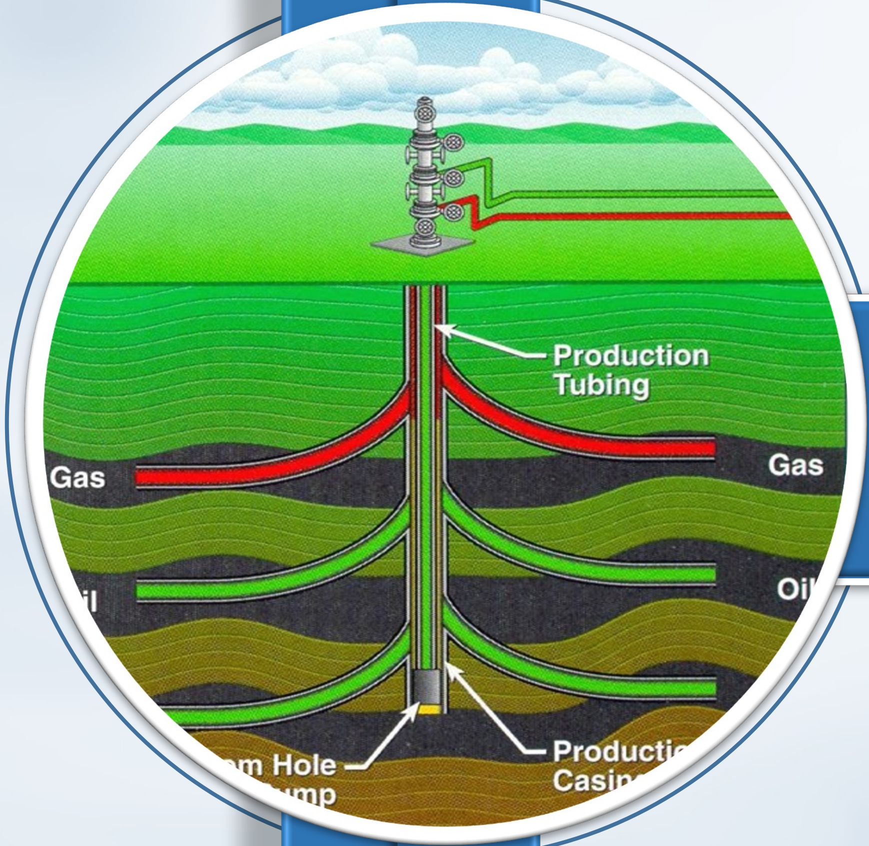


DRILLING ENGINEERING CONCEPTS

Drilling Engineering Concepts
Current Scope

A. Why Drill (not the only W ?)
B. Types of Rigs
C. Rig Systems
D. BHA
E. Casing

F. Cementing
G. Drilling Fluids
H. Basic Logging
I. Introduction to directional drilling

Drilling Rig Systems

Although drilling rigs differ greatly in outward appearance and method of deployment, all rotary rigs have the same basic drilling equipment. The main component parts of a rotary rig are:

- Power system
- Hoisting system
- Circulating system
- Rotary system
- Well control system (BOP)

The rig is basically comprised of a derrick, the drawworks with its drilling line, crown block and traveling block, and a drilling fluid circulation system including the standpipe, rotary hose, drilling fluid pits and pumps. These components work together to accomplish the three main systems / functions of all rotary rigs:

- Hoisting System
- Circulating System
- Rotating System

Drilling Rig Systems

The Hoisting System

The derrick supports the hook and elevators by means of the traveling block, drilling line, crown block and drawworks.

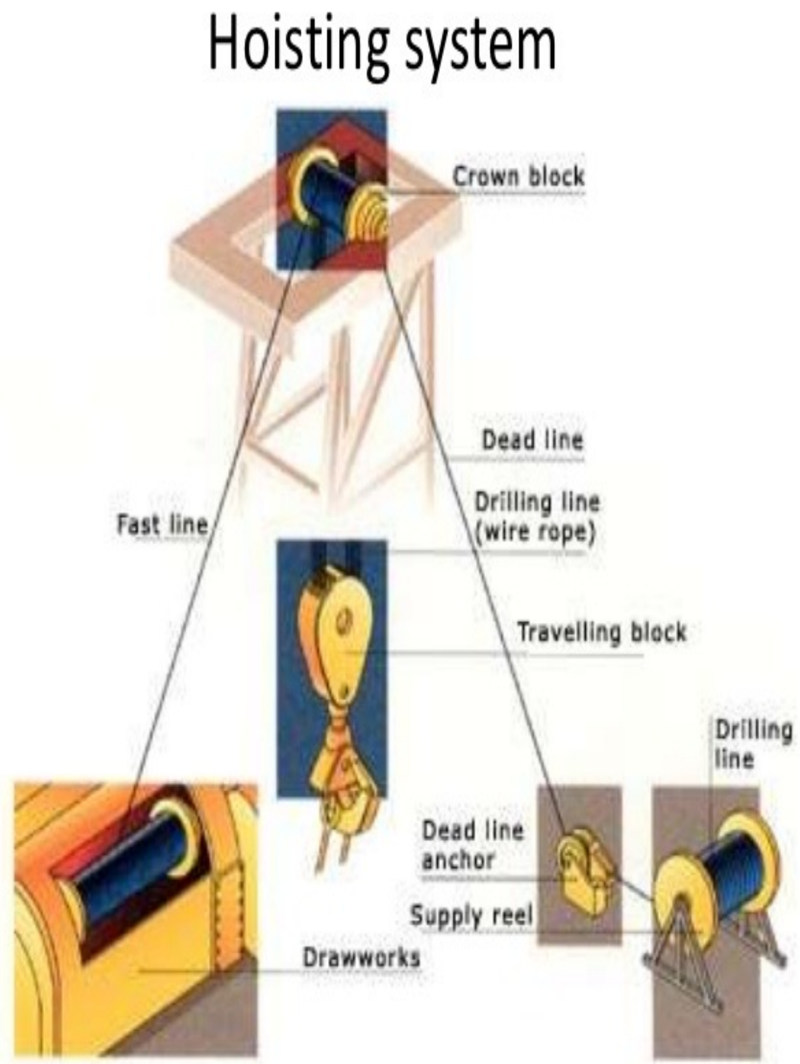
The drawworks is powered by prime movers - two, three or even four engines.

Derrick

The derrick is a metallic structure which has four supporting legs resting on a square base. It is erected on a substructure which supports the rig floor and the rotary table and provides work space on the rig floor.

The derrick and its substructure support the weight of the drillstem at all times. The drillstem is suspended by the traveling block and drilling line, the entire load rests on the derrick. Whenever it is suspended from the crown block or resting in the rotary table. The height of the derrick does not affect its load-capacity, but it can limit the length of drill pipe sections that can be pulled out of the hole for many reasons (ex: changing drill bit). This is because the crown block must be sufficiently elevated above the rig floor.

Drilling Rig Systems



Traveling Block, Crown Block, Drill Line and Hook

The traveling block, crown block and drilling line are used to connect the derrick with the drill string to be lowered into or pulled out of the hole.

During drilling operations, this drill string usually composed of the drill pipe, heavy weight drill pipe, drilling jar, drill collars and drill bit. The drilling line passes from the drawworks to the top of the derrick. From there, it is sheaved between the crown block and traveling block to give an eight, ten or twelve-line suspension. It is then clamped to the rig floor by the deadline anchor. The drilling line wears evenly as it is used; it has to be Cut-off time to time.

The cutoff procedures are related accumulated ton-miles of service. The ton-mile unit is calculated as the drill line moves a one-ton load a distance of one mile, and then the line receives one ton-mile of usage.

Drilling Rig Systems

The Drawworks

The main purpose of the drawworks is to lift the drillstring out of and to lower it back into the borehole. The drilling line is reeled on a drum in the drawworks. When engaged, the drum turns and either reel-in the drill line to raise the traveling block, or reel-out the drill line to lower it.

The drawworks is characterized by the brake system, which enables the driller to easily control a load of thousands of pounds of drillpipe or casing. There are at least two brake systems. One brake is a mechanical friction device and can bring the load to a complete stop. The other brake is hydraulic or electric; it can control the speed of the descent of a loaded traveling block, but is not capable of bringing it to a complete stop. It is used to reduce the wear on the primary friction system.

An integral part of the drawworks is the transmission system. This gives the driller a wide choice of speeds for hoisting the drillstring. The drawworks also has a drive sprocket that drives the rotary table by means of a heavy-duty chain. In some cases, however, the rotary table is driven by an independent engine or electric motor.

Drilling Rig Systems

Another feature of the drawworks is the two catheads. The make-up cathead, on the driller's side, is used to spin up and tighten the drillpipe joints. The other, located opposite the driller's position on the drawworks is the breakout cathead. It is used to loosen the drillpipe when the drillpipe is pulled out of hole.

An independent air hoist (tugger) is used on many rigs for handling light loads around the rig-floor.

Main Control of the drilling operation takes place from driller's cabin, which has improved significantly over the years.

Typical Driller's Cabin

Modern Driller's Cabin

Drilling Rig Systems

Circulating system

During drilling operations, In order to circulate the drilling fluids, the circulating system, mud pumps and prime movers are used.

The drilling fluids are circulated from the mud tanks, through the drillstring, down to the bit and up to the surface through annulus.

The cuttings are displaced from the bottom, up to the surface and separated from the drilling fluids using the shale shakers and mud cleaner.

The recovered cuttings can be used by geologists to identify which formation is being drilled.

Drilling Rig Systems

Mud pumps

The mud pump is the heart of the circulating system. In drilling rig, usually there are two mud pumps. They are used to circulate the drilling fluid from the mud pits, through the drillstring, down to the bit and return up to the surface through the annulus. There are two types of mud pumps: duplex and triplex.

The duplex pumps are double reciprocating acting. They have two cylinders, each cylinder is filled on one side of the piston with the drilling fluid, whereas in the other side the drilling fluid is being discharged. In duplex pump, the discharged volume of the drilling fluid is twice the volume of piston.

The triplex pumps are single acting pumps. They have three cylinders and the drilling fluid is filled in one side of the piston. The triplex pumps system is connected to centrifugal pumps to charge the suction parts with the drilling fluid.

The power generated by the triplex can be relatively higher then duplex because it operates at higher speed.

The mud pumps are connected to strand pipe with high pressure piping. The stand pipe is clamped to the derrick, and anchors one end of the rotary hose and keeps it clear of the rig floor during operations. The other end of the hose is connected to the swivel.

Drilling Rig Systems

Mud Pits

The mud pits are a series of large interconnected steel tanks fitted with agitators to keep solids in suspension. There are some pits are used for circulation and others are used for mixing and storing drilling mud. Fresh water and base oil which are used for making drilling fluids are pumped from storage tanks.

Shale Shakers

Once the drilling fluid has completed one cycle from the mud pits and coming back to surface passing through the drill string, down to drill bit and up to the surface, it will contains solids, some gas if the drilling is performed through reservoir and other contaminants. These non-drilling fluids product or contaminants must be removed in order to keep the required properties needed to drill safely.

The drilling fluid passes over a series of vibrating screens of different mesh sizes. Tanks can also allow residues settling before the mud passed to the mud pits. Fine solids are removed by other components such as mud cleaner or centrifuges.

Drilling Rig Systems

Rotating system

Rigs can be equipped with Kelly system or top-drive system. Both systems are used to rotate the drill string and the drill bit.

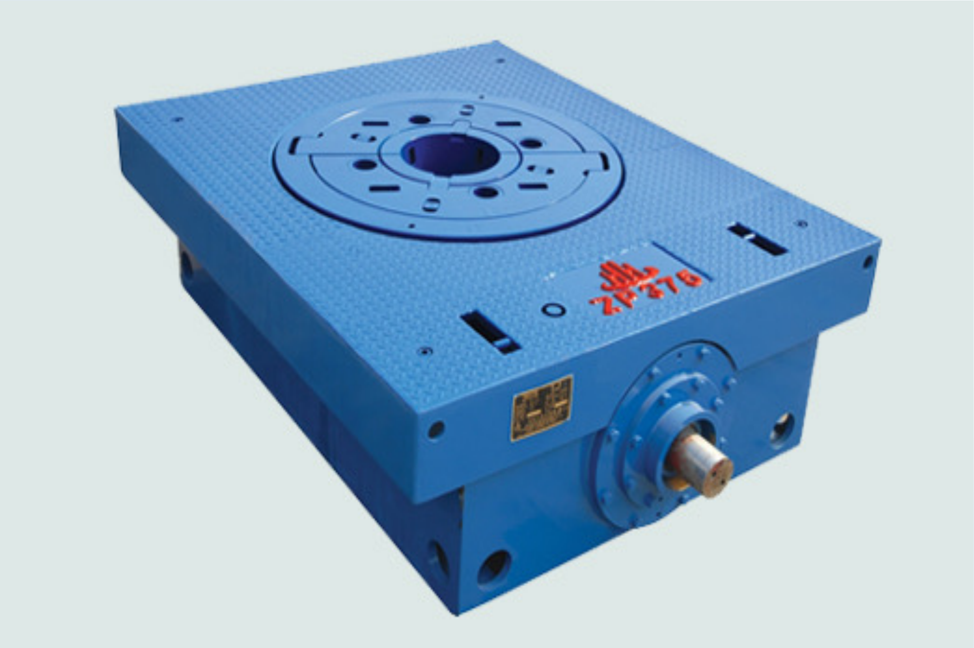
Kelly system

The Kelly is nearly 40 feet long, hexagonal or square on the outside and hollow inside to allow the passage for the drilling fluids.
The Kelly engages in the Kelly bushing, which allow the Kelly to move freely up and down even when rotating the Kelly by the rotary table.
The Kelly cock valve is a safety valve which can be closed to prevent back pressure to damage surface equipment like the swivel and the rotary hose.

The hook is attached with the swivel which does not rotate but supports the Kelly. The drilling fluids are pumped into the drill string through the gooseneck connection above the swivel via the rotary hose.

Drilling Rig Systems

The rotary motion is transmitted from the rotary table to the Kelly bushing by the master bushing. The Kelly bushing engages into the master bushing using four pins which enter in four openings. Rollers within the Kelly bushing permit the Kelly to move upwards and downward.



Rotary table

The rotary table is used for two main tasks:
- Rotating the drill string
- Holding the weight of the drill string when it is not supported by the hook or the elevator.

A direct drive to the rotary is often used with independent engine or electric motor.

Drilling Rig Systems

Top drive system

It is called top drive system because the rotating motion is accomplished by a drive motor attached to the travelling block above all the drill string. An electric motor is used to generate the rotary torque which is applied to the drill string.

The main advantage of the top drive system is that connections have to be screwed or unscrewed every 30m (90 ft), because drilling can be performed by stands rather than single joint of drill pipe. The swivel and handling equipment are an integral piece of equipment in the top drive which can make the circulation and back reaming while pulling the pipe an easy task. These advantages serve to reduce drilling time which is the most important factor in drilling programming and operations.

The Kelly and the Kelly bushing are not required while using the top drive system.

Drilling Rig Systems

Well Control System (BOP)

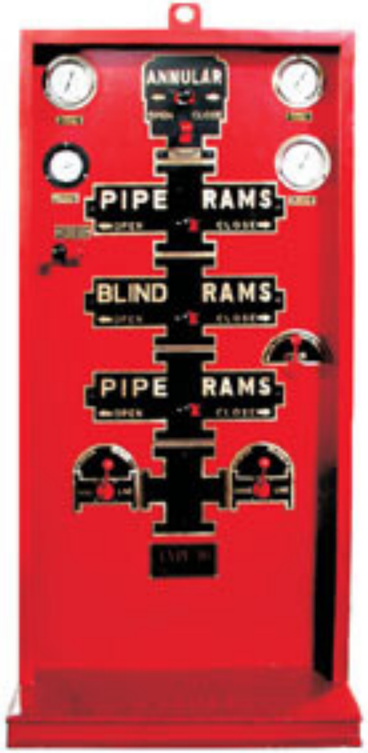
The BOP is an important piece of equipment in the rig. It is used as second barrier against any loss of pressure control. It is fitted with a stacked arrangement of following equipment :

- Annular preventer
- Rams
- Choke line
- Kill line

Annular preventer

This part of BOP seals and closes the well by a circular piece of rubber. It can close on any pipe and casing sizes, and it closes the open hole.

Drilling Rig Systems



Control Systems for BOP

Rams

Two rams which can be activated hydraulically yare used.

Pipe ram can close on drill pipe because they have semi-circular openings which allow them to seal the area around the drill pipe. Blind rams are used to close the well when pipes are not in the hole, if the blind is closed on drill pipe, this will not stop the seepage of formation fluids, because they have flat edges. Shear rams are used as last solution in well control. They can cut the pipe and close the well.

Choke line

This line allows the circulation of the inflex to choke manifold. It has two main valves: hydraulic and manual. The manual valve is used as safety valve in case of hydraulic valve failing.

Kill line

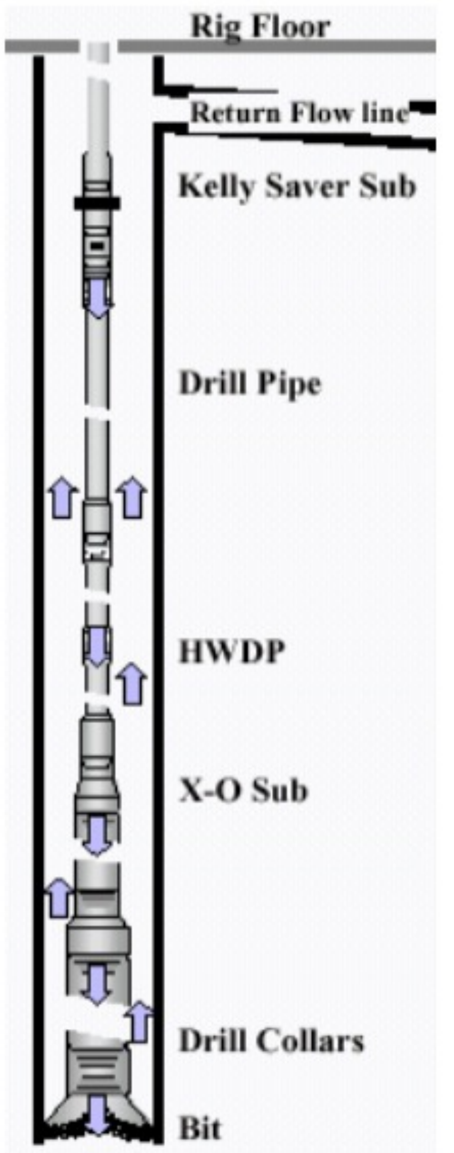
This line is used to inject heavy mud while well killing process. It has two valves: hydraulic and manual valves. It is fitted also with check valve or non return valve to avoid the back circulation of kill mud or formation fluids.

Drilling Rig Systems

Besides the main systems described above there are several other set of equipment / Units for supporting drilling operations which include Engines (power supply) and SCADA (Supervisory Control and Data Acquisition) Systems, Cementing Unit, Logging Unit and Logistical support vehicles / vessels for people and supplies.

Cranes and Storage equipment for cement, Chemicals, Maintenance workshop,, are also needed for the drilling rig in order to accomplish the desired outcome of Drilling a well.

Bottom Hole Assembly (BHA + Drill String)



Bottom Hole Assembly (BHA) + Drill string:

BHA comprises of following and is conveyed to the depth using drill string

- Drilling Bit (Bit): To break up the rock formations
- Drill Collars (DC) + Heavy Weight Drill pipe (HWDP) : To Apply weight on bit (WOB)
- Stabilizers : To centralize the drill string in the hole
- Reamers : To enlarge the drilled hole for certain reasons
- Jars : To free up the BHA / drill string if it gets stuck during drilling process.
- Shock Subs : To reduce the vertical oscillation (bouncing) of the drill string.

BHA may also contain other components such as a downhole motor and rotary steerable system (RSS), measurement while drilling (MWD), Logging While drilling (LWD) tools as required by drilling process / design. The components are joined together using rugged threaded connections. Short " XO subs" are used to connect items with dissimilar threads.

BHAs are conveyed using Drill pipes (DP) / Heavy weight Drill pipes (HWDP) which are graded as per requirement. BHA + Drill pipe together are called "Drill String".

Bottom Hole Assembly (Drill Bit)

Drilling Bit :

Bit Selection is directly related to the performance of drilling and several options are available for selecting the right type of bit.

Data required for the correct bit selection include the following:

1. Prognosed lithology column with detailed description of each formation
2. Drilling fluid detail
3. Well profile / trajectory (whether the well is vertical / directional)

Although there are several types as roller journal, milled tooth insert etc, Two broad categories of bits are available 1. Tri Cone Bits (TCR) 2. Polycrystalline Diamond Compact (PDC) Bits. PDC bits have no moving parts but are not very cost effective.

International Association of Drilling Contractors (IADC) established a three code system for TCR bits.

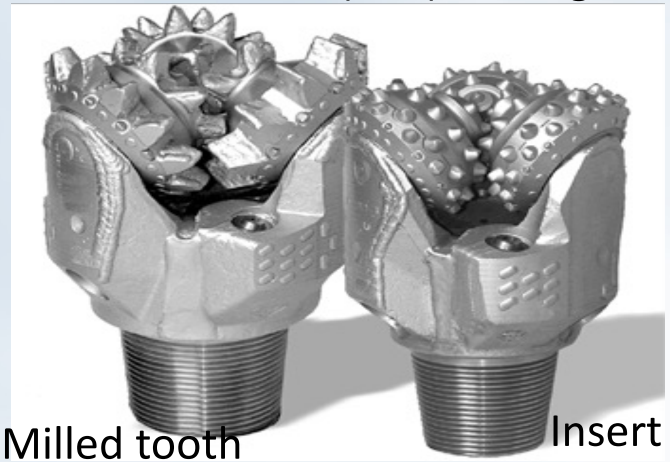
The first code or digit defines the series classification relating to the cutting structure.

For milled tooth bits, the first code carries the numbers 1 to 3, which describes soft, medium and hard (and semi-abrasive or abrasive) rocks respectively. This number actually signifies the compressive strength of rock.

For insert bits, the first code carries the numbers 4-8.

Bottom Hole Assembly (Drill Bit)

Roller Cone (TCR) Drilling Bit



Milled tooth

Insert

PDC – Polycrystalline Diamond Compact Bit

The second code relates to the formation hardness subdivision within each group and carries the numbers 1 to 4. The second code is a subdivision of the first code (1 to 8)
These numbers signify formation hardness, from softest to hardest within each series.

The third code defines the mechanical features of the bit such as non-sealed or sealed bearing. The third code has seven types of sub codes referring to following :

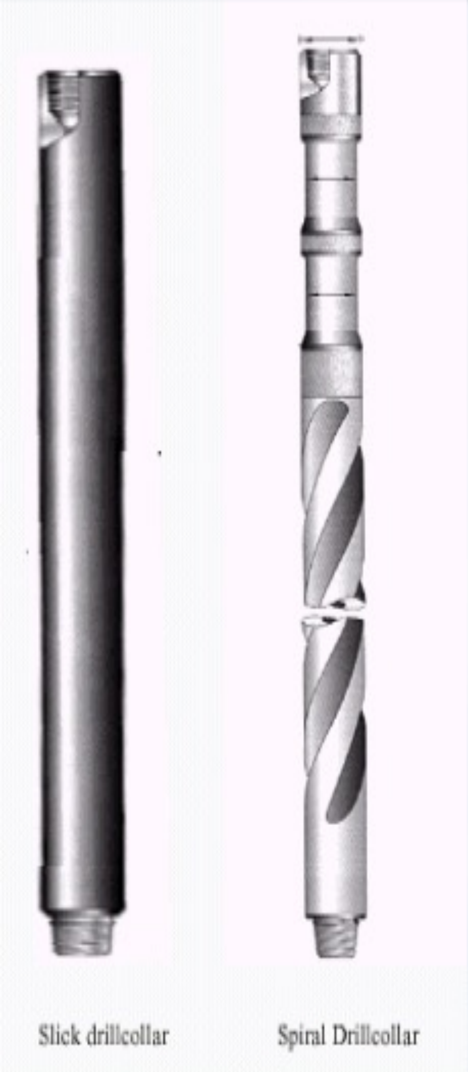
1. Non-sealed roller bearing
2. Roller bearing air cooled
3. Sealed roller bearing
4. Sealed roller bearing with gauge protection
5. Sealed friction bearing
6. Sealed friction bearing with gauge protection
7. Special features - category now obsolete.

As an example, a code of “1-2-1” refers to :

First code 1 for Milled tooth bit, Second Code 2 for medium soft formations (if this number was 4, then it is hard soft formation) and Third code of 1 for non-sealed bearings

Drilling bit Manufacturers should be consulted for selecting the bit along with offset data.

Bottom Hole Assembly (Drill Collars)



Hole Section	Recommended Drill Collar OD (ins)
36	91⁄2 + 8
26	91⁄2 + 8
171⁄2	91⁄2 + 8
16	91⁄2 + 8
121⁄4	8
81⁄2	61⁄4
6	43⁄4

Drill collars are the predominant component of the BHA and are used to put weight on bit (WOB) while drilling. These are thick walled tubulars of specific dimensions and are graded as per Industry norms.

Slick (same OD) and Spiral drill collars are used for specific application where differential sticking is a possibility. Drill collars with Non Magnetic (NMDC) materials are also required for specific applications.

For specific areas where differential sticking is a big risk, spiral drill collars + spiral heavy-walled drillpipe (HWDP) should be used in order to minimise contact area with the formation.

Drill collars are the first section of the drillstring to be designed. Length and size of the collars will affect the grade, weight and dimensions of the drill pipe to be used.

Bottom Hole Assembly (Drill Collar)

Procedure For Calculating Drill Collar length For a Drill String :

Determine the buoyancy factor (BF) for the mud weight in use using the formula : BF = 1 – (MW / 65.5)
Where MW=Mud weight in use in pounds/gallon; and 65.5 represents the Weight of a gallon of steel.

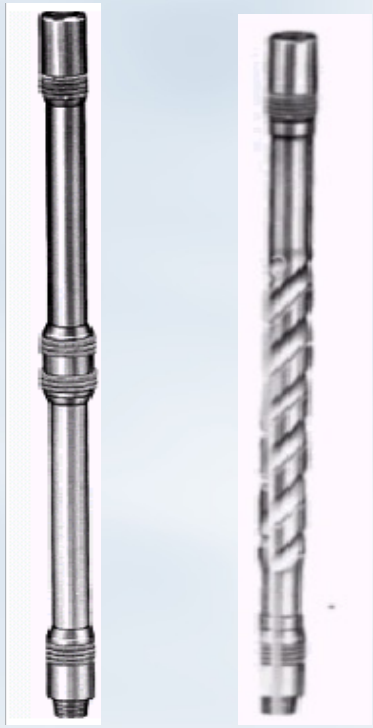
Calculate the required drill collar length (DC_{length}) to achieve the desired weight on bit (WOB) by equating to the Drill Collar length and weight (W_{dc}) adjusted for BF and Safety Factor by Formula

WOB = (DC_{length} x W_{dc} x BF x 0.85 as safety factor)
The 0.85 safety factor ensures that only 85% of the buoyant weight of the drillcollars is used as weight on bit. Hence the neutral point remains within the collars when unforeseen forces (bounce, minor deviation and hole friction) cause fluctuations on the WOB.

Eg : For WOB of 55000 pounds (55KLbs), and MW of 12 ppg, Let's calculate BF. BF = 1- (12/65.5) = 0.817 ; Therefore for WOB of 55 Klbs You will need to have 55KLbs/0.817 = 67.32Klbs and considering Safety Factor of 0.85 you will need to have 67.32Klbs/0.85 = 79.199Klbs. Therefore weight of the drill collars in Air (W_{dc}) = 79199 Lbs

Standard weight per foot for 8" OD drill collar is 192Lbs/ft. Therefore Length of Drill collar (DC_{length}) will be : 79199 /192 = 412.5ft. Also Standard length of Drill collar is 30 ft there fore we need 412.5ft /30ft or Say 14 Drill collars..

Bottom Hole Assembly (HWDP)



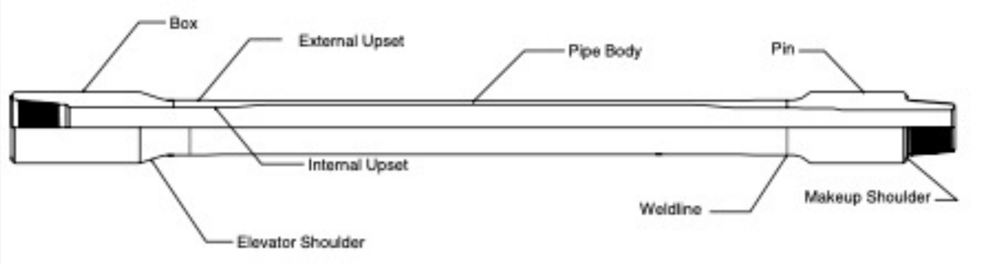
Standard and Spiral HWDP

The Heavy Weight Drill Pipe (HWDP) has the same OD as a standard drillpipe but with much reduced inside diameter (usually 3") and has an extra tool joint.

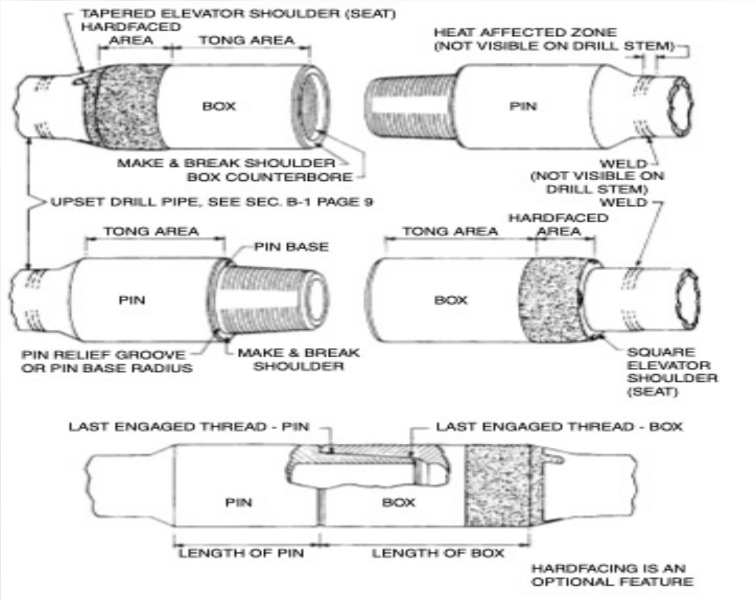
HWDP is used between standard drillpipe and drillcollars to provide a smooth transition between the section moduli of the drillstring components.

HWDP can be distinguished from standard drillpipe by an integral wear centre wear pad which acts as a stabiliser thereby increasing the overall stiffness of the drillstring.

In directional and horizontal wells, HWDP is used to provide part or all of the weight on bit while drilling.



Standard Drill pipe and tool joint



Bottom Hole Assembly (Drill Pipe)

Grade		Minimum Yield Strength, psi
Letter Designation	Alternate Designation	
D	D-55	55,000
E	E-75	75,000
X	X-95	95,000
G	G-105	105,000
S	S-135	135,000

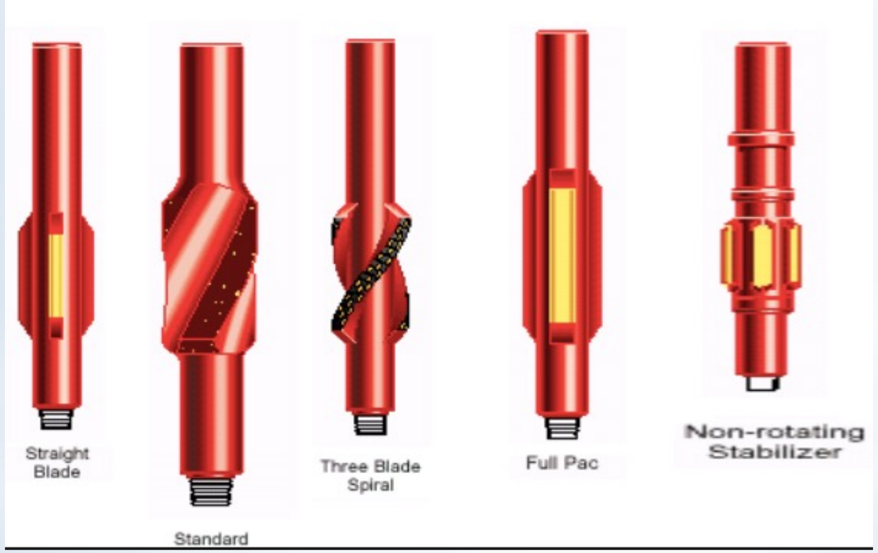
The grade of drill pipe describes the minimum yield strength of the pipe, API defines five grades: D,E, X,G and S. However, in oilwell drilling, only grades E,G and S are actually used. In most drillstring designs, the pipe grade is increased if extra strength is required. Drill pipe, unlike other oilfield tubulars such as casing and tubing, is re-used and therefore often worn when run. As a result the drill pipe is classified to account for the degree of wear. The API has established guidelines for pipe classification in API RP7G. Summary of Classification is as follows :

- New : No wear, has never been used.
- Premium :Uniform wear and a minimum wall thickness of 80% of new pipe.
- Class 2: Drill pipe with a minimum wall thickness of 65% with all the wear on one side so long as the cross sectional area is the same as the premium class.
- Class 3: Drill pipe with a minimum wall thickness of 55% with all the wear on one side.

Drill pipe classification is an important as degree of wear will affect the pipe properties and strengths.

For ordering purposes, drill pipe is also identified by its nominal weight. As stated in API 5C3"Nominal weight is approximately equal to the calculated theoretical weight per foot of a 20 foot length of threaded and coupled pipe based on the dimensions of the joint in use for the class of product when the particular diameter and wall thickness was introduced".

Bottom Hole Assembly (STABILISERS)



Stabilisers are tools placed above the drill bit and along the bottom hole assembly (BHA) to control hole deviation, dogleg severity and prevent differential sticking. They achieve these functions by centralising and providing extra stiffness to the BHA.
Improved bit performance is achieved owing to good stabilisation.
There are basically two type of stabilisers:

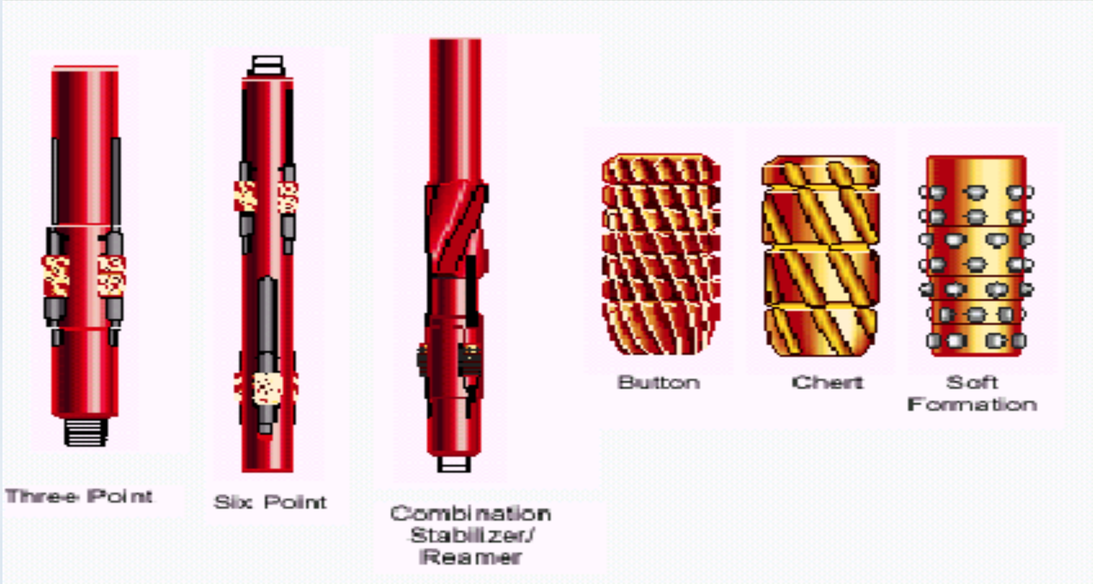
- Rotating stabilisers
- Non-rotating stabilisers

Rotating stabilisers include: Integral blade stabiliser, sleeve stabiliser and welded blade stabiliser.

Integral Blade Stabilisers are machined from a solid piece of high strength steel alloy. The blade faces are dressed with sintered tungsten carbide inserts. The blades can either be straight or spiral.

Non-rotating stabilisers comprise a rubber sleeve and a mandrel. The sleeve is designed to remain stationary while the mandrel and the drillstring are rotating. This type is used to prevent reaming of the hole walls during drilling operation and to protect the drillcollars from wall contact and wear.

Bottom Hole Assembly (REAMER)



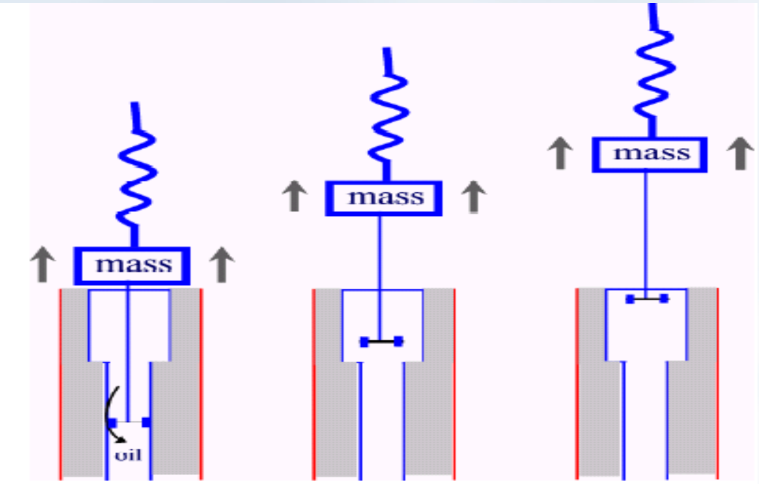
Roller reamers can have either 3 or 6 cutter sets. Both near bit and string reamers are available. Near bit reamers can be bored for a float valve.

Roller reamers are used to replace near bit and string stabilisers in bottom hole assemblies where high torque and swelling or abrasive formations are encountered. Consideration should be given to replacing the near bit and first string stabiliser with a roller reamer if high torque or severe gauge wear of stabilisers has been encountered.

The standard configuration is to replace the near bit and first string stabiliser with a three point roller reamer. For severely abrasive formations or wear significant high torque is encountered a six point roller reamer may be used in place of the near bit stabiliser.

Sealed bearing roller reamers should always be used in preference to non-sealed bearing reamers. The use of sealed bearings minimizes risk of dropping a cutter block set from the reamer. Cutter block sets are available in hardfaced steel or dressed with tungsten carbide. The selection of the appropriate block set will depend upon the formation drilled and to ensure that there is not much wear to the cutter blocks.

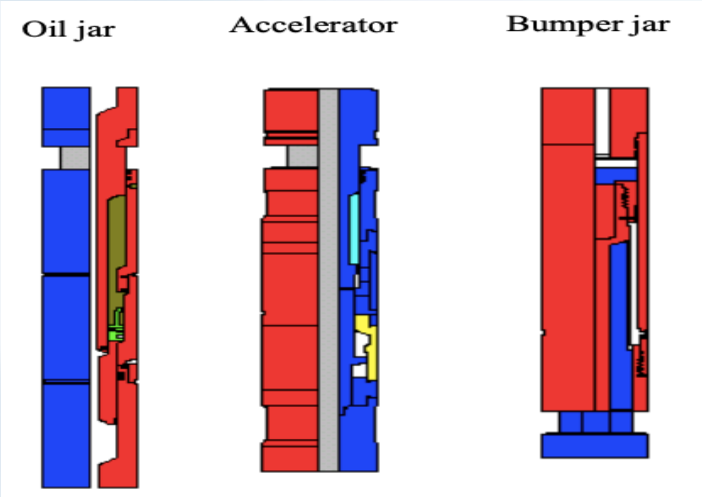
Bottom Hole Assembly (Drilling Jars)



Pull tension Oil moves below

Piston moves up

Piston strikes upward jarring



A jar is a mandrel which slides within a sleeve. The free end of the mandrel is shaped in the form of a hammer to provide a striking action against the face of the anvil.

Depending on the type of tripping mechanism, there are two basic types of jar acting upards / downwards. Figure shows an upward acting jar (Jar Up)

Jars provide a means of supplying powerful upward or downward blows to using mechanically stored energy / uses hydraulic fluids / oil.

Oil Jar typically provide upward blows to release a stuck pipe.

Accelerator : Store energy above the drillcollars in order to increase the impact efficiency of oil jars.

Bumper Jar : Provide free travel to assist in engaging the fish and to allow downward blows to be transmitted to the fishing tools (BHA) .

Selection deployment of jars for BHA should always be done in consultation with manufacturers operating procedures and recommendations.

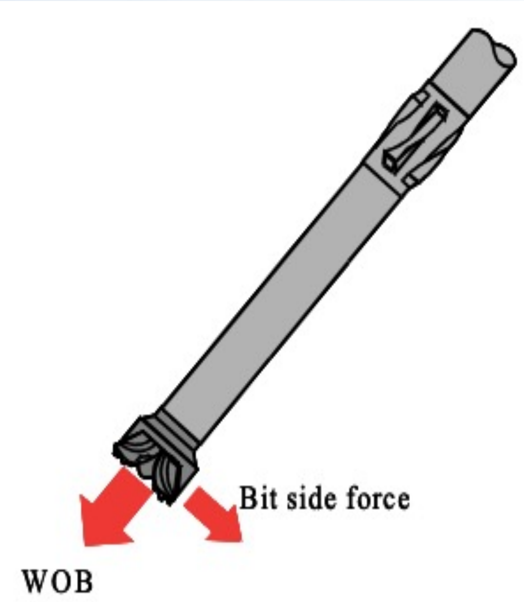
In general, an increase in jar stroke length increases the jarring effect. With these obvious advantages, a long stroke hydraulic jar is preferable to a mechanical jar.

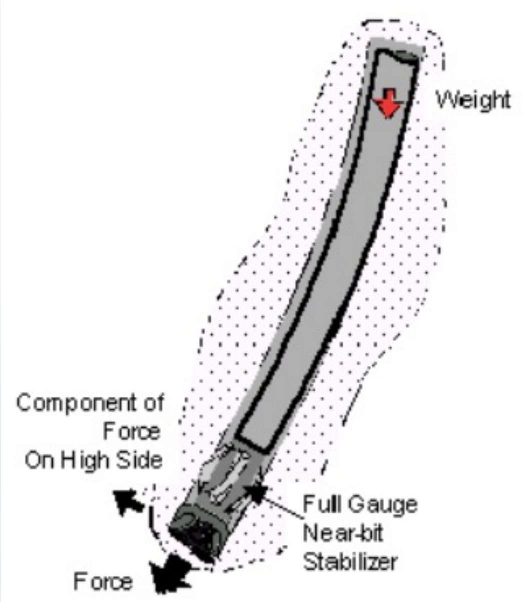
Bottom Hole Assembly

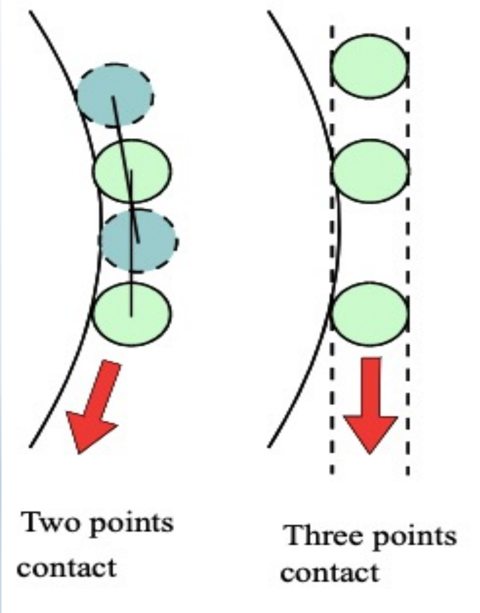
BHA refers to the drillcollars, HWDP, stabilisers and other accessories which are primary components used in the drillstring . Based on the drill collar, and stabilizer positions will create several challenges for directional control of the well. All wells whether vertical or deviated require careful design of the bottom hole assembly (BHA) to control the direction of the well in order to achieve the target objectives.

There are three ways in which the BHA may be used for directional control:

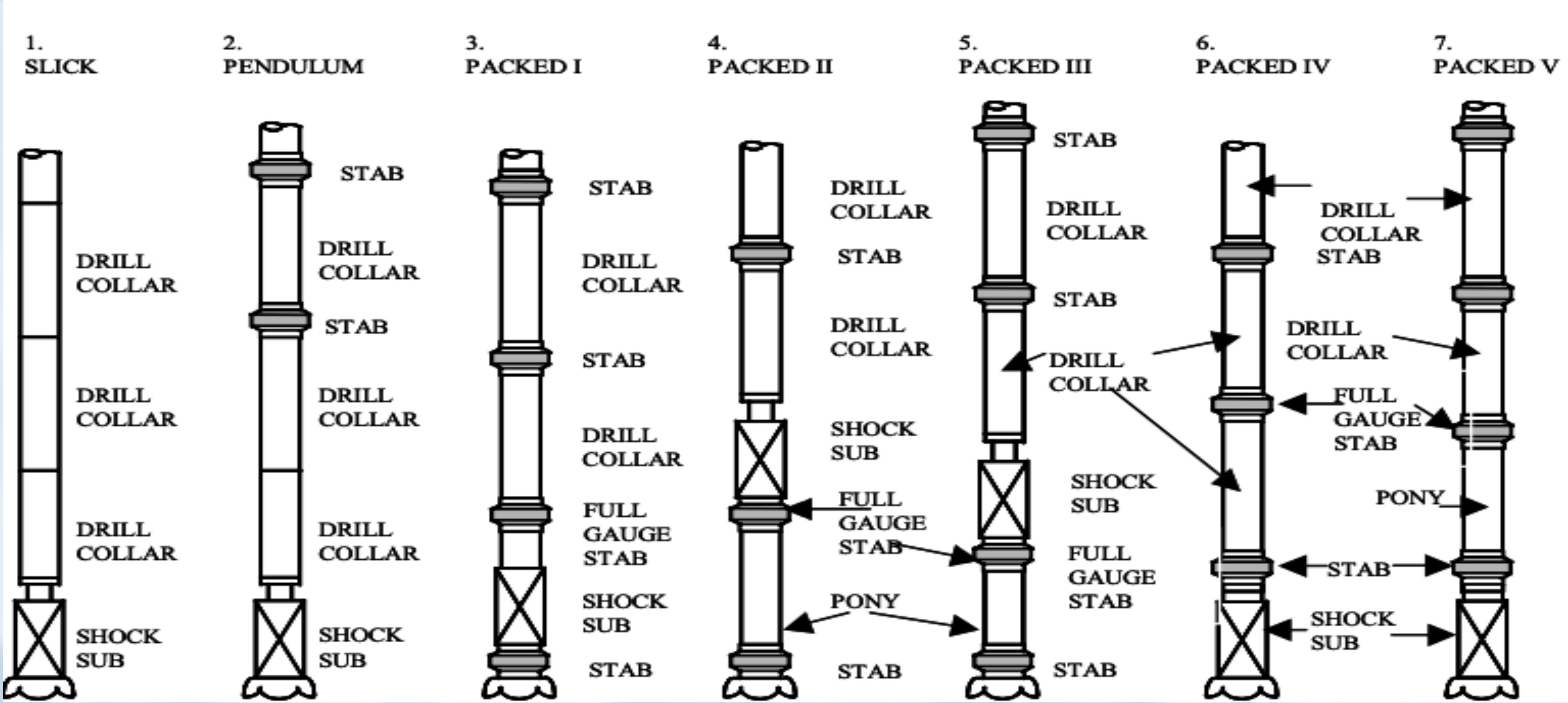
1. Pendulum Principle
2. Fulcrum principle
3. Packed hole stabilisation principle



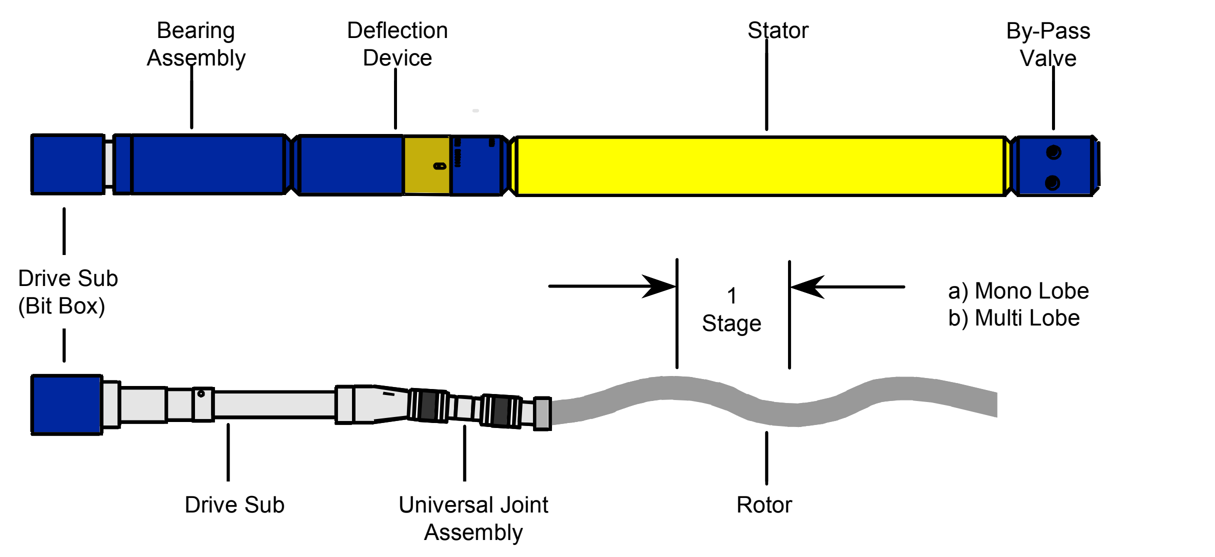




Bottom Hole Assembly (Standard BHA)

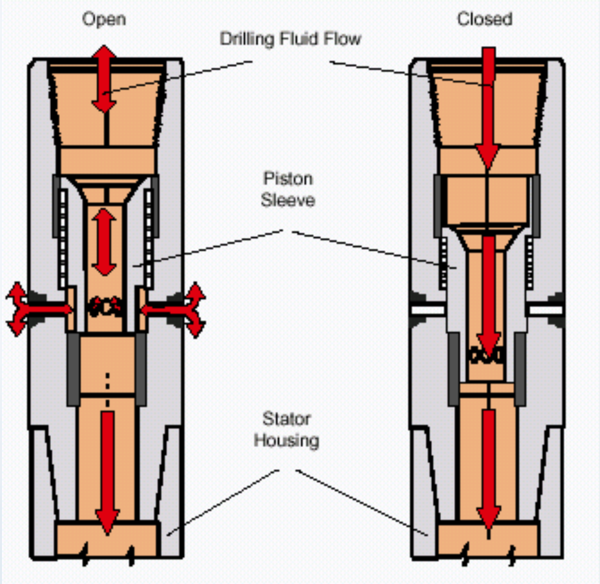


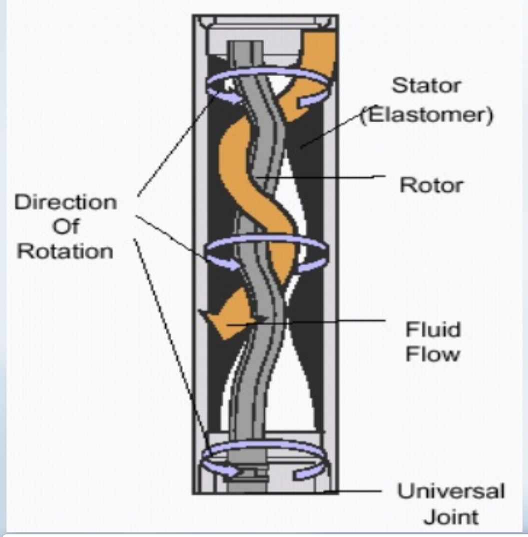
Bottom Hole Assembly – Specialty Tools PDM



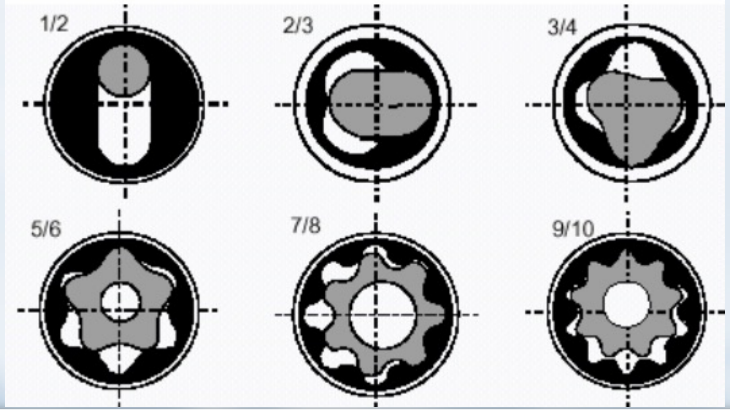
A positive displacement motor (PDM) consists of

- Power section (rotor and stator)
- By-pass valve
- Universal joint
- Bearing assembly



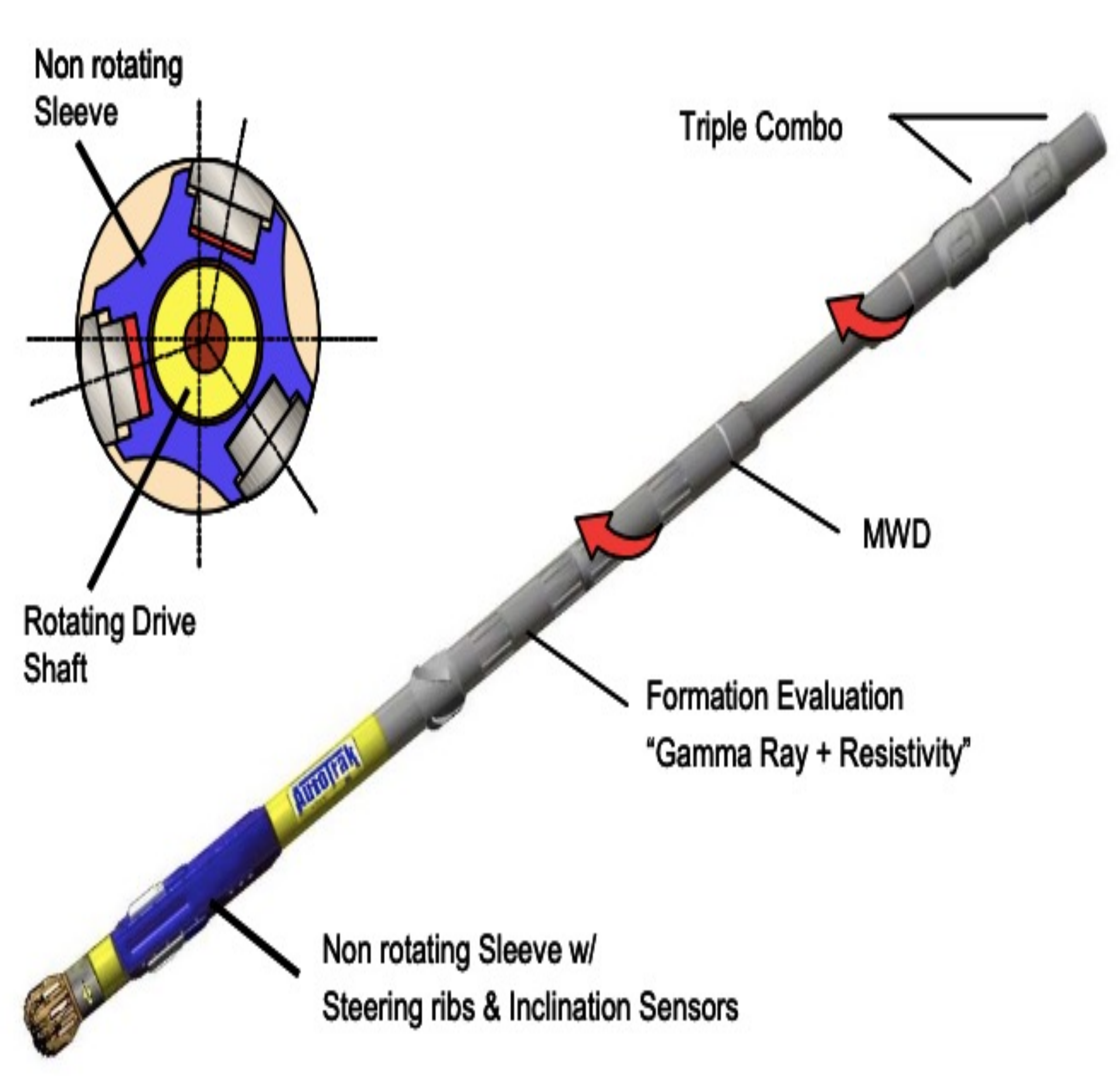


Power Section



PDMs are used for directional drilling. The rotational movement achieved by moving drilling fluid is transmitted through the Universal joint and drive sub to the bit for drilling to continue. The lobe configuration determine the torque and speed (rpm) achievable by the PDM.

Bottom Hole Assembly – Specialty Tools RSS



These systems do not use bent subs for affecting hole angles. Changes in hole angles are brought about by the action of three pads contained within a non-rotating sleeve. The pads are kept in constant contact with the formation by internal mud powered actuators. If no angle change is required, the system is put in neutral mode by pushing the pads in every direction thereby cancelling each other.

If changes in angle and direction are required, the electronics within the instruments cause each pad to extend against the side the hole opposite the intended bias direction. The resultant action of these forces then cause the bit to build or drop angles as required. Signals can be sent from surface to the instrument downhole as is the case with most current rotary steerable systems or the hole inclination and direction are programmed into the instrument at surface and the instrument then automatically corrects the hole trajectory without driller's intervention.

Casing

Oil and gas wells have some type of casing that is used to prevent hole collapse, allow more well control and isolate high and low-pressure zones.

The casing is just a metal pipe that comes in different sizes, thicknesses, and strengths. Higher pressure wells usually require thicker higher grade casing to prevent well collapse. Types of Casing Used in Drilling

Conductor Casing – this is the first casing that is installed in the well. It is usually pretty short (<100 m) and is used to prevent the hole from collapsing and prevent well fluids from mixing with groundwater. It is also used to secure the casing head which is an adaptor used to attach the blowout preventer stack to the casing.

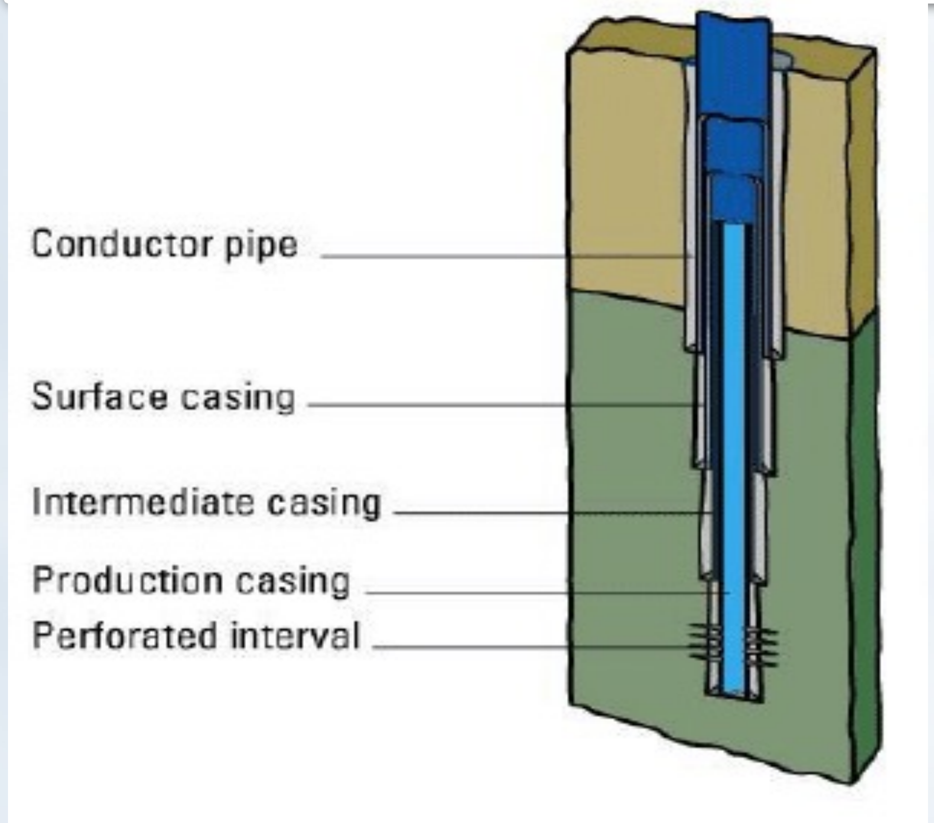
Surface Casing – surface casing is much longer than the conductor casing and it is the next casing that is run in the well during drilling operations. It is used for well control and to prevent well fluids from going into aquifers.

Intermediate Casing – if there are any abnormal pressure zones in the well, an intermediate casing is installed to prevent well kicks or fluid losses.

Production Casing – after the wells is drilled to the target depth, a production casing is installed. It is used to provide isolation between the well fluids and a formation.

Liner – the difference between the casing and the liner is that the liner doesn't extend all the way to the surface. Liners are usually used to decrease the costs and are attached to the end of the casing instead of the wellhead. Sometimes tiebacks of the same diameter as a liner are used to provide a path for fluids to flow from the liner to the surface.

Casing



Casing program design is accomplished by two steps.

In the first step, the casing sizes and corresponding bit sizes should be determined.

In the second step, the setting depth of the individual casing strings ought to be evaluated. Following basic information is required :

- The purpose of the well (exploratory or development drilling)
- Geological cross-sections that should consist of type of formations, expected hole problems, pore and formation's fracture pressure, number and depth of water, oil, gas horizons
- Load capacity of a derrick and mast of the Rig
- Available rock bits, reamer shoes and casing sizes
- Review the API Casing data available from the tables.

The casing is usually cemented in the well to give it more stability and to prevent hydrocarbons from flowing along the outside diameter of the casing.

API Casing Data (Bit Sizes and Clearances)

Casing Specifications					Recommended Max. Bit Size	
Casing Size O.D. (inches)	Casing Coupling O.D. (inches)	Nominal Weight lb./ft.	Inside Diameter I.D. (inches)	API Drift I.D. (inches)	Roller Cone Bit Size O.D. (inches)	Fixed Cutter Bit Size O.D. (inches)

Group	Grade	Type	Total Elongation Under Load %	Yield Strength ksi min.	Yield Strength ksi max.	Tensile Strength min. ksi	Hardness[a] max. HRC	Hardness[a] max. HBW/HBS	Specified Wall Thickness in	Allowable Hardness Variation[b] HRC
1	2	3	4	5	6	7	8	9	10	11

Casing

Selecting Casing setting depth for longer life of well is one of the important contribution of the drilling engineer along with the Geoscientist.

Select the sizes of the available casings based on the bit size and rig capacity.

Having defined bit and casing string sizes, the setting depths of the individual strings should be determined.

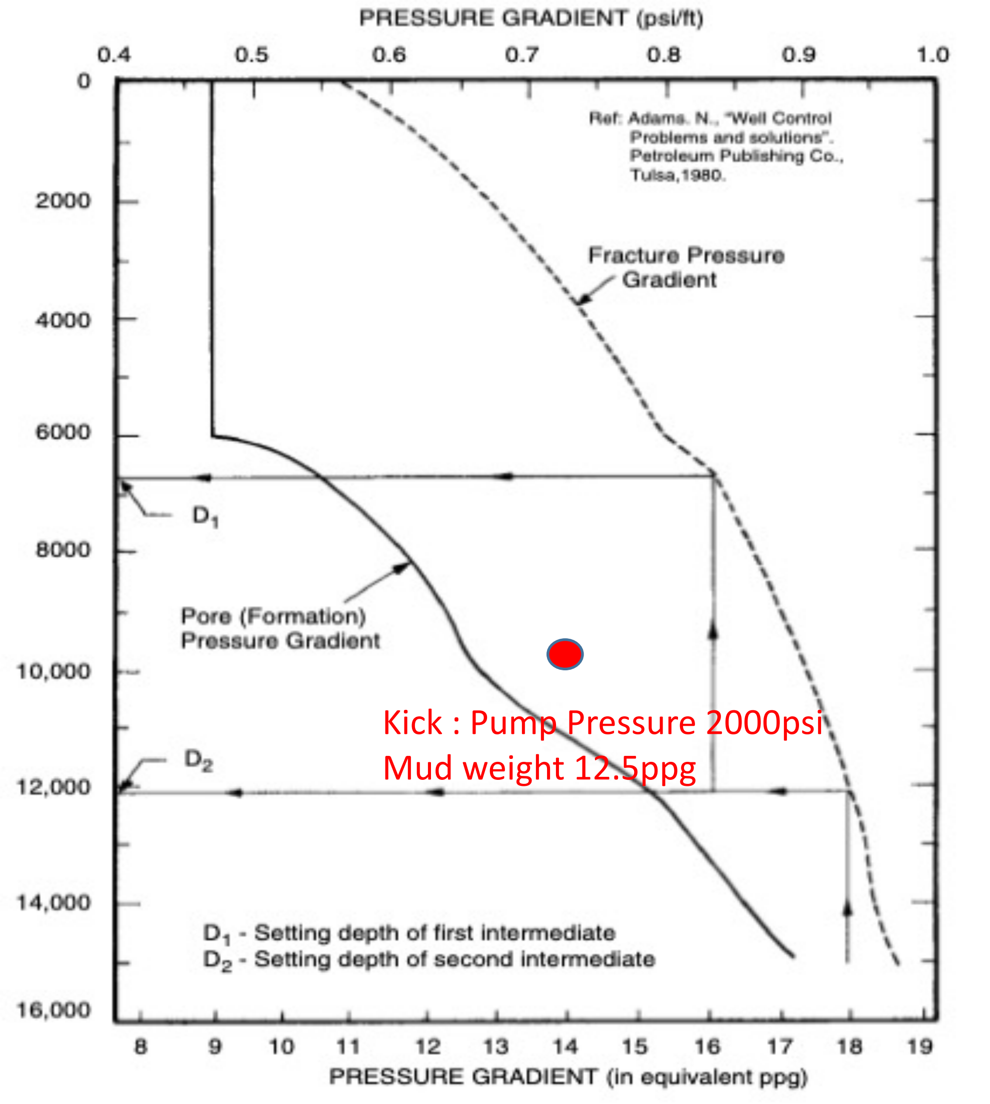
Casing depth should be set to ensure the safety of the drilling crew from possible blowout, and to maintain the hole stability, well completion aspects (formation damage) and state regulations.

In general, casing should be set

- Where drilling fluid shall not contaminate the fresh water
- Prevent the borehole from unstable formations (cave or slough in)
- Prevent Loss circulation which can induce blow out.
- Prevent formation Damange

Typically the pore pressure and fracture pressure are plotted over depth to select casing setting depths.

Casing



Suppose that in some area the expected formation pressure gradient is 0.65 psi/ft and formation fracture pressure gradient is 0.85 psi/ft. A gas-bearing formation is expected at depth of 15,000 ft. Assume that a gas kick occurs that, to be removed from the hole, induces a surface pressure of 2,000 psi. The first intermediate casing is set at a depth of 7,200 ft. Determine the setting depth for the second intermediate casing string if required in given conditions. Assume drilling fluid pressure gradient = 0.65 psi/ft.

Solution

The formation fracture pressure line is

$$P_f = (0.85)(D)$$

The borehole pressure line is

$$P_{bh} = 2,000 + (0.65)(D)$$

So

$$(0.85)(D) = 2,000 + (0.65)(D)$$

$$D = \frac{2,000}{0.2} = 10,000 \text{ ft.}$$

The second intermediate casing string is required and must be set at a depth of 10,000 ft.

Drilling engineer's role is to review data and recommend solutions

Casing

Casing is classified according to its manner of manufacture, steel grade, dimensions, and weights, and the type of coupling. API specification 5CT defines the requirements for oil field tubulars

Group	Grade	Type	Total Elongation Under Load %	Yield Strength ksi min.	Yield Strength ksi max.	Tensile Strength min. ksi	Hardness[a] max. HRC	Hardness[a] max. HBW/HBS	Specified Wall Thickness in	Allowable Hardness Variation[b] HRC
1	2	3	4	5	6	7	8	9	10	11
1	H40		0.5	40	80	60				
	J55		0.5	55	80	75				
	K55		0.5	55	80	95				
	N80	1	0.5	80	110	100				
	N80	Q	0.5	80	110	100				
2	M65		0.5	65	85	85	22	235		
	L80	1	0.5	80	95	95	23	241		
	L80	9Cr	0.5	80	95	95	23	241		
	L80	13Cr	0.5	80	95	95	23	241		
	C90	1.2	0.5	90	105	100	25.4	255	≤ 0.500	3.0
	C90	11	0.5	90	105	100	25.4	255	0.501 to 0.749	4.0
	C90	1.2	0.5	90	105	100	25.4	255	0.750 to 0.999	5.0
	C90	1.2	0.5	90	105	100	25.4	255	≥ 1.000	6.0
	C95		0.5	95	110	105				
	T95	1.2	0.5	95	110	105	25.4	255	≤ 0.500	3.0
	T95	1.2	0.5	95	110	105	25.4	255	0.500 to 0.749	4.0
	T95	1.2	0.5	95	110	105	25.4	255	0.750 to 0.999	5.0
	T95	1.2	0.5	95	110	105	25.4	255	≥ 1.000	6.0
3	P110		0.6	110	140	125				
4	Q125		0.65	125	150	135	b		≤ 0.500	3.0
	Q125		0.65	125	150	135	b		0.500 to 0.749	4.0
	Q125		0.65	125	150	135	b		≥ 0.750	5.0

[a] In case of dispute, laboratory Rockwell C hardness testing shall be used as the referee method.
[b] No hardness limits are specified, but the maximum variation is restricted as a manufacturing control in accordance with section 7.8 and 7.9 of API Spec. 5CT.
Source: From API Specification 5CT, page 164.

The specification requires the manufacturers to have a strict control on the QAQC and total compliance to the following requirements for use of the Industry.

- Process of manufacture
- Materials of the tubulars meeting properties
  - Tensile properties, Yield strength, hardness
- Strict Inspection and testing
- Dimensional control as per the applicable tolerance limits. For example

Label 1	Tolerance on outside diameter, m_{eu} or L_0
≤3–1/2	+3/32 in. to –1/32 in.
>3–1/2 to ≤5	+7/64 in. to –0.75% D
>5 to ≤8–5/8	+1/8 in. to –0.75% D
>8–5/8	+5/32 in. to –0.75% D

Casing

Casing Jointers : Popularly round-thread casing only, jointers.

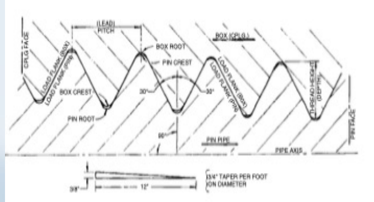
Coupling API standards established three types of threaded joints:

1.Coupling joints with rounded thread (long or short)

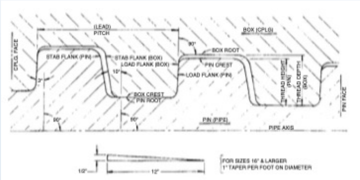
2.Coupling joints with asymmetrical trapezoidal thread buttress

3.Extreme-line casing with trapezoidal thread without coupling

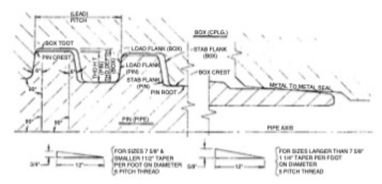
There are also many non-API joints, like Hydril "CTS," Hydril "Super FJ-P," Armco SEAL-LOC, Mannesmann metal-to-metal seal casing and others.



Rounded Thread



Buttress thread



Extreme line casing thread

Round-Thread Casing Coupling Dimensions, Masses and Tolerances

Label 1	Size[a] Outside diameter D in.	Outside diameter W in.	Minimum length in Short N_L	Minimum length in Long N_L	Diameter of recess Q^b in.	Width of bearing face b in.	Mass lb Short	Mass lb Long
1	2	3	4	5	6	7	8	9
$4\frac{1}{2}$	4.500	5.000	$6\frac{1}{4}$	7	$4\frac{19}{32}$	$\frac{5}{32}$	7.98	9.16
5	5.000	5.563	$6\frac{1}{2}$	$7\frac{3}{4}$	$5\frac{3}{32}$	$\frac{3}{16}$	10.27	12.68
$5\frac{1}{2}$	5.500	6.050	$6\frac{3}{4}$	8	$5\frac{19}{32}$	$\frac{1}{8}$	11.54	14.15
$6\frac{5}{8}$	6.625	7.390	$7\frac{1}{4}$	$8\frac{3}{4}$	$6\frac{23}{32}$	$\frac{1}{4}$	20.11	25.01
7	7.000	7.656	$7\frac{1}{4}$	9	$7\frac{3}{32}$	$\frac{3}{16}$	18.49	23.87
$7\frac{5}{8}$	7.625	8.500	$7\frac{1}{2}$	$9\frac{1}{4}$	$7\frac{25}{32}$	$\frac{7}{32}$	27.11	34.46
$8\frac{5}{8}$	8.625	9.625	$7\frac{3}{4}$	10	$8\frac{25}{32}$	$\frac{1}{4}$	35.79	47.77
$9\frac{5}{8}$	9.625	10.625	$7\frac{3}{4}$	$10\frac{1}{2}$	$9\frac{25}{32}$	$\frac{1}{4}$	39.75	56.11
$10\frac{3}{4}$	10.750	11.750	8	—	$10\frac{29}{32}$	$\frac{1}{4}$	45.81	—
$11\frac{3}{4}$	11.750	12.750	8	—	$11\frac{29}{32}$	$\frac{1}{4}$	49.91	—
$13\frac{3}{8}$	13.375	14.375	8	—	$13\frac{17}{32}$	$\frac{7}{32}$	56.57	—
16	16.000	17.000	9	—	$16\frac{7}{32}$	$\frac{7}{32}$	76.96	—
$18\frac{5}{8}$	18.625	20.000	9	—	$18\frac{27}{32}$	$\frac{7}{32}$	119.07	—
20	20.000	21.000	9	$11\frac{1}{2}$	$20\frac{7}{32}$	$\frac{7}{32}$	95.73	126.87

Tolerance on outside diameter W, ±1% but not greater than ±1/8 in. Groups 1, 2 and 3.
Tolerance on outside diameter W, ±1% but not greater than +1/8 in., Group 4.

[a] The size designation for the coupling is the same as the size designation for the pipe on which the coupling is used.

[b] Tolerance on diameter of recess, Q, for all groups is 0 to +0.031 in.

Casing Threads / Coupling

Round Threads : The purpose of round top (crest) and round bottom (root) is to improve the resistance of the threads from galling in make-up, providing a controlled clearance between make-up thread crest and root for foreign particles or contaminants and to make the crest less susceptible to harmful damage from minor scratches or dents. Sufficient interference should ensure leak path through the connection from the annular clearance between mated crest and roots. Proper thread compound is necessary to ensure leak resistance.

Buttress Threads are designed to resists high axial tension or compression loading in addition to offering resistance to leakage. The 3◦ load flank offers resistance to disengagement under high axial tension loading, while the 10◦ stub flank offers resistance to high axial compression loading. In any event, leak resistance is again accomplished with use of proper thread compound and/or thread coating agents. Leak resistance is controlled by proper assembly (interference) within the perfect thread only.

Extreme-line casing threads in all sizes uses a modified acme type thread having a 12◦ included angle between stub and load flanks, and all threads have crests and roots flat and parallel to the axis. For all sizes, the threads are not intended to be leak resistant when made up. Threads are used purely as a mechanical means to hold the joint members together during axial tension loading. The connection uses upset pipe ends for pin and box members that are an integral part of the pipe body. Axial compression load resistance is primarily offered by external shouldering to the connection or makeup.

Casing

Leak resistance is obtained on makeup by interference of metal-to-metal seal between a long radius curved seal surface on the pin member engaging a conical metal seal surface of the box member (Figures 8.5 and 8.9). Thread compound is not necessarily a critical agent to ensure leak resistance, but instead is used primarily as an anti galling or antiseizure agent.

Material Couplings for pipe (both casing and tubing) shall be seamless and, shall be of the same grade as the pipe. Exceptions are stipulated in Sections 9.2 and 9.3 in API Spec 5CT, for grades H-40, J-55, K-55, M65, N-80, and P-110, where couplings of stipulated higher grades are acceptable. When couplings are electroplated, the electroplating process should be controlled to minimize hydrogen absorption.
Note: Most buttress thread couplings will not develop the highest minimum joint strength unless couplings of the next higher order are specified (see API Specification 5CT for more detailed information).

Casing Performance

Minimum Performance Properties of Casing Results of years of field experience have revealed that to reduce the risk of failure, the minimum yield strength should be used instead of average yield strength to determine the performance properties of casing. Values for collapse resistance, internal yield pressure, pipe body, and joint strength for steel grades are available in API Bulletin 5C2, 21st Edition, October 1999.

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
																			★ Joint Strength — 1,000 lbs							
					Threaded and Coupled			Extreme Line				Internal Yield Pressure at Minimum Yield, psi							Threaded and Coupled						Extreme Line	
													Round Thread		Buttress Thread				Round Thread		Buttress Thread					
															Regular Coupling		Special Clearance Coupling									
Size: Outside Diameter in. *D*	Nominal Weight, Threads and Coupling lb per ft	Grade	Wall Thickness in. *t*	Inside Diameter in. *d*	Drift Diameter in.	Outside Diameter of Coupling in. *W*	Outside Diameter Special Clearance Coupling in. W_c	Drift Diameter in.	Outside Diameter of Box Power-tight in. *M*	Collapse Resistance psi	Pipe Body Yield Strength 1000 lbs	Plain End or Extreme Line	Short	Long	Same Grade	Higher Grade	Same Grade	Higher Grade	Short	Long	Regular Coupling	Regular Coupling Higher Grade	Special Clearance Coupling	Special Clearance Coupling Higher Grade‡	Standard Joint	Optional Joint

Casing Few Formulas from API C5

The yield strength collapse pressure is not a true collapse pressure but rather the external pressure P_{yp} that generates minimum yield stress Y_p on the inside of the wall of a tube as calculated by

$$P_{yp} = 2Y_p \left[\frac{(D/t) - 1}{(D/t)^2} \right]$$

Steel Grade	D/t range for formula (1)	D/t range for formula (2)	D/t range for formula (3)	D/t range for formula (4)
H-40	16.44 & less	16.44 to 26.62	26.62 to 42.70	42.70 & greater
J-K-55	14.80 & less	14.80 to 24.39	24.39 to 37.20	37.20 & greater
C-75	13.67 & less	13.67 to 23.09	23.03 to 32.05	32.05 & greater
L-N-80	13.38 & less	13.38 to 22.46	22.46 to 31.05	31.05 & greater
C-95	12.83 & less	12.83 to 21.21	21.21 to 28.25	28.25 & greater
P-105	12.56 & less	12.56 to 20.66	20.66 to 26.88	26.88 & greater
P-110	12.42 & less	12.42 to 20.29	20.29 to 26.20	26.20 & greater

The minimum collapse pressure for the plastic range (Pp) of collapse is calculated by

$$P_p = Y_p \left[\frac{A}{D/t} - B \right] - C$$

The minimum collapse pressure for the plastic to elastic transition zone P_T is calculated by

$$P_T = Y_p \left| \frac{F}{D/t} - G \right|$$

The minimum collapse pressure for elastic transition zone P_E is calculated by

$$P_E = \frac{46.95 \times 10^6}{(D/t)((D/t) - 1)^2}$$

	Formula Factor				
Steel Grade	A	B	C	F	G
H-40	2.950	0.0463	755	2.047	0.03125
J-K-55	2.990	0.0541	1205	1.990	0.03360
C-75	3.060	0.0642	1805	1.985	0.0417
L-N-80	3.070	0.0667	1955	1.998	0.0434
C-95	3.125	0.0745	2405	2.047	0.0490
P-105	3.162	0.0795	2700	2.052	0.0515
P-110	3.180	0.0820	2855	2.075	0.0535

Casing Formulae from API

The reduced minimum collapse pressure caused by the action of axial tension stress is calculated by

$$P_{CA} = P_{CO}\left[\sqrt{1 - 0.75[(S_A + P_i)/Y_p]^2}\right] - 0.5(S_A + P_i/Y_p)$$

D = nominal outside diameter in in.
t = nominal wall thickness in in.
Y_p = minimum yield strength of pipe in psi
P_{Yp} = minimum yield strength collapse pressure in psi
P_p = minimum plastic collapse pressure in psi
P_T = minimum plastic/elastic transition collapse pressure in psi
P_E = minimum elastic collapse pressure in psi
P_{CA} = minimum collapse pressure under axial tension stress in psi
P_{CO} = minimum collapse pressure without axial tension stress in psi
S_A = axial tension stress in psi
P_i = internal pressure in psi

Internal yield pressure for **pipe** is calculated from

$$P_i = 0.875\left[\frac{2Y_p t}{D}\right]$$

The factor 0.875 appearing in the formula allows for minimum wall thickness

where

P_i = minimum internal yield pressure in psi
Y_p = minimum yield strength in psi
t = nominal wall thickness in in.
D = nominal outside diameter in inches.

Casing Formulae from API

Internal yield pressure for threaded and coupled pipe is the same as for plain end pipe, except where a lower pressure is required to avoid leakage due to insufficient coupling strength. The lower pressure is based on

$$P = Y_c \left[\frac{W - d_1}{W} \right]$$

where

P = minimum internal yield pressure in psi
Y_c = minimum yield strength at coupling in psi
W = nominal outside diameter of coupling
d_1 = diameter of the root of the coupling thread at the end of the pipe in the powertight position (see API Bulletin 5C3, 6th Edition, October 1994).

Pipe body yield strength is the axial load required to yield the pipe. It is taken as the product of the cross sectional area and the specified minimum yield strength for the particular grade of pipe. Values for pipe body yield strength were calculated by means of the following formula:

$$P_Y = 0.7854(D^2 - d^2)Y_p$$

where

P_Y = pipe body yield strength in psi
Y_p = minimum yield strength
D = specified outside diameter in in.
d = specified inside diameter in in.

Casing Formulae – from API

Round Thread Casing Joint Strength Round thread casing joint strength is calculated from. The lesser of the values obtained from the two formulas govern and apply both to short and long threads and couplings.

Formula for minimum strength of a joint failing by fracture is

$$P_j = 0.95\, A_{jp} U_p$$

Formula for minimum strength of a joint failing by thread jump out or pull out.

$$P_j = 0.95\, A_{jp} L \left[\frac{0.74 D^{-0.59} U_p}{0.5L + 0.14D} + \frac{Y_p}{L + 0.14D} \right]$$

P_j = minimum joint strength in lb

A_{jp} = cross - sectional area of the pipe wall under the last perfect thread in in.^{2}

$= 0.7854 ((D - 0.1425)^2 - d^2)$ for eight round threads

D = nominal outside diameter of pipe in in.

d = nominal inside diameter of pipe in in.

L = engaged thread length in in.

$= L_4 - M$ for nominal makeup, API Spec 5B

Y_p = minimum yield strength of pipe in psi

U_p = minimum ultimate strength of pipe in psi

Extreme-line casing joint strength is calculated from

$$P_j = A_{cr} U_p$$

where

P_j = minimum joint strength in lb

A_{cr} = critical section area of box, pin or pipe, whichever is least, in in.^{2} (see API Bulletin 5C3)

U_p = specified minimum ultimate strength in psi (Table 8.9)

Casing

Buttress thread casing joint strength is calculated from formulae . The lesser of the values obtained from the two formulae governs.

Pipe thread strength is

$$P_j = 0.95\,A_p U_p |1.008 - 0.0396(1.083 - Y_p/U_p)D|$$

Casing thread strength is

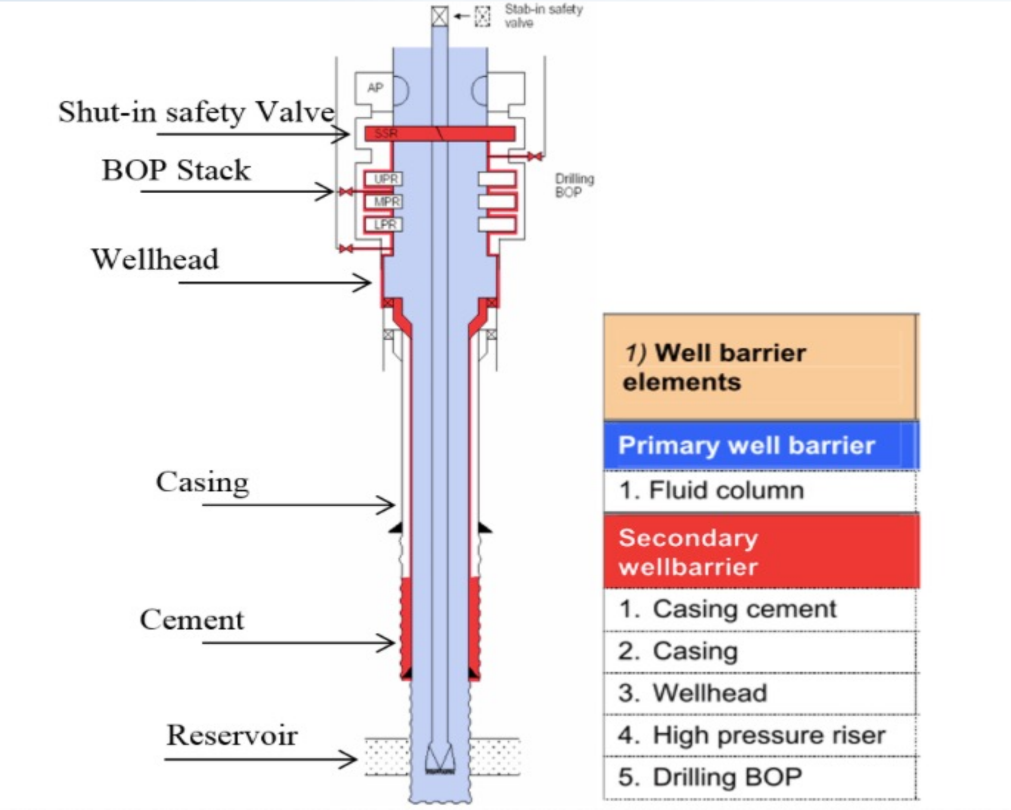
$$P_j = 0.95\,A_c U_c$$

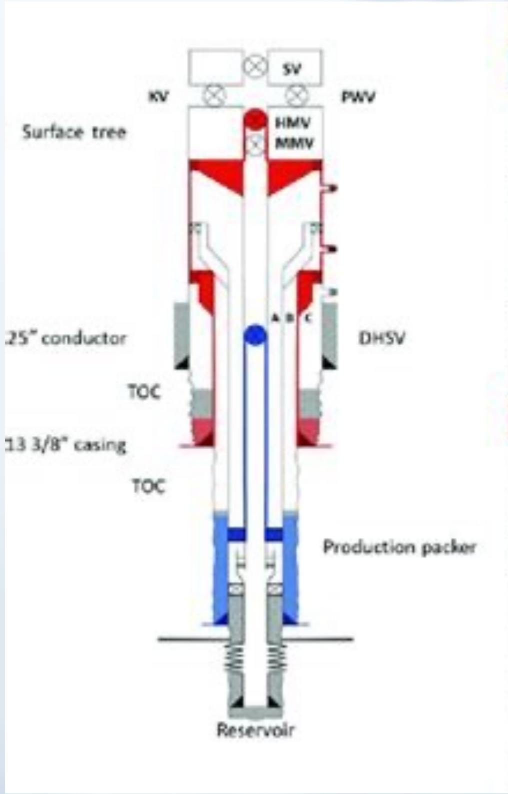
where

P_j = minimum joint strength in lb
Y_p = minimum yield strength of pipe in lb
U_p = minimum ultimate strength of pipe in psi
U_c = minimum ultimate strength of coupling in psi
A_p = cross-sectional area of plain end pipe in in.^{2}
$= 0.7854(D^2 - d^2)$
A_c = cross-sectional area of coupling in in.^{2}
$= 0.7854(W^2 - d_i^2)$
D = outside diameter of pipe in in.
W = outside diameter of coupling in in.
d = inside diameter of pipe in in.
d_i = diameter of the root of the coupling thread at the end of the pipe in the powertight position

Casing – Well Barrier Element

Casing is the most important Well Barrier element in the well's life. Therefore appropriate design considerations must be given by the drilling engineers. Several computer simulations / Softwares are available to determine stresses on this well barrier element and to ensure that the design is made with an objective of desired lifespan of the well.





Well Barrier Elements
Primary well barrier
In-situ formation (cap rock)
Casing cement (9 5/8")
Casing (9 5/8")
Production packer
Completion string
Completion string components (chemical injection valves)
Downhole safety valve (and control line)
Secondary well barrier
In-situ formation (13 3/8")
Casing cement (13 3/8")
Casing (13 3/8")
Wellhead (casing hanger with seal assembly)
Wellhead/annulus access valves
Tubing hanger (body seals and neck seal)
Wellhead (WH/XMT connector)
Surface tree

https://youtu.be/Do9dz6ypD7w

Thank You

Thank You for your undivided attention !

We are now open to questions.