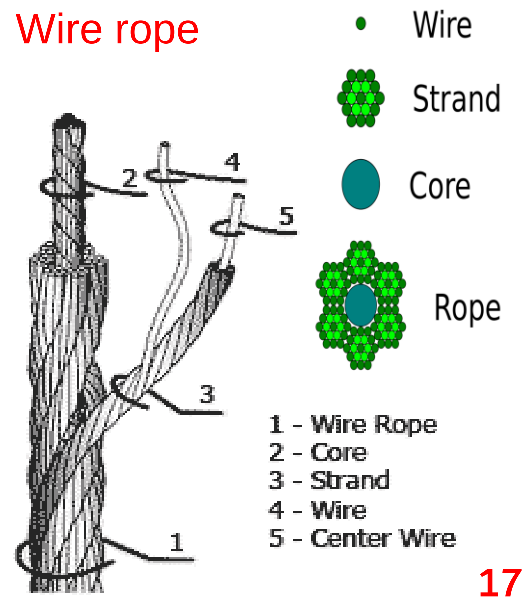
- The drilling line is wound continuously on the Crown and Traveling Blocks, with two outside ends being wound on the hoisting drum and attached to the deadline anchor respectively.
- Lay used for Drilling Lines: Right Regular Lay (RRL)
- The description (1” X 5000’ 6 X 19 RRL) of a rotary drilling line means: Diameter of line, Length of line, Number of Strands per Line, Number of Wires per Strand, and Right Regular Lay, respectively.
- The deadline anchor firmly holds one end of the drilling line and keeps it from moving. It is bolted to the substructure.
- The anchor also serves for weight sensing. As the weight of the load on the deadline flexes the deadline, the sensor picks up the flexes and sends a signal to the weight indicator on the rig floor. The weight indicator then translates the signal into weight on the bit and the hook load.
- With one end of the line firmly fastened to the anchor and the other end attached to the drawworks drum, the driller can reel in the drilling line with the drawworks.
- The crown block always has one pulley more than the traveling block.





Deadline Anchor

Wire rope

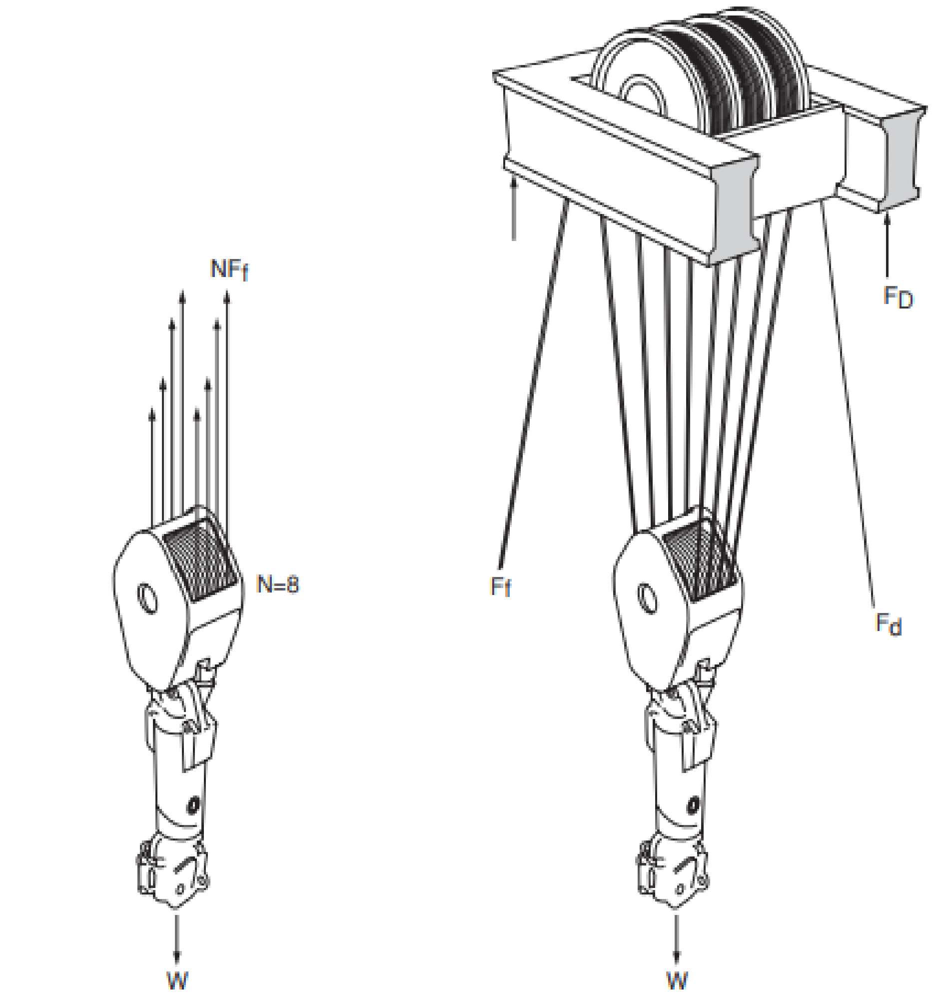


Drilling Line Static Loads

- The tensile strength of the drilling line and the number of times it is reeved through the blocks will depend on the load which must be supported by the hoisting system.
- The tensile load (lbs.) on the drilling line, and therefore on the fast line, Ff and dead line Fd in a frictionless system can be determined from the total load supported by the drilling lines, W (lbs.) and the number of lines, N reeved around the crown and travelling block:

$$F_f = Fd = W/N$$

W – Hook load, N – Number of drilling lines in a travelling block, $T_f = T_d$ (T_f and Td are the same value because the same tension in the drilling line)



(a) Free body diagram of traveling block (b) Free body diagram of crown block

Drilling line tension

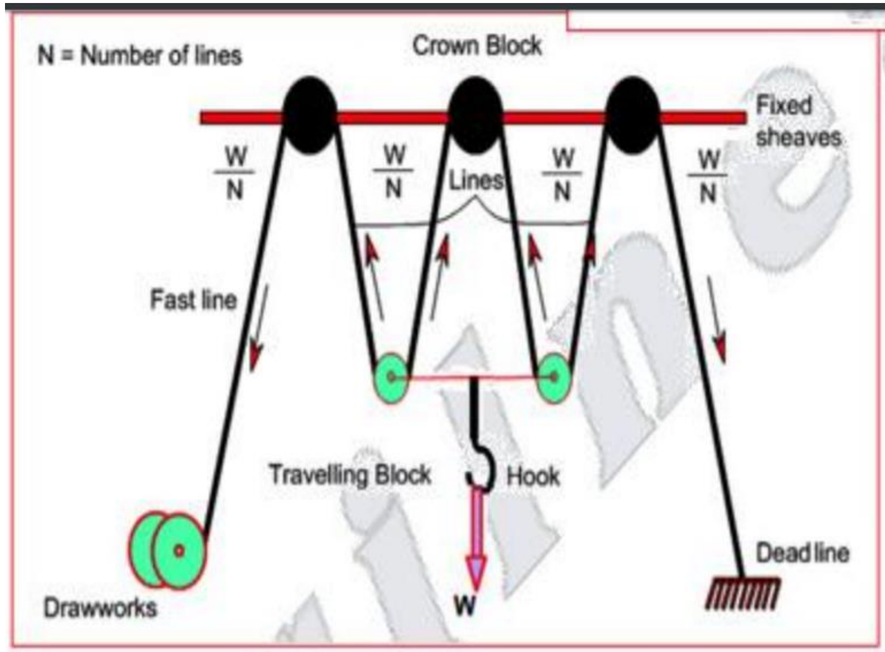
Drilling Line Dynamic Loads

- Under dynamic condition, friction in sheave bearings and block lines make the fast tension higher than the dead line tension.
- It means that the fast line tension will increase under a dynamic condition; however, the dead line tension will remain the same because it is still in static condition.
- There is however inefficiency in any pulley system. The level of inefficiency is a function of the number of lines .
- The reeving efficiency is a measure of how effectively the drill line and sheaves transfer the drawworks power to the moving external load.
- The tensile load on the drilling line and therefore on the fast line under the dynamic environments can be described as:

$$F_f = W/E*N$$

T_f – The fast line tension, W – Block weight, N – Number of lines

E – Efficiency. The efficiency factors for a particular system is shown in the **Table**.



Drilling line tension

Number of Lines (N)	Efficiency (E)
6	0.874
8	0.842
10	0.811
12	0.782
14	0.755

Table Efficiency Factors for Wire Rope Reeving, for Multiple Sheave Blocks (APIRP9B)

Derrick Load

- **Static** Derrick load is equal to summation of hook load, fast line tension and dead line tension :

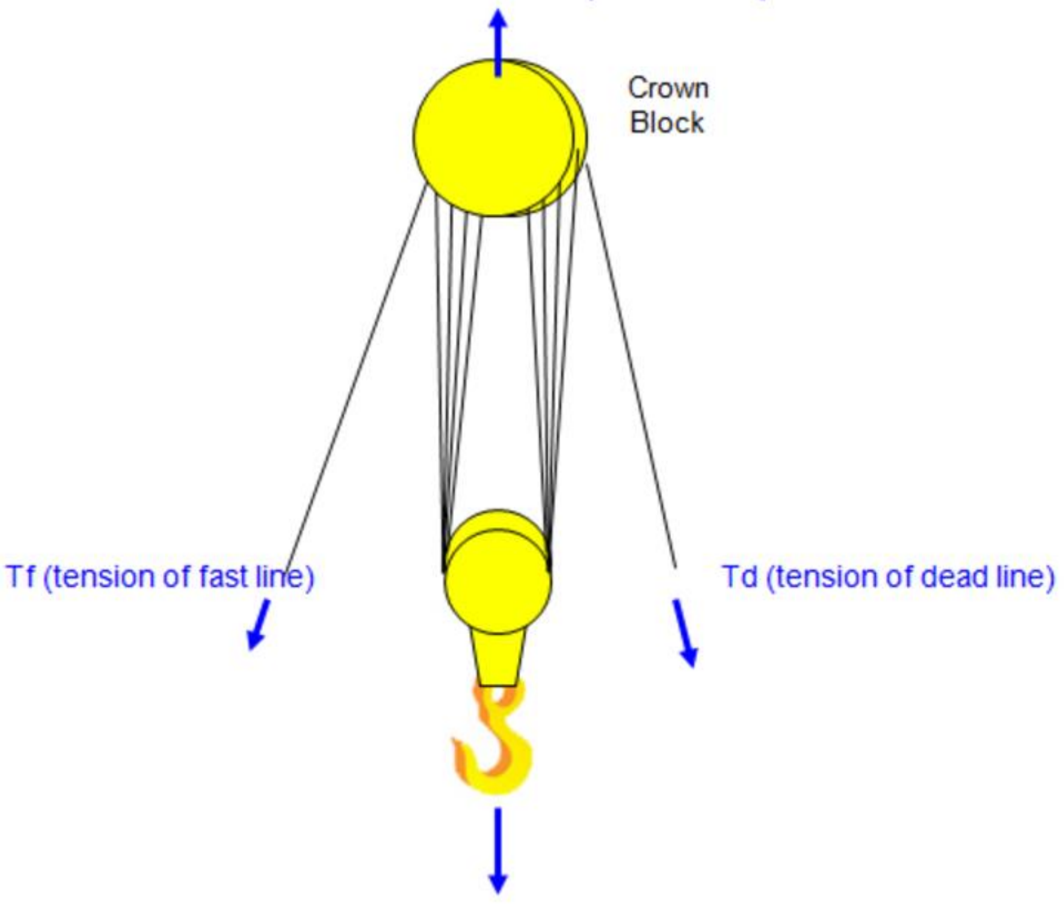
$$FD = Tf + W + Td$$

$$FD = W/N + W + W/N$$

$$\therefore FD = (N+2) \times W \div N$$

$$F_D = W * \frac{(n+2)}{n}$$

FD – Derrick load
Tf – Fast line tension
Td – dead line tension
W – hookload



- Note: Neglect a small effect of small angle of the fast line and the dead line.
- **Dynamic** Derrick load:

$$FD = Tf + W + Td$$

$$FD = W/E*N + W + W/N$$

Derrick Load Calculation

Exercise: Buoyed weight of the drill string is 260,000 lb which will be pulled out of hole. Weight of travelling block and hook is 40,000 lb. The rig has 10 lines strung in crown block and travelling block.

Number of Lines (N)	Efficiency (E)
6	0.874
8	0.842
10	0.811
12	0.782
14	0.755

- Efficiency of 10 lines = 0.811
- Total hook load = 260,000 + 40,000 = **300,000** lb
- The fast line tension, Tf = 300,000 ÷ (10 x 0.811) = **36,991** lb
- The dead line tension, Td = 300,000 ÷ 10 = **30,000** lb
- Derrick load under the dynamic condition:

FD = Tf + W + Td = 36,991 + 30,000 + 300,000 = **366,991** lb

FD – Derrick load
Tf – Fast line tension
Td – dead line tension
W – hookload

Drilling Line Selection

- The required capacity of a drilling line depends on Load to be supported (W) , number of active lines (N), desired margins of overpull (Mop) and Desired safety coefficient (S).
- The formula used for drilling line selection is:

$$\mathbf{Tr_{mini} = Ta * S = \left(\frac{W+MOP}{N*\eta m}\right) * S}$$

Tr_{mini} = Minimum wire rope breaking load
Ta = Maximum tension on fast line
S = Safety factor
W = Weight at the hook (weight of the drill string or casing + traveling block weight)
MOP = Margin of overpull tons
ηm = reeving efficiency
N= Number of lines

- Equation means: Minimum wire rope breaking load = maximum Traction on fast line x Safety Factor
- The coefficients (S) used are recommended by the API: tripping, drilling & coring 3; running casing 2; and fishing operation 2.
- The margin of overpull is defined by the operator. The value of 50 tons is a sufficient for the margin that will allow pulling to get free in case of stuck pipe.

Exercise for wire rope sizing

A heavy rig with API wire rope 1-3/8 “, 8 lines, traveling block = 15 tons, Minimum wire rope breaking load = 72.5 t.

$$Trmini = Ta * S = \left(\frac{W + MOP}{NX\eta m}\right) * S$$

a) Maximum weight of casing

72.5 = 2* [(15+ Maximum weight of casing)+ 50]/ [8*0.842]

Maximum weight of casing = nnnn t

b) Maximum weight of the drill string while tripping, drilling, or coring

72.5 = 3* [(15+ Maximum weight of drill string)+ 50]/ [8*0.842]

Maximum weight of drill string = nnnn t

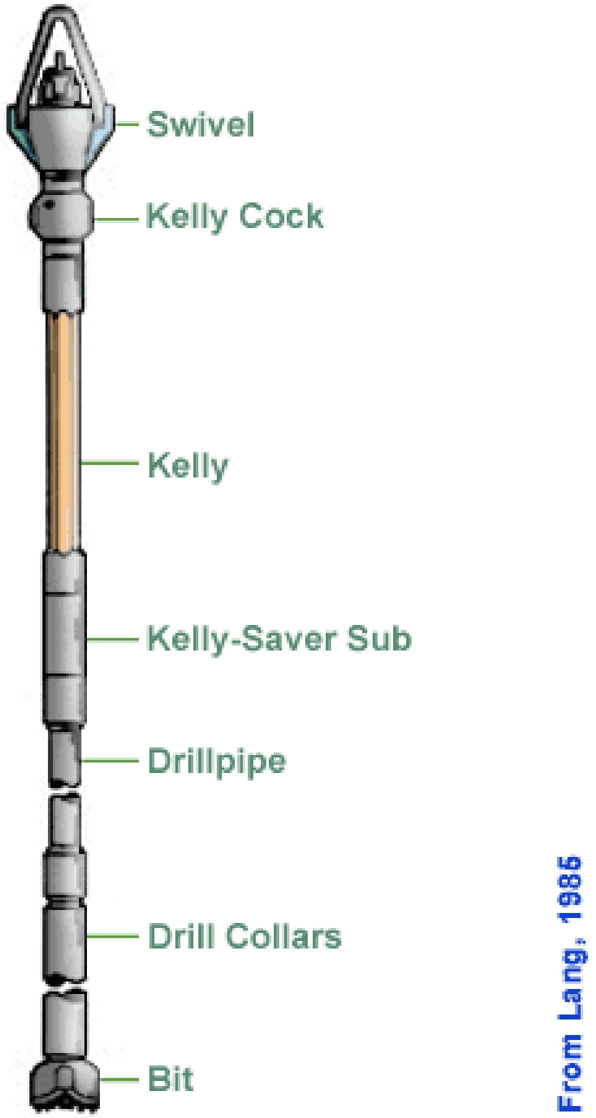
c) Maximum weight of the drill string while fishing operation

72.5 = 2* [(15+ Maximum weight of drill string)+ 50]/ [8*0.842]

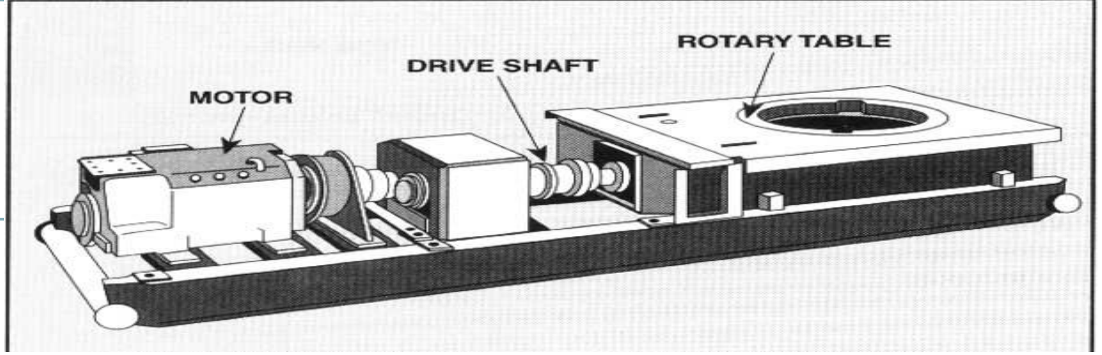
Maximum weight of drill string = nnnn t

Rotary System

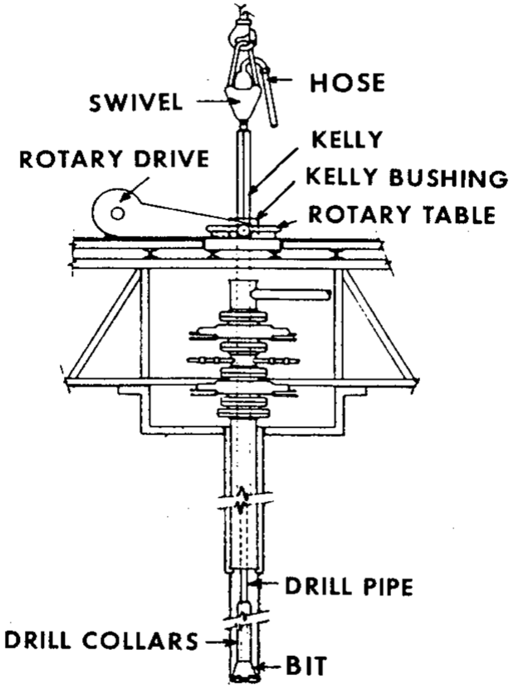
- Wells are drilled by the pipe &bit rotation, therefore it is very important to have an efficient rotation system. The rotary system transmits rotating function to the drillstring and consequently the bit.
- The main parts of the rotary system (or the drill string) are simplified in the figure.
- The bottomhole assembly (BHA) is that portion of the drill string between the drill pipe and the drill bit.
- As the drill string moves downhole, it is subjected to a variety of stresses, including tension, compression, vibration, torsion, friction, formation pressure and circulating fluid pressure. It is also exposed to abrasive solids and corrosive fluids.
- The drill string must provide weight to the bit; allow control over wellbore deviation; and help ensure that the hole stays "in gauge".

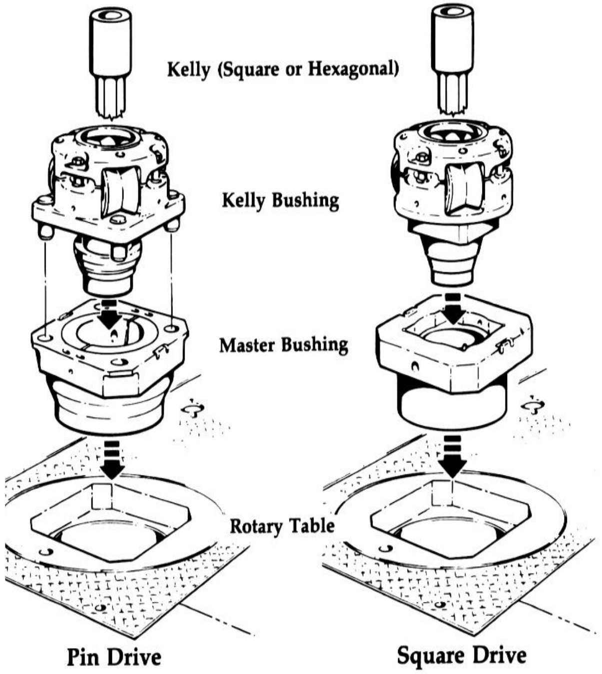


Rotary System “Kelly”



- The working principle of rotation system is the Kelly, which is connected to the drill pipe drove by the rotary table and then the whole drilling string can be rotated for drilling.
- The rotary table is the component that drives the drillstring.
- The Kelly is the part of the drill string that allows a round pipe to be turned at great speed and also allow to be picked up and down while still rotating.
- The main function of a kelly is to transfer energy from the rotary table to the rest of the drill string.
- There are two type of Kelly, square or hexagonal. The shape of the Kelly makes it the drive for the drill string and it is driven by the rotary drive bushing.
- Drive bushings transfer the rotary power to the drill string so that it can be turned. They are installed on the Kelly allowing the Kelly to be raised and lowered while at the same time rotating the drill string.





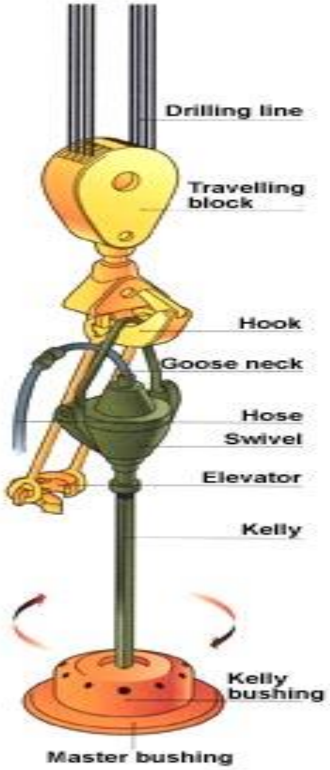
Square Kelly

Hexagonal Kelly

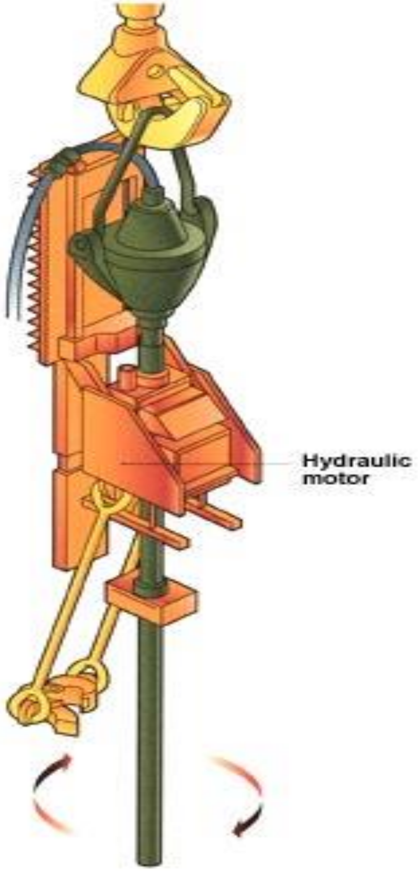
Top Drive Drilling

- Now day modem rigs have rotation and circulation hydraulically powered device “Top Drive” which is basically a combined rotary table and Kelly.
- The top drive consists of a DC drive motor that moves in a track along the derrick and connects directly to the drillstring without the need to a rotary table.
- The top drive is mounted on the rig's swivel, the swivel attaches to the travelling block and supports the drillstring weight.
- Some early top drives are suspended below a separate rotary swivel, while some have an integrated swivel where the Kelly and swivel is set back in the rat hole.
- Top Drive

1. Replaced Kelly and Kelly bushing and it rotates the string. It is an alternative to the rotary table and Kelly drive.
2. Drilling to be carried out stand by stand instead. A rotary table type rig can only drill 30’ sections of drill pipe while a top drive can drill 90-feet drillpipe. Therefore, there are fewer connections of drill pipe and hence improving time efficiency.
3. Top drive is not removed during trips.



Rotary Table drive Drilling



Top Drive Drilling

Difference Between Kelly Drive and TDS Drive Kelly

- Rotary table provide rotation.
- Cheaper , slow , inefficient, unsafe.
- Kelly capable to drill with one single drill pipe.
- While tripping if need back reaming & circulation, need to PU Kelly with swivel from rat hole and connect with string TDS String is rotated with TDS motor.
- Take longer time to make connection.
- For tripping (RIH/POOH), Kelly must be rack back with swivel in rate hole on rig floor.
- Kelly is old drive system.
- Kelly is not round pipe reduce life of BOP rubber element.
- Kelly need two case hole on rig floor, Rate hole & mouse hole.
- In Kelly crew have to operate elevator manually, less safety.
- In Kelly system, bit is off bottom equivalent to Kelly length when connect another pipe for drilling.

- String is rotated with TDS motor.
- Expensive, Fast, efficient, safe.
- TDS is capable to drill with drill pipe stand.
- Its very convenient to connect TDS and back ream with circulation at any point.
- Take less time to make connection.
- TDS keep hanging all time with travelling block & hook while tripping.
- TDS is new drive system.
- In TDS drill pipe are completely round, better for BOP element.
- In case of TDS we need only mouse hole on rig floor.
- TDS have hydraulic system to move links and elevator, more safety.
- In TDS bit almost on bottom, when make new connection.

Rotary System “Swivel”

- The swivel is hung under the traveling block and directly above the Kelley.
- It provides the ability for the **Kelly to rotate** while the **traveling block** to remain in a **stationary** rotational position while simultaneously allowing the **introduction of drilling fluid** into the drill string.
- It is connected directly to the hook while in the drilling or circulating mode but taken off and set back while pulling the string from the well bore.

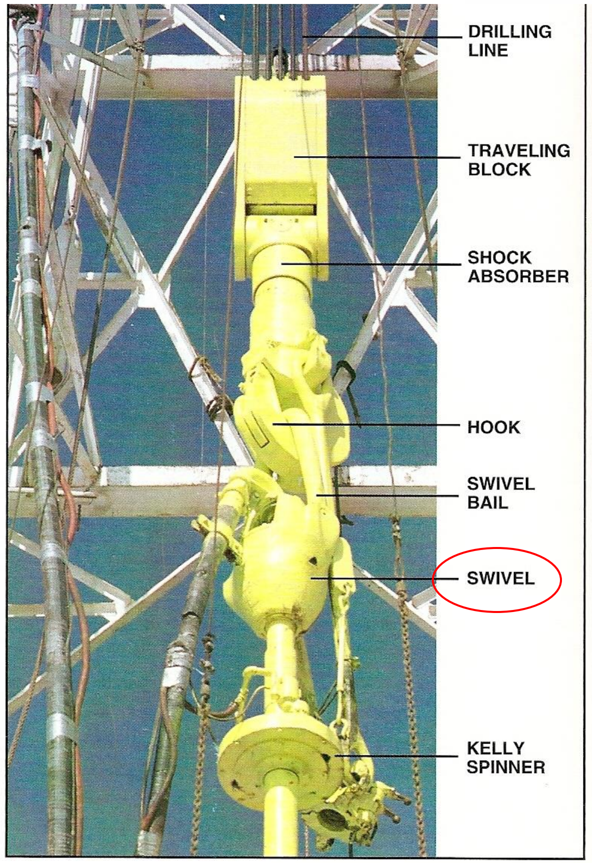
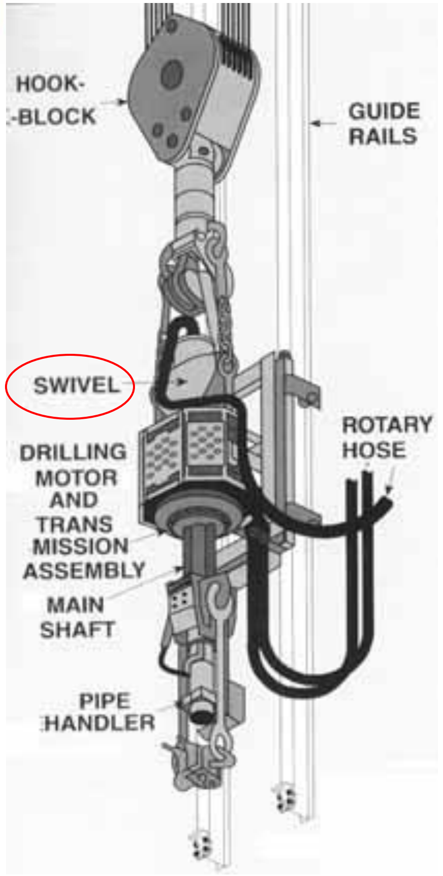


Figure 97. Traveling block, shock absorber, hook, and other

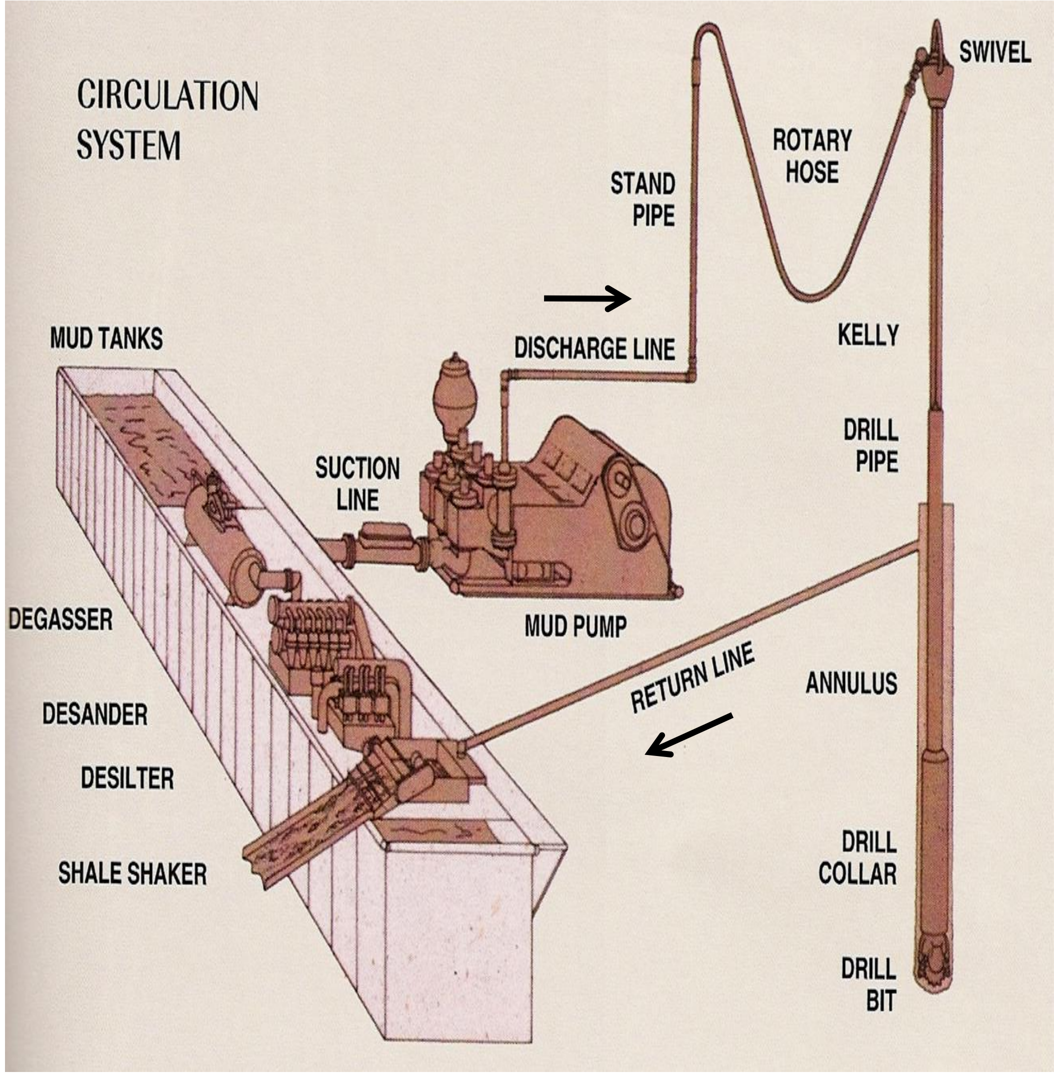
Swivel with Rotary Table



Swivel with Top Drive

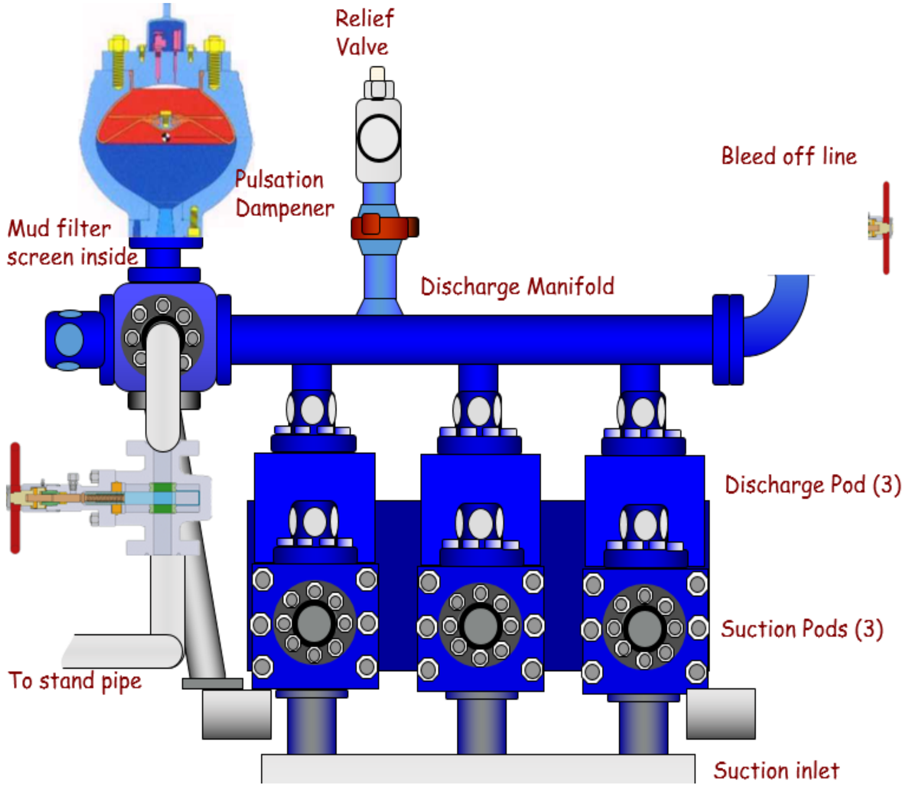
Circulating System

- The drilling mud travels up the stand pipe and through the rotary hose, and then downward through the Kelly or top drive system, drill pipe and bottomhole assembly by the mud pumps.
- After mud reached the bottom of the well through the bit nozzles, it brings rock cuttings to the surface through the annulus between drill pipe and well wall.
- The mud with rock cuttings will be separated through surface solid control system. After these, clean drilling mud will be retreated with certain chemicals and again pumped into the wellbore.
- Rotary hose connects from the standpipe to the swivel thus allowing the drilling fluid to circulate while drilling. This high pressure hose moves up and down every time the pipe is moved and needs to be pressure tested at the same time as the blowout preventer (BOP’s).
- The string circulating starts at the swivel and ends at the BHA (mostly Bit).



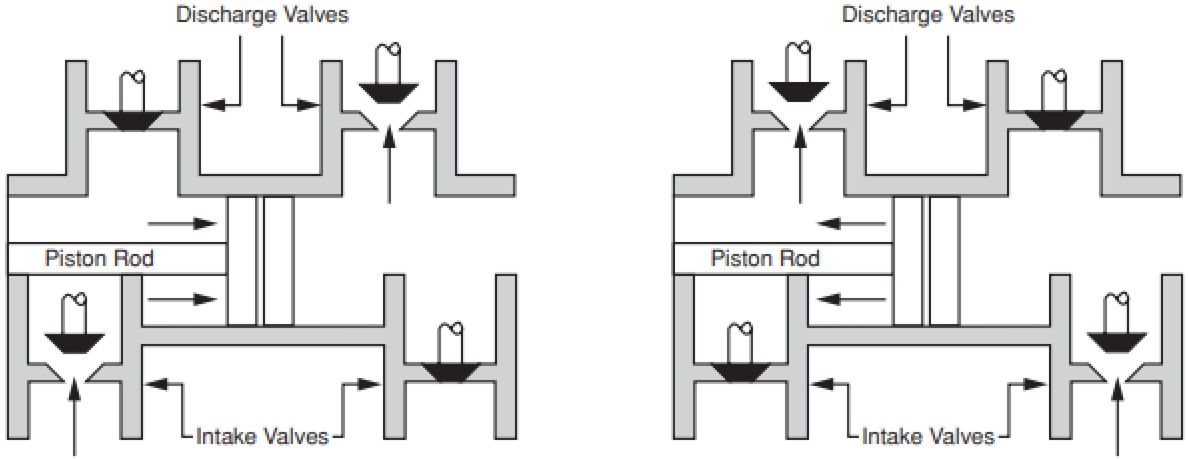
Mud pumps

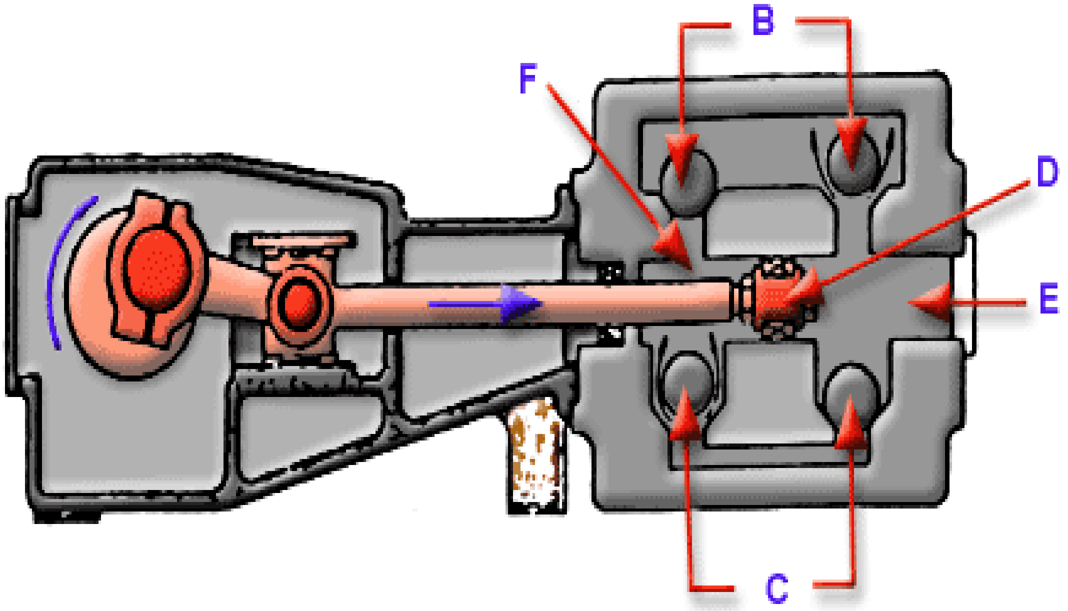
- The mud pumps provide power to move the fluid at the required pressure and volume.
- The Pump is equipped with a discharge pulsation dampener that is designed reduce hydraulic noise and improve detection of MWD signals that are transported from the tools to surface via the drilling fluid. The pulsation dampener is filled up with nitrogen from the top inlet valve to a maximum pressure of 750 psi.
- The reset relief valve is used as a safety valve on mud manifolds to protect against damaging pressure surges. The pressure setting can be changed while the valve is under pressure. When the preset pressure is exceeded, the valve snaps to the fully open position. After pressure is relieved, a trip-free reset lever closes the valve. Setting accuracy is not affected by vibration, pressure surges, or valve operation.



Mud pumps- Duplex Pumps – Double Acting

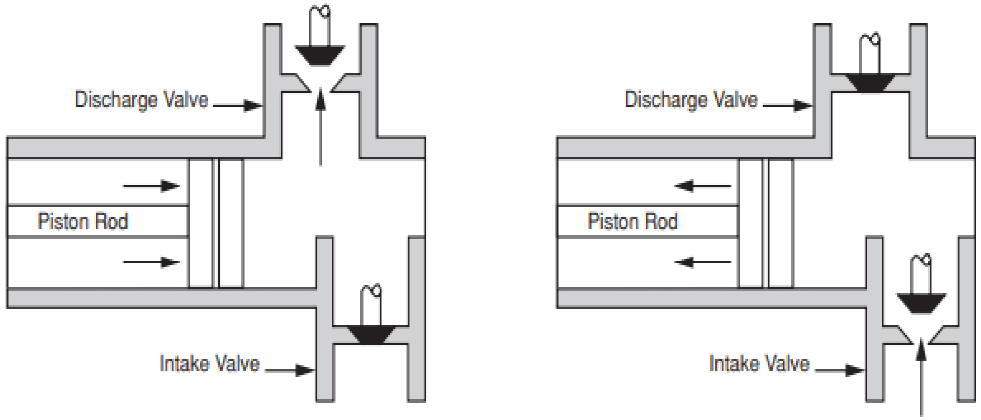
- Duplex pumps have two cylinders and are double-acting (i.e. pump on the up-stroke and the down-stroke). The liquid is pumped when the piston moves in either direction.
- Each of the two cylinders is filled on one side of the piston at the same time that fluid is being discharged on the other side of the piston.
- When the piston moves to the right, the liquid in the cylinder to the right of the piston (E) is discharged, and the cylinder to the left of the piston (F) is filled. When the direction of the piston is reversed, the liquid in F is discharged, and the cylinder at E is filled with suction fluid.
- With each complete cycle of a piston, mud is discharged at twice the volume of the cylinder minus the volume of the piston rod.

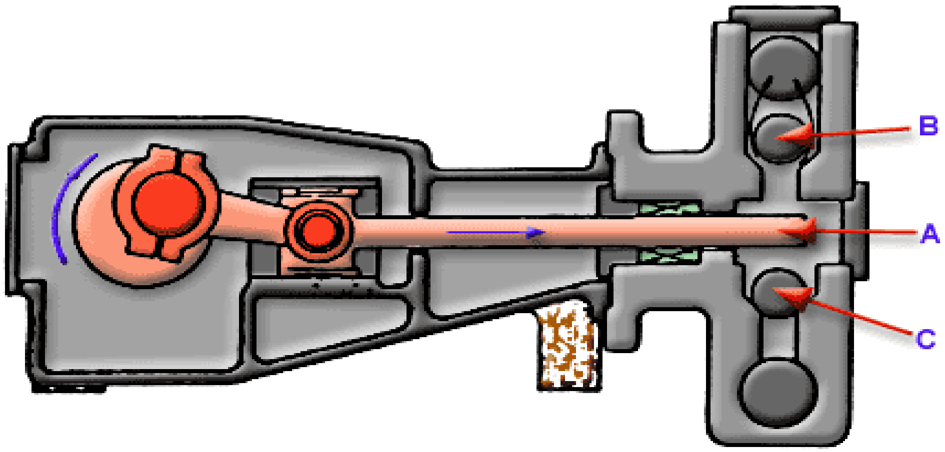




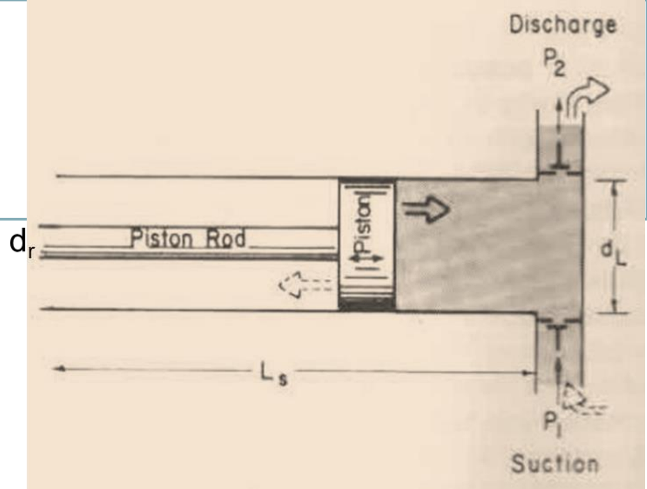
Mud pumps- Triplex Pumps – Single Acting

- Triplex pumps have three cylinders and are single-acting (i.e. pump on the up-stroke only).
- As the plunger (A) moves to the right, the fluid is compressed until its pressure exceeds the discharge pressure, and the discharge check valve (B) opens. The continued movement of the plunger to the right pushes liquid into the discharge pipe.
- As the plunger begins to move to the left, the pressure in the cylinder becomes less than that in the discharge pipe, and the discharge valve (B) closes. Further movement to the left causes the pressure in the cylinder to continue to decline until it is below suction pressure. At this point the suction check valve (C) opens. As the plunger continues to move to the left, the cylinder fills with liquid from the suction.
- As soon as the plunger begins to move to the right, it compresses the liquid to a high enough pressure to close the suction valve (C), and the cycle is repeated.
- Triplex pumps have the advantages of being lighter, give smoother discharge and have lower maintenance costs.





Pump Flow Rate



- The flow rate is the amount of fluid that a pump can deliver per unit of time. at a given speed. It is expressed in L/min or gpm.
- The volume displaced by each piston during one complete pump cycle is given by:

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

- The pump factor for a single-acting pump having three cylinders becomes

$$F_p = 3\frac{\pi}{4} L_s d_l^2 E_v$$

- The flow rate: $Q = F_p \times N$

Where N is the number of stroke per unit time

- For simplicity, Triplex pump is given by :

Qt = 0, 0386 nLD²

Qt = theoretical flow rate of the pump (l/min)
n = number of strokes per minute {strokes/min)
L = length of stroke (inches)
D = diameter of liner (inches).

- The true measured rate of a pump is always lower than the calculated theoretical flow rate.
- The Volumetric efficiency is the ratio between true measured flow rate and the theoretical flowrate of a pump.

Pump Flow Rate

Example: Consider a triplex pump having 6-in liners and 11-in strokes operating at 120 cycles/min and a discharge pressure of 3000 psig. Compute Pump factor in units of gal/cycle at 100% volumetric efficiency, Flow rate in gal/min and Pump power developed.

1. Pump factor in units of gal/cycle at 100% volumetric efficiency

$$F_p = 3\frac{\pi}{4} L_s d_l^2 E_v = 3\frac{\pi}{4} 11 \times 6^2 \times 1 = 933 \frac{in^3}{cycle} = 4.04\ gal/cycle$$

Gallon = 231 cubic inch

2. Flow rate in gal/min

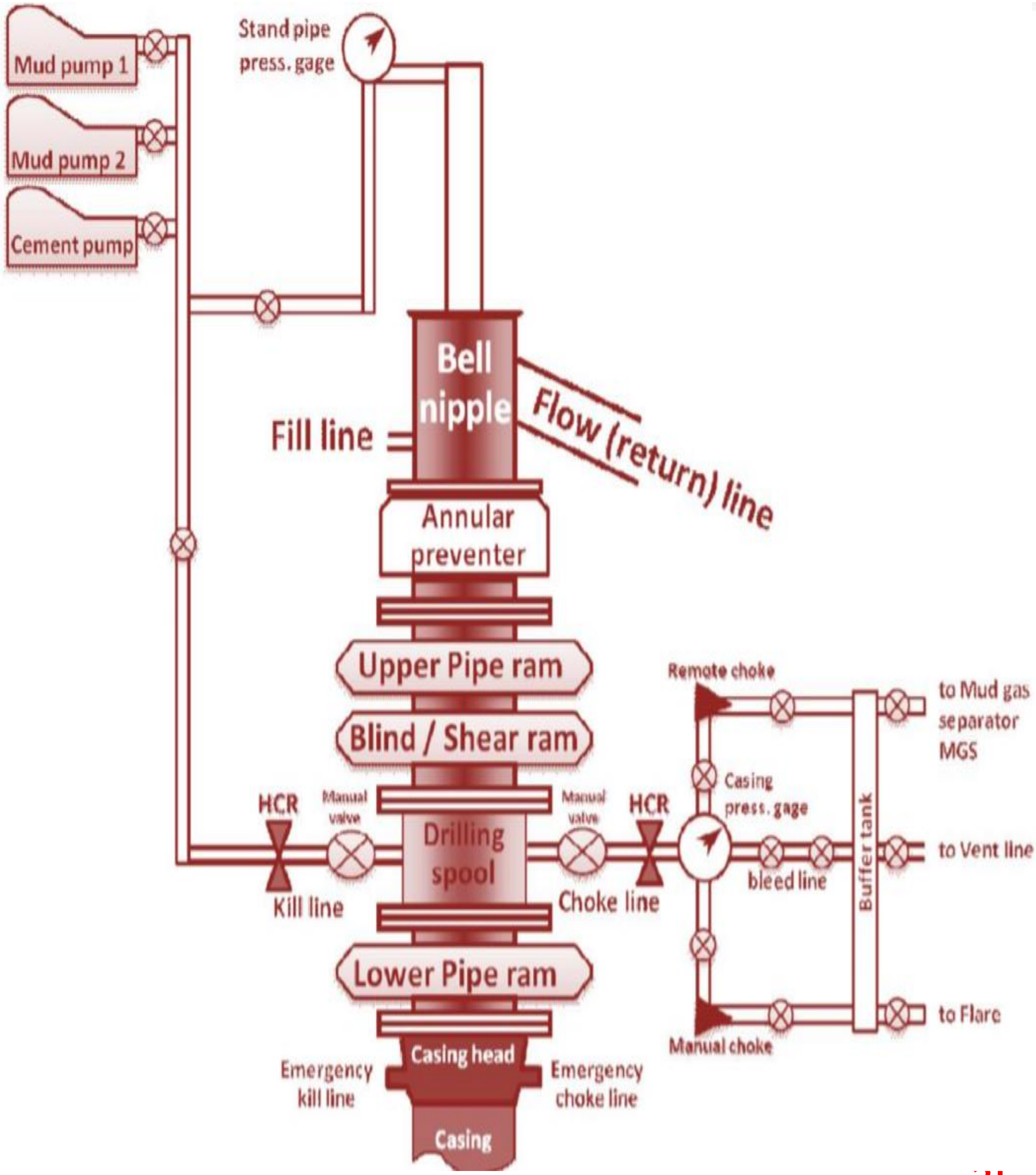
$$Q = F_p \times N = 4.039 \times 120 = 484.68\ gal/min$$

3. Pump power developed

$$P_H = \frac{\Delta p \times Q}{1714} = \frac{3000 \times 484.68}{1714} = 848\ hp$$

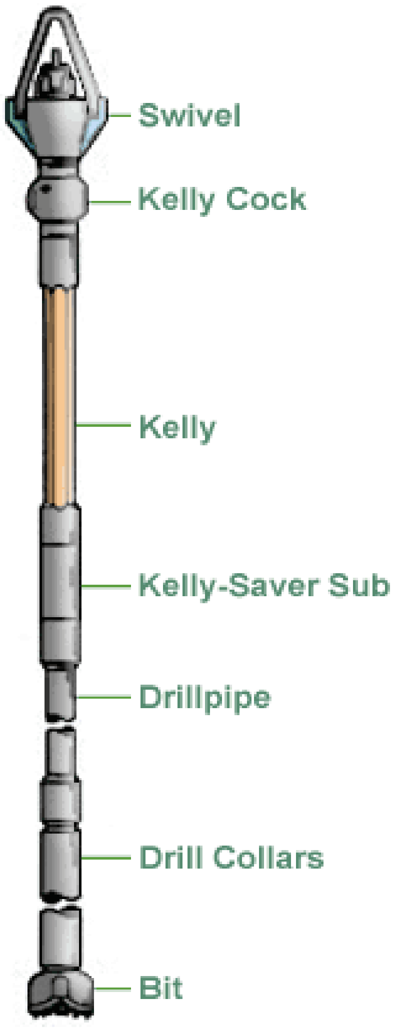
Well Control

- Drill a well is very dangerous, because the pressure in the reservoir could be significant high. Therefore, well control system must be installed.
- The main part of this system is the blowout preventer (BOP). This equipment is set on the top of the well bore. If there is a sudden pressure change in the well which push the formation fluid up to the surface, BOP will be closed the seal the well from blowout.
- A ram-type BOP uses a pair of opposing steel plungers, rams. The rams extend toward the center of the wellbore to restrict flow. Outlets at the sides of the BOP housing (body) are used for connection to choke and kill lines or valves.
- **Annular preventer** close around a drill pipe, restricting flow in the annulus between the outside of the drill pipe and the wellbore, but do not obstruct flow within the drill pipe.
- **Blind rams** which have no openings for tubing, can close off the well when the well does not contain a drill string or other tubing, and seal it.
- **Shear rams** cut through the drill string or casing with hardened steel shears.
- **Kill line**: permits mud to be pumped down to the annulus to restore a pressure balance.
- **Choke line**: Annular pressure relief lines.



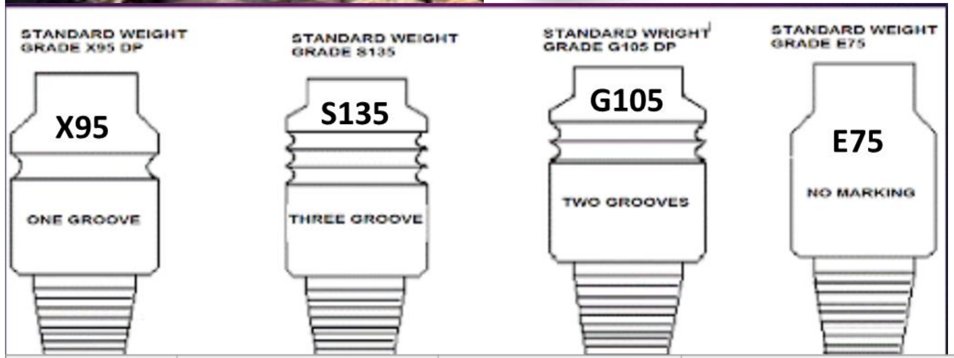
Drill String

- The main parts of the rotary system (or the drill string) are: Kelley, Drill pipe, Drill collars, Heavy wall drill pipe, Stabilizer, Rotary reamers, etc..
- Note: the bottomhole assembly (BHA) is that portion of the drill string between the drill pipe and the drill bit.
- As the drill string moves downhole, it is subjected to a variety of stresses, including tension, compression, vibration, torsion, friction, formation pressure and circulating fluid pressure. It is also exposed to abrasive solids and corrosive fluids.



Drill pipe

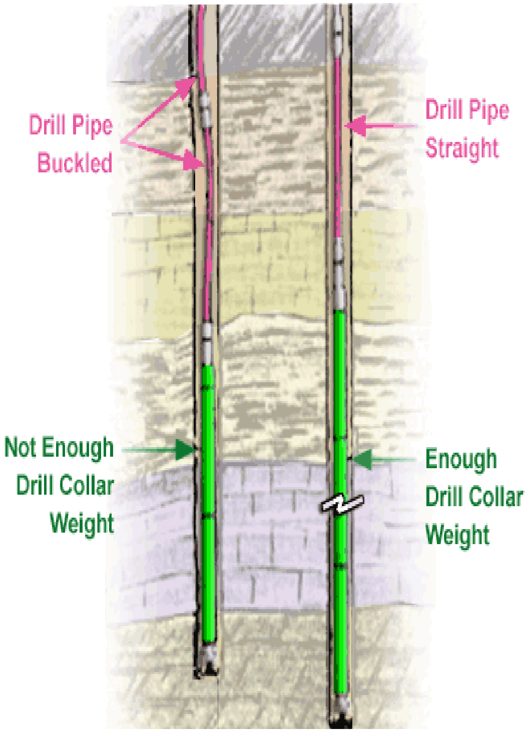
- The primary purposes of drill pipe are to provide length to the drill string and transmit rotational energy from the Kelly to the bottomhole assembly and the drill bit. The drill pipe connects the rig surface equipment with the bottomhole assembly and the bit, both to pump drilling fluid to the bit and to be able to raise, lower and rotate the bottomhole assembly and bit.
- The Minimum Yield stress which gives a stretch of 0.5% (e.g. a strain of 0.005) in normal strength steels (E75 and X95) is taken as the maximum stress that should ever be imposed on that material. For high tensile drill string steels, a higher strain is used to calculate Minimum Yield Stress. For G105 it is 0.006 and for S135 it is 0.007 (defined in API Specification 5D).
- The Minimum Yield Stress is referred to in the name of the grade; thus E75 grade steel has a Minimum Yield Stress of 75,000 psi, G105 has a Minimum Yield Stress of 105,000 psi.



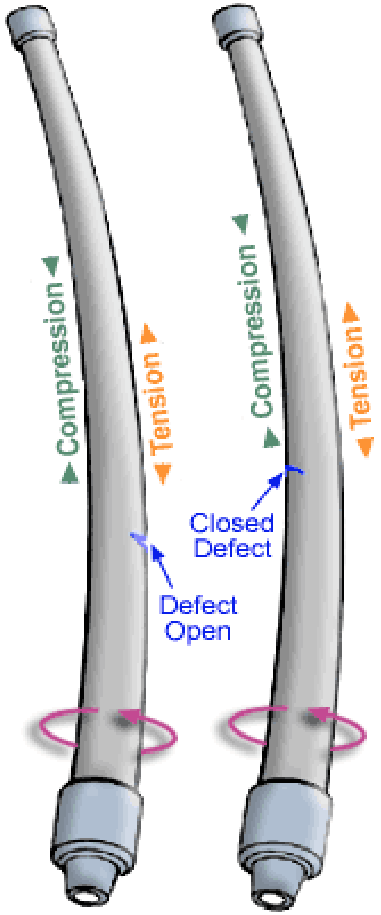
Grade	Minimum Yield psi	Maximum Yield psi	Tensile Strength psi
E	75,000 (517 MPa)	105,000 (724 MPa)	85,000 (586 MPa)
X	95,000 (655 MPa)	125,000 (862 MPa)	105,000 (724 MPa)
G	105,000 (724 MPa)	135,000 (931 MPa)	115,000 (793 MPa)
S	135,000 (931 MPa)	165,000 (1138 MPa)	145,000 (1000 MPa)

Drill Collar

- The drill collars provide weight and stability to the drill bit, maintain tension on the drill pipe and help keep the hole on a straight course.
- Drill collars can be slick or spiraled which used to keep the hole to pipe contact to a minimum and assist in stopping hole problems such as differential sticking.
- Downhole MWD sensors measure weight-on-bit more accurately and transmit the data to the surface.
- Tension can be maintained by running an adequate number of collars in the bottomhole assembly to ensure that the **neutral point** (that is, the point below which the drill string is in compression, and above which it is in tension) will always be below the drill pipe.

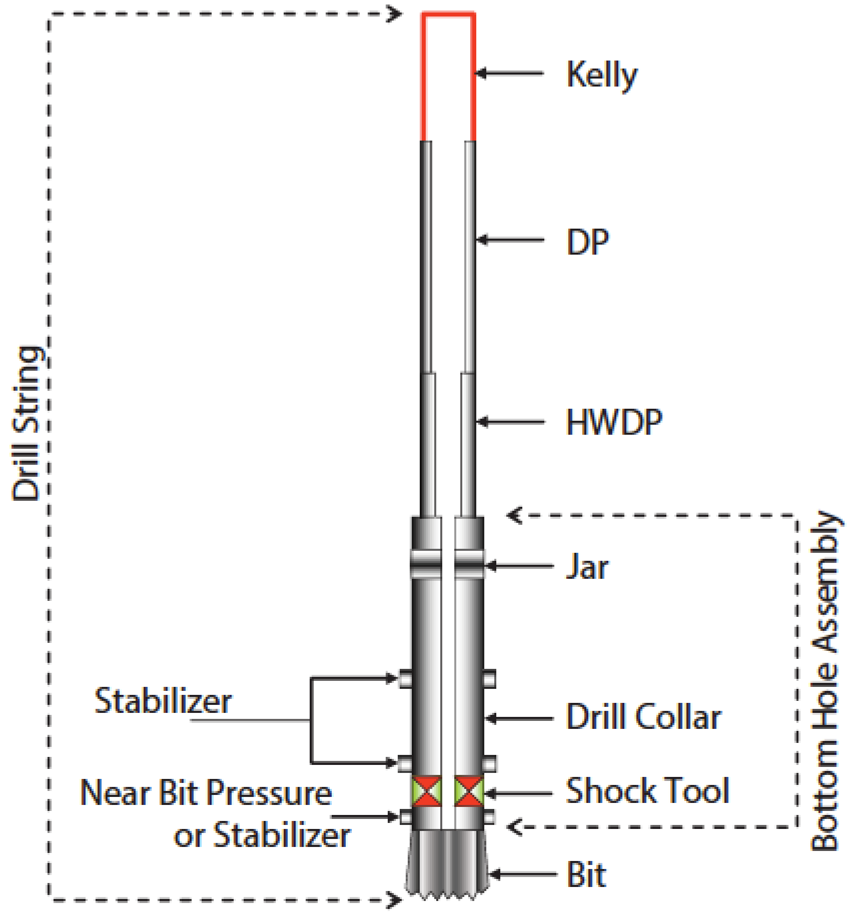


From Rowe, Moris & Wilson, 1981



Heavy Wall Drill Pipe

- Heavy wall drill pipe (HWDP) was first used in directional drilling, which generally requires flexibility in the drill string. It is now widely used in vertical and horizontal drilling as well. With less wall contact than would be experienced with drill collars, its usage reduces torque and wall-sticking tendencies. Its smaller degree of wall contact, together with its greater stiffness relative to regular drill pipe, results in increased stability and better directional control. Heavy wall drill pipe is also useful in reducing hook loads, making it ideal for smaller rigs drilling deeper holes.
- HWDP serves as an intermediate-weight drill string member between the drill pipe and the much heavier drill collars, thereby reducing fatigue failures, providing additional hole stability and aiding in directional control.
- Approximately 6 joints of HWDP are placed on top of the drill collars to keep the transition zone out of the drill pipe.

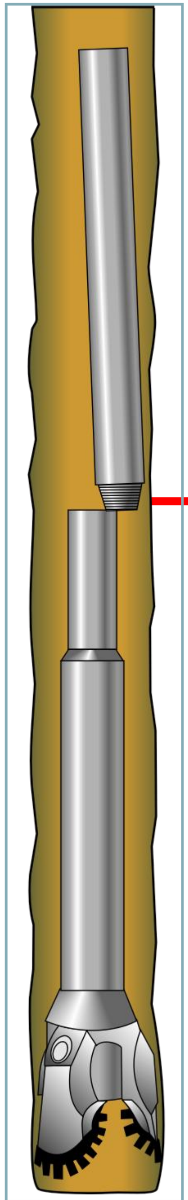


Pipes Failures

- The body of a drill collar is stiffer than the connection and bending occurs in the connection.
- In HWDP, bending occurs in the body and not at the connection, so fewer connection failures are experienced.
- With BHA components, most of the bending occurs in the connections. BHA connections are subjected to bending and fatigue from buckling.

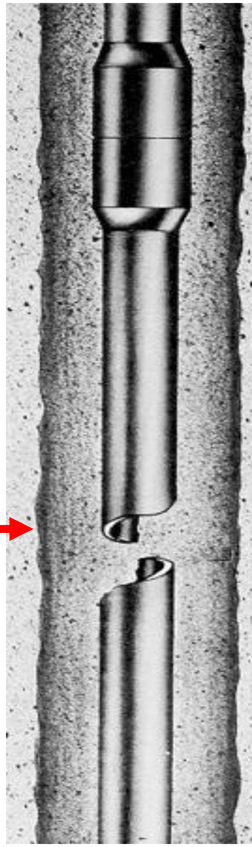
❖ In a vertical well, drill pipe will buckle with little or no compressive load. Buckling will create bending stresses in the drill pipe which can lead to fatigue if the bending stresses are high enough.

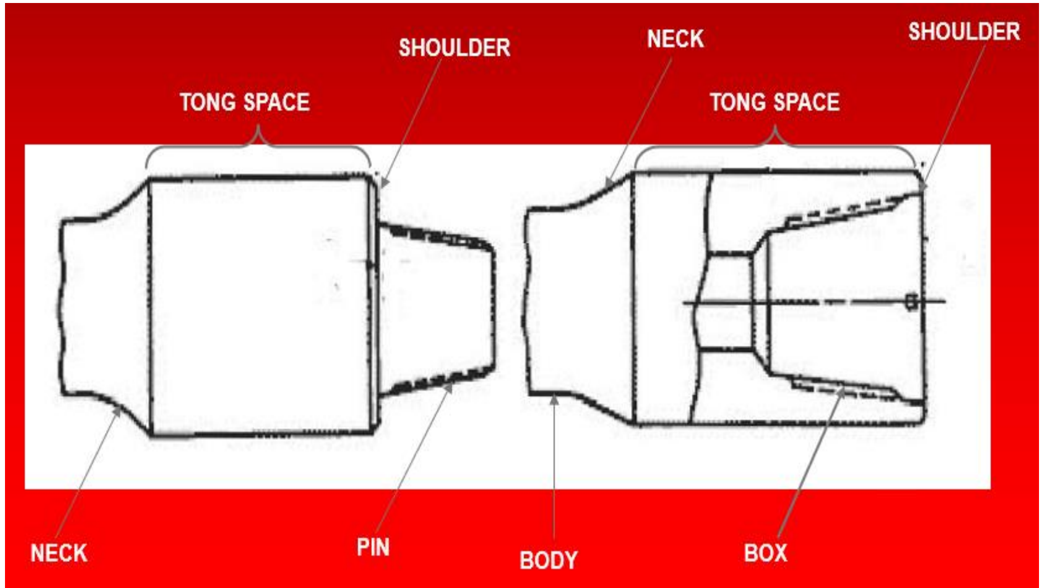
❖ In a directional well, the compressive load must exceed the critical buckling load in order to buckle the drill pipe. Therefore, drill pipe can be run in compression in a directional well without causing buckling. The critical buckling load is a function of the pipe size, inclination and radial clearance.



Connection Failure

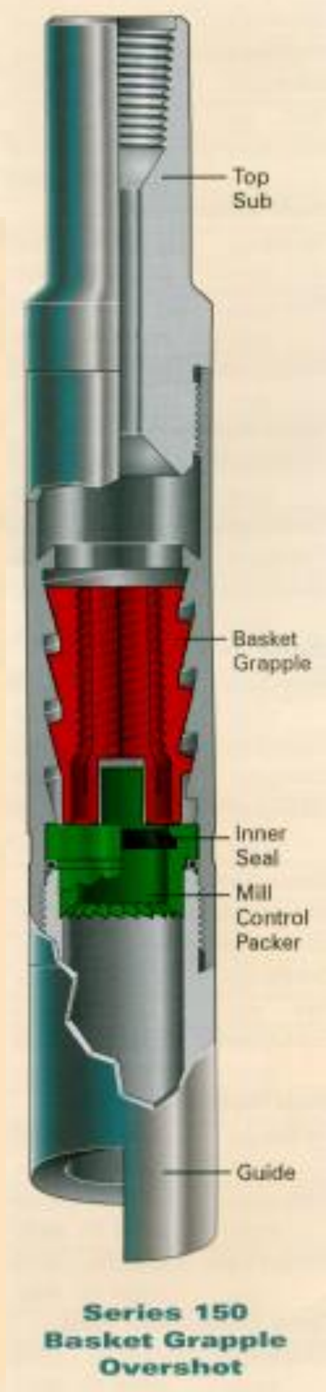
Drill Pipe Twist-off





Fishing Tools

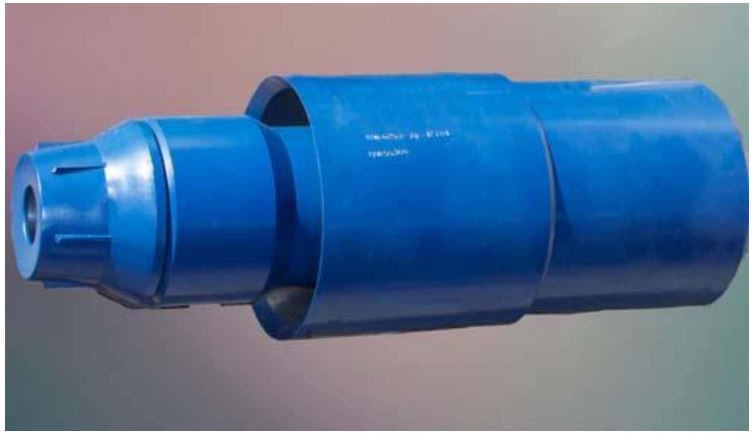
- In technical terms, a fish can be any object which has been lost or stuck in a borehole, and has a serious negative impact on well operations.
- To solve this issue, there are three main technologies: pulling, milling, or cutting the pipe itself, and other downhole parts.
- A fishing job depends on the cost and likelihood of success. Else, the option is to leave the fish where it is, and sidetracking or redrilling the well to follow an alternative path, completing the well in a shallower zone, or abandoning the well altogether.
- Overshot is an external catch fishing tool designed to retrieve tubular items from the well bore. Taper Tap is an internal catch fishing tool designed to retrieve tubular members from the wellbore.



Other Tubular Equipment

Casing scraper run after cementing of production casing to ensure inner casing diameter.

Junk sub run after drilling casing accessories to catch junk or debris from the wellbore to drop into the basket.



Scraper is designed to remove scale, mud cake, cement sheath, embedded bullets, and other foreign materials inside the casing wall.

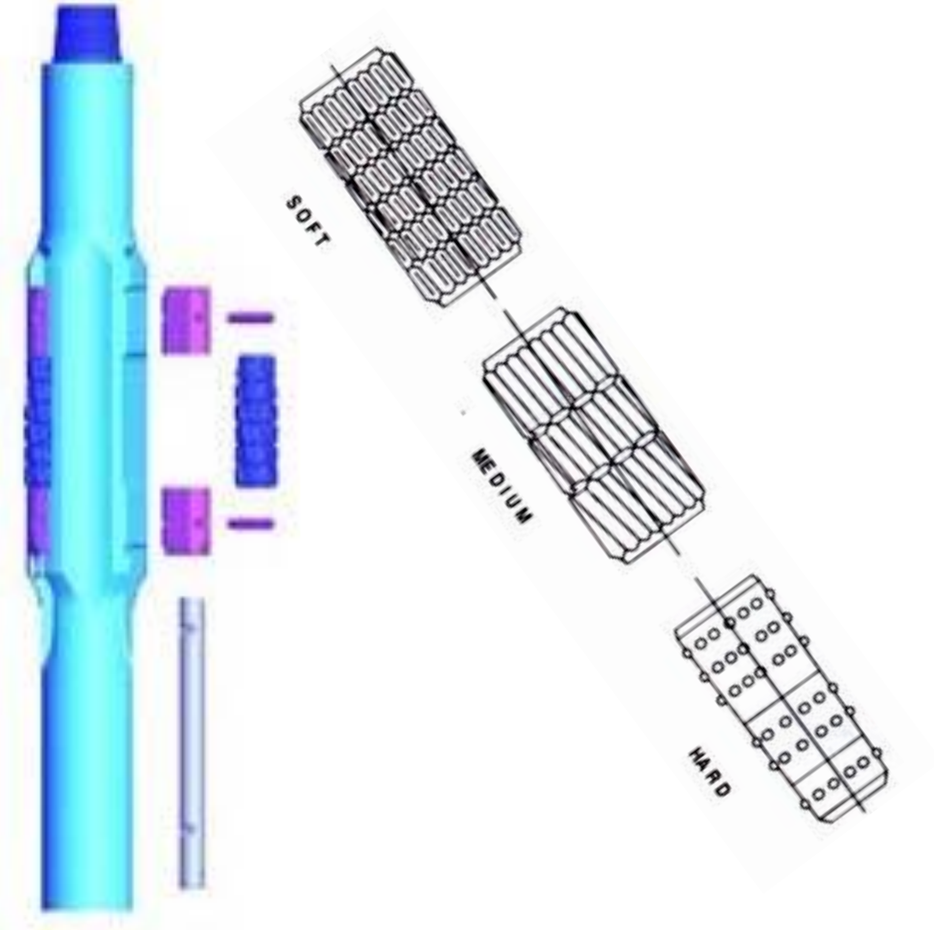
B.S

X.O.S

- Bit sub (B.S) to connect bit to BHA.
- Cross over sub (X.O.S) to connect two different threads.

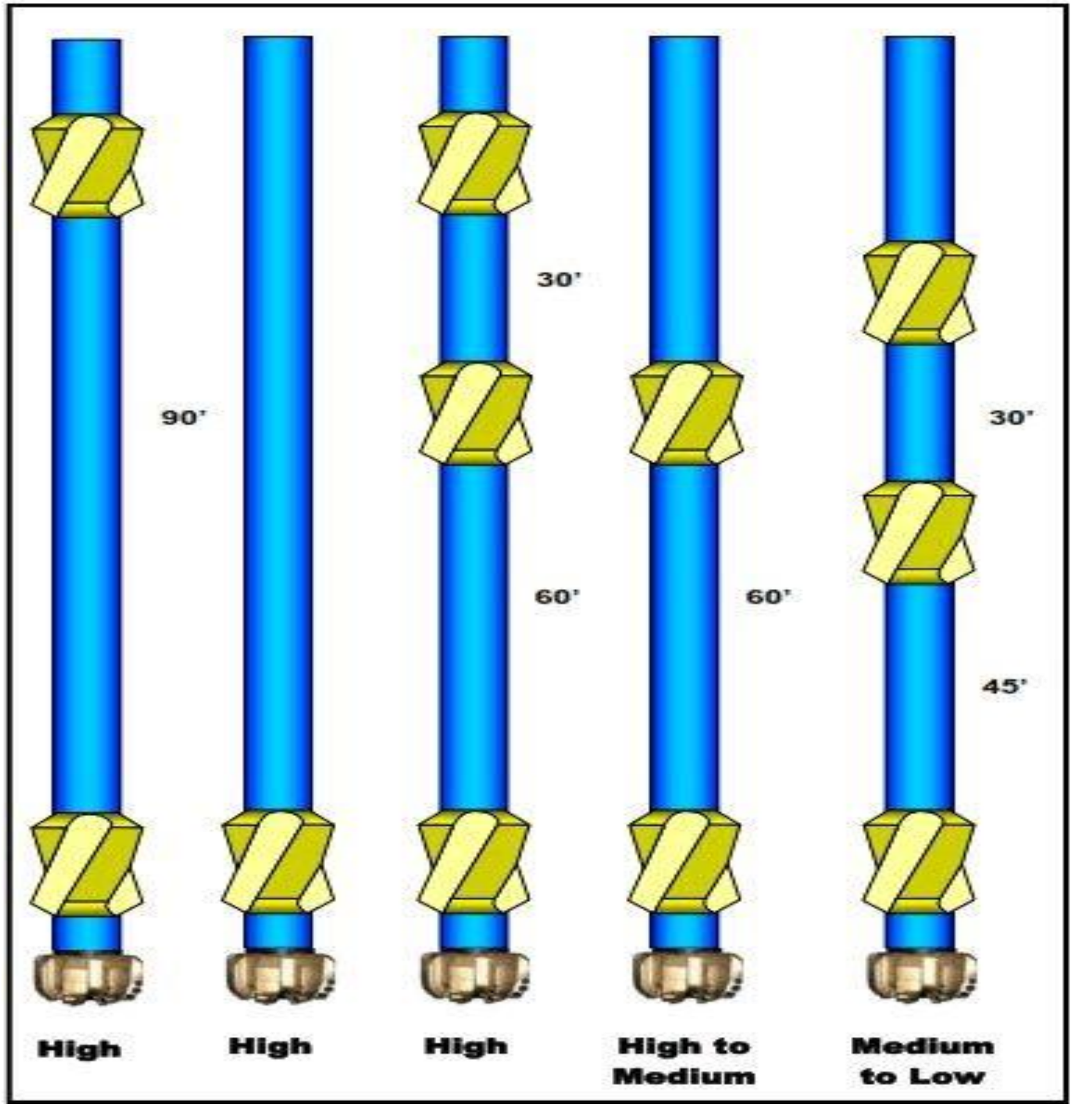
Reamer

- In hard formations, the outside cutting structure of a bit gradually wears away if it is not protected.
- This results in a hole diameter that becomes smaller with increasing depth.
- When a hole is severely undergauge, it is necessary to ream each new bit back to bottom before drilling can resume.
- This not only costs rig time and reduces bit life, but it increases the possibility of sticking the drill string.



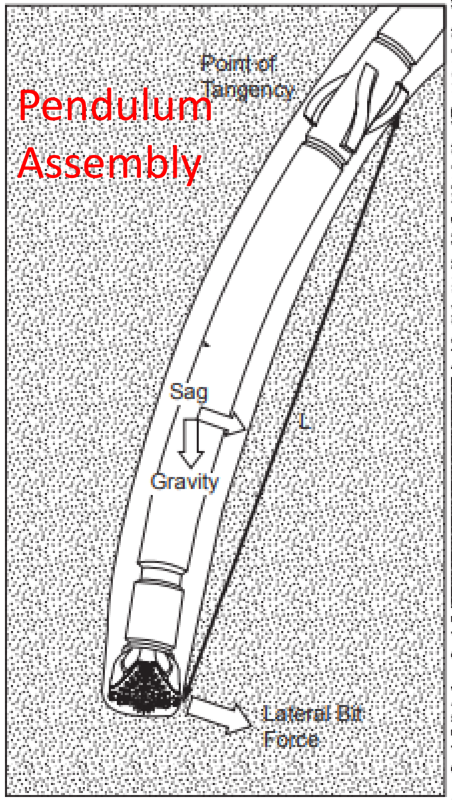
Stabilizers

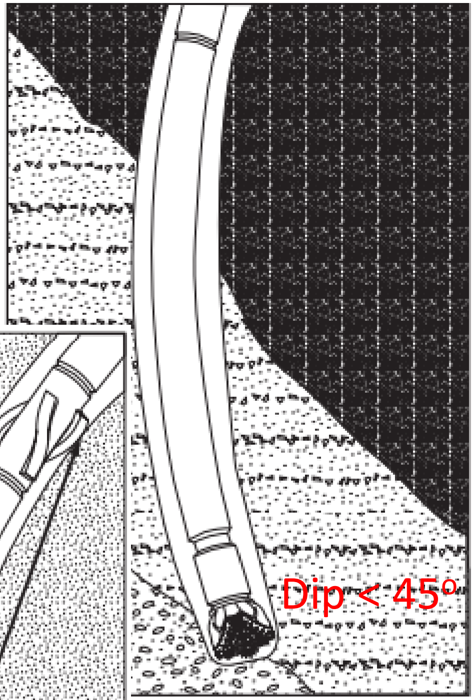
- Stabilizers centralize the drill string at selected points in the borehole to ensure that the weight of the drill collars is concentrated on the bit, reduce torque and bending stresses in the drill string, prevent wall-sticking or key-seating of the drill collars, and maintain constant bit direction in straight-hole drilling.
- Centralize the drill collars, help maintain the hole at full-gauge diameter and aid in directional control.
- String Stabilizers are designed to assist in directional control by adjusting the size and position of the stabilizer the bit can be made to drop, build or hold angle.
- The near bit stabilizer is also used to help with directional control, but its main purpose is to centralize the bit prolonging the working life.

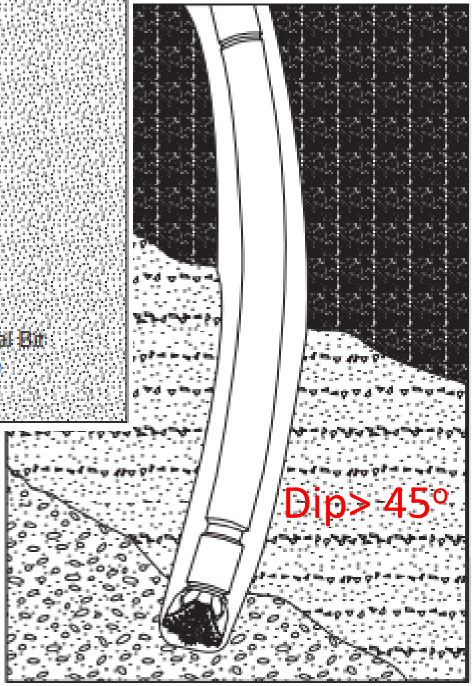


Design of a Stabilized String

- A drilling bit does not normally drill a vertical hole. When the slope (or dip) of the beds is less than 45 degrees the bit tends to drill up-dip (perpendicular to the layers). If the dip is greater than 45 degrees it tends to drill parallel to the layers.
- In hard rock, where greater WOB is applied, the resulting compression and bending of the drillstring may cause further deviation.
- Pendulum assembly technique is utilized for controlling deviation.
  - The first stabilizer is placed some distance behind the bit.
  - The unsupported section of drill collar swing to the low side of the hole.
  - A pendulum assembly will therefore tend to decrease the angle of deviation of the hole and tend to produce a vertical hole.
- The distance "L" from the bit up to the point of wall contact is important, since this determines the pendulum force. To increase this distance, a stabilizer can be positioned some distance above the bit. If placed too high the collars will sag against the hole and reduce the pendulum force.
- When changing the hole angle it must be done smoothly to avoid dog legs.







Drill Collar Calculations

- The using small OD drill collar size can cause an undersized hole, making it difficult for Casing Running.
- The required OD of the drill collars can be calculated as follows:

$$D_{odc} = 2D_{occ} - D_b$$

- Where:

D_{odc} is the outside diameter of drill collars;

D_{occ} is the outside diameter of casing coupling;

D_b is the bit diameter.

- The diameter of drill collar from the above equation can be not API. It can checked with API diameters (API tables include the weights for each size). According to API, drill collar sizes are ranging from 2 3/8″ to 12″.

- The required Collar length to provide a desired weight on the Drilling Bit can be calculated as follows:

$$Lc = \frac{WOB \times SF}{BF \times W_c \times COS\theta}$$

- Where:

$$BF = 1 - \frac{MW\ ppg}{65.5\ ppg}$$

WOB = desired weight on bit, lb

SF= safety factor (1.1-1.15)

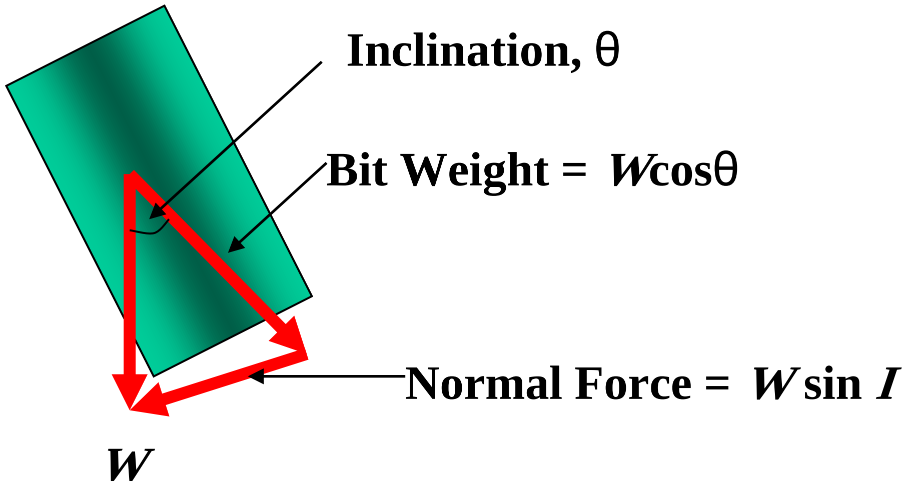
BF= buoyancy factor,

Wc= drill collar weight in air, lb/ft

θ = maximum hole angle at BHA, degrees

- This method does not take into account the hydraulic forces acting on the bottom end of the Drill Collars and on the shoulder areas between Drill Collars and the Heavy Weight Drill Pipe (HWDP) or Drill Pipes.

Drill Collar Calculations



Example:

Select the drill-collar size and length for the following drilling conditions:

Hole size = 8¾ in.

Casing size 7 in. with 7.656-in. OD coupling

WOB = 45,000 lbf

Mud SG = 1.2 (water = 1.0, steel = 7.85)

Hole inclination angle = 10°

Design factor = 1.2

SOL :

D_{odc} = 2(7.656)-8.75=6.562 in. From the table , [redacted] , the weight is 102 lb/ ft

BF = 1 –(1.2/7.85)= 0.847,

and the length of the drill collars, is

Ldc = (1.2)(45,000)/(102)(0.847)(cos10)

$$D_{odc} = 2D_{occ} - D_b$$

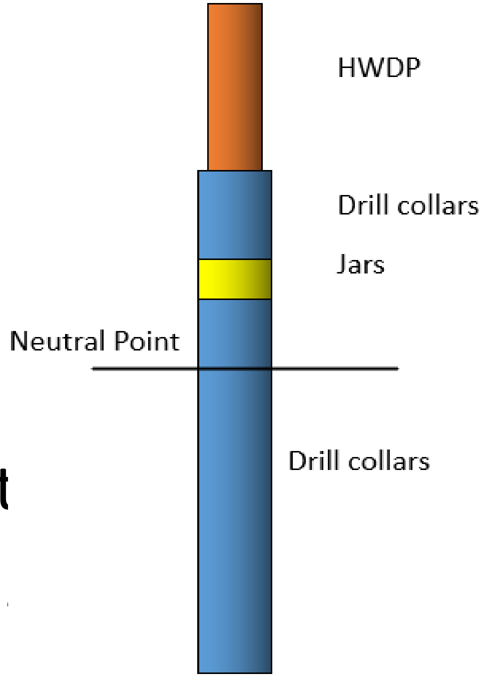
$$Lc = \frac{WOB \times SF}{BF \times W_c \times COS\theta}$$

Ldc = (1.2)*(45,000)/(102)*(0.847)*(cos10)=635 ft

OD in	ID in	Weight Kg/m	Weight Ibm/ft	Thread type
4¾	2.25	69.9	46.8	3 1/2 IF
6¾	2.8125	149.4	102	4 1/2 IF
8	3	218.8	147	6 5/8 R
9½	3	324.4	217	7 5/8 R

Neutral point

- The neutral point is usually defined as the point in the drillstring where the axial stress changes from compression to tension.
- The location of this neutral point depends on the weight-on-bit and the buoyancy factor of the drilling fluid.
- In practice, since the WOB fluctuates, the position of the neutral point changes. It is therefore quite common to refer to a "transition zone" a the section where axial stress changes from compression to tension.



In Vertical well:

$$Lnp = \frac{WOB}{WDC * BF}$$

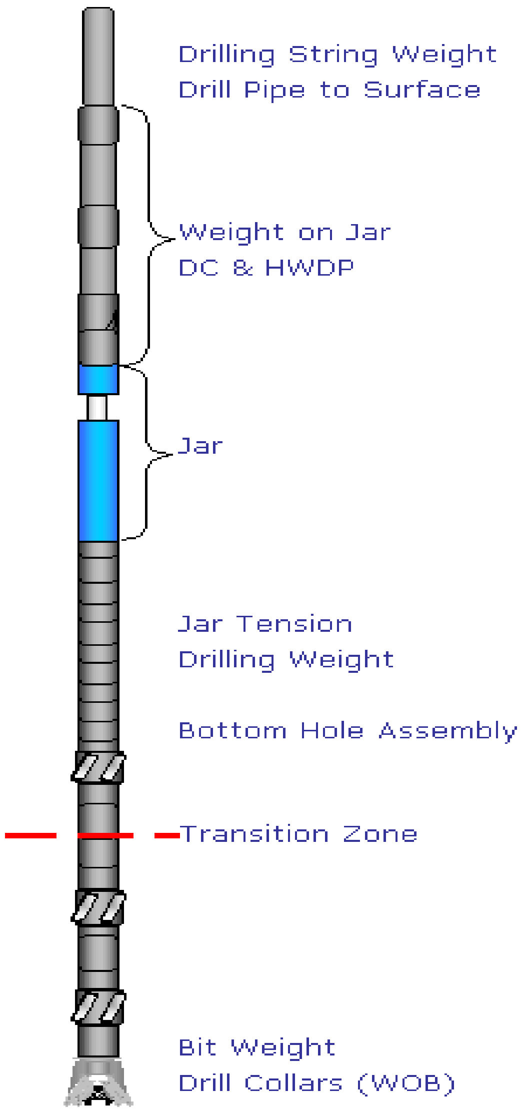
Lnp : the distance from the bit to the neutral point.
WDC: the weight per meter of the drill collars
BF : the buoyancy factor of the drilling mud.

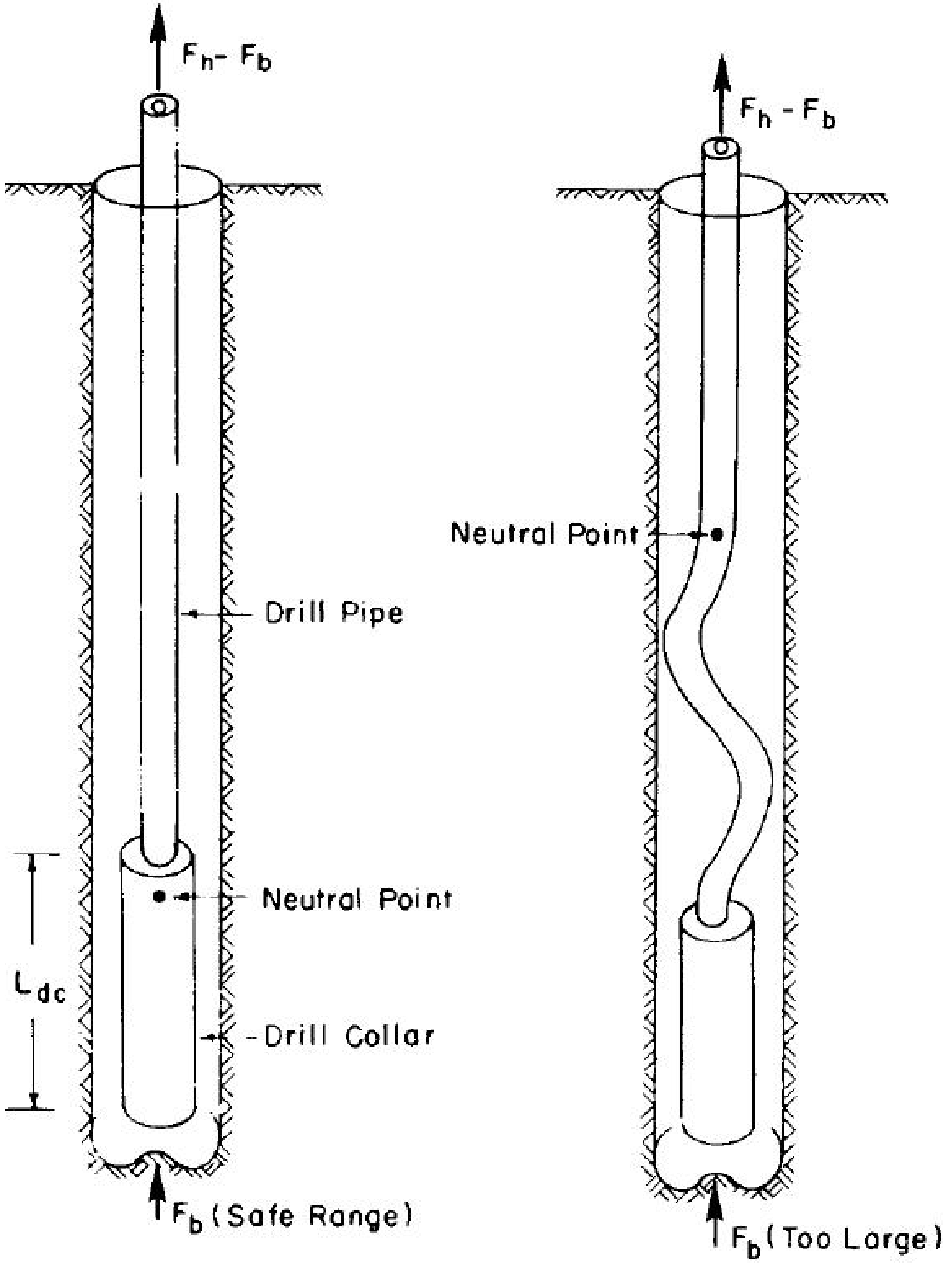
In Deviated well:

$$Lnp = \frac{WOB}{WDC * BF * \cos\theta}$$

Buckling

- To avoid the buckling on the drill pipe, the neutral point should be designed in such a way that it is located on the drill collars.
- Drillstring components located in this "transition zone" may, therefore, alternately experience compression and tension.
- These cyclic oscillations can damage downhole tools. A prime example is drilling jars, whose life may be drastically shortened if the jars are located in the transition zone.





Axial Tension/Compression Stress

- For axial stress determining, all forces acting on the Drilling Bottom Hole Assembly BHA must be considered including the hydrostatic forces.
- The stress (σ, psi) produced by an **axial** load (tension or compression) (F, lbf) on the cross section (A, in2) of a drillstring can be expressed as (**σ = F/A**).
- The **largest** tension load exists at the top of the drill-string because of the weight of the drill collars, stabilizers, drill-pipe, and other string components.
- The bottom of the string is subjected to axial compressive force because of the hydrostatic pressure acting at the bottom of the pipe.

Axial Tension/Compression Stress

The axial force on the cross section under consideration:

$$F = W_1 + W_2 + F_1 - F_2 - F_b$$

The hook load can be calculated as follows:

$$F_h = w_{dp}^{a} L_{dp} + w_{dc}^{a} L_{dc} + 0.052\rho_m L_{dp}(A_{dc} - A_{dp}) - 0.052\rho_m(L_{dp} + L_{dc})A_{dc} - F_b$$

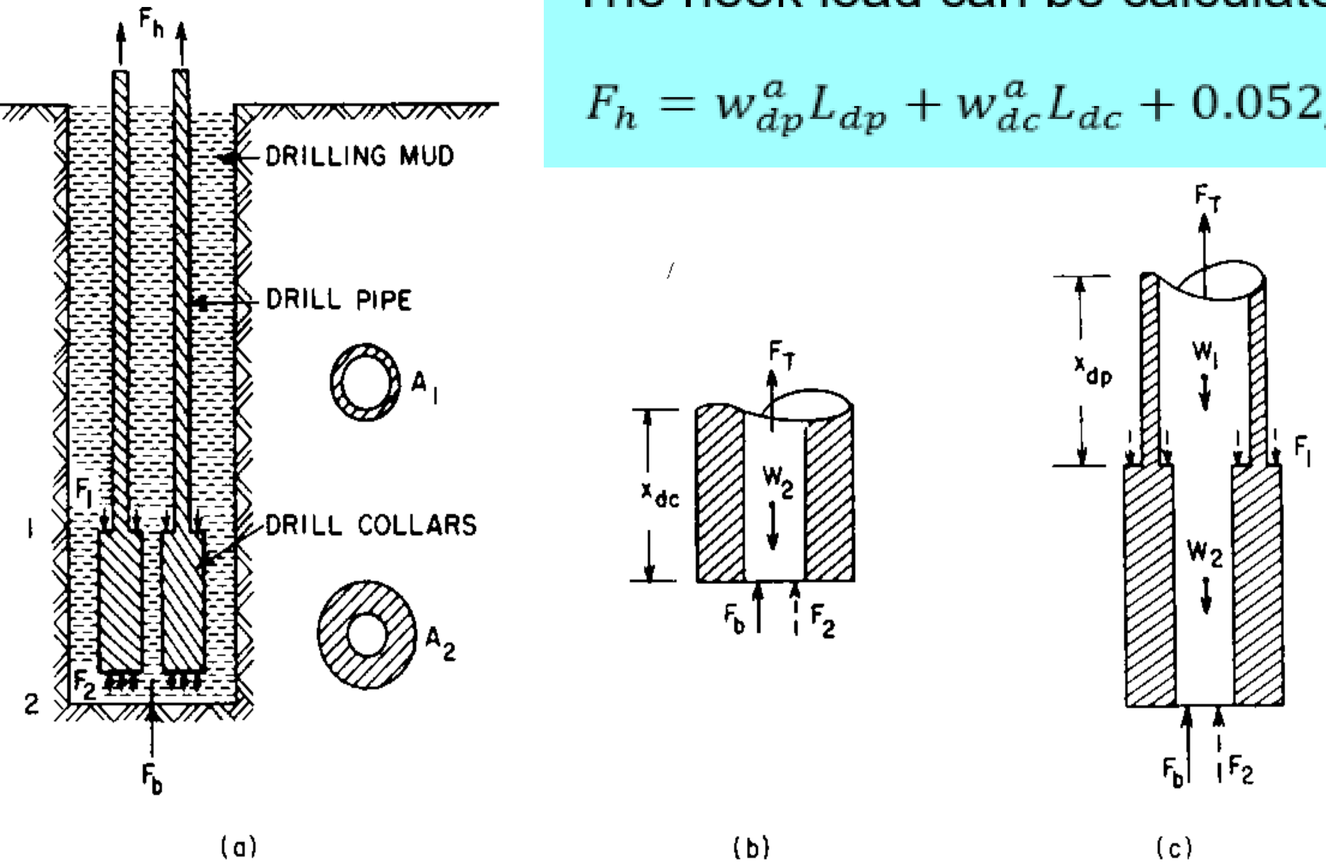
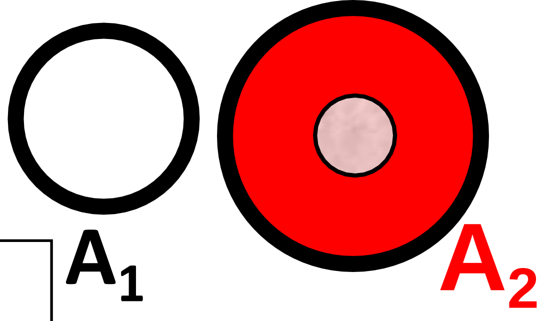


Fig. 4.10—Effect of hydrostatic pressure on axial forces in drillstring: (a) schematic of drillstring, (b) free body diagram for drill collars, and (c) free body diagram for drillpipe.

- **F1**: the hydrostatic pressure at the top of the drill collars
- **F2**: the hydrostatic pressure at the bottom of the drill collars
- **Fb**: bit weight
- **W1**: weight of drill pipe
- **W2**: weight of drill collar

Axial Tension in Drill String



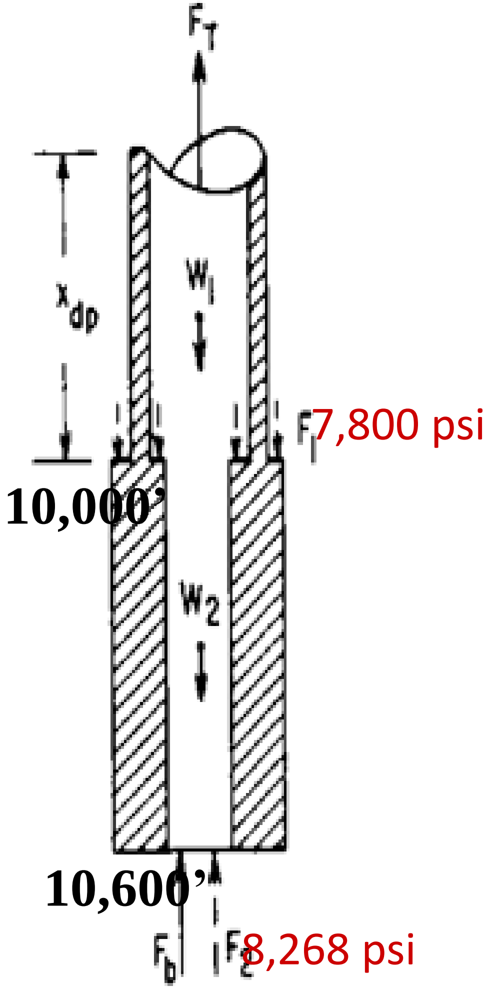
Example

A drill string consists of 10,000 ft of 19.5 #/ft drillpipe and 600 ft of 147 #/ft drill collars suspended off bottom in 15#/gal mud (F_b = bit weight = 0). **What is the axial tension** in the drillstring as a function of depth?

$$A_1 = \frac{19.5 \text{ lb/ft}}{490 \text{ lb/ft}^3} * \frac{144 \text{ in}^2}{\text{ft}^2} = 5.73 \text{ in}^2$$

$$A_2 = \frac{147}{490} * 144 = 43.2 \text{in}^2$$

$$A_2 - A_1 = 43.2 - 5.73 = 37.5 \text{in}^2$$



Example - Summary

$F = W_1 + W_2 + F_1 - F_2 - \boldsymbol{F_b}$

$F = W_1 + W_2 + P_1\,(A_{dc} - A_{dp}) - P_2 * A_{dc} - \boldsymbol{F_b}$

$W_1 = 10{,}000 * 19.5 = 195000$ **lbf**

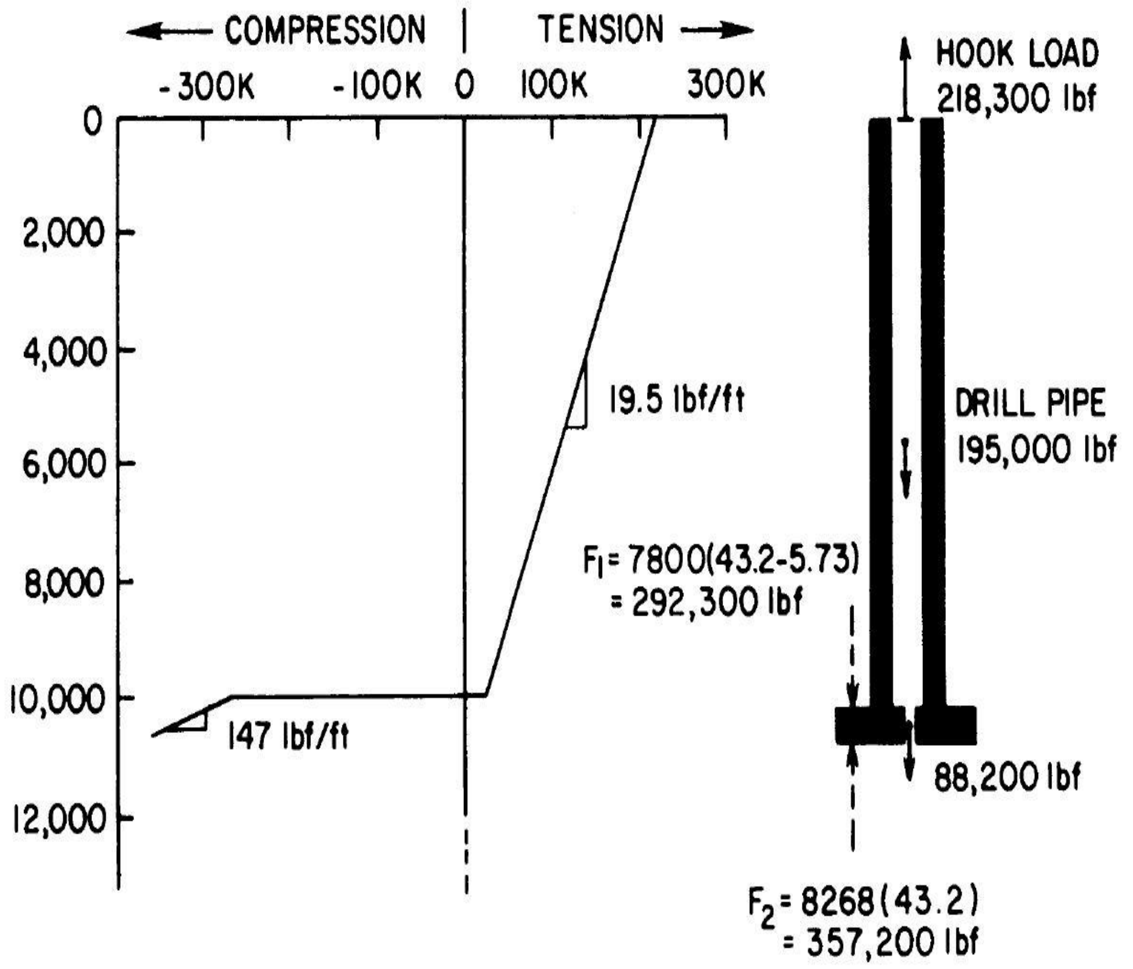
$W_2 = 600 * 147 = 88200$ **lbf**

$F_1 = 0.052 * 15 * 10{,}000 * 37.5 = 292500$ **lbf**

$F_2 = 0.052 * 15 * 10{,}600 * 43.2 = 357178$ **lbf**

$F_T = 195000 + 88200 + 292500 - 357178 - \boldsymbol{0}$

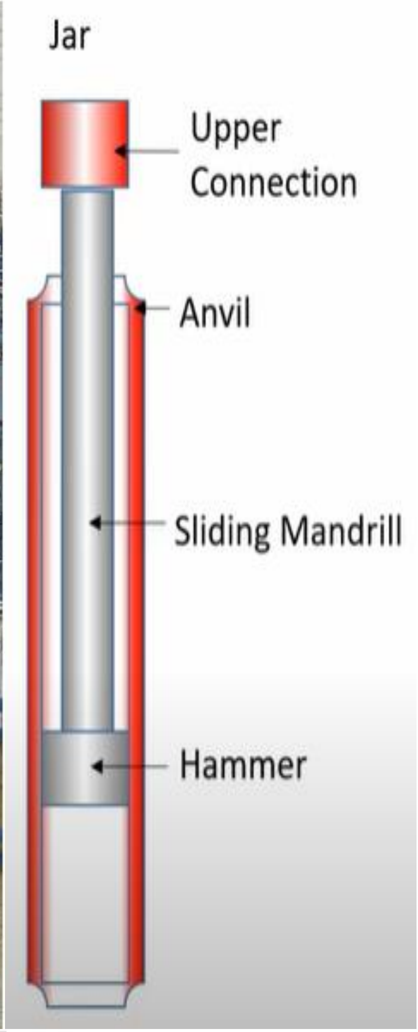
$\boldsymbol{F_T = 218522}$ **lbf (Hook Load, Tension force)**



Axial tensions as a function of depth

Jars

- Jar provides a method for dynamically transferring strain energy (axial shock) from the drill string above the Jar to the stuck point below the Jar.
- A jar contains a hammer (مطرقة) and anvil (سندان) to deliver an impact (like a slide hammer), and a trigger mechanism. Under the influence of an applied load (drill string tension or drill string weight), the jar trigger trips, the hammer delivers the jar's up or down free stroke and strikes the anvil. The resultant impact is several times greater than the applied load.
- There are three types of jar. Oil (Hydraulic) operated, Mechanically operated and Hydro- mechanical jars.
- All types of jars operate on the principle that energy can be build up by stretching the stucked string with the yield limits of the steel and suddenly releasing the energy through a tripping mechanism in the tool.
- The reaction is a longitudinal wave running back and forth. This, in turn, causes motion along the side of the string and the hole in which the pipe is stuck. If the forces are large enough to overcome the friction loads at the interface of the pipe and hole, the string will move.



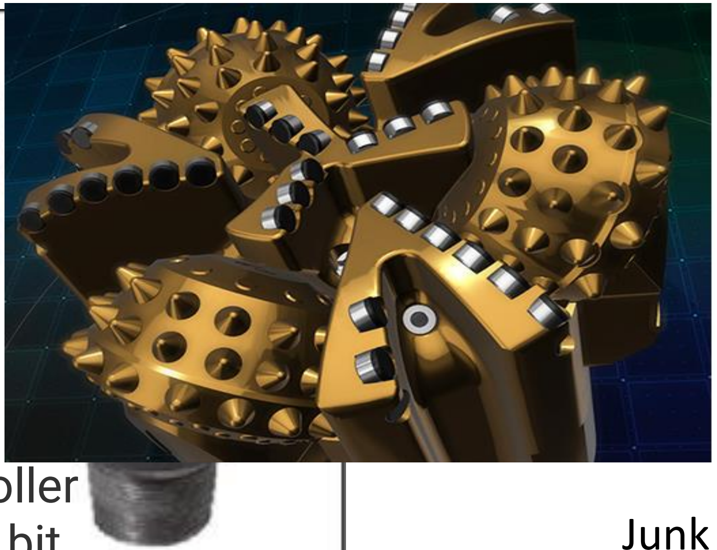
Drilling Bits

Milled-tooth

Insert-tooth

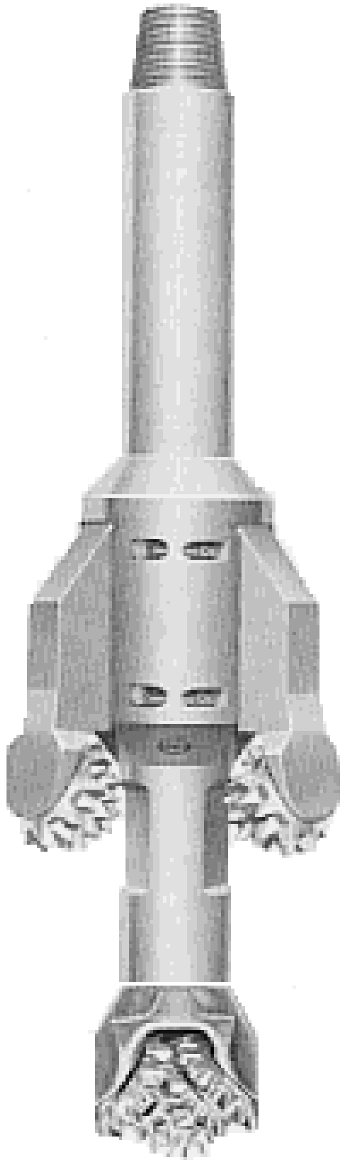
PDC

Diamond bit



PDC-roller hybrid bit

Junk Mill



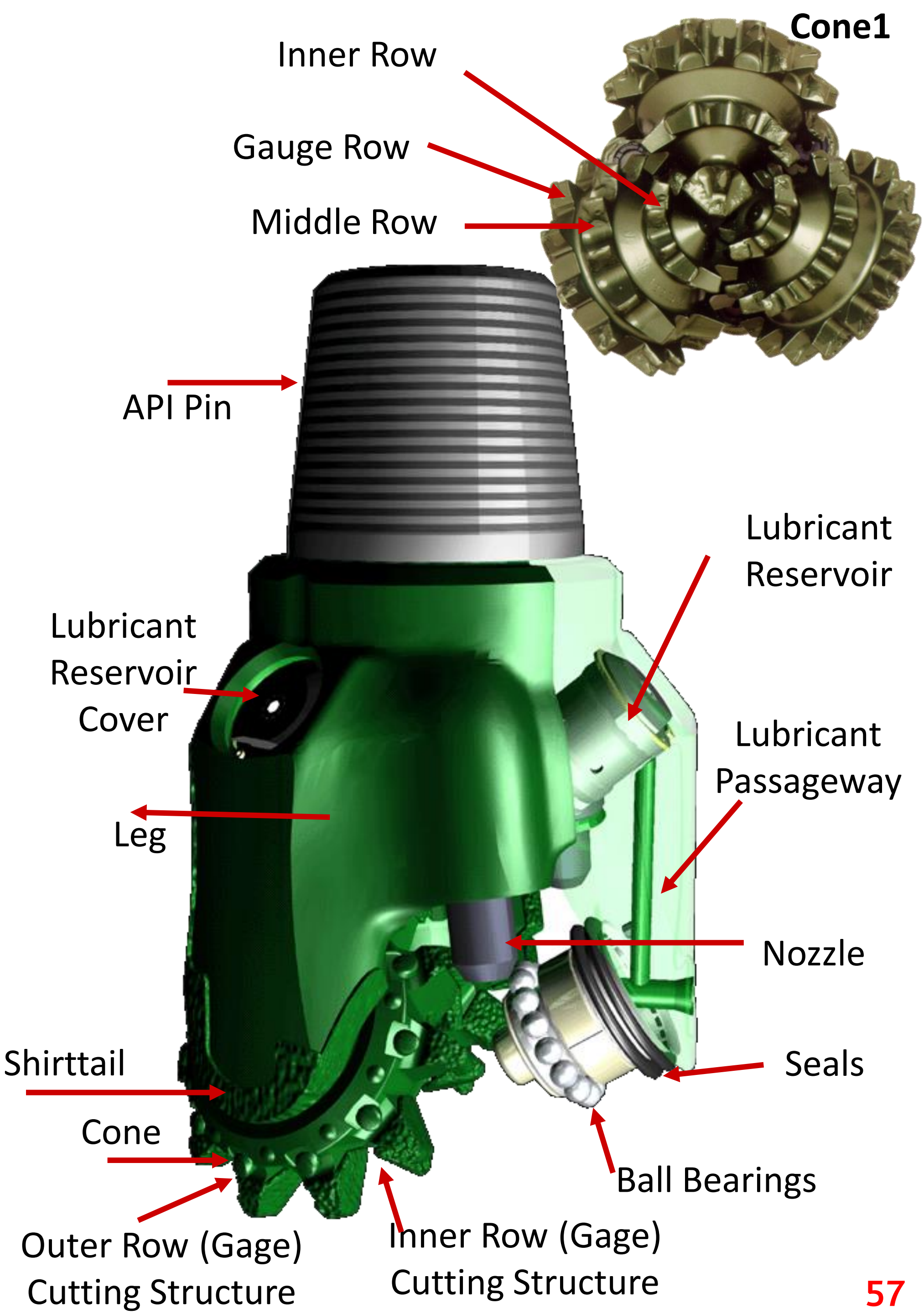
Hole Opener

Drilling Bits

- There are two main categories of drilling bits: rolling cutter or tri-cone bits (milled-tooth bits and tungsten carbide inserts bits) and fixed cutter bits (PDC and Diamond bits).
- A hole opener is utilized in 36 conductor hole drilling or pilot hole drilling which has a diameter less than required.
- Junk Mill is designed to mill fish such as packers, squeeze tools, perforating guns, drill pipe, tool joints, reamer, reamer blades and rock bits.

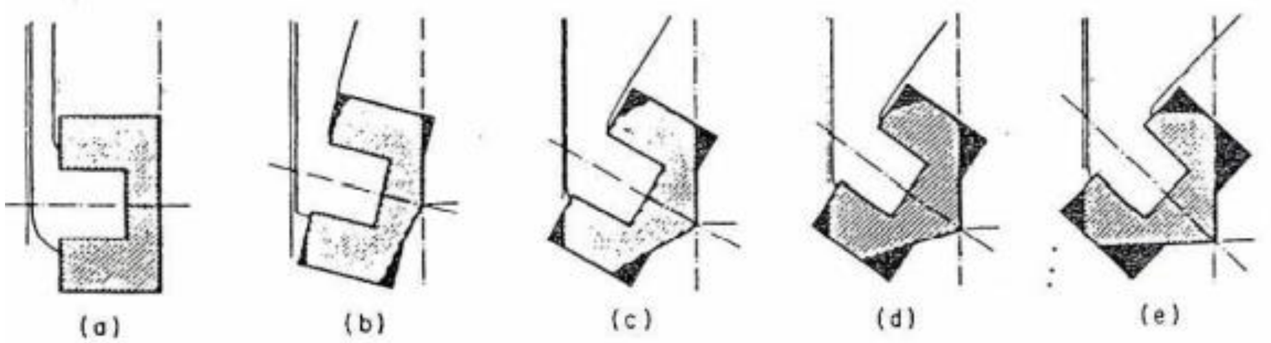
Tri-cone

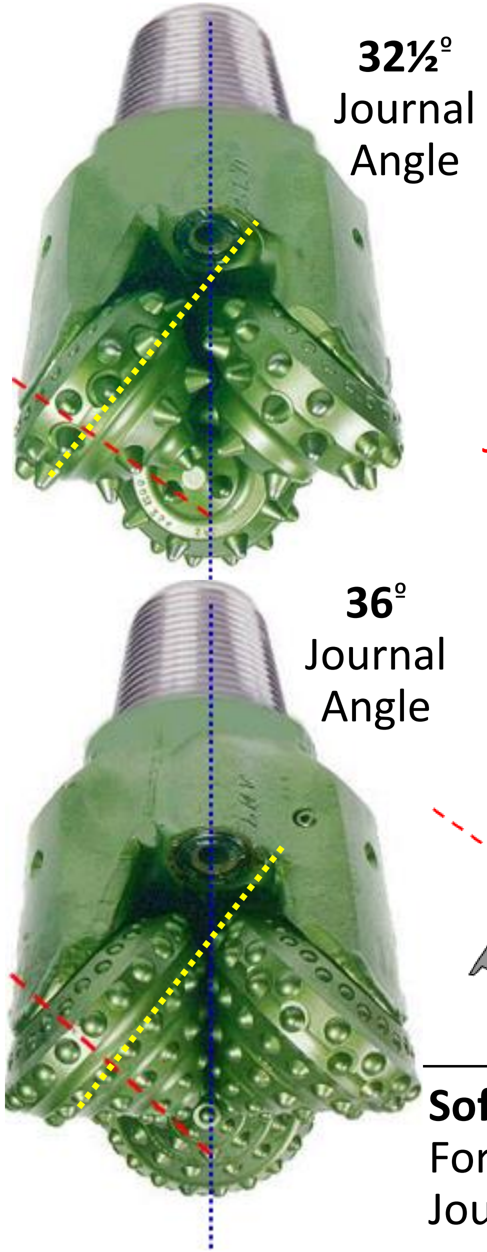
- The cutting action is provided by cones which have either steel teeth or tungsten carbide inserts.
- Rock bits are classified as milled tooth bits or insert bits depending on the cutting surface on the cones.
- The cones of the 3 cone bit are mounted on bearing pins, or arm journals, which extend from the bit body. The bearings allow each cone to turn about its own axis as the bit is rotated.
- Tri-cone bits have three cones. Each cone can be rotated individually when the drill string rotates the body of the bit.
- The cones have roller bearings fitted at the time of assembly.
- The rolling cutting bits can be used to drill any formations if the proper cutter, bearing, and nozzle are selected.
- Milled-tooth bits have steel tooth cutters, which are fabricated as parts of the bit cone. The bits cut or gouge formations out when they are being rotated.
- The design of roller cone bits can be described in terms of the four principle elements of their design: Bearing assemblies, Cones, Cutting elements, and Fluid circulation.
- Directly influence the type of Cutting Action
  1. Offset
  2. Journal Angle
  3. Cone Profile Angles
  4. Bottom Hole Profile

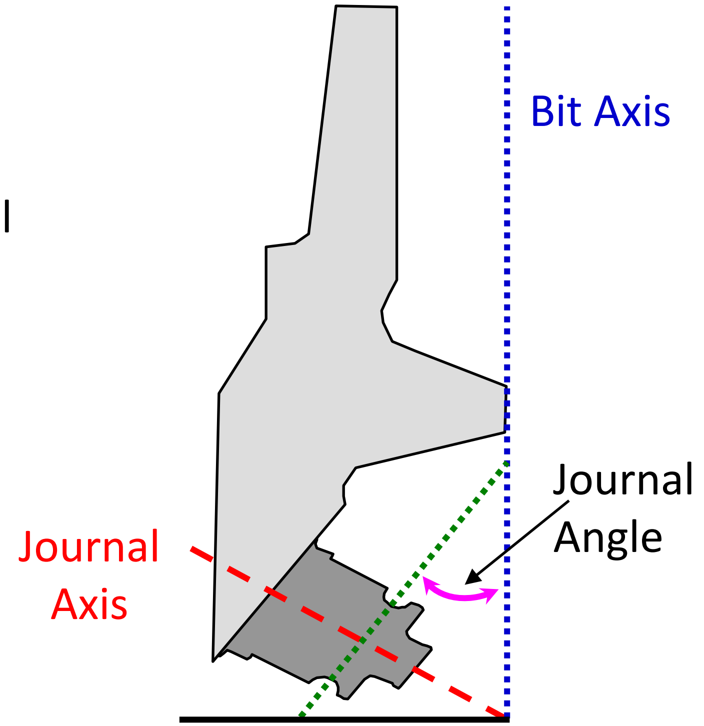


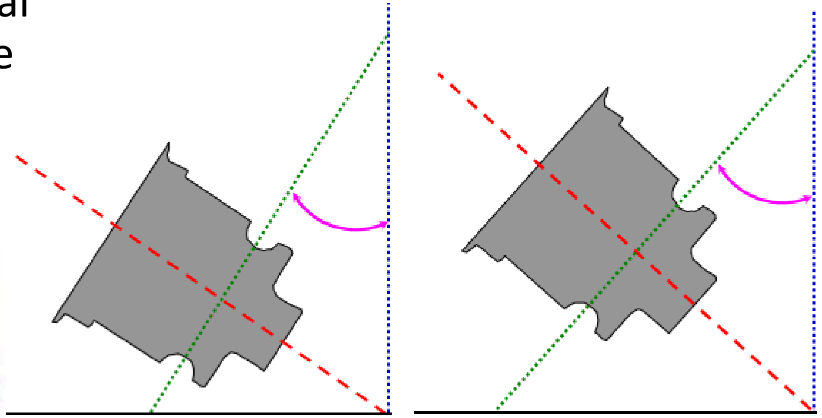
Journal Angle

- All three cones have the same shape except that the No. 1 cone has a spear point.
- Journal Angle is the angle formed by a line perpendicular to the axis (or centerline) of the journal and the axis (or centerline) of the bit.
- The journal angle is larger for hard formation bits as compared to soft formation bits.
- Increasing Journal Angle increases the cone size.







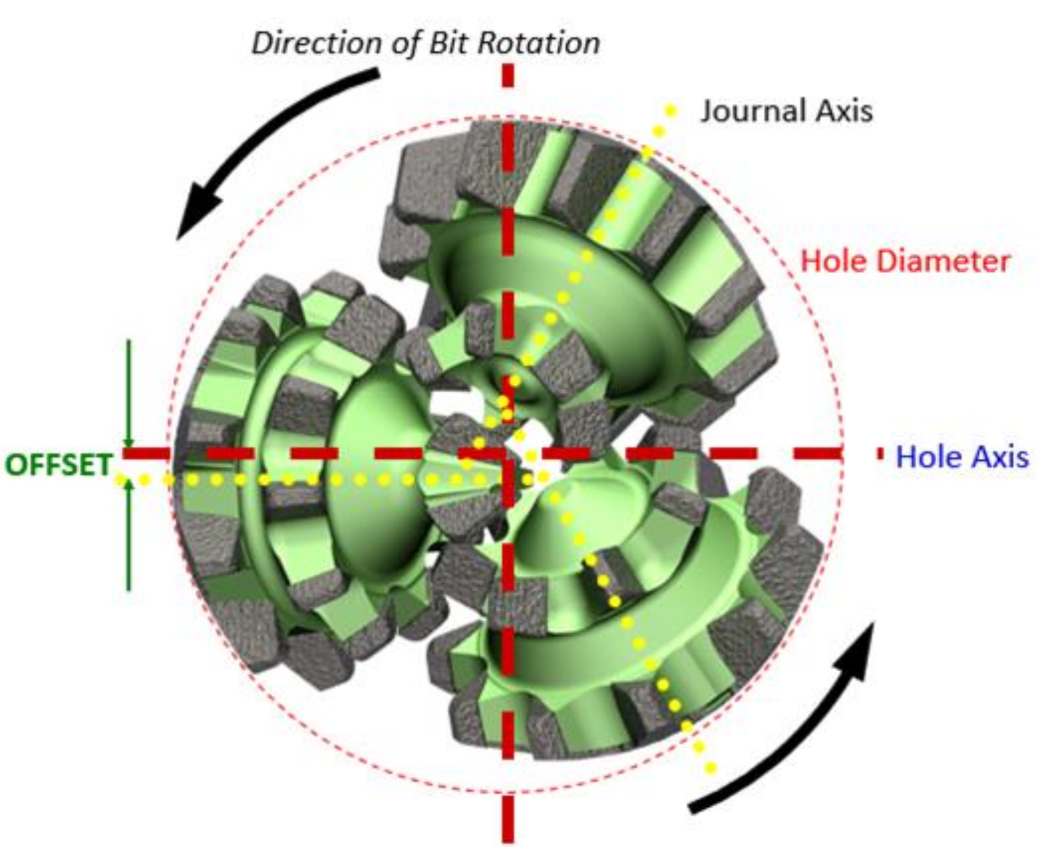


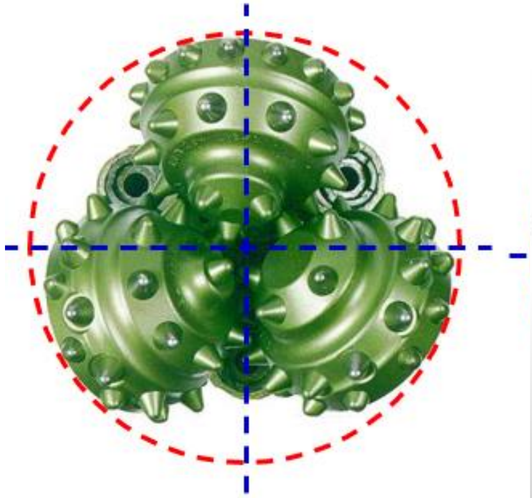
Soft to Medium Formations, **32½º** Journal Angle

Medium to **Hard** Formations, **36º** Journal Angle

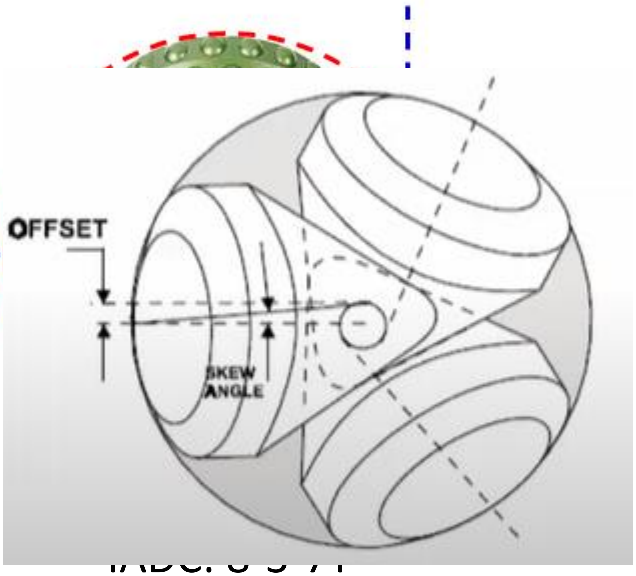
Bit Offset

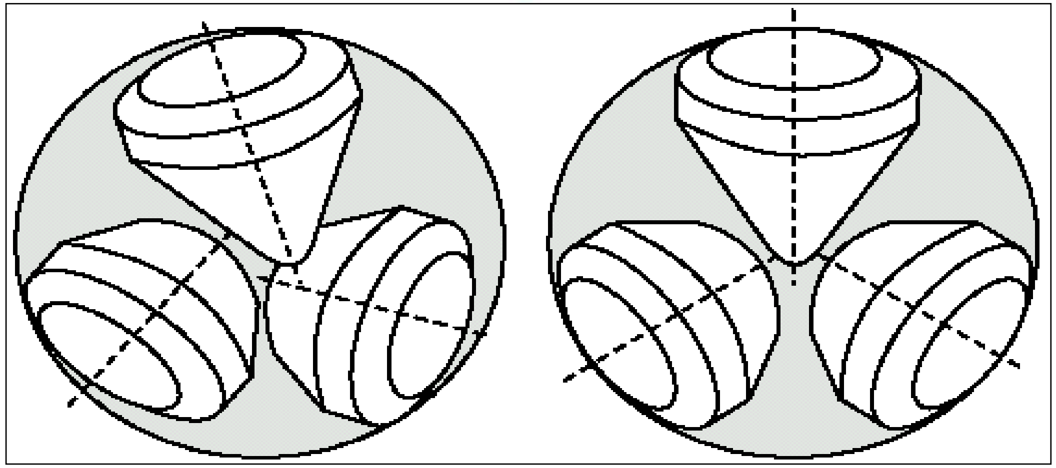
- It the horizontal distance between the axis of the bit and a vertical plane through the axis of the journal.
  – Very Soft formations (aggressive) *typically $^{3}/_{8}$”*
  – Very Hard formations (durable) *typically $^{1}/_{32}$”*





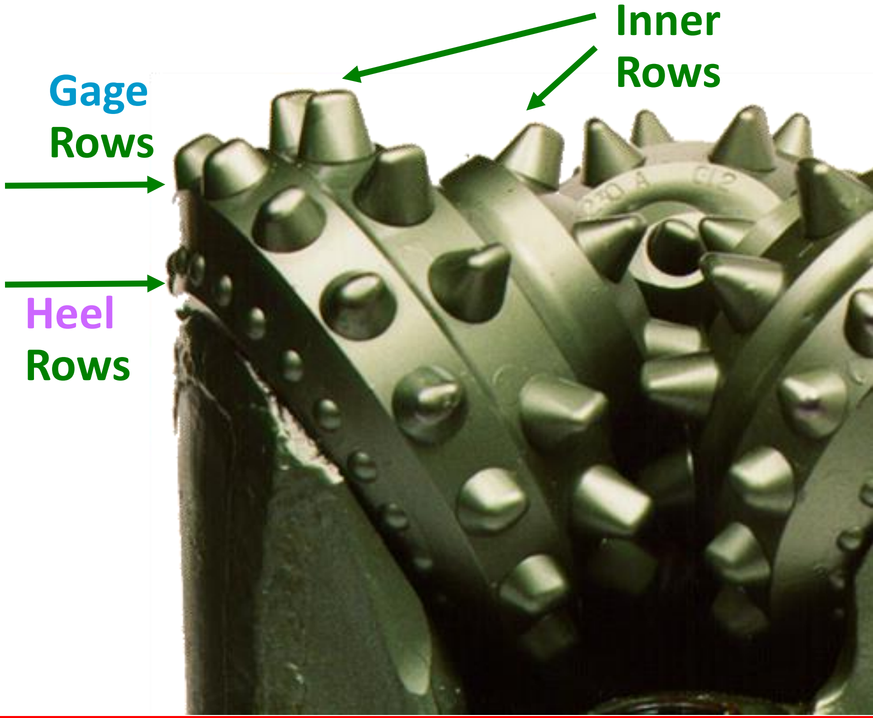
IADC: 4-2-7Y

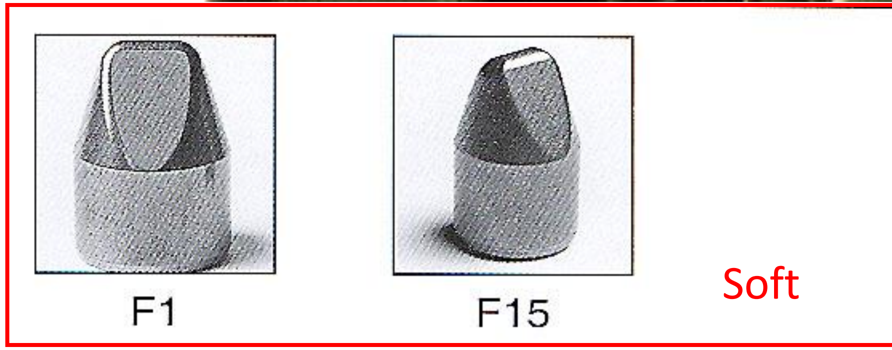


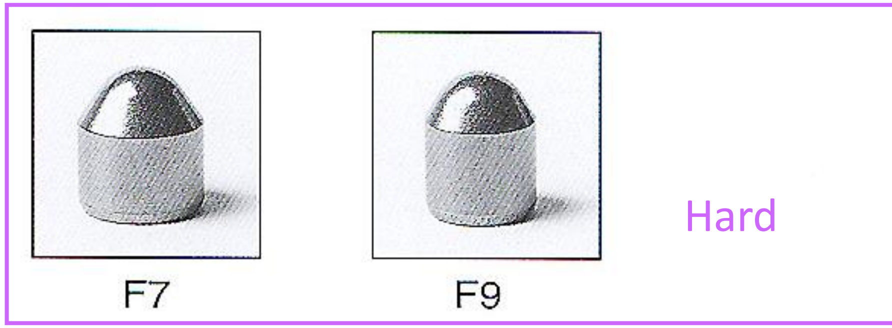


Cutting Structure

- Soft formation: The teeth should be long, slender and widely spaced. These teeth will produce freshly broken cuttings from soft formations.
- Hard formation: The teeth should be short and closely spaced. These teeth will produce smaller, more rounded, crushed, and ground cuttings from hard formations.







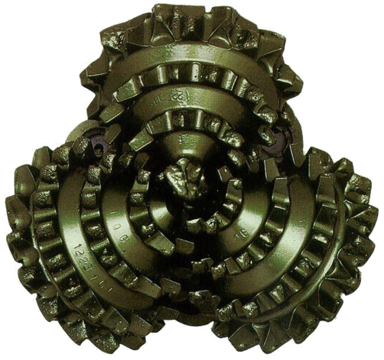
Cutting Structure

Milled Tooth Cutting Structure

Very Soft

Medium-Soft

Soft



Medium

Insert Bit Cutting Structures

Very Soft

Soft

Medium-Soft

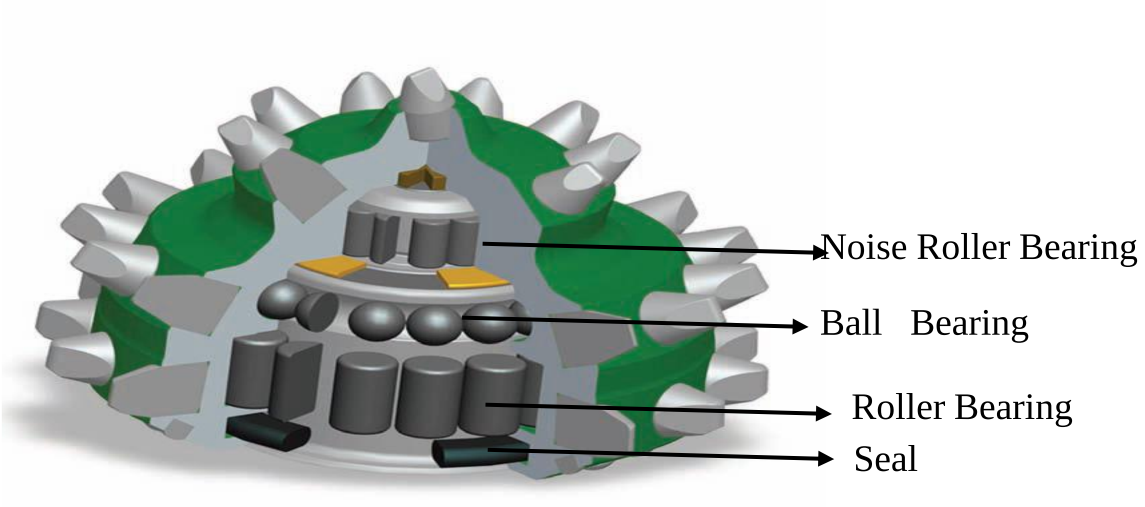
Medium-Hard

Hard

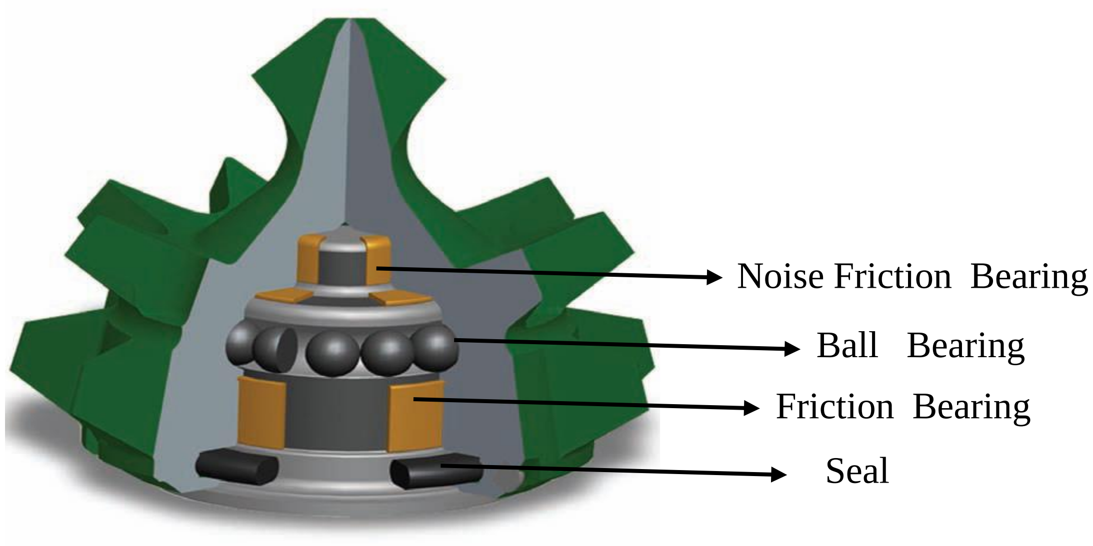
Very Hard

Bearing Assembly

- There are three types of bearings used in Roller bits: Roller (R), Ball (B) and Friction (F).
- The bearings should be large enough to support the applied loading, but this must be balanced against the strength of the journal and cone shell which will be a function of the journal diameter and cone shell thickness.
- The sealing mechanism prevents abrasive solids in the mud from entering and causing excess frictional resistance in the bearings. The bearings are lubricated by grease which is fed in from a reservoir as required.
- Journal bearing bits do not have roller bearings. Ball bearings are still used to retain the cones on the journal. The cones are mounted directly onto the journal. This offers the advantage of a larger contact area over which the load is transmitted from the cone to the journal.

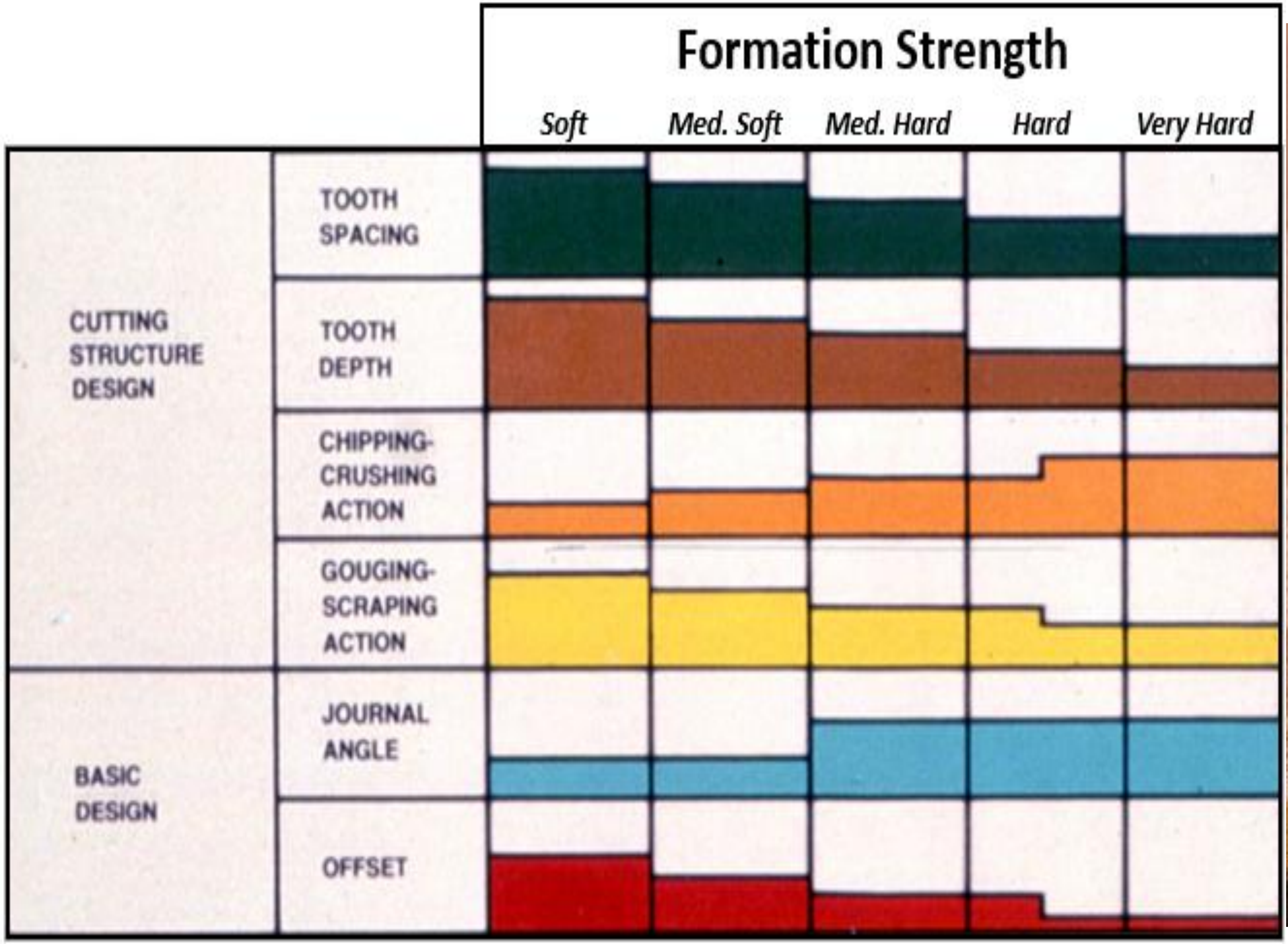


Roller Bearings



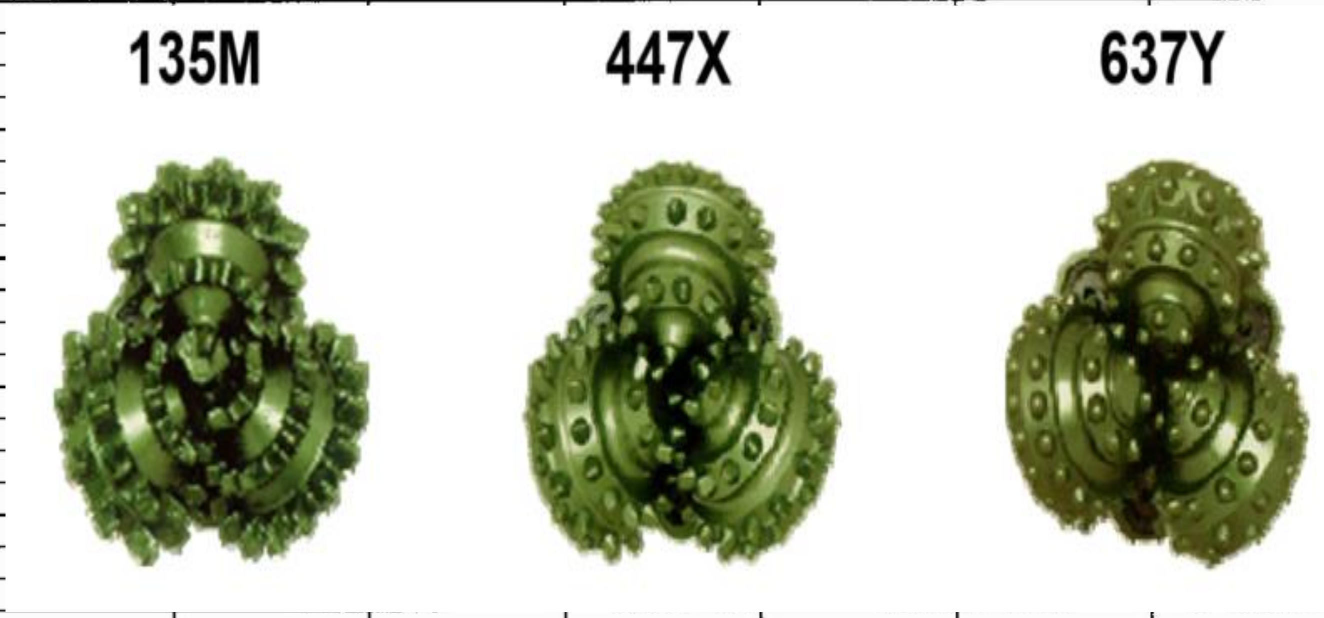
Friction Bearings

Design Factor Summary



IADC Roller Bit Classification Chart

	FORMATIONS	SERIES	TYPES	Standard Roller Bearing 1	Roller Bearing Air Cooled 2	Roller Bearing Gage Protected 3	Sealed Roller Bearing 4	Sealed Roller Brg.–Gage Protected 5	Sealed Friction Bearing 6	Sealed Friction Brg.–Gage Protected 7
				BEARING/GAGE						
Steel Tooth Bits	Soft formations with low compressive strength and high drillability	1	1							
			2							
			3							
			4							
	Medium to medium hard formations with high compressive strengths	2	1							
			2							
			3							
			4							
	Hard semi-abrasive and abrasive formations	3	1							
			2							
			3							
			4							
Insert Bits	Soft formations with low compressive strength and high drillability	4	1							
			2							
			3							
			4							
	Soft to medium formations with low compressive strength	5	1							
			2							
			3							
			4							
	Medium hard formations with high compressive strength	6	1							
			2							
			3							
			4							
	Hard semi-abrasive and abrasive formations	7	1							
			2							
			3							
			4							
	Extremely hard and abrasive formations	8	1							
			2							
			3							
			4							



FEATURES AVAILABLE

A – Air application
B – Special bearing seal
C – Center jet
D – Deviation control
E – Extended jets (full length)
G – Gage/body protection (additional)
H – Horizontal/steering application
J – Jet deflection
L – Lug pads
M – Motor application
S – Standard steel tooth model
T – Two cone bit
W – Enhanced cutting structure
X – Predominantly chisel tooth inserts
Y – Conical tooth insert
Z – Other shape insert

Diamond Bits

- Industrial diamonds have been used for many years in drill bits and in core heads.
- Despite its high wear resistance diamond, it is sensitive to shock and vibration and therefore great care must be taken when running a diamond bit.
- Effective fluid circulation across the face of the bit is also very important to prevent overheating of the diamonds and matrix material and to prevent the face of the bit becoming smeared with the rock cuttings (bit balling).
- The major disadvantage of diamond bits is their cost (sometimes 10 times more expensive than a similar sized rock bit).
- There is also no guarantee that these bits will achieve a higher ROP than a correctly selected roller cone bit in the same formation.
- They are however cost effective when drilling formations where long rotating hours (200-300 hours per bit) are required.

Diamond Bits

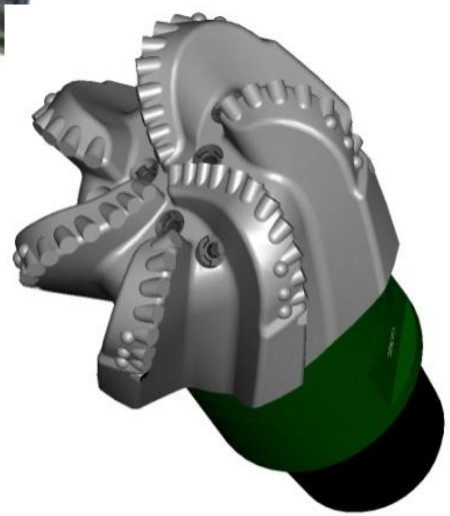
- Since diamond bits have no moving parts they tend to last longer than roller cone bits and can be used for extremely long bit runs. This results in a reduction in the number of round trips and offsets the capital cost of the bit.
- This is especially important in areas where operating costs are high (e.g. offshore drilling). In addition, the diamonds of a diamond bit can be extracted, so that a used bit does have some salvage value.
- A new generation of diamond bits known as polycrystalline diamond compact (PDC) bits were introduced in the 1980’s. These bits have the same advantages and disadvantages as natural diamond bits but use small discs of synthetic diamond to provide the scraping cutting surface.
- PDC bits have been particularly successful (long bit runs and high ROP).
- TSP Bits A further development of the PDC bit concept was the introduction in the later 1980’s of **Thermally Stable Polycrystalline** (TSP) diamond bits. These bits are manufactured in a similar fashion to PDC bits but are tolerant of much higher temperatures than PDC bits.

Polycrystalline Diamond Compact PDC

- More blades allow more cutters to be mounted, but reduce the area for the mud to flow and remove cuttings. Where drilling is expected to be fast, a lower number of blades is likely to be selected.

- As with roller cone bits, fewer and larger cutters are used for softer formations. These bits generate large size cuttings and drill very fast in the right application.

- With straight blades, the cutter radial forces are summed up as whole on the gauge. With spiral blades, only a component of each radial force is used and the net effect on gauge is less than that of straight blades.



Bit Selection

- Using IADC bit classification charts.
- 3-rolling-cone cutter bits - most versatile
  — Longest tooth size, more WOB.
  — Shortest tooth size, less WOB.
- Diamond drag bit in non-brittle formation
- Polycrystalline diamond compact (PDC) drag bits
  — Use in uniform sections of carbonates or evaporates
  — Do not use in gummy shale formations, which have the tendency to stick to the bit cutters.
- Threshold bit weight: must exceed the rock compressive strength, (*UCS or UCS = Uniaxial Unconfined Compressive Strength*).

Hardness	UCS (psi)	Examples
Ultra Soft	< 1,000	gumbo, clay
Very Soft	1,000 - 4,000	unconsolidated sands, chalk, salt, claystone
Soft	4,000 - 8,000	coal, siltstone, schist, sands
Medium	8,000 - 17,000	sandstone, slate, shale, limestone, dolomite
Hard	17,000 - 27,000	quartzite, basalt, gabbro, limestone, dolomite
Very Hard	> 27,000	marble, granite, gneiss

Formation	Hardness	Formation	Hardness
Dibdiba	soft	Saadi	Medium
Lower Faris	Soft to medium	Tanuma	Soft to medium
Ghar	soft	Khasieb	Medium
Dammam	Soft to medium	Mishrif	Medium to hard
Rus	Medium to hard	Rumaila	Medium to hard
Um-al rudoma	Medium	**Ahmadi**	**Medium to hard**
Tayarat	Soft to medium	**Mawdod**	**Medium to hard**
Sharanish	soft	**Nahr- Umr**	**Medium**
Hartha	Medium to hard	**Shuaiba**	**Medium to hard**
		Zubair	**Medium**

Drilling Cost Equation

- **Drilling** cost **per** foot is the total drilling cost per footage drilled. This value is used for evaluating drilling projects, bit performance, drilling performance, etc.

$$C_f = \frac{C_b + C_r(t_b + t_c + t_t)}{\Delta D} \qquad \frac{\$}{ft}$$

C_f = drilling cost, \$/ft

C_b = cost of bit, \$/bit

C_r = fixed operating cost of rig, \$/hr

t_b = total rotating time, hrs

t_c = total non-rotating time, hrs

t_t = total trip time (round trip), hrs

ΔD = meters drilled by the bit

Example: Determine the drilling cost per foot (CT) using the following data: Bit cost (C_b) = 27,000 \$, Drilling time (t_b) = 50 hours, Rig cost (C_r) = \$3500/hour, Round trip time (t_t) = 12 hours, Footage per bit (ΔD) = 5000 ft?

CT = (27,000 + 3,500 (50 + 12)) ÷ 5000

CT = 48.8\$ per foot

Drilling Fluid

- A drilling fluid is any fluid which is circulated through a well in order to remove cuttings from a wellbore.
- The fluids include water or oil as well as Air fluids.
- A drilling fluid must fulfill many functions in order for a well to be drilled successfully, safely, and economically.
- The main functions of drilling fluid and the properties which are associated with fulfilling these functions are summarized in Table 1.

Function	Physical/Chemical Property
Transport cuttings from the Wellbore	Yield Point, Apparent Viscosity, Velocity, Gel Strength
Prevent Formation Fluids Flowing into the Wellbore	Density
Maintain Wellbore Stability	Density, Reactivity with Clay
Cool and Lubricate the Bit	Density, velocity,
Transmit Hydraulic Horsepower to Bit	Velocity, Density, Viscosity

Specifications (Criteria) of Drilling Fluid:

- Mechanical and chemical stability.
- Minimize Formation Damage.
- Minimize Environmental Impact
- Limit Corrosion of Drillstring and Casing
- Provide Medium for Wireline Logging
- Minimize Lost Circulation

Principal Functions of Drilling Fluids

- Cuttings Removal and Transport: circulation of the drilling fluid causes cuttings to rise from the bottom of the hole to the surface. Efficient cuttings removal requires circulating rates that are sufficient to override the force of gravity acting upon the cuttings. Other factors affecting the cuttings removal include drilling fluid density and rheology, annular velocity, hole angle, and cuttings-slip velocity.
- Suspension of Solid Particles: when the rig's mud pumps are shut down and circulation is stopped (e.g., during connections, trips or downtime), cuttings that have not been removed from the hole must be held in suspension. Otherwise, they will fall to the bottom (or, in highly deviated wells, to the low side) of the hole. The rate of fall of a particle through a column of drilling fluid depends on the density of the particle and the fluid, the size of the particle, the viscosity of the fluid, and the thixotropic (gel-strength) properties of the fluid. The controlled gelling of the fluid prevents the solid particles from settling, or at least reduces their rate of fall. However, high gel strengths require higher pump pressure to break circulation. In some cases, it may be necessary to circulate for several hours before a trip in order to clean the hole of cuttings and to prevent fill in the bottom of the hole from occurring during a round trip.

Principal Functions of Drilling Fluids

- Sealing of permeable formation: as the drill bit penetrates a permeable formation, the liquid portion of the drilling fluid filters into the formation and the solids form a relatively impermeable "cake" on the borehole wall. The quality of this filter cake governs the rate of filtrate loss to the formation. Drilling fluid systems should be designed to deposit a thin, low permeability filter cake on the formation to limit the invasion of mud filtrate. This improves wellbore stability and prevents a number of drilling and production problems. Potential problems related to thick filter cake and excessive filtration include “tight” hole conditions, poor log quality, increased torque and drag, stuck pipe, lost circulation and formation damage. Bentonite is the best base material from which to build a tough, low-permeability filter cake. Polymers are also used for this purpose.

- Stabilizing the Wellbore: the weight of the mud must be within the necessary range to balance the mechanical forces acting on the wellbore. The other cause of borehole instability is a chemical reaction between the drilling fluid and the formations drilled. In most cases, this instability is a result of water absorption by the shale. Inhibitive fluids (calcium, sodium, potassium, and oil-base fluids) aid in preventing formation swelling, but even more important is the placement of a quality filter cake on the walls to keep fluid invasion to a minimum.

Principal Functions of Drilling Fluids

- Preventing Formation Damage: any reduction in a producing formation's natural porosity or permeability is considered to be formation damage. If a large volume of drilling-fluid filtrate invades a formation, it may damage the formation and obstruct hydrocarbon production.

- Cooling and Lubricating the Bit: friction at the bit, and between the drillstring and wellbore, generates a considerable amount of heat. The circulating drilling fluid transports the heat away from these frictional sites by absorbing it into the liquid phase of the fluid and carrying it away.

- Transmitting Hydraulic Horsepower to the Bit: during circulation, the rate of fluid flow should be regulated so that the mud pumps deliver the optimal amount of hydraulic energy to clean the hole ahead of the bit. Hydraulic energy also provides power for mud motors to rotate the bit and for Measurement While Drilling (MWD) and Logging While Drilling (LWD) tools.

Principal Functions of Drilling Fluids

- Facilitating the Collection of Formation Data: mud loggers monitor mud returns and drilled cuttings. They examine the cuttings for mineral composition and visual signs of hydrocarbons etc.. This information is recorded on a mud log that shows lithology, penetration rate, gas detection and oil-stained cuttings, plus other important geological and drilling parameters.

- Partial support of Drill String and Casing Weights: With average well depths increasing, the weight supported by the surface wellhead equipment is becoming an increasingly crucial factor in drilling. Both drill pipe and casing are buoyed by a force equal to the weight of the drilling fluid that they displace. When the drilling fluid density is increased, the total weight supported by the surface equipment is reduced considerably.

- Assistance in Cementing: during casing runs, the mud must remain fluid and minimize pressure surges so that fracture-induced lost circulation does not occur. The mud should have a thin, slick filter cake. To cement casing properly, the mud must be completely displaced by the spacers, flushes and cement. Effective mud displacement requires that the hole be near-gauge and that the mud have low viscosity and low, non-progressive gel strengths.

Drilling Fluid Properties

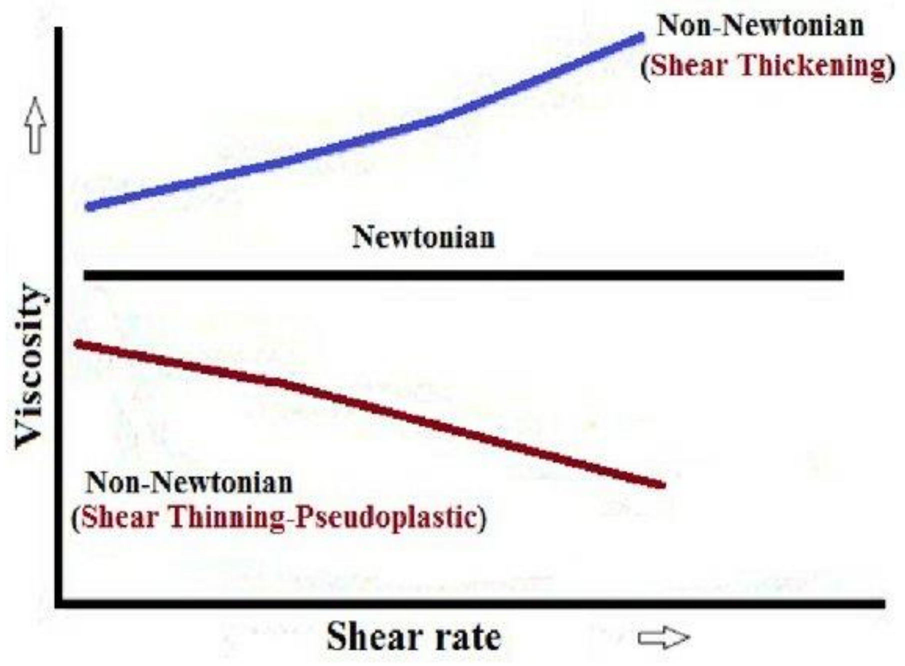
- The properties of a drilling fluid can be analyzed by its physical and chemical attributes. Each mud property contributes to the character of the fluid and must be monitored regularly. The API has presented a recommended practice for testing liquid drilling fluids. These tests help engineers to determiner whether the drilling fluids is performing its function properly.

Mud Weight or Mud Density

- Mud weight or mud density is **a weight of mud per unit volume**.
- Unit: pounds per gallon (ppg or lb/gal), or (**g/cm3**).
- **Mw** $_{ppg}$ **= 8.35 Mw** $_{gm/cm3}$
- **It controls formation pressure and it also helps wellbore stability.**
- Increasing mud density is done with additions of a weight material, e.g. Barite and decreasing mud density is done by dilution and solids control practices.
- The additional barite makes the drilling fluid quite viscous because the barite absorb water from the drilling fluid.

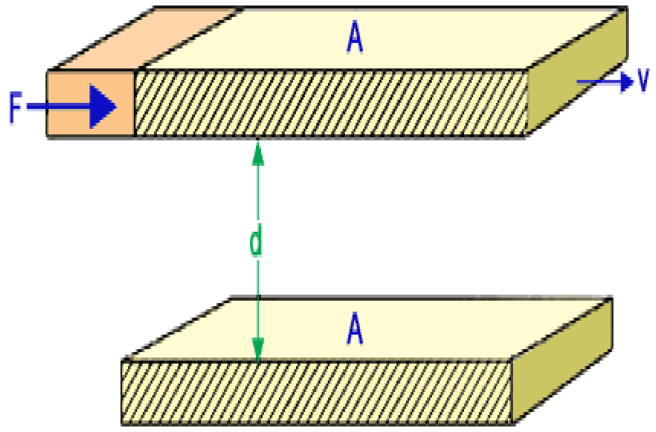
Drilling Fluid Properties - Viscosity

- Viscosity is a measure of a liquids resistance to flow. Two common methods are used on the rig to measure viscosity: Marsh funnel and Rotational viscometer.
- Non-Newtonian fluids (i.e. most drilling fluids) exhibit different viscosities at different flow rates and since the flow rate of the mud varies throughout this test it cannot provide a quantitative assessment of the rheological properties of the mud.
- Viscosity is independent of the shear rate in Newtonian fluids, while it is a function of the shear rate in non-Newtonian fluids.
- Shear rate = rate of strain or velocity gradient. It is the rate at which a fluid is sheared.
- All gases and most liquids such as water are **Newtonian** fluids. The base fluids (freshwater, seawater and diesel oil) of most drilling fluids are Newtonian. However, most of the drilling fluids are usually non-Newtonian because they are made up of a liquid and a solid. Newtonian fluids are all liquid, with no solids suspended in the liquid.



Shear Stress and Shear Rate

- The concepts of shear rate and shear stress apply to all fluid flow, and can be describe in term of two fluid layers (A and B) moving past each other when a force (F) has been applied.
- When a fluid is flowing, a force exists in the fluid that opposes the flow is known as the **shear stress**.
- It can be thought of as a frictional force that arises when one layer of fluid slides by another.
- Since it is easier for shear to occur between layers of fluid than between the outer most layer of fluid and the wall of a pipe, the fluid in contact with the wall does not flow.
- The rate at which one layer is moving past the next layer is the **shear rate**. The shear rate is therefore a velocity gradient.



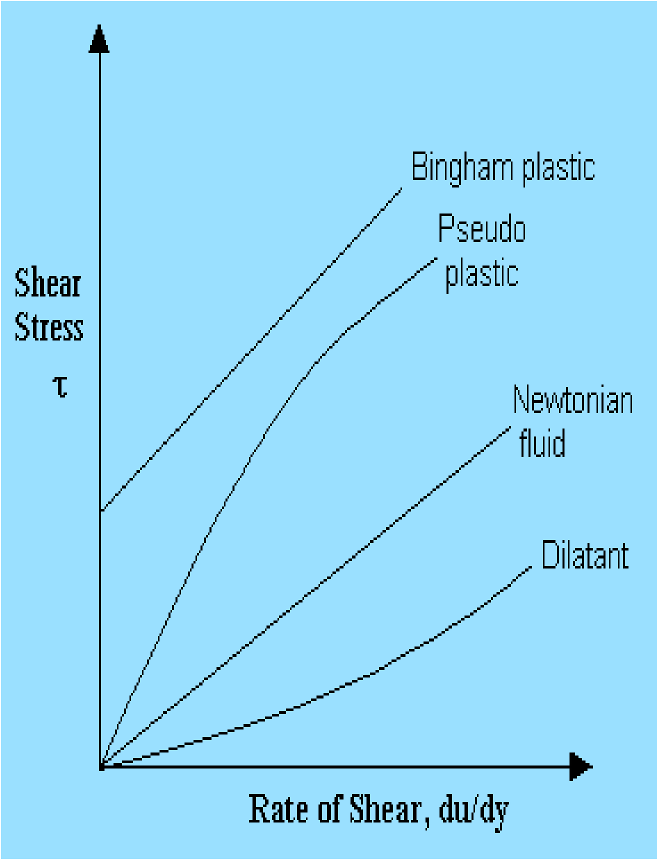
$$\gamma = \frac{v_2 - v_1}{d}$$

The formula for the shear rate is

Newtonian and Non-Newtonian Fluids

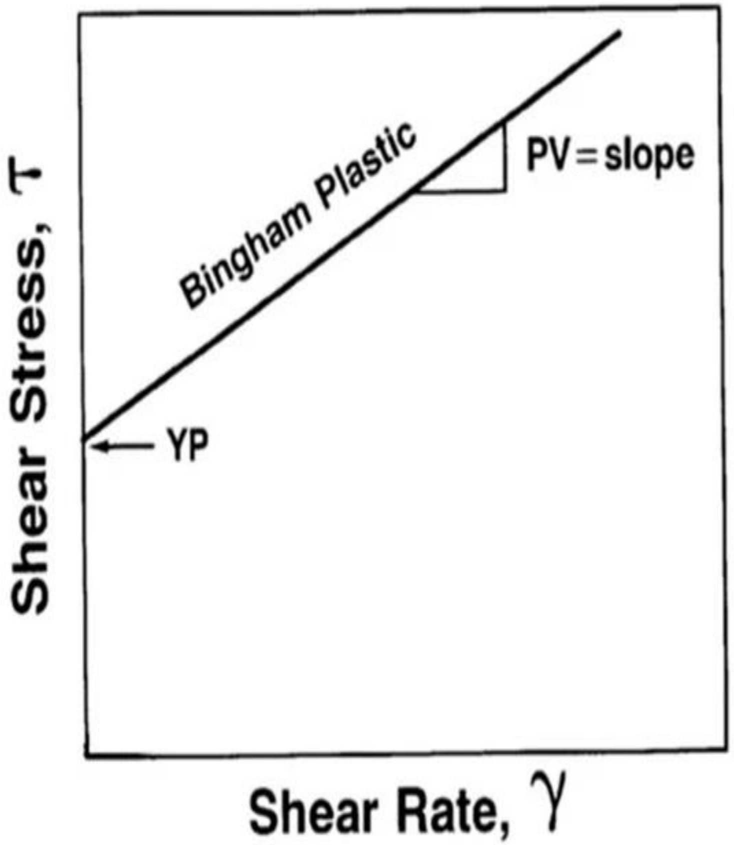
- In Newtonian fluids, the shear stress is directly proportional to the shear rate. The points lie on a straight line passing through the origin (0,0) of the graph on rectangular coordinates. The viscosity of a Newtonian fluid is the slope of this shear stress/shear rate line.
- Fluids which obey the Newton's law of viscosity are called as Newtonian fluids.

  Newton's law of viscosity is given by: (**$\tau = \mu \, dv/dy$**) where τ = shear stress, μ = viscosity of fluid, dv/dy = shear rate. Viscosity (μ), by definition, is the ratio of shear stress (τ) to shear rate (dv/dy).
- In non-Newtonian fluids, there is a non-linear relationship between shear stress and shear rate because the interaction between the solids is different at different shear rates.
- Since most drilling fluids are non-Newtonian fluids, no single rheological model can precisely describe the flow characteristics of all drilling fluids, many models have been developed to describe the flow behavior of non-Newtonian fluids as Bingham Plastic, Power Law and Modified Power Law models. The use of these models requires measurements of shear stress at two or more shear rates. From these measurements, the shear stress at any other shear rate can be calculated.



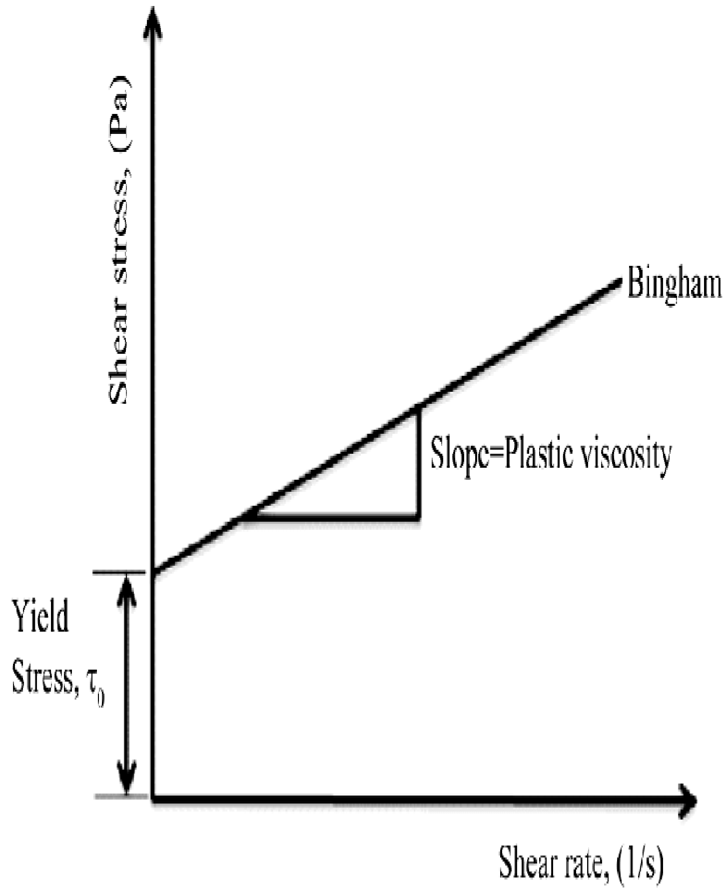
Newtonian and Non-Newtonian Fluids

- Rheological properties (Apparent viscosity, plastic viscosity, yield point, and gel strengths) of non-Newtonian drilling fluids are measured in the oil industry using the Bingham Plastic mathematical rheological model.
- In the Bingham Plastic model, it is assumed that the curve of shear stress vs. the shear rate is a straight line, which should not cross the origin (i.e., the curve intercept point with the shear stress, which is called the yield point, should be more than zero).
- The yield stress (stress required to initiate flow) of a Newtonian fluid will always be zero.
- When the shear rate is doubled, the shear stress is also doubled. When the circulation rate for this fluid is doubled, the pressure required to pump the fluid will be squared (e.g. 2 times the circulation rate requires 4 times the pressure).



Plastic Viscosity and Yield Point

- Plastic Viscosity shows the mechanical forces of the solids in the mud and therefore the PV value should be kept as low as possible.
- It's rising indicates the inefficiency of the solids control equipment.
- According to the Bingham plastic model, the PV is the slope of shear stress and shear rate.
- PV is measured by taking the difference between the reading taken at the two highest speeds of 600 rpm and 300 rpm (PV = θ_{600} - θ_{300}).
- Yield Point is the resistance to initial flow, or the stress required starting fluid movement.
- The Bingham plastic fluid plots as a straight line on a shear-rate (x-axis) versus shear stress (y-axis) plot, in which YP is the zero-shear-rate intercept (PV is the slope of the line).
- YP is calculated from 300-rpm and 600-rpm viscometer dial readings by subtracting PV from the 300-rpm dial reading and it is reported as lbf/100 ft2 (YP = θ_{300} - PV).
- YP is used to evaluate the ability of mud to lift cuttings out of the annulus. A higher YP implies that drilling fluid has ability to carry cuttings better than a fluid of similar density but lower YP.

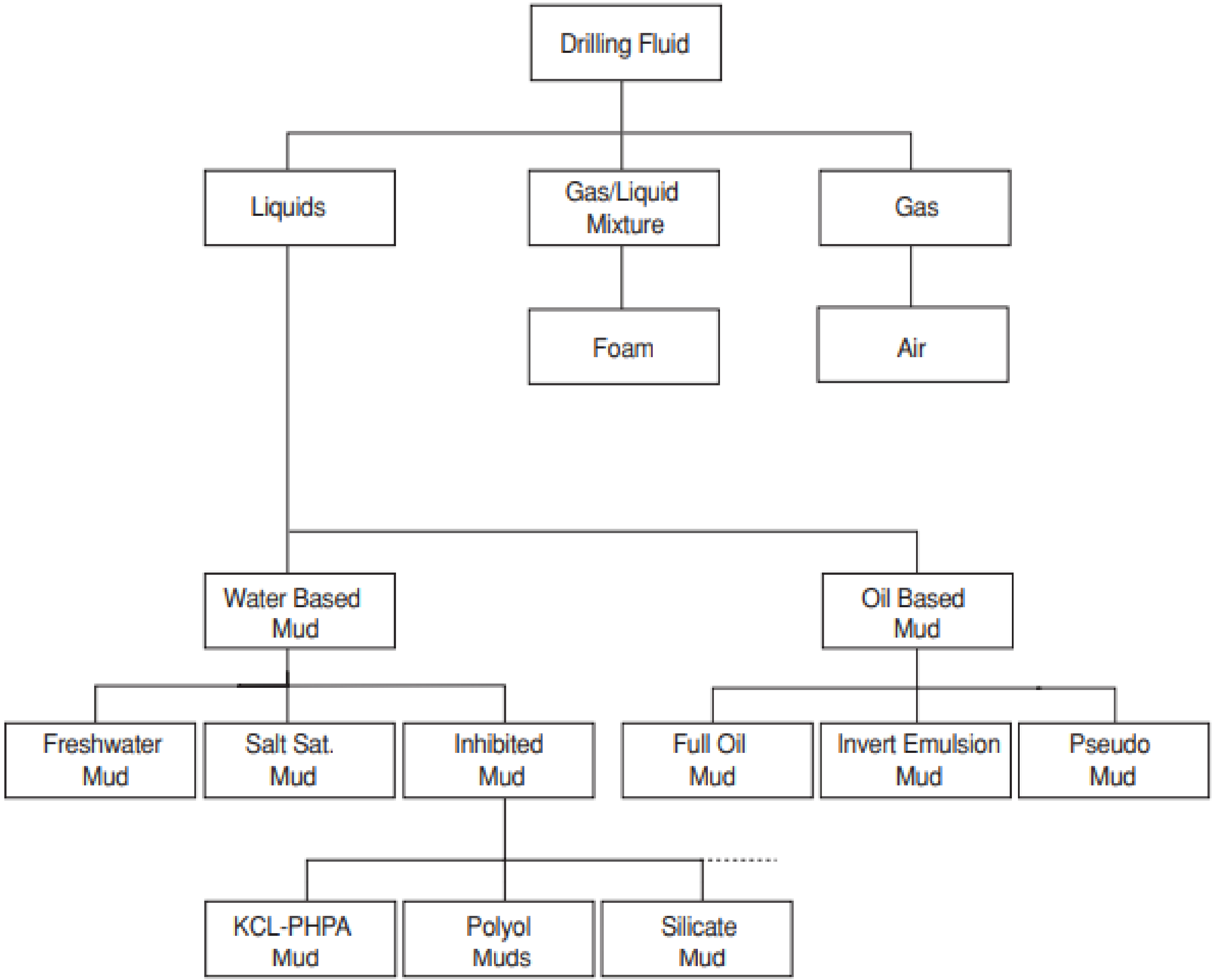


Gel Strengths

- The gel strength quantifies the thixotropic behavior of a fluid, i.e. the ability to have strength when static, in order to suspend cuttings, and flow when put under enough force.
- The gel strength of the mud will provide an indication of the pressure required to initiate flow after the mud has been static for some time.
- The gel strength of the mud also provides an indication of the suspension properties of the mud and hence its ability to suspend cuttings when the mud is stationary.
- Unit: Same as Yield Point
- There are two readings for gel strengths, 10 second and 10 minute with the speed set at 3 rpm.
- The fluid must have remained static prior to each test, and the highest peak reading will be reported.

Types of Drilling Fluid

- The two most common types of drilling fluid used are water based mud (most used muds world-wide) and oil based mud.
- Water-based muds (WBM) are those drilling fluids in which the continuous phase of the system is water (salt water or fresh water) and Oil- based muds (OBM) are those in which the continuous phase is oil.
- Fresh water is used as the base for most of these muds, but in offshore drilling operations salt water is more readily available.



Water-Based Muds

- A water-based mud is composed of a three-phase system: water, active solids, and inert solids.
- Some solids (clays) react with the water and chemicals in the mud and are called active solids (hydrophilic). The activity of these solids must be controlled in order to allow the mud to function properly.
- The solids which do not react within the mud are called inactive or inert solids (hydrophobic) (e.g. Barite). The other inactive solids are generated by the drilling process.
- Water based muds are relatively inexpensive because of the ready supply of the fluid from which they are made - water.
- The main disadvantage of using water based muds is that the water in these muds causes instability in shales. Shale is composed primarily of clays and instability is largely caused by hydration of the clays by mud containing water.
- To limit (or inhibit) interaction between WBMs and water-sensitive formations, a WBM was presented that combines potassium chloride (KCL) with a polymer called partially-hydrolyzed polyacrylamide, KCl- PHPA mud. PHPA helps stabilize shale by coating it with a protective layer of polymer.

Oil-Based Muds

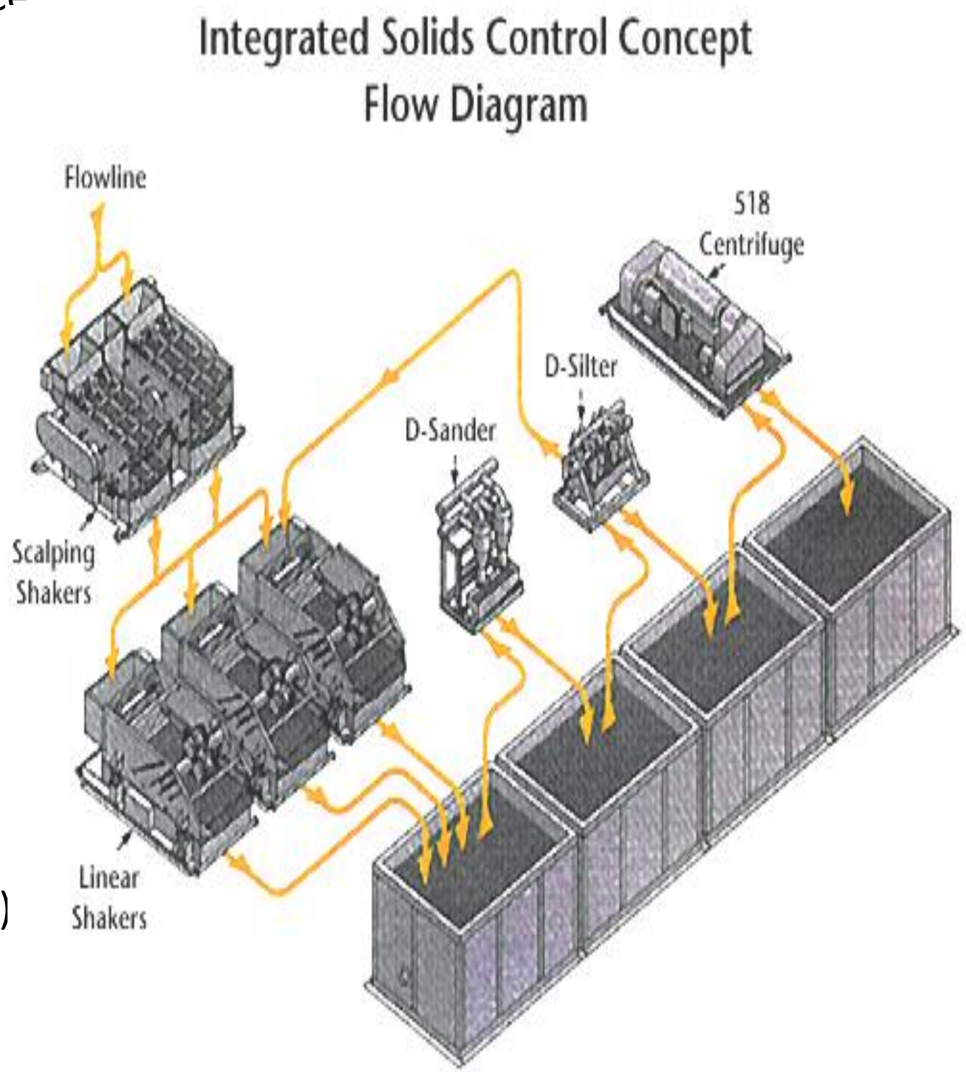
- In the 1970s, the industry turned increasingly towards oil-based mud, OBM as a means of controlling reactive shales. Oil-based muds are similar in composition to water-based except that the continuous phase is oil.
- When the continuous phase of a drilling fluid is oil, it is classified as an oil based mud. When water is added as the discontinuous phase then it is called an invert emulsion.
- The most common type of oil-based muds are Invert Oil Emulsion Muds (IOEM). In Invert Oil Emulsion Muds (IOEM), water may make up a large percentage of the volume (between 5% and 50%), but oil is still the continuous phase (the water is dispersed throughout the system as droplets).
- These fluids are particularly useful in shales and other water sensitive formations, as clays do not hydrate or swell in oil. OBM's do not contain free water that can react with the clays in the shale. Generally the higher Oil/Water Ratio (OWR) is used for drilling troublesome formations.

Oil-Based Muds

- They are also useful in high angle/horizontal wells because of lubricating properties and low friction values between the steel and formation which result in reduced torque and drag. Corrosion of pipe is controlled since oil is the external phase.
- OBM also provides temperature stability, a reduced risk of differential sticking and low formation damage potential in production zones.
- OBMs are well-suited to be used over and over again. They can be stored for long periods of time since bacterial growth is suppressed.
- However, Oil muds are more expensive and require more careful handling (pollution control) than WBM's.
- Emulsifiers act at the interface between the oil and the water droplets. These levels are held in excess, to act against possible water and solid contamination.
- Wetting Agent is a high concentration emulsifier used especially in high density fluids to oil wet all the solids. If solids become water wet they will not be suspended in the fluid, and would settle out of the system.

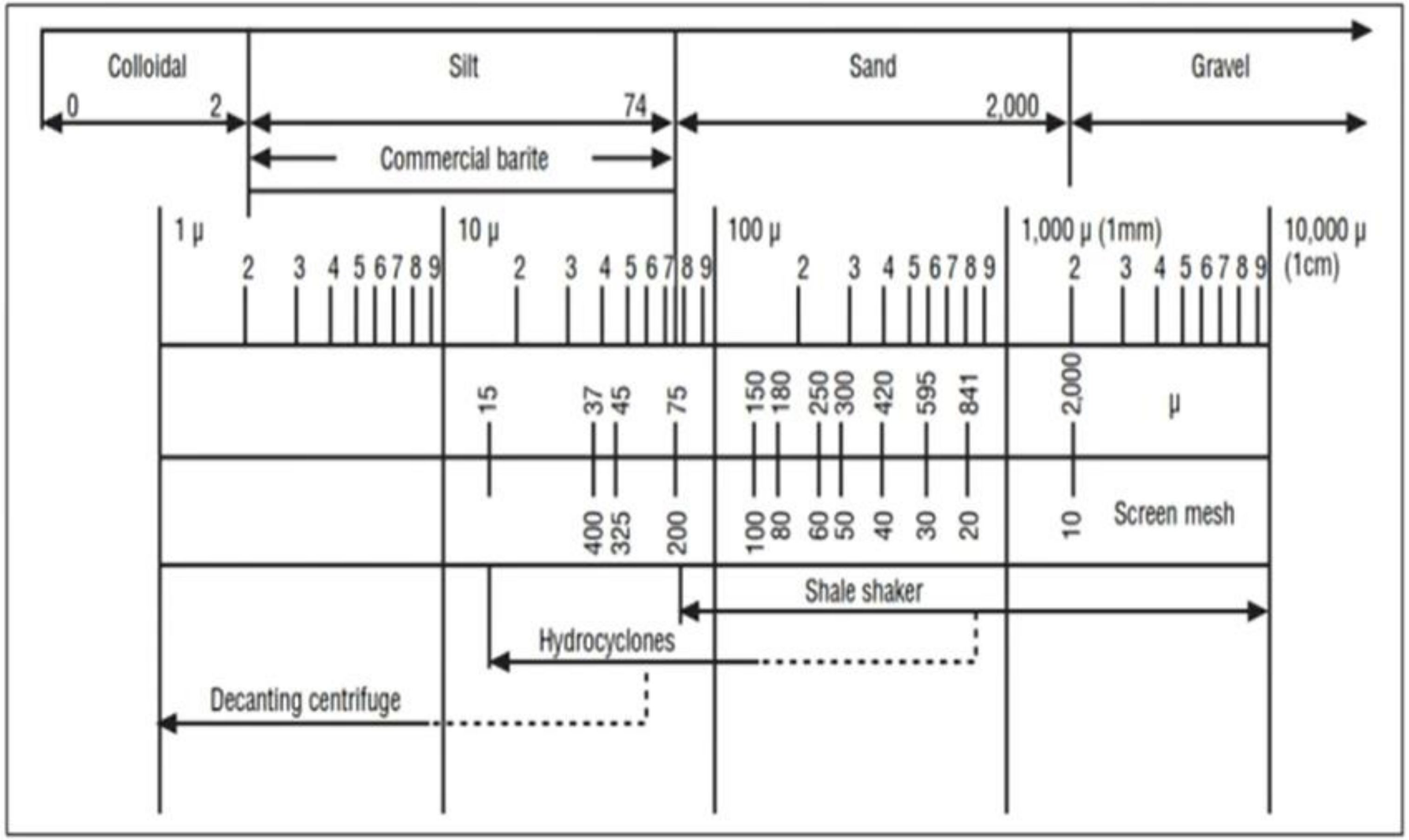
Solids control

- Most solids in drilling fluid can be removed by mechanical means at the surface. Small particles are more difficult to remove and have a greater effect on drilling-fluid properties than large particles.
- The two primary sources of solids are chemical additives and formation cuttings.
- If the cuttings are not removed, they will be ground into smaller and smaller particles that become more difficult to remove from the drilling fluid.
- PV, YP and gels are all affected by mud solids. Rheological and filtration properties can become difficult to control when the concentration of drilled solids (low-gravity solids) becomes excessive. Penetration rates and bit life decrease and hole problems increase with a high concentration of drill solids.
- Solids-control equipment is designed to control the buildup of undesirable solids in a mud system.
- Solids control is accomplished either mechanically with a screen (shale shaker) or with the application of time and gravity (settling pit and Hydrocyclone). If time is not available, then centrifugal separation devices is effective.



Particle Sizes

- Particles can be subcategorized as:-
  - ➢ (2- 44) µm are silt-sized,
  - ➢ Less than 2 µm are called colloidal. Clay particles are colloidal in size.
  - ➢ Greater than 44 µm are considered sand-sized particles (regardless of their material).
- While sand- and silt-sized particles can be physically separated in a liquid, a colloidal-sized particle cannot. It must be removed using a chemical reaction, which typically enlarges the particle and makes it susceptible to physical separation.

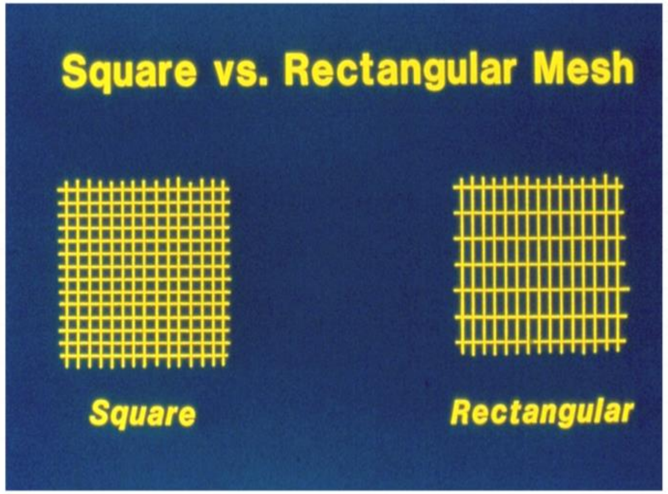


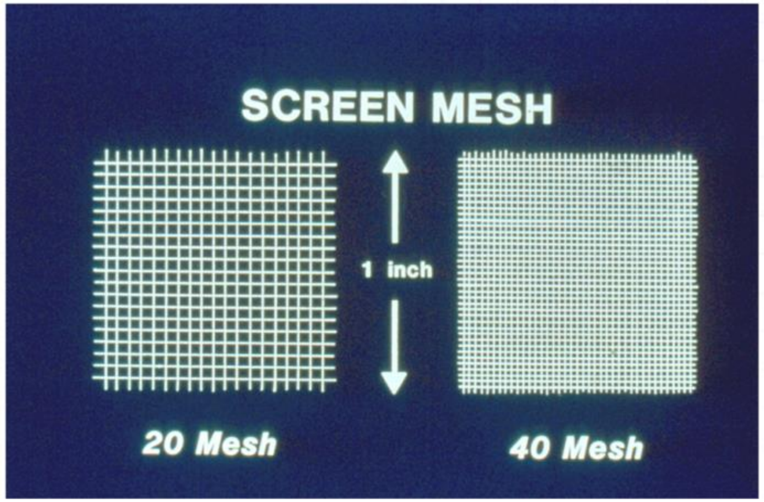
Category	Size	Example
Colloidal	2 µ or less	Bentonite, clays and ultra-fine drill solids
Silt	2 – 74 µ (< 200 mesh)	Barite, silt and fine drill solids
Sand	74 – 2,000 µ (200 – 10 mesh)	Sand and drill solids
Gravel	Larger than 2,000 µ (>10 mesh)	Drill solids, gravel and cobble

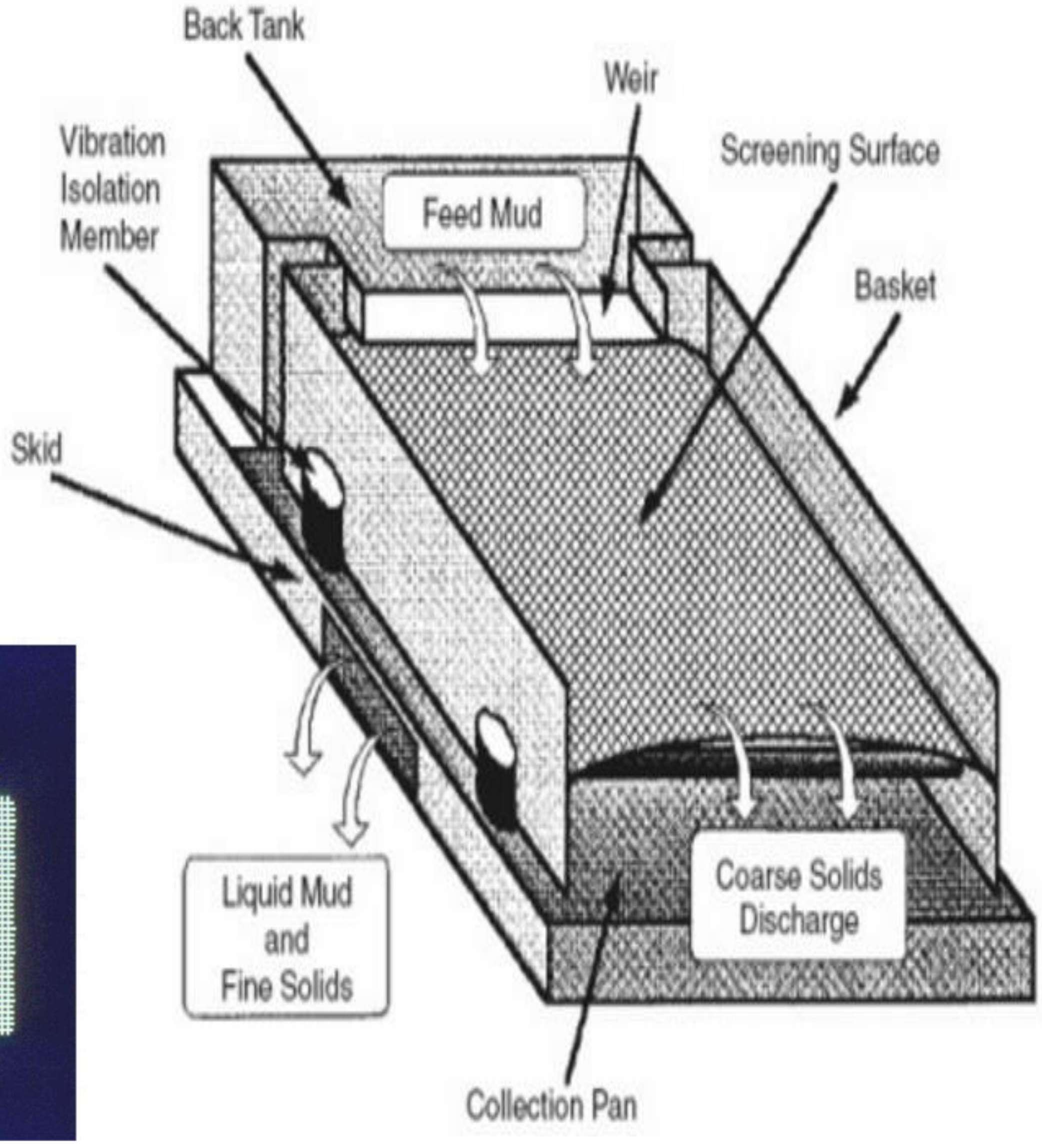
Table 1: Classification of solids by size.

Shale Shakers

- It is the First and most important piece of solids Control equipment.
- The shale shaker contains one or more vibrating screens through which mud passes as it circulates out of the hole.
- Mesh screen size is the number of openings per linear inch.







Hydrocyclones

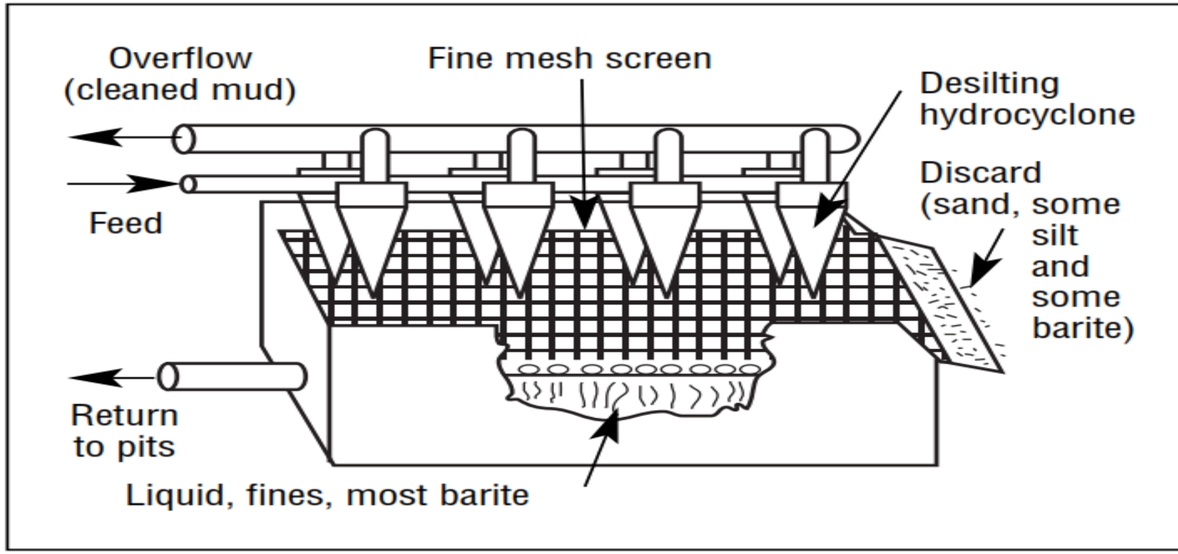
- Hydrocyclones are a means to circulate a drilling fluid around a cylinder at a high rate of speed.
- Hydrocyclones come in various sizes and shapes. They are usually specified by the size particles they are designed to remove. There are desanders, desilters, mud cleaners, and centrifuges.
- A desander typically has a few large diameter cones (greater than 6 in. diameter), whereas a desilter has a larger number of small diameter cones (less than 6 in. in diameter).
- Desanders are designed to remove sand-sized particles and desilters are designed to remove silt-sized particles.


Desanders


Desilters

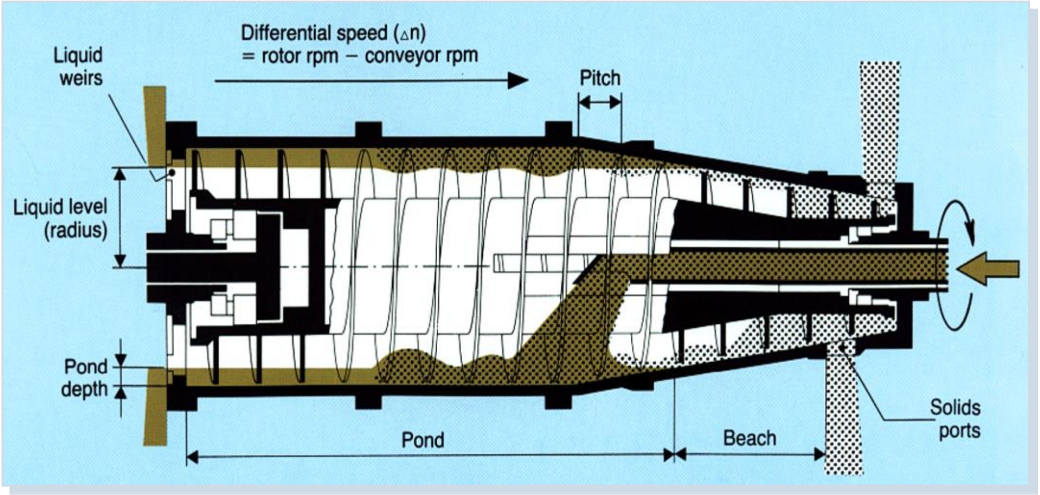
Mud Cleaners

- Mud cleaner is Desilter/desander mounted over fine mesh shale shaker.
- It is used for expensive fluid systems or weighted muds because barite tends to be removed with silt-sized particles. By using a mud cleaner, barite can be recovered and reused.
- It discards drilled solids while retaining expensive barite, chemicals and liquids in the fluid system.



Decanting Centrifuge

- High efficiency separation equipment separates by imparting high centrifugal forces in a rotating bowl.
- When installed downstream of properly configured shakers, a decanter centrifuge efficiently removes most of the fine particles that traditional solids-removal equipment cannot capture.
- A screw conveyor is fitted inside the bowl for continuous removal of separated solids.
- Typical bowl speeds are 1,800 to 4,000 rev.
- Through centrifugal force, the solids form a layer around the bowl wall. The solids, being heavier, collect at the bowl wall. From there they are continuously removed by the screw conveyor.



Mud Weight Calculating

- The main components are liquid, the clay and the barite. All the materials present in mud contribute to its density. However, the chemicals used to control viscosity and gel properties are usually present in small amount and are neglected in weighting calculations.
- Freshwater has density of about **8.33** Ib/gal, the bentonitic clay commonly added to a mud has specific gravity of about 2.5 (2.4 × 8.34 = **20** ppg), and finely ground barite has specific gravity of about 4.2 (4.2 × 8.34 = **35** ppg).
- **Material balance equation:**

$$Mass_a + Mass_{m1} = Mass_{m2}$$

$$\rho_a V_a + \rho_{m1} V_{m1} = \rho_{m2} V_{m2}$$

$$V_a = V_{m2} (\rho_{m2} - \rho_{m1})/ \rho_a - \rho_{m1})$$

$$V_a = V_{m1} (\rho_{m2} - \rho_{m1})/ (\rho_a - \rho_{m2})$$

Where:

V_a: Added material volume

V_{m1}: Primary fluid volume

V_{m2}: Final mixture volume

ρ_a: Added material density

ρ_{m1}: primary fluid density

ρ_{m2}: Final mixture density

Mud Weight Calculating

Fresh water bentonite drilling fluid with (**500** bbl) and (**9** ppg). After Barite adding, the density reached (**12** ppg). Determine the volume and weight percentages of solid material in the liquid.

$$\mathbf{V_a = V_{m2} (\rho_{m2} - \rho_{m1}) / (\rho_a - \rho_{m1})}$$

$$\mathbf{(V_a / V_{m2})^* \ 100\%}$$

$$\mathbf{= (\rho_{m2} - \rho_{m1}) / (\rho_a - \rho_{m1})}$$

$(V_{Bentonite} / V_{m2})^* \ 100\%$

$= (\rho_{m2} - \rho_{m1}) / (\rho_{Bentonite} - \rho_{m1})$

$= (9 - 8.33) / (20.8 - 8.33)$

$V_{Bentonite} / V_{m2} = 5.3\ \%$

$(V_{Barite} / V_{m2})^* \ 100\% = (\rho_{m2} - \rho_{m1}) / (\rho_{Barite} - \rho_{m1})$

$= (12 - 9) / (35.8 - 9)$

$V_{Barite} / V_{m2} = 11\ \%$

Total volume percentage of the solid = 5.3 + 11 = 16.3 %

Mud Weight Calculating

Fresh water bentonite drilling fluid with (**500** bbl) and (**9** ppg). After Barite adding, the density reached (**12** ppg). Determine the volume and weight percentages of solid material in the liquid.

Solution

$$(V_a / V_{m2})^* \, 100\% = (\rho_{m2} - \rho_{m1}) / (\rho_a - \rho_{m1})$$

Multiplying by $* \, \rho_a / \rho_{m2}$

$$(\rho_a V_a / \rho_{m2} V_{m2})^* \, 100\% = \rho_a (\rho_{m2} - \rho_{m1}) / \rho_{m2} (\rho_a - \rho_{m1})$$

$(\rho_{Bentonite} V_{Bentonite} / \rho_{m2} V_{m2})^* \, 100\% = 20.8 \, (9 - 8.33) / 9 \, (20.8 - 8.33)$

$(\rho_{Bentonite} V_{Bentonite} / \rho_{m2} V_{m2})^* \, 100\% = 12.5 \, \%$

$(\rho_{Barite} V_{Barite} / \rho_{m2} V_{m2})^* \, 100\% = 35.8 \, (12 - 9) / 12 \, (35.8 - 9)$

$(\rho_{Barite} V_{Barite} / \rho_{m2} V_{m2})^* \, 100\% = 33 \, \%$

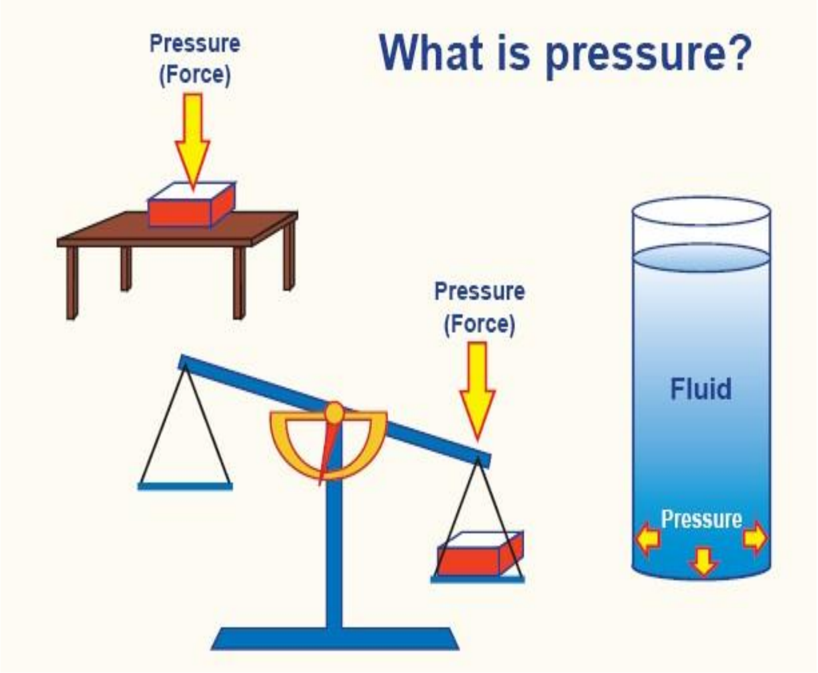
Total weight percentage of the solid = 12.5 + 33 = 45.5 %

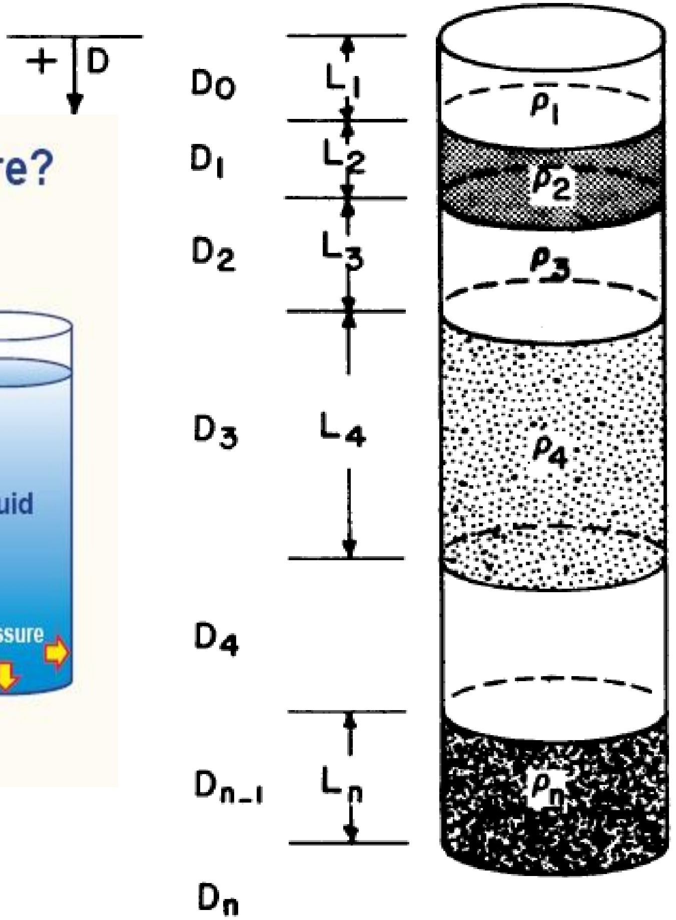
Hydrostatic pressure

- Hydrostatic pressure is the power exerted by a column of drilling fluid.

P = 0.052 x ρ x TVD

$$p = p_0 + 0.052 \sum_{i=1}^{n} \rho_i \left(D_i - D_{i-1}\right)$$

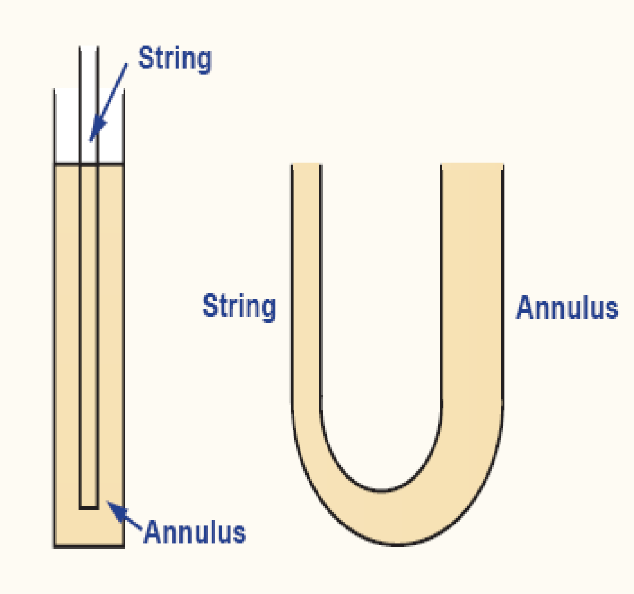


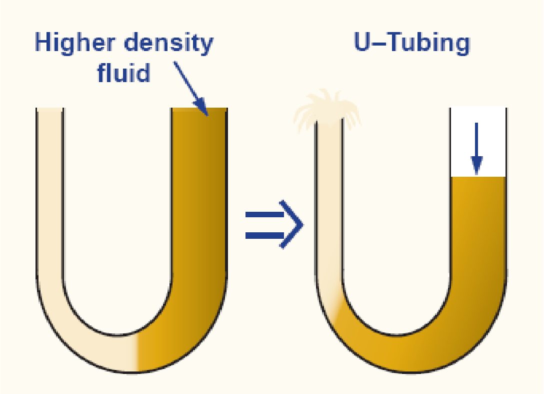


- P - hydrostatic pressure, psi.
- ρ - mud weight in pounds per gallon (ppg).
- TVD - True Vertical Depth, ft.
- D – thickness, ft

Hydrostatic pressure

It is easier to consider the wellbore as a U-tube, then hydrostatic pressure effect may be obvious.





$$p_a = p_0 + 0.052\left\{\begin{array}{l}10.5(7{,}000) + 8.5(300) + 12.7(1{,}700) \\ +16.7(1{,}000) - 9.0(10{,}000)\end{array}\right\}$$

$$p_0 = 0 \text{ psig}$$

$$p_a = 1{,}266 \text{psig}$$

Pressure gradient = nnn psi/ft