CEMENT ADDITIVES

The most important function of oil & gas well primary cementing is to isolate the various zones within the wellbore. In others words, the cement must prevent fluids or gases in one particular zone from mingling with those of another. A properly designed and placed cement slurry accomplishes this by creating the necessary seal between the casing and the formation. The cement must prevent migration or fluid channeling throughout the cement.

Today's well cement systems must perform in a variety of down hole conditions, from 0 °C - over 350 °C., and at bottom hole pressures in excess of 30,000 psi. Messina has developed a complete line of cement additives, which modify the characteristics and performance of the cement slurry. This means that a slurry can be designed to function over the wide range of conditions that occur in the wellbore.

For more information, please choose from the categories below.
http://www.messina-oilchem.com/Cement/CementAdd-intro.html

CATEGORIES
Cements
Accelerators (Code "CA-A")
Extenders (CODE: "CA-EX" OR "LWS")
Fluid Loss Control Additives (CODE:"CA-FL")
Friction Reducers (CODE: "CA-FR")
Lost Circulation Materials (CODE: "CA-LC") AND
Formation Control (CODE: "CA-FC")
Retarders (CODE: "CA-R")
Strength Retrogression Materials (CODE: "CA-HT") AND
Weighting Agents (CODE: "CA-W")
Antifoamers (CODE: "CA-AF") AND Foam Cement Additives (CODE: "CA-FA")
Thixotropic Cement Additives (CODE: "CA-TX") AND
Gas Control Additives (CODE: "CA-GS" OR "LX")
Cement Matrix Intensifier (CODE: "CA-SAF"),
Lead Slurry Gellants (CODE: "CA-GA"), AND
Salt Cement Slurries
Cement Preflushes and Spacers

Send mail to messina.oilfield.chemicals@att.net with questions or comments about this web site.

Last modified: November 08, 2000

DIVERTER

http://www.workover.co.uk/bops/blow_out_prevention_Diverter_System.htm

Diverters provide the safe venting of shallow gas flows that can be found in some parts of the world. They range from 21 1/4 to 30 inches, with working pressure ranging from 500 to 2,000 psi.

Many of today rigs have a diverter housing installed when the rig is built. But it wasn't always this way. For many years much of the diverter equipment in the field was installed before the availability of systems properly designed for diverting. For many years diverting a flow was done using a 21 1/4 Annular rigged up in such away as to open the side ports and close the bag.

Diverter malfunctions have led to serous accidents with people and rigs with many blowouts occurring at shallow drilling depths where gas charged sediment A diverter is a safety system that reroutes a well fluid flow away from the rig. Shallow gas is allowed to flow until the well is bridged over or killed by pumping in heavy mud and is intended for use when there is danger of penetrating pressurized shallow gas zone, while the casing shoe strength may not be sufficient to contain shut-in pressures.

In some parts of the world the danger of hitting gas as high as 300' to 500' is real threat. In extreme cases the rig may pin down and drill a pilot hole. Modern day diverters are sturdy; resist erosive cut-out, high thrust and impact loads. They are fundamentally simple. Bends that induce turbulence are minimized. Valves, insert cartridges, linkages, and the sequencing process that sometimes cause malfunction are now eliminated. Safeguarding the rig and personnel during the most dangerous phase of drilling. " The Top Hole "

Rigs and people were lost due to such flow some form of diverter had to be developed. Many ideas were tried. Many of today diverters are just improvements on what was an idea tried out by men in the field. One of the more successful idea was the use of the annular, a spool with 10 inch outlets and hydraulic valves.

Often it would made up and the 21 1/4 annular would diverter. It was designed in such a way that it would fit directly to the 30 inch. This would be accomplished by welding a swage to the larger casing and installing the diverter spool on top and then the annular such a system is still in use to day and can often be found on land rig throughout the world.

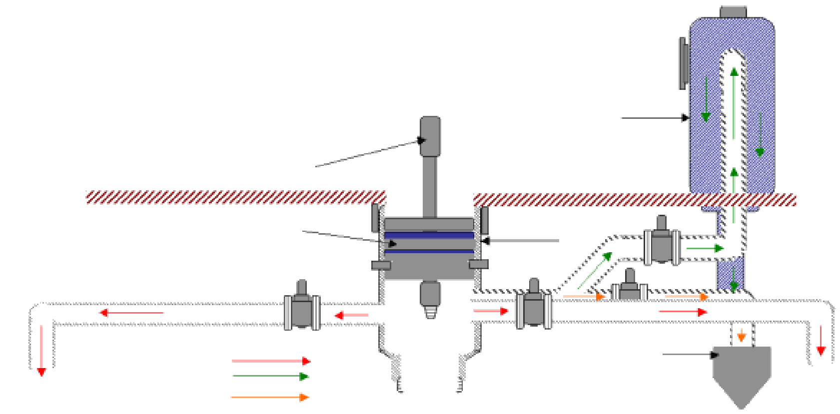
The concept is simple as the annular closes the side vents opens. The idea was to make up line from the spool a direct then over the side, often the outlet would be only a few feet from the water. By making a small manifold that screwed into the annular the fluid applied to the closing position on the annular would open the vent valves and if applied to the opening port would close the side vents.

Diverter take an awful beating if put into use. It is there for important that the outlet be big enough to take the flow and debris the formation will push up I would not recommend side outlets of less than 12 inch and the vent lines as straight as possible. If working offshore I would also recommend the line drops as far and as close to mean sea level as you can possibly get it. This will help keep the line clear by giving a siphoning effect. In the Middle East in the 80's we would use the diverter once running into the major salt water flows. The flows were often accompanied by H2s gas this would be sucked from the floor and dropped 110 feet leaving the floor free of gas.

Modem day diverter have many advantages least of all on nipple up time, a combination of overshot's and riser that fit to the top of the stack make it possible to slide the bell nipple up inside the overshot with out having to nipple down or move the stack out of the way. Always handy for setting slips or install the next spool or for dumping cement.

With the diverter housing incorporated into the rig sub structure there is no reason why the bag should not be installed while drilling the main hole section. In area where high salt water flows and shallow gas are known a diverter should always be installed and the bag be used until the protective string of casing is run and cemented in place.

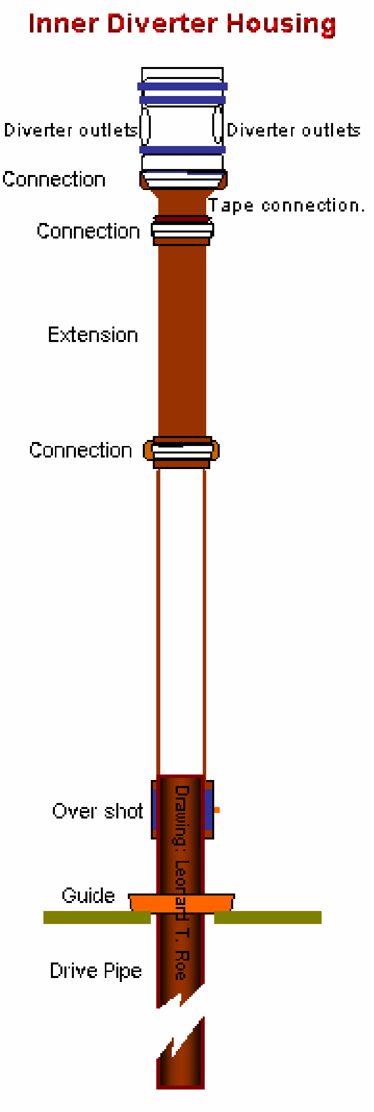
As well as install on surface they can be installed subsea. This allows any diverted gas to be taken away from a floating rig by the current. This is normal a bag type diverter with an outlet incorporated and is installed in the riser system.



For a diverter to be permanently installed into the system, consideration must be given to the to the flow path. The flow path should have at least 4 directions and the line a minimum of 10 inch, 12 would be better. The flow path should have: a line leading to both side of the rig. One to the flow line for normal circulating and branching from it one to the **poorboy degasser**.

It should also have a minimum of 2 operating points with one beside the driller. The second could be in the pusher’s office or in a convenient place outside. The **green arrows** show the fluid path from the flow line up to the poorboy degasser back down into the flow line. This is done by closing of both diverter "**red arrows**" closing the flow line "**orange arrows**" and opening the poorboy line "**green arrows**". Many system are rated for 2000 psi. However 30 inch pipe isn't. Of course the bag and housing have a lot more to them but my artistic talent don't stretch that far.

The design eliminates line disconnections and reconnections at each installation. The diverter assembly is latched into the permanent housing supported by the rotary beams. Permanent attachments to the housing include flow line, vent line, overflow line, and hydraulic function connection.



The diagram you see are drawings from memory of a system installed on some of the offshore rigs I have had the pleasure of working. It is every efficient circulating and diverting system.

The system had 2 control points One beside the driller and one in the toolpusher's office. But there was a third. Install on the accumulator unit.

Companies such as Cameron and Hydril have continued developed the diverter and the BOP systems to cover every situation from surface to submerged bottom mounted stacks, both have excellent and informative website.

There is still a long way to go with this page but drawings take a long time. However if you have something to add I will be more than willing to incorporate it in this page.

I really would like someone that has run a subsea diverter or stack to help out as I have no idea what goes on in that area. This had a slight difference. That being an over ride system that would allow the system to be totally closed in thus enabling stripping operations.

As said before modern diverters are solid. There are few points that have to be taken into consideration.

- If installed as the riser with the BOPs, the bell nipple flange connecting to the annular must be made up tight.
- The overshot pack off must never be closed without pipe inside and the right size overshot must be used.
- Always clean and greases the stump for the overshot is to go over.
- If drilling out a lot of cement or fast soft drilling take a little time to flush out the diverter lines once a day poetically on top hole "this is where you need it most".
- Never ever allow welder to weld around it and drop the rod end on the rotary "Having to pull the inner diverter from the housing with half a ton of old burn of welding rod down the side is a sure way to wreck the block and hook".
- Always clean before installing.

I know this is standard but having to use the rig skidding system to get them apart.

Just a calculation or two:

What size is needed for the diverter lines:
Lets take 20 in. K55, 106 lbs/ft, ID 19 in. burst pressure of 2410 psi. The pipe on top of the drilling string will be 5 OD

The formula for sizing the overboard line being:
SQRT(D^{2}-d^{2}) Ex SQRT(19^{2}-5^{2}) = SQRT(361-25) = 18.33 in.

Often when reading program or calculation you will find only volumes per ft given. I have always been one for working out questions and if I have the answer I like to know the question. If someone give me a volume of .017762 bbl/ft, I would automatically check what is the ID of the pipe. The particular volume here is for a pipe with 4.276 ID but how would you work it out if you did not know:

To find out the ID of a pipe from the capacity in bbl/ft. Use the formula

SQRT(volume in bbl/ft x 1029.41) = SQRT(0.017762 x 1029.41) = 4.276 ID.

Drilling - Well Control

For people that are new to this site I must express a word of warning. Although the site has made every effort to bring the subject of well control to the internet it is unfortunately not recognized by any well control school, drilling contractor or oil company worldwide, Therefore I cannot award a certified certificate of merit and the site cannot be used in job application. However it can prepare you for any surface well control certificate and if you should be so lucky as to live in a country that allow the walk in test you would have know problem passing any surface stack test.

My advice, if you plan for worst, it won't happen. If it should don't try to being the hero, rig hands are not trained to handle dangerous situation. If things turn bad, get the people to safety and secure the area. Good **BOP** and emergency drills with the crews are essential. These drills need to be taken seriously and not just as a paper game to make the home office feel good.

Testing the casing head and blowout equipment, before and while drilling, will ensure that that if a problem is encountered you are in control. Making a trip and swabbing the well has caused many a fire and blowout. Make sure that all of your flow and volume control devices are working and **pay attention to the mud tanks**. Make sure all hands have well control school training but more important they understand well control and know their way around the rig.

The bottom line is: have the rig supervisors trained to give their people confidence in what they are doing in their 'kick' stations. In short, don't take chances with other people lives, sure, it always happens to the other person? To me, you are the other person.

Despite efforts to understand and **control formation pressures**, blowouts still occur. Nearly every well drilled has the potential to blow out. Experience has shown that blowouts occur as the result of human error or mechanical failures. For a well to Kick certain condition must be met. An imbalance between the formation pressure and the hydrostatic head of the fluid column at pressured formation. The formation must have sufficient permeability to allow the formation fluids to flow.

A **blowout** is an uncontrolled flow of formation fluids as the result of failure to control subsurface pressures and can occur at the surface or into a subsurface formation. The important of identifying high formation pressures before drilling, detect pressure changes while drilling, and controlling them safely during drilling or workover operations can never be over stressed.

The key to effective pressure control is in the preparation and vigilance on the part of those who are responsible for drilling and controlling formation pressures. Training, carefully planning and continuously supervised pressure control program will lessen the possibility of a blowout considerably. Respect for formation pressures and the confidence that comes from training and practice in controlling pressures are the elements that minimize the frequency and severity of blowouts.

A second key is understanding: For far to long well control school have approached the subject at the end as appose to the beginning. If better understanding of how formation were formed was taken into account people would find that well control problems can be recognized and anticipated before drilling into them. In this writer opinion school tend to concentrate for to much on the cure as appose to prevention.

To make it easier to understand a short description will be given of some of the terms used. If some things have to be explained in more detail, there will be a link and a link back.

Barrel: a measure of volume for petroleum products in the United States. One barrel is the equivalent of 42 U.S. gallons or 0.15899 cubic meters. One cubic meter equals 6.2897 barrels.

Bottom hole pressure: the pressure at the bottom of a borehole. It is caused by the hydrostatic pressure of the well bore fluid, and sometimes any back-pressure held at the surface, as when the well is shut-in with blowout preventer. When mud is being circulated, bottom hole pressure is the hydrostatic pressure plus the remaining circulating pressure required to move the mud up the annulus.

Blowout preventer: one of several valves installed at the wellhead to prevent the escape of pressure either in the annular space between the casing and drill pipe or in open hole (i.e. hole with no drill pipe) during drilling and completion operations. Blow-out preventer on land rigs are located beneath the rig at the land's surface, on jackups or platform rigs, above the water's surface, and on floating offshore rigs, on the seafloor.

Differential pressure: the difference between two fluid pressures; for example, the difference between the pressure in a reservoir and in a well bore drilled in the reservoir, or between atmospheric pressure at sea level and at 10,000 feet. The term shut in means to close in the well to restrict and control the movement of invading formation fluids.

Kick means. Formation fluid invading the well bore it can be Water, Oil, Gas or a mixture. Blow Out is the invading fluid has entered the well bore and is out of control. This does not necessarily mean the fluid is at the surface. This could happen under ground and is known as an underground blowout.

Hydrostatic pressure: the force exerted by a body of fluid at rest; it increases directly with the density and the depth of the fluid and is expressed in psi or kPa. In drilling, the term refers to the pressure exerted by the drilling fluid in the well bore. In a water-drive field, the term refers to the pressure that may furnish the primary energy for production. This can be found using the formula,
(**density of fluid * true vertical depth * .052**)
note: if you are using this site to study, remember this formula it will crop up a lot.

Permeability: a measure of the ease with which fluids can flow through a porous rock.

Porosity: the ratio of the volume of empty space to the volume of solid rock in a formation, indicating how much fluid a rock holds.

Hydrocarbons: organic compounds of hydrogen and carbon, whose densities, boiling points, and freezing points increase as their molecular weights increase. Although composed of only two elements, hydrocarbons exist in a variety of compounds because of the strong affinity of the carbon atom for other atoms and for itself. The smallest molecules of hydrocarbons are gaseous, the largest are solids. ***Petroleum is a mixture of many different hydrocarbons.***

Formation Pressure. Formation pressure/Pore pressure are said to be Normal if coursed solely by the hydrostatic head of the subsurface water that is contained in the formation and there is a pore to pore pressure communication with the atmosphere.

Normal Formation pressure. is equal to Hydrostatic pressure of water extending from the surface to the subsurface formations. And is derived from the water gradient in that particular area. Gradient of water can be found using the formula,
(Weight of water pounds per Gallon* 0.052)
The same formula is used for all fluid gradients.
Fresh water= 8.33 ppg and is = to1 specific gravity.

Note: the degree of the hydrostatic pressure gradient is influenced by the concentration of dissolved solid and gases in the formation fluid. An increasing the dissolved solids increases the formation pressure gradient on the other hand an increase in formation gasses will decrease the formation pressure gradient.

The point where atmospheric contact may not be established at sea level or rig level **Abnormal Pressures**. As we live in the real world, any thing that is not normal is abnormal. Abnormal pressures can be expected in such conditions as:

Under compaction in shale's. More than 50% of the total volume of uncompressed clay could consist of water when first deposited. At this time, it has a high porosity. Under normal conditions, compaction will give a loss of porosity and water. As the overlaying sediments increases the water is forced out and the pore, spaces within the shale are reduced. The result being that water must be removed before any more compaction can continue.

If for any reason this balance is disrupted such as, slowing down of the fluid being removal at the proper rate the fluid pressure in the shale will increase. The result a higher porosity for the shale in that area.

Pressure: the force that a fluid (liquid or gas) exerts uniformly in all directions within a vessel, pipe, hole in the ground, such as that exerted against the inner wall of a tank or that exerted on the bottom of the well bore by a fluid.

Faults: A fault is where the formation slips it could drop or raise as a result you can have some very strange engagements. A brilliant example of this is in the Zit Bay field in Egypt where 2 rigs can be standing along side each other and both be drilling different formations. Pressure trapped in after the formation move can move a high-pressure zone up some 2-3000 feet and trap the pressure inside the fault or it can move a weak zone down. It is possible that it can do both very close to each other. And if drilling a directional hole can present you with some sleepless night.

Tectonic Causes. A horizontal compacting force in the sub formations. Water would normally be released as it is being compacted. However, if another horizontal compacting formation squeezes the clay laterally and the fluids are not allowed to escape as the rate equal to the reduction in pore volume you will get an increase in formation pressure.

Salt beds: Salt is one of the main culprits when it comes to over pressured formations. Constant deposit of salt over large areas can cause abnormal pressures. It is totally impermeable when it come to fluid you can encounter many types of salt in the same hole. It behaves plastically. Due to this if can deform and flow acting more like a fluid than solid .as it is heavier than water it will exert it pressure in all direction as the fluid in the formations below can not escape. They will in turn become over pressured.

Staying with the salt there is another type that being Diapirism and where salt pushes upward and forms a salt dome disturbing and penetrating the formation above it. This can trap formation fluid due to the folding fault it makes. Much has been said about the mud gradient. How do we test for the formation gradient? (Formation pressure.) A simple test should be run on every new section of the hole.

Reservoir: a subsurface, porous, permeable rock body in which oil and or gas is stored. Most reservoir rocks are limestone, dolomites, sandstones, or a combination of these. The 3 basis types of hydrocarbon reservoirs are oil, gas, and condensate.

The **leak off test**: This test is preformed once the casing shoe has been drilled and should be preformed to the point of rupture and not formation brake down. Meaning the pressure applied should show a small loss and not be pumped away into the formation and completely brake down the formation. The test is simple and well proven. The purpose of such a test is to give basic data needed to use in further fracture calculation and to test the cement bond at the shoe.

The leak off test is not to be confused with an" Integrity test ". Both have a different roll to play but are similar in approach. The Integrity test is a means of finding out if the casing shoe will take the intended maximum mud weight for the next hole section. This is used in proven fields where the formation pressures are known.

The casing shoe is said to be the weakest part of the hole and when a casing string is first drilled out this is true. Once the hole is extended, this test should be run at different intervals. Abnormal pressures change the formation gradient and in some incidents, they will be weaker than at the shoe.

As I have said the leak off test, is an information test and from this we get a lot of useful information. Such as The Maximum Allowable Annular Surface Pressure " MAASP" and the Kick Tolerance and the Maximum Allowable Mud Weight All are critical to a safe drilling operation and should be known at all times. They do tend to confuse some people. Therefore, we will spend a bit of time with them. Before we go onto the Well Control side of things.

Page of information will be compile and added to the well control section. Hopefully by the time the section is finished both you and I will all know what I am talking about.

I would like to bring up a small point before I continue. Many years ago some very helpful and willing people took both the time and trouble to teach me my trade. As time has passed I too have handed on such information to people that have wanted to learn. This has been done freely and willingly. I intend to complete this well control manual and publish it to the internet in the hope that someone reading it will learn and use it effectively. Since starting I have received quite a few letter from schools. Some have asked what qualifications or right I have to teach. To them and only them let me tell you now so as there will be no more confusion as to who has the right.

The manuals you have were written by people that learn there trade long before you started the schools. There is no copyright on well control or it teaching and it is the duty of every experienced hand to teach and train others. Gentlemen you can ether. "Shut up, Put up or what would be a far better idea "JOIN me"" Together we can build on the base of what has already been taught and make our industry a safer place to work.

Drilling - Blowout Preventer (BOP)

When people talk about the **blowout preventer** they will often refer to it as:
a) the Stack
b) the BOP's
c) the BOP, all are the same but there are different type.
d) the BOPE, this stands for Blowout Preventer Equipment

The **BOP system** are a set of valves installed on the wellhead to prevent the escape of pressure either in the annular space between the casing and drill pipe or in open hole (hole with no drill pipe) during drilling, completion and workover operations.

Most **BOP stacks** are designed with a **triple ram configuration** which provides positive protection against blowouts and secures the well in emergencies. This permits work to be carried out under pressure on surface equipment while the pipe is still in the wellbore. The BOP is placed directly above the wellhead.

The BOP closure design consists of a hydraulic actuator assembly connected to each of the two ram assemblies. This allows the rams to be hydraulically compressed around the line from opposite sides which effects a seal thus containing well pressure below the rams.

Older bops would need the **choke and kill lines** on different level or two kill lines so that pressure could be equalized in the event of stripping but now days bops are being designed with this in mind and the pressure across the rams is equalized, through an integral equalizer assembly located between each ram assembly. This takes place prior to hydraulic retraction of the rams and opening of the valve.

This system enables the wellbore pressure to be equalized from the bottom to the top of each ram assembly. Ram assemblies may be interchanged to create different configurations. Manual overrides which operate the rams in case of hydraulic failure are also part of the system with handles. These overrides can also hold the rams mechanically locked in the closed position.

An innovative attribute on the BOP is the plumbing feature. Single point open n close ports in each modular body permit operation of both hydraulic for each set of rams. BOPs are available in nominal sizes 3 1/16" to 30", with w.p. ratings from 5000 - 20000 PSI. They are useable in both **standard n sour environments**.

<u>Standard ram assembly</u> configurations would normally be as such :

1) Pipe seal rams - that serve to seal around the top string isolating the wellbore pressure below the rams
2) Shear/seal rams - that serve to shear the tubing and seal off well pressure
3) Pipe seal rams - that serve to seal around the top string isolating the wellbore pressure below the rams metal seal adapters, in conjunction with O-rings or rubber are used to make a metal to metal seal on the body to body connection. This configuration results in a highly effective seal at both low and high pressures.

The **BOPs** on land rigs are installed beneath the rig floor just above the surface. On Jack-ups, Swamp barges and platform rigs, they are install below the rig floor but above the mean sea level (MSL) both systems are known as **surface stacks**. On floating offshore rigs, they will be installed below the mean sea level, on the seafloor or incorporated into the riser. This system is known as a **subsea stack**.

However no matter where they are installed they all provide the same function. To back up or take over should the primary well control fails. The systems collectively are known as the **secondary well control system**.

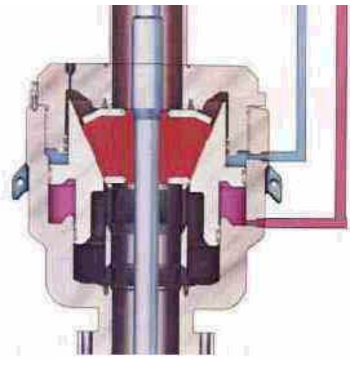
The drawing is a Cameron type U single BOP and could have a rated Cold w.p. from 2000 - 15000 psi and a bore size of 21 1/4" - 7". This particular BOP is design for working on the surface.

The U type comes in 2 forms, the single set of ram and a double set. The double is the same with the only difference that there are two rams one on top of the other with no flange connection between them. The bottom of the signal will be bolted or clamped to the wellhead. Placed on top will normally be a drilling spool and then the double giving 3 sets of rams. On top will be installed an **annular preventer**. The combined system is known as the "**BOP Stack**."

A BOP operate from hydraulic pressure that is accumulates in a **BOP Accumulator unit** that store hydraulic "oil or water" under pressure at 3000 psi. It is then delivered to the BOP having been regulated to an operating pressure of 1500 psi or to the annular at 1000 psi.

The operating fluid pushes a set of pistons inside the bonnet into the open and closed position. Attach to the pistons are a set of rams. The ram can be any size depending on the size of the pipe being used. When the rams are closed they are forced around the pipe and seal off the well from below. We refer to this a "shutting in the well"

The **Annular Preventer** is different in as much as it is designed to close around different sizes of pipe. In this case instead of pushing the seal in and out, it pushes a one piece piston up and down. The rubber insert is pushed up and compressed around the pipe giving an effective seal.



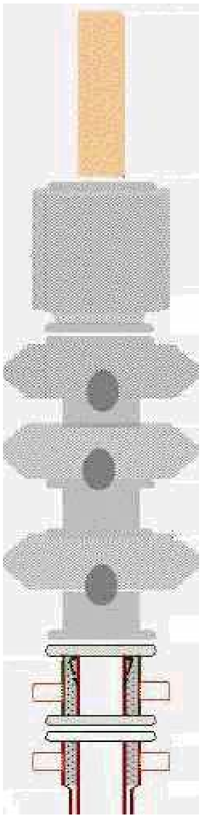
This is a Hydrill GK annular Preventer, designed to be well pressure assisted in maintaining packing unit seal off once initial seal off has been effected. As well pressure further increases, closure is maintained by well pressure alone.

Exceptions are the GK 7-1/16"-15,000 and 20,000 psi which are **not** well pressure assisted and closing pressure must be maintained on the BOP to assure seal off. It must have a minimum closing pressure of 800 psi and is normally set at 1000 psi operating pressure.

As you can see it is designed to close around any pipe as well as the kelly and on open hole. Its flexibility gives it some advantages over fixed ram size. Such as stripping pipe through the rubber without opening the packer.

By bleeding and lowering the operating pressure pipe can be moved in and out of the hole and still keep the well closed in. With the well closed in any invading formation fluid or gas would controlled and directed from the BOP to a choke system by an assortment of attached pressure hose and valves.

On many land and workover operation the stack may only consist of a double bop and annular. However if room permits the stack will consider of 3 sets of ram's and an annular.



The drawing shows a **typical stack arrangement**. Starting from top:

The **bell nipple**: This is connected from the stack to the flow line (not shown) and returns the returning drilling fluid to the tanks.

The **annular preventer**.
Could be Cameron, Hydrill or NL Shaffer

Double set of Bops: These would normally house a set of pipe rams and blind/shear, The pipe ram's should be the size of the top string of pipe in the hole.
Drilling spool, inserted between the two sets of rams There may be an occasion where the pipe may needs to be hung off on the ram's and the well secured and left for a later date.
Single Bop: world normally house a second set of pipe ram's the same size as the pipe in the hole.

Casing head. Below this head will be the last casing string run.

Well head: This is where the well will be built and will remain unless the hole is abandon if this becomes the case it will be cut off.

BOP SAFETY

Any **well control equipment** that is to be install must be rate above the maximum expected formation pressure of the well about to be drilled. **BOPs** and related well control equipment must be tested immediately after installation, and maintained ready for use until drilling operations are completed.

All kill lines, blow down lines, manifolds, and fittings must have a min. w.p. and temperature rating exceeding the max. anticipated surface pressure n temperature.

Blowout prevention equipment must have **manually-operated** position selectors, hydraulic actuating systems and accumulators of sufficient capacity to close all of the hydraulically-operated equipment, and must have a pressure of greater than **1200 psi** remaining on the accumulator.

Dual control stations must be installed with a high-pressure backup system. One control panel must be located at the driller's station and one control panel must be located on the ground at least 50 feet away from the wellhead or rotary table.

Air or other gaseous fluid drilling systems must have blowout prevention assemblies. Assemblies may include a rotating head, a double ram BOP or equivalent, or a blind ram BOP or gate valve.

A proposed blowout prevention program and blowout contingency plan must be available for all to view.

Before drilling below the **conductor casing string**, at least one remotely controlled annular preventer and flow diverter system must be installed. The annular preventer must permit the diversion of geothermal and other fluids.

Before drilling below the surface casings or intermediate or production casings, the blowout prevention equipment must include a minimum of

- One **expansion-type BOP** and accumulator or a rotating head
- Both a manual and a remote-controlled hydraulically-operated **double ram BOP**, or acceptable alternative having a min. w.p. and temperature rating exceeding the max. anticipated surface pressure and temperature
- A **drilling spool** with side outlets, or the equivalent
- A **fill up** line
- A **kill line** equipped with at least one valve
- A **blow down** line equipped with at least two valves and securely anchored at all bends and at the end.
- **Blowout equipment** must be tested or inspected in accordance with the following provisions and the results recorded in the drilling log
- **Ram-type BOP** and auxiliary equipment must be tested to a min. of **3000 psig** or to the w.p. of the casing or assembly, whichever is less. **Expansion-type BOP** must be tested to 70% of the above pressure testing requirements.
- The blowout prevention equipment must be pressure tested when installed

Before drilling out plugs and casing shoes;
Once each week, alternating the control stations; and following repairs that require disconnecting a pressure seal in the assembly.

During drilling operations, blowout prevention equipment must be actuated to test proper functioning as follows:

- Once each trip for blind n pipe rams but not less than once each day for pipe rams; n At least once each week on the drill pipe for expansion-type BOP.
- All flange bolts must be inspected at least weekly and tightened as necessary during drilling operations.
- The auxiliary control systems must be inspected daily to check the mechanical condition and effectiveness.
- Blowout prevention and auxiliary control equipment must be cleaned, inspected and, if necessary, repaired before installation.
- Blowout prevention controls must be plainly labeled. All crew members must be instructed on the function and operation of this equipment.
- A blowout prevention drill must be conducted daily for each drilling crew.
- A drill string safety valve in the open position must be maintained on the rig floor at all times while drilling operations are being conducted. A kelly cock must be installed between the kelly and the swivel.
- Unless the well is secured with BOPs or cement plugs, a member of the drilling crew or the toolpusher must monitor the rig floor from the time drilling operations are initiated and until the well is completed or abandoned.
- Minimum standards for well control equipment.
- A well control device that is installed at the surface must be capable of complete closure of the wellbore and must be closed whenever the well is unattended.

Below you will find the basic or minimum equipment needed:

<u>2M system:</u>

- Annular preventer, or double ram, or 2 rams [one blind and one pipe ram]
- kill line (2 inch minimum)
- 1 kill line valve (2 inch minimum)
- 1 choke line valve
- 2 chokes (refer to diagram in Attachment 1)
- Upper kelly cock valve with handle available
- Safety valve and subs to fit all drill strings in use
- Pressure gauge on choke manifold
- 2 inch minimum choke line
- Fill-up line above the uppermost preventer.
- BOP open and closing lines with a pressure rate above that of the maximum pressure rating of that of the accumulator maximum pressure and to be steel coated.

3M system:

- Annular preventers
- Double ram with blind rams and pipe rams
- Drilling spool, or blowout preventer with 2 side outlets (choke side must be a 3-inch minimum diameter, kill side shall be at least 2-inch diameter)
- Kill line (2 inch minimum)
- A minimum of 2 choke line valves (3 inch minimum) 1 hydraulically operated and controlled from rig floor
- 3 inch diameter choke line
- 2 kill line valves, one of which shall be a check valve (2 inch minimum)
- 2 chokes 1 hydraulically operated and controlled from rig floor
- Pressure gauge on choke manifold
- Upper kelly cock valve with handle available
- Safety valve and subs to fit all drill string connections in use
- All BOP connections subjected to well pressure shall be flanged, welded, or clamped
- Fill-up line above the uppermost preventer.
- BOP open and closing lines with a pressure rate above that of the max. pressure rating of that of the accumulator maximum pressure and to be steel coated.
- Remote choke control on the rig floor

5M system:

- Annular preventer
- Pipe ram, blind ram, and, if conditions warrant, another pipe ram may also be required
- A second pipe ram preventer must be used with a tapered drill string
- Drilling spool, or blowout preventer with 2 side outlets (choke side shall be a 3-inch minimum diameter, kill side shall be at least 2-inch diameter)
- 3 inch diameter choke line
- 2 choke line valves (3 inch minimum) 1 hydraulically operated and controlled from rig floor
- Kill line (2 inch minimum)
- 2 chokes with 1 remotely controlled from rig floor
- 2 kill line valves and a check valve (2 inch minimum)
- Upper kelly cock valve with handle available.
- When the expected pressures approach w.p. of the system, 1 remote kill line tested to stack pressure (which must run to the outer edge of the substructure and be unobstructed)
- Lower kelly cock valve with handle available
- Safety valve (s) and subs to fit all drill string connections in use.
- Inside BOP or float sub available
- Pressure gauge on choke manifold
- All BOP connections subjected to well pressure shall be flanged, welded, or clamped.
- Fill-up line above the uppermost preventer.

- BOP open and closing lines with a pressure rate above that of the max. pressure rating of that of the accumulator maximum pressure and to be steel coated.

10M & 15M system:

- Annular preventer
- 2 pipe rams
- Blind rams
- Drilling spool, or blowout preventer with 2 side outlets (choke side shall be a 3-inch minimum diameter, kill side shall be at least 2-inch diameter)
- 3 inch choke line
- 2 kill line valves (2 inch minimum) and check valve
- Remote kill line (2 inch minimum) shall run to the outer edge of the substructure and be unobstructed
- Manual and hydraulic choke line valve operated and controlled from rig floor (3 inch minimum)
- 3 chokes, 1 being remotely controlled
- Pressure gauge on choke manifold
- Upper kelly cock valve with handle available
- Safety valves and subs to fit all drill string connections in use
- Inside BOP or float sub available
- Wearing ring in casing head
- All BOP connections subjected to well pressure must be flanged, welded, or clamped
- Fill-up line installed above the uppermost preventer.
- BOP open and closing lines with a pressure rate above that of the maximum pressure rating of that of the accumulator maximum pressure and to be steel coated.

If a repair or replacement of the BOP is required after testing, the work must be performed prior to drilling out the casing shoe.

When the BOP cannot function to secure the hole, the hole has to be secured using cement, retrievable packer or a bridge plug packer, or other acceptable approved method to assure safe well conditions.

Minimum standards for choke manifold equipment.

- All choke lines shall be straight lines unless turns use tee blocks or are targeted with running tees, and must be anchored to prevent whip and reduce vibration.
- Choke manifold equipment configuration must be functionally. The configuration of the chokes may vary.
- All valves (except chokes) in the kill line choke manifold, and choke line must be of a type that does not restrict the flow (full opening) and that allows a straight through flow.
- Pressure gauges in the well control system shall be a type designed for drilling fluid service

Minimum standards for pressure accumulator system.

- **2M system** accumulator must have sufficient capacity to close all BOP's and retain 200 psi above pre-charge. Nitrogen bottles that meet manufacturer's specifications.

- **3M system** accumulator must have sufficient capacity to open the hydraulically-controlled choke line valve (if installed), close all rams plus the annual preventer, and retain a minimum of 200 psi above pre-charge on the closing manifold without the use of the closing pumps. "This is a minimum requirement." The fluid reservoir capacity must be double the usable fluid volume of the accumulator system capacity and the fluid level to be maintained at the manufacturer's recommendations. The system must have 2 independent power sources to close the preventers. Nitrogen bottles (3 minimum) may be 1 of the independent power sources and, if so, shall maintain a charge equal to the manufacturer's specifications.

- **5M and higher system** accumulator must have sufficient capacity to open the hydraulically-controlled gate valve (if installed) and close all rams plus the annular preventer (for 3 ram systems add a 50% safety factor to compensate for any fluid loss in the control system or preventers) and retain a minimum pressure of 200 psi above pre-charge on the closing manifold without use of the closing unit pumps. The fluid reservoir capacity shall be double the usable fluid volume of the accumulator system capacity and the fluid level of the reservoir must be maintained at the manufacturer's recommendations. Two independent sources of power must be available for powering the closing unit pumps.

- Sufficient nitrogen bottles are suitable as a backup power source only, and must be recharged when the pressure falls below manufacturer's specifications.

Minimum standards for accumulator pre-charge pressure test.

This test shall be conducted prior to connecting the closing unit to the BOP stack and at least once every 6 months. The accumulator pressure must be corrected if the measured pre charge pressure is found to be above or below the maximum or minimum limit specified below (only nitrogen gas may be used to pre-charge):

Accumulator w.p. rating	Min. acceptable operating pressure	Desired pre-charge pressure	Max. acceptable pre-charge pressure	Min. acceptable pre-charge pressure
1,500 psi	1,500 psi	750 psi	800 psi	700 psi
2,000 psi	2,000 psi	1,000 psi	1,100 psi	900 psi
3,000 psi	3,000 psi	1,000 psi	1,100 psi	900 psi

Minimum standards for power availability.

Power for the closing unit pumps must be available to the unit at all times so that the pumps will automatically start when the closing valve manifold pressure has decreased to the pre-set level.

Minimum standards for accumulator pump capacity.

Each BOP closing unit must be equipped with a sufficient number and sizes of pumps so that, with the accumulator system isolated from service, the pumps will be capable of opening the hydraulically-operated gate valve (if equipped), plus closing the annular preventer on the smallest size drill pipe in use, and maintained a minimum of 200 psi above specified accumulator pre-charge pressure.

See well control accumulator system for more details on pump sizing.

Minimum standards and provisions for locking devices.

A manual locking device (i.e., hand wheels) or automatic locking devices must be installed on all systems of 2M or greater.
A valve should be installed in the closing line as close as possible to the annular preventer to act as a locking device.
This valve must be maintained in the open position and closed only when the power source for the accumulator system is inoperative.

Minimum standards provisions for remote controls.

Remote controls shall be readily accessible to the driller.
Remote controls for all 3M or greater systems shall be capable of closing all preventers.
Remote controls for 5M or greater systems shall be capable of both opening and closing all preventers.
Master controls must be at the accumulator and must be capable of opening and closing all preventers and the choke line valve (if so equipped).
No remote control for a 2M system is required.
A second remote control should be installed within or just beside the toolpusher office and should be function tested along with all other test

Min. standards and enforcement provisions for well control equipment testing.

All tests described below should be performed using clear water or an appropriate clear liquid for subfreezing temperatures with a viscosity similar to water.

Ram type preventers and associated equipment must be tested to approved stack working pressure if isolated by a test plug or to 80 percent of internal yield pressure of casing if BOP stack is not isolated from casing. I.E "test cup".

Pressure should be maintained for at least 15 minutes or until requirements of test are met, whichever is longer. If a test plug is utilized, no bleed-off of pressure is acceptable.

For a test not utilizing a test plug, if a decline in pressure of more than 10 percent in 30 minutes occurs, the test must be considered to have failed. The valves on casing head below test plug must be open during test of BOP stack.

Annular type preventers must be tested to 60 percent of rated working pressure. Pressure Must be maintained at least 15 minutes or until provisions of test are met, whichever is longer.

As a minimum, a test should be performed:

A. When initially installed:
B. Whenever any seal subject to test pressure is broken:
C. Following related repairs:
D. At 14-day intervals:
E. Before any drill stem testing unless recently tested

<u>Drilling- Choke n Kill</u>

When a well kick
It is closed in, after evaluation the well will be killed, this process can take several forms most involve the use of a **<u>choke</u>, some form of throttle**. The drawing features a dual chokes, one adjustable and one positive, to help maintain a constant flow rate, which controls the pressure at the bottom of the hole "Bottom Hole Pressure".

A third feature is a straight through by pass enabling the flow to go directly to the sump a safety feature no manifold should be without Chokes are throttling valves that allow operators to control the well stream. They are capable of withstanding erosion resulting from the very high velocities occurring at and immediately downstream from the orifice.

Choke Manifold allows operators to limit erosion to the replaceable parts within the choke. Direct flows to different areas of the rig. Redirect flow should for some unforeseen reason repair need to be made during the kill. There is really no standard drilling choke. It is very much dependent on where you work and for who.

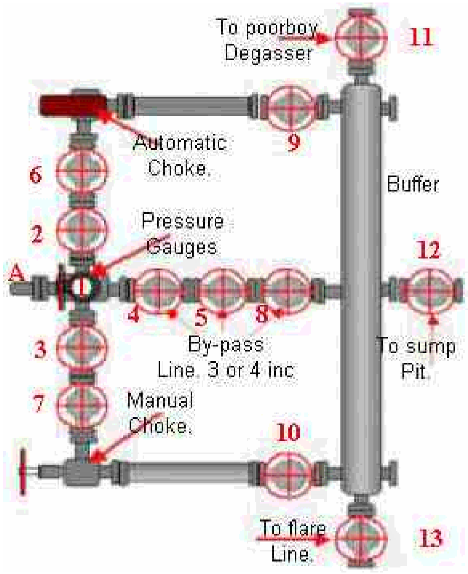
Ideally the choke should be as close to the drilling console as possible. Should this not be possible a remote control and an automatic choke should be part of the standard equipment list. The basic standard drilling choke manifold should be design with a full-bore flow path through the manifold, allowing total bypass of the choke control.

On one side of the bypass, an adjustable choke allows more flexible control for well, on the other side is a positive choke to give more accurate flow. By using the valves and choke, the operator can change the choke without having to stop the operation.

Pressure gauges from both the standpipe manifold and the choke should be connected to the remote and be independent line. Both a low and high pressure gauge should be used on the choke. Part of the training drills should include the lining up of the choke circulating system. This is more apparent on land where the choke can be up to 50 feet from the rig and the driller may have to walk away from the control panel to see what is going on.

Over the past 6 years or so I have worked with only local crew members. During that time we have had to kill well with over 7500 psi closed in. Had they not been constantly trained it is very possible rigs and people would have been lost.

Most toolpusher do a daily walk around. Several checks are made, Drill Line, Mud Pits, Pumps, Mud Shakers and the likes. The remote control should be included along with several valves. Not forgetting the valves on the BOPs.



The drilling choke can be split into two section.

Down Stream Side "high Pressure" up to and including the chokes.
Up Stream the back side from the choke.

All Valves up to and including the choke must be tested to the same pressure rating as the BOPs.

The choke you see here is about as basic as you can get but is very capable of doing the job.

Before Testing, all line should be wash and cleaned out. Once finished the valves should be left in the open position.

Test (1), The fluid enters at point "A", this would normally be the manifold and is a 4 valve test. Valves 1-2 -3 -4 .

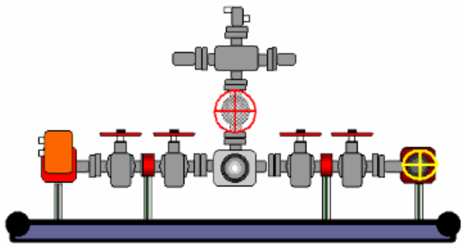
Test (2), 5-6-7

Test (3), Valve 8 - Automatic choke-Manual Choke.
Remember to function test the chokes.

Test (4), 8- 9-10

All the above test are at the same rating as done for the BOPs as 9-10 may be used to back up the choke.

Skid mounted basic choke [*drawings copyright of Leonard T. Roe*]



We now come to the buffer chamber. I personally like to see this tested to the same rate as the BOP or 80% of its cold working pressure. An important point to remember is one line will lead to the poor boy degasser and very few of them have a pressure rate above 2000 psi.

Should you have lines leading from the backside be sure they are anchored down. 400 psi coming from the end of 300 feet of 2 7/8 will make a hell of a mess of someone if it hits them.

After any kill, flush out all the lines. If working on land and you move often move with the valves closed. As said before the training of the people is of the utmost don't just think of it as the assistant drillers job, the floor crew are just as important having 3 valves moving at one time on a high pressure kick can be a life saver. A weekly supervised check on all valve is essential as is the maintenance.

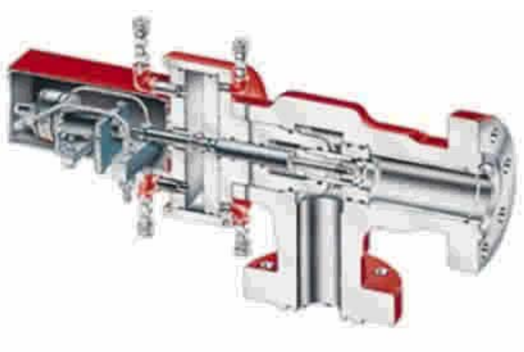
Pressure gauges are often a problem. The answer to this is to make full use of the J2 transmitter. I have found this to be far more superior in most ways and would certainly recommend them.

Over the years I have been approached by people that feel they can use the drilling choke as a testing choke. This cost cutting on well testing has been forced onto drilling contractor due to condition prevailing in the race to keep rigs working. A drilling choke is design for the purpose of well control and is not a testing choke. Such corner cutting should be avoided at all cost as it only leads to other short cuts such as using the kelly valve as part of the test tree.

I have took the liberty of borrowing some of the needed information from the Cameron web site. They have an excellent web site and online training section. To see more of the web site click on the Cameron Logo or go to my "Yahoo" oil industry links at Yahoo. I would like to point out that Cameron are not responsible for anything I say on this web site and any complaints should be directed at me.

For people wishing to find information on oil and drilling companies "Yahoo" has one the best data base on the net work and I can save a lot of time by logging into it direct. However I must point out that is their data base and not mine. I just know where it is ? As said I will leave no stone unturned to get the information needed to trainee our people even if a few rules need to be bent a little.

Hydraulically Actuated Drilling Choke



Hydraulically Actuated Drilling Choke

Cameron hydraulically actuated drilling chokes are available in working pressure rated from 5000 to 20,000 psi with inlet and outlet flange sizes from 3-1/16" to 4-1/16".

The standard orifice size is 1-3/4". Other sizes are available All parts rated suitable for H2S and 250 deg F service. The cylindrical gate and large body cavity provide high flow capacity and quiet operation.

The gate and seat can be replaced or reversed without removing the choke from the manifold. The fluid enters the choke from the below, the gate is adjusted so just the right amount of fluid is release. This would be kept up until such time as the kill fluid is ready. Once ready the well would be open up. The choke would then be used control the discharge and hold a back pressure until the invading fluid is out.

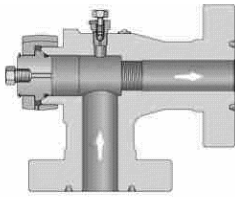
There are 2 types of choke used in drilling, the Hydraulically Actuated Drilling Choke and the manually actuated drilling choke

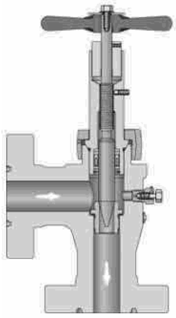
Manually Actuated Drilling Choke

Cameron manually actuated drilling chokes are available in working pressures from 5000 to 20,000 psi with inlet and outlet flange sizes from 3-1/16" to 4-1//6". The standard orifice size is 1-3/4". Other sizes, end connections and high temperature trim are available on request. All parts are rated suitable for H2S and 250 deg F service. Thrust bearings in the actuator provide low torque hand wheel operation.

The Cameron H2 is a multi-purpose needle and seat choke that handles standard, erosive and corrosive service with pressure ratings up to 10,000 psi.
Three configurations are available: positive choke (fixed flow); adjustable choke (variable flow rate); and PAC (positive/adjustable choke).

The PAC feature allows conversion to an adjustable choke for bringing a well on slowly. It can then be returned to positive operation when a fixed flow bean is desired.





The forged body Cameron H2I positive and adjustable chokes accept the same beans and seats as the H2 choke. However, the bean/seat is recessed in the body below the inlet flow path to extend the life of the H2I. Each H2I body is equipped with a port for monitoring or venting pressure. Bonnet and body connection threads are designed for easy access for cleaning and maintenance.

A bleed screw allows pressure to be vented so the bonnet can be safely removed. The bleed screw assembly uses metal-to-metal seals. The gland and replaceable metal seal protect the choke body threads from wear.

The H2 n H2I are designed n manufactured in accordance with API 6A, 17th Edition.

J-2 Pressure Transmitter

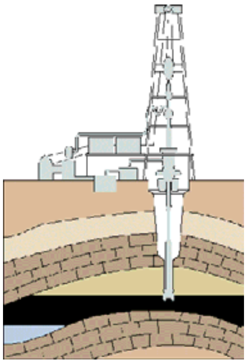
J-2 Pressure Transmitter

J-2 step-down pressure transmitters, normally located on the standpipe and the choke manifold, convert actual mud pressure to a low pressure pneumatic signal. These signals are transmitted through hoses to the control console where pressure readings are registered on the panel gauges.
J-2 is a hydraulic transmitter working at 300 psi

Drilling - Equipment n Systems

On a drill rig, there are many different pieces of equipment and systems. Maybe the biggest piece is the **derrick**, that sticks up into the air, made of metal n about 50 m tall. As a derrick mainly to support all other equipment that is needed for drilling. Up the top of a derrick, is the **crown block**. Hanging down is the **travelling block**. Part of the travelling block's job is to put weight onto the drill to force it down into the earth.

Another of the main systems on a drill rig is the **hoisting system**. This raises and lowers the **drill pipe**, the long pieces of piping that reach into the ground. On the rig floor is a **winch**, known as the **drawworks**.



A wire rope is attached to this and runs up the derrick, over the crown block at the top and down to the travelling block. It is then attached to the drill pipe. The drawworks work a bit like a fishing rod, raising and lowering the drill pipe and most other things down the hole.

In the drill floor is a **rotary table**, attached to the travelling block. This is what changes the speed and the direction of the drill. In between the rotary table and the drill pipe is the **kelly**. This is a square pipe, and transfers any motion that the rotary table creates to the actual drill pipe.

The piece that is closest to the actual work is the **drill bit**. There are two types of drill bits called Rolling Cutter (or tri-cone) bits and PDC (or diamond) bits.

Rolling Cutter bits have got hard steel 'teeth' on them, that are attached to 3 roller cones. The teeth come in different sizes on different bits, and the distance between each tooth on one bit may be different to the distance on another bit. Generally, the softer the formation that is going to be drilled into, the longer, and the wider spaced the teeth are, and the more offset the cones are. Rolling Cutter bits are designed for a maximum cut rate without clogging up the hole.

Diamond bits do actually have diamonds on them. They are known as 'industrial' diamonds, because they weren't considered good enough to be used in jewellery. These are imbedded into the bit. These bits can be used when drilling through very hard formations, and have more of a grinding action than the rolling cutter bits. They also last for longer. PDC bits use a kind of synthetic diamond, but work pretty much the same way. However, diamond bits are very expensive.

These drill bits come in different sizes. This is because a hole is drilled so that it gets narrower as it gets deeper. To make a hole narrower, you need a smaller drill bit. This you need to have lots of different drill bits, and each one, is very expensive. The bit is attached to the end of a drill pipe, which is rotated by the turntable. The deeper the bit goes, the more pipe is needed. Workers on the surface add new bits to the top of the disappearing pipe. Each is about 9m long.

Drill bits get blunter and less effective the more they drill or, sometimes, the drilling operators find that a different type of bit is needed. When this happens, all piping needs to be pulled out of the hole to get to the drill bit. It is stacked up inside the derrick, as it comes out. Changing the bit may take 24 hours.

Casing needs to be put into the hole before drilling can continue with confidence. Casing also comes in different sizes, or diameters, which is the distance across the open end. This is so that the lengths of casing fit into the hole, which gets smaller all the time.

Casing helps to hold the hole open in response to pressure in the surrounding rock and lowers the chance of cave-ins and leaks. Casing is heavy steel piping which is installed at certain stages of drilling. The drilling pipe is removed, and the casing lowered down the hole.

Then **wet cement** is pumped down the hole. A plug is put on top of this, and then a special type of mud called **drilling mud** is pumped down the hole. The weight of the mud pushes the plug down, forcing the cement into the **annulus**, the space between the wall of the well and the casing. This process is repeated until the well has been drilled to the zone of interest. The zone of interest is where other methods of exploration have suggested that there is oil.

The **drilling mud** that is pumped into the hole to force the cement into the annulus has normally very dense and heavy compound, barium sulphate, in it to make the actual mud heavier. This mud provides a pressure on the inside of the casing while drilling, and helps to stop cave-ins. If the mud is not dense enough, however, fluids from the rocks around the well can enter the well, and might cause the well to kind of 'explode'. To help prevent this, the density of the mud is controlled.

This drilling mud also carries bits of rock that have been loosened by the drill bit to the surface, keeping the hole clean and clear for drilling. It also cools the bit to keep it from over-heating. A drill bit can easily overheat because of friction between it and the earth. This is using friction between the surfaces of your hands to make them warmer. It is the same thing working between the drill bit and the soil.

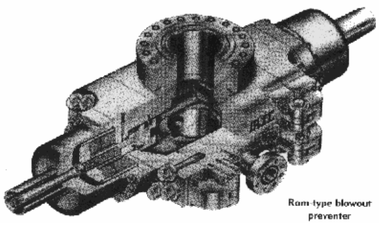
Apart from cooling the bit down, drilling mud does two other things. It lubricates the drill string, and coats the wall of the hole. By coating the wall, it helps to hold it together so that it doesn't collapse before the next bit of casing is put in.

The mud is pumped through a **closed system**, which means that no new mud comes in to the circuit that it runs through, and that all the mud is 'recycled'. It is pumped down the hole, back to the surface, through purifying machines and back down the hole again. These purifying machines clean the mud and take any impurities, such as rock cuttings, out of it so that it can be used again.

First, the mud passes over a vibrating screen known as a **shale shaker**, which separates the cuttings from the mud. Next, it is cleaned by **de-sanders** and **de-pitters**, and then runs through various pumps and lines and down the drill pipe. It then comes out through the jets in the drill bit, cleaning the bit as it goes, and back up to the top of the hole.

Because it is a closed system, there should never be an increase or a decrease in the amount of mud circulating at any one time. If there is more or less, it means that mud is disappearing into the rocks around the well and there is a leak, or that more fluid is coming out of the rocks and into the hole and to the surface.

The amount of mud is monitored and, if more mud is coming out, alarms are set off. This is mainly because it indicates a **high pressure** at the bottom of the well, and a blow-out, or an explosion, may occur. If there is less mud, then there is probably a leak somewhere in the system. This too could signal problems.



These problems can be overcome by installing blow-out preventers in the hole. **Blow-out Preventers** [**BOP**] are a set of big valves that sit at various places in the hole. At the top of the hole is an **Annular Preventer**. This has a piece of rubber in the middle that seals around the drill pipe passing through it.

Another type of **BOP** is **Ram Type Preventer**. These come in different sizes, to seal around the different sizes of **casing**. Some are 12m high and can weigh 200 tonnes.

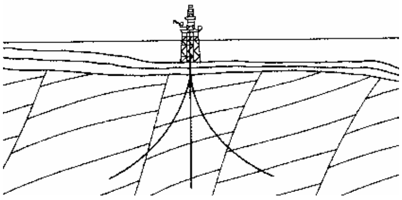
BOP's are open during drilling and can be closed when a blow out is suspected, like when there is more mud coming out of the drill hole than should be. BOP's are needed because, sometimes when drilling, the drill bit goes into new type of rock, or different reservoir, that may have liquid or gas inside that is at a very high pressure.

A **reservoir** is a bit like a bottle of soft drink. The oil, gas or water is trapped inside, just waiting for a chance to escape. When the drill bit goes into it, it is like suddenly taking the lid off the bottle. The contents can spray everywhere. This is because it has been under pressure, and wants to escape so that it can take up more space. If it comes into the well hole really fast, it may cause an explosion, with rocks, lengths of drill pipe and mud being thrown out of the hole.

This can be very dangerous to anyone near the hole, and a blow-out can also damage the environment. A **BOP** is like putting the lid back on the bottle, and stopping everything in the well shaft from flying out. The BOP then slowly lets the gases and liquids from the rock to flow out of the hole. This way it is controlled. Because BOPs are so important for safety and environmental reasons, they are checked every day to make sure that they work.

Rocks and soil are of different hardness, so it takes longer to cut through some than others. Sometimes a drill bit can cut through 60 m in an hour, but other times it may be struggling to get through 30cm, or the length of a ruler, in one hour. To make drilling a bit faster, you can add extra weight onto the drill. There are heavy metal tubes, known as drill collars that sit just above the drill bit. They sit here, and not at the top, so that the drill pipe doesn't wobble as much.

Directional Drilling



To make a hole drilled to the side is fairly difficult. You can get some drill bits that only munch away on one side, which makes the hole go in a certain direction. Sometimes a drill pipe with a bend on it is fitted to the bit, which makes the drill bit face in a direction other than down, and it drills in this direction. Another way to make a hole 'crooked' is to use a bent sub and mud motor down the well.

Top Drives System

Since 1990 several Top Drives have been developed:
Electrical 1 speed, 2 speed, 2 motors – AC or DC, and various types of hydraulically driven machines.
The Top Drive Systems:
Combine controlled rotation with pipe handling. Perform all normal operations such as Tripping, Running casing n Drilling
Top drive from 600 to 2300HP, Rating from 350 to 1000 tons

They are available for both offshore and land market applications. Both the AC and DC together with the hydraulic drive will be available for most of the range.

Hydraulic Roughnecks

The hydraulic roughneck is a machine designed to make-up and break-out drill pipe and drill collars in the well centre or at the **mousehole**. The gateless torque wrench features multi-size jaws allowing intervention free connections for all tubular sizes.
Range: 27/8” DP through 11 1/4”DC.

They are delivered with local controls, remote controls or fully automated. Also available in a compact version for land rigs. Independent elevation of drill pipe spinner available.

Active Heave Compensation For Top-Mounted n In-Line Compensator

The Maritime Hydraulics Active Heave Compensator System is based on installing an Active Compensator Cylinder into the existing passive In-Line and Crown mounted Compensator system.
An advanced heave motion sensor and a compensator position sensor provide input signals to the control system of the Active cylinder.
Compensating Load: 1000lb to 1.000.000lb – 25ft stroke.

Drilling - Kelly Valves

Kelly Valves are manually operated high-pressure safety valves. They provide positive sealing for upward and downward pressures and are used for multiple applications. Kelly Valves are installed e.g. in drill stems or tubing strings. Often used as an **inside BOP** and would be installed in the open position.

The Valve will than be closed to shut in any flow. If the flow starts while the rig is tripping a grey type inside BOP would be installed above it. The valve would then be opened and the pipe stripped back to bottom.

Operation

The valve is operated by use of a standard hexagon wrench. The open and closed position of the ball plug are accurately determined by means of stops at the plug itself which ensure maximum safety.

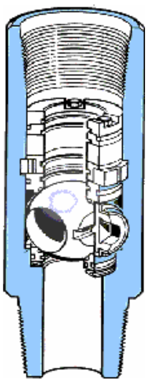
Maintenance

The simple design of the Kelly Valve permits easy maintenance and quick spare replacement recommends service intervals to be 6 months under normal drilling conditions.
Al thought easy to maintain if left for to long without overhaul the can be hard work. Part of the repair kit is a small puller as sometimes the body is hard to remove.

Design

All Kelly Valves are engineered for pressure ratings up to 15000 psi w.p.
Kelly Valves are economical, easy to handle and after a long service period spare part kits are provided for a new life.

Features



- The superior floating ball valve design with a full open bore n 2-seat sealing system has been successfully approved for drilling n production.
- 2 independent seals provide high reliability. Bubble tight sealing up to maximum pressure is achieved by hard faced metallic seats with soft seal back-up.
- The valves are internally and externally flushable, and available with various types of connections.
- High strength material body. Threads are cold rolled n phosphated. Internal parts are made of corrosion resistant stainless steel.
- Final pressure tests are carried out according to API Spec. 7, Section 2 or as to customers' request.
- An Independent Design Review Certificate has been issued by the German TÜV for the Standard Kelly Valves, after extensive finite element analysis (FEM) has been carried out.

Special Applications

Top-Drive Valves are available on customers request. Kelly Valves can be the supplied for Service in H2S environment acc. to NACE MR 0175.

Drilling - Mud Wiper

The Drill Pipe Cleaning Tool
Haggard ID Wiper, Inc
www.offshore-technology.com/contractors/drilling/hag/index.html

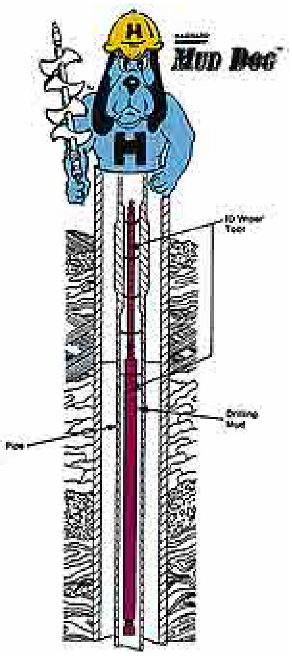
The **MUD DOG wiper** will do the dirty work while tripping drill pipe, keeping the mud in the well bore instead of the rig floor and racking area (messy stuff to work in).

Time spent cleaning the rig floor and racking area = BIG BUCKS. Mud saved with the MUD DOG wiper is estimated to be 1 barrel per 10000' of pipe pulled from the well bore. Thixotropic properties of the mud and pipe size govern amount of mud being saved by the well bore cuts clean up cost.

Not to worry should a kick require pumping the MUD DOG wiper down hole to control well, the float chamber will not collapse, due to safety shear plug equalizing the pressure of the pump and hydrostatic.
(*Poacher Supplied Tool Will Collapse And Do Strange Things).*

Let the MUD DOG wiper maintain a clean dry work area for the rig crews and enhance the safety program. Better working conditions makes for better crews.

Specific Advantages Of Mud Dog ID Wiper



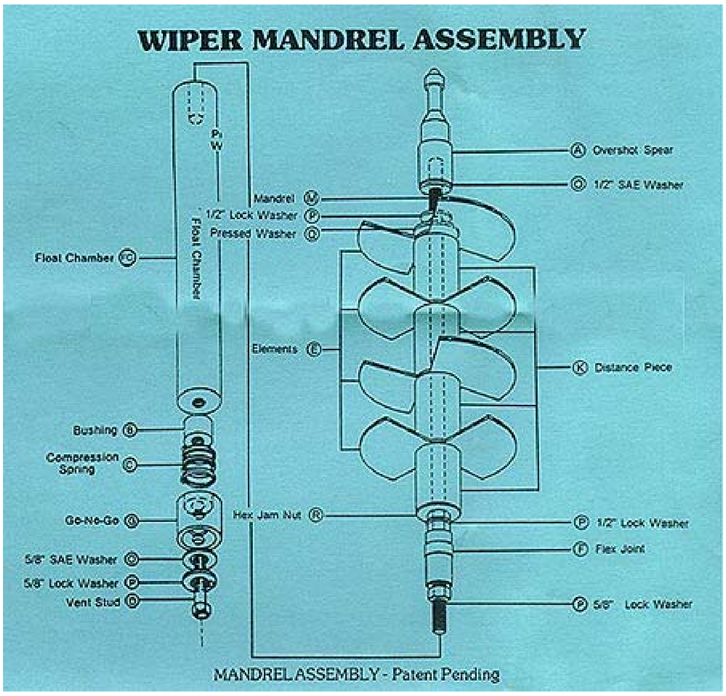
Keeps mud in well bore, resulting in clean rig floors

Cleans up time converted to trip time reduction = BIG BUCKS

Crew comfort = morale builder

Reduces or eliminates ice plugs in tool joints; winder operations, ice in pin-threads of tool joint; clean tool joints reduces the need for excessive pipe dope.

PUMP DOWN SAFE, buoyancy chamber will not collapse if pumped to bit. Shear plug will equalize pressure in float chamber with 150 psi application.


WIPER MANDREL ASSEMBLY
Float Chamber FC
Float Chamber
Mandrel M
1/2" Lock Washer P
Pressed Washer Q
Elements E
Bushing B
Compression Spring C
Go-No-Go G
5/8" SAE Washer O
5/8" Lock Washer P
Vent Stud D
Hex Jam Nut R
A Overshot Spear
O 1/2" SAE Washer
K Distance Piece
P 1/2" Lock Washer
F Flex Joint
P 5/8" Lock Washer
MANDREL ASSEMBLY - Patent Pending

Drilling - Gas Cut Mud

Gas cut mud is the term used when the mud contains a percentage of gas in the form of small bubbles when it returns to the surface. Generally, gas cut mud does not decrease the hydrostatic pressure so much as to cause under balance/kick situations. This is because the gas content in the mud is mostly compressed, except very close to the surface.

Every atmosphere (14.7 psi) reduces the gas volume by half. Therefore, the mud weight considerably reduces the volume of the gas. If the volume of the gas in mud is very small, the reduction in bottom hole pressure will also be very small.

It is very important to understand that the gas expanding as it nears the immediate surface causes almost all the bottom hole pressure reduction. Drilling fluid must be check at both the suction pit and the returning flow-line. Although there will be a slight volume gain due to gas cut mud the possibility of it being notice are sight.

Where it will be noted is the return flow line Flow line mud weight can be very low in some cases. Just how much the cut mud will affect the bottom hole pressure created by the mud column will be explained in this page - Causes of Gas Cut Mud:

Gas cut mud can occur because of 3 reasons:

1. When a gas bearing formation is penetrated the cuttings will always release an amount of gas into the mud. This will be the first gas to register at the surface and is a positive indication that a gas bearing formation has been penetrated. This type of gas will not cause a mud weight reduction, but if there is any doubt, pick up the kelly out of the preventer, shut down the mud pumps and check for flow.

2. Some formations, with a very low permeability, have a pore pressure that is bigger than the hydrostatic pressure from the mud column. As long as the mud is circulated, there is a small overbalance in the well due to pressure loss in the annulus. When circulation is stopped a small under balance will occur and this causes varying amounts of gas to intrude into the well bore. This often occurs when the pumps are shut down during a connection, or during a trip, such conditions are respectively called Trip Gas and Connection Gas.

3. The third cause of gas cut mud can be a washout (hole) in the well bore. This washout, or cavity, acts as a trap for old gas cut mud that is picked up by the mud at a later time and transported to the surface.

Reduction Caused by Gas Cut Mud

Reduction of bottom hole pressure, caused by gas cut mud, can be calculated by using the following formula:

$P = 2.3 * N * LOG\ P_1$

P = Reduction in pressure in physical atmospheres where 1 physical atmosphere
1atm = 14.7 psi
P_1= Bottom hole pressure in physical atmospheres.
N = Difference between gas and mud at the surface, See calculation
N = (MWA - MWC) / MWC
MWA = original mud weight in ppg.
MWC = weight of gas cut mud in ppg.

Example
Well depth 12,000-ft Mud weight 14 ppg. cut to 7 ppg.

P1 = (12000*0.052*14)/14.7 = 594 atm
log 594 = 2.77
N = 14 - 7/7 = 1

P = 2.3*N*log 594 = 2.3*1*2.77 = 6.37atm =94 psi

The pressure in the well (bottom hole) is, therefore, reduced by 94 psi which answers to change in mud weight of 0.15 ppg. A more practical and precise method for calculating bottom hole pressure reduction is reached by using the volumetric method. The volumetric method is used in the following way.

The volume of gas cut which has flowed back into the mud tanks is measured This figure can be used to calculate the change in hydrostatic pressure in psi/bbl units by the following formula:

$$P = \frac{\text{Pit Volume}}{AV} * (0.052 * MWA)$$

P = reduction in bottom hole pressure in psi (because of gas cutting)
Pit Vol = Volume increase of mud in mud tanks (because of gas cutting) in bbls
AV = Capacity for annulus in top of well bore bbl/ft.
MWA = Mud weight in ppg.

Sum-up.
Example shows that even with a flow line weight reduction of 50% through gas cutting, bottom hole pressure is not seriously affected in that the pressure change is less than the change caused through pressure loss in the annulus.

Although pressure reductions from gas cut seldom cause under balances, there are other factors that can lead to dangerous situations.

Foremost, gas cut mud is an indication of (possible) low mud weights and pump effectiveness can be seriously reduced by gas cut mud.

If mud becomes seriously gas cut, the pump output is seriously decreased, which leads to a following fall in annulus pressure, a fall in bottom hole pressure and, therefore, risk of influx and blow-out.

If is, therefore, most important that gas cut mud is de-gassed (gas content extracted) before it is pumped down hole.

Over reaction:
It may be that the most common fault in connection with gas cut mud is the tendency to maintain the original mud weight with barite, without removing all the gas from the mud.

When a moderate gas cutting gives a relatively small change in hydrostatic pressure, it is possible that addition of barite to increase mud weight can lead, in extreme cases, to lost circulation.

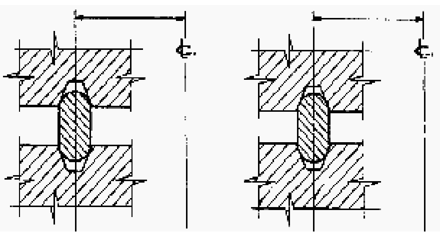
Drilling - RTJ Gasket

Ring Type Joint Gasket Design

API Type "R" Ring Joint
API Type "RX"
API Type "BX"
API Face-to-Face Type "RX"

"RX" Pressure-Energized Ring Joint Groove
Cameron Type "AX" Pressure-Energized Ring Joint Gasket
Cameron Type "CX" Pressure-Energized Ring Joint Gasket
Application of Type "AX" and "CX" Pressure-Energized Ring Joint Gaskets

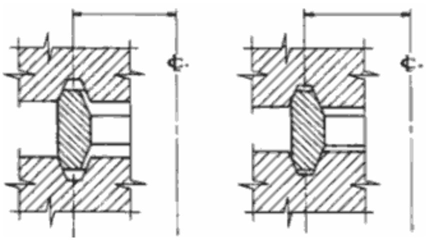
The type "R" ring joint gasket is not energized by internal pressure.



Sealing takes place along small bands of contact between the grooves and the gasket, on both the OD and ID of the gasket. The gasket may be either octagonal or oval in cross section.

The type "R" design does not allow face-to-face contact between the hubs or flanges, so external loads are transmitted through the sealing surfaces of the ring. Vibration and external loads may cause the small bands of contact between the ring and the ring grooves to deform plastically, so that the joint may develop a leak unless the flange bolting is periodically tightened. Standard procedure with type "R" joints in the BOP stacks is to tighten the flange bolting weekly.

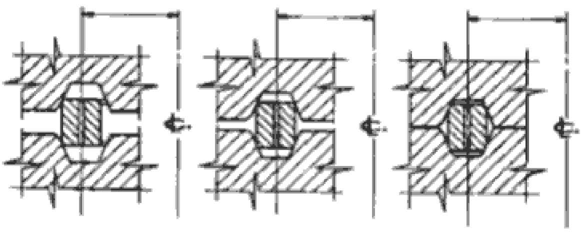
The "RX" pressure-energized gasket developed by Cameron n adopted by API.



Sealing takes place along small bands of contact between the grooves and the OD of the gasket. The gasket is made slightly larger in diameter than the grooves, and is compressed slightly to achieve initial sealing as the joint is tightened.

The "RX" design does not allow face-to-face contact between the hubs or flanges. However, the gasket has large load-bearing surfaces on its inside diameter to transmit external loads without plastic deformation of the sealing surfaces of the gasket. Cameron recommends that a new gasket be used each time the joint is made up.

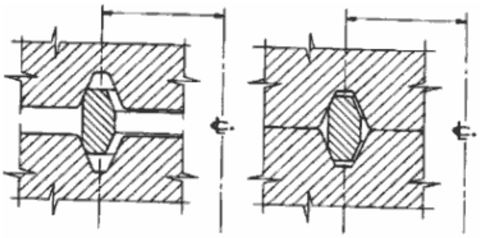
The "BX" pressure-energized ring joint gasket



The gasket was designed for face-to-face contact of the hubs or flanges. Sealing takes place along small bands of contact between the grooves and the OD of the gasket. The gasket is made slightly larger in diameter than the grooves, and is compressed slightly to achieve initial sealing as the joint is tightened. Although the intent of the "BX" design was face-to-face contact between the hubs or flanges, the groove and gasket tolerances, which are adopted, are such that, if the ring dimension is on the high side of the tolerance range and the groove dimension is on the low side of the tolerance range, face-to-face contact may be very difficult to achieve.

Without face-to-face contact, vibration and external loads can cause plastic deformation of the ring, eventually resulting in leaks. Both flanged and clamp hub "BX" joints are equally prone to this difficulty. The "BX" gasket is frequently manufactured with axial holes to ensure pressure balance, since both the ID and the OD of the gasket may contact the grooves.

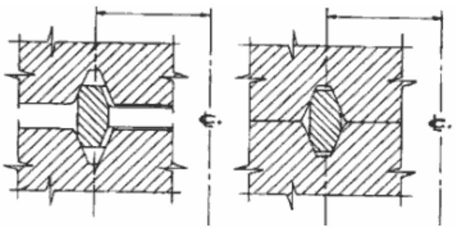
The face-to-face "RX" pressure-energized ring joint gasket



The gasket was adopted by API as the standard joint for clamp hubs. Sealing takes place along small bands of contact between the grooves and the OD of the gasket. The gasket is made slightly larger in diameter than the grooves, and is compressed slightly to achieve initial sealing as the joint is tightened.

Face-to-face contact between the hubs is ensured by an increased groove width, but this leaves the gasket unsupported on its ID. Without support from the ID of the grooves, the gasket may not remain perfectly round as the joint is tightened. If the gasket buckles or develops flats, the joint may leak.

Cameron's API face-to-face type "RX"

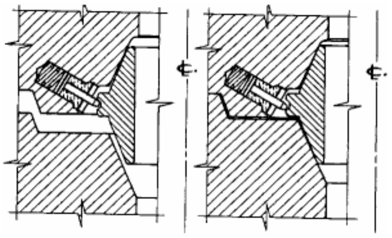


Cameron modified the API face-to-face type "RX" pressure-energized ring joint grooves to prevent any possible leaking caused by the buckling of the gasket in the API groove.

The same API face-to-face type "RX" pressure-energized ring joint gaskets are used with these modified grooves. Sealing takes place along small bands of contact between the grooves and the OD of the gasket. The gasket is made slightly larger in diameter than the grooves, and is compressed slightly to achieve initial sealing as the joint is tightened.

The gasket ID will also contact the grooves when it is made up. This constraint of the gasket prevents any possible leaking caused by the buckling of the gasket. Hub face-to-face contact is maintained within certain tolerances. The maximum theoretical standoff from the stack up of the tolerances of the gasket and the groove is 0.022 inches. Ref: X-23325-1

The "AX" pressure-energized ring joint gasket was developed by Cameron.

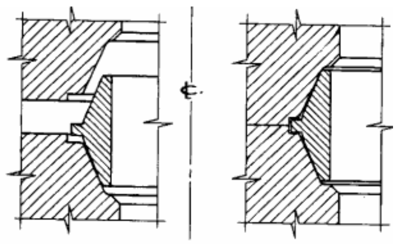


Sealing takes place along small bands of contact between the grooves and the OD of the gasket. The gasket is made slightly larger in diameter than the grooves and is compressed slightly to achieve initial sealing as the joint is tightened.

The ID of the gasket is smooth and is almost flush with the hub bore. Sealing occurs at a diameter which is only slightly greater than the diameter of the hub bore, so the axial pressure load on the collets connector is held to an absolute minimum. The belt at the centre of the gasket keeps it from buckling or cocking as the joint is being made up. The OD of the gasket is grooved. This allows the use of retractable pins or dogs to positively retain the gasket in the base of the collets connector when the hubs are separated.

The gasket design allows face-to-face contact between the hubs to be achieved with minimal clamping force. External loads are transmitted entirely through the hub faces and cannot damage the gasket.

The "CX" pressure-energized ring joint gasket was developed by Cameron.



Sealing takes place along small bands of contact between the grooves and the OD of the gasket. The gasket is made slightly larger in diameter than the grooves, and is compressed slightly to achieve initial sealing as the joint is tightened.

The gasket is patterned after the "AX" gasket, but is recessed, rather than being flush with the hub bore for protection against key-seating. The gasket seals on approximately the same diameter as do the "RX" and "BX" gaskets. The belt at the centre of the gasket keeps it from buckling or cocking as the joint is being made up.

Since the "CX" gasket is protected from key-seating, it is suitable for use throughout the BOP and riser system, except at the base of the collets connector. The gasket design allows face-to-face contact between the clamp hubs or flanges to be achieved with minimal clamping force. External loads are transmitted entirely through the hub faces and cannot damage the gasket.

Notes

Both the "AX" and "CX" pressure-energized ring gaskets allow face-to-face contact between the hubs to be achieved with minimal clamping force.

The "AX" gasket is used at the base of the collets connector, since the lower gasket must be positively retained in the connector when the hubs are separated.

The "AX" design ensures that axial pressure loading on the collets connector is held to an absolute minimum.

The "AX" gasket also is suitable for side outlets on the BOP stack since these outlets are not subject to key-seating.

The "CX" gasket is recessed for protection against key-seating.

The "CX" gasket is suitable for use throughout the BOP and riser system, except at the base of the collets connector.